

Utilities Consumers' Group (UCG)

1 **TOPIC: General Requests**

2
3 **QUESTION:**

4
5 a) Identify all persons (in-house and consultants) who have worked on this application
6 to date and cost for each person.

7
8 b) Explain what measures Yukon Energy took to simplify this rate application to lower
9 the costs of regulation and lessen the reliance for outside lawyers and consultants
10 to deliberate our future.

11
12 c) Give the updated estimated costs for this 2021 GRA.

13
14 **ANSWER:**

15
16 **(a), (b) and (c)**

17
18 A very wide range of YEC staff and management, along with InterGroup Consultants, have
19 worked to date on the Application, including responding to IRs. Updated estimated costs
20 and costs by person are not readily available and will be provided to the extent required
21 when the proceeding is concluded and the Board reviews cost submissions.

22
23 To the extent GRA preparation cost information is readily available it is provided in the
24 response to UCG-YEC-1-104.

25
26 In an effort to simplify this rate application and lower costs of regulation, YEC in this
27 Application separated clearly capital projects that remain in WIP and therefore are not
28 relevant to the 2021 test year revenue requirement in order to help the Board and
29 intervenors reduce IR and other related costs on matters not of priority at this time.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: YUB Rules of Practice October 17, 2012**

4
5 Response to information requests

6 14. (1) Subject to subsection (3) where an information request has been directed to a party
7 and served on that party in accordance with the Board's directions, the party shall prepare
8 a response that:

9 a) repeats each question in the information request,

10 b) provides full and adequate response to each question, and

11 c) identifies the individual or individuals who were responsible for preparing the response

12
13 **QUESTION:**

14
15 a) Please be certain to identify each response with the individual/s who prepared it.

16
17 **ANSWER:**

18
19 **(a)**

20
21 The requested information cannot be practically or reasonably provided at an individual
22 level.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: Yukon Energy 2021 Rate Application**

4
5 **QUESTION:**

6
7 a) Please provide details of all customer and stakeholder consultations conducted by
8 Yukon Energy Corporation during development of this application prior to
9 submitting it to the YUB.

10
11 b) Please provide specific details on how YEC's customers were informed of
12 proposals being considered for inclusion in the application and how input from
13 customers was used to develop details of the application.

14
15 c) Please provide all documentation related to issues discussed during these
16 consultations and a list of all parties involved in the consultations.

17
18 d) Please identify how and when the leadership / Board of YEC approved the General
19 Rate Application as provided to the YUB. Please identify the dates on which these
20 approvals were provided.

21
22 **ANSWER:**

23
24 **(a) to (c)**

25
26 YEC did not conduct customer or stakeholder consultations during development of the
27 application prior to the filing.

28
29 **(d)**

30
31 The Board of Directors of YEC approved filing of the application by normal resolution at a
32 meeting in October 2020.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application page 1**

4
5 YEC states "Pursuant to the Order in Council (OIC) 1995/90 (as amended by 2018/220)
6 direction, the Board must ensure until the end of 2018 that rate adjustments for retail
7 customers and major industrial customers apply equally, when measured as percentages,
8 to all classes of retail customers and to the class of major industrial customers.
9 Consequently, for both 2017 and 2018, all proposed rate adjustments for retail customers
10 and industrial customers apply equally, as percentages".

11
12 **REFERENCE: Board Order 2010-13, Appendix A – Reasons for Decision**

13
14 "Therefore, the Board directs the Companies to file a joint COS study within six months of
15 the expiry of OIC 2008/149. The Board further directs the Companies to incorporate all
16 findings and directions of this Decision into the next COS study."

17
18 **QUESTION:**

19
20 a) Since the OIC 2008/149 expired at the end of 2018, please confirm the above
21 Board direction was accomplished. If not, why not?

22
23 b) Please explain what Yukon Energy plans to do about following Board directions
24 and orders?

25
26 **ANSWER:**

27
28 The reference provided to November 2020 Application page 1 does not appear to be
29 correct. Page 1 of the Application notes:

30
31 Pursuant to the Order in Council (OIC) 1995/90 direction (as amended by OIC
32 2018/220), the Board must ensure that rate adjustments for retail customers and
33 major industrial customers apply equally, when measured as percentages, to all
34 classes of retail customers and to the class of major industrial customers.
35 Consequently, all proposed 2021 rate adjustments for retail customers and
36 industrial customers apply equally, as percentages.

1 As detailed below the relevant provisions of OIC 2008/149 remain in effect.

2
3 The direction outlined in OIC 2008/149 was extended by OIC 2012/68. Insofar as it affects
4 all classes of retail customers, this direction in effect extended the earlier Section 2.1(1)
5 direction in OIC 2008/149 until December 31, 2013; and ensured that the same
6 percentage rate adjustments will also apply to the class of major industrial customers.¹
7 This direction was extended by OIC 2014/23, and OIC 2018/220 removed subsection
8 2.1(3) which established an expiry date for Section 2.1. With this change, the provisions
9 of Section 2.1(1) currently remain in effect without any expiry date.

10
11 See Tab 4, page 4-7 and 4-8 and Tab 6, page 6-1.

12
13 **(b)**

14
15 In Order 2013-01 the Board provided a series of directives related to the Cost of Service
16 Study as filed by the Companies noting that it “[did] not accept the COS study as filed by
17 the Companies”, “an updated COS study approved by the Board is essential to
18 establishing a future rate restructuring process” and directed the Companies to “file a joint
19 COS study within six months of the expiry of OIC 2008/149” that “incorporate[s] all findings
20 and directions of the decision.”

21
22 The provisions of Section 2.1(1) currently remain in effect without any expiry date, and
23 provide that material rate design changes that would result in rebalancing of rates between
24 different customer classes cannot be undertaken at this time. The remaining outstanding
25 directives in Order 2010-13 will be addressed in the next joint cost of service and rate
26 design application.

¹ Subject to certain provisions noted in Tab 4, Section 4.4 of the 2021 GRA.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application page 2**

4
5 YEC states: "This GRA addresses a difficult situation, Yukon Energy's actual ROE has
6 continued to fall well short of the 2018 approved ROE, and a new GRA is required to
7 address ongoing revenue shortfalls."
8

9 **QUESTION:**

- 10
11 a) Please provide details of any measures since the last 2017/18 GRA that have been
12 taken to manage Yukon Energy's ongoing welfare.
13
14 b) Did Yukon Energy attempt any debt re-negotiation with Yukon Development
15 Corporation (YDC) or any Promissory Note's flexible debt re-financing provisions
16 to help alleviate some pressure. If not, why not?
17
18 c) Did YDC make any contributions that reduced project costs to be recovered from
19 ratepayers? If yes, explain what for and how much.
20
21 d) Are there any secondary sales revenues or other related revenues forecast for
22 2021? If not, what will YEC do with any revenues if these circumstances change?
23
24 e) Were there any adjusted thermal fuel costs recouped from the Diesel Contingency
25 Fund operation or the implementation of the Whitehorse Diesel-Natural Gas
26 Conversion Project (LNG Project or LNG Plant project).
27
28 f) Please provide specific details YEC realized to:
29 i. reduce ongoing costs?
30 ii. reduce waste?
31 iii. improve performance?
32
33 g) Please provide steps YEC has taken to date to study and consider a performance-
34 based regulation mechanism, including earnings sharing.

1 **ANSWER:**

2
3 **(a)**

4
5 The Application describes measures and actions being undertaken by YEC to ensure its
6 ongoing viability and fiscal health.

7
8 **(b)**

9
10 No. Refinancing of YDC debt is undertaken when options exist to reduce existing interest
11 rates, in order to reduce debt costs. No such options were available in 2020 when the
12 GRA was being prepared.

13
14 **(c)**

15
16 No.

17
18 **(d)**

19
20 Per Tab 2, Table 2.1 there are no secondary sales revenues forecast for 2021. As noted
21 in Tab 2, page 2.2 of the Application, YEC will update 2021 test year forecasts in the
22 compliance filing if any secondary sales are expected to occur in 2021 as a result of
23 surplus water availability.

24
25 **(e)**

26
27 It is not clear what this question is addressing. The DCF no longer exists. The Application
28 details operation of the LNG facilities.

29
30 **(f)**

31
32 Please see the Application, Tab 3 for details on YEC operations.

33
34 **(g)**

35
36 In UCG-YEC-1-19(c) from the 2008/09 GRA, Yukon Energy addressed this UCG
37 concept as follows:

1 As noted in response UCG-YEC-1-32 provided during the 2005 Required
2 Revenues and Related Matters proceeding, a multi-year performance based
3 regulatory framework is not currently in place in Yukon. Implementing this form of
4 regulation would likely require significant changes to the regulatory framework in
5 the Yukon that have not yet been assessed. Yukon Energy has not assessed
6 measures that the Yukon Government might adopt to bring in legislation or policy
7 related to performance-based regulation.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application page 2**

4
5 YEC states: "Yukon Energy has developed an approach to enable a rate adjustment for
6 the 2021 test year to address YEC's financial requirements without any material change
7 in customer bills."
8

9 **REFERENCE: November 2020 Application, page 4**

10
11 YEC states: "In accordance with OIC 1995/90 direction, the Application proposes that
12 Yukon Energy revenue shortfall for the test year be recovered through a Rider J increase
13 of 15.01 percentage points in 2021 applicable to all YEC and AEY retail firm customers
14 and all major industrial firm rates. This Rider J increase results in an overall increase in
15 existing rates (excluding existing Rider J1 true-up and Rider F) of 11.54% for 2021.
16

17 **QUESTION:**

- 18
19 a) Please explain this second reference in simple laymans language as it is massively
20 confusing. How can YEC exclude/deduct true-up and rider F from your requested
21 revenue requirement increase? Why would they not simply come off our bills when
22 paid off?
23
24 b) Please confirm the YEC is requesting a 15.01 per cent increase for the 2021 test
25 year. Explain.
26
27 c) As YEC proclaims in the first reference that there will not be any material change
28 in the customer bills, please explain how the expected reduction of the fuel Rider
29 F will offset the requested increase for the proposed interim request, i.e. give the
30 amount of Rider F reduction (as a percentage) expected and how this matches
31 with the proposed interim rider of 10.08% increase requested?
32
33 d) Please give the amount of the true-up Rider as a percentage that YEC claims will
34 offset the 15.01% increase slated for December 1, 2021 final rates.

1 e) Does YEC plan to reintroduce a Rider F charge after the first quarter of January,
2 2022 or when/if the price of diesel fluctuates from the rate hearing decision price?
3 If yes how does the YEC propose this will keep bills from material changes?

4
5 f) Please provide detailed calculations of the total bill impacts for non-government
6 residential customers (including customer charges, energy charges, all rate
7 riders), similar to format as Table 4.2A-3 (1000kWh.) for 500, 750, and 15000 kWh.
8 per month comparing bills from Jan /2018 to Dec/2021.

9
10 g) Please provide detailed calculations of the total bill for non-government general
11 service customers (including demand charges, energy charges, all rate riders)
12 similar to Table 4.2A-4 (2000kWh.) for 1500, 2500 and 3000 kWh. per month
13 comparing bills from Jan 2018 to Dec/2021.

14
15 **ANSWER:**

16
17 **(a)**

18
19 The referenced paragraph meant to clarify that the required rate increase for the 2021
20 GRA at 11.54% results in an increase of 15.01% to Rider J as this rider only applies to the
21 existing base rates [i.e., does not apply to riders].

22
23 Rider F and Rider J1 are not part of YEC's revenue requirement as they do not relate to
24 the 2021 test year costs.

- 25
26 • YEC's Rider J1 is related to YEC's 2017-18 GRA shortfall true-up which is in effect
27 until the earlier of November 30, 2021, or at such earlier month end when the
28 \$12.557 million shortfall has been recovered.

- 29
30 • Rider F relates to Fuel Price Variance Account that reflects fuel price variances for
31 both YEC and AEY.

32
33 **(b)**

34
35 Not confirmed. Please see response to (a).

36
37 The rate increase is 11.54%, while 15.01% is an increase to Rider J.

1 (c)

2
3 Effective July 1, 2021, the Rider F rider is expected to be set to approximate zero which
4 reduces the average residential monthly bill for 1,000 kW.h energy consumption by \$13.71
5 [6.7% of monthly bill].
6

7 The proposed interim increase in Rider J by 10.08% would increase the monthly bill by
8 the same amount [\$13.71 or 6.7% of monthly bill]. The increase in bills for interim rates
9 will be offset by reduction in Rider F resulting in no change in customer bills for that usage
10 level.
11

12 (d)

13
14 Effective December 1, 2021, Rider J1 expires which reduces the average residential
15 monthly bill for 1,000 kW.h energy consumption by \$12.58 [6.2% of monthly bill].
16

17 The expected increase in Rider J by 4.93% [15.01% total increase less 10.08% interim
18 increase] would increase the monthly bill by \$6.71. However, a new true-up rider is
19 required to collect 2021 GRA shortfalls which is estimated to be about \$6.59/month for
20 1,000 kW.h consumption for residential customers. This leads to a total bill increase at
21 \$13.30/month or 6.5% of monthly bill.
22

23 The increase in bills from the 2021 GRA is almost fully offset by the referenced reductions
24 in bills, therefore, the expected bill impact by December 1, 2021 is 0.4%.
25

26 The increase in bills for interim rates will be offset by a reduction in Rider F resulting in no
27 change in customer bills for that usage level.
28

29 (e)

30
31 YEC does not “plan” Rider F adjustments; adjustments are driven by changes in the
32 market value of fuel. Additionally, Rider F for the first quarter of 2022 will depend on the
33 balance in the Fuel Price Variance Account that reflects fuel price variances not only for
34 YEC but also of AEY. Therefore, YEC cannot provide what Rider F would be in 2022.

- 1 **(f) and (g)**
- 2
- 3 Please see UCG-YEC-1-6 Attachment 1.

Table 1
Yukon Bills– Existing vs. Proposed - Non-Government Residential 500 kW.h/monthly Energy Consumption
(prior to consideration of subsidies, rebates and taxes)

Line #	Customer Use per month:												YEC's 2021 GRA			
	500 kWh		Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		Jul-21		Dec-21	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
Base Rates																
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)		\$0.1214	\$60.70	\$0.1214	\$60.70	\$0.1214	\$60.70	\$0.1214	\$60.70	\$0.1214	\$60.70	\$0.1214	\$60.70	\$0.1214	\$60.70
3=KWh*Base rate	Second Block Energy (kWh)															
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		-\$0.000110	-\$0.06	-\$0.000110	-\$0.06	-\$0.000110	-\$0.06	\$0.009700	\$4.85	\$0.013710	\$6.86	\$0.0	\$0.00	\$0.0	\$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		16.51%	\$12.44	16.51%	\$12.44	22.32%	\$16.82	22.32%	\$16.82	22.32%	\$16.82	32.40%	\$24.41	37.33%	\$28.13
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			\$0.00		\$0.00	9.25%	\$6.97	9.25%	\$6.97	9.25%	\$6.97	9.25%	\$6.97	4.84%	\$3.65
7=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-\$0.006800	-\$3.40	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00
8=(1+2+3)*Rider J rate	AEY Rider J (%)			\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
9=(1+2+3)*Rider R rate	AEY Rider R (%)		8.30%	\$6.25	8.30%	\$6.25	8.30%	\$6.25	8.30%	\$6.25	8.30%	\$6.25	8.30%	\$6.25	8.30%	\$6.25
10=Sum(1:9)	Total Before Tax Rebate, IER, GST			\$90.59		\$93.99		\$105.34		\$110.24		\$112.25		\$112.98		\$113.38

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

Table 2
Yukon Bills– Existing vs. Proposed - Non-Government Residential 750 kW.h/monthly Energy Consumption
(prior to consideration of subsidies, rebates and taxes)

Line #	Customer Use per month:											YEC's 2021 GRA					
	750 kWh		Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		Jul-21		Dec-21		
	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	
Base Rates																	
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	
2=KWh*Base rate	First Block Energy (kWh)		\$0.1214	\$91.05	\$0.1214	\$91.05	\$0.1214	\$91.05	\$0.1214	\$91.05	\$0.1214	\$91.05	\$0.1214	\$91.05	\$0.1214	\$91.05	
3=KWh*Base rate	Second Block Energy (kWh)																
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		-\$0.000110	-\$0.08	-\$0.000110	-\$0.08	-\$0.000110	-\$0.08	\$0.009700	\$7.28	\$0.013710	\$10.28	\$0.0	\$0.00	\$0.0	\$0.00	
5=(1+2+3)*Rider J rate	YEC Rider J (%)		16.51%	\$17.45	16.51%	\$17.45	22.32%	\$23.59	22.32%	\$23.59	22.32%	\$23.59	32.40%	\$34.24	37.33%	\$39.45	
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			\$0.00		\$0.00	9.25%	\$9.78	9.25%	\$9.78	9.25%	\$9.78	9.25%	\$9.78	4.84%	\$5.12	
7=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-\$0.006800	-\$5.10	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	
8=(1+2+3)*Rider J rate	AEY Rider J (%)			\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00	
9=(1+2+3)*Rider R rate	AEY Rider R (%)		8.30%	\$8.77	8.30%	\$8.77	8.30%	\$8.77	8.30%	\$8.77	8.30%	\$8.77	8.30%	\$8.77	8.30%	\$8.77	
10=Sum(1:9)	Total Before Tax Rebate, IER, GST			\$126.74		\$131.84		\$147.76		\$155.12		\$158.13		\$158.49		\$159.05	

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

**YUKON ENERGY CORPORATION
2021 GENERAL RATE APPLICATION
UCG-YEC-1-6 Attachment 1**

**Table 3
Yukon Bills— Existing vs. Proposed - Non-Government Residential 1,500 kW.h/monthly Energy Consumption
(prior to consideration of subsidies, rebates and taxes)**

Line #	Customer Use per month:		YEC's 2021 GRA													
			1,500 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		Jul-21		Dec-21
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
Base Rates																
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40
3=KWh*Base rate	Second Block Energy (kWh)	500	\$0.1282	\$64.10	\$0.1282	\$64.10	\$0.1282	\$64.10	\$0.1282	\$64.10	\$0.1282	\$64.10	\$0.1282	\$64.10	\$0.1282	\$64.10
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		-\$0.000110	-\$0.17	-\$0.000110	-\$0.17	-\$0.000110	-\$0.17	\$0.009700	\$14.55	\$0.013710	\$20.57	\$0.0	\$0.00	\$0.0	\$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		16.51%	\$33.04	16.51%	\$33.04	22.32%	\$44.67	22.32%	\$44.67	22.32%	\$44.67	32.40%	\$64.84	37.33%	\$74.71
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			\$0.00		\$0.00	9.25%	\$18.51	9.25%	\$18.51	9.25%	\$18.51	9.25%	\$18.51	4.84%	\$9.70
7=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-\$0.006800	-\$10.20	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00	\$0.0	\$0.00
8=(1+2+3)*Rider J rate	AEY Rider J (%)			\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
9=(1+2+3)*Rider R rate	AEY Rider R (%)		8.30%	\$16.61	8.30%	\$16.61	8.30%	\$16.61	8.30%	\$16.61	8.30%	\$16.61	8.30%	\$16.61	8.30%	\$16.61
10=Sum(1:9)	Total Before Tax Rebate, IER, GST			\$239.44		\$249.64		\$279.78		\$294.50		\$300.51		\$300.12		\$301.17

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

YUKON ENERGY CORPORATION
2021 GENERAL RATE APPLICATION
UCG-YEC-1-6 Attachment 1

Table 5
Yukon Bills– Existing vs. Proposed - Non-Government General Service 2,500 kW.h/monthly Energy Consumption, 10 kW Demand
(prior to consideration of subsidies, rebates and taxes)

Line #	First Block Energy Use - Customer Use per month:											YEC's 2021 GRA					
		2,500 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		Jul-21		Dec-21		
		10 kW															
		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill		
Base Rates																	
1	Demand Charge (per kW per month)	\$7.39	\$73.90	\$7.39	\$73.90	\$7.39	\$73.90	\$7.39	\$73.90	\$7.39	\$73.90	\$7.39	\$73.90	\$7.39	\$73.90		
2=KWh*Base rate	First Block Energy (kWh)	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00		
2a=KWh*Base rate	Second Block Energy (kWh)	\$0.1288	\$64.40	\$0.1288	\$64.40	\$0.1288	\$64.40	\$0.1288	\$64.40	\$0.1288	\$64.40	\$0.1288	\$64.40	\$0.1288	\$64.40		
3=KWh*Rider F rate	Rider F (kW.h)	-\$0.00011	-\$0.28	-\$0.00011	-\$0.28	-\$0.00011	-\$0.28	\$0.00970	\$24.25	\$0.01371	\$34.28	\$0.00000	\$0.00	\$0.00000	\$0.00		
4=(1+2)*Rider J rate	YEC Rider J (%)	16.51%	\$55.85	16.51%	\$55.85	22.32%	\$75.51	22.32%	\$75.51	22.32%	\$75.51	32.40%	\$109.60	37.33%	\$126.28		
5=(1+2)*Rider J1 rate	YEC Rider J1 (%)	9.25%	\$31.29	9.25%	\$31.29	9.25%	\$31.29	9.25%	\$31.29	9.25%	\$31.29	9.25%	\$31.29	4.84%	\$16.39		
6=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]	-\$0.00680	-\$17.00	\$0.00000	\$0.00	\$0.00000	\$0.00	\$0.00000	\$0.00	\$0.00000	\$0.00	\$0.00000	\$0.00	\$0.00000	\$0.00		
7=(1+2)*Rider J rate	AEY Rider J (%)		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		
8=(1+2)*Rider R rate	AEY Rider R (%)	8.30%	\$28.08	8.30%	\$28.08	8.30%	\$28.08	8.30%	\$28.08	8.30%	\$28.08	8.30%	\$28.08	8.30%	\$28.08		
9=Sum(1:8)	Total Before Tax Rebate, GST		\$404.96		\$421.96		\$472.91		\$497.43		\$507.46		\$507.27		\$509.04		

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

**YUKON ENERGY CORPORATION
2021 GENERAL RATE APPLICATION
UCG-YEC-1-6 Attachment 1**

**Table 6
Yukon Bills– Existing vs. Proposed - Non-Government General Service 3,000 kW.h/monthly Energy Consumption, 12 kW Demand
(prior to consideration of subsidies, rebates and taxes)**

Line #	First Block Energy Use - Customer Use per month:											YEC's 2021 GRA					
	3,000 kWh		Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		Jul-21		Dec-21		
	12 kW																
		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill		
Base Rates																	
1	Demand Charge (per kW per month)	\$7.39	\$88.68	\$7.39	\$88.68	\$7.39	\$88.68	\$7.39	\$88.68	\$7.39	\$88.68	\$7.39	\$88.68	\$7.39	\$88.68		
2=KWh*Base rate	First Block Energy (kWh)	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00	\$0.1000	\$200.00		
2a=KWh*Base rate	Second Block Energy (kWh)	\$0.1288	\$128.80	\$0.1288	\$128.80	\$0.1288	\$128.80	\$0.1288	\$128.80	\$0.1288	\$128.80	\$0.1288	\$128.80	\$0.1288	\$128.80		
3=KWh*Rider F rate	Rider F (kW.h)	-\$0.00011	-\$0.33	-\$0.00011	-\$0.33	-\$0.00011	-\$0.33	\$0.00970	\$29.10	\$0.01371	\$41.13	\$0.00000	\$0.00	\$0.00000	\$0.00		
4=(1+2)*Rider J rate	YEC Rider J (%)	16.51%	\$68.93	16.51%	\$68.93	22.32%	\$93.18	22.32%	\$93.18	22.32%	\$93.18	32.40%	\$135.25	37.33%	\$155.83		
5=(1+2)*Rider J1 rate	YEC Rider J1 (%)	9.25%	\$38.62	9.25%	\$38.62	9.25%	\$38.62	9.25%	\$38.62	9.25%	\$38.62	9.25%	\$38.62	4.84%	\$20.22		
6=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]	-\$0.00680	-\$20.40	\$0.00000	\$0.00	\$0.00000	\$0.00	\$0.00000	\$0.00	\$0.00000	\$0.00	\$0.00000	\$0.00	\$0.00000	\$0.00		
7=(1+2)*Rider J rate	AEY Rider J (%)		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		
8=(1+2)*Rider R rate	AEY Rider R (%)	8.30%	\$34.65	8.30%	\$34.65	8.30%	\$34.65	8.30%	\$34.65	8.30%	\$34.65	8.30%	\$34.65	8.30%	\$34.65		
9=Sum(1:8)	Total Before Tax Rebate, GST		\$500.33		\$520.73		\$583.60		\$613.03		\$625.06		\$626.00		\$628.18		

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application, page 2**

4
5 YEC states: "The 2021 GRA approach will also work to prevent rate and bill instability
6 beyond 2021, and reduce rate increase requirements for subsequent GRA."

7
8 **QUESTION:**

9
10 a) Please explain exactly how the YEC proposes to accomplish this broad statement.

11
12 b) Please explain how the YEC will guarantee its' trust to ratepayers that YEC will
13 follow through with this statement. Or does this mean that instead of 20% increase
14 next application, you will only need 15 per cent yet again? Or is this just another
15 statement like 'other rates will go down when we connect the mines'?

16
17 **ANSWER:**

18
19 **(a)**

20
21 See discussion provided in Tab 1, Page 1-3 and 1-4, as well as Tab 4, pages 4-9 to 4-11.

22
23 **(b)**

24
25 As noted in Tab 1, a new GRA is overdue to enable Yukon Energy to address serious
26 ongoing revenue shortfalls, and further delay in adjusting rates will have material
27 implications for the financial integrity of the corporation. Further delay in implementing rate
28 changes beyond 2021 would result in a material decrease in customer bills in 2021 when
29 Rider F is reduced and the 2017-18 YEC GRA true-up comes off, followed by a later and
30 more material increase in customer bills in 2022 or thereafter (at the time of the next GRA).

31
32 Yukon Energy has in its application outlined an approach to resolve outstanding revenue
33 shortfall issues in 2021 without materially disrupting customer bills. Success will depend
34 on completing the regulatory process on a timely basis, and implementing interim and final
35 rates as outlined in the Application.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application, page 4. Summary of Requests #1**

4
5 YEC states it requests “approval of a forecast revenue requirement of \$75.135 million for
6 2021.

7
8 **QUESTION:**

9
10 a) Please confirm that the YUB approved revenue requirements were \$48.544 million
11 for 2017 and \$49.864 million for 2018.

12
13 b) Please explain, in layman's language, why an increase of \$25 million or 50% since
14 the last GRA (in three years) should be acceptable to your ratepayers.

15
16 c) Please provide a chart showing approved revenue requirement amounts for all
17 GRA years since YEC took control of Management in 1998.

18
19 **ANSWER:**

20
21 **(a)**

22
23 Not confirmed. The numbers noted were the revenue requirements in the 2017-2018 GRA
24 filing. The approved revenue requirement was \$49.202 million for 2017 and \$49.794
25 million for 2018 (see Order 2019-08 approving Yukon Energy’s second compliance filing).

26
27 **(b)**

28
29 Most of the forecast \$25 million increase in revenue requirement as referenced is
30 increased sales funded fully at existing rates. The forecast 2021 revenue shortfall to be
31 recovered through increased rates is \$10.971 million (see Table 4-1).

32
33 The forecast 2021 revenue requirements primarily reflect proposed adjustments to thermal
34 generation requirements (due to increased loads) and fuel prices (beyond YEC’s control),
35 changes to labour and non-labour costs, changes to depreciation resulting from a
36 depreciation study provided as directed, and the impact of increases in rate base relative
37 to 2018 approved numbers, the last test year reviewed by the Board during Yukon

1 Energy's 2017/2018 GRA application. Details on the basis for each area of cost increase
2 are specified in Tab 3 of the Application. These are costs required to be incurred for
3 ongoing operation of the utility.

4

5 **(c)**

6

7 The request is unreasonably broad and not directly relevant to the current proceeding.
8 YEC has therefore not provided the requested chart.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application Tab.1-7

1.3 CHANGES IN FORECAST LOADS

The 2021 load forecast is about 28% higher than the 2018 approved forecast. As noted in Table 1-2, revenues from higher loads are largely offset by increases in fuel costs. Higher non-industrial loads also result in capacity shortfalls that must be addressed and that are driving both capital and O&M cost increases.

Test year forecasts for 2021 reflect the following:

Wholesale Load – Actual 2018 (332.3 GWh) 17.6 GWh higher than approved forecast (314.7 GWh); firm wholesales for 2021 are forecast at 343.5 GW.h.

Industrial Load – Actual 2018 industrial load exceeded approved forecast (36.9 GWh vs 32.2 GWh). Forecast firm Yukon Energy sales to industrial customers for the 2021 test year is 102.911 GW.h.

REFERENCE: November 2020 Application Tab1-7/8

Thermal Generation requirements are growing due to higher firm grid loads – The

2018 Compliance Filings approved a forecast of 16.4 GW.h for long-term average (LTA) thermal generation requirements to supply the 2018 forecast grid load of 420 GWh. The 2021 LTA forecast total firm generation load for the 2021 test year is 538.7 GW.h, compared to the 2018 approved load of 420.3 GWh.

thermal generation forecast is 184.3 GW.h for a forecast grid load 538.7 GW.h. The increased LTA thermal generation accounts for \$10.8 million of the 2021 GRA cost increases from the approved 2018 GRA (based on 2018 GRA approved fuel prices). These added LTA thermal generation costs due to load growth are more than fully recovered by the increased revenues (\$14.4 million) from the load growth.

QUESTION:

a) If increase revenues from higher loads are largely offset by increases in fuel costs, the reverse holds true in that fuel costs are largely offset by revenues from higher loads, why is Yukon Energy claiming a revenue shortfall of \$2.1 million in this application for fuel costs?¹

b) Please confirm Yukon Energy's policy approach through this application is to apply for forecast costs in fuel and purchased power; set the fuel rider in August to zero which basically offsets the requested interim rider (if the proposed fuel increase is accepted; and then rekindle Rider F at a latter [sic] date in 2022.

¹ Application November 2020, Page 3, Fuel Price Changes (19.4% of revenues shortfall).

1 c) Please confirm that the wholesale load is forecast to increase by 3.34% in 2021
2 from the 2018 Actual load.

3
4 d) Please confirm that industrial load is forecast to increase by 179% in 2021 from
5 the 2018 Actual load.

6
7 e) If this is indeed the case, why does Yukon Energy insist "that higher non-industrial
8 loads result in capacity shortfalls that must be addressed and that are driving both
9 capital and O&M cost increases"? Is it not the industrial loads that are mostly
10 driving these proposed increases?

11
12 f) What does Yukon Energy propose to do in this application to offset this blatant
13 discrimination demonstrated for firm wholesale ratepayers?

14
15 **ANSWER:**

16
17 **(a)**

18
19 As noted on page 3 of the Application, higher fuel prices account for \$2.1 million of the
20 2021 GRA revenue shortfall. See Tab 3, Section 3.2 of the Application.

21
22 **(b)**

23
24 Not confirmed.

25
26 As outlined in Tab 4, Section 4.5, the application is proposing that Rider J for 2021 of
27 32.40% for all firm non-industrial, and 28.75% for all firm industrial, be applied initially as
28 of July 1, 2021 as an interim refundable rate rider, equal to a 10.08 percentage point
29 increase in the existing Rider J rates for non-industrial and industrial rates [reflects about
30 67% of the total Rider J rate increase for 2021 in the current GRA].

31
32 July 1, 2021 is proposed as the effective date for the interim rates to reduce customer bill
33 volatility. The current Rider F rider is forecast to be reduced effective July 1, 2021, and
34 the Rider J 10.08% is set only to offset the Rider F reduction based on estimate for a 1,000
35 kW.h/month residential customer consumption with Rider F assumed to approximate zero
36 as at July 1, 2021.

1 The GRA will re-set forecast fuel prices (driven in particular by higher natural gas price)
2 such that Rider F going forward will now be based off updated fuel prices. YEC does not
3 control actual diesel or natural gas prices, and therefore does not control future Rider F
4 changes after mid 2021. Rider F will continue to apply, providing rate adjustments (down
5 or up) depending on changes to fuel prices relative to the 2021 GRA updated forecast
6 prices.

7
8 **(c)**

9
10 Per Tab 2, Table 2.1, the 2021 wholesale load is forecast to increase by 3.39% over the
11 2018 Actual load.

12
13 **(d)**

14
15 Confirmed.

16
17 **(e) and (f)**

18
19 See response to UCG-YEC-1-10 (a), (b) and (d). Industrial loads are not driving the
20 capacity shortfalls noted in the question, as industrial loads are excluded from the
21 determination of the N-1 dependable capacity shortfall.

22
23 Industrial loads are contributing to other cost requirements – however, many of the non-
24 fuel O&M and capacity cost requirements are not linked clearly to grid load requirements,
25 e.g., sustaining capital requirements, increased labour requirements, etc.

26
27 There is no basis for any suggestion of discrimination in favour of any group of customers.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: Application November 2020, Page 3**

4
5 **Energy & Peak Load Changes (8.4% of revenue shortfall):** Dependable capacity
6 requirements caused by peak load growth for non-industrial sales drives diesel rental
7 costs that account for \$3.8 million (34.9%) of the 2021 GRA revenue shortfall. Higher
8 overall loads provide increased revenues at existing rates (\$14.4 million) that reduce the
9 2021 revenue shortfall by \$2.9 million after considering load-related cost impacts of \$10.8
10 million for increased long-term average thermal generation fuel cost requirements at 2018
11 GRA fuel prices (to address added energy generation) and \$0.7 million for increased Mayo
12 B Promissory Note interest due to higher loads.

13
14 **QUESTION:**

- 15
16 a) Does this above statement mean that if dependable capacity for peak load growth
17 for non-industrial sales is needed (i.e. running of diesels or LNG) that the industrial
18 loads will be temporarily discontinued during peak time frames? In other words are
19 the mines on SCADA disconnect during peak loads requiring the usage of our
20 rental diesels?
21
22 b) If not, why does Yukon Energy state that it is “dependable capacity requirements
23 caused by peak load growth for non- industrial sales” which drives this cost?
24
25 c) Please confirm the Mayo B Promissory Note is to Yukon Development
26 Corporation.
27
28 d) Should it not be the government/YEC (through edicts and OICs and PPAs) that
29 takes fiscal responsibility for increased mine loads driving such rate increases
30 rather than recouping this from the firm ratepayers through this rate application?

1 **ANSWER:**

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

4
5 The diesel rental units are required to meet the N-1 dependable capacity criterion. The N-
6 1 criterion does not include consideration of major industrial customer loads as these loads
7 typically maintain sufficient on-site diesel for their own emergency purposes.

8
9 Industrial loads are not discontinued during peak periods – the referenced quote is
10 focused on the requirements to ensure sufficient capacity to meet the N-1 criterion.

11
12 As reviewed in various past YUB proceedings, including PPA proceedings for new
13 industrial loads, there is no basis for asserting that industrial loads are driving rate
14 increases.

15
16 **(c)**

17
18 See response to UCG-YEC-1-22.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: Application November 2020**

4
5 Section 6.1 of OIC 1995/90 requires the Board to ensure that rates charged to major
6 industrial customers are sufficient to recover the cost of service to that customer class.

7
8 **REFERENCE: YEC 2003-04 Rate Hearing Transcripts p.649**

9
10 Mr. Morrison: "Customers are customers, load is load. And we don't attribute specific
11 diesel costs to different customers.

12
13 **QUESTION:**

- 14
15 a) Please reconcile the above underlined statements, if YEC cannot differentiate what
16 the specific diesel costs are to serve each individual mine, how can YEC guarantee
17 your regulator that you are adhering to the above OIC.

18
19 **ANSWER:**

20
21 **(a)**

22
23 The referenced OIC direction addresses "cost of service" which includes all relevant costs
24 (including all historic costs in rate base) allocated to customer classes based on specific
25 rules and procedures. The OIC quote has nothing to do with whether YEC is capable of
26 attributing specific diesel costs to different customer classes, let alone specific customers.

27
28 All cost of service studies provided to date to the Board have confirmed that rates charged
29 to major industrial customers as a class continue to recover the cost of service to that
30 customer class, calculated on a Yukon-wide basis as required under OIC 1995/90.

31
32 The costs to serve added major industrial customers have also been reviewed by the
33 Yukon Utilities Board (YUB) during the review of Power Purchase Agreements (PPA) with
34 industrial customers. Board reports from these proceedings have not shown any basis for
35 asserting that these customers are driving rate increases.

1 New industrial customers cover the costs to negotiate and conclude the PPA and
2 incremental costs for connection and also make contributions towards existing and new
3 transmission.

4
5 Specifically, YUB in Appendix A to the Order 2018-04 paragraph 26 stated the following:
6

7 Generally, in terms of customer contributions for capital costs, the Board has
8 previously stated the following:
9

10 The incremental costs (spur costs) for connections to existing or new
11 transmission facilities should be completely borne by the industrial
12 customer.
13

14 Further, the Board agrees with the principle that industrial customers
15 should make a contribution towards an appropriate share of new or to
16 existing bulk transmission.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: Application November 2020, Tab 1-9**

4
5 **Defined Benefit Pension Deferral Account:** In this Application Yukon Energy is requesting
6 approval of defined benefit pension plan deferral account that captures variances in contributions
7 to the defined benefit pension plan from the cost included in the test year revenue requirements
8 as a result of the required annual actuarial evaluations. A similar deferral account was approved
9 for AEY by Board Order 2014-06.

10
11 **QUESTION:**

- 12
13 a) Please explain how this affects the revenue requirement for this application and if
14 it does by how much in dollars and percentage?

15
16 **ANSWER:**

17
18 **(a)**

19
20 The proposed Defined Benefit Pension Plan Deferral Account does not impact 2021 GRA
21 revenue requirements, but captures variances in contributions to the defined benefit
22 pension plan between the test years. For example, if the actual contributions for 2021 or
23 after vary from the amount included in the 2021 test year [or future test year forecasts]
24 then the variance is included in the deferral account. The deferral account balance then
25 will be dissolved based on YUB Order in the future GRAs.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: Application November 2020, Tab 1-8/9**

4
5 **VGC Group and Alexco Fixed Charge:** Rate Schedule 39 as currently approved includes a
6 22 Fixed Charge for VGC Group and for Alexco of \$8,402/ month, subject to amendment from time
7 23 to time, including provision for allocation of the Fixed Charge between VGC Group and Alexco in
8 24 years when both customers are Major Industrial Customers of YEC.6 As reviewed in Appendix 4.3
9 25 of this Application, YEC expects to file with the Board in late November/ early December 2020 for
10 26 approval of an amended Transmission Facilities Fixed Cost effective January 1, 2021 of \$428,812,
11 resulting in an
12 1 interim Fixed Charge (85% of the Transmission Facilities Fixed Cost) effective
13 2 January 1, 2021 of \$35,734 per month, with allocation of the interim Fixed Charge between VGC
14 3 Group and Alexco [Table 4.3-2, Appendix 4.3 of this Application]. Aside from changes related to
15 4 the 2021 GRA, a final Fixed Charge for 2021 would occur after 2021 year end as required to
16 5 reflect final actual Transmission Facilities Fixed Cost and the actual MWh energy sales in 2021
17 6 that occurred to VGC Group and Alexco.

18
19 **QUESTION:**

- 20
21 a) Since Alexco came on line again in November 2020, and it is obvious that Yukon
22 Energy had this amendment to the agreement already to go, why did YEC not
23 include this Filing with this application to reduce the revenue requirement as well
24 as regulatory costs for another process?
25
26 b) Will the firm ratepayer benefit from this Alexco agreement amendment in this 2021
27 rate application?
28
29 c) If yes, please show where and how in the application this adjustment is included.
30
31 d) If no, please explain why not?
32
33 e) Will Alexco be responsible for any of the transmission line and sub-station
34 contribution costs to lower the rate base cost?
35
36 f) If not, why not.

1 **ANSWER:**

2
3 **(a) through (f)**

4
5 The Fixed Charge provision referenced in the quote is set to recover the defined
6 Transmission Facilities Fixed Cost, which amount is allocated as directed between major
7 industrial customers using the defined Transmission Facilities. The applicable
8 Transmission Facilities Fixed Cost amount did not change when Alexco once again
9 became a major industrial customer – only the allocation of this amount between VGC
10 Group and Alexco changed. Accordingly, Alexco will be responsible for its share of the
11 Transmission Facilities Fixed Cost as approved by the Board from time to time.

12
13 The above quote also references YEC's planned filing for an amendment to the
14 Transmission Facilities Fixed Cost as required within 60 days after the Transmission
15 Facilities Development Operation Date. This amendment cannot be filed until the
16 Transmission Facilities Development Operation Date has occurred, which is now expected
17 to be in March 2021. This amendment will increase the Fixed Charge to be recovered from
18 VGC Group and Alexco. This application requirement exists separate from the 2021 GRA
19 application, and was therefore assumed not to be part of the 2021 GRA application.

TOPIC: Revenue Requirement Requests

REFERENCE: Application November 2020 Tab Table 3.3

Labour \$ 11,932 \$ 12,083 \$ 11,863 \$ 12,727 \$ 13,310 \$ 13,310
Production 1,799 3,300 3,935 4,876 5,978 5,978
Transmission 1,419 1,058 1,304 1,403 1,394 1,394
Distribution 535 449 293 536 491 491
General O&M 1,219 1,395 1,530 1,352 1,391 1,391
Administration 3,001 3,016 3,365 3,491 3,858 3,858
Insurance and Reserve for
Injuries/Damages 1,510 1,525 1,596 1,778 1,902 2,259
Property Taxes 708 671 673 739 750 750
Total OM&A (Tab 7, Schedule 10) \$ 22,125 \$ 23,497 \$ 24,559 \$ 26,903 \$ 29,074 \$ 29,430

Forecast

5 Non-labour costs are forecast to increase by \$5.928 million in 2021 over 2018 approved costs. The 6 average annual compound increase in non-labour expenses is approximately 16.51% (2021 expenses 7 over 2018 approved) primarily due to \$3.834 million costs for diesel rentals required to meet the N-1 8 single contingency capacity planning criteria (no diesel rental costs were included in the 2018 approved 9 costs).

10 An increase in labour expense makes up \$1.378 million, or 19%, of the total \$7.306 million increase in 11 operating and maintenance expense forecast for 2021 over 2018 approved costs. The average annual 12 compound increase in labour expenses is approximately 3.71% (2021 expenses over 2018 approved).

3.3.1 Labour

14 Total labour expenditure is made up of labour expense for maintenance and administration and 15 capitalized labour. Capitalized labour is charged to capital projects and becomes part of revenue 16 requirement through annual depreciation charges incurred after in service. Maintenance and 17 administration labour expense is charged directly to revenue requirement. Total maintenance and 18 administration labour expense is forecast to be \$13.310 million in 2021 as compared to 2018 approved 19 costs of \$11.932 million, reflecting an increase of \$1.378 million.

QUESTION:

- a) Please breakdown expenditure amounts and reason for all non-labour forecast costs of \$5.928 minus the \$3.834 million diesel rentals; i.e \$2.094 million amount.
- b) According to Table 3.3 and line 10 above, Labour costs are forecast to increase by \$1.378 million or 11.5% since last GRA approval. Please breakdown all labour expenditures for maintenance and explain the need for each increase.
- c) Please breakdown all labour expenses for administration and explain the need for each increase.

1 d) According to Table 3.3 above, Administration costs are forecast to increase by
2 (Administration 3,001 3,016 3,365 3,491 3,858 3,858) \$0.857 million or 28.6%
3 since last GRA approval. Please give breakdown of all Administration costs and
4 reason for increase in each partitioning.

5
6 e) According to Table 3.3 above, According to Table 3.3 above, (Insurance and
7 Reserve for Injuries/Damages 1,510 1,525 1,596 1,778 1,902 2,259) costs are
8 forecast to increase by \$0.749 million or 50% since last GRA approval. Please give
9 details on why this reserve has increased this great amount since the last GRA
10 approval.

11
12 **ANSWER:**

13
14 **(a)**

15
16 Breakdowns of expenditures and reasons for all non-labour forecast costs are provided in
17 the Application, starting at section 3.3.2 (page 3-13) through 3.3.8 (page 3-20).

18
19 **(b) and (c)**

20
21 Breakdowns of expenditures for all labour forecast costs are provided in the Application,
22 starting at section 3.3.2 (page 3-13) through 3.3.8 (page 3-20). Reasons for the increase
23 are provided in the Application at section 3.3.1.

24
25 **(d)**

26
27 Breakdowns of expenditures for all Administration costs and reasons for the more
28 significant increases are provided in the Application, starting at section 3.3.6 (page 3-17).

29
30 **(e)**

31
32 Breakdowns of expenditures for all Insurance and Reserve for Injuries and Damages costs
33 and reasons for the increases are provided in the Application, starting at section 3.3.7
34 (page 3-18 to page 3-20).

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application Tab2-3**

4
5 21 Actual hydro generation in 2020 is forecast at 86.0% of grid generation, reflecting annual water
6 22 availability at about LTA. Current forecast hydro generation for 2021 is 94.0% of grid generation,
7 23 reflecting forecast water availability above LTA.

8
9 **QUESTION:**

10
11 a) What does this exactly mean, i.e. do you have the actual hydro generation for 2020
12 or is it forecast?

13
14 b) If not, please rephrase this to make it understandable.

15
16 **ANSWER:**

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

19
20 The “actual” hydro generation in the preamble refers to the hydro generation forecast to
21 occur based on expected water availability in 2020. This differs from the long-term average
22 generation which was used as the basis for thermal cost calculations.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application Tab2-12**

4
5 18 As indicated in Table 2.2, the peak demand for the integrated system is forecast to be 112.7 MW in 2021.
6 19 The actual peak demand was 93.0 MW in 2018, 90.0 MW in 2019 and 103.8 MW in 2020.

7
8 **QUESTION:**

9
10 a) Does this 112.7MW forecast peak demand for 2021 include the three mines now
11 on line? If not, please provide this mining peak load.

12
13 b) If this does include the mines, please breakdown the peak demand for firm
14 ratepayers and for industrial ratepayers.

15
16 **ANSWER:**

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

19
20 The peak forecast of 112.7 MW includes both non-industrial and industrial peak. The
21 forecast non-industrial peak for 2021 is 100.6 MW as noted on page 2-4 of the Application.
22 The remaining 12.1 MW is forecast industrial peak.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application Tab 2-13**

4
5 11 To address the severity of a potential
6 12 outage, Yukon Energy incorporated a second test – the N-1 standard which determines system
7 13 capacity assuming the loss of the system's single largest generating or transmission-related
8 14 generation resource. This standard does not include industrial loads as part of the assessment. It
9 15 ensures there is sufficient grid generation installed to meet firm residential and commercial
10 16 customers' loads when a failure occurs to the single largest system component

11
12 **QUESTION:**

13
14 a) Does this mean that the industrial loads are temporarily taken off the system until
15 the reason for a potential outage is fixed and normal hydro power is restored, i.e.
16 only firm customers are accommodated with the N-1 back-up supply?

17
18 b) If not, why not?

19
20 **ANSWER:**

21
22 **(a) and (b)**

23
24 The N-1 criteria does not include consideration of major industrial customer loads as these
25 loads typically maintain sufficient on-site diesel for their own emergency purposes and
26 therefore can be temporarily taken off the system during an emergency.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application Tab2-15**

4
5 In summary, under N-1, there is surplus of dependable capacity of approximately 1.25
6 MW in 2021. Without rented diesel units, the N-1 capacity shortfall would be 25.75 MW 567 in 2021.

7
8 **QUESTION:**

9
10 a) How much above the standard rental costs for the diesels, when they are being
11 used (i.e. is there a usage fee added to the stand-by rental? And how much?).

12
13 b) Please chart the operating-owned YEC diesels with capacity for each in
14 Whitehorse, Faro, Mayo, Dawson, Ross River, Teslin, Carmacks, Carcross,
15 Haines Junction, and any others.

16
17 c) Please chart the operating ATCO diesels in all their operating area on the grid with
18 each capacity.

19
20 d) Would we today require diesels on the integrated grid if the mines were not
21 operating (answer without peak load and with peak load)?

22
23 **ANSWER:**

24
25 **(a)**

26
27 Please see response to CW-YEC-1-17 (a) through (e).

28
29 **(b)**

30
31 Please see page 11 of 10-Year Renewable Electricity Plan provided in CW-YEC-1-36 (a)
32 Attachment 1 for the map that shows generation facilities and Appendix A for the list of
33 generation facilities with capacity information.

1 **(c)**

2
3 AEY would be in a better position to provide the requested information. This information
4 as required for the N-1 capacity criteria is provided in Tab 2 of the Application.

5
6 **(d)**

7
8 Yes. When planning the system to the N-1 contingency criterion (used to determine the
9 requirement of system capacity and consequent diesel rentals), the mines are not included
10 in the analysis. Accordingly, the mines have no impact to the diesel requirements, as they
11 have their own diesel backup.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application Tab 2-17

TAB 2 - SALES AND GENERATION Table 2.2:

Summary of Energy Balance, Losses, and Peak

Forecast Line No. Description 2018 Approved 2018 Actual 2019 Actual 2020 Forecast 2021

Sales and Losses

1 Total Energy Sales 388,332 412,470 403,492 465,788 495,151

2 Losses - MWh 34,173 37,898 37,185 42,193 43,575

3 Losses - % 8.8% 9.2% 9.2% 9.1% 8.8%

4 Total Generation 422,506 450,368 440,676 507,980 538,726

5 Secondary Sales Related Generation 2,241 282 0 0 0

6 Firm Load Generation 420,265 450,086 440,676 507,980 538,726

QUESTION:

a) Give reason for the continual increase in loss of MWh on the grid through the four year period listed?

b) From above 118,461MWh increase of firm load generation from forecast 2021 to 2018 approved, or 28% (divided by 4 years equals a 7% increase per year) when you state earlier that the yearly firm load is increasing at 3.5% ???which is it?

ANSWER:

(a)

The MWh volume of grid losses increase as grid generation increases. YEC is proposing to maintain 8.8% line losses for the 2021 GRA which is the same as 2017/18 GRA.

(b)

On page 1-7 of the application YEC notes that the 2021 generation forecast for firm load is about 28% higher than the 2018 approved forecast. This is about 8.6% average annual increase.

YEC is unable to confirm the source for 3.5% referenced in the preamble.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application Tab 2-17**
4 **Peak – MW2 Integrated System 92.9 93.0 90.0 103.8 112.7**
5

6 **QUESTION:**
7

8 a) Please explain the major difference of 19.8MW from 2018 approved to 2021
9 forecast for integrated peak.
10

11 **ANSWER:**
12

13 **(a)**
14

15 The question references “19.8 MW from 2018 approved” – Table 2.2 shows the 2018
16 approved forecast peak at 92.9 MW (vs actual at 93.0 MW).
17

18 The 2018 approved peak was based on the long-term peak forecast from the 2016
19 Resource Plan. The 2021 forecast peak at 112.7 MW is based on the updated peak
20 forecast from YEC’s 2020 10-Year Renewable Electricity Plan, consideration of the most
21 recent peak of 103.8 MW in 2020, and forecast industrial peak load (12 MW). The major
22 change driving an increase in the non-industrial peak since 2018 is the increased number
23 of 100% electrically heated homes.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application Tab 2.1-1**

4
5 **APPENDIX 2.1: LONG-TERM AVERAGE THERMAL GENERATION CALCULATIONS**

6 As per previous Board directives, Yukon Energy's GRA revenue requirement annual
7 thermal generation costs for test years are based on long-term average (LTA) hydro
8 generation (rather than forecasts of actual hydro generation resulting from actual water
9 conditions). Accordingly, for the purpose of the 2021 GRA to test year, hydro and thermal
10 generation forecasts are based on LTA water supply for hydro generation as updated with
11 the latest information.

12
13 The determination of LTA annual hydro availability is adjusted as required in each GRA to
14 address material changes in LTA hydro system capability due to changes in loads,
15 installed capacity, licensing/permits or other factors.

16
17 The forecast 2021 LTA thermal generation for the Application is 84.3 GW.h, based on the
18 Table 2.1-1 developed to determine annual expected YEC thermal generation based on
19 long-term average YEC hydro generation at YEC 2021 forecast grid loads (net of expected
20 IPPs and expected Fish Lake generation) ranging from 475 to 585 GW.h/year. The
21 forecast for the test year is based on the following proposed updates to the determination
22 of LTA annual hydro availability for the current GRA: a) Yukon Energy now has more water
23 year records compared to 2017/18 GRA [38 water years, from 1981 to 2018, compared to
24 35 water years, 1981 to 2015, used in 2017/18 GRA]. This added information has tended
25 to increase LTA hydro estimates.

26
27 **QUESTION:**

- 28
29 a) Does YEC have any management command/influence on the hydro system
30 capability and usage? Explain.
31
32 b) Why is not the 2019 year included in your forecast model?
33
34 c) Do we now have more than average water conditions in our systems available for
35 generation? Provide latest Update on Forecast Water Conditions for 2020
36 qualifying answer.

1 d) If yes, will this increased hydro use not result in a windfall for the utility if this
2 particular forecasting model is accepted.

3
4 e) Please explain how the LWRF is functioning under these positive conditions.

5
6 **ANSWER:**

7
8 **(a)**

9
10 Yukon Energy optimizes the dispatch of the hydro system within the license requirements
11 to maximize the hydro system capabilities. The main hydro management/influence that
12 YEC conducts is managing the reservoir levels. Many external factors can influence the
13 reservoirs outside of YEC's control, such as precipitation and the timing of freshet.

14
15 **(b)**

16
17 The model is updated every 2 to 3 years with hydrological data. 2019 data will be included
18 in the next model update.

19
20 **(c)**

21
22 Based on initial calculations it appears the Aishihik and Mayo river system were higher
23 than average and Whitehorse was slightly lower than average for the 2020 water year. All
24 three hydro facilities refilled to at or near Full Supply Level in 2020.

25
26 **(d) and (e)**

27
28 Increased hydro use does not result in any windfall for the utility so long as LWRF deferral
29 account procedures are in place to address water-related variances in hydro generation
30 from GRA approved forecast that impact thermal generation fuel costs.

31
32 By way of example, Table 2.2 in the Application indicates a ST hydro forecast for 2021
33 that is 54 GWh higher than the LTA hydro forecast. If the ST forecast was to occur in 2021,
34 and the 2021 GRA revenue requirement forecasts based on LTA hydro are approved, the
35 actual thermal generation would be approximately 54 GWh lower than forecast in the GRA
36 – and the full \$9.9 million of fuel cost (at the forecast blend fuel price of \$0.1838/kWh)
37 would be paid into the LWRF by YEC as part of the 2021 LWRF Annual Report filing.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application Tab 3-3

The forecast Return on Rate Base increases by 20% (\$2.832 million) from 2018 approved to 2021 forecast as proposed in the Application. The increase primarily reflects about 12% increase in mid-year rate base in 2021 over 2018 approved. Yukon Energy's capital structure continues to be financed with 60% long-term debt and 40% equity. The forecast 2021 average cost of long-term debt at 2.81% is 58 basis points [or 26%] higher than the 2018 approved cost at 2.23%, primarily reflecting Mayo B related debt's higher interest with higher loads. The forecast 2021 return on equity at 8.70% remains unchanged from the 2018 approved cost.

Yukon Energy's forecast for new long-term debt interest rate for the 2021 test year is based on long-term Canada bonds plus 120 basis points as directed by the Board. Please see Tab 3, Section 3.5.1. The interest rate adopted for new debt forecast in the test year is 2.19%, determined using a formulaic approach based on the long-term Canada Bonds rate plus 120 basis points (Government of Canada Long-Term Bond Benchmark at 0.99% as of June 30, 2020).

QUESTION:

- a) Why is long term debt rates proposed to increase by 26% since last approved GRA while the Bank of Canada rate trending downward, now at 0.25 per cent?
- b) Is the add-on of 120 basis points non- negotiable for a new application? If not, why not?
- c) Why are ratepayers paying, the holder of the Mayo B debt, prime rates when it is to our publicly-owned shareholder who owns the debt?
- d) Does not this term note higher load reflect the mines of that area?
- e) Does Yukon Energy make increased revenues from selling to the mines?
- f) Why are firm ratepayers paying a premium for this term note when it is through a government decision via Yukon Energy to sell to the mines at a pre-determined contract price?

1 **ANSWER:**

2
3 **(a)**

4
5 The Application explains the impact from the Mayo B note increase relative to interest
6 rate for new debt.

7
8 **(b)**

9
10 Directive 24 of Order 2018-10 notes as follows (as summarized in Tab 6):

11
12 In Board Order 2013-01, the Board directed that a formulaic approach be used for
13 forecasting future costs of debt. This direction was not followed. The Board
14 reiterates the direction and expects this direction to be followed. In future GRAs,
15 both Yukon utilities are to provide their cost-of-debt forecast based on the formulaic
16 approach (long-term Canada bonds plus 120 basis points). If a utility chooses to
17 employ a market-based approach, that utility must also provide a forecast based
18 on the approved formulaic approach.

19
20 Yukon Energy's forecast for new long-term debt interest rate for the 2021 test year is
21 based on long-term Canada bonds plus 120 basis points as directed by the Board.

22
23 **(c), (d), (e) and (f)**

24
25 Tab 3, page 3-36 summarize the terms of the Mayo B Promissory Note. The terms of this
26 debt have been reviewed in several previous GRAs. The debt interest rate is impacted by
27 load levels on the grid. Higher loads from mines or other customers increase YEC
28 revenues, and enable more effective use of Mayo B hydro generation such that payment
29 of the full interest rate on the Mayo B Promissory Note is justified.

30
31 The Mayo B Promissory Note is a mitigation measure established at the time of that
32 project's capitalization to protect ratepayers against low load risk impacts related to Mayo
33 B rate base costs. The instrument contains a flexible interest provision that can reduce the
34 annual interest rate expense to YEC when actual grid loads are lower than a prescribed
35 minimum needed to justify the full interest rate; if the calculated interest expense is
36 negative then YDC pays that amount to YEC in order to reduce the impact of Mayo B
37 costs to ratepayers. The 2017/18 GRA noted that in each year since 2013, YEC's annual

- 1 interest expense on the Mayo B Promissory Note has been reduced by the flexible interest
- 2 provisions. Lower loads in 2014 resulted in negative interest payments from YDC to YEC
- 3 of \$0.112 million.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application 3-6**

4
5 8 Purchased power costs also include forecast purchases in
6 9 2021 under the Yukon government Independent Power Production (IPP) Policy of 1.983 GW.h¹ as
7 10 provided in Table 2.2. The purchase cost for the IPPs in 2021 is assumed at \$0.1583/kW.h based on the
8 11 latest approved thermal fuel cost for YEC in its 2017/18 GRA.2 Total IPP purchase cost is forecast at
9 12 \$0.314 million for 2021.

10
11 **QUESTION:**

- 12
13 a) What is the YEC protocol to purchase from IPP?
14
15 b) Please give a cost /benefit analysis of this 2021 forecast IPP purchase cost of
16 \$0.134 million?
17
18 c) Please provide purchase agreement with this IPP or any IPP?
19

20 **ANSWER:**

21
22 **(a)**

23
24 Please see YUB-YEC-1-95(c) for SOP IPP program material, including SOP Program
25 Guide, SOP Program Rules, SOP Application Process, SOP Application Form,
26 Interconnection Standards; and Electricity Purchase Agreement Template.

27
28 **(b)**

29
30 Per the quotation provided in the preamble – the Total IPP purchase cost is forecast at
31 \$0.314 million for 2021 (not \$0.134 million). OIC 2019-25 provides direction regarding IPP
32 costs that the Board must allow the utility to recover, based on paying the IPP the last
33 approved blend fuel price per kWh for each kWh delivered. IPP costs will equal thermal
34 fuel cost savings when all IPP generation can be used to displace thermal generation.

35
36 **(c)**

37
38 Please see Attachment 1 to this response.

ELECTRICITY PURCHASE AGREEMENT

BETWEEN

NOMAD CONTRACTING & ELECTRICAL SERVICES LTD.

- and -

YUKON ENERGY CORPORATION

MOUNT SIMA SOLAR PROJECT

(YUKON STANDING OFFER PROGRAM)

Dated the 27th day of August, 2020

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Yukon Energy Corporation

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

STANDING OFFER PROGRAM

THIS ELECTRICITY PURCHASE AGREEMENT ("EPA") is made as of the 27th day of August, 2020

BETWEEN:

NOMAD CONTRACTING & ELECTRICAL SERVICES LTD., a corporation incorporated under the laws of the Yukon ("**Seller**")

- and -

YUKON ENERGY CORPORATION, a corporation incorporated under the laws of the Yukon ("**Buyer**")

WHEREAS:

- A. The Government of Yukon issued the *Energy Strategy for Yukon* in January 2009 and in October 2015 issued the *Independent Power Production Policy* as reviewed and updated in October, 2018 (the "**IPP Policy**") as part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy". The IPP Policy created a framework for the development of the Standing Offer Program. In support of the objectives of the IPP Policy, the Government of Yukon issued the SOP OIC and, together with the Utilities, developed the SOP Rules;
- B. Seller has proposed the development of the Project on the Electrical Grid pursuant to the Standing Offer Program and such Project has been reviewed and approved in accordance with the SOP Rules; and
- C. This EPA is being entered into by the Parties in respect of the Project under the Standing Offer Program in accordance with the SOP Rules.

NOW THEREFORE Seller and Buyer agree as follows:

ARTICLE 1
DEFINITIONS, INTERPRETATION AND SCHEDULES

1.1 Definitions and Interpretation

The definitions and certain principles of interpretation that apply to this EPA are set out in Schedule "A".

1.2 Schedules

The following Schedules attached hereto are incorporated into and made a part of this EPA:

Schedule "A" - Definitions and Interpretation

Schedule "B"	- Project Description
Schedule "C"	- Form of Annual Operating Plan
Schedule "D"	- System Interconnection Study Report
Schedule "E"	- Monthly Energy Shortfall Payment
Schedule "F"	- Termination Payment
Schedule "G"	- System Interconnection Guidelines
Schedule "H"	- Joint Operating Procedure
Schedule "I"	- Delivery Time Adjustment Table

ARTICLE 2

CONDITIONS PRECEDENT AND TERM

2.1 Conditions Precedent

- (a) Except as provided in this Section, this EPA has no legal force until the Conditions Precedent described in Schedule "B" are satisfied by Seller or waived by Buyer. The Conditions Precedent may only be waived by Buyer by notice in writing to Seller.
- (b) Seller will:
 - (i) seek to satisfy each of the Conditions Precedent on or before the Condition Date;
 - (ii) keep Buyer informed of any circumstances which may result in any of those Conditions Precedent not being satisfied in accordance with their terms; and
 - (iii) promptly notify Buyer upon satisfaction of any of those Conditions Precedent and provide such supporting evidence as may be reasonably required by Buyer.
- (c) If the Conditions Precedent are not satisfied or waived on or before the Condition Date, or it becomes apparent that the Conditions Precedent will not, in the reasonable opinion of Buyer, be satisfied by the Condition Date, the Conditions Precedent will be taken to have failed and Buyer shall be entitled to terminate this EPA, in which event each Party shall release the other from any and all claims, damages, costs, expenses or liabilities whatsoever incurred by it and its Affiliates in relation this EPA provided that (i) Seller shall remain liable for all costs incurred by Buyer in respect of the System Interconnection Study Report, System Upgrade Costs or New Interconnection Facilities Costs and (ii) otherwise each Party shall be responsible for its own costs incurred by it in connection with this EPA.
- (d) Section 2.1(a) does not apply to this Article 2, Section 3.5 and Articles 10, 11, 12, 13 and 15 which shall be in full force and effect from the date of this EPA.

2.2 Term

Subject to Section 2.1, this EPA shall commence on the Effective Date and continues for the period specified in Schedule "B", unless it is terminated earlier in accordance with this EPA.

ARTICLE 3 CONSTRUCTION AND OPERATION

3.1 Construction and Operation Costs, Liabilities and Actions

Seller will be fully responsible for the permitting, design, engineering, construction, Interconnection, commissioning, operation, maintenance, reclamation and decommissioning of the Seller's Plant and shall be responsible for all costs, expenses, liabilities and other obligations associated with such activities.

3.2 Standard of Construction and Operation

Except as otherwise consented to in writing by Buyer, such consent not to be unreasonably withheld, conditioned or delayed, Seller will ensure that the location, design, engineering, construction, Interconnection, commissioning, operation and maintenance of the Seller's Plant, are and will be carried out at all times during the Term:

- (a) in accordance with the description of the Seller's Plant in Schedule "B" and the information in the Application in all material respects;
- (b) in compliance with the Project Standards; and
- (c) by qualified and experienced individuals.

The Parties shall conduct their respective operations in accordance with the Joint Operating Procedure.

3.3 Project Changes

Without Buyer's prior written consent, not to be unreasonably withheld, conditioned or delayed Seller will not make any change to:

- (a) the Seller's Plant as described in Schedule "B"; or
- (b) any other aspects of the Seller's Plant or the information in any System Interconnection Study Report completed for Seller's Plant prior to the Effective Date which would require changes by Buyer to the System Upgrades where such change would increase Buyer's liability for any costs or otherwise increase the obligations or risks of Buyer with respect to the Seller's Plant or any other project.

Seller acknowledges that Buyer may require, as a condition of its consent to any change described in this Section, that Seller agree in writing to reimburse Buyer for any reasonable incremental liability for any losses, costs and damages incurred by Buyer or any third party, with respect to the Seller's Plant or any other project, as a result of any change described in this Section. Buyer may also require that Seller provide performance assurance or security to Buyer in order to ensure that Buyer has no financial exposure in respect of such reimbursement obligation.

3.4 Development Progress Reports

Seller will deliver a Development Progress Report to Buyer on each January 1, April 1, July 1 and October 1 after the Effective Date until Seller's COD. Buyer shall be entitled to request such

additional information as it may reasonably require from time to time in respect of Seller's development of Seller's Plant.

3.5 Responsibility for Upgrade Costs

Seller will be responsible for and shall pay Buyer for all System Upgrade Costs and New Interconnection Facilities Costs in accordance with the following:

- (a) the System Interconnection Study Report sets out Buyer's estimate of System Upgrade Costs and the New Interconnection Facilities Costs. Seller shall (i) pay to Buyer in advance an amount equal to such estimate of System Upgrade Costs and New Interconnection Facilities Costs ("**Upgrade Costs Advance**") and/or (ii) provide such other security in form, substance and amount as may be acceptable to Buyer in its Discretion to secure the obligation of Seller to pay such costs ("**Upgrade Costs Security**"). Buyer shall not be required in any circumstances to accept Upgrade Costs Security except in its Discretion. Buyer shall not be required to perform any work or incur any System Upgrade Costs or New Interconnection Facilities Costs where Buyer determines in its Discretion that the amount of Upgrade Costs Advance it has received together with any Upgrade Costs Security is not sufficient to adequately secure the obligation of Seller to pay all System Upgrade Costs and New Interconnection Facilities Costs and Seller shall forthwith provide to Buyer such additional Upgrade Costs Advance and/or Upgrade Costs Security as may be reasonably required by Buyer;
- (b) Buyer will exercise Good Industry Practice to perform, or cause to be performed, the work required in respect of the System Upgrades and the New Interconnection Facilities for the Project. Buyer shall be entitled to draw upon the Upgrade Costs Advance and Upgrade Costs Security from time to time in its Discretion to satisfy any System Upgrade Costs and New Interconnection Facilities Costs as and when incurred by Buyer; and
- (c) notwithstanding the estimate of System Upgrade Costs and New Interconnection Facilities Costs provided by Buyer to Seller contemplated in Section 3.5(a) or the amount of any Upgrade Costs Advance and Upgrade Costs Security provided by Seller, Seller shall be responsible for and shall pay Buyer the actual System Upgrade Costs relating to the System Upgrades incurred by Buyer. Following the completion of the System Upgrades and the payment in full by Seller of all System Upgrade Costs incurred by Buyer for such work, Buyer shall release to Seller any undrawn portion of the Upgrade Costs Advance and Upgrade Costs Security.

3.6 Metering

As part of the System Upgrades and New Interconnection Facilities, Buyer will install and maintain an appropriate Meter installation at the POI, and ensure that such Meter is tested and sealed according to any Measurement Canada standards. Seller will allow Buyer to access the Seller's Plant as may be necessary from time to time to install and maintain the Meter at the POI. If there is any dispute regarding the accuracy of the Meter, either Party may give notice to the other Party of the dispute. In that case, the Parties will resolve the matter in accordance with the *Electricity and Gas Inspection Act* (Canada).

3.7 Insurance

Seller will, at its cost, obtain and maintain (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than \$5,000,000, and (b) property insurance, with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender may require. All commercial general liability policies must include Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must include a waiver of subrogation in favour of Buyer. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Yukon and must be endorsed to provide to Buyer 30 days' prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. Seller will give Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by Seller under this Section not more than 30 days after the effective date of coverage and promptly upon renewal thereafter. Seller will be responsible for the full amount of all deductibles under all insurance policies required to be maintained by Seller under this Section.

3.8 Seller's COD

- (a) Except with Buyer's prior written consent, Seller's COD may not occur earlier than 90 days prior to Target Seller's COD.
- (b) Buyer will not be required to incur any incremental expense or other liability of any kind to enable Seller's COD to occur prior to Target Seller's COD.

3.9 Change in Target Seller's COD

If the estimated date for completing the System Upgrades or the New Interconnection Facilities as required to achieve Buyer's COD is later than 90 days prior to the Target Seller's COD, Buyer shall provide notice to Seller of such delay and, provided Seller is not responsible for any delay in completing the System Upgrades or the New Interconnection Facilities (including a failure to pay amounts contemplated in Section 3.5), upon Seller's written request that the Target Seller's COD be postponed, Buyer will postpone the Target Seller's COD to the estimated date for completing the System Upgrades and the New Interconnection Facilities plus 90 days.

3.10 No Liability For Delay

Buyer shall exercise reasonable commercial efforts to achieve Buyer's COD prior to Target Buyer's COD. Buyer will have no liability under this EPA for delays in completion of (a) any System Upgrades or the New Interconnection Facilities, or (b) other work undertaken by Buyer or any of Buyer's Affiliates on the Seller's Plant side of the POI, in each case howsoever arising.

3.11 Outages

- (a) **Notice of Seller's Outage** - Seller will notify Buyer of any Outages in Seller's Plant, or changes in any such Outages, by delivering to Buyer an Outage Notice or revised Outage Notice:
 - (i) promptly in the case of a Forced Outage or a Maintenance Outage;

- (ii) not less than 90 days in advance of any Planned Outage, or such shorter time period with Buyer's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and
 - (iii) promptly in the case of any changes to the duration, start time or end time of any Outage.
- (b) **Notice of Buyer's Outage** - In addition to Buyer's reporting requirements under Section 4.8(d), Buyer will notify Seller of any Planned Outages that will result in a Buyer's Distribution/Transmission Constraint or changes in any such Planned Outages, by delivering to Seller an Outage Notice or revised Outage Notice:
 - (i) not less than 90 days in advance of any such Planned Outage, or such shorter time period with Seller's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and
 - (ii) promptly in the case of any changes to the duration, start time or end time of any Outage.
- (c) **Coordination and Scheduling of Outages** - Seller will coordinate all Planned Outages or Maintenance Outages with Buyer's maintenance schedule or other requirements where such schedule or requirements are publicly available or otherwise notified to Seller.

3.12 Annual Operating Plan

On or before October 31 in each year during the Term, Seller will provide to Buyer its Annual Operating Plan, including any required update to the then current Annual Operating Plan, for the 12-month period commencing on January 1 of the next year. Seller will promptly provide Buyer with a revised Annual Operating Plan from time to time upon Seller becoming aware of any expected material change in the original Annual Operating Plan for that period. The Parties agree the Annual Operating Plan is provided for planning purposes and does not guarantee or limit the quantity or timing of Delivered Energy to the POI.

ARTICLE 4 PURCHASE AND SALE OBLIGATIONS

4.1 Energy prior to Buyer's COD

Subject to satisfaction of all obligations of Seller under this EPA, upon the occurrence of Seller's COD but prior to the occurrence of Buyer's COD, Buyer will not be obligated to purchase, or accept delivery from Seller of, any Energy, provided if Buyer does accept, in its sole discretion, delivery of Energy at the POI, Buyer will pay for such Energy accepted by Buyer prior to Buyer's COD in accordance with Section 5.1.

4.2 Energy after Buyer's COD

From and after Buyer's COD for the remainder of the Term, Seller will sell and deliver all Energy to Buyer at the POI and Buyer will, subject to Sections 4.3 and 4.4, purchase and accept delivery of all Delivered Energy. Buyer will pay for Delivered Energy from and after Buyer's COD in accordance with Section 5.1.

4.3 Limit on Delivered Energy and Capacity

Notwithstanding the foregoing provisions of this Article 4:

- (a) in any hour, Buyer will not be obligated at any time to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Seller's Plant Capacity in such hour (as measured in KWh) and no amount will be payable by Buyer for Delivered Energy in excess of the Seller's Plant Capacity in such hour, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI;
- (b) in any calendar year, Buyer will not be obligated to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Project Energy Volume and no amount will be payable by Buyer for Delivered Energy in any such calendar year in excess of the Project Energy Volume in such calendar year, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI; and
- (c) in determining the total amount of Delivered Energy for a year, month, hour or any other time period under this EPA for any purpose, the amount of Delivered Energy in each hour of such time period will not exceed the Seller's Plant Capacity in such hour, even if Seller delivered to the POI Energy in excess of such amounts, or the Seller's Plant was capable of generating Energy in excess of such amounts.

4.4 Distribution/Transmission Constraints

Buyer will not be in breach or default of its obligations under Sections 4.1, 4.2 or 5.1 if Buyer is not able to accept delivery of Energy at the POI as a result of a Distribution/Transmission Constraint. Buyer will have no liability with respect to a Distribution/Transmission Constraint, except as set out in Section 4.8, if applicable.

4.5 Exclusivity

- (a) Seller will not at any time during the Term commit, sell or deliver any Energy (or related Environmental Attributes) to any Person other than Buyer under this EPA. Seller will not use any Energy (or related Environmental Attributes) for any purpose whatsoever except for sale to Buyer under this EPA. These prohibitions do not apply if, and for so long as, Buyer is in breach of its obligations under Section 4.2.
- (b) Seller shall not be entitled to interconnect a generating facility to the Seller's Plant and transmit electricity via the Seller's Plant to the POI.

4.6 Custody, Control, Risk of and Title To Energy

Custody, control, risk of, and title to, all Energy (including any Delivered Energy exceeding the limits set out in Section 4.3 even where Buyer has not paid for such excess Delivered Energy) shall pass from Seller to Buyer at the POI. Seller will ensure that all Energy delivered to Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances.

4.7 Line Losses

Seller will be responsible for all Line Losses, costs and liabilities relating to the transmission of Energy and other electricity, if applicable, from the POI to the interconnection point between the New Interconnection Facilities and the Electrical Grid. Such Line Losses shall be determined in accordance with the Line Loss Methodology.

4.8 Distribution/Transmission Constraint

- (a) If, in any month after Buyer's COD, Seller is unable to deliver Energy at the POI or Seller's ability to deliver Energy at the POI is reduced solely as a result of a continuous Distribution/Transmission Constraint which exceeds 30 minutes in duration and which:
 - (i) is not caused by a Planned Outage by Buyer of the Distribution System or Transmission System;
 - (ii) is not caused by an event beyond the reasonable control of Buyer; and
 - (iii) is not caused by Seller, the Seller's Plant or anything on Seller's side of the POI;

(a "**Non-Permitted Distribution/Transmission Constraint**") then, notwithstanding that Buyer is excused under Section 4.4 from its obligations under Section 4.2, Buyer shall pay Seller, for each calendar month in which the Non-Permitted Distribution/Transmission Constraint has occurred, the Monthly Energy Shortfall Payment calculated in accordance with Schedule "E" less any costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint.
- (b) Buyer will not be required to pay any Monthly Energy Shortfall Amount under this Section in any of the following circumstances:
 - (i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;
 - (ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure; or
 - (iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Non-Permitted Distribution/Transmission Constraint occurs.
- (c) Seller will maintain accurate and complete Records of all costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint and will report all such costs to Buyer and provide Buyer with all information required to calculate such costs.
- (d) Buyer will give Seller notice of all Distribution/Transmission Constraints in each month which individually exceed 30 minutes in duration when it provides its monthly statements in accordance with Section 5.3.

- (e) In the event of a Dispute by the Parties in respect of the amount of any Monthly Energy Shortfall Amount, the matter shall be resolved in accordance with Article 12.

4.9 Buyer Dispatch/Turn-Down Right

- (a) Buyer may at any time during the Term deliver notice to Seller requiring Seller to Dispatch/Turn-Down and Seller will promptly comply with any such direction except to the extent that any operational, technical or regulatory constraint prevents or limits Seller's ability to comply with such direction.
- (b) For each hour of the applicable Dispatch/Turn-Down, Buyer will pay Seller an amount equal to:
 - (i) the price payable for post-COD Delivered Energy under Section 5.1 multiplied by (A) the aggregate of the duration of the applicable Dispatch/Turn-Down (measured as a fraction determined as the aggregate number of minutes in such Dispatch/Turn-Down period divided by 60) multiplied by (B) an amount equal to the positive difference, if any, of (1) the "Non-Permitted Distribution / Transmission Constraint Hourly Deemed Energy" set out in Table E-1 of Schedule "E" for the applicable calendar month less (2) the amount of Delivered Energy in such hour of Dispatch/Turn-Down (the positive difference being the **"Dispatch/Turn-Down Deemed Energy"**); less
 - (ii) any costs Seller avoided or, acting reasonably, could have avoided during the period of the Dispatch/Turn-Down.
- (c) Buyer will not be required to pay any amount in respect of Dispatch/Turn-Down Deemed Energy under this Section in any of the following circumstances:
 - (i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;
 - (ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure;
 - (iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Dispatch/Turn-Down occurs;
 - (iv) during any other hour when the Seller's Plant would otherwise not have been operating if there had been no Dispatch/Turn-Down notice; or
 - (v) where Buyer's requirement for Seller to Dispatch/Turn Down is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2.
- (d) Where Buyer requires the Dispatch/Turn-Down as result of a Non-Permitted Distribution/Transmission Constraint, Section 4.8 will apply.

4.10 Electric Service to Seller

If at any time Buyer delivers electrical energy to service Seller's Plant Load, then such electrical energy shall be accounted and paid for separately under the applicable agreement for such electricity energy services and will not be netted off of Delivered Energy for the purposes of determining amounts payable by Buyer in accordance with Section 5.1.

ARTICLE 5 PRICE AND PAYMENT TERMS

5.1 Energy Price

In each billing period, Buyer shall pay to Seller, for each KWh of Delivered Energy, the Energy Price calculated in accordance with Schedule "B".

5.2 No Further Payment

The amount payable by Buyer as specified in Section 5.1 is the full and complete payment and consideration payable by Buyer for Delivered Energy and for Environmental Attributes.

5.3 Statements and Payment

(a) Statements

- (i) Buyer will, by the 15th day of each month after the Buyer's COD, deliver to Seller a statement for the preceding month. The statement must indicate, among other things:
 - (A) the amount of, and price payable for, Delivered Energy for that month;
 - (B) any amount owing by Buyer in respect of a Non-Permitted Distribution/Transmission Constraint pursuant to Section 4.8;
 - (C) any Final Amounts owing by either Party to the other Party.

Where there has been any Delivered Energy purchased by Buyer in the period prior to Buyer's COD, the first statement following Buyer's COD shall also account for all amounts payable by Buyer to Seller for such period prior to Buyer's COD. The statement must set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed and be accompanied by sufficient data to enable Seller, acting reasonably, to satisfy itself as to the accuracy of the statement.

- (ii) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the case of willful misstatement, fraud or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this Section within the 36 month period, which will be resolved in accordance with this EPA.

- (iii) If Seller gives notice to Buyer of an error, omission or disputed amount on a statement as described in Section 5.3(a)(ii), Seller may direct Buyer to promptly produce new statements for the relevant month(s). The new statements will show the undisputed amount and disputed amount each in a separate statement or will otherwise separate the amounts in a single statement in a manner acceptable to Seller, acting reasonably.

(b) Payment

- (i) Within 30 days after receipt of a statement delivered under Section 5.3(a), and subject to Section 5.5, Buyer will pay to Seller or Seller will pay to Buyer the amount set out in the statement, except to the extent Seller in good faith disputes all or part of the statement by notice to Buyer as described in Section 5.3(a)(ii).
- (ii) If Seller disputes any portion of a statement, the applicable Party must pay the undisputed net amount payable by it pursuant to the statement or, if applicable, the new statement of the undisputed amount described in Section 5.3(a)(ii).
- (iii) The Parties will endeavor to resolve any error, omission or disputed amount on a statement amount within 30 days of the notice described in Section 5.3(a)(ii).
- (iv) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 2%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

(c) Payment Calculations

- (i) For the purpose of all payment calculations under this EPA:
 - (A) all payment calculations will be rounded to the nearest cent; and
 - (B) Energy will be expressed in KWh rounded to two decimal places.
- (ii) For the purpose of all payment calculations under this EPA, where CPI is to apply, if Statistics Canada (or the then recognized statistical branch of the Canadian Government):
 - (A) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);
 - (B) at any time ceases to publish or provide the CPI, then the provisions of Section 2.7 of Schedule "A" will apply;
 - (C) has not published the CPI for a relevant period at the time Buyer is required to provide Seller with a statement, Seller will prepare the invoice based on the CPI in effect at the time the invoice is issued and

when the CPI for the relevant period is published, Buyer will recalculate the invoice amounts in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

- (D) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then Buyer will recalculate the invoice amounts for the relevant period in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

5.4 Taxes

All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes, including GST and any successor thereto, which, if applicable, will be added to each statement and paid by Buyer.

5.5 Set-off

If Buyer and Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party will be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount will pay to the other Party the difference between the amounts owed, provided that this Section applies only to any purchase price for Delivered Energy and any Final Amount owing by either Party to the other Party. Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defenses which such Party has, or may be entitled to, arising from or related to this EPA.

5.6 Change in Law and GRA Cost Recovery

- (a) If at any time after the Effective Date:
 - (i) the costs to Buyer of complying with its obligations under this EPA are, as a result of one or more Changes in Law, increased or decreased (including, for greater certainty, any increase of the obligations or risks of Buyer with respect to the Seller's Plant, but excluding any increase of the obligations or risks of Buyer with respect to the System Upgrades or New Interconnection Facilities); or
 - (ii) the costs to Buyer of complying with its obligations under this EPA which were of a category or type previously recovered under a General Rate Application are determined under a General Rate Application to no longer be approved for recovery from Buyer's customers in such General Rate Application;

then, to the extent that Buyer would not have incurred such costs except for the Seller's Project and/or the entering into of this EPA, the amount payable by Buyer as specified in Section 5.1 shall be adjusted by the amount necessary to reflect those changed costs which Buyer is unable to recover from Buyer's customers in a General Rate Application.

- (b) For each relevant event in Section 5.6(a)(i) or 5.6(a)(ii), Buyer shall provide Seller with a statement setting out such information as is reasonably necessary to demonstrate that such an event has occurred, the reasonableness and necessity of the measures taken by

Buyer in relation to the event, its efforts to mitigate the costs associated with such event including reasonable efforts of Buyer to recover such costs from its customers in a General Rate Application, the nature and extent of any increase or decrease in the amount payable by Seller as specified in Section 5.1, and any such other information as may be reasonably requested by Seller.

- (c) If in Seller's view there has been a Change in Law that may decrease Buyer's costs, Seller may request Buyer to demonstrate how such Change in Law has affected its costs under this EPA by providing the applicable information contemplated in Section 5.6(b).
- (d) The payments between the Parties shall thereafter be adjusted effective as of the date such event in Section 5.6(a)(i) or 5.6(a)(ii) affects the costs of Buyer hereunder.
- (e) If there is any Dispute between the Parties with respect to this Section 5.6, including as to the appropriate increase or decrease in any payments between the Parties under this Agreement, the Dispute shall be resolved in accordance with Article 12.

ARTICLE 6 ENVIRONMENTAL ATTRIBUTES

6.1 Environmental Attributes

Seller hereby transfers, assigns and sets over to Buyer all right, title and interest in and to the Environmental Attributes. Seller will ensure that all Environmental Attributes transferred to Buyer under this EPA are free and clear of all liens, claims, charges and encumbrances. Seller shall use commercially reasonable efforts to (i) provide information reasonably requested by Buyer in relation to such Environmental Attributes, including as may be required to allow Buyer to verify or certify that such Environmental Attributes exist or have been created and (ii) assist in having Seller's Plant certified, licensed, qualified or approved under any rules, regulations, programs or applicable Laws of any Governmental Authority or independent certification agency in respect of Environmental Attributes, provided that Buyer shall pay Seller all costs reasonably incurred by Seller in respect of the same. Any failure by Seller to exercise such commercially reasonable efforts under this Section 6.1 is a "material default" for the purposes of this EPA, and Buyer may terminate this EPA under Section 9.1(j).

ARTICLE 7 EPA ADMINISTRATION, RECORDS AND AUDITS

7.1 Records

Each of Buyer and Seller will prepare and maintain all Records, or duplicates of such Records, at Buyer's head office or local Yukon office or the Seller's Plant, as applicable, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed in writing between the Parties, for a period of not less than 7 years from the date on which each such Record is created. The Audit Parties may take copies of such Records for the purposes of an inspection or audit under Section 7.2.

7.2 Inspection and Audit Rights

For the sole purpose of verifying:

- (a) compliance with this EPA;
- (b) the accuracy of statements, supporting information and calculations delivered by a Party under this EPA;
- (c) the qualification of the Seller's Plant and the Energy for the Environmental Certification; or
- (d) the liability of Seller for System Upgrades Costs and New Interconnection Facilities Costs,

Buyer or Seller, as applicable, will, on reasonable prior written notice from either Party desiring to conduct an audit, provide the Audit Parties with prompt access during normal business hours to (i) in respect of Buyer, Buyer's records solely relating to this EPA, or (ii) in respect of Seller, Seller's Plant and all records relating to the Seller's Plant, including any Seller Confidential Information, as applicable, to enable the Audit Parties to conduct an inspection or audit thereof. The Audit Parties will exercise any access and audit rights under this Section in a manner that minimizes disruption to the operation of the Party subject to the audit. The audit rights contained in this Section 7.2 shall be subject to the limitations set forth in Section 5.3.

7.3 Seller Consents

Seller will promptly provide any consents required to enable any of the Audit Parties to make enquiries with any Governmental Authority or any Person administering the Environmental Certification concerning any or all of the following: (a) the qualification of the Seller's Plant and the Energy for Environmental Certification, the status of the Environmental Certification and copies of any audits, inspections or reports prepared in connection with the Environmental Certification; and (b) compliance by Seller with Laws and Permits applicable to the Seller's Plant.

ARTICLE 8 FIRST NATION CLAIMS

8.1 Notification of First Nation Claim

Given the ownership and location of the Project, Seller and Buyer do not expect any First Nation Claims. However, if Buyer or Seller receives or obtains evidence of a First Nations Claim, it will notify the other Party as soon as practicable.

8.2 Obligation to Consult

If Buyer receives, obtains evidence or becomes aware of a First Nations Claim, it may direct Seller, at Seller's cost, to:

- (a) consult with the First Nations making the First Nation Claim, or, if requested by Buyer, assist Buyer in the consultation process;

- (b) take any measures Seller deems necessary to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts provided the measures are consented to in advance by Buyer and the First Nations making the First Nation Claim; and
- (c) provide regular written reports to Buyer concerning Seller's compliance with this Section, as may be reasonably requested by Buyer.

8.3 Seller Termination for First Nation Claim

At any time prior to Buyer's COD, if:

- (a) within 60 days of Buyer receiving, obtaining evidence or becoming aware of a First Nations Claim, Buyer does not make a direction to Seller as contemplated in Section 8.2;
- (b) Buyer notifies Seller in writing that it will not make a direction to Seller as contemplated in Section 8.2; or
- (c) after consultation with the First Nations making the First Nation Claim it becomes clear that the measure(s) necessary for Seller to resolve the First Nation Claim or to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts would, in Seller's discretion, impose a commercially unreasonable cost on Seller, or would require the consent of Buyer under this EPA or agreement by Buyer to amend this EPA in order to address any Potential Impacts and such consent or agreement to amend is not provided within 60 days after Seller's request to Buyer,

then Seller may terminate this EPA on notice to Buyer. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. A termination by Seller under this Section will, for all purposes of this EPA, be treated in the same manner as a termination by Seller under Section 9.3(c) of this EPA (including the obligations of Seller under Section 9.7). The termination of this EPA is the exclusive remedy to which Seller may be entitled to if Seller elects to terminate this EPA under this Section.

8.4 Buyer Termination for First Nation Claim

At any time prior to Buyer's COD, if Buyer receives, obtains evidence or becomes aware of a First Nations Claim, Buyer may, at its sole discretion, terminate this EPA on notice to Seller. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. Upon a termination by Buyer under this Section 8.4, Seller shall reimburse Buyer for costs or liabilities described in Sections 9.7(a), (b) and (c). The reimbursement by Seller of such costs or liabilities, the indemnification by Seller contemplated in Section 8.5 and the termination of this EPA are the exclusive remedies to which Buyer may be entitled to if Buyer elects to terminate this EPA under this Section.

8.5 Seller Indemnity for First Nation Claim

Seller shall indemnify and hold Buyer and its Affiliates harmless from any and all claims, damages, costs, expenses, or liabilities whatsoever incurred by Buyer and its Affiliates in relation to such First Nation Claim and such indemnity shall survive termination of this EPA.

ARTICLE 9 TERMINATION

9.1 Termination by Buyer

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA by notice to Seller if:

- (a) Seller's COD does not occur within 730 days following Target Seller's COD for any reason whatsoever (including Force Majeure), provided that Buyer may terminate this EPA under this provision only if Buyer delivers a termination notice prior to Seller's COD; or
- (b) at any time after Buyer's COD, Seller fails to deliver at least an average of 25% of the aggregate Projected Monthly Energy as set out in Schedule "E" to Buyer over all hours in a period of 730 continuous days for any reason whatsoever (including Force Majeure, a Distribution/Transmission Constraint), but excluding a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or
- (c) at any time after Buyer's COD, Buyer is unable to accept delivery of Energy at the POI for a period of 730 continuous days due to Force Majeure invoked by Buyer or a Distribution/ Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or
- (d) Seller breaches Section 4.5; or
- (e) Seller fails to complete any application, payment, filing, study, document or other step in the process for interconnecting the Seller's Plant to the Distribution System, Transmission System or New Interconnection Facilities, as applicable, in accordance with the requirements of, and within the time limits, including any cure periods, specified by Buyer, and such failure could reasonably be expected to have an adverse impact on Buyer or any third party; or
- (f) any System Interconnection Study Report completed after the Effective Date contains information that is inconsistent with the description of the Seller's Plant in Schedule "B" and Seller has not received Buyer's consent under Section 3.3 for the change to Schedule "B"; or
- (g) Seller is Bankrupt or Insolvent; or
- (h) Seller, as a result of an act or omission of Seller, ceases to be exempt from regulation as a "public utility" as defined in the *Public Utilities Act* with respect to the Seller's Plant and the sale of Energy to Buyer under this EPA, and the loss of such exemption could reasonably be expected to have an adverse effect on the benefit to Buyer of this EPA; or

- (i) an amount due and payable by Seller to Buyer under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Buyer has given notice of the default to Seller; or
- (j) Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Buyer to Seller of the default Seller has cured the default or, if the default cannot be cured within that 30 day period, Seller demonstrates to the reasonable satisfaction of Buyer that Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any purported Assignment of this EPA without the consent of Buyer.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Seller.

9.2 Notice of Termination Event

Seller will notify Buyer promptly if Seller is Bankrupt or Insolvent or if there is a material risk that Seller will become Bankrupt or Insolvent or if Seller has defaulted under any agreement with a Facility Lender or if any Permit or land tenure agreement for the Seller's Plant is terminated or expires.

9.3 Termination by Seller

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Seller may have under this EPA or at law or in equity in respect of any of the following events, Seller may terminate this EPA by notice to Buyer if:

- (a) after Buyer's COD, Buyer has not accepted delivery of Energy for a period of 730 continuous days due to an event described in Section 4.4 or any event of Force Majeure and Seller is not entitled to receive any payment pursuant to Section 4.8 in respect of that period; or
- (b) the Seller's Plant has suffered major damage where the cost to repair the damage exceeds the net present value (using the Present Value Rate) of the expected revenues under the EPA for the remainder of the Term less the net present value (using the Present Value Rate) of the estimated operating and maintenance costs for the Seller's Plant for the remainder of the Term; or
- (c) Seller has been unable to achieve Seller's COD for a period of 730 days after Target Seller's COD or has been unable to deliver Energy to the POI for a period of 730 continuous days after Seller's COD in either case solely as a result of Force Majeure invoked by Seller or a Distribution/Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or
- (d) Buyer is Bankrupt or Insolvent; or
- (e) except where an amount has been disputed in the manner specified in Section 5.3(a)(ii), an amount due and payable by Buyer to Seller under this EPA remains unpaid for 30 days

after its due date and such default has not been cured within 30 days after Seller has given notice of the default to Buyer; or

- (f) Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Seller to Buyer of the default Buyer has cured the default or, if the default cannot be cured within that 30 day period, Buyer demonstrates to the reasonable satisfaction of Seller that Buyer is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Buyer.

9.4 Termination by Buyer for Convenience

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA for convenience upon 90 days prior notice to Seller.

9.5 Effect of Termination

Upon expiry of the Term or earlier termination of this EPA in accordance with its terms:

- (a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of this EPA and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination or that are stated to arise on termination of this EPA, subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA;
- (b) both Parties will remain bound by Section 3.5 with respect to the satisfaction of residual obligations for the period prior to termination or that are specified to arise on, or continue following, termination, and Sections 12.1 and 13.1 associated with Delivered Energy prior to termination of this EPA; and
- (c) Seller will remain bound by Sections 7.1 and 7.2 for a period of 36 months following expiry or termination of this EPA;

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

9.6 Buyer Payment on Termination

If Seller terminates this EPA under any of Sections 9.3(d), 9.3(e) or 9.3(f) or Buyer terminates this EPA for convenience under Section 9.4, Buyer will pay to Seller an amount equal to the applicable Termination Payment due at the time of termination determined in accordance with Schedule "F".

9.7 Seller Payment on Termination

If Buyer terminates this EPA on or before 90 days after Seller's COD or Seller terminates this EPA on or before Buyer's COD under any of Sections 9.3(a), 9.3(b) or 9.3(c), Seller will, within 30 days after receipt of an invoice from Buyer, reimburse Buyer for:

- (a) all System Upgrade Costs and New Interconnection Facilities Costs incurred by Buyer, or which Buyer has become contractually obligated to pay, prior to the termination of the EPA including System Upgrade Costs and New Interconnection Facilities Costs Seller would otherwise be responsible for under Section 3.5;
- (b) any incremental liability for System Upgrade Costs and New Interconnection Facilities Costs which Buyer will incur as a result of the termination of this EPA; and
- (c) any System Upgrade Costs and New Interconnection Facilities Costs which Seller is responsible for under any reimbursement agreement pursuant to Section 3.3.

9.8 Calculation and Payment

Buyer will pay any amount which it owes under Section 9.6 within 30 Business Days after the date of delivery of an invoice by Seller to Buyer. Any amounts owing by Seller to Buyer under this EPA will be netted against any amount owing by Buyer to Seller under Section 9.6.

9.9 Exclusive Remedies

Payment by Buyer of the amount determined under Section 9.6 is the exclusive remedy to which Seller is entitled, and Buyer's limit of liability, for termination of this EPA by Seller pursuant to any of Sections 9.3(d), 9.3(e) or 9.3(f). Subject to Section 9.4 and 9.7, termination of this EPA is the exclusive remedy to which Buyer or Seller, as the case may be, is entitled if Buyer or Seller elects to exercise its right to terminate this EPA under any of Section 9.1, 9.3(a), 9.3(b) or 9.3(c). For greater certainty, subject to Section 9.4 and 9.7, Seller will not be required to pay any termination payment on termination by Buyer of this EPA. Neither Party will have any right to terminate this EPA except as expressly set out herein.

ARTICLE 10 REPRESENTATIONS AND WARRANTIES

10.1 Seller's Representations

Seller represents and warrants to Buyer, and acknowledges that Buyer is relying on those representations and warranties in entering into this EPA, as follows:

- (a) Seller is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;
- (b) this EPA constitutes a valid and binding obligation of Seller enforceable against Seller in accordance with its terms; and
- (c) this EPA has been duly authorized, executed and delivered by Seller.

10.2 Buyer's Representations

Buyer represents and warrants to Seller, and acknowledges that Seller is relying on those representations and warranties in entering into this EPA, as follows:

- (a) Buyer is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;
- (b) this EPA constitutes a valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms; and
- (c) this EPA has been duly authorized, executed and delivered by Buyer.

ARTICLE 11 LIABILITY LIMITATIONS

11.1 Limit of Liability

Buyer's liability for damages for any failure to take or pay for Delivered Energy under this EPA is limited to the amount payable by Buyer for that Delivered Energy under Article 5, amounts owing under Sections 4.8 and any interest thereon calculated under this EPA.

11.2 Consequential Damages

Neither Party will be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages with respect to, arising out of, relating to or in any way connected with a Party's performance or non-performance under this EPA.

ARTICLE 12 DISPUTES

12.1 Dispute Resolution Procedure

Any dispute, controversy or claim arising out of or relating to this EPA ("**Dispute**") shall be exclusively and finally resolved in accordance with the dispute resolution procedure set forth in this Article 12 (the "**Dispute Resolution Procedure**").

12.2 Commencement of the Dispute Resolution Procedure

The Parties shall make reasonable efforts to first resolve any Dispute. If a Dispute cannot be resolved by the Parties, then either Party may initiate the Dispute Resolution Procedure by giving notice of the Dispute to the other Party (the "**Notice of Dispute**"). The Notice of Dispute shall contain a brief statement of the nature of the Dispute, set out the relief requested, and request that the Dispute Resolution Procedure be commenced.

12.3 Negotiations

Upon the submission of a Notice of Dispute pursuant to Section 12.2, each of the Parties shall refer the Dispute to a designated senior management executive with the authority to negotiate a

settlement of the Dispute for that Party (the "**Senior Management Executives**"). The Senior Management Executives of the Parties shall attempt to resolve the Dispute within 30 days from the date on which the Notice of Dispute was issued, or such longer period as the Senior Management Executives may otherwise unanimously agree. If the Senior Management Executives unanimously agree upon a resolution of the Dispute, such resolution shall be memorialized in a written settlement agreement mutually acceptable to the Parties and shall be binding on the Parties.

12.4 Arbitration

If a Dispute is not resolved by Senior Management Executives within 30 days from receipt of a Notice of Dispute (or such longer period as the Senior Management Executives may otherwise agree in writing), the Dispute shall, at the request of either Party, be resolved by binding arbitration under the Rules of Arbitration of the International Chamber of Commerce (the "**ICC Rules**"), except to the extent of conflicts between the ICC Rules and the provisions of this EPA, in which event the provisions of this EPA shall prevail. The following provisions shall apply to an arbitration commenced pursuant to this Section 12.4:

- (a) the number of arbitrators shall be one;
- (b) the place, or legal seat, of the arbitration shall be Whitehorse, Yukon;
- (c) the language to be used in the arbitral proceedings shall be English;
- (d) all awards issued by the arbitrator shall be final, non-appealable and binding on the Parties. Any award may be filed in any court of competent jurisdiction and may be enforced by a Party as a final judgment in such court. The Parties expressly waive, to the maximum extent permitted by law, any right of appeal of any award or reference of any matter to any court, other than as may be necessary to recognize or enforce an award;
- (e) the arbitrator shall be guided by the International Bar Association's Rules on the Taking of Evidence in International Commercial Arbitration;
- (f) the Parties shall request that the arbitrator render its final award within 12 months of the commencement of the arbitration, or as soon as possible thereafter, provided that no award shall be invalid if it is not rendered within the time period herein specified;
- (g) any award for monetary damages shall be made and payable in Canadian Dollars and may include interest from the date of any breach or violation of this EPA until paid in full at the rate determined by the arbitrator;
- (h) the Parties agree that any arbitration carried out hereunder shall be kept private and confidential, and that the existence of the proceedings and any element of it (including all awards, the identity of the Parties and all witnesses and experts, all materials created for the purposes of the arbitration, all testimony or other oral submissions, and all documents produced by a Party that were not already in the possession of the other Party) shall be kept confidential, except (i) with the consent of the Parties, (ii) to the extent disclosure may be lawfully required in bona fide judicial proceedings relating to the arbitration, (iii) where disclosure is lawfully required by a legal duty, and (iv) where such information is already in the public domain other than as a result of a breach of this clause. The Parties

also agree not to use any information disclosed to them during the arbitration for any purpose other than in connection with the arbitration;

- (i) where a Dispute relates to the EPA, the Parties shall agree to consolidate the matters in Dispute under such agreements in a single arbitration;
- (j) the Parties agree that during the resolution of a Dispute pursuant to this Article 12, the Parties shall continue to perform their obligations under this EPA, provided that such performance shall be without prejudice to the rights and remedies of the Parties and shall not be read or construed as a waiver of a Party's right to claim for recovery of any loss, costs, expenses or damages suffered as a result of the continued performance of this EPA; and
- (k) each Party will be responsible for its own costs under this Article 12, subject to the award of an arbitrator.

ARTICLE 13 CONFIDENTIALITY

13.1 Confidentiality

- (a) **Additional Confidentiality Obligation** - During the Term and for two years thereafter:
 - (i) Buyer will treat as confidential, and will not disclose to any third Person, Seller Confidential Information, and
 - (ii) Seller will treat as confidential, and will not disclose to any third Person, Buyer Confidential Information.
- (b) **Disclosure of Confidential Information** - Notwithstanding Section 13.1(a) above:
 - (i) Seller may also disclose Buyer Confidential Information and Buyer may disclose Seller Confidential information in the following circumstances:
 - (A) disclosures expressly authorized under this EPA or otherwise set out in this EPA;
 - (B) disclosures to enable a Party to fulfill its obligations under the EPA;
 - (C) disclosure in any arbitration or legal proceedings for the enforcement of the EPA;
 - (D) disclosure to the Party's directors, officers, employees, Facility Lenders, consultants and advisors, and purchasers of the Environmental Attributes, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;
 - (E) subject to Section 13.1(b)(ii)(D), disclosure required to be made by a Party by an order of a court, a regulatory agency or a tribunal or under any law, regulatory requirements or any requirement of any stock exchange that is binding upon a Party, provided that (i) to the extent

reasonably practicable, the Party intending to make such disclosure gives reasonable notice to the other Party before make the disclosure, and (ii) limits the disclosure to that required by the applicable order, Laws or regulatory or stock exchange requirement;

- (F) disclosure to a third Person if such information was known by that third Person before disclosure by Buyer or Seller, as the case may be, provided the third Person did not know of the information as a result of a breach of the non-disclosure obligations in this EPA; or
 - (G) disclosure with the consent of Buyer, in the case of Buyer Confidential Information, or Seller, in the case of Seller Confidential Information.
- (ii) Buyer may disclose Seller Confidential Information in the following circumstances:
- (A) disclosure to Buyer's Affiliates or to a third Person, and their respective employees, consultants and advisors, for the purpose of reselling or marketing any Energy, including disclosure of Seller Confidential Information by such Affiliate or third Person to those who have purchased or may purchase the Energy;
 - (B) for purposes other than those described in Section 13.1(b)(i), to Buyer's Affiliates and to any directors, officers, employees, consultants and advisors of any Affiliates, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;
 - (C) to any ministers, deputy ministers, servants or employees of the Yukon or the federal government, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality; or
 - (D) disclosure in any regulatory proceeding, whether related to this EPA or not, to the extent that Buyer considers disclosure is necessary or desirable to support its position in such proceeding.

ARTICLE 14 FORCE MAJEURE

14.1 Force Majeure

- (a) If there is a Force Majeure affecting a Party's ability to perform an obligation under this EPA, and that Party wishes to declare a Force Majeure, that Party will promptly notify the other Party of the Force Majeure. The notice of Force Majeure must identify the nature of the Force Majeure, the date the Force Majeure commenced, the expected duration of the Force Majeure, and the particular obligations affected by the Force Majeure. If (i) a notice of Force Majeure is provided in accordance with this Section, (ii) the event in question is in fact an event of Force Majeure as defined in this EPA, and (iii) the event of Force Majeure commenced on the commencement date in the notice of Force

Majeure, then the Force Majeure will be deemed to have been invoked as of the commencement date stated in the notice.

- (b) Neither Party will be in default of any obligation under this EPA if a Party is unable to perform that obligation due to an event or circumstance of Force Majeure, provided notice is delivered in accordance with this Section and the circumstances are, in fact, an event or circumstance of Force Majeure.
- (c) Subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure. The Party invoking Force Majeure will make commercially reasonable efforts to promptly remove the Force Majeure and will promptly respond to any inquiry from the other Party regarding the efforts being undertaken to remove the Force Majeure and will give prompt notice of the end of the Force Majeure.

ARTICLE 15

GENERAL PROVISIONS

15.1 Independence

The Parties are independent contractors, and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

15.2 Enurement

This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

15.3 Assignment

- (a) Seller may not assign this EPA except with the prior consent of Buyer, which consent may not be unreasonably withheld, conditioned or delayed provided such Assignment is to a Facility Lender. Any Assignment (other than an Assignment to a Facility Lender) is subject to the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of Seller under this EPA arising both before and after the Assignment, and providing the representations and warranties set out in Section 10.1 effective as at the time of Assignment, and Seller not being in default under this EPA. Unless agreed to in writing by Buyer, Seller shall remain jointly and severally liable with the assignee for all obligations of Seller under this EPA.
- (b) Any request by Seller for Buyer's consent under Section 15.3(a) must be delivered to Buyer not less than 30 days before the date of the proposed Assignment. A request under this Section must be accompanied by such information as reasonably required by Buyer to assess the request for consent including the name, address and ownership structure of the assignee, details of any consultation with First Nations that may be impacted by the Seller's Plant or the Assignment with respect to the proposed Assignment, list of the directors and officers of the assignee and information concerning the assignee's operations, experience and financial status.
- (c) If Seller seeks consent to Assign this EPA to a Facility Lender, Buyer may require, as a condition of its consent to the Assignment, that Seller and the Facility Lender enter into a

Lender Consent Agreement with Buyer containing customary provisions. If required by a Facility Lender, Buyer will enter into a Lender Consent Agreement with the Facility Lender and Seller containing customary provisions. Seller will reimburse Buyer for all costs reasonably incurred by Buyer in connection with any request by Seller for Buyer's consent pursuant to Section 15.3(a).

15.4 Entire Agreement

This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA.

15.5 Amendment

This EPA may not be amended except by an agreement in writing signed by both Parties.

15.6 No Waiver

Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

15.7 Notices

Any notice, consent, waiver, declaration, request for approval or other request, statement or bill that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address for that Party stated in Schedule "A" and:

- (a) notices under Section 14.1, Article 8 and Article 9 must be delivered by hand or by a courier service during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day;
- (b) all notices other than notices described in Section 15.7(a) may be delivered by email during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day; and
- (c) either Party may change its address for notices under Section 3 of Schedule "A" to this EPA by notice to the other Party.

15.8 Interconnection Notices

Nothing in the System Interconnection Guidelines and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA, except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the System Interconnection Guidelines will

constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA.

15.9 Commodity Contract/Forward Contract

The Parties agree and intend that this EPA constitutes an "eligible financial contract" under the *Bankruptcy and Insolvency Act* (Canada) and *Companies' Creditors Arrangement Act* (Canada).

15.10 Further Assurances

Each Party will, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA including, in the case of Seller, completing any registration process required in respect of Environmental Attributes as requested by Buyer.

15.11 Severability

Any provision of this EPA which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

15.12 Counterparts

This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

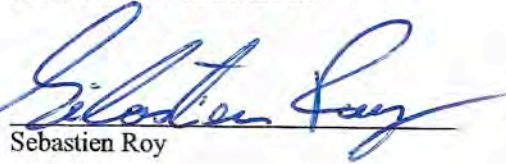
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IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA effective as of the date set out on page one of this EPA.

**NOMAD CONTRACTING &
ELECTRICAL SERVICES LTD.**

YUKON ENERGY CORPORATION

Per:


Sebastien Roy

Per:

Andrew Hall
President and Chief Executive Officer

Per:


Anne-Marie Legare

Per:

Michael Brandt
Vice-President

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**NOMAD CONTRACTING &
ELECTRICAL SERVICES LTD.**

YUKON ENERGY CORPORATION

Per: _____
Sebastien Roy

Per:  27 August 2020

Andrew Hall
President and Chief Executive Officer

Per: _____
Anne-Marie Legare

Per:  _____
Michael Brandt
VP, Business & Corporate Development

SCHEDULE "A"

DEFINITIONS AND INTERPRETATION

1. DEFINITIONS

References in a Schedule to a section or Section mean a section or Section of this EPA, and not a Schedule, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

- 1.1 "Affiliate"** means, with respect to any Party or any third Person, any Person directly or indirectly Controlled by, Controlling, or under common Control with, such Party or the third Person.
- 1.2 "Annual Operating Plan"** means a 12-month operating plan for the Seller's Plant that includes for term of each operating plan, (a) a schedule of the expected total deliveries of Energy at the POI in each month and (b) a schedule of any Planned Outages of the Seller's Plant expected by Seller. The Annual Operating Plan will be consistent with Good Industry Practice and shall be substantially in the form attached hereto as Schedule "C", subject to such modifications thereto as may be reasonably required by Buyer.
- 1.3 "Application"** means the application and all supporting documents and information with respect to the Seller's Plant filed by Seller with Buyer in the Standing Offer Program.
- 1.4 "Assign" or "Assignment"** means to assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term and, without limiting the foregoing, each of the following is deemed to be an Assignment of this EPA by Seller:
- (a) any sale or other disposition of all or a substantial part of Seller's ownership interest in the Seller's Plant, or of all or any interest of Seller in this EPA or revenue derived from this EPA;
 - (b) any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant or Seller's ownership interest therein; and
 - (c) any change of Control, merger, amalgamation or reorganization of Seller.
- 1.5 "Audit Parties"** means the applicable Party conducting an audit under this EPA and its Affiliates, representatives, consultants, advisors and any other third Person retained in respect of the applicable audit.
- 1.6 "Bankrupt or Insolvent"** means, with respect to a Person:
- (a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it;
 - (b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law;
 - (c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy;

- (d) the Person has voluntarily suspended the transaction of its usual business; or
 - (e) a court of competent jurisdiction has issued an order declaring the Person bankrupt or insolvent.
- 1.7 **"Business Day"** means any calendar day which is not a Saturday, Sunday or Yukon statutory holiday.
- 1.8 **"Buyer"** means Yukon Energy Corporation and its successors and permitted assigns.
- 1.9 **"Buyer Confidential Information"** means technical or commercial information disclosed by Buyer to Seller that Buyer directs, and clearly marks, as confidential, including the System Interconnection Guidelines and this EPA but excluding information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Seller, or (ii) is known to Seller before disclosure to it by Buyer, or becomes known to Seller, thereafter by way of disclosure to Seller by any other Person who is not under an obligation of confidentiality with respect thereto.
- 1.10 **"Buyer's COD"** shall occur when the System Upgrades have been completed and Buyer provides a notice of completion of the same to Seller.
- 1.11 **"Change in Law"** means (a) the enactment, adoption, promulgation, modification or repeal of any applicable Laws or any change in the interpretation or administration of any applicable Laws resulting from a decision of a Governmental Authority which occurs after the Effective Date; but in each case excluding a Change in Law relating to income tax, or (b) the requirement for a new Permit (including due to a change in the circumstances in which a Permit is required), a change in the terms of any Permit after the date such Permit is granted, or any change in the interpretation or administration of any Permits resulting from a decision of a Governmental Authority.
- 1.12 **"Condition Date"** means the date specified as such in Schedule "B".
- 1.13 **"Conditions Precedent"** means those conditions precedent set out in Schedule "B".
- 1.14 **"Control"** of any Person means:
- (a) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or Persons performing similar functions;
 - (b) ownership of 50% or more of the equity or beneficial interest in that Person; or
 - (c) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.
- 1.15 **"CPI"** means the "Canada All Items (Not Seasonally Adjusted)" Consumer Price Index as published by Statistics Canada or any successor agency thereto.
- 1.16 **"Delivered Energy"** means in each month after Buyer's COD the amount of Energy delivered by Seller at the POI in that month as recorded by Buyer's Meter less the applicable Line Losses.

- 1.17 **"Development Progress Report"** means a report describing the progress of the financing, design, engineering, construction, Interconnection, and commissioning of the Seller's Plant, that is in form and content acceptable to Buyer, acting reasonably.
- 1.18 **"Discretion"** (whether or not capitalized) means sole, absolute and unfettered discretion unless this EPA expressly states otherwise.
- 1.19 **"Dispatch/Turn-Down"** means for Seller to turn down or shut off the Seller's Plant.
- 1.20 **"Dispatch/Turn-Down Deemed Energy"** has the meaning given to such term in Section 4.9(b)(i).
- 1.21 **"Distribution System"** means the distribution, protection, control and communication facilities in the Yukon that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35 kilovolts or less, and includes all additions and modifications thereto and repairs or replacements thereof.
- 1.22 **"Distribution/Transmission Constraint"** means any disconnection of the Seller's Plant from the Distribution System or Transmission System, or any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System preventing or limiting deliveries of Energy at the POI or within the Distribution System or Transmission System or any direction from Buyer to reduce generation of the Seller's Plant as a result of any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System.
- 1.23 **"Effective Date"** shall mean the date on which all Conditions Precedent have been satisfied or waived in accordance with Section 2.1.
- 1.24 **"Electrical Grid"** means the electrical grid into which the Seller's Plant will be interconnected, as identified in Schedule "B".
- 1.25 **"Eligible Clean Energy"** means wind, hydro, geothermal, biomass and solar energy sources permitted under the IPP Policy for the SOP generated by a Project located in Yukon which is directly connected into the YIS or the WLG through the New Interconnection Facilities.
- 1.26 **"Energy"** means all electrical energy expressed in KWh generated by the Seller's Plant, excluding electrical energy generated by the Seller's Plant which is required to service the Seller's Plant Load.
- 1.27 **"Energy Price"** has the meaning given to such term in Schedule "B".
- 1.28 **"Environmental Attributes"** means the following as attributable to Energy delivered to Buyer under this EPA:
- (a) all attributes directly associated with, or that may be derived from, the Energy delivered to Buyer under this EPA having decreased environmental impacts relative to certain other generation facilities or technologies including any existing or future credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradeable;

- (b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to the actual or assumed reduction, displacement or offset of emissions at any location other than the Seller's Plant as a result of the generation, purchase or sale of the Energy delivered to Buyer under this EPA;
 - (c) any credit, reduction right, off-set, allowance, allocated pollution right, certificate or other unit of any kind whatsoever whether or not tradeable resulting from or otherwise related to the reduction, removal, or sequestration of emissions at or from the Seller's Plant; and
 - (d) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing, but for certainty not including:
 - i. benefits or proceeds from environmental incentive programs offered by Governmental Authorities that do not require a transfer of the attributes in (a) to (c) above; and
 - ii. benefits or proceeds from social programs, including programs relating to northern or rural development, employment or skills training, or First Nations, that do not require a transfer of the attributes in Sections (a) to (c) above.
- 1.29 "Environmental Certification"** means any certification Buyer requires Seller to obtain under Section 6.1.
- 1.30 "Facility Lender"** means any lender(s) providing any debt financing or debt hedging facilities for the design, engineering, construction and/or operation of the Seller's Plant and any successors or assigns thereto and any Person taking any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant.
- 1.31 "Final Amount"** means an amount owing by either Party to the other Party under this EPA, including as a result of a breach of this EPA, where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award under Section 12.1 of this EPA or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.
- 1.32 "First Nation Claim"** means a legal claim or proceeding or written threat to commence a legal claim or proceeding from or on behalf of First Nations where such claim or threat alleges a breach or potential breach of, or an impact to: any First Nations' Treaty rights, rights under a Settlement Agreement (as that term is defined in the Yukon Umbrella Final Agreement), or rights under section 35 of the *Constitution Act*, 1982, by (a) this EPA, (b) the Seller's Plant, (c) the Interconnection or any works related to the Interconnection, or (d) any authorization granted by the Yukon or federal government relating to the Seller's Plant and its operations.
- 1.33 "First Nations"** means any one of the 14 First Nations in the Yukon.
- 1.34 "Force Majeure"** means any event or circumstance not within the control of the Party, or any of its Affiliates, claiming Force Majeure, but does not include:
- (a) any economic hardship or lack of money, credit or markets;

- (b) an event or circumstance that is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws;
- (c) a mechanical breakdown or control system hardware or software failure, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the breakdown or failure was caused by a latent defect in the design or manufacture of the equipment, hardware or software, which could not reasonably have been identified by normal inspection or testing of the equipment, hardware or software;
- (d) an event or circumstance caused by a breach of, or default under, this EPA or a willful or negligent act or omission by the Party seeking to invoke Force Majeure;
- (e) any Distribution/Transmission Constraint unless such event is caused by an event or circumstance not within the control of Buyer; or
- (f) any acts or omissions of: (i) any Affiliate, employee, director, officer, agent or other representative of the Party invoking Force Majeure; (ii) any vendor, supplier, contractor, subcontractor, consultant or customer of or to the Party invoking Force Majeure; or (iii) any other Person for whom the Party invoking Force Majeure is responsible at law, unless the act or omission is caused by an event or circumstance that would constitute Force Majeure if the Person described above was a party to this EPA in place of a Party invoking Force Majeure.

1.35 "Forced Outage" means the immediate removal of one or more generating units of the Seller's Plant or transmission or distribution infrastructure of the Seller's Plant from service in response to equipment alarms or any damage identified during a Planned Outage or Maintenance Outage requiring extension of those Planned Outage or Maintenance Outage.

1.36 "General Rate Application" means any application, review, process, or procedure in which the YUB sets and approves rates to be charged by Buyer for the supply of the service for which it is franchised in accordance with the *Public Utilities Act*.

1.37 "Good Industry Practice" means:

- (a) in respect of Buyer, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the Yukon; and provided that Buyer shall be in compliance with Good Industry Practice in respect of any equipment comprising the Distribution System or Transmission System, if it operates such equipment in accordance with all applicable original equipment manufacturer guidelines and requirements provided to Buyer by supplier of such equipment; and
- (b) in respect of Seller, any of the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in

light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in Western Canada.

- 1.38 **"Governmental Authority"** means any federal, provincial, local or foreign government or any of their boards or agencies, or any regulatory authority other than Buyer and Seller and entities controlled by Buyer or Seller.
- 1.39 **"GST"** means the goods and services tax imposed under the *Excise Tax Act* (Canada) as that Act may be amended or replaced from time to time.
- 1.40 **"Interconnection"** means the POI.
- 1.41 **"IPP Policy"** has the meaning given to such term in the recitals to this EPA.
- 1.42 **"Joint Operating Procedure"** means the joint operating procedure attached as Schedule "H" as may be modified by Buyer from time to time.
- 1.43 **"KW"** means kilowatt.
- 1.44 **"KWh"** means kilowatt-hour.
- 1.45 **"Laws"** means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority in effect from time to time.
- 1.46 **"Lender Consent Agreement"** means a lender consent agreement in the form and substance acceptable to Buyer, acting reasonably.
- 1.47 **"Line Losses"** means losses of electricity associated with the transmission and transformation of Energy and other electricity, if applicable, from the Seller's Plant to the POI that are recorded by the Meter or reasonably estimated by Buyer.
- 1.48 **"Line Loss Methodology"** means the Line Loss Methodology set forth in the System Interconnection Study Report for the purposes of this Project.
- 1.49 **"Maintenance Outage"** means any outage of Buyer's Distribution System or Transmission System or the Seller's Plant that is not a Planned Outage or a Forced Outage that typically has a flexible start and end time and of shorter duration than a Planned Outage.
- 1.50 **"Meter"** means a meter owned by Buyer that is: (a) capable of accurately measuring the quantity of Energy generated by the Seller's Plant and delivered to the POI independent of all other generation equipment or facilities, (b) capable of being remotely interrogated; and (b) calibrated to measure on an hourly basis the quantity of Energy delivered by Seller to the POI.
- 1.51 **"Monthly Energy Shortfall Payment"** has the meaning given to such term in Schedule "E".

- 1.52 **"New Interconnection Facilities"** means those additions, modifications and upgrades required to interconnect the Project to the Electrical Grid which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any System Upgrades.
- 1.53 **"New Interconnection Facilities Costs"** means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the New Interconnection Facilities, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.
- 1.54 **"Non-Permitted Distribution/Transmission Constraint"** has the meaning given to such term in Section 4.8(a).
- 1.55 **"Outage"** means a Forced Outage, Maintenance Outage, or Planned Outage of Buyer's Distribution System or Transmission System or Seller's Plant.
- 1.56 **"Outage Notice"** means a notification of any Outage or revised notification of any Outage required to be delivered by Seller to Buyer or Buyer to Seller under this EPA that describes the timing, frequency, nature and duration of the Outage and that is in a format that may be prescribed by Buyer from time to time.
- 1.57 **"Party"** means Buyer or Seller, and **"Parties"** means both Buyer and Seller.
- 1.58 **"Permits"** means permits, certificates, licences, approvals and other authorizations issued by any Governmental Authorities as may be required for the design, construction, ownership, operation, maintenance and decommissioning of (i) the Seller's Plant and the delivery of Energy to the POI, and (ii) the System Upgrades and the New Interconnection Facilities.
- 1.59 **"Person"** means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.
- 1.60 **"Planned Outage"** means an outage that is scheduled well in advance for purposes of inspections, maintenance, or repair of Buyer's Distribution System or Transmission System or Seller's Plant, that typically has a predetermined duration and scope of work, occurs only once or twice per year, and may last for several days.
- 1.61 **"POI" or "Point of Interconnection"** means the point at which the Seller's Plant interconnects with the Distribution System or Transmission System, as identified on the Single Line Diagram.
- 1.62 **"Potential Impacts"** means any adverse or potentially adverse impact on the established or potential aboriginal rights (including title) of First Nations as a result of:
- (a) this EPA;
 - (b) the Project;
 - (c) the interconnection of the Seller's Plant to the Distribution System or Transmission System; or

- (d) any activities directly related to the Seller's Plant that enable Seller to comply with its obligations under this EPA that are carried out by Seller, any Affiliate, consultant or contractor of Seller, or any other Person for whom Seller is responsible at law.
- 1.63 **"PPT"** means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.
- 1.64 **"Present Value Rate"** means the annual yield on a Government of Canada bond having a term and maturity date that most closely matches the remaining Term (as at the date of the applicable calculation) and expiry date of this EPA, plus 3%.
- 1.65 **"Prime Rate"** means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Whitehorse, Yukon, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.
- 1.66 **"Project"** means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.
- 1.67 **"Project Cluster"** means two or more existing or proposed Projects under the SOP Rules that Buyer determines in its Discretion are so closely related to each other that they should be considered a project cluster for the purposes of the Standing Offer Program.
- 1.68 **"Project Energy Volume"** (in KWh) means the maximum annual Energy which Buyer may sell to Seller from the Project in any calendar year as set out in Schedule "B"; provided that where the Term does not commence on January 1, such amount shall be prorated for the first and last contract year which do not reflect a full calendar year.
- 1.69 **"Project Standards"** means:
- (a) all applicable Laws;
 - (b) the terms and conditions of all Permits, including land tenure agreements, issued in connection with the Seller's Plant;
 - (c) Good Industry Practice;
 - (d) the description of the Seller's Plant in Schedule "B";
 - (e) the requirement that Energy must qualify as Eligible Clean Energy; and
 - (f) the terms and conditions of this EPA (including the System Interconnection Guidelines).
- 1.70 **"Public Utilities Act"** means the *Public Utilities Act* (Yukon) and any successor or replacement legislation.
- 1.71 **"Records"** means all records and logs required to properly administer this EPA, including:
- (a) Energy generation records and operating logs;
 - (b) Meter readings;

- (c) maintenance reports;
- (d) invoice support records;
- (e) documents concerning compliance with Project Standards, but excluding any such documents that are protected by solicitor-client privilege;
- (f) records related to System Upgrade Costs and New Interconnection Facilities Costs;
- (g) all information reasonably required to establish the amount of Energy Seller could have sold during a Distribution/Transmission Constraint including logs of all Outages of the Seller's Plant and other reductions in Energy output (specifying the date, time, duration and reasons for each such outage and each reduction in Energy output); and
- (h) information relating to the Environmental Certification, information relating to the existence, nature and quality of Environmental Attributes, information required for the purposes of any Environmental Attributes or energy certification or tracking system, and any other information Buyer requires to enable it or any of its Affiliates to obtain and realize the benefit of the Environmental Attributes,

all consistent with Good Industry Practice.

1.72 "Regulatory Agency Authorizations" means the issuance of those Permits which are specified as required for the Project in the YESAB assessment report recommendation to proceed issued in respect of the Project.

1.73 "Seller" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

1.74 "Seller Confidential Information" means any of Seller's confidential technical or financial information provided by Seller to Buyer in confidence with express written notice to Buyer of the confidential nature of the information, but excluding:

- (a) this EPA; and
- (b) information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Buyer, or (ii) is known to Buyer before disclosure to it by Seller, or becomes known to Buyer thereafter by way of disclosure to Buyer by any other Person who is not under an obligation of confidentiality with respect thereto.

1.75 "Seller's COD" means the commercial operation date of Seller's Plant which is the date on which all of the following conditions have been satisfied in respect of the Seller's Plant:

- (a) Seller has obtained all Permits required for the construction, commissioning, and operation of the Seller's Plant and all such Permits are in full force and effect;
- (b) the Seller's Plant has been fully constructed in accordance with the Project Standards;
- (c) Seller is not: (A) Bankrupt or Insolvent; (B) in default of any payment obligation or requirement to post security under this EPA; (C) in material default of any of its other covenants, representations, warranties or obligations under this EPA; or (D) in material

default under any Permit or Law applicable to the construction, commissioning or operation of the Seller's Plant or under any land tenure agreement for the site on which the Seller's Plant is located;

- (d) a Meter has been installed at the POI in accordance with Section 3.6 of this EPA;
- (e) Seller has delivered to Buyer a written notice together with certificate of Seller's professional registered engineer confirming that Seller's COD has been achieved; and
- (f) Buyer has delivered a Commission Notice to Operate, or such other document(s) of similar effect as may be substituted therefor, which evidences no material deficiencies, in respect of the Seller's Plant Capacity and Seller's Plant operations;

and for purposes of this EPA, Seller's COD will be deemed to have occurred at 24:00 PPT on the later of the dates set out above.

- 1.76 "Seller's Plant"** means Seller's plant described in Schedule "B" and all assets required to interconnect that plant to the Distribution System or Transmission System; all rights, property, facilities, assets, equipment, materials, Permits and contracts required to design, engineer, procure, construct, commission, operate and maintain the plant described in Schedule "B" and to interconnect that plant to the Distribution System or Transmission System, whether real or personal and whether tangible or intangible including all land tenure and all books, Records and accounts with respect to the Seller's Plant described in Schedule "B"; and shall include replacement parts or equipment which are of the same or similar nature as the parts or equipment being replaced and which do not materially increase the amount of Energy available from Seller's Plant.
- 1.77 "Seller's Plant Capacity"** means the electrical generating capacity of the Seller's Plant set out in Schedule "B".
- 1.78 "Seller's Plant Load"** means any electrical energy consumed by Seller's Plant.
- 1.79 "Single Line Diagram"** means the simplified electrical representations of the Seller's Plant, the Interconnection, the Distribution System and Transmission System attached hereto in Schedule "B".
- 1.80 "SOP OIC"** means that Order in Council issued by the Government of Yukon on January 24, 2019 regarding, among other things, the Standing Offer Program.
- 1.81 "SOP Rules"** means the Standing Offer Program Rules developed by the Government of Yukon which governed this EPA as at the date of this EPA.
- 1.82 "Standing Offer Program" or "SOP"** means the Standing Offer Program as described in the IPP Policy.
- 1.83 "System Interconnection Guidelines"** means those system interconnection guidelines in the form attached as Schedule "G" hereto, as amended or replaced by Buyer from time to time.
- 1.84 "System Interconnection Study Report"** means the detailed interconnection study issued to Seller by Buyer which, among other things, (i) evaluates the impact of the Project on the reliability of Buyer's system, (ii) provides a planning-level estimate of the required System

Upgrades and New Interconnection Facilities and associated costs, and (iii) establishes the Line Loss Methodology for this Project, a copy of which is attached as Schedule "D".

- 1.85 "System Upgrades"** means additions, modifications and upgrades to the Distribution System, Transmission System or any portion of Buyer's generation system that are determined by Buyer to be required in order to facilitate the interconnection and to allow such Distribution System, Transmission System or any portion of Buyer's generation system to support the integration of the Energy produced by the Seller's Plant in accordance with this EPA and the System Interconnection Guidelines, which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any New Interconnection Facilities.
- 1.86 "System Upgrade Costs"** means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the System Upgrades, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.
- 1.87 "Target Buyer's COD"** means the target date for achieving Buyer's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.
- 1.88 "Target Seller's COD"** means the target date for achieving Seller's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.
- 1.89 "Term"** has the meaning given to such term in Section 2.1.
- 1.90 "Termination Payment"** has the meaning given to such term in Schedule "F".
- 1.91 "Transmission System"** means the transmission, substation, protection, control and communication facilities owned and operated by Buyer, and includes all additions and modifications to those facilities and repairs or replacements of those facilities.
- 1.92 "Upgrade Costs Advance"** has the meaning given to such term in Section 3.5(a).
- 1.93 "Upgrade Costs Security"** has the meaning given to such term in Section 3.5(a).
- 1.94 "Utilities"** means both Yukon Energy Corporation or Yukon Electrical Company, doing business as ATCO Electric Yukon, as applicable.
- 1.95 "YESAA"** means the *Yukon Environmental and Socio-economic Assessment Act*, SC 2003, c 7.
- 1.96 "YESAB"** means the Yukon Environmental and Socio-economic Assessment Board.
- 1.97 "YUB"** means the Yukon Utilities Board and any successor thereto appointed from time to time under the *Public Utilities Act*.

2. INTERPRETATION

- 2.1 Headings** - The division of this EPA into Articles, sections, Sections, paragraphs and Schedules and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.
- 2.2 Plurality and Gender** - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.
- 2.3 Governing Law** - This EPA is made under, and will be interpreted in accordance with, the Laws of the Yukon. Subject to Section 12.1, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Yukon at Whitehorse, and those courts have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.
- 2.4 Industry Terms** - Technical or industry specific phrases or words not otherwise defined in this EPA have the well-known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.
- 2.5 Statutory References** - Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.
- 2.6 Currency** - References to dollars or \$ means Canadian dollars, unless otherwise stated.
- 2.7 Reference Indices** - If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA will be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under Section 12.1 of this EPA.
- 2.8 Conversions** - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.
- 2.9 Additional Interpretive Rules** - For the purposes of this EPA, except as otherwise expressly stated:
- (a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Schedules attached to this EPA;
 - (b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular section, Section or other subdivision;
 - (c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto;

- (d) the words "year" and "month" refer to a calendar year and a calendar month;
- (e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;
- (f) all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively; and
- (g) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, will be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

3. ADDRESSES FOR NOTICES

3.1 Notices to Buyer - Except as noted below, all notices addressed to Buyer will be delivered to the following address:

To: **YUKON ENERGY CORPORATION**
#2 Miles Canyon Road
Box 5920
Whitehorse, YT Y1A 6S7
Attention: IPP Manager
Email: ipp@yec.yk.ca

3.2 Notices to Seller - All notices addressed to Seller will be delivered to the following address:

To: **NOMAD CONTRACTING & ELECTRICAL SERVICES LTD.**
62 Mt Sima Rd
Whitehorse, YT Y1A 0A8
Attention: Sebastien Roy
Email: nomad_electric@outlook.com

SCHEDULE "B"

PROJECT DESCRIPTION

CONTRACT PARTICULARS:

1. **Condition Date:**

Nil.

2. **Conditions Precedent:**

Nil.

3. **Term:**

The "**Term**" of this EPA commences on the Effective Date and continues for a period of 25 years following Buyer's COD.

4. **Energy Price and Seasonal Adjustment:**

- (a) In each billing period, Seller shall pay to Buyer, for each KWh of Delivered Energy the "**Energy Price**" calculated as follows:

$$\text{Energy Price}_n = (.5 * \$0.158/\text{KWh} * \text{CPI}_{\text{January 1, } n} / \text{CPI}_{\text{January 1, 2020}}) + (.5 * \$\_\_/\text{KWh})$$

Where:

n = the year for which the relevant calculation is being conducted

$\text{CPI}_{\text{January 1, } n}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted;

- (b) For each hour, the Energy Price determined above for Delivered Energy during that hour will be adjusted to an amount (expressed in \$/KWh) equal to the percentage of that Energy Price applicable for that hour as set out in the table in Schedule "I".

SELLER'S PLANT

1. **Location of Control Building:**

60° 38' 045" N and -135° 01' 050" W

2. **Eligible Clean Energy Type:**

Solar PV

3. **Seller's Plant Capacity:**

150kW

4. **Project Energy Volume:**

Month	Energy Volume (KWh)
January	3,126.3
February	13,232.0
March	28,210.3
April	36,987.5
May	37,860.9
June	36,194.0
July	34,918.6
August	32,736.9
September	23,825.4
October	16,396.7
November	4,833.6
December	1,742.6

5. **Seller's Plant Description:**

Please refer to Seller's single line diagram in Exhibit B-1.

Total AC Power: 150 kW
Primary AC line voltage: 480 V
Total AC line current: 180.4 A
Total DC power: 246.4 kW
Open-circuit DC voltage: 1000V/String
Operating DC voltage: 700V/String
Total DC operating current: 352 A

6. **Target Seller's COD:**

June 1, 2021

7. **Electrical Grid:**

Yukon Integrated System.

BUYER'S SYSTEM UPGRADES

1. **System Upgrades:**

No upgrades are required other than a change to OCR5953 reclose interval to allow for the operation of the Nomad solar plant islanding detection

2. **New Interconnection Facilities:**

The proposed interconnection to the AEY SL649 distribution line will consist of:

- One slack-span tap from the mainline

- One OH to UG riser pore
- One switchable 300 kVA pad mount transformer and vault
- Estimated 25m of overhead 1/0 ACSR
- Estimated 15m of underground #1 cable
- 2 pole tap
- 150 kVA 14.4kV/25kV – 277/480V oilfield transformer

Please refer to Buyer's single line diagram in Exhibit B-2.

3. **Target Buyer's COD:**

June 1, 2021

BREAKERS/SWITCHES AND SYNCHRONIZATION

H365NR Safety switch, heavy duty, fusible, 400A, 3 poles, 250 hp, 600 VAC/DC, NEMA 3R, neutral factory installed and a CHU362RB 60A 3P Type3R 600VAC/DC Heavy Duty Non Fusible Safety Switch will be used. The specifications of such switches are attached.

After voltage is restored after an outage no reconnections will be attempted until the Seller has permission to reconnect from the System Control Center (as identified in Schedule "H"). After permission is given, the Seller must check that voltage and frequency are stable and within 10% of nominal values before closing in to reconnect:

- A plus or minus 10% voltage range is acceptable; and
- A plus or minus 10% frequency range is acceptable.



Main

Product or component type	Single Throw Safety Switch
Disconnecter device type	Non-fusible disconnect
Number of poles	3
Electrical connection	Lugs
Series name	Heavy duty

Complementary

Line Rated Current	60 A
Device composition	None
Device mounting	Surface
System Voltage	600 V AC/DC
AWG gauge	AWG 14...AWG 3 (copper or aluminium)

Environment

Product certifications	CSA
NEMA degree of protection	NEMA 3R galvanized steel

Offer Sustainability

Sustainable offer status	Green Premium product
RoHS (date code: YYWW)	Compliant - since 1313 - Schneider Electric declaration of conformity Schneider Electric declaration of conformity
REACH	Reference not containing SVHC above the threshold Reference not containing SVHC above the threshold
Product environmental profile	Available
Product end of life instructions	Need no specific recycling operations

Product data sheet

Characteristics

H365NR

Safety switch, heavy duty, fusible, 400A, 3 poles, 250 hp, 600 VAC/DC, NEMA 3R, neutral factory installed

Product availability : Stock - Normally stocked in distribution facility



Price* : 5,765.00 USD



Main

Product	Single Throw Safety Switch
Current Rating	400 A
Certifications	UL listed file E2875
Enclosure Rating	NEMA 3R galvanized steel
Factory Installed Neutral	Neutral (factory installed)
Disconnect Type	Fusible disconnect
Short Circuit Current Rating	10 kA H or K 200 kA R, J or L
Mounting Type	Surface
Number of Poles	3
Electrical Connection	Lugs
Duty Rating	Heavy duty
Voltage Rating	600 V AC/DC
Wire Size	AWG 1/0...750 kcmil copper or aluminium

Complementary

Maximum Horse Power Rating	100 hp 480 V AC 50...60 Hz 3 phase NEC 240.6 250 hp 480 V AC 50...60 Hz 3 phase NEC 430.52 125 hp 600 V AC 50...60 Hz 3 phase NEC 240.6 350 hp 600 V AC 50...60 Hz 3 phase NEC 430.52 50 hp 250 V DC 50 hp 600 V DC
Maximum Height	50.31 in (1277.87 mm)
Depth	10.13 in (257.30 mm)
Width	27.88 in (708.15 mm)

Tightening torque	550 lbf.in (62.14 N.m) AWG 1/0...750 kcmil)

Ordering and shipping details

Category	00054 - H&HU SW,NEMA3R,400-1200A
Discount Schedule	DE1
GTIN	00785901026686
Nbr. of units in pkg.	1
Package weight(Lbs)	186 lb(US) (84.37 kg)
Returnability	Yes
Country of origin	MX

Packing Units

Unit Type of Package 1	PCE
Package 1 Height	14.02 in (35.6 cm)
Package 1 width	28.31 in (71.9 cm)
Package 1 Length	51.50 in (130.8 cm)

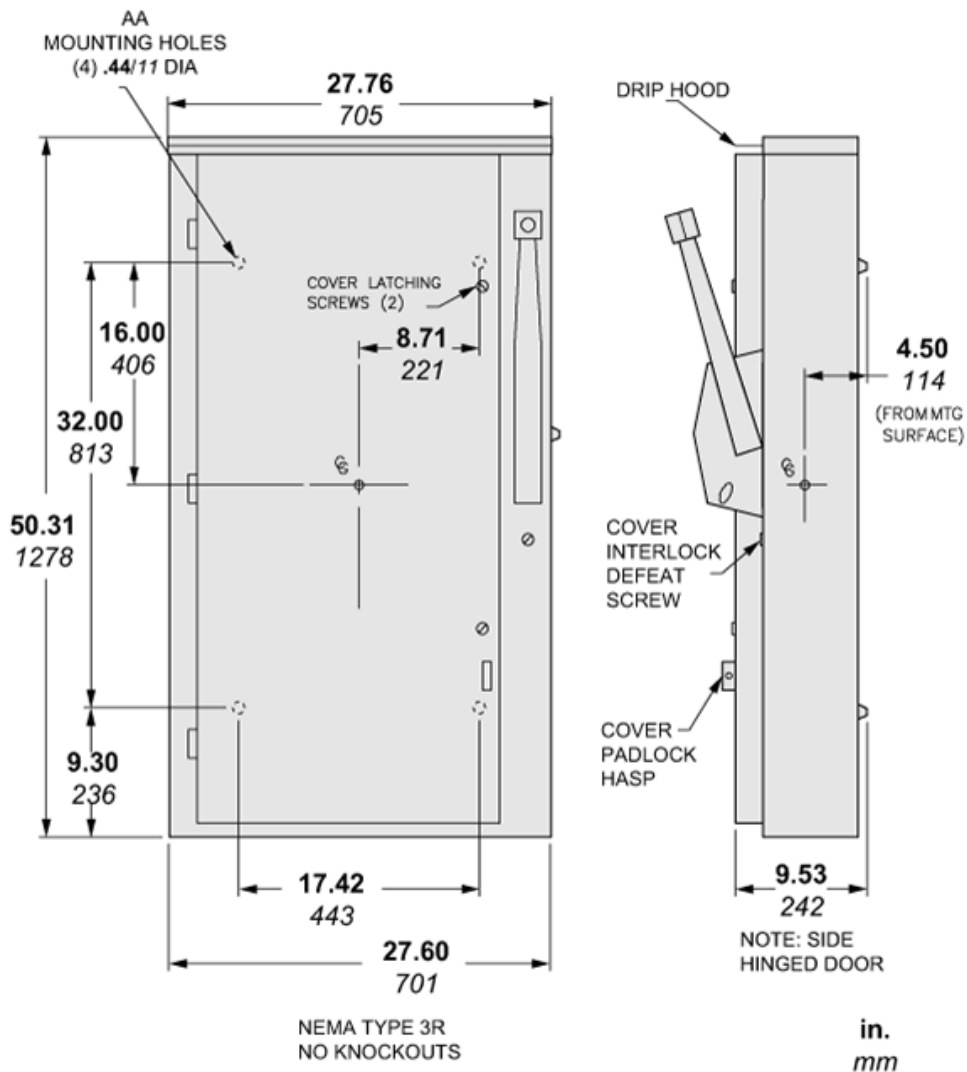
Offer Sustainability

Sustainable offer status	Green Premium product
REACH free of SVHC	Yes
EU RoHS Directive	Compliant EU RoHS Declaration
Mercury free	Yes
RoHS exemption information	Yes
China RoHS Regulation	China RoHS declaration Product out of China RoHS scope. Substance declaration for your information.
Environmental Disclosure	Product Environmental Profile

Contractual warranty

Warranty	18 months

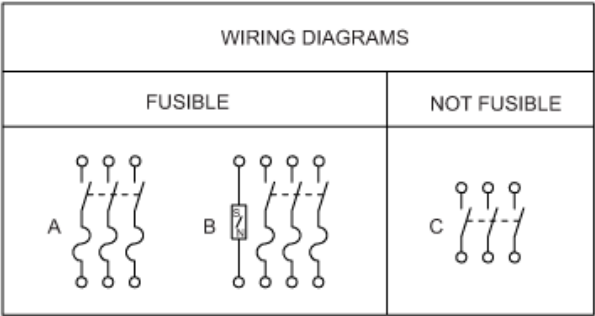
Approximate Dimensions



Product data sheet
Connections and Schema

H365NR

Wiring Diagrams



TERMINAL LUGS DATA			
AMPERE	MAX WIRE	MIN WIRE	TYPE
400	(1) 750 KCMIL	(1) #1/0 AWG	AL OR CU
	OR (2) 300 KCMIL	OR (2) #1/0 AWG	

EXHIBIT B-1

Seller's Single Line Diagram

(Please see attached)



**Nomad Electric IPP Project
Mount Sima Industrial Area, Yukon**

SOLAR PHOTOVOLTAIC

DC Power: 246.4 kW
AC Power: 150 kW at 1.0 Power Factor
Inverter AC Output (x 5): 30 kW
Inverter DC Input (x 5): 49.28 kW
Operating DC Voltage: 700V/String
Number of Strings: 40
Number of Strings per Inverter: 8
Number of Modules per String: 16

- A) 150kVA Transformer (25 kV to 480 V)
- B) Yukon Energy Meter Base
- C) 400A – 3P – FUSED AC Disconnect
- D) 400A – 4 Wire Splitter – 5 sub taps
- E) 60A – 3P – FUSED AC Disconnect
- F) Huawei 30KTL Inverter (480 Vac) with integrated DC Disconnect
- G) Canadian Solar CS3U-385W Bi-facial Modules

Grid Connection as per ATCO Design

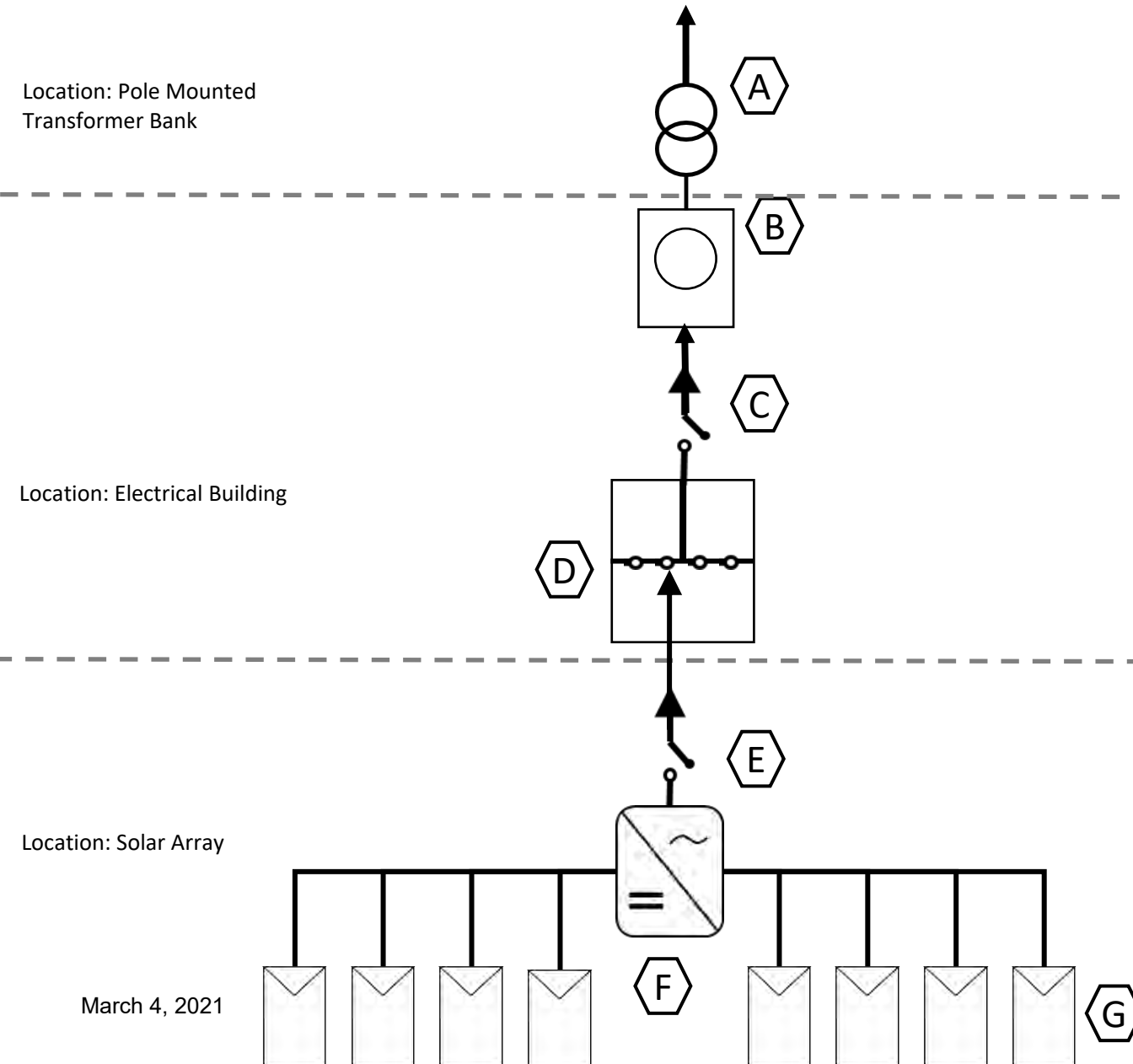


EXHIBIT B-2

Buyer's Single Line Diagram

(Please see attached)



SCHEDULE "C"

FORM OF ANNUAL OPERATING PLAN

DATE: _____, 20__.

TO: Yukon Energy Corporation ("Buyer")

RE: Electricity Purchase Agreement between Nomad Contracting & Electrical Services Ltd. ("Seller") and Buyer dated the 27th day of August, 2020 (the "EPA")

The following sets out the Annual Operating Plan of Seller for the 12 months commencing on January 1, 20__ (the "**Applicable Period**").

- (a) The following (from Table E-1 of Schedule "E" of the EPA) is the schedule of the expected total deliveries of Energy at the POI in each month of the Applicable Period:

	Projected Hourly Energy (KWh/h) (A)	Projected Monthly Energy (KWh) (B)
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

- (b) The following is the schedule of any Planned Outages of the Seller's Plant expected by Seller for the Applicable Period:

[to come]

- (c) The following is the schedule of operations and maintenance activities planned for the Seller's Plant expected by Seller for the Applicable Period:

[to come]

Dated effective as of the date set forth above.

**NOMAD CONTRACTING &
ELECTRICAL SERVICES LTD.**

Per: _____
[Name]
[Title]

Per: _____
[Name]
[Title]

SCHEDULE "D"
SYSTEM INTERCONNECTION STUDY REPORT

(Please see attached)



Yukon Energy Corporation

200 kW Nomad Solar Plant Assessment

Prepared by:

Teshmont Consultants LP
by its General Partner, Teshmont GP Inc.

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2019 November 08

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP (“Teshmont”), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision History

Revision Number	Date Released	Prepared by	Reviewed by	Comments
Rev00	2019 November 01	Ashraful (Rony) Islam, PEng	David King, PEng Ashraf Haque, PEng	
Rev01	2019 November 08	Ashraful (Rony) Islam, PEng	David King, PEng Ashraf Haque, PEng	

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1. Introduction

Teshmont was requested to perform a grid impact and interconnection study for the connection of the 200 kW Nomad solar plant to the existing Yukon electric system. The proposed plant will be connected to one of the ATCO Electric's 25 kV distribution feeders originating at their MacRae Substation

The system impact study will include:

- Load flow study
- Short circuit study
- Protection assessment

2. ETAP Modelling and Study Assumptions

2.1. Modelling

Teshmont used the ETAP power system analysis software to model the 200 kW Nomad solar plant and the 25 kV feeder to which it will be connected. The feeder was modeled starting at YEC's Whitehorse (S150) Substation, to ATCO's MacRae Substation at downstream to the location where the solar plant will be connected. The model was prepared based on the following information received from YEC:

1. MacRae Substation is approx. 7.6 km downstream from Whitehorse Substation. The solar plant will be connected approximately 1.1 km downstream from MacRae Substation.
2. Construction details.
 - a) Line 9L from Whitehorse substation to MacRae Substation is constructed of 267 ACSR (Partridge)
 - b) MacRae substation to Nomad solar plant interconnection point is approximately:
 - i. 1.1 km of 2/0 ACSR (Quail),
 - ii. 0.6 km of 1/0 ACSR (Raven)
3. Load data: Summer Peak (SP) and Winter Peak (WP) load data at S6839, S6840, S9833 and S5953 metering points are prepared as shown in Table 2-1 and Table 2-2 based on the information received from YEC.

Table 2-1: S6839, S6840 and S9833 Meter Data Modeling

Metering Points of Feeder 9L	Summer Peak (SP) Load			Winter Peak (WP) Load		
	MW	Power Factor * (%)	MVA	MW	Power Factor (%)	MVA
S6839	0.196	90	0.218	2.423	90	2.692
S6840	0.441	90	0.49	2.348	90	2.609
S9833	0.702	90	0.78	3.492	90	3.880

* Assumed

Table 2-2: S5953 Load Distribution Across 5L649 Feeder

S5953 Load Distribution	Summer Peak (SP)			Winter Peak (SP)		
	MW	Power Factor (%)	MVA	MW	Power Factor (%)	MVA
5L649 downstream load	0.125	90	0.139	0.417	90	0.463
Nomad solar plant tap line load	0.175	90	0.194	0.583	90	0.647

- Settings of the voltage regulators in MacRae Substation as shown in Table 2-3.

Table 2-3: R61/R62/R63 Regulator Settings

Function	Setting
Control Mode	Forward
Set Voltage	124 V
Bandwidth, Volts	2 V
Time Delay, Initial	60 Sec
Time Delay, Operating	60 Sec

- Solar PV Model: Teshmont used a typical PV Panel and Inverter model from the ETAP library and configured it to model a 200 kW solar plant.

The modeled feeder and downstream equipment in ETAP are shown in Figure 1.

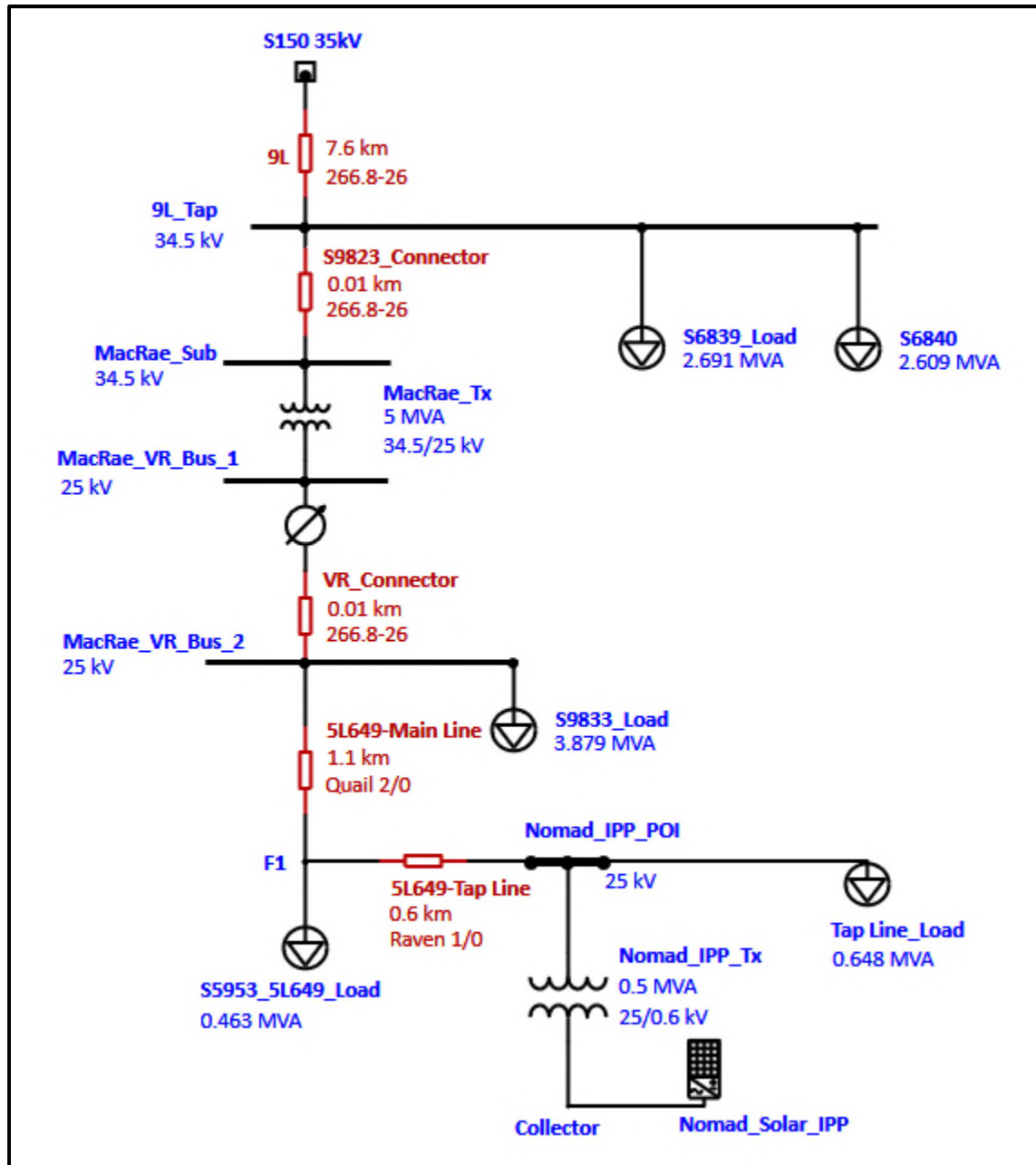


Figure 1: ETAP Single Line Diagram of 9L Feeder

2.2. Assumptions

The following assumptions are taken for this project:

1. The SP and WP loads at S6839, S6840, S9833 and S5953 metering points were prepared and modeled as directed by YEC. The maximum loads during the winter season are assumed as cold load and a 50% reduction factor is applied to obtain the WP loads.

2. The short circuit contribution of the solar plant is assumed to be 150% of the full load current.
3. The Nomad solar plant will be set in power factor control mode at unity power factor.
4. Typical values for settings and assumed configurations are used to model the downstream feeder and associated equipment where data is not available.

3. Analysis

3.1. Short Circuit Study and Protection Coordination Review

Teshmont modeled the solar plant short circuit contribution as 150% of its full load current. As such, the 200 kW solar plant will contribute 7 A of constant fault current.

For a three-phase fault at the solar plant, the estimated minimum three phase fault current is 799 A and maximum three phase fault current is 1156 A.

For a 40 ohm fault impedance, the estimated minimum ground fault current is 317 A and a maximum ground fault current is 331 A.

3.1.1. Equipment Ratings

Existing equipment ratings are adequate.

3.1.2. Overcurrent Protection Settings

The downstream OCR S5953 phase current pickup setting is 140 A and the ground current pick up setting is 110 A.

For 1 MW of downstream load, the load current is 23 A. The relay overcurrent pickup setting is approximately six times the load current. The magnitude of downstream fault currents will remain sufficient to be seen by the OCR.

OCR S5953 will continue to detect and operate for downstream faults at the Solar Plant.

3.1.3. Anti-Islanding Protection

To meet the anti-islanding requirements of IEEE 1547, the solar plant inverters must detect an islanding event and safely separate from the grid within 2 seconds.

The existing first reclose interval for OCR S5953 is set for 0.6 seconds. This will need to be reset to 2 seconds or greater to allow the solar plant to disconnect before the first reclose attempt.

3.2. Load Flow Study and Assessment of Voltage Regulator Settings

The load data provided by YEC/ATCO confirms that the output of the solar plant will always be less than the feeder load. Therefore there will always be forward load flow in the regulators and they can continue to be set in locked-forward mode.

The MacRae substation voltage regulator (VR) settings were modeled according to the settings provided by YEC/ATCO. The voltage regulator is set to control the secondary 25 kV bus at the load side.

Using the study case “VG_S6” case, regulator improves the voltage from 98.52% (source side) to 103.1% at the MacRae 25 kV bus (load side). At Nomad solar plant point of interconnection (POI), the voltage is noted 102.8% in pre-project scenario and 102.9% in post-project scenario.

Using the study case “VG_W6” case, regulator improves the voltage from 94.91% (source side) to 101.4% at the MacRae 25 kV bus (load side). At Nomad solar plant POI, the voltage is noted 101.2% in pre-project scenario and 101.3% in post-project scenario.

4. Conclusion

The connection of the 200 kW Nomad solar plant to the YEC/ATCO distribution feeder 5L649 out of MacRae Substation will have no negative impact on the YEC grid.

Existing equipment ratings and feeder protection settings are adequate, other than a change will be required to OCR5953 reclose interval to allow for the operation of the Nomad solar plant islanding detection.

SCHEDULE "E"

MONTHLY ENERGY SHORTFALL PAYMENT

Monthly Energy Shortfall Payments

In any calendar month in which there has occurred a Non-Permitted Distribution/Transmission Constraint then Buyer shall pay Seller Monthly Energy Shortfall Payment,

where:

"Monthly Energy Shortfall Payment" means the Monthly Constraint Shortfall multiplied by the price which is payable for Delivered Energy under Section 5.1 of the EPA; and

"Monthly Constraint Shortfall" (expressed in KWh) means, for each calendar month, means the aggregate of the duration of each Non-Permitted Distribution/Transmission Constraint (measured as a fraction determined as the aggregate number of minutes in such Non-Permitted Distribution/Transmission Constraint divided by 60) multiplied by the "Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy" set out in Table E-1 below for the applicable calendar month.

Table E-1

	Projected Hourly Energy (KWh/h) (A)	Projected Monthly Energy (KWh) (B)	Non-Permitted Distribution/Transmission Constraint Factor (F1)	Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy (KWh/h) (A x F1)
January	4.20	3,126	__%	
February	19.69	13,232	__%	
March	37.92	28,210	__%	
April	51.37	36,988	__%	
May	50.89	37,861	__%	
June	50.27	36,194	__%	
July	46.93	34,919	__%	
August	44.00	32,737	__%	
September	33.09	23,825	__%	
October	22.04	16,397	__%	
November	6.71	4,834	__%	
December	2.34	1,743	__%	

Revisions to Projected Hourly Energy and Projected Monthly Energy

Within 90 days following the end of the 2nd year after Buyer's COD, the Parties shall review and revise the values in Table E-1 above for Projected Hourly Energy and Projected Monthly Energy to reflect the

average actual amount of Delivered Energy sold to Buyer in the 2 years following Buyer's COD for the applicable months.

SCHEDULE "F"

TERMINATION PAYMENT

The "**Termination Payment**" at any time shall be equal to (a) the Gross Termination Payment set out below for the Contract Year in which the termination occurred, less (b) the actual amounts paid or owing by Buyer to Seller for Delivered Energy for the Contract Year in which the termination occurred.

Table F-1

Termination Year	Gross Termination Payment
Year 1	\$477,336
Year 2	\$474,530
Year 3	\$471,081
Year 4	\$466,934
Year 5	\$462,026
Year 6	\$456,293
Year 7	\$449,663
Year 8	\$442,059
Year 9	\$433,397
Year 10	\$423,588
Year 11	\$412,533
Year 12	\$400,128
Year 13	\$386,259
Year 14	\$370,801
Year 15	\$353,622
Year 16	\$334,577
Year 17	\$313,511
Year 18	\$290,254
Year 19	\$264,624
Year 20	\$236,423
Year 21	\$205,439
Year 22	\$171,441
Year 23	\$134,179
Year 24	\$93,383
Year 25	\$48,762

SCHEDULE "G"
SYSTEM INTERCONNECTION GUIDELINES

(Please see attached)



Yukon Energy Corporation

Independent Power Producers Interconnection Technical Guide

Revision: 04b
Release Date: 2019 01 24

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP (“Teshmont”), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision History

Revision Number	Date Released	Prepared by	Reviewed by	Comments
00	May 14, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng Robert Baker, PEng	First Draft
01	May 30, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Second Draft
02	June 5, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Third Draft. Incorporated YEC Comments.
03	June 18, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fourth Draft. Incorporated YEC Comments.
04	September 17, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fifth Draft. Incorporated YEC Comments.

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Appendix C	Information Provided by the Utility
Appendix D	Applicable Codes and Standards
Appendix E	Sample Operating Agreement
Appendix F	Typical Interconnection Single Line Diagrams
Appendix G	Protective Settings Commissioning Document

Executive Summary

The purpose of the Interconnection Technical Guide is to provide guidelines for Independent Power Producers (IPP) who wish to interconnect a generation facility of greater than 50 kW and up to 10 MW to the Yukon Integrated System (YIS) via the Yukon Energy Corporation (YEC) or ATCO Electrical Yukon (AEY) distribution systems. The maximum allowable generation at the Point of Interconnection (POI) between the distribution system and IPP will depend on the results of a system impact study conducted by YEC. This guide details the technical and operational requirements of the facility and is not intended to be used as a design guide.

The purpose of this document is to:

- Provide technical specifications for the interconnection of IPP generation to the YIS (via YEC or AEY distribution systems).
- Clarify, where necessary, the technical requirements in CSA Standard C22.3 No. 9-08 (R2015) “Interconnection of Distributed Resources and Electricity Supply Systems” [1] and to provide an outline for how each section applies to interconnections with the YIS.

1. *Introduction and Scope*

1.1. *Purpose*

This guide establishes criteria and technical requirements for Independent Power Producers (IPP) who wish to interconnect generation, with a net capacity greater than 50 kW and up to 10 MW, to the Yukon Integrated System (YIS), at the distribution level (35 kV and below), or at the transmission level (above 35 kV). This guide has been developed considering CSA Standard C22.3 No. 9-08 (R2015) [1] and IEEE Standard 1547-2018 [2] and is subject to regular review and revision due to evolving standards.

The technical guide is intended to assist IPPs who apply to connect to the YIS through the Standing Offer Program, Call for Power, or through other unsolicited requests to connect.

1.2. *Limitations*

The criteria and technical requirements described within this section apply to the following generation interconnections:

- Interconnections to the Yukon Energy Corporation (YEC) and ATCO Electric Yukon (AEY) distribution systems at voltages of 34.5 kV and below, and
- Interconnections to the YEC transmission system at voltages over 34.5 kV by means of an existing or new substation. Transmission interconnections will require specific detailed review and approval by YEC and all interconnection costs will be borne by the IPP.

This Guide establishes the minimum requirements for the Point of Interconnection (POI). The IPP generation may be subject to additional requirements to ensure the project meets all applicable standards.

This Guide is not to be used:

- As an Operating Agreement and does not address the following:
 - o Joint operating agreements
 - o Costs
 - o Tariffs
 - o Other contractual issues
- As an Interconnection Process and Procedures Guide, and does not include the following:
 - o Protection of the IPP's generation facilities
 - o Transmission system impact and upgrades
 - o System planning and design
 - o Operation of the distribution system
 - o Other system related issues
- As a design handbook for a generation facility.
- For any IPP generation not connected indirectly or directly to the YIS, i.e. an island grid.

2. Terms, Definitions, and Abbreviations

2.1. Definitions

Accredited Certification Organization – An organization that has been accredited by the Standards Council of Canada to operate a certification program for electrical equipment, such as the Canadian Standards Association (CSA).

Anti-islanding – A means of detecting and preventing a DR from energizing a part of the distribution system that becomes disconnected from the grid.

ATCO Electric Yukon – A private investor-owned utility, and member of the ATCO Group of Companies.

Automatic Circuit Recloser (ACR) – An overcurrent protection device used by utilities to detect faults on distribution system feeders, which has the ability to open and then reclose after a specified time delay allowing adequate time for temporary faults to clear.

Bi-directional Meter – A meter that measures real and reactive power and energy in both directions.

Cease to Energize – The cessation of energy outflow capability.

Clearing Time – The time from the start of the abnormal condition to when the distributed resource ceases to energize the distribution system.

Dispensated Metering Equipment – Any metering equipment that has received Measurement Canada approval under Section 9(2) or 9(3) of the Electricity & Gas Inspection Act.

Disconnecting Means – A device or group of devices that allows the conductors of a circuit to be disconnected from their source of supply.

Distributed Generation (DG) – Small, decentralized electric power generation facilities, typically interconnected to the distribution system.

Distribution System – The portion of the electrical system that operates at a nominal voltage of 34.5 kV line to line and below, and which distributes electric power between distribution substations and customers.

Effectively Grounded Distribution System – Distribution facilities where the neutral conductor is solidly grounded and the ratio of the zero sequence reactance to the positive sequence reactance is less than or equal to 3 and the ratio of the zero sequence resistance to the positive sequence reactance is less than 1.

Electromagnetic Interference (EMI) – Any electromagnetic disturbance that interrupts, obstructs, or otherwise degrades or limits the effective performance of a device, equipment or system.

Exporting – supplying power into the distribution system through the POI.

Facilities – A physical plant including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery.

Flicker – The subjective impression of fluctuating luminance caused by voltage fluctuations.

Frequency – The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz (Hz).

Generation – The process of converting solar, thermal, wind, hydro, or chemical energy into electric energy.

Independent Power Producer (IPP) – An agency or individual other than a public utility (as defined by the Public Utilities Act) who generates electricity to sell (to the utilities). An independent power producer does not own transmission facilities and is dependent on the utilities to purchase and distribute the power it produces.

Interconnection – The physical connection of DG to YEC's distribution system so that parallel operation can occur.

Island Grid – A community power system which is energized solely by one or more local power producers and is separated electrically from the YIS.

Islanding – A condition where a portion of the utility's distribution system is energized exclusively by one or more power producers through their DR interconnection.

Operating Interface Point – See Point of Interconnection.

Parallel Operation – the simultaneous energization at a POI by the generating facility and the utility distribution system.

Point of Interconnection (POI) – The location of the electrical connection between an IPP facility and the utility's distribution system. This will be the point where the ownership changes from the utility to the IPP.

Power Factor – The ratio of active power to apparent power. It is the cosine of the phase angle difference between the current and voltage of a given phase.

Protection Scheme – The protection functions, including associated sensors, relays, and power supplies, intended to protect a distribution system or interconnection equipment.

Public Utility – As defined by the Public Utilities Act and Regulations (i.e., YEC and/or AEY).

Ride-through – The ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Secondary Injection Testing – A method in which low level signals obtained from current and voltage signal generators are injected into a power system protective device to test device response.

Stabilized – The state of the distribution system after voltage and frequency has returned to normal range for a period of at least five minutes (or another period of time, as agreed with YEC) following a disturbance.

Stand Alone – The state where a distributed generation can operate by controlling the frequency and voltage of their facility while in islanded or isolated mode.

Telemetry – Transmission of measurable quantities using telecommunications systems.

Total Demand Distortion (TDD) – The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the maximum demand current. Harmonic components of order greater than 50 may be included when necessary.

Total Harmonic Distortion (THD) – The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the fundamental. Harmonic components of order greater than 50 may be included when necessary.

Transfer Trip – A remote signal directed from an upstream device to command a DG to cease to energize the distribution system upon detection of an islanding condition and to prevent re-energization.

Transmission System – The portion of the system that operates above a nominal voltage of 34.5 kV line to line and transmits electric power between YEC substations.

Trip Time – The time between the start of the abnormal condition and the interconnection device ceasing to energize the distribution system.

Type Test – A test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance.

Utility – See Public Utility (i.e., YEC and/or AEY).

Visible-Break Disconnect – A switch or circuit breaker by means of which the generator and all protective devices and control apparatus can be simultaneously disconnected under full load entirely from the circuits supplied by the generator. All blades or moving contacts must be connected to the generator side, and the design of the disconnect switch must allow adequate visible inspection of all contacts in the open position.

Voltage Flicker – A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.

Yukon Energy Corporation (YEC) – A publicly-owned electrical utility that is the main generator and transmitter of electrical energy in Yukon.

Yukon Integrated System – The integrated Whitehorse-Aishihik-Faro and Mayo-Dawson electrical grids which are owned by YEC.

2.2. Abbreviations

ACR	Automatic Circuit Recloser
AEY	ATCO Electric Yukon
AEUC	Alberta Electrical Utility Code
CEA	Canadian Electricity Association
CEC	The Canadian Standards Association's C22.1-98 Safety Standard for Electrical Installations Part 1, also known as the Canadian Electrical Code
CSA	Canadian Standards Association
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IPP	Independent Power Producer
LTC	Load Tap Changer
NEMA	National Electrical Manufacturers Association
POI	Point Of Interconnection
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SIS	System Impact Study
YEC	Yukon Energy Corporation
YIS	Yukon Integrated System
YUB	Yukon Utilities Board

3. Party Responsibilities

Refer to the IPP Policy as released in January 2019 for the individual responsibilities of the Government of Yukon, utilities (YEC and AEY), Yukon Utilities Board and the IPP during the generation interconnection process.

3.1. IPP Responsibilities

The IPP is responsible to:

- Provide technical information to the utility as specified in Appendix A and Appendix B;
- Assume ownership of the facility including the design, installation, operation, and maintenance of all equipment, station and distribution line facilities from the POI to the IPP facility, unless otherwise agreed to in writing;
- Pay the costs of system interconnection in accordance with the commercial terms established by the utilities;
- Obtain all regulatory approvals, including environmental assessment approvals, if necessary, for the construction and operation of its facilities. The IPP facilities shall be designed, constructed, operated and maintained in compliance with the applicable statutes, regulations, by-laws, codes and technical requirements specified by the utility (e.g. remote monitoring etc.);
- Submit all specifications of its facilities and detailed plans to the utility for review prior to receiving permission to connect to their distribution system;
- Ensure the technical requirements given in the standards and codes in Appendix D are met;
- Ensure metering requirements are met (see section 12); and
- Negotiate the timing and any testing requirements for the commissioning process with YEC

3.2. YEC Responsibilities

YEC is responsible for the operation of the Yukon Integrated System (YIS) and for certain local distribution systems interconnected with the YIS. This guide applies to all transmission and YEC distribution system interconnections.

YEC is responsible for all system studies performed on the YIS. The IPP and AEY, in the case of an AEY interconnection, shall provide all necessary information to YEC for the interconnection of the IPP facility. The system studies conducted by YEC will be paid for by the IPP.

After receiving the application for interconnection, YEC shall provide the IPP, at the IPP's cost, the information specified in Appendix C.

3.3. AEY Responsibilities

AEY is responsible for the operation of certain local distribution systems interconnected with the YIS. This guide applies to these AEY distribution system interconnections.

After receiving the application for interconnection, AEY shall, in consultation with YEC, provide the IPP, at the IPP's cost, the information specified in Appendix C.

4. General Requirements

4.1. Standards

When planning, designing, and operating an IPP Generation Facility, the IPP shall meet all applicable national, territorial and local construction and safety codes and standards.

The interconnection facility must comply, as a minimum, with the following:

- All CSA Standards, including the Canadian Electrical Code (CEC),
- Applicable YEC and AEY standards and the requirements set forth in this Guide,
- National, Territorial and local Governing law, acts, by-laws and codes, and
- Alberta Electrical Utility Code (AEUC) [4].

Applicable standards are located in Appendix D, however not all may be applicable for the IPP facility and additional standards may apply.

The interconnection of new generation can adversely affect the electric service to existing or future customers. The IPP must work with the utility to mitigate any adverse effects.

The facility must be constructed and maintained to provide a safe environment for employees as well as the public. If the generation facility adversely affects other customers, the utility may disconnect it until such time as the concern has been mitigated. The IPP is responsible for any costs incurred as a result.

The IPP is required to install, operate and maintain the facility and to ensure it is in sufficiently good order and repair at all times. Maintenance shall conform to good electrical practice, adequate for safe parallel operation when connected to the YIS. The utility and the IPP shall share commissioning reports, operating procedures and annual shutdown, maintenance, and inspection reports.

4.2. Operating Requirements

A joint operating agreement template will be developed in conjunction with the utility. The agreement requirements are not included within the scope of this Guide. A sample operating agreement is located in Appendix E.

5. Site Specific Conditions and Capacity Limitations

During the preliminary stage of project development any limitations regarding the proposed interconnection, and any additional system upgrades required, will be determined in consultations between the IPP, YEC and AEY, if interconnected via an AEY distribution system.

A system impact study will be necessary to identify any site-specific conditions and capacity limitations of the distribution and/or transmission system. To facilitate the study, the utility and the IPP will exchange information concerning load, feeder characteristics, protection philosophies, station layouts, capacities, ratings and other relevant information of the distribution and/or transmission system. The utility controls reliability design and reliability standards.

Under certain circumstances, YEC and AEY may limit the size or reconfigure the proposed connection arrangement of the IPP facility in order to maintain the integrity of their system.

6. YIS Transmission and Distribution System Characteristics

6.1. YEC Transmission System

6.1.1. General System Configuration

The YIS is an 'Islanded grid' which has no interconnection with the main North American electric grid. The Yukon must produce all of its own power, and cannot generate more electricity than is there is load, since there are no neighboring markets into which to sell surplus energy.

The YIS includes the 138 kV Whitehorse – Aishihik – Faro (WAF) grid, the 69 kV Mayo-Dawson-Keno (MD) grid, and the 138 kV Carmacks-Stewart Transmission Line (CSTL) which interconnects the WAF and MD grids. YEC provides power to major industrial customers connected to the 69 kV and 138 kV grids.

A map of the YIS is shown in Figure 6–1.

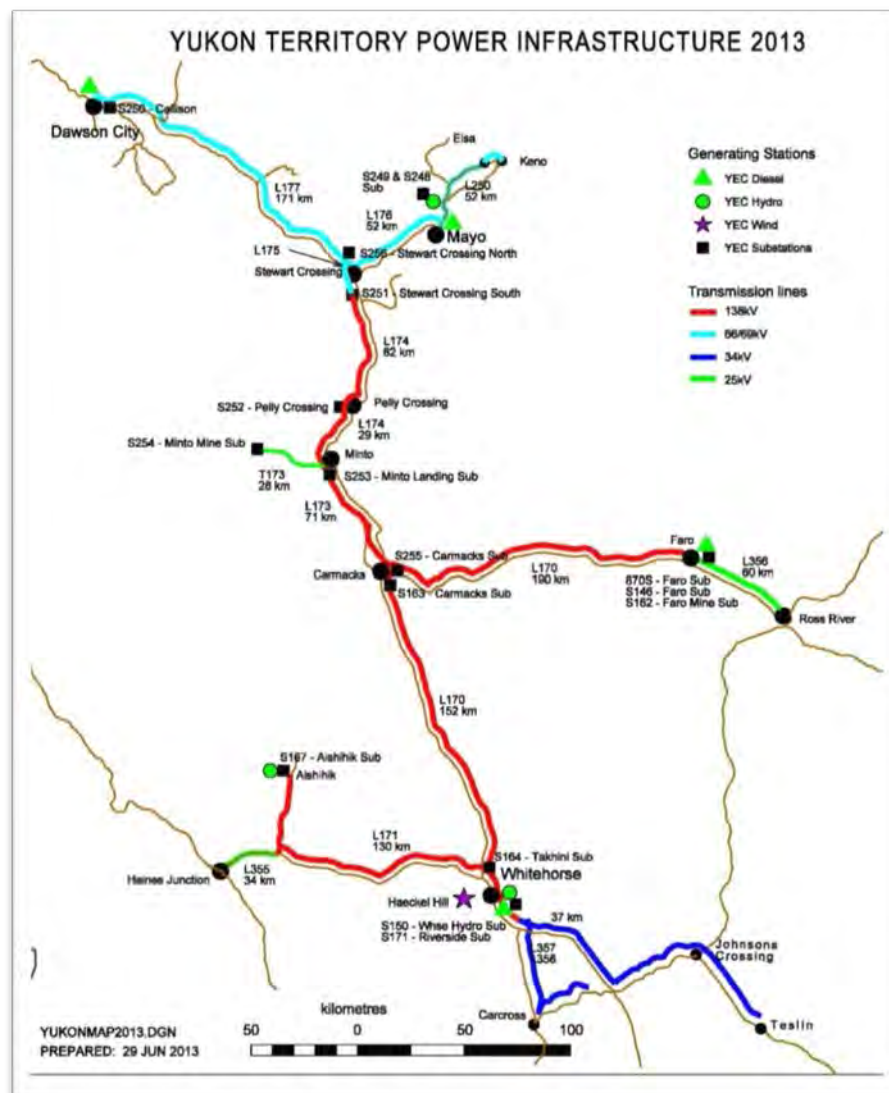


Figure 6–1: YIS Map

6.1.2. System Unbalance

Voltage unbalance on the transmission system is minimal during normal operation. The voltage unbalance under normal operating conditions will be less than three (3) percent. The IPP facilities may be subjected to voltage unbalance and negative sequence current during system disturbances. The generation connected to the transmission system must be able to withstand significantly unbalanced voltages with high negative phase sequence currents for short periods of time.

6.1.3. Frequency

The YEC transmission system operates at 60 Hertz (Hz) Alternating Current (AC) with equipment standard for this frequency. Frequency variations are typically in the range between 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, however variations between 58 Hz to 66 Hz or greater can occur for larger contingencies.

The frequency of the electric system is controlled by synchronous generator governor systems. Such governor systems respond automatically to changes in system frequency to prevent further deviation. These variations are system dependent and subject to change.

6.1.4. Steady State Voltage Levels

During normal steady state conditions, the 69 kV and 138 kV systems can vary between 90% and 105% of nominal voltage. However, under extreme conditions, the 69 kV and 138 kV systems can vary between 85% and 110% of nominal voltage with some 138 kV facilities designed to operate continuously up to 110% of nominal voltage.

6.1.5. System Fault Levels and System Impedances

The IPP generation facilities connecting directly to the transmission system shall be designed for operation at short circuit (fault) levels that take into account reasonable future development of the YIS transmission system. The short circuit levels to be used in the design depend on the point(s) of interconnection and future planned development and are available on request from YEC.

6.1.6. Fault Clearing and Automatic Reclosing

The YIS does not implement auto-reclosing at the transmission level.

6.1.7. System Grounding

The transmission system is effectively grounded.

6.2. YIS Distribution System Characteristics

6.2.1. General

Both YEC and AEY operate distribution systems in the Yukon which are interconnected with the YIS. The systems are predominantly three phase, wye connected, with nominal voltages of 4.16/2.4 kV, 6.9/4 kV, 12.5/7.2 kV, 13.8/8 kV, 25.00/14.4 kV and 34.5/20 kV.

AEY also operates a number of distribution systems which are not interconnected to the YIS, and are not covered by this Guide:

- Watson Lake
- Old Crow
- Beaver Creek
- Destruction Bay / Burwash Landing
- Swift River

For information on connecting to the AEY distribution systems which are isolated from the YIS, refer to AEY's document entitled, "ATCO Electric Yukon's Isolated Community Generation System Interconnection Guidelines".

6.2.2. Voltage Levels

The YEC and AEY distribution systems operate to meet CSA Standard CAN3 C235.83 – "Preferred Voltage Levels for AC Systems 0 to 50,000V" which defines the preferred operating voltage levels for normal and extreme operating conditions. The distribution system steady state voltage is typically maintained between + 5% to 7% and - 5% to 7%.

6.2.3. Power Quality (Harmonics and Voltage Flicker)

The YEC and AEY distribution systems operate to limit the maximum individual frequency voltage harmonics to 3% of the fundamental frequency and the voltage total harmonic distortion (THD) to 5% on the utility side of the POI.

6.2.4. Voltage Regulation

The operating voltages on the low voltage buses of YEC distribution substations are generally regulated by transformer automatic load tap changers (LTC), bus voltage regulators or feeder voltage regulators. YEC will provide set-points for the equipment upon request.

6.2.5. Voltage Unbalance

Distribution facilities are typically three-phase systems, incorporating single-phase distribution taps. The voltage unbalance on a distribution system under normal operating conditions may exceed 3%, due to the unbalanced loading and single-phase regulation. Voltage unbalance will be calculated using the following formula, as derived from CSA Standard C22.3 No. 9-08 (R2015) [1]:

Voltage Unbalance (%) = 100 x (negative sequence voltage of the fundamental frequency component) / (positive sequence voltage of the fundamental frequency component)

6.2.6. *Fault Levels*

Fault levels and maximum allowable fault currents vary significantly through the distribution system and must be considered in the design of the IPP interconnection.

6.2.7. *System Grounding*

The utility distribution facilities are typically three phase, four wire, multi-grounded systems that incorporate single phase distribution taps. The lines are normally operated as effectively (solidly) grounded with grounded-wye connected sources at the distribution substation secondary bus.

6.2.8. *Phasing*

The phase sequence on the utility system may vary, and must be confirmed between the IPP and the utility during the design phase of the installation.

6.2.9. *Fault and Line Clearing and Automatic Reclosing*

The YEC distribution systems do not currently include auto reclosing. The AEY distribution systems may have auto reclosing and this will be confirmed during the design phase of the application.

7. Power Quality Requirements for the System Interconnection

7.1. Harmonics

The following industry standards may provide guidance for appropriate performance.

- IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018 [2]
- IEEE 519-2014 – IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems [5]
- IEC 61000-4-15 – Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications [6]

The generation facility shall not inject harmonic currents such that will cause objectionable voltage distortion as per standard IEEE 519 Harmonic current injections cause intolerable voltage distortions on the distribution system and may damage equipment.

The Utility, at the IPP's expense, shall conduct a Power Quality Assessment of the distribution system in the immediate vicinity of the interconnection using a measurement technique compliant with IEC 61000-4-7.

When performing a Power Quality Benchmark, the measurements at the customer's POI shall be taken over a one week (168 hour) period during typical production load levels.

7.2. Flicker

The generation facility shall meet the requirements of Section 6.2.3 and shall not cause unacceptable levels of flicker on the distribution system. The utility, at the IPP's expense, shall measure the flicker level using a power quality measuring device that meets the requirements of the IEC Flickermeter Standard 61000-4-15.

When performing a Flicker assessment, the measurements at the customer POI shall be taken over a representative load cycle of one day or greater.

7.3. Speed Regulation and Frequency Control

The frequency of the YIS is controlled by the generators operated by YEC.

The YIS operates at 60 Hertz (Hz) Alternating Current (AC). The nominal frequency variations are typically 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, and the frequency may drop to 58 Hz or rise to 66 Hz or higher for larger contingencies.

The frequency of the YIS is automatically controlled by the governor systems of the generators operated by YEC, within the specified limits.

IPP generators rated at 1 MVA and greater are required to have a governor system, capable of operating in droop mode, to respond to system frequency changes. The droop setting of the governor will typically be in the range of 5%.

IPP generators rated less than 1 MVA may operate in base load mode rather than in frequency control mode.

The utility will define frequency requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC.

Equipment connected to the YIS shall be capable of withstanding the dynamic frequency performance criteria listed in Table 1.

Table 1: Transmission Minimum Frequency Performance

Under Frequency Limit	Over Frequency Limit	Minimum Time
60.0-59.0 Hz	60.0-61.0 Hz	N/A (continuous operating range)
58.9-58.5 Hz	61.1-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	Instantaneous trip

Under-frequency and over-frequency relaying that automatically disconnects generators from YIS must not operate for frequencies in the range of 59.0 to 61.0 Hz if no other abnormal system event is underway.

7.4. Voltage Regulation and Power Factor

The IPP is responsible for ensuring that the voltage levels at the POI are maintained within this guidelines prescribed by the utility. The IPP interconnection must maintain the voltage levels, under all feeder load conditions, at the same values as they were prior to the interconnection.

Synchronous generators connected to the distribution system must be equipped with adequate excitation controllers. The IPP shall operate generators with Automatic Voltage Regulators (AVR) adjustable from 95% to 105% of nominal bus voltage. The Generation should be run in Voltage control unless required to run in power factor (pf) mode by the Utility. Operation in MW or MVAR control is not acceptable. The AVR response should with no intentional delay when in Voltage Control mode.

Induction generators do not have voltage or reactive power control capability and consume reactive power (VAR). In this case, the generator must provide reactive compensation to correct the power factor to 0.9 lagging or better at the POI, unless other terms are specified by the utility.

Inverter type generating equipment can control the power factor over a wide range, typically ± 0.75 . An inverter type generator connected to the distribution facility must be capable of adjusting the power factor in the range of ± 0.9 . The IPP may operate outside that range only by prior agreement with the utility.

The utility will define voltage and reactive power requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC. The IPP and utility will identify and

agree on the exact transformer ratio to allow optimal voltage regulation on the system and the IPP will determine whether an on-load tap changer is needed.

In order to coordinate with its existing voltage control devices, the utility may require that the generator operate in a power factor control mode. This means operating within a constant power factor set point range. The voltage/power factor regulator must be capable of controlling the power factor of the generator. The utility shall determine the actual set point between these limits.

In power factor control mode, the voltage regulator must have a voltage override that causes it to reduce excitation if the voltage at the POI exceeds an upper limit to be specified by the utility. The normal upper limit is 105% of nominal; however, the voltage regulator shall have the provision to adjust this upper limit between 100% and 110% of nominal. The voltage regulator must also have provision for a time delay between sensing an excursion of the upper voltage and initiating control action. The power factor control equipment must have the capability to allow for the adjustment of this time delay from between 0 and 180 seconds. The utility will specify the required time delay for each project.

7.5. Voltage Unbalance

Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. Of particular concern is negative sequence voltage and the resulting effect, particularly on rotating generators and motors connected to the system.

To protect the utility and the IPP equipment, the 3-phase generation contribution at the POI should not cause a voltage unbalance greater than 1% or a current unbalance greater than 5%.

If the existing unbalance at the POI is shown to be already close to the maximum unbalance condition, the IPP contribution may cause the unbalance to exceed the specified amount. This will be considered on a case-by-case basis.

7.6. Voltage and Frequency Transients

The IPP is responsible for the cost of any necessary transient or dynamic stability studies, which must be performed in a manner approved by YEC.

7.7. Resonance and Self-Excitation of Induction Generators

The potential effects of resonance should be considered as part of the design of the generating facility. The effects include:

- Ferro-resonance in the transformer,
- Sub-synchronous resonance due to the presence of capacitor banks, and
- Harmonic resonance with other customers when capacitors are being added as part of the installation.

When induction generators are used, the potential for self-excitation should be assessed and addressed as part of the system impact study and mitigated accordingly.

The IPP shall be responsible for the engineering analysis as part of the design process to evaluate the existence of, and to eliminate the harmful effects of resonance and the assessment of the self-excitation effects of induction generators. The engineering analysis of resonance and the assessment of the self-excitation effects of induction generators must be submitted to YEC for approval or further evaluation.

7.8. DC Current Injection

The IPP facility system shall not inject a dc current at the POI.

7.9. Fault Levels

The utility will provide the IPP with the anticipated fault levels or the data necessary for the IPP to calculate the distribution system fault contributions at the POI.

The IPP facility must not increase the fault levels on the utility distribution or transmission system above their design levels for maximum faults.

8. Physical Interconnection

8.1. Safety

The safety of the public, operating personnel and the environment is of primary concern in the design, construction, operation and maintenance of the interconnection facilities.

8.2. Point of Interconnection (POI)

The POI is the point at which the utility (YEC or AEY) distribution facilities or conductors are connected to the IPP's facilities or conductors, and where any transfer of electric power between the IPP and the utility takes place. The POI must be identified in the design and on the Single Line Diagram (SLD).

Depending on ownership, YEC or AEY will coordinate the design, construction, maintenance and operation of the facility on the distribution system side of the POI. The IPP is responsible to coordinate the design, construction, maintenance and operation of the facility on the generation side of the POI.

All voltage and frequency parameters specified in this section must be met at the POI unless otherwise stated.

The IPP is responsible for any incremental costs to the electric systems caused by the interconnection. The responsible utility will carry out the engineering, design and construction required for these installations and charges those costs back to the IPP. Ongoing O&M costs incurred on the distribution feeder side will also be recovered by the utility.

There may be cases where either the utility or the IPP may own equipment located on the other's side of the POI. For example, the utility may own and operate communications, supervisory, or metering equipment, which is located on the IPP side of the POI. The IPP must provide a site with the necessary space for utility to install current transformers, potential transformers, switching equipment, meters, and any other AC and DC auxiliaries, protection and controls, SCADA or communications equipment required to interconnect with the generating facility. The site is to be approved by the utility and a 120-volt AC power service is to be available for the use of portable tools.

8.3. Point of Disconnection

For transmission interconnections, the visible-break disconnect switch shall be located on the high voltage side of the interconnection transformer.

For distribution interconnections, the visible-break disconnect switch may be located on the high or low voltage side of the interconnection transformer.

The disconnect switch must be gang operated to simultaneously isolate all three phases.

If the IPP site interconnects multiple generators, one disconnect switch must be capable of isolating all of the generators simultaneously. There may be other means of meeting this requirement; however the approval of the utility must be obtained before using other means.

The IPP must follow the utility switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

8.3.1. High Side and Low Side Disconnect Switches

For transmission interconnections the disconnect switch on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

For distribution interconnections the disconnect switch, if on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the utility, and if on the low voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

8.3.2. Disconnect Switch Specification

The disconnect switch must be a manual, visible-break disconnect that provides safe isolation for the utility's personnel from the generators and all other possible customer sources of energy.

The disconnect switch must:

- Be adequately rated to break the connected generation/load;
- Be located within five meters (horizontal) of the POI, unless otherwise approved by the utility;
- Provide a direct, visible means to verify contact operation;
- Allow simultaneous disconnection of all ungrounded conductors of the circuit;
- Plainly indicate whether the switch is in the "open" or "closed" position;
- Be lockable in the "open" position;
- Be capable of being energized from both sides;
- Be readily accessible to the utility's operating personnel;
- Be externally operable without exposing the operator to contact with live parts;
- Be capable of being closed without risk to the operator while there is a fault on the system;
- Be labeled with utility's switch number;
- Meet all applicable CSA Part II standards and all applicable codes; and
- Undergo annual inspections and maintenance, with reports submitted to the utility for approval.

8.4. Interconnection Transformer

A generator step-up transformer boosts the voltage of the DG to match the voltage of the utility distribution feeder. The transformer winding configuration impacts how system faults are detected and what type of protection is required (see Section 9.10). The IPP must submit their transformer connection proposal to the utility for review and approval prior to placing an order for purchase.

8.5. Interconnection Grounding

The IPP facility must be grounded in accordance with the latest revisions of the CEC and AEUC. A ground grid of sufficient size to handle the maximum available ground fault current must be designed and installed in order to limit ground potential rise (GPR) step and touch potentials to safe levels as set forth in ANSI/IEEE Std. 80 IEEE Guide for Safety in AC Substation Grounding.

The ground grid will be designed for foreseeable future fault levels obtainable from the System Impact Study.

Grounding of the interconnection shall be designed to provide:

- Solid grounding of the distribution feeder neutral connection,
- Fault detection that isolates all sources of ground fault contribution,
- A circuit to block the transmission of harmonic currents and voltages, and
- Protection of the low voltage side from damage due to high side faults.

The preferred configuration, for an IPP owned interconnection transformer, is delta connection on the generator side of the transformer and a grounded-wye configuration on the utility's side of the transformer. If this configuration is not technically feasible, the configuration chosen must still address the above concerns. Grounding must conform to the AEUC [4].

Sample single line diagrams are shown in Appendix F.

8.6. *Phasing and Phasing Sequence*

Since phasing is not standardized across distribution facilities, the phase sequence must be coordinated between the IPP and utility's distribution system.

8.7. *Interrupting Device Ratings*

The design of the generation facility must consider the fault contributions from both the distribution system and the IPP generation facility, to ensure that all circuit fault interrupters are adequately sized. The utility will inform the IPP of the present and anticipated future fault contribution from the interconnected electric system.

9. Interconnection Protection

9.1. General

The purpose of the IPP facility protection is to reduce the risk of damage to IPP and utility equipment and maintain the reliability of supply.

The protection scheme shall be designed to detect the following conditions at the POI:

- Balanced and unbalanced system faults (i.e. line-ground, line-line and three phase faults)
- Frequency variations
- Voltage variations
- Reverse power flow
- Islanding conditions
- Out of synchronism

Depending upon location, the protection scheme may be required to detect additional conditions such as open phase, ferro-resonance, negative sequence voltage, or zero sequence currents.

The protection scheme must fully coordinate with any existing distribution system protective devices. The IPP must submit a complete protection design package, including all relay settings, tripping schemes and schematics, to the utility for review and approval prior to installation. Both existing and ultimate bus fault levels should be considered. A sample Protective Setting Commissioning Sheet with guideline limits is included in Appendix G.

The point of measurement for voltage and frequency shall be at the POI or as agreed upon with the utility.

The IPP must revise and re-submit the protection information for any proposed modification.

9.2. Device Ratings

Equipment shall be rated to carry and interrupt the fault levels that are, or will be, present at the IPP facility - this includes the ultimate fault currents specified by the utility. The IPP's equipment covers all station and distribution facilities, including but not limited to all protection equipment forming the entrance and distribution line protection: circuit breakers, current transformers, potential transformers, secondary cabling, dc system/battery charger, switchboard wiring and protective relays.

9.3. Minimum Protection Requirements

The following minimum protection requirements shall be provided for an interconnected IPP facility:

- Overcurrent
- Over-frequency
- Under-frequency
- Over-voltage
- Under-voltage

Additional protection requirements are dependent upon the transformer configuration and the distribution system characteristics.

9.4. Phase and Ground Fault Protection

The IPP must install utility grade protective devices to detect and promptly isolate the generation facility for faults occurring either in the DG facility itself or on the distribution system. Virtual devices (i.e., computer or programmable-logic controller systems) are acceptable provided they meet standard utility practice for system protection and they have been type tested and approved by an independent testing laboratory.

The protective devices in the IPP generation facility must fully coordinate with the protective relays on the distribution system unless otherwise agreed. The IPP must calculate the protective device settings and submit the relay characteristics and settings to YEC for review and approval.

The generation facility must be able to detect the following situations and isolate itself from the distribution system:

- A short circuit between any phase(s) and ground (if distribution system is a grounded system)
- A short circuit between phase(s)

9.5. Over-Frequency and Under-Frequency Protection

Each synchronous generator must be capable of continuous operation between 59.0 Hz and 61.0 Hz and of limited time operation for larger deviations from normal frequency, as shown in Table 1.

Over/under frequency relays are normally installed to protect the generators from extended off-nominal operation. It is expected that larger (> 1 MW) synchronous generators shall remain connected to the system during frequency excursions. To ensure that the generator is not tripped prematurely, YEC will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

9.6. Over-Voltage and Under-Voltage Protection

The IPP must operate its generation facility such that the voltage levels on the utility's system are not significantly altered by the connection of the generation facility. IPP facility paralleling shall not cause voltage fluctuations of more than $\pm 5\%$ at the POI.

The IPP must install necessary relays to trip the circuit breaker when the phase-to-ground voltage, measured on any one of the three phases, deviates outside predetermined limits. Under-voltage relays should be adjustable and should have a settable time delay to prevent unnecessary tripping of the generator on external faults. Over-voltage relays should be adjustable and may be instantaneous.

The interconnection facility must cause the generator to cease to energize the utility's system within the trip times indicated in Table 2. "Trip time" refers to the period of time between the start of the abnormal condition and the moment the interconnection device ceases to energize YEC's system.

To ensure that the generator is not tripped prematurely, the utility will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

Table 2: Response to Abnormal Voltages

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: $V < 50\%$	Trip time: Instantaneous

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: $50\% < V < 90\%$	Trip time: 120 cycles
RMS Voltage: $90\% < V < 105\%$	Normal Operation
RMS Voltage: $105\% < V < 120\%$	Trip time: 30 cycles
RMS Voltage: $V \geq 120\%$	Trip time: Instantaneous

The IPP may reconnect when the system is stabilized (i.e. voltage and frequency have returned to normal range for a time as identified by the utility).

9.7. Additional Protection

The utility may require additional protection on a case by case basis. Possible protection may include:

- **Unbalance or negative sequence protection:** The IPP generator is tripped on excessive current unbalance. This is important if fuse protection is used on the primary of the generator step-up transformer or for any other open phase condition
- **Broken delta protection (59G):** Using a grounded wye-broken delta potential transformer, this protection can facilitate detection of ground faults on ungrounded systems.
- **Rate of change of frequency:** Protection to detect a power island condition.
- **Reverse power protection:** Protection to detect a generator motoring condition.

9.8. Anti-Islanding Protection

Islanding is the condition where the generation facilities and a portion of the distribution system have become isolated from the rest of the system, and continue to operate in isolated mode. Unless agreed upon by the utility, generating facilities shall not be permitted to remain connected to an islanded system, i.e. islanding is not generally allowed. Generation facilities may continue to supply station service loads while disconnected from the interconnection system.

Anti-islanding protection is required to:

- Prevent power quality issues to customers connected to the island,
- Avoid out-of-phase reclosing between the utility and the DR facility, and
- Prevent safety hazards created as a result of back feeding isolated portions of the utility distribution system.

For rotating generators, the IPP must install a transfer tripping scheme using tele-protection signals from the system to separate the DG facility from the distribution system in the event of an islanding condition.

Transfer tripping requirements are also applicable to induction generators, unless the IPP can demonstrate that there is no potential for self-excitation. For inverter-based generation a detection scheme designed in accordance with the requirements of IEEE 1547 [2] may be acceptable.

The IPP is responsible for damage to the YIS caused as a result of failure to safely separate from the system during an islanding event or subsequently during reconnection to the system following the event.

9.9. Transformer Winding Configuration

The winding configuration of any three phase transformer will have an influence on the location of the protection measurement points and the level of protection required for the IPP interconnection. See Appendix F for examples for typical synchronous generator protection single line diagrams for different transformer configurations.

9.10. Conditions for Connecting to an Energized Distribution System

The IPP system must not energize the utility distribution system when the distribution system is de-energized or following the operation of any interconnection protection functions. The utility will inform the IPP facility when it is safe to reconnect to the distribution system.

Where transfer trip protection is installed, the transfer trip protection must ensure that the generator disconnects before a substation feeder breaker or intermediate automatic circuit reclose (ACR) operation. General requirements are:

- Generator lockout within 0.6 seconds of breaker or ACR opening; and
- Fail-safe lockout within 6 seconds of communication loss.

These conditions will be finalized via the operating agreement between the utility and the IPP.

9.11. Synchronization

Any DG facility able to generate voltage while disconnected from the YIS requires synchronization facilities before connection is permitted.

The IPP facility shall maintain in synchronism with the system while operating in parallel. The generating facility has the responsibility of maintaining synchronization with the system. The utility cannot synchronize to the generating facility. Any proposed synchronizing scheme must be submitted to the utility, prior to the installation.

For synchronous generators, an approved automatic synchronizing device must be provided in all cases where the plant is to be operated unattended. Automatic synchronizing shall be supervised by a synchronizing check relay. Synchronizing controls should satisfy the conditions in Table 3 for synchronous generators.

Table 3: Synchronization Criteria for Synchronous Generators

Aggregate Rating of Generators (kVA)	Frequency Difference (Hz)	Voltage Difference (%)	Phase Angle Difference (degrees)
0-500	0.3	10	20
>500 – 1500	0.2	5	15
>1500	0.1	3	10

Induction generators do not require synchronization since there is no generated voltage prior to connecting to the distribution system. The generator speed shall be brought to within 0.5% of its rated value. These units may be started as induction motors using power from the distribution system provided that these units do not cause unacceptable voltage flicker as specified in Section 7.2 on start - up or on connect/disconnect. The interconnection process of the induction generator shall not create a voltage drop pf greater than 5 percent.

Inverter-type or line-commutating voltage-following equipment does not require synchronization facilities. Operation of the interconnection (or disconnecting of the DR facility) shall not cause voltage drop greater than 5 percent and shall meet the flicker requirements

9.12. Protection from Electromagnetic Interference (EMI)

The influence of EMI must not result in a change in state or mis-operation of the interconnection facility.

9.13. Surge Withstand Performance

The interconnection facility must have the capability to withstand voltage and current surges in accordance with the environments described in IEEE/ANSI C62.41 or C37.90.1

9.14. Batteries and Auxiliaries

Batteries and auxiliaries shall have sufficient capacity to ensure the operation of all DC loads during loss of AC supply. Typically the batteries must be capable of supplying the substation DC load for 8 hours.

9.15. Mitigation of Protection Scheme Failure

Relays with self-diagnostic features, which provide information on the integrity of the protection scheme, should be used whenever possible.

The protection scheme must be designed by a qualified professional engineer, or a competent technical person working with the utility's engineers, to ensure that the self-diagnostic feature is integrated into the overall protection scheme for the safe and reliable operation of the system.

Depending on the scheme and its design, where relays with the self-diagnostic feature do not trip the appropriate breaker(s), sufficient redundant or backup protection must be provided for the system. The malfunctioning relay must also send a signal to notify operating personnel to investigate the malfunction.

9.16. Instrument Transformers used for Protection

Instrument transformers used for protection must comply with CAN/CSA-C60044-6 or IEEE C57.13 [8].

10. Remote Monitoring and Information Exchange

The IPP facility shall provide information in real-time to YEC SCC regarding:

- a. Connection or circuit breaker status,
- b. Real and reactive power output in kW and kVAR,
- c. Load Tap Changer (LTC) position of the interconnecting transformer,
- d. Communication and RTU failure alarm,
- e. Intelligent Electronic Device (IED)/Relay failed status, and
- f. Voltage at the POI.

The communication protocol and the equipment required will be specified by YEC.

The IPP facility shall log the operation of any protective device, including which protection elements operated, and the status of the DG facility including power output, voltage, and current waveforms.

YEC may have additional requirements on a case by case basis.

If it is determined that the IPP facility will have an impact on YEC's Transmission Network, the IPP will be required to provide a Remote Terminal Unit (RTU) or Data Link to a YEC RTU capable of exchanging Supervisory Control and Data Acquisition (SCADA) information with the YEC Control Centre. The protocol for data exchange via the RTU shall be compatible with that used for communications used by YEC. The communication protocol and the equipment required will be specified by YEC.

The IPP will be required to provide the following typical data needed by the (SCADA) system:

- a. Individual generator(s) MW and MVAR
- b. Individual generator(s) MWh and MVARh
- c. Generator(s) breaker status
- d. Individual generator on/off status, if no generator breaker exists
- e. Total station MW and MVAR
- f. Station service MW, MVAR, hourly MWh and MVARh
- g. Generator transformer(s) high voltage side breaker(s) and isolator(s) status
- h. Bus voltage at high voltage bus
- i. PSS status, if applicable
- j. AVR status, if applicable
- k. AVR voltage setpoint, if requested
- l. Total plant MW setpoint, if requested
- m. Generator step-up transformer tap setting, if requested

11. Construction

The construction and installation of the IPP's generating facility must meet all applicable statutes, regulations, by-laws and codes. The IPP is responsible for obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities. Copies of all permits, compliance reports and inspection documents must be provided to the utility prior to energizing the POI.

All single line diagrams provided to the utility must be drawn in accordance with IEEE standards and conventions, and must be stamped by a professional engineer assuming responsibility for the design.

12. Metering

12.1. General

Two meters, primary meter and backup meter, will be required at the IPP facility:

- The utility shall install, own, operate and maintain one meter (primary) necessary for measuring the energy and demand supplied to the YIS, unless otherwise specifically provided in a contract with the IPP. This meter shall remain the sole property of YEC. The meter will comply with Measurement Canada requirements and will be owned and maintained by YEC.
- The IPP shall install, own, operate and maintain the other meter (backup) which does not necessarily have to comply with Measurement Canada requirements.

Generators exporting power onto the distribution system shall be equipped with bi-directional meters with four-quadrant measurement capability. An appropriate number of channels are required for four-quadrant meters to separately record active and reactive power in both the export and the import directions.

The high voltage side of the interconnection transformer is designated as the Measured Billing Point for all energy imported and exported from the IPP facility.

The metering equipment will be:

- Suitable for use in the environmental conditions reasonably expected to occur at the installation site; and
- Appropriate for measuring the power system characteristics reasonably expected to exist at the installation under all power system conditions and events.

The IPP shall provide Measurement Canada Approved instrument transformers. Each meter shall be connected to its own individual core/winding. For the utility meter the IPP shall wire from the instrument transformers to the meter receptacle using CSA-approved tamper resistant conduit and accessories suitable for the utility meter or metering equipment.

For transmission interconnections the IPP will provide burden calculations for proposed instrument transformer secondary wiring, for approval by YEC. If necessary the wiring burden may have to be reduced, by increasing the CT secondary conductor size, to meet Revenue Meter requirements.

The IPP shall supply and install the meter base to meet the utility requirements. The utility will provide the specifications for the meter base during the design phase.

12.2. Meter Requirements

The primary meter supplied by the utility will:

- Be Measurement Canada Approved for revenue metering;
- Be dispensated, with accuracy class ratings for active and reactive energy management as per Table 4;
- Be verified and sealed in accordance with the Electricity and Gas Inspection Act;
- Be capable of maintaining the interval boundaries within 60 seconds of the hour and every quarter hour thereafter;

- Measure all quantities required to determine active energy and reactive energy transferred in the required directions at the Measured metering point;
- Provide a separate register to maintain the continuously cumulative readings of the active energy and reactive energy transferred in the required directions at the Measured metering Point;
- Retain readings and, if applicable, all clock functions for at least 14 days in the absence of line power;
- Be equipped with meter failure alarm and communication failure alarm;
- Communicate all metering and equipment status to the YEC system control centre via the IPP's communication equipment;
- Apply loss compensation (such as line losses) factors where applicable to the revenue meters; and
- The meter shall have an accuracy class of 0.2% or better.

The backup meter supplied by IPP will:

- The backup metering will be of the same accuracy class and capability as the primary metering and shall include all equipment to provide the necessary billing data.
- Be non- dispensated, with accuracy class ratings for active and reactive energy management as per Table 5;
- .

Table 4: Schedule of Accuracies for Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Points of Delivery	Points of Supply	Measurement Transformers Accuracy Class
10 and above	1.0%	1.0%	0.3%
10	1.0%	1.0%	0.3%

Table 5: Schedule of Accuracies for Non-Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Watt-hour Meter Accuracy Class	Var-hour Meter Accuracy Class
10 and above	0.2%	0.5%
10	0.5%	1.0%

12.3. Measurement Transformers

The applicable winding(s) of the current and potential instrument transformers supplied and installed by the IPP must:

- Be approved by Measurement Canada for revenue metering.
- Be burdened to a degree that does not compromise the accuracy required by this guideline.
- Have a minimum of two cores per instrument transformer. One core connection for the utility meter and the other core connection for the IPP meter.
- Be used solely for metering and not to be used for any other purposes.
- Have an accuracy class rating that equals or exceeds the values specified in Table 4.

12.4. Remote Communications Equipment

The remote communications equipment may or may not be an integral part of the meter or the recorder. However, it must incorporate protocol schemes that will prevent the corruption of data during interval data transmission. The protocol must be suitable for the communications equipment type and nature of the communications media and path.

12.5. Password Protection

Two or more levels of password protection will be required for each meter data collection agency. One level is for full access to set time functions and a second level is for read only access to interval data and event logs.

12.6. Safety Requirements

The facility installation must conform to:

- Measurement Canada Standard Drawings;

- AEUC [4];
- CSA Standard C22.2 General requirements - Canadian electrical code, part II [7] ; and
- ANSI/IEEE C57.13-2016 IEEE Guide for Grounding of Instrument Transformers [8].

13. Interconnection Tests

13.1. General Testing Requirements

The IPP must notify YEC (and AEY if the interconnection is via the AEY distribution system) in writing at least three weeks prior to the initial energization and start-up testing of the IPP generation facility. YEC may witness any testing of the equipment and protection schemes associated with the interconnection. Tests must align with the requirements specified in IEEE 1547 and CSA 22.3 No 9-08.

13.2. Type Testing

Type testing is considered an acceptable method of verification where suitable and applicable equipment standards exist, and must be performed once for each specific protection scheme. All interconnection equipment must include a type testing procedure as part of the documentation in order to determine the protection settings meet the requirements set forth within this technical guide. A type test may be performed on one device or a combination of devices. In a case of a combination of devices which comprise a system, the testing will demonstrate that the devices are able to operate as a system.

The type tests shall be performed on a representative unit or system, either in a factory, testing laboratory, or in the field. Results from a resource within a similar product family or design, including hardware or software, shall be acceptable as a representative within the same product family where ratings are within 50% to 200% of the tested resource.

The following type tests must be performed in accordance with IEEE 1547.1 [9]:

- Temperature stability
- Response to abnormal frequency
- Response to abnormal voltage
- Synchronization
- Interconnection integrity
- Unintentional islanding
- Open phase
- Reconnect following abnormal condition disconnect
- DC injection (for inverters without interconnection transformers)
- Harmonics

13.2.1. Temperature Stability

The temperature stability test verifies the interconnection equipment maintains measurement accuracy of parameters over its specified voltage range.

13.2.2. Response to Abnormal Frequency

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal frequency.

13.2.3. *Response to Abnormal Voltage*

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal voltage.

13.2.4. *Synchronization*

This test verifies the interconnected IPP facility will accurately and reliably synchronize with the utility as per IEEE 1547.1.

13.2.5. *Interconnection Integrity*

The interconnection integrity test verifies the IPP facility meets the surge withstand requirements as specified in Section 9.14 when tested in accordance with IEEE 1547.1.

13.2.6. *Unintentional Islanding*

Where YEC requires an anti-islanding protection function (other than transfer trip) or minimum import power levels, this test verifies that an IPP facility will cease to energize in accordance with IEEE 1547.1.

13.2.7. *Open Phase*

The open phase test verifies that the IPP facility will cease to energize the utility interconnection upon the loss of an individual phase on the distribution network when tested in accordance with IEEE 1547.1.

13.2.8. *Reconnect following Abnormal Condition Disconnect*

This test verifies the functionality of the IPP facility interconnection component or system reconnect timer, which shall delay the reconnection to the utility following a trip event prior to the distribution system stabilization, as specified in Section 9.11.

13.2.9. *DC Injection (for Inverters without interconnection transformers)*

This test verifies that an inverter-based IPP facility will comply with the DC current inject limit specified in Section 7.9 when tested in accordance with IEEE 1547.1.

13.2.10. *Harmonics*

The individual current harmonics and the total demand distortion (TDD) of the IPP facility shall be measured and recorded under normal operating conditions to ensure the values are within the limits specified in Section 7.1

13.3. *Production Tests*

Production tests shall be conducted on each IPP generating unit and interconnection equipment prior to delivery to verify they meet the applicable standards and verify the operability of every generating unit manufactured for customer use.

The tests assume the equipment has met the applicable interconnection and interoperability requirements of the applicable standards and may be conducted as a factory test or performed as part of an evaluation or commissioning test. Facilities with adjustable set points shall be tested at a single

series of test points specified by the manufacturer. The summary report must provide a list of normal and abnormal performance category capability, final function settings, and final operating mode settings.

The following production tests are specified within IEEE 1547.1:

1. Response to abnormal frequency
2. Response to abnormal voltage
3. Synchronization

14. Commissioning Tests and Verifications

14.1. General

Commissioning tests are tests and verification on the IPP facility equipment to confirm the system as delivered, designed, and installed meets the interconnection and interoperability requirements of this guide and the applicable standards. These tests include visual inspections, and may include operability and functional performance tests as required.

Prior to the energization of the IPP facility, or changes to the facility, verification testing must be performed and coordinated with the utility. After the equipment is installed and ready for operation, the testing must be performed by a qualified individual in accordance the manufacturer's published test procedures, or IPP developed procedures that have been approved by the utility. Qualified individuals include: licensed, professional engineers; factory-trained and certified technicians and licensed electricians experienced in testing protective equipment. The utility reserves the right to witness the verification test or to require written certification that the test was performed.

Verification testing must also be performed annually or when major system upgrades or modifications are carried out.

14.2. Interconnection Verifications and Inspections

The following commissioning tests and inspections shall take place:

- a. Final IPP facility protection settings shall be verified, recorded, and provided to the utility. A sample protective settings commissioning report is located in Appendix G.
- b. Visual inspection shall ensure the grounding coordination requirements in Section 8.5 have been met.
- c. Visual inspection shall ensure the presence of a disconnecting means in accordance with Section 8.3 has been met.
- d. The polarities, burdens, and ratios of field wired instrument transformers shall be verified as correct and in accordance with the design documentation.
- e. Field installed power and control wiring shall be verified to be in compliance with drawings and manufacturer requirements.
- f. For three-phase systems, the phase rotation of the distribution system and the IPP facility as installed shall be verified as compatible.
- g. All monitoring and information exchange provisions shall be verified as functional in accordance with Section 10.
- h. Calibration checks of each protective relay or the equivalent protection device shall be performed using injection of appropriate ac quantities, secondary injection, or set-point adjustment verification.
- i. Functionality of the protective relays or the equivalent protection device, circuit breakers, and telecommunications equipment shall be tested to verify the system operates as intended.
- j. Load tests of protective relays or the equivalent shall be conducted immediately after energization, where applicable.

- k. The ohmic value and connection of the transformer neutral impedance grounding device shall be verified as correct.
- l. Upon loss of DC power supply to the protective relays or the equivalent protection device, it shall be verified the protection scheme activates the interconnection circuit breaker.
- m. Upon loss of a communication signal, it shall be verified the fail-safe transfer trip occurs when required by the utility in accordance with Section 9.8.
- n. Inverter operation must be verified annually by operating the load break disconnect switch and verifying the generation facility shuts down and does not restart for five minutes after the disconnect switch has closed.
- o. Any system depending on a battery for trip power must be checked for proper voltage and logged monthly. Once every four years, the battery must be replaced or a discharge test performed.
- p. The IPP shall submit to the utility the station LAN design architecture for review during the conceptual design phase of the project.
- q. The IPP is responsible for all hardware design, RTU drawings, installation, testing and commissioning.
- r. The IPP shall prepare a preliminary but tested version of the RTU Configuration and a preliminary version of the Point Assignment, and send them to the YEC SCC, together with all RTU drawings, P&C drawings and DNP point lists of all LAN devices, at least ten weeks before the in service date.
- s. The IPP and YEC SCC shall jointly test all control, status and analog points and confirm visibility at the SCC.

14.3. Disconnection Means Operability

Prior to the operation of the IPP facility, the disconnecting means provided in accordance with Section 8.3 operates as intended.

14.4. Energization Cessation

Tests shall be conducted in accordance with IEEE 1547.1 to verify the functionality of the protection that ensures the IPP facility does not energize the utility under the following conditions described within this standard:

- 1. Abnormal frequency
- 2. Abnormal voltage
- 3. Protection scheme failure

Additional protection functions shall also be verified in accordance with IEEE 1547.1 as needed. The following protective functions must be verified if used at the IPP facility:

- 1. If available, the anti-islanding function must be checked by operating a load break disconnect switch and verifying that the IPP facility ceases to energize the output terminals and does not restart once the load break disconnect switch has reclosed.
- 2. If reverse power or minimum power function is used to meet the interconnection requirements, the functionality must be tested using secondary injection techniques. Alternatively, this

function can be tested by the means of a local trip test or by adjusting the IPP output and local loads to verify that the applicable non-export criterion are met.

14.5. Re-Verification

Re-verification of the interconnection and interoperability requirements may be required when any of the following occurs:

- Functional software or firmware changes have been made to the IPP facility equipment;
- Any hardware component of the facility has been modified in the field, been replaced or repaired with parts that are not substitutive components compliant with the applicable standards;
- Protection settings have been changed after factory testing; or
- Protection functions have been adjusted after the initial commissioning / verification process.

15. Maintenance

The IPP has full responsibility for the maintenance of its equipment, up to the Point-of-Interconnection, consistent with the Interconnection Agreement and this Guide. The IPP shall maintain the facilities in accordance with Rule 2-300 of the Canadian Electrical Code to ensure safe parallel operation with the YEC or AEY system. Failure to do so may result in disconnection of the IPP generation facility.

The IPP must present to the utility the planned maintenance procedures and a maintenance schedule for the interconnection protection equipment, and keep records of such maintenance.

The utility reserves the right to periodically inspect the interconnection protection system to verify that it meets the requirements outlined in this document.

Maintenance procedures up to the POI will be performed in accordance with good utility practice and the utility's policies and procedures.

16. Marking and Tagging

The disconnect switch must be clearly marked as the “IPP Disconnect Switch” and tagged with an identification number approved by the utility. The IPP must follow the utility’s switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

The IPP switchgear equipment must include the manufacturer name and the manufacturer’s serial number.

17. Modification of Installation

The IPP shall obtain written approval from the utility before commencing any modification to the generation facility. If the change requires the installation or modification of equipment, the IPP shall provide documentation that the new equipment meets the requirements of Type and Production tests.

If the changes require modifications to the protection and controls information the IPP must obtain approval from the utility for the proposed modifications. Whenever changes are made to interconnection hardware or software that can affect the functions listed below, the potentially affected functions must be retested:

- Over-voltage and under-voltage
- Over-frequency and under-frequency
- Non-islanding function (if applicable)
- Reverse or minimum power function (if applicable)
- Inability to energize dead line
- Time delay restart after utility outage
- Fault detection, if used
- Synchronizing controls (if applicable)

To ensure that commissioning tests are performed correctly, the utility may require the ability to witness the tests and receive written certification of the results.

18. Technical Data Requirements

The following outlines the minimum data required at various stages for planning, design and commissioning the IPP's project. This data is required by YEC (and AEY if connected to AEY distribution system) to ensure suitable steps are taken to interconnect the IPP facility to the YEC system. Expanded data requirements for the proposal and design stages are located in Appendix A and Appendix B. The IPP Policy (in development as of June 2018) shall apply.

18.1. Proposal Stage

During the proposal stage the IPP Facility conceptual design must be submitted before any further detailed studies is approved by the utility. The list of information to be provided for this approval may be the result of preliminary discussions with the utility. Based on the information provided by the IPP, the utility will provide their proposition, their commitment and their own requirements concerning the connection of the IPP facility.

The following list of drawings and data required for the proposal stage of the project includes, but is not limited to:

- A Single Line Diagram (SLD) showing the following :
 - o The proposed protection relays, circuit and fuses with fuse type and rating,
 - o The connections of all substation equipment with voltage levels and equipment ratings
 - o The location of the revenue metering equipment.
- Description of protection scheme
- Generating station site plan showing the layout and location (coordinates) of the generating plant and the location of lockable, "visible" disconnect device
- Based on the size of the project the utility may require more additional generator, exciter and speed governor data for a preliminary interconnection study.

18.2. Approval (Design) Stage

Once the project has been approved by the utility the IPP will proceed to submit the facility detailed design.

The following list of drawings and data required for approval stage of the project includes, but is not limited to:

- Single Line Diagram
- Description of protection scheme
- Control schematic
- Protection and control philosophy
- Major equipment nameplate schedules and statements
- Fuse and protective relay coordination study and settings
- Current transformer characteristic curve
- Measurement Canada approval numbers for instrument transformers

- Generating station site plan showing the layout and land location coordinates and legal description. The drawing should also show the proposed terminal pole or service manhole with the routing of aerial line or underground cables from utility to the generating station.
- SCADA Diagram
- Obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities.
- Proposed In-Service Date

18.3. Verified Stage

When the project is nearing completion, the IPP must submit the proposed testing, commissioning and start-up procedures to be performed before the facility is connected to the YIS.

The following list of drawings and data required for commissioning and verification stages of the project includes, but is not limited to:

- Commissioning report
- Copies of all permits, compliance reports and inspection documents
- Final Single Line Diagram
- Final protection scheme
- Final control schematic
- Protection and control philosophy
- Major equipment nameplate schedules, statements, test reports and data sheets
- Final fuse and protective relay coordination settings
- Current transformer characteristic curve
- Final generating station site plan showing the layout and land location coordinates and legal description

19. References

The technical guide was created using the following primary reference standards. Additional applicable standards are located within Appendix D.

- [1] CSA Standard C22.3 No. 9-08 (R2015) – Interconnection of Distributed Resources and Electricity Supply Systems, CSA Group, 2015.
- [2] IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018.
- [3] Energy Strategy For Yukon Independent Power Production Policy, Yukon Energy, Mines and Resources, 2018
- [4] Alberta Electrical Utility Code, latest Edition
- [5] IEEE Std 519-2014 - IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems
- [6] IEC 61000-4-15: Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications
- [7] CSA Standard CAN/CSA-C22.2 NO. 0-10 (R2015) - General requirements - Canadian electrical code, part II
- [8] IEEE Std C57.13-2016 (Revision of IEEE Std C57.13-2008) - IEEE Standard Requirements for Instrument Transformers
- [9] IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

Appendix A

Information Required from IPP (Proposal Stage)

Appendix A

Information Required from IPP (Proposal Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
<i>Commercial Contact</i>	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
<i>Engineering Contact</i>	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
<i>Operating Contact</i>	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Prime Mover Type	
Number of Generators	
Generator Nominal kW Rating	
Generator Nominal kVA Rating	
Generator Nominal kV Rating	
Power Factor, at Rated Output	
Annual Energy Production (MW-hr)	
Production Capacity Range(MW)	

Transformer Data

Transformer Rating (ONAN/ONAF, kVA)	
Transformer Voltage Rating (kV)	
Load Tap Changer steps	
Winding Connection	
Positive Sequence Impedance (% ONAN base)	
Zero Sequence Impedance (% ONAN base)	

Prime Mover Data

Prime Mover Type	

Drawings

General Site Map, Including IPP Generation Facility	
Preliminary Substation Layout Drawings	
Preliminary Protection & Metering Single Line	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

Appendix B

Information Required from IPP (Design Stage)

Appendix B

Information Required from IPP (Design Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
<i>Commercial Contact</i>	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
<i>Engineering Contact</i>	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
<i>Operating Contact</i>	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Number of Generators	
Manufacturer	
Model	
Nominal kW Rating	
Nominal KVA Rating	
Nominal kV Rating	
Power Factor at Rated Output	
Maximum Authorized Real Power (MARP)	
Leading and Lagging Reactive Power at MARP	
Generator Grounding (Resistive, Reactive, None)	
<i>Individual Generator Parameters - impedances in per unit, on nominal machine base</i>	
Speed (RPM)	
Inertia Constant, H (generator)	
Direct Axis Synchronous Reactance , X_D	
Direct Axis Transient Reactance , X'_D	
Direct Axis Subtransient Reactance , X''_D	
Quadrature Axis Synchronous Reactance , X_Q	
Quadrature Axis Transient Reactance , X'_Q	
Quadrature Axis Subtransient Reactance , X''_Q	
Open Circuit Direct Axis Transient Time Constant, T'_{DO}	

Short Circuit Direct Axis Transient Time Constant, T'_D	
Open Circuit Direct Axis Subtransient Time Constant, T''_{D0}	
Short Circuit Direct Axis Subtransient Time Constant, T''_D	
Quadrature Axis Transient Time Constant, T'_{Q0}	
Quadrature Axis Subtransient Time Constant, T''_{Q0}	
Saturation Factor (1.0 per unit flux)	
Saturation Factor (1.2 per unit flux)	
Armature Resistance, R_A	
Stator Leakage Reactance, X_L	
Negative Sequence Resistance, R_2	
Negative Sequence Reactance, X_2	
Zero Sequence Resistance, R_0	
Zero Sequence Reactance, X_0	
Armature Short Circuit Time Constant, T_A	
Governor Droop (%)	
Short-time unbalanced current factor (K)	
Continuous negative sequence current level (%).	
<i>Induction Generator Data (if applicable) - impedances in per unit, on nominal machine base</i>	
Rating (kVA)	
Rated Power Factor	
Speed (RPM)	
Inertia Constant, H (generator)	
Stator Resistance, R_s	
Stator Reactance, X_s	
Rotor Resistance, R_R	
Rotor Reactance, X_R	
Armature Magnetizing Reactance, X_M	
Other Attachments	
Reactive capability curve (D-curve) comes with	
a. Under excitation limiter	
b. Over excitation limiter	

Exciter nameplate	
VEE curves	
Single line diagram	

Power Factor Regulator

Reactive Power Limit - Lagging (out)	
Reactive Power Limit - Leading (in)	
Accuracy Tolerance (%)	

Voltage Regulator

Voltage Regulator Range (V)	
Accuracy Tolerance (%)	

Transformer Data

Transformer kVA Ratings	
Transformer kV Ratings	
Cooling Type (ONAN, ONAF)	
Winding Connection	
Transformer Grounding (Resistive, Reactive, None)	
Grounding Impedance in Ohms (if applicable)	
Positive Sequence Impedance (% ONAN base)	
Zero Sequence Impedance (% ONAN base)	
<i>Tap Details (if applicable)</i>	
On-Load Tap Range	
On-Load Tap Size	
Off-Load Tap Range	
Off-Load Tap Size	
Other Attachments	
Factory Test Reports (minimum requirements)	
No Load Loss & Exciting Current Measurements	
Measurement of Load Loss & Impedance Voltage and Zero Sequence Impedance Measurements	

Prime Mover Data

Prime Mover Type	
Prime Mover Rating	
Inertia Constant (prime mover)	
Manufacturer	
Model	
Other Attachments	
Elevation versus Output Curve	
Ambient Temperature versus Output Curve	

Drawings Required

General Site Map, Including IPP Generation Facility	
Complete and Accurate Protection Diagrams	

Single Line Diagrams	
AC / DC Schematics	
Wiring Diagrams	
Major Equipment Nameplates (Transformer, Generator, etc.)	

Protection Requirements

Proposed Protection Schemes Provided	
Verified Interconnection Functionality Provided	
Inertia Constant (prime mover) Provided	
Maintenance Plans for Protection Devices Provided	
Maintenance Plans for Interrupting Devices Provided	

Compliance with Electrical Inspector

Permit or Equivalent Compliance Provided (Yes / No)	

Metering Requirements

Element (2 Element, 3 Element)	
Metering Service Provider	
Metering Data Manager	
Asset ID Number	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

D.1 Modelling Information

In some cases, a generator (or the aggregate generation on a line) is large enough that adjacent customers or the dynamic stability of utility's distribution system could be affected. The IPP is responsible for the cost of any required transient or dynamic stability studies, and the studies must be done in a manner suitable to, and approved by, the utility.

IPPs are responsible for ensuring the data they submit provides an adequate mathematical representation of the facility's electric behavior. If the data is not available prior to purchasing equipment, it must be submitted as soon as it becomes available.

The studies must accurately determine:

1. The impact of the IPP's facility on adjacent customers of the utility.
2. The dynamic stability, in aggregate, of the utility system.

Data may be supplied by the manufacturer or acquired directly by testing. It must include generator characteristics (i.e., speed, reactance, resistance, excitation system etc.) and governor characteristics (i.e., lead time/lag time constants, valve or gate opening data etc.).

The information requirements vary for induction generators and inverter generators, and for hydro or thermal systems.

Appendix C

Information Provided by the Utility

Appendix C

Information Provided by the Utility

After receiving the application for interconnection, the utility will provide the following information to the IPP, if required:

- a. Single Line Diagram or maps of the system up to the POI.
- b. Minimum and maximum 60 Hz source impedances (positive-sequence, negative- sequence and zero-sequence) at the POI.
- c. Maximum and minimum normal and emergency system operating voltage ranges at the POI.
- d. Harmonic impedance envelope at the POI if available.
- e. Planning, operating and reliability criteria, standards and policies.
- f. The results of a planning study (e.g. the System Impact Study) documenting the availability of the requested amount of system capacity and any other specific technical issues to be addressed.
- g. Cost estimates and time schedule to build the upstream facilities.
- h. Characteristics and settings of protection on the distribution system.
- i. Costs to implement any required changes to the distribution system that are identified by the System Impact Study.

Some or all of this information will be required by the IPP to properly design the interconnection protection. The utility will identify when the costs of producing this information are to be assigned to the IPP.

Appendix D

Applicable Codes and Standards

Appendix D

Applicable Codes and Standards

D.1 Primary Standards

CSA Standard C22.3 No. 9-08 (R2015) Interconnection of Distributed Resources and Electricity Supply Systems

IEEE Standard 1547-2018 Standard for Interconnecting Distributed Resources with Electric Power Systems with Associated Electric Power Systems Interfaces

Power Quality Standards

ANSI C84.1-2016 American National Standards for Electric Power Systems and Equipment Ratings (60 Hertz). Establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems from 100 V through 1200kV.

IEEE Std. 493-2007 IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book).

IEEE Std. 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

IEEE Std. 1100-2005 IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).

IEEE Std. 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality.

IEEE Std. 1250-2011 IEEE Guide for Identifying and Improving Voltage Quality in Power Systems.

In addition to the power quality standards, the following standards are applicable to the interconnection of generation facilities to YEC's system:

IEEE Std. 100 - 2000 IEEE Standard Dictionary of Electrical and Electronics Terms.

IEEE Std 315-1975 (Reaffirmed 1993) ANSI Y32.3-1975 (R1989) CSA Z99-1975 Graphic Symbols for Electrical and Electronics Diagrams (including Reference Designation Letters).

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems.

C37.1-2007 ANSI/IEEE Standard Definitions, Specifications and Analysis of Systems Used for Supervisory Control, Data Acquisition and Automatic Control.

C37.2-2008 IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.

C37.18-1979 ANSI/IEEE Standard Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery.

C37.20.1-2015 ANSI/IEEE Standard for Metal-Enclosed Low-Voltage (1000 Vac and below, 3200 Vdc and below) Power Circuit Breakers Switchgear.

C37.20.3-2001 ANSI/IEEE Standard for Metal-Enclosed Interrupter Switchgear.

C37.24-2017 ANSI/IEEE Standard for Evaluating the Effect of Solar Radiation on Outdoor Metal-Enclosed Switchgear.

C37.27-2015 ANSI/IEEE Standard Application Guide for Low-Voltage AC (635 V and below) Power Circuit Breakers with Separately Mounted Current-Limiting Fuses.

C37.29-1981 ANSI/IEEE Standard for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C37.50-1989 ANSI Standard Test Procedures for Low-Voltage AC Circuit Breakers Use In Enclosures.

C37.51-1989 ANSI Standard Conformance Test Procedure for Metal Enclosed Low- Voltage AC Power Circuit-Breaker Switchgear Assemblies.

C.52-1974 ANSI Standard Test Procedures for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C57.12-2015 IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers.

C57.12.13-1982 Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations.

C57.13.1-2006 IEEE Guide for Field Testing of Relaying Current Transformers.

C57.13.2-2005 IEEE Standard Conformance Test Procedures for Instrument Transformers.

C37.58-2003 (R2010) ANSI Standard Conformance Test Procedures for Indoor AC Medium- Voltage Switches for Use in Metal-Enclosed Switchgear.

C37.90-2005 ANSI/IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

C37.90.1-2002 ANSI/IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems.

C37.90.2-2004 ANSI/IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

C37.95-2014 IEEE Guide for Protective Relaying of Utility Consumer Interconnections.

C37.98-2013 ANSI/IEEE Standard for Seismic Testing of Relays.

IEC 1000-3-3 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Less than 16A.

IEC1000-3-5 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Greater than 16A.

UL1008 Transfer Switch Equipment.

UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

IEEE P1547, DRAFT Standard for Distributed Resources Interconnected with Electric Power Systems.
Canadian Electrical Code, CSA no. C22-1, latest version.C22.2 No. 31- M89 (R2000) Switchgear Assemblies.

Can/CSA - C22.2 No. 1071 95Commercial and Industrial Power Supplies.

Can/CSA - C22.2 No. 1010.1-92 Safety Requirements For Electrical Equipment for Measurement, Control and Laboratory Use.

Can/CSA - C22.2 No. 144-M91 (R2015) Ground Fault Circuit Interrupters.

C22.2 No. 193-M1983 (R2014) High-Voltage Full-Load Interrupter Switches.

C22.2 No. 201-M1984 (R2014) Metal Enclosed High-Voltage Busways.

C22.2 No. 229-M1988 (R2014) Switching and Metering Centres.

CSA Standard CAN3 C235 83 Preferred Voltage Levels for AC Systems 0 to 50,000V.

Alberta Electrical and Communication Utility Code (formerly the Alberta Electrical and Communication Utility System Regulation 44/1976 or future amendments).

Measurement System Standard / Transmission Administrator Metering Standard GC301 Practices for Management and Transfer of Metered Data.

C37.04-1999 IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.06-2000 American National Standard for Switchgear--AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis--Preferred Ratings and Related Required Capabilities.

C37.09-1999 IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.010- IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.011-2011 IEEE Application Guide for Transient Recovery Voltage for AC High- Voltage Circuit Breakers.

C37.012-2014 IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V.

C37.013-1997 IEEE Standard for AC High-Voltage Generator Circuit Breaker Rated on a Symmetrical Current Basis.

C37.015-2017 IEEE Application Guide for Shunt Reactor Switching.

C37.081-1981 (R1988) Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.081a-1997 Supplement to IEEE Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.11-2014 IEEE Standard Requirements for Electrical Control for Electrical Control for AC High-Voltage (>1000 V) Circuit Breakers.

C37.13-2008 IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures.

C37.14-2015 IEEE Standard for DC (3200 V and below) Power Circuit Breakers Used in Enclosures.

C37.16-2009 IEEE Standard for Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage AC (635 V and below) and DC (3200 V and below) Power Circuit Breakers.

C37.20.2-2015 IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear.

C37.23-2015 IEEE Standard for Metal-Enclosed Bus.

C37.30-1997 IEEE Standard Requirements for High-Voltage Switches.

C37.32-2002 American National Standard for Switchgear--High-Voltage Air Switches, Bus Supports, and Switch Accessories--Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide.

C37.34-1994 IEEE Standard Test Code for High-Voltage Air Switches.

C37.35-1995 IEEE Guide for the Application, Installation, Operation, and Maintenance of High-Voltage Air Disconnecting and Load Interrupter Switches.

C37.36b-1990 IEEE Guide to Current Interruption with Horn-Gap Air Switches.

C37.37-1996 IEEE Standard for Loading Guide for AC High-Voltage Air Switches (in Excess of 1000 V).

C37.38-1989 IEEE Standard for Gas-Insulated, Metal-Enclosed Disconnecting, Interrupter, and Grounding Switches.

C37.42-2016 IEEE Standard Specifications for High-Voltage (>1000 V) fuses and Accessories.

C37.44-1981 (R1992) American National Standard Specifications for Distribution Oil Cutouts and Fuse Links.

C37.54-1996 American National Standard for Switchgear--Indoor Alternating-Current High-Voltage Circuit Breakers Applied as Removable Elements in Metal-Enclosed Switchgear Assemblies--Conformance Test Procedures.

C37.55-2002 American National Standard for Switchgear--Metal-Clad Switchgear Assemblies--Conformance Test Procedures.

C37.57-2003 (R2010) American National for Switchgear--Metal-Enclosed Interrupter Switchgear Assemblies-Conformance Testing.

C37.66-2005 American National Standard for Requirements for Oil- Filled Capacitor Switches for AC Systems (1 kV to 38 kV).

C37.81-2017 IEEE Guide for Seismic Qualification of Class 1E Metal- Enclosed Power Switchgear Assemblies.

C37.85-1989 (R1998) American National Standard for Switchgear--Alternating- Current High-Voltage Power Vacuum Interrupters-Safety Requirements for X- Radiation Limits.

ANSI/IEEE C37.90.1-2102 Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus.

120-1989 (Reaff-1997) IEEE Master Test Guide for Electrical Measurements in Power Circuits.

1291-1993 IEEE Guide for Partial Discharge Measurement in Power Switchgear.

IEEE Std C62.23-2017 Application Guide for Surge Protection of Electric Generating Plants.

ANSI /IEEE C62.41-1991 Recommended Practices on Surge Voltages in Low- Voltage AC Power Circuits.

C57.13-2016 IEEE Standard Requirements for Instrument Transformers.

C57.13.3-2014 IEEE Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases.

C57.98-2011 IEEE Guide for Transformer Impulse Tests.

C57.19.100-2012 IEEE Guide for Application of Power Apparatus Bushings.

C57.110-2008 IEEE Recommended Practice for Establishing Liquid-Filled and Dry-Type Power and Distribution Transformer Capability When Supplying Non-sinusoidal Load Currents.

C62.92.4-2014 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV – Distribution.

IEEE Std. 242-2001 Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems.

ANSI C12.20-2010 Electricity Meters 0.2 And 0.5 Accuracy Classes.

ANSI C62.1-1981 Surge Arresters for AC Power Circuits.

ANSI C62.11-2012 Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV).

NEMA CC 1-2009 Electric Power Connectors for Substations.

NEMA LA 1-2009 Surge Arresters.

NEMA MG 1-2016 Motors and Generators

Appendix E

Sample Operating Agreement

Appendix E

Sample Operating Agreement

1. Purpose

This agreement outlines the steps to take to ensure a reliable and safe interconnection between the IPP and YEC and/or AEY through a variety of circumstances.

2. Definitions

Operating Authority: The organizational unit assigned responsibility for operating a portion of the electrical system. For each utility the YEC System Control Center (SCC) operator is the operating authority. For the IPP, the <IPP Contact> is the operating authority.

Operational Boundary/Interface Point or Point of Interconnection: The location on the electrical system at which responsibilities between Operating Authorities meet. The breaker <Breaker ID> is the interface point between the IPP and the utility.

3. Operational Information

Circuit Breaker Identification

List circuit breakers providing interconnection between IPP and the utility.

3.1 Interlocks

List identified circuit breaker interlocks with sequence information

3.2 Contact Information

SCC – Phone (867) XXX-XXXX or (867) XXX-XXXX (recorded lines)

Contact Name	Title	Phone Number
<Utility Contact>	Leadhand SCC	(867) XXX-XXXX
<Utility Contact>	Operation Coordinator	(867) XXX-XXXX
<Utility Contact>	Manager Operations	(867) XXX-XXXX
<Utility Contact>	Director of Operations	(867) XXX-XXXX
<IPP Contact>	<Contact Position>	(867) XXX-XXXX

3.3 Normal Operation

Under normal operating conditions the IPP facility will be connected to the utility grid. The breakers status under normal operating conditions is as follows.

Breaker	Status
<Breaker ID>	Open/Closed
<Breaker ID>	Open/Closed
<Breaker ID>	Open/Closed
<Breaker ID>	Open/Closed

4. Operating Procedures

4.1. Line L### (<Utility Line> to <IPP Facility>) Isolation

L### isolation requires the minimum notification defined in section 4.3, with the exception of emergency repairs. The utility will provide a Condition Guarantee on breaker <Breaker ID>. The Condition Guarantee is used in communications between external parties. It is a formal method of communication that switching has been completed. It ensures the status of the breaker/device will not change until the work is complete, the lock out tag out is surrendered and all workers are clear.

4.2. Voltage Support

Based on the power quality conditions defined in Schedule <X> of the Power Purchase Agreement (PPA) and system security requirements, SCC may request voltage support. Voltage support can be accomplished by placing IPP generation on line, or other means such as capacitor banks or transformer tap changing. If such support is part of the operating agreement then:

- When the IPP has generation online, the generators regulate the generator bus voltage between 100 and 105% of nominal and the utility shall have control of this set-point. Generators reactive output will be adjusted by the utility in real time, to regulate the system voltage, by pulsing the AVR voltage set-points. The IPP sets the acceptable range within which the utility can adjust voltage.
- The utility must have full SCADA visibility of the IPP substation and control of critical elements.

4.3. SCC Remote Monitoring and Control

- SCC will have visual indication of the IPP breakers, generator status, capacitor status and electrical measurement information for the IPP facility.
- The utility control will be limited to:
 - Approving requests from the IPP to connect and disconnect from the utility system
 - Approving requests from the IPP for changes in generation output
 - Requesting the IPP to disconnect from the utility system for operational and safety reasons
- All IPP requests must be communicated and approved by the utility
- The utility shall have control (open and close) of incoming line breaker <Breaker ID> at the IPP facility.

5. Operational Notification

5.1. Daily Operating Communications

Under normal operating conditions IPP will be supplying <XXX> kW to the YIS. Generation changes of more than <XXX> kW must be communicated and approved by the utility.

5.2. The transition from winter to summer and conversely summer to winter generation levels must be established with SCC with a minimum of 30 days' notice.

5.3. IPP Facility Planned Maintenance and Scheduling

The IPP shall operate under the utility approved maintenance procedures established.

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours. Changes in the availability and capacity of the onsite generation need to be communicated to SCC. The utility and the IPP shall share annual shutdown/maintenance plans in February of each year.

5.4. Transmission and Distribution Maintenance and Scheduling

The utility performs annual line maintenance on its transmission and distribution lines, during which grid power to the IPP facility may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.

The utility will provide a minimum of 30 days' notice of the start date and expected duration of work that will curtail or otherwise interrupt the supply of grid power to the IPP facility.

6. Loss of Supply Procedures

6.1. Loss of Supply - Short Term

In the event of a disturbance that results in the loss of grid power to the IPP facility, SCC will make one attempt to re-energize the line to the IPP facility. If successful the following steps apply to resume the IPP facility operation with grid power.

- a) SCC will confirm the status of the breakers located at the IPP's POI.
- b) SCC will request closed breaker <Breaker ID>.
- c) Once complete and with confirmation from SCC the IPP facility may proceed with the restarting of their operation. The IPP will communicate to SCC on generation greater than <XXX> kW. The request to increase generation may be communicated verbally or via SCADA.

6.2. Loss of Supply - Long Term

In the event of a disturbance that results in the loss of grid power to the IPP facility and SCC is unsuccessful in re-energizing the line the following steps will apply.

- a) SCC will confirm the status of the breakers.
- b) At the direction of SCC the IPP personnel will start and stage their generation on line supplying power to the IPP facility.
- c) Once the line to the IPP facility has been re-energized, SCC will request the IPP synchronize and close its POI breaker.
- d) The IPP facility is now connected to YEC system. Once complete and with confirmation from SCC the IPP facility may proceed with resuming generation. The IPP will communicate to SCC on generation increases greater than <XXX> kW. The request to load up may be communicated verbally or via SCADA.

7. Revision and Approval

- 7.1. This Agreement comes into effect once it is signed by the IPP and the utility.
- 7.2. This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.
- 7.3. The Parties shall provide 90 days' notice in writing of the intention to modify the Agreement.
- 7.4. The Agreement may be revised upon mutual agreement of both Parties. The agreement will be formally reviewed every two (2) years.

Approved by: _____
Yukon Energy Corporation

Approval Date: _____

Approved by: _____
ATCO Electrical Yukon

Approval Date: _____

Approved by: _____
IPP

Approval Date: _____

Appendix F

Typical Interconnection Single Line Diagrams

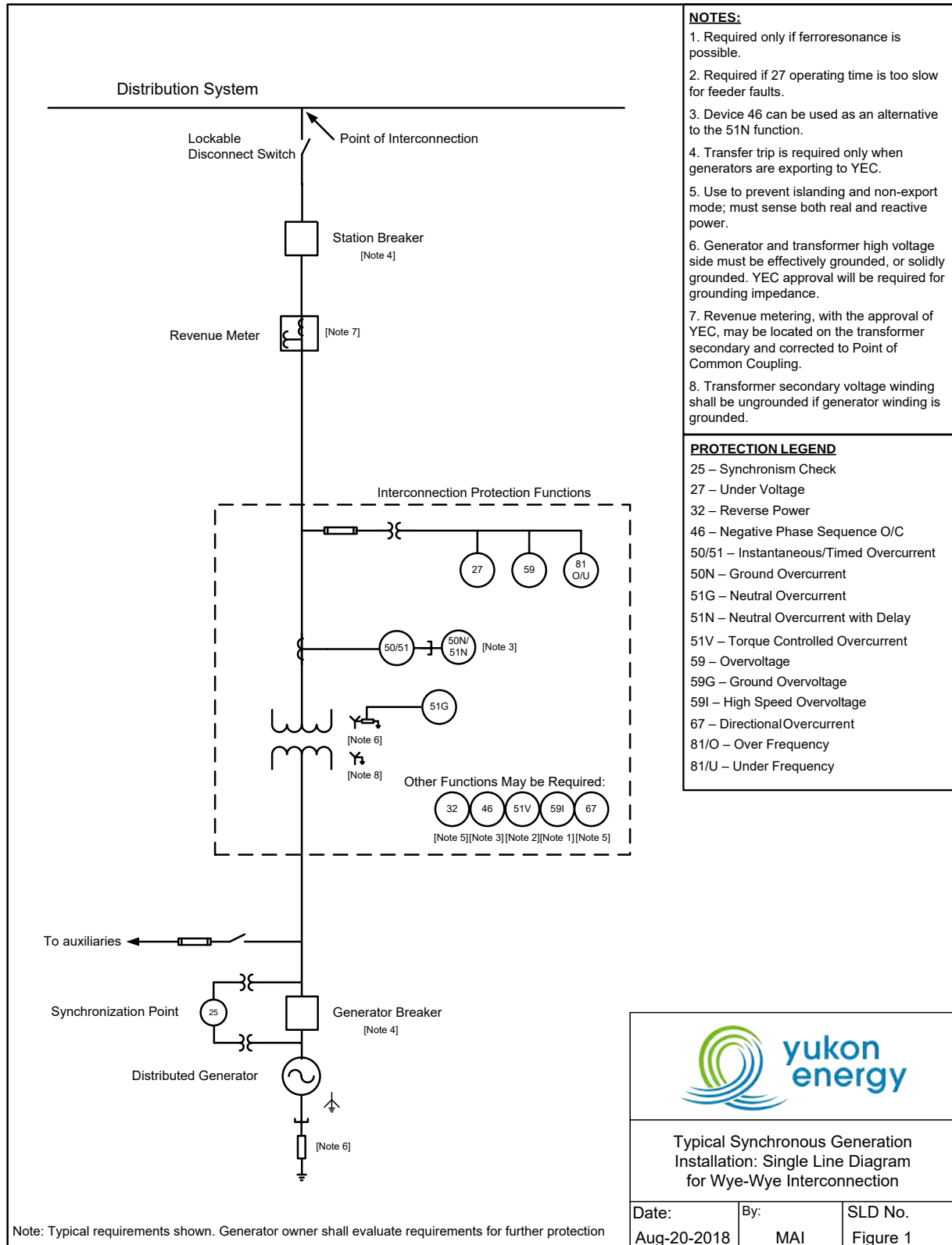


Figure F- 1: Single Line Diagram for Wye-Wye Interconnection

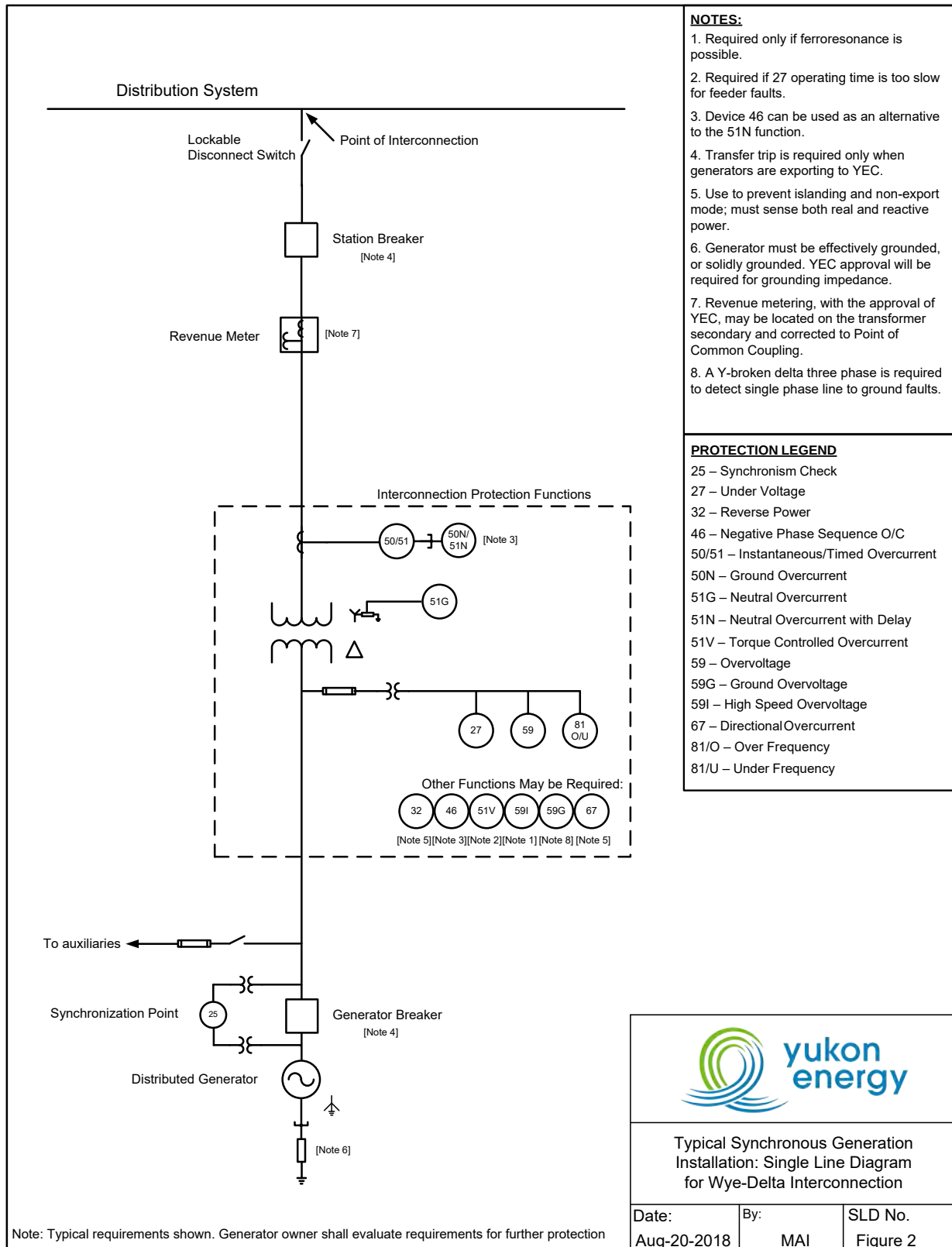


Figure F- 2: Single Line Diagram for Wye-Delta Interconnection

Appendix G

Protective Settings Commissioning Document

Appendix G

Protective Settings Commissioning Document

Over Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	106% - 120% 1% Increments						30 Cycles					
Fast Trip	144% - 120% 1% Increments						100 ms					

Under Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	50% - 90% 1% Increments						120 Cycles					
Fast Trip	Less than 50% 1% Increments						100 ms					

Non-Islanding Function Test

Loss of Utility Voltage	100 ms	
Generator Restart Delay	5 min Minimum	
Dead Bus Test	Fail to Start Successful (Yes/ No)	

Over Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	60.5 Hz - 61.5 Hz 1% Increments						3 minutes					
Fast Trip	61.5 Hz - 61.7 Hz 1% Increments						30 seconds					

Under Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	59.5 Hz - 58.5 Hz 1% Increments						3 minutes					
Second Trip	58.5 Hz - 57.9 Hz 1% Increments						30 seconds					
Third Trip	57.9 Hz - 57.4 Hz 1% Increments						7.5 seconds					
Fourth Trip	57.4 Hz - 56.9 Hz 1% Increments						45 cycles					
Fifth Trip	56.9 Hz - 56.5 Hz 1% Increments						7.2 cycles					
Fast Trip	Less than 56.4 Hz 1% Increments						100 ms					

Reverse AC Current Protection Function

	CURRENT TO TRIP						DURATION TO TRIP					
	DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED			DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip												

Synchronization Limits for Synchronous Generators

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Frequency Difference	+ 0.2 Hz		
Voltage Difference	5%		
Phase Difference	10° (degrees)		

Phase and Ground Fault Protection

	MAXIMUM CURRENT OR VOLTS TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Phase Current							200 ms					
Neutral Current							200 ms					

Transfer Trip Protection

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Generator Lockout	0.6 seconds		
Fail Safe Lockout	6 seconds		

Test Certification and Historical Data

Type Of Test	Original Commissioning Test		Protection System Re-Test	

Date of Test

Utility Representative Title

IPP Owner Representative

Signature

IPP Owner Representative Title

Date

Signature

SCHEDULE "H"
JOINT OPERATING PROCEDURE

(Please see attached)

	JOINT OPERATING PROCEDURE	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		Operations	Guy Morgan, VP, Operations	IPP / AEY / YEC Operating Agreement
		ISSUED DATE:	REVIEW DATE:	APPROVED BY:
		August __ 2020	September 1, 2021	_____ President & CEO

1.0 Purpose

- 1.1 This agreement defines the operating arrangement between the **Nomad Contracting & Electrical Services**. (IPP), ATCO Electric Yukon (AEY) and Yukon Energy Corporation (YEC). This agreement defines the roles and responsibilities for each entity to allow the IPP to operate reliably and safely on the Yukon Power System (YPS).

2.0 General Information

2.1 Breaker Identification

Breaker	Description
S6423	Connection between the IPP and AEY distribution

2.2 Definitions

- a) **Operating Authority** The organizational unit assigned responsibility for operating a portion of the electrical system.
- For YEC the SCC operator is the operating authority and is responsible for the system generation and security.
 - For AEY the Supervisor of Operations is the operating authority and is responsible for the distribution system and security.
 - For the IPP the Technical Coordinator is the operating authority of their generation and associated equipment.
- b) **Operator in Charge (OIC)** The worker designated by the Operating Authority to coordinate control of the power system or portion thereof, in accordance with the requirements of established operating standards and procedures.
- c) **Power Systems Work Standards (PSWS)** The standards that workers will utilize for establishing conditions on the power system that will, when combined with appropriate work standards, procedures and methods, provide a safe work area.

- d) **Condition Guarantee (COG)** Formal assurance to another Operating Authority or Operator in Charge (OIC) that identified devices are in the position requested and will not change status until the device status request is formally released by the requestor.
- e) **Point of Interconnection (POI)** The location on the electrical system at which responsibilities between Operating Authorities meet. The IPP Switch – S6359 is the interface point between IPP and AEY.

2.3 YEC Contact Information

- SCC (System Control Center) – phone 393-5355 or 393-5324 (recorded lines)
- Mike Hannah (Leadhand SCC) 393-5399, cell 334-6759
- Myles O'Brien (Operation Coordinator) 393-5352
- Ed Peake (Manager Operations) 393-5383, cell 334-6586
- Guy Morgan (Director of Operations) 393-5366, cell 334-6904
- YEC Group Email – SCC@yec.yk.ca

AEY Contact Information

- Tony Badry - Supervisor of Operations 633-7057, cell 335-4002
- Matt Johnson – Operator in Charge 633-7009, cell 334-3145

IPP Control Room Desk

- Sebastien Roy 335-0177

IPP Contact Information

- Sebastien Roy nomad_electric@outlook.com

2.4 Normal Operation

Under normal operating conditions the IPP will generate into the Yukon Power Grid. The breakers status under normal operating conditions are as follows.

Breaker	Status
S6423	Closed

3.0 Operating Procedures

3.1 Planned 5L649 (IPP to AEY) Isolation

5L649 isolation requires the minimum notification defined in section 5.1, except for emergency repairs. AEY will provide a condition guarantee on S6423 - Condition Guarantee will be issued in accordance with **Section 800** of the PSWS – **Operating Interface Points**.

3.2 Planned 5L649 (AEY to IPP) Isolation
5L649 isolation requires the minimum notification defined in section 5.2, except for emergency repairs. IPP will provide a condition guarantee on S6423 - Condition Guarantee will be issued in accordance with **Section 800** of the PSWS – **Operating Interface Points**

3.3 SCC Remote Monitoring
SCC will have visual indication of IPP breakers, PV status, and electrical measurement information from the IPP site.

4.0 Power Quality Requirements

4.1 IPP will operate IPP Facilities in accordance with the power quality requirements of YEC as set out in the System Interconnection Guidelines (Schedule D).

5.0 Operational Notification

5.1 IPP Planned Maintenance and Scheduling

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC / ATCO OIC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours.

Planned changes in the availability and capacity of the onsite generation needs to be communicated to SCC / ATCO OIC at least 30 days in advance of such changes.

Unplanned availability should be conveyed as soon as possible.

The Parties will share annual shutdown/maintenance plans in February of each year and plan to minimize the impact on IPP generation potential by scheduling outages during off-peak generation months where practicable.

5.2 AEY Distribution Maintenance and Scheduling:

- a) AEY performs annual line maintenance on the distribution lines, during which connection to the IPP may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.
- b) AEY will provide a minimum of 5 working days' notice of the start date and expected duration of work that will curtail or otherwise interrupt the supply of IPP generation to the YPS.

6.0 Loss of Supply Procedures

6.1 Loss of Supply - Short Term

In the event of a disturbance that results in the loss of the grid connection to the IPP the IPP generation will remain off-line until approval from AEY and YEC.

The following steps apply to resume IPP operation with Grid Electricity.

- a) SCC will confirm the status of the breaker located at IPP site. If SCADA communications are down the switch status will be physically verified and reported to AEY before 5L649 will be energized.

Breaker	Expected Status
S6423	Open

- b) The following switching sequence will be followed to re-energize 5L649 and synchronize IPP back to grid supply.

Step	Switch Sequence	Operation
1	Confirm 5L649 Energized	IPP/AEY
2	S6423 Closed	IPP
3	IPP starts system	IPP/YEC

- c) Once complete and with confirmation from SCC, IPP may proceed with the restarting of their operation. IPP Group will communicate to SCC once their system is back on line.

6.2 Loss of Supply - Long Term

In the event of a disturbance that results in the loss of the grid connection to the IPP the IPP generation will remain offline until approval from AEY and YEC.

- a) SCC will confirm the status of the breaker located at IPP site. If SCADA communications are down the switch status will be physically verified and reported to AEY before 5L649 will be energized.

Breaker	Expected Status
S6423	Open

- b) The following switching sequence will be followed to re-energize 5L649 and synchronize IPP back to grid supply.

Step	Switch Sequence	Operation
1	Confirm 5L649 Energized	IPP/AEY
2	S6423 Closed	IPP
3	IPP starts system	IPP/YEC

7.0 Revision and Approval

- 7.1 This Agreement comes into effect once it is signed by IPP, AEY and YEC.
- 7.2 This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.
- 7.3 The Parties will provide 90 days' notice in writing of the intention to modify this Agreement.
- 7.4 The Agreement may be revised at any time if operational needs require and are mutually agreed to by all Parties. This agreement will be formally reviewed every two (2) years.

8.0 Appendices

- 8.1 ATCO Electric's Power System Work Standards (PSWS.pdf)

Approved by: _____
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Approval Date: August ____, 2020

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POWER SYSTEM WORK STANDARDS

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ATCO Electric Ltd.
Transmission and Distribution
Operating Authority
P.O. Box 610
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**Transmission and Distribution
Operating Authority**

DO YOU HAVE ANY SUGGESTIONS

The PSWS is a living breathing document and suggested changes to the document will be reviewed on an ongoing basis. All suggestions and comments will be considered. Any major changes will be immediately issued and any other minor changes will be completed during the next revision.

Please email suggestions to @ Electric SOC PSWS, and include the following information:

Suggested Change:

Reason for Change:

Contact Information:

Your Name

Phone or Email address

Supervisors Approval

A MESSAGE FROM THE OPERATING AUTHORITY

Work on or near the power system involves inherent risks to employees, system security and customer supply. Strict adherence to appropriate work standards, procedures and methods minimizes those risks and allows employees to work safely.

Power System Work Standards (PSWS) was developed by a team of experienced employees, including Operators-in-Charge of the transmission and distribution systems, to complement and support other ATCO Electric safety standards. All employees working on or near the ATCO Electric power system are required to:

- Meet applicable training, knowledge and skill requirements, as per HS&E Practice 1101: Power System Worker Authorization.
- Understand and consistently follow the standards in this document.
- Perform work, only as authorized by their supervisor and the Operator-in-Charge.

Your commitment will help to ensure employee safety and the efficient operation of the power system.



Craig Steinbach
Manager, System Operations
Transmission Operating Authority



Randy Loveseth
Senior Manager, Distribution Operations
Distribution Operating Authority



Chris Clark
Vice President
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SECTION 100: HOW TO USE THIS DOCUMENT

101 Purpose

Power System Work Standards provides ATCO Electric employees with standards to establish conditions on the power system that will – when combined with appropriate work standards, procedures and methods – allow work to take place on or near the power system.

Employees must obtain permission from the Operator-in-Charge (OIC) before starting any work on the power system.

NO PERMISSION = NO WORK

101.1 Limitations

It is important to note that this document only provides a process for establishing required power system conditions through Worker-Administered switching or the OIC permitting process. Employees must implement barriers to protect against all hazards identified in the job planning process.

102 Scope

Power System Work Standards applies to all employees authorized to work on or near ATCO Electric's power system apparatus and/or supporting control and communication apparatus.

103 Document Compliance

Power System Work Standards complies with the following:

- Alberta Electrical Utility Code (AEUC)
- Occupational Health & Safety Act, Regulation and Code
- ATCO Electric Corporate Health, Safety and Environment Principles and Policies
- Operations HS&E Management System and Best Practices
- Operations HS&E Safety Standards Manual.

104 Definitions

Apparatus – Equipment of every kind and description used in the generation, transformation, distribution, delivery or use of electrical power or energy. The term also includes the supporting control and communication equipment used to manage the delivery and use of electrical power.

Charged – Containing stored electrical energy.

Condition Guarantee (COG) – Formal declaration that a device is in a specific state, tagged to identify that state and guarantee is given that the device will not be operated until the Condition Guarantee is released. This is not a work permit.

Control System Permit (CSP) – Allows work to be performed on apparatus under 750 V that directly impacts or could impede operation of the power system.

De-energized (Dead) – At a potential equal to or not significantly different from that of ground (earth) at the work site.

Device – A type of electrical apparatus used as a switch or control mechanism (e.g., gang switch, recloser, auto-sectionalizing scheme).

Disable – To make a device inoperable.

Do Not Operate Tag– See Appendix B.

Employee – For the purposes of this document, any individual employed by or contracted to ATCO Electric who is competent to perform assigned duties.

Employee-in-Charge – Individual responsible for all employees in a work group or groups working on or near the same related power system apparatus. An employee who works alone is considered the Employee-in-Charge.

Enable – To make a device operable.

Energized (Live) – At a potential that is significantly different from that of ground (earth) at the work site and that presents an electrical hazard.

Note: A part is energized when it is electrically connected to a source of electric energy. It can also be energized when it is electrically charged under the influence of an electric or magnetic field. Apparatus must be considered energized unless confirmed to be isolated and grounded.

Guarantee of Isolation (GOI) Permit – Allows work on a line or apparatus that has been isolated from all power system sources of potential above 750 volts.

Human Machine Interface (HMI) – A software-based local control and monitoring system.

Hold-Off Permit (HOP) – Prevents automatic or manual restoration following an unplanned circuit outage.

Isolate – To completely disconnect a device or circuit from other devices or circuits, separating it physically, electrically and mechanically from all sources of electrical energy.

Note: Such separation may not eliminate all the effects of electromagnetic induction.

Live Line Work – All work performed on energized electrical equipment or lines, using protective insulating devices, live line tools or bare-hand techniques.

Locked – Physically secured with a keyed padlock. (This definition only applies to devices where provision for locking is provided.)

Near – For the purposes of electrical operations, distance at which there is a possibility of contacting energized lines or equipment.

Operating Authority – Person designated by ATCO Electric to make policy decisions that affect operations of the power system. Also known as the Operator of a Utility System, as defined in the AEUC.

Operating Interface Point – Location on the power system that separates the responsibilities of respective Operators-in-Charge. Operating interface points are identified on switching diagrams. See Appendix A.

Operator-in-Charge (OIC) – Qualified Worker designated by the Operating Authority to coordinate control of the power system or a portion thereof, in accordance with the requirements of established safety standards, operating standards and procedures.

OIC-Administered Switching – Switching directed by the Operator-in-Charge, in accordance with switching orders developed by the Operator-in-Charge.

Permit – Portion of the switch order that provides authorization to work under established power system conditions.

Permit Holder – Employee to whom authorization has been issued to work on the power system.

Potential – Voltage, in the context of electricity.

Power System – All electrical apparatus that comprise the transmission and distribution systems.

Qualified Worker – Worker(s) who, through possession of a recognized degree, certificate, professional standing or through extensive knowledge and training experience, has successfully demonstrated the ability to perform the required duties and tasks of the work.

Release – Surrender of the permit.

Requester – Employee who initiates a work permit.

Return to Normal – Restoration of the power system or apparatus to a desired operating state.

Supervisory Control and Data Acquisition (SCADA) – Computer system that transfers field data and operating control to a centralized location.

Software Tags – Tags applied to computer-based systems by the Operator-in-Charge to prevent the operation of devices by those systems.

Switching – Process by which the electrical configuration of a system is changed, usually through the operation of devices designed for this action, but may also include the removal or installation of jumpers and the making or breaking of normally permanent connections.

Single Line Diagram (SLD) – Simplified electrical representation of substations or power system switch maps or any part thereof.

Switch Order – Documentation that describes the specific switching sequence required to place power system devices in a desired operating state.

System Switching Information (SSI) – Form that contains information required for conditioning the power system.

Switchman – Employee who operates electrical apparatus and performs switching and tagging of devices under the direction of or with the permission of the Operator-in-Charge.

System Security – Integrity of the power system. It is maintained by identifying the next contingency related to the work being considered that could impact power system operations and/or customer supply.

Tailboard – Conversation between Operators-in-Charge, Switchmen and/or Permit Holders that transpires before any switching action or issuing of permits.

Test and Operate (T&O) Permit – Allows apparatus to be operated or energized, without impacting the power system,

so adjustments, repairs, maintenance or commissioning tests can be performed.

Transfer of Authority – Formal transfer of duties, responsibilities or jurisdiction (temporary work zone) from one Operator-in-Charge to another.

Unqualified Worker – Worker(s) who is not a qualified worker; i.e., does not possess a recognized degree or certificate, professional standing or the knowledge/experience to successfully demonstrate the ability to perform the required duties and tasks of the work.

Worker-Administered switching (WA) – Switching performed by an employee who has received permission from the Operator-in-Charge to establish the power system conditions required to work on or near the power system.

Working Day – (for scheduling purposes) Monday through Friday inclusive, excluding statutory holidays.

SECTION 200: RESPONSIBILITIES

201 Operating Authority

The Operating Authorities are responsible for the operation of the transmission and distribution systems. The Operating Authority is also responsible for ensuring the Operator-in-Charge (OIC) responsibility is assigned.

202 Operator-in-Charge

The **Distribution Operator-in-Charge (DOIC)** is responsible for all power system apparatus rated 36 kV and below, excluding that portion shown on transmission Single Line Diagrams.

The **Transmission Operator-in-Charge (TOIC)** is responsible for all power system apparatus rated 72 kV and above and substation equipment rated below 72 kV, as shown on transmission Single Line Diagrams or switching maps. Exceptions to this requirement are identified as interface points on affected switching maps.

The **Operator-in-Charge** must:

- Coordinate the day-to-day operation of the transmission or distribution system, in compliance with approved standards and procedures.
- Establish power system conditions that will – when combined with appropriate work standards, procedures and methods – allow work to take place on or near the power system.
- Issue permits, as required, for all work on the transmission or distribution systems, including the attachment and detachment of apparatus.
- Maintain operational documentation for a minimum of three years.

203 Permit Holder

The Permit Holder is normally the Employee-in-Charge of a single work group or multiple work groups, as applicable.

The Permit Holder must be a Qualified Worker.

The Permit Holder is required to:

- Request and hold the permits that will – when combined with appropriate work standards, procedures and methods – allow work to take place on or near the power system.
- Notify the Operator-in-Charge (OIC) prior to starting work.
- Provide all employees and work groups under their direction permission to work under the permits held.
- Stop work and promptly notify the OIC in the event of any unscheduled occurrence or incident related to the power system that may affect:
 - employee safety
 - power system security
 - continuity of customer supply.
- Release all permits to the OIC when the work is complete.

204 Switchman

The Switchman must be a Qualified Worker.

The Switchman is responsible to:

- Perform switching at the direction of the OIC, or
- Establish their own protection under Worker-Administered (WA) switching , with permission of the OIC.

205 Employees

Employees have a responsibility to comply with all standards provided in the *Power System Work Standards*.

SECTION 300:

NOTIFICATION AND PERMISSIONS TO ESTABLISH REQUIRED CONDITIONS

301 Notification and Permission Requirements

301.1 Substation Entry

All persons entering a substation must be a Qualified Worker or be escorted by a Qualified Worker.

The Employee-in-Charge (EIC) must notify the Transmission Operator-in-Charge (TOIC) prior to entering or departing a substation. The EIC must provide the following information:

- first and last name
- substation name or number
- reason for entering
- risks associated with the work
- expected duration of work (and, as applicable, the need for an extension).

This information allows the OIC to contact the EIC, if necessary (e.g., to gather information, to respond to an unplanned outage).

If an entry alarm is received from a remotely-monitored substation without a confirming call, the OIC must:

- Call the substation.
- Contact a local employee to investigate, if no one answers the call.
- Request police assistance, as required.

If the EIC fails to report back after completing the work, the OIC must initiate an investigation.

Note:

- Employees are also required to check in and out of unmanned Isolated Generation Sites (IGS) sites.
- The TOIC is responsible for monitoring entry into IGS sites.
- The preceding section shall also apply to IGS entry.

301.2 Work on the Power System

NO PERMISSION = NO WORK.

Necessary permit request (s) must be sent, in writing, to either the Transmission or Distribution Operations scheduling group.

- Equipment rated 25 kV or less, including apparatus under 750 V that directly impacts or could impede operation of the power system (e.g., relays, voice and data communication systems, protection circuits), requires a minimum notice of:
 - three working days when one OIC is involved
 - five working days when two or more OIC's are involved.
- Equipment rated 72 kV and above requires a minimum notice of 30 days; approval is required from the Alberta Electric System Operator (AESO).

The OIC (s) must review the permit request with the employee to identify any concerns.

The OIC (s) must advise the employee if the permit can be issued, as requested, as soon as possible.

302 Permission to Establish Required Conditions

After considering system security, customer supply and current permits, the OIC will schedule the work and provide permission to establish the required conditions through either OIC-Administered switching or Worker-Administered switching.

302.1 OIC-Administered Switching

The OIC cannot direct any switching without a written switching order, except in the following situations:

- A switch order is not required to operate a device for voltage control (e.g., Static VAR Compensator (SVCs), tap changers, synchronous condensers, capacitors or reactors, regulator banks and auto boosters).
- A switch order is not required in an emergency situation. See Section 1001.
- During troubleshooting situations, the OIC must document each switching step prior to completing that action. All troubleshooting actions must be transferred to the switch order and a second approval received before a permit is issued.

The Switchman must obtain the switch order from the OIC before performing the switching and must verify the switching instructions against the Single Line Diagram (SLD) or switching map. If the written switch order is not available onsite, the OIC will summarize the overall process and will provide the Switchman with step-by-step switching instructions pertinent to the switching location. The Switchman must:

- Record the switching steps, exactly as stated.
- Repeat the switching steps back to the OIC.

Upon completion of the switching, the OIC will issue a permit (e.g., Hold-off, GOI, Test and Operate, CSP) to the Qualified Worker or a Condition Guarantee to a Qualified Worker or to an adjacent OIC who requested the operation or confirmation of devices in order to establish a safe work area.

302.2 Worker-Administered Switching

The Operator-in-Charge (OIC) gives permission to a Qualified Worker to establish their own protection. This only applies to workers establishing protection for themselves or for a crew that is supervised by a Qualified Worker.

NO PERMIT IS ISSUED.

Worker-Administered (WA) switching can only occur with the authorization of the OIC. The OIC gives permission for the Qualified Worker to do the switching, allowing them to work on or near the power system.

WA switching may occur where a single device or multiple devices can easily establish protection and when risk to the power system is minimal (e.g., single- or three-phase radial distribution lines), provided the following conditions are met:

- Status of affected devices must be communicated to the OIC.
- All devices are under the authority of one OIC (e.g., no distribution-connected generation, no operating Rural Electrification Association (REA).
- There is only one Employee-in-Charge (EIC) of the work.
- The work is limited to one continuous work period. (The length of time required to complete the work at a specific work site. Issuance and release of daily permission will still be required.)
- There will be no overlapping WA switching permissions.

The following rules pertain to the administration of WA switching:

- The OIC will give permission for a Qualified Worker to establish their own protection under WA switching.
- The OIC will issue a unique reference number for the WA switching.

- The Qualified Worker will conduct a risk assessment of the work.
- The Qualified Worker will write up the switch order/tag.
- The Qualified Worker will advise the OIC when the work is complete.
- The Qualified Worker and the OIC will document the time of switching.

SECTION 400: ESTABLISHING REQUIRED CONDITIONS

401 Conducting a Power System Risk Assessment

401.1 General

To minimize hazardous situations and/or adverse effects on the power system, the Operator-in-Charge (OIC) must conduct a thorough risk assessment:

- before switching
- during switching
- after switching.

The risk assessment must include a review of the following, as applicable:

- system voltages and line flows
- status of adjacent substations
- status of interconnected utilities and customer loads
- apparatus and system capabilities
- effect of the next worst contingency
- conflicting scheduled outages
- current permits.

401.2 Distribution Tie Switches

Before operating distribution switches that tie different distribution feeders or transmission substations together, the Distribution OIC and/or Transmission OIC must consider:

- the possibility of inadvertently bypassing regulators
- settings and control of voltage regulators
- load shift
- the state of the transmission system
- system capabilities
- protection settings
- settings and switching of capacitors
- existing permits.

402 Switching

402.1 Communicating During Switching

The OIC must communicate switching instructions directly to the Switchman at the worksite. All parties must use full name identification when relaying switching instructions.

Verbal communications must be:

- Repeated back by the receiving party, as heard.
- Verified against the switch order.

402.2 General Switching Procedures

- A tailboard must occur between the OIC and the Switchman immediately before any switching to review the switching steps and to make sure that the switch order is complete, correct, understood and that all related hazards are identified.
- When possible, preference will be to perform switching remote from the device. Remote operation refers to offsite control, using Supervisory Control and Data Acquisition (SCADA), or onsite control, using the

Human Machine Interface (HMI) in the substation control building.

- The Switchman is required to inspect local devices and apparatus and report any deficiencies that could impact the switching to the OIC.
- The switching steps provided on the switch order must be followed.
- If there are inconsistencies or concerns – at any time – about the switching instructions, the switching must be stopped. Switching cannot proceed until the identified concerns are addressed.
- The Switchman must have the switch order in their possession when performing the switching and must record the time each switching step is successfully completed.
- Before operating any switch, the Switchman and OIC must ensure the device is rated for the operation.
- Any device that can be locked shall be locked, using a company system lock.

403 Isolating Apparatus

Isolation points must be fully opened and must be confirmed to have an adequate visible air gap on all phases.

- Where no visible air gap exists, isolated apparatus must be tested for potential and the isolating device must be locked and tagged as inoperable (e.g., padmount transformer with live front bushings and internal switchgear). Isolators and/or open jumpers can be used as isolation points.
- When motor-operated switches or circuit switchers are used as isolation points, the isolation procedure must include disabling the motor mechanism.
- When a normally open switch is used as an isolation point, the switch must be confirmed open onsite and tagged.
- When isolating a portion of the system where a Potential Transformer (PT) or station service is

connected, the PT or station service must also be isolated, using the secondary or primary disconnects, unless it is confirmed to have no known or potential power system source.

- When isolating an indoor switch gear:
 - The breaker must be removed from the cubicle or racked out to the disconnect position and tagged to create the isolation point.
 - If the breaker is not removable, the associated solid blade disconnects or bus switches must be opened and tagged to create the isolation point.

404 Tagging

Employees must understand and utilize the following tagging procedures:

- To prevent unauthorized operation of devices, standard ATCO Electric Do Not Operate tags (or software tags, where available) must be installed, as directed by the Operator-in-Charge (OIC), or, in the case of Worker-Administered (WA) switching, as directed by the employee performing the switching.
- Each active permit must have a corresponding tag at each location that is required to be tagged. Five active GOIs would require five tags on each isolation point.
- Where a Condition Guarantee has been issued, the OIC who receives the Condition Guarantee is allowed to install additional locks and tags on associated isolating devices.
- An OIC who receives a Condition Guarantee can use the associated tags to form part of the permit(s) issued.
- Where possible, a software tag must be installed on the equipment associated with each tag installed on a device in the field.

- Only a Qualified Worker may install or supervise the installation or removal of tags – as directed by the OIC – or, in the case of WA switching, at the direction of the employee who installed the tags.
- When installing tags on field devices, only one tag will be utilized per bag.
- Tags must be installed on the same side as the switch identification number and as close as possible to the switching device (e.g., on the operating handles or, in the case of solid blade disconnects, on the associated structure – preferably at eye level).
- The OIC must be notified if:
 - a tag is discovered on any device or apparatus that appears unsupported by a switch order
 - an employee suspects a device has been operated without a tag or switch order.

The OIC will initiate an investigation and take appropriate action (e.g., direct removal of the tag, direct tagging and issue a permit or energize), as applicable.

- All tags placed on power system devices and apparatus must be associated with a:
 - unique switch order reference number or
 - WA switching reference/event number.

Only standard ATCO Electric Do Not Operate tags or OIC-Administered software tags may be used.

- The following information must be legibly recorded on the ATCO Electric Do Not Operate tag:
 - identifying number of the line or apparatus on which work is being done
 - identifying number or legal location of the device to which the tag is applied
 - reason for the isolation or condition
 - switching step(s), if the tag is being used as a switching order
 - person (WA) or OIC requesting the tag

- full name of the Switchman
- time and date of the tag installation and removal
- Reference/Event number (e.g., 12345).

For a sample tag, see Appendix B.

SECTION 500: PERMIT PROCESS

501 Single Line Diagrams

501.1 General

Before performing any switching, the Switchman must have, in their possession: a valid, approved, up-to-date Single Line Diagram (SLD) or switch map that accurately details the apparatus contained within that system.

Copies of interim SLDs or switching maps may be obtained through the Transmission Control Centre (transmission system) or Distribution Control Centre (distribution system) and then authorized by the appropriate Operator-in-Charge (OIC).

501.2 Revisions

Verified and approved interim SLDs or switch maps (i.e., checked, dated and signed by the Employee-in-Charge) must be provided to the OIC whenever modifications are made to the power system.

The OIC may accept verbal notification of a change to an SLD or switch map from an Employee-in-Charge (EIC) if the change is minor and easily understood (e.g., a change to a switch number) and if the EIC commits to provide the OIC with a verified and approved interim SLD or switch map as soon as possible.

The OIC has the discretion to deny the verbal notification and to request a verified and approved interim SLD or switch map before accepting the change.

- Interim and revised SLDs or switch maps used to operate the power system must be authorized by the appropriate OIC.
- The OIC must obtain approval from the affected Operating Authority to change an operating interface point.

502 Permit Scheduling

502.1 General

In preparing to establish the required conditions to work on or near the power system, employees must complete the following seven steps, as applicable:

1. Provide Project Outage Plans and System Switching Information (SSI), as necessary.
2. Submit current SLDs or switch maps.
3. Determine the power system conditions required to accommodate the work.
4. Notify or request permission from the appropriate OIC to establish those conditions.
5. Receive permission to establish required conditions through OIC-Administered switching or Worker-Administered (WA) switching.
6. Obtain or develop switch orders.
7. Establish an onsite means of communication with the OIC.

502.2 System Switching Information/Permit Request

System Switching Information (SSI)/permit requests and work orders on request must include the following:

- line or apparatus affected and the work location
- type of permit(s) required
- dates and times the permit(s) is required and the anticipated duration of the work

- estimated time needed to release the permit in a critical situation
- description of the work
- required isolation points, as applicable
- risks the Permit Holder is able to identify (e.g., local impacts if something goes wrong with the work)
- means of communication to be used between the Permit Holder and OIC
- name of the Permit Holder or Requestor
- updated switch map or SLD.

503 Switch Order/Permit Form

503.1 General

Using the information on the System Switching Information (SSI) request, the OIC will conduct a power system risk assessment, schedule the work and prepare a switching order/permit form with the following information:

- unique reference number
- dates, times and duration the required power system conditions will be in effect
- switching sequence to be used to create those conditions
- switching sequence to be used to return to normal
- permit issuance and release documentation.

503.2 Numbering Switching Steps

Switching step numbers must be sequential at each switch location. To add switching steps to an existing switching order, use alphabetical suffixes to preserve the existing sequence (e.g., 36A, 36B, 36C).

503.3 Numbering Permits

The OIC must assign each permit a unique number.

- A reference number (e.g., 12345) will be generated when a new switching order is documented on the system (e.g., CROW, Maximo, OMS). For each required permit, the OIC will create a unique permit number, using the reference number as a base, followed by a unique alphabetical suffix (e.g., 12345A, 12345B).
- Where an electronic system is not available to assign a unique reference number, the OIC must use the following format: initials-year/month/day-sequence. *The date reflects the work start date. The month must be expressed as a three-letter abbreviation.* For example, reference number LJD-01Aug20-1 would have a permit number of LJD-01Aug20-1A.

504 Issuing and Holding Permits

504.1 General

The permit is the employee's assurance that the power system conditions defined by the switch order will not change until the permit is released. This assurance requires strict adherence to the following:

- In planned situations where switching is involved in establishing the required conditions, the Permit Holder should have, in their possession, a current copy of the Single Line Diagram (SLD) or switch map and the switch order prepared by the Operator-in-Charge (OIC) before the permit is issued.

If the written switch order is not available onsite, the OIC will verbally provide the portion that contains the permit to the Permit Holder. The Permit Holder must:

- Record the permit exactly as stated.
- Repeat the permit back to the OIC.

A tailboard discussion must be held between the Permit Holder and the OIC prior to:

- Issuing a permit to verify required power system conditions have been established through the switch order.
- Releasing a permit to confirm established conditions can be returned to normal.
- All parties must use full name identification and repeat-back procedures whenever issuing, receiving or releasing permits.
- All required switching and tagging on the switch order must be completed before the associated permit is issued.
- The Employee-in-Charge (EIC) may accept a permit only for the work group(s) under their direction.
- If the Permit Holder must leave the work location, he or she must either release the permit(s) or arrange to maintain established conditions with the permission of the OIC (e.g., by providing a means of contact while offsite or changing Permit Holder s). See Section 504.2.
- Permits must be released when no longer required.
 - If permits are not released and the Permit Holder cannot be contacted, the OIC must contact the Permit Holder's immediate supervisor. The supervisor, if unable to locate the Permit Holder, must contact the Operating Authority for approval to release the permits.
- If continuous or scheduled communications cannot be maintained with the OIC, all applicable permits must be released.
- During critical situations, permits must be released as soon as possible at the request of the OIC.

504.2 Changing Permit Holders

If a Permit Holder must leave a site before the work is complete, established conditions can be maintained (with the permission of the OIC) by briefly overlapping the original permit with a new permit issued to another employee.

- The original Permit Holder must personally advise the OIC and everyone working under the permit of the proposed change.
- The new Permit Holder must review and confirm the established conditions with the OIC.
- The OIC will issue the new permit before releasing the original permit.

Note: If a tag is used for Worker-Administered Switching, the new Qualified Worker must place their tag on the device before the original tag is removed.

504.3 Expanding or Contracting Isolated Work Zone

If a work zone has to be expanded or contracted from an existing permit, the OIC must:

- Direct installation of tags on the new devices that are required to be isolated/opened to establish the new work zone.
- Transfer the required existing tags and reference numbers defined in the previous switching order to the new switch order, if a new switching order is required.
- Check that all devices have been identified and tagged to establish required conditions on the new permit.
- Issue the new permit to the Permit Holder.
- Release the previous permit.
- Direct removal of tags from the previous permit that are no longer required.

505 Return to Normal

When the work is complete, the Permit Holder must inform the OIC and – when applicable – provide the appropriate OIC (s) with suitable written documentation (e.g., final inspection, commissioning report stating “Approved to Energize”).

Devices within the confines of the permit will be returned to their original operating state or placed in the operating state desired by the OIC, as applicable.

In the case of Worker-Administered (WA) switching, the Permit Holder must remove all tags and document the time the switching action was completed (and the tag removed).

Return to normal switching may proceed after all permits have been released.

SECTION 600: PERMITS

601 Guarantee of Isolation Permit

The Guarantee of Isolation (GOI) permit allows work on isolated apparatus and guarantees:

- The line or apparatus has been isolated from all known or potential power system sources and has been tagged on all boundaries of isolation.
- Isolation from all known or potential power system sources above 750 V, substation Potential Transformers (PT) and station service disconnects, as applicable.
- The operating state of the isolating devices will not change until the permit is released.

601.1 Restrictions and Requirements

- A GOI Permit may be held by any Qualified Worker.
- When a device is being used as an isolation point for a GOI Permit, a Test and Operate (T&O) will not be allowed on that device.
- Before a GOI Permit is issued, tags must be securely placed on all isolating devices.
- Devices located within the isolation points of a GOI Permit – that are not tagged – may be operated by the Permit Holder with the understanding that before the permit is released the devices will be returned to their original operating state or placed in the operating state desired by the Operator-in-Charge (OIC) as applicable.

- When applied potential (e.g., Doble testing, Hypot testing, primary injections) is being used to test apparatus within a GOI zone, the Permit Holder must inform the OIC that such testing will be taking place. No additional GOIs are to be issued within the same zone of isolation while injection testing is in progress.
- In the case of two or more work groups working under the same GOI Permit, the Permit Holder must:
 - Provide each work group with permission to establish their own work protection (e.g., install grounds).
 - Check all grounds are removed when work is completed and before the work zone is restored to normal.

601.2 Issuing a Guarantee of Isolation Permit

When all conditions have been met, the OIC issues the GOI Permit to the Permit Holder, using the following words:

This is (name) informing (name) that (device or line) is now (isolated between/opened at) (location or locations). You may proceed with your work under GOI Permit # _____ Date _____.

601.3 Releasing a Guarantee of Isolation Permit

Before releasing the GOI Permit, the OIC and Permit Holder must verify that the switch order tailboard has been completed.

The Permit Holder releases the GOI Permit to the OIC with these words:

This is (name) informing (name) that I have completed my work on (device or line) and I am releasing my GOI Permit # _____ Date _____.

602 Test and Operate Permit

The Test and Operate (T&O) Permit provides assurance the OIC has assessed system security and that adjustments, repairs or tests can be performed on apparatus that may or may not be energized – as covered by the permit. It allows apparatus to be operated or energized so that adjustments, repairs, maintenance or commissioning tests can be performed.

A Test and Operate Permit is NOT intended to serve as a form of personal protection.

602.1 Restrictions and Requirements

- A T&O Permit may be held by any Qualified Worker.
- Only one T&O Permit will be issued on a single apparatus at any time.
- A T&O Permit will not be issued on any device defined as an isolation point for a GOI Permit.
- A T&O Permit will not be issued on any device that is part of a Hold-Off Permit.
- Before a T&O Permit is issued, tags must be securely placed on the switching devices that create the test condition.
- If a device or apparatus is required to be operated during tests, it may be operated only on instructions from the Permit Holder (e.g., opening/closing a circuit breaker).

602.2 Issuing a Test and Operate Permit

After all requirements have been met, the OIC issues the T&O Permit to the Permit Holder, using the following words:

This is (name) informing (name) that it is okay to test and operate (device) at (location) under Test and Operate Permit # ____ Date ____.

602.3 Releasing a Test and Operate Permit

Before releasing a T&O Permit, the Permit Holder must verify the work has been completed and that devices associated with the permit are in their original operating state or the operating state desired by the OIC, as applicable.

The Permit Holder releases the T&O Permit to the OIC with these words:

This is (name) informing (name) that I have completed my work on (device) at (location) and I am releasing my Test and Operate Permit #_____ Date _____.

603 Hold-Off Permit

A Hold-Off Permit (HOP) prevents automatic or manual restoration after an unplanned circuit outage, preventing further exposure of apparatus and employees to electrical potential. It confirms that restoration and reclosing schemes are disabled.

Normal Open (NO) switches in the field will not be tagged for HOPs.

603.1 Restrictions and Requirements

- A HOP may be held by any Qualified Worker.
- Tags must be placed on devices required to create the HOP, including the:
 - Control Panel – control switches of circuit breakers associated with the electrical apparatus covered by the HOP
 - Control Panel/Structures – control switches of any auto-sectionalizing, auto-transfer or automatic reclosing schemes that could re-energize the apparatus covered by the HOP.
- If the HOP is established through supervisory control, field tags referenced in paragraph one above do not have to be installed; however, the OIC must apply software tags to all devices associated with the permit.

- If the OIC receives an alarm indicating the associated protection may fail to operate under fault conditions (e.g., alarm for loss of DC), the OIC must notify the Permit Holder. The Permit Holder and OIC must then determine if the HOP can continue.
- If the associated protection operates or a loss of potential is suspected, the Permit Holder must notify the OIC or the OIC must notify the Permit Holder, as applicable.
- The Permit Holder must notify the OIC if a contact or incident occurs.
- Any device or line covered by the HOP that becomes de-energized will not be re-energized without the consent of the Permit Holder. (It is permissible to leave insulating equipment and tools connected to the line during the re-energization process).

603.2 Issuing a Hold-Off Permit

After all requirements have been met, the OIC issues the HOP to the Permit Holder, using the following words:

This is (name) informing (name) that reclosing has been disabled on (device or line) at (location) and (location) under Hold-Off Permit # _____ Date _____.

603.3 Releasing a Hold-Off Permit

Before releasing the permit, the Permit Holder must verify the work has been completed and that devices associated with the permit are in their original operating state or the operating state desired by the OIC, as applicable (e.g., as required for attaching or detaching apparatus).

The Permit Holder releases the HOP to the OIC with these words:

This is (name) informing (name) that I have completed my work on (device or line) and I am releasing my Hold-Off Permit # _____ Date _____.

604 Control System Permit

The Control System Permit (CSP) allows the OIC to assess risks and to condition the system to minimize the impact to system security, customer supply and other permits before work is performed on apparatus under 750 V that directly impacts or could impede operation of the power system. A CSP shall be initiated for work on the following apparatus:

- relays
- voice and data communication systems
- protection circuits
- DC systems
- Substation AMR.

If there is any doubt about whether a CSP is required, the employee should contact the OIC.

604.1 Restrictions and Requirements

- A CSP may be held by any Qualified Worker.
- A CSP will not be issued on protective relays or any other apparatus associated with the devices covered by a HOP.
- Before receiving a CSP, the Permit Holder must describe to the OIC what they are doing and outline any local impacts if something goes wrong with the work.
- If unexpected problems are encountered, the Permit Holder must report to the OIC before proceeding.
- If conditions on the power system change and continuation of the work will jeopardize system security or customer supply, the OIC must request the release of the CSP.

604.2 Issuing a Control System Permit

The OIC will review the information provided by the Permit Holder, conduct a power system risk assessment, document any operational impacts and consider other existing permits before issuing a CSP.

The OIC issues the CSP to the Permit Holder, using the following words.

*This is (name) informing (name) that it is ok to proceed with your work under Control System Permit # _____.
Date _____.*

604.3 Releasing a Control System Permit

Before releasing the permit, the Permit Holder must verify that the apparatus associated with the permit is in its original operating state or the operating state desired by the OIC, as applicable.

The Permit Holder releases the CSP to the OIC with these words:

*This is (name) informing (name) that I have completed my work and it is ok to close Control System Permit # _____.
Date _____.*

SECTION 700: CONSTRUCTION – ATTACHING AND DETACHING APPARATUS

701 Procedure

When new construction is physically close to the point where it will eventually be tapped onto the existing electrical system, a tag may be installed on the open span or open jumpers to prevent inadvertent connection to the electrical system. Jumpers and open spans used for isolation purposes shall be assigned a unique identifier. The tag can be installed as part of the Condition Guarantee or alternatively installed as part of Worker-Administered (WA) switching.

When new construction is physically close to the existing electrical system and is only separated by a switch, a lock and/or tag must be installed on the open switch. The lock and/or tag can be installed as part of the Condition Guarantee or alternatively installed as part of WA switching.

To attach or detach apparatus from the energized power system, the Employee-in-Charge (EIC) must:

1. Provide the appropriate OIC with suitable written documentation (e.g., final inspection, commissioning report stating “Approved to Energize” or de-commissioning report stating “Approved to De-Energize”).
2. Provide the OIC (s) with an interim Single Line Diagram (SLD) or switch map, verified and approved by the EIC.
3. Identify the power system conditions required to complete the work and request permission to establish those conditions from the OIC (s).

4. Release associated WA switching permissions, permits or Condition Guarantees.

Note: When a project requires energization in stages, the EIC must:

- Identify isolation points that define each stage in the project work plan and provide a copy of the work plan to the OIC (s).
- Provide the OIC (s) with an interim SLD or switch map (that has been verified and approved by the EIC) before each segment is energized.

SECTION 800:

OPERATING INTERFACE POINTS

801 Location of Operating Interface Points

To determine the location of operating interface points, refer to the table provided in Appendix A.

802 Condition Guarantee

The Condition Guarantee (COG) provides the formal assurance to another Operating Authority or Operator-in-Charge (OIC) that identified devices are in the position requested and will not change status until the device status request is formally released by the requestor.

A Condition Guarantee is not a permit.

802.1 Restrictions and Requirements

The OIC must give adjoining OICs prior notification of any action or condition that could impact their system, including, as applicable:

- changes to operating conditions
- operation of adjacent devices
- any work being performed that could present a risk to their system.

When establishing conditions that require switching beyond an operating interface point, the OIC must:

- Exchange copies of corresponding switching orders with the adjoining OIC when coordinated switching is required with the other party.

- Receive, before completing the switching process, a verbal COG from the adjoining OIC that required switching and tagging has been performed on their system and established conditions will not change until released by the OIC making the request.

802.2 Issuing a Condition Guarantee

When all conditions have been met, the OIC issues the COG to the adjacent OIC, using the following words:

This is (name) at the ATCO Electric SOC informing (name) at (company or organizational name) you have a Condition Guarantee that (describe condition) on/at (line number or substation name and number). Reference # _____, Date _____.

802.3 Releasing a Condition Guarantee

Once the adjacent OIC no longer requires the Condition Guarantee, they release it with these words:

This is (name) at (company or organizational name) informing (name) at the ATCO Electric SOC that work is completed on (line or equipment number and location). I am releasing my Condition Guarantee Reference # _____, Date _____. (line or equipment) can be returned to normal.

SECTION 900: PROCEDURAL TOOLS

901 Voice Communications

Voice communication systems must be available for use between the Permit Holder and the Operator-in-Charge (OIC), and the Switchman and the OIC.

- Employees may use the following devices for communication:
 - cell/satellite phone
 - land line phone
 - company radio.
- All transmission substations must have one or more voice communication systems available for use at all times. If there is any doubt as to the effect of a portable radio or cell phone on apparatus in the building (e.g., a warning sign is posted), it must not be used.
- Where continuous communication is not possible, due to the site location, the OIC may allow scheduled communications. Consideration must be given to the:
 - impact on system security, due to the communication delays
 - possibility that customer outages may be extended, due to the communication delays.

902 Record Keeping

All switch orders for Worker-Administered (WA) switching shall be kept locally for a minimum of one year.

The OIC must maintain the following records for a minimum of three years:

- all switching orders (e.g., electronic, paper) used to issue permits
- documentation of any investigations regarding tagging or unauthorized operation of power system devices or apparatus
- logs – electronic or paper – including:
 - all permit information, including reference numbers
 - all Condition Guarantee information
 - Operator-Administered switching
 - Worker-Administered switching.

SECTION 1000: SPECIAL SITUATIONS

1001 Emergency Situations

Power System Work Standards (PSWS) provides ATCO Electric employees with standards for establishing conditions on the power system that will – when combined with appropriate work standards, procedures and methods – allow work to take place on or near the power system.

In an emergency, (a present or imminent event that requires prompt coordination of action to protect the health, safety or welfare of people or to limit damage to property and/or the environment), a Qualified Worker may take action to remove apparatus from service without prior authorization.

- ALWAYS protect yourself.
- NEVER put yourself in imminent danger or do anything that causes you to doubt your decision – call for help.

After emergency action has been taken, the Qualified Worker must report the action and the reason for the action to the appropriate Operator-in-Charge (OIC) as soon as possible.

The OIC will review the action and take the necessary steps to restore the power system.

Note: An investigation must be completed when emergency action has been taken.

1002 Inadvertent Operation of Apparatus

If an employee inadvertently operates any component of the power system, the employee must NOT attempt to correct the error. The employee must immediately notify the OIC.

The OIC will review the inadvertent operation and take the necessary steps to restore the power system, as applicable.

All employees must realize the potential results of their actions – all incidents must be reported and investigated.

APPENDIX A – Operating Interface Points

	Transmission	Distribution
Transmission	Not Applicable	Any distribution system apparatus downstream from the apparatus shown on the substation switching diagram.
Distribution	Any distribution system apparatus downstream from the apparatus shown on the substation switching diagram.	Not Applicable
Generation	As agreed to by the Operating Authorities and clearly defined on the single line diagrams. Where there is a direct interconnection, a Joint Operating Procedure must be established .	Located on the distribution system apparatus electrically closest to the unit breaker, unit transformer or station auxiliary transformer.
Customer	As agreed to by the Operating Authorities and clearly defined on associated customer and company single line diagrams. Where there is a direct interconnection, a Joint Operating Procedure must be established .	As agreed to by the Operating Authorities and clearly defined on associated customer and company single line diagrams and/or distribution switching maps. Where there is a direct interconnection, a Joint Operating Procedure must be established).
Other Utility	As agreed to by the Operating Authorities and clearly defined on associated utility, company and transmission single line diagrams. Where there is a direct interconnection, a Joint Operating Procedure must be established .	As agreed to by the Operating Authorities and clearly defined on associated utility, company and distribution single line diagrams.

APPENDIX B – Do Not Operate Tag

ATCO Electric

DO NOT OPERATE TAG

DANGER

DO NOT REMOVE THIS TAG

CAUTION

MEN AT WORK

DO NOT OPERATE

SEE OTHER SIDE

ATCO Electric

SAFETY FIRST ALWAYS
NO PERMISSION, NO WORK

DO NOT OPERATE TAG

LINE / TAP / CIRCUIT / EQUIPMENT: _____

SWITCH NO. OR
JUMPER LOCATION: _____

ISOLATION/CONDITION ☐ GOI ☐ HOP ☐ T&O ☐ COG ☐ WA

SWITCH STEP # () _____

SWITCH STEP # () _____

SWITCH STEP # () _____

REQUESTED BY: ☐ OIC ☐ WA

OPENED / CHECKED BY: _____

DATE: YYYYMMDD TIME: JABB HRS

CLOSED / CHECKED BY: _____

DATE: YYYYMMDD TIME: JABB HRS

OIC REFERENCE/EVENT NUMBER: _____

0005-0308-0813

REPROGRAPHICS

SCHEDULE "I"

DELIVERY TIME ADJUSTMENT TABLE

Seasonal Adjustment is subject to change.

Month	Seasonal Adjustment
January	100%
February	100%
March	100%
April	100%
May	100%
June	100%
July	100%
August	100%
September	100%
October	100%
November	100%
December	100%

ELECTRICITY PURCHASE AGREEMENT

BETWEEN

536774 YUKON INC.

- and -

YUKON ENERGY CORPORATION

NORTH KLONDIKE HIGHWAY SOLAR PV PROJECT

Under the YUKON STANDING OFFER PROGRAM

Dated the 5th day of June, 2020

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YUKON ENERGY CORPORATION
STANDARD FORM ELECTRICITY PURCHASE AGREEMENT
STANDING OFFER PROGRAM

THIS ELECTRICITY PURCHASE AGREEMENT ("EPA") is made as of the 5th day of June, 2020
BETWEEN:

536774 YUKON INC., a corporation incorporated under the laws of the
Yukon ("**Seller**")

- and -

YUKON ENERGY CORPORATION, a corporation incorporated under
the laws of the Yukon ("**Buyer**")

WHEREAS:

- A. The Government of Yukon issued the *Energy Strategy for Yukon* in January 2009 and in October 2015 issued the *Independent Power Production Policy* as reviewed and updated in October, 2018 (the "**IPP Policy**") as part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy". The IPP Policy created a framework for the development of the Standing Offer Program. In support of the objectives of the IPP Policy, the Government of Yukon issued the SOP OIC and, together with the Utilities, developed the SOP Rules;
- B. Seller has proposed the development of the Project on the Electrical Grid pursuant to the Standing Offer Program and such Project has been reviewed and approved in accordance with the SOP Rules; and
- C. This EPA is being entered into by the Parties in respect of the Project under the Standing Offer Program in accordance with the SOP Rules.

NOW THEREFORE Seller and Buyer agree as follows:

ARTICLE 1
DEFINITIONS, INTERPRETATION AND SCHEDULES

1.1 Definitions and Interpretation

The definitions and certain principles of interpretation that apply to this EPA are set out in Schedule "A".

1.2 Schedules

The following Schedules attached hereto are incorporated into and made a part of this EPA:

- Schedule "A" - Definitions and Interpretation
- Schedule "B" - Project Description

Schedule "C"	-	Form of Annual Operating Plan
Schedule "D"	-	System Interconnection Study Report
Schedule "E"	-	Monthly Energy Shortfall Payment
Schedule "F"	-	Termination Payment
Schedule "G"	-	System Interconnection Guidelines
Schedule "H"	-	Joint Operating Procedure
Schedule "I"	-	Delivery Time Adjustment Table

ARTICLE 2

CONDITIONS PRECEDENT AND TERM

2.1 Conditions Precedent

- (a) Except as provided in this Section, this EPA has no legal force until the Conditions Precedent described in Schedule "B" are satisfied by Seller or waived by Buyer. The Conditions Precedent may only be waived by Buyer by notice in writing to Seller.
- (b) Seller will:
 - (i) seek to satisfy each of the Conditions Precedent on or before the Condition Date;
 - (ii) keep Buyer informed of any circumstances which may result in any of those Conditions Precedent not being satisfied in accordance with their terms; and
 - (iii) promptly notify Buyer upon satisfaction of any of those Conditions Precedent and provide such supporting evidence as may be reasonably required by Buyer.
- (c) If the Conditions Precedent are not satisfied or waived on or before the Condition Date, or it becomes apparent that the Conditions Precedent will not, in the reasonable opinion of Buyer, be satisfied by the Condition Date, the Conditions Precedent will be taken to have failed and Buyer shall be entitled to terminate this EPA, in which event each Party shall release the other from any and all claims, damages, costs, expenses or liabilities whatsoever incurred by it and its Affiliates in relation this EPA provided that (i) Seller shall remain liable for all costs incurred by Buyer in respect of the System Interconnection Study Report, System Upgrade Costs or New Interconnection Facilities Costs and (ii) otherwise each Party shall be responsible for its own costs incurred by it in connection with this EPA.
- (d) Section 2.1(a) does not apply to this Article 2, Section 3.5 and Articles 10, 11, 12, 13 and 15 which shall be in full force and effect from the date of this EPA.

2.2 Term

Subject to Section 2.1, this EPA shall commence on the Effective Date and continues for the period specified in Schedule "B", unless it is terminated earlier in accordance with this EPA.

ARTICLE 3 CONSTRUCTION AND OPERATION

3.1 Construction and Operation Costs, Liabilities and Actions

Seller will be fully responsible for the permitting, design, engineering, construction, Interconnection, commissioning, operation, maintenance, reclamation and decommissioning of the Seller's Plant and shall be responsible for all costs, expenses, liabilities and other obligations associated with such activities.

3.2 Standard of Construction and Operation

Except as otherwise consented to in writing by Buyer, such consent not to be unreasonably withheld, conditioned or delayed, Seller will ensure that the location, design, engineering, construction, Interconnection, commissioning, operation and maintenance of the Seller's Plant, are and will be carried out at all times during the Term:

- (a) in accordance with the description of the Seller's Plant in Schedule "B" and the information in the Application in all material respects;
- (b) in compliance with the Project Standards; and
- (c) by qualified and experienced individuals.

The Parties shall conduct their respective operations in accordance with the Joint Operating Procedure.

3.3 Project Changes

Without Buyer's prior written consent, not to be unreasonably withheld, conditioned or delayed Seller will not make any change to:

- (a) the Seller's Plant as described in Schedule "B"; or
- (b) any other aspects of the Seller's Plant or the information in any System Interconnection Study Report completed for Seller's Plant prior to the Effective Date which would require changes by Buyer to the System Upgrades where such change would increase Buyer's liability for any costs or otherwise increase the obligations or risks of Buyer with respect to the Seller's Plant or any other project.

Seller acknowledges that Buyer may require, as a condition of its consent to any change described in this Section, that Seller agree in writing to reimburse Buyer for any reasonable incremental liability for any losses, costs and damages incurred by Buyer or any third party, with respect to the Seller's Plant or any other project, as a result of any change described in this Section. Buyer may also require that Seller provide performance assurance or security to Buyer in order to ensure that Buyer has no financial exposure in respect of such reimbursement obligation.

3.4 Development Progress Reports

Seller will deliver a Development Progress Report to Buyer on each January 1, April 1, July 1 and October 1 after the Effective Date until Seller's COD. Buyer shall be entitled to request such

additional information as it may reasonably require from time to time in respect of Seller's development of Seller's Plant.

3.5 Responsibility for Upgrade Costs

Seller will be responsible for and shall pay Buyer for all System Upgrade Costs and New Interconnection Facilities Costs in accordance with the following:

- (a) the System Interconnection Study Report sets out Buyer's estimate of System Upgrade Costs and the New Interconnection Facilities Costs. Seller shall (i) pay to Buyer in advance an amount equal to such estimate of System Upgrade Costs and New Interconnection Facilities Costs ("**Upgrade Costs Advance**") and/or (ii) provide such other security in form, substance and amount as may be acceptable to Buyer in its Discretion to secure the obligation of Seller to pay such costs ("**Upgrade Costs Security**"). Buyer shall not be required in any circumstances to accept Upgrade Costs Security except in its Discretion. Buyer shall not be required to perform any work or incur any System Upgrade Costs or New Interconnection Facilities Costs where Buyer determines in its Discretion that the amount of Upgrade Costs Advance it has received together with any Upgrade Costs Security is not sufficient to adequately secure the obligation of Seller to pay all System Upgrade Costs and New Interconnection Facilities Costs and Seller shall forthwith provide to Buyer such additional Upgrade Costs Advance and/or Upgrade Costs Security as may be reasonably required by Buyer;
- (b) Buyer will exercise Good Industry Practice to perform, or cause to be performed, the work required in respect of the System Upgrades and the New Interconnection Facilities for the Project. Buyer shall be entitled to draw upon the Upgrade Costs Advance and Upgrade Costs Security from time to time in its Discretion to satisfy any System Upgrade Costs and New Interconnection Facilities Costs as and when incurred by Buyer; and
- (c) notwithstanding the estimate of System Upgrade Costs and New Interconnection Facilities Costs provided by Buyer to Seller contemplated in Section 3.5(a) or the amount of any Upgrade Costs Advance and Upgrade Costs Security provided by Seller, Seller shall be responsible for and shall pay Buyer the actual System Upgrade Costs relating to the System Upgrades incurred by Buyer. Following the completion of the System Upgrades and the payment in full by Seller of all System Upgrade Costs incurred by Buyer for such work, Buyer shall release to Seller any undrawn portion of the Upgrade Costs Advance and Upgrade Costs Security.

3.6 Metering

As part of the System Upgrades and New Interconnection Facilities, Buyer will install and maintain an appropriate Meter installation at the POI, and ensure that such Meter is tested and sealed according to any Measurement Canada standards. Seller will allow Buyer to access the Seller's Plant as may be necessary from time to time to install and maintain the Meter at the POI. If there is any dispute regarding the accuracy of the Meter, either Party may give notice to the other Party of the dispute. In that case, the Parties will resolve the matter in accordance with the *Electricity and Gas Inspection Act* (Canada).

3.7 Insurance

Seller will, at its cost, obtain and maintain (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than \$5,000,000, and (b) property insurance, with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender may require. All commercial general liability policies must include Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must include a waiver of subrogation in favour of Buyer. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Yukon and must be endorsed to provide to Buyer 30 days' prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. Seller will give Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by Seller under this Section not more than 30 days after the effective date of coverage and promptly upon renewal thereafter. Seller will be responsible for the full amount of all deductibles under all insurance policies required to be maintained by Seller under this Section.

3.8 Seller's COD

- (a) Except with Buyer's prior written consent, Seller's COD may not occur earlier than 90 days prior to Target Seller's COD.
- (b) Buyer will not be required to incur any incremental expense or other liability of any kind to enable Seller's COD to occur prior to Target Seller's COD.

3.9 Change in Target Seller's COD

If the estimated date for completing the System Upgrades or the New Interconnection Facilities as required to achieve Buyer's COD is later than 90 days prior to the Target Seller's COD, Buyer shall provide notice to Seller of such delay and, provided Seller is not responsible for any delay in completing the System Upgrades or the New Interconnection Facilities (including a failure to pay amounts contemplated in Section 3.5), upon Seller's written request that the Target Seller's COD be postponed, Buyer will postpone the Target Seller's COD to the estimated date for completing the System Upgrades and the New Interconnection Facilities plus 90 days.

3.10 No Liability For Delay

Buyer shall exercise reasonable commercial efforts to achieve Buyer's COD prior to Target Buyer's COD. Buyer will have no liability under this EPA for delays in completion of (a) any System Upgrades or the New Interconnection Facilities, or (b) other work undertaken by Buyer or any of Buyer's Affiliates on the Seller's Plant side of the POI, in each case howsoever arising.

3.11 Outages

- (a) **Notice of Seller's Outage** - Seller will notify Buyer of any Outages in Seller's Plant, or changes in any such Outages, by delivering to Buyer an Outage Notice or revised Outage Notice:
 - (i) promptly in the case of a Forced Outage or a Maintenance Outage;

- (ii) not less than 90 days in advance of any Planned Outage, or such shorter time period with Buyer's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and
 - (iii) promptly in the case of any changes to the duration, start time or end time of any Outage.
- (b) **Notice of Buyer's Outage** - In addition to Buyer's reporting requirements under Section 4.8(d), Buyer will notify Seller of any Planned Outages that will result in a Buyer's Distribution/Transmission Constraint or changes in any such Planned Outages, by delivering to Seller an Outage Notice or revised Outage Notice:
 - (i) not less than 90 days in advance of any such Planned Outage, or such shorter time period with Seller's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and
 - (ii) promptly in the case of any changes to the duration, start time or end time of any Outage.
- (c) **Coordination and Scheduling of Outages** - Seller will coordinate all Planned Outages or Maintenance Outages with Buyer's maintenance schedule or other requirements where such schedule or requirements are publicly available or otherwise notified to Seller.

3.12 Annual Operating Plan

On or before October 31 in each year during the Term, Seller will provide to Buyer its Annual Operating Plan, including any required update to the then current Annual Operating Plan, for the 12-month period commencing on January 1 of the next year. Seller will promptly provide Buyer with a revised Annual Operating Plan from time to time upon Seller becoming aware of any expected material change in the original Annual Operating Plan for that period. The Parties agree the Annual Operating Plan is provided for planning purposes and does not guarantee or limit the quantity or timing of Delivered Energy to the POI.

ARTICLE 4 PURCHASE AND SALE OBLIGATIONS

4.1 Energy prior to Buyer's COD

Subject to satisfaction of all obligations of Seller under this EPA, upon the occurrence of Seller's COD but prior to the occurrence of Buyer's COD, Buyer will not be obligated to purchase, or accept delivery from Seller of, any Energy, provided if Buyer does accept, in its sole discretion, delivery of Energy at the POI, Buyer will pay for such Energy accepted by Buyer prior to Buyer's COD in accordance with Section 5.1.

4.2 Energy after Buyer's COD

From and after Buyer's COD for the remainder of the Term, Seller will sell and deliver all Energy to Buyer at the POI and Buyer will, subject to Sections 4.3 and 4.4, purchase and accept delivery of all Delivered Energy. Buyer will pay for Delivered Energy from and after Buyer's COD in accordance with Section 5.1.

4.3 Limit on Delivered Energy and Capacity

Notwithstanding the foregoing provisions of this Article 4:

- (a) in any hour, Buyer will not be obligated at any time to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Seller's Plant Capacity in such hour (as measured in kWh) and no amount will be payable by Buyer for Delivered Energy in excess of the Seller's Plant Capacity in such hour, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI;
- (b) in any calendar year, Buyer will not be obligated to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Project Energy Volume and no amount will be payable by Buyer for Delivered Energy in any such calendar year in excess of the Project Energy Volume in such calendar year, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI; and
- (c) in determining the total amount of Delivered Energy for a year, month, hour or any other time period under this EPA for any purpose, the amount of Delivered Energy in each hour of such time period will not exceed the Seller's Plant Capacity in such hour, even if Seller delivered to the POI Energy in excess of such amounts, or the Seller's Plant was capable of generating Energy in excess of such amounts.

4.4 Distribution/Transmission Constraints

Buyer will not be in breach or default of its obligations under Sections 4.1, 4.2 or 5.1 if Buyer is not able to accept delivery of Energy at the POI as a result of a Distribution/Transmission Constraint. Buyer will have no liability with respect to a Distribution/Transmission Constraint, except as set out in Section 4.8, if applicable.

4.5 Exclusivity

- (a) Seller will not at any time during the Term commit, sell or deliver any Energy (or related Environmental Attributes) to any Person other than Buyer under this EPA. Seller will not use any Energy (or related Environmental Attributes) for any purpose whatsoever except for sale to Buyer under this EPA. These prohibitions do not apply if, and for so long as, Buyer is in breach of its obligations under Section 4.2.
- (b) Seller shall not be entitled to interconnect a generating facility to the Seller's Plant and transmit electricity via the Seller's Plant to the POI.

4.6 Custody, Control, Risk of and Title To Energy

Custody, control, risk of, and title to, all Energy (including any Delivered Energy exceeding the limits set out in Section 4.3 even where Buyer has not paid for such excess Delivered Energy) shall pass from Seller to Buyer at the POI. Seller will ensure that all Energy delivered to Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances.

4.7 Line Losses

Seller will be responsible for all Line Losses, costs and liabilities relating to the transmission of Energy and other electricity, if applicable, from the POI to the interconnection point between the New Interconnection Facilities and the Electrical Grid. Such Line Losses shall be determined in accordance with the Line Loss Methodology.

4.8 Distribution/Transmission Constraint

- (a) If, in any month after Buyer's COD, Seller is unable to deliver Energy at the POI or Seller's ability to deliver Energy at the POI is reduced solely as a result of a continuous Distribution/Transmission Constraint which exceeds 30 minutes in duration and which:
 - (i) is not caused by a Planned Outage by Buyer of the Distribution System or Transmission System;
 - (ii) is not caused by an event beyond the reasonable control of Buyer; and
 - (iii) is not caused by Seller, the Seller's Plant or anything on Seller's side of the POI;

(a "**Non-Permitted Distribution/Transmission Constraint**") then, notwithstanding that Buyer is excused under Section 4.4 from its obligations under Section 4.2, Buyer shall pay Seller, for each calendar month in which the Non-Permitted Distribution/Transmission Constraint has occurred, the Monthly Energy Shortfall Payment calculated in accordance with Schedule "E" less any costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint.
- (b) Buyer will not be required to pay any Monthly Energy Shortfall Amount under this Section in any of the following circumstances:
 - (i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;
 - (ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure; or
 - (iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Non-Permitted Distribution/Transmission Constraint occurs.
- (c) Seller will maintain accurate and complete Records of all costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint and will report all such costs to Buyer and provide Buyer with all information required to calculate such costs.
- (d) Buyer will give Seller notice of all Distribution/Transmission Constraints in each month which individually exceed 30 minutes in duration when it provides its monthly statements in accordance with Section 5.3.

- (e) In the event of a Dispute by the Parties in respect of the amount of any Monthly Energy Shortfall Amount, the matter shall be resolved in accordance with Article 12.

4.9 Buyer Dispatch/Turn-Down Right

- (a) Buyer may at any time during the Term deliver notice to Seller requiring Seller to Dispatch/Turn-Down and Seller will promptly comply with any such direction except to the extent that any operational, technical or regulatory constraint prevents or limits Seller's ability to comply with such direction.
- (b) For each hour of the applicable Dispatch/Turn-Down, Buyer will pay Seller an amount equal to:
 - (i) the price payable for post-COD Delivered Energy under Section 5.1 multiplied by (A) the aggregate of the duration of the applicable Dispatch/Turn-Down (measured as a fraction determined as the aggregate number of minutes in such Dispatch/Turn-Down period divided by 60) multiplied by (B) an amount equal to the positive difference, if any, of (1) the "Non-Permitted Distribution / Transmission Constraint Hourly Deemed Energy" set out in Table E-1 of Schedule "E" for the applicable calendar month less (2) the amount of Delivered Energy in such hour of Dispatch/Turn-Down (the positive difference being the **"Dispatch/Turn-Down Deemed Energy"**); less
 - (ii) any costs Seller avoided or, acting reasonably, could have avoided during the period of the Dispatch/Turn-Down.
- (c) Buyer will not be required to pay any amount in respect of Dispatch/Turn-Down Deemed Energy under this Section in any of the following circumstances:
 - (i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;
 - (ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure;
 - (iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Dispatch/Turn-Down occurs;
 - (iv) during any other hour when the Seller's Plant would otherwise not have been operating if there had been no Dispatch/Turn-Down notice; or
 - (v) where Buyer's requirement for Seller to Dispatch/Turn Down is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2.
- (d) Where Buyer requires the Dispatch/Turn-Down as result of a Non-Permitted Distribution/Transmission Constraint, Section 4.8 will apply.

4.10 Electric Service to Seller

If at any time Buyer delivers electrical energy to service Seller's Plant Load, then such electrical energy shall be accounted and paid for separately under the applicable agreement for such electricity energy services and will not be netted off of Delivered Energy for the purposes of determining amounts payable by Buyer in accordance with Section 5.1.

ARTICLE 5 PRICE AND PAYMENT TERMS

5.1 Energy Price

In each billing period, Seller shall pay to Buyer, for each kWh of Delivered Energy, the Energy Price calculated in accordance with Schedule "B".

5.2 No Further Payment

The amount payable by Buyer as specified in Section 5.1 is the full and complete payment and consideration payable by Buyer for Delivered Energy and for Environmental Attributes.

5.3 Statements and Payment

(a) Statements

(i) Buyer will, by the 15th day of each month after the Buyer's COD, deliver to Seller a statement for the preceding month. The statement must indicate, among other things:

(A) the amount of, and price payable for, Delivered Energy for that month;

(B) any amount owing by Buyer in respect of a Non-Permitted Distribution/Transmission Constraint pursuant to Section 4.8;

(C) any Final Amounts owing by either Party to the other Party.

Where there has been any Delivered Energy purchased by Buyer in the period prior to Buyer's COD, the first statement following Buyer's COD shall also account for all amounts payable by Buyer to Seller for such period prior to Buyer's COD. The statement must set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed and be accompanied by sufficient data to enable Seller, acting reasonably, to satisfy itself as to the accuracy of the statement.

(ii) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the case of willful misstatement, fraud or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this Section within the 36 month period, which will be resolved in accordance with this EPA.

- (iii) If Seller gives notice to Buyer of an error, omission or disputed amount on a statement as described in Section 5.3(a)(ii), Seller may direct Buyer to promptly produce new statements for the relevant month(s). The new statements will show the undisputed amount and disputed amount each in a separate statement or will otherwise separate the amounts in a single statement in a manner acceptable to Seller, acting reasonably.

(b) Payment

- (i) Within 30 days after receipt of a statement delivered under Section 5.3(a), and subject to Section 5.5, Buyer will pay to Seller or Seller will pay to Buyer the amount set out in the statement, except to the extent Seller in good faith disputes all or part of the statement by notice to Buyer as described in Section 5.3(a)(ii).
- (ii) If Seller disputes any portion of a statement, the applicable Party must pay the undisputed net amount payable by it pursuant to the statement or, if applicable, the new statement of the undisputed amount described in Section 5.3(a)(iii).
- (iii) The Parties will endeavor to resolve any error, omission or disputed amount on a statement amount within 30 days of the notice described in Section 5.3(a)(ii).
- (iv) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 2%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

(c) Payment Calculations

- (i) For the purpose of all payment calculations under this EPA:
 - (A) all payment calculations will be rounded to the nearest cent; and
 - (B) Energy will be expressed in kWh rounded to two decimal places.
- (ii) For the purpose of all payment calculations under this EPA, where CPI is to apply, if Statistics Canada (or the then recognized statistical branch of the Canadian Government):
 - (A) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);
 - (B) at any time ceases to publish or provide the CPI, then the provisions of Section 2.7 of Schedule "A" will apply;
 - (C) has not published the CPI for a relevant period at the time Buyer is required to provide Seller with a statement, Seller will prepare the invoice based on the CPI in effect at the time the invoice is issued and when the CPI for the relevant period is published, Buyer will recalculate the invoice amounts in

the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

- (D) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then Buyer will recalculate the invoice amounts for the relevant period in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

5.4 Taxes

All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes, including GST and any successor thereto, which, if applicable, will be added to each statement and paid by Buyer.

5.5 Set-off

If Buyer and Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party will be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount will pay to the other Party the difference between the amounts owed, provided that this Section applies only to any purchase price for Delivered Energy and any Final Amount owing by either Party to the other Party. Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defenses which such Party has, or may be entitled to, arising from or related to this EPA.

5.6 Change in Law and GRA Cost Recovery

- (a) If at any time after the Effective Date:

- (i) the costs to Buyer of complying with its obligations under this EPA are, as a result of one or more Changes in Law, increased or decreased (including, for greater certainty, any increase of the obligations or risks of Buyer with respect to the Seller's Plant, but excluding any increase of the obligations or risks of Buyer with respect to the System Upgrades or New Interconnection Facilities); or
- (ii) the costs to Buyer of complying with its obligations under this EPA which were of a category or type previously recovered under a General Rate Application are determined under a General Rate Application to no longer be approved for recovery from Buyer's customers in such General Rate Application;

then, to the extent that Buyer would not have incurred such costs except for the Seller's Project and/or the entering into of this EPA, the amount payable by Buyer as specified in Section 5.1 shall be adjusted by the amount necessary to reflect those changed costs which Buyer is unable to recover from Buyer's customers in a General Rate Application.

- (b) For each relevant event in Section 5.6(a)(i) or 5.6(a)(ii), Buyer shall provide Seller with a statement setting out such information as is reasonably necessary to demonstrate that such an event has occurred, the reasonableness and necessity of the measures taken by Buyer in relation to the event, its efforts to mitigate the costs associated with such event including

reasonable efforts of Buyer to recover such costs from its customers in a General Rate Application, the nature and extent of any increase or decrease in the amount payable by Seller as specified in Section 5.1, and any such other information as may be reasonably requested by Seller.

- (c) If in Seller's view there has been a Change in Law that may decrease Buyer's costs, Seller may request Buyer to demonstrate how such Change in Law has affected its costs under this EPA by providing the applicable information contemplated in Section 5.6(b).
- (d) The payments between the Parties shall thereafter be adjusted effective as of the date such event in Section 5.6(a)(i) or 5.6(a)(ii) affects the costs of Buyer hereunder.
- (e) If there is any Dispute between the Parties with respect to this Section 5.6, including as to the appropriate increase or decrease in any payments between the Parties under this Agreement, the Dispute shall be resolved in accordance with Article 12.

ARTICLE 6 ENVIRONMENTAL ATTRIBUTES

6.1 Environmental Attributes

Seller hereby transfers, assigns and sets over to Buyer all right, title and interest in and to the Environmental Attributes. Seller will ensure that all Environmental Attributes transferred to Buyer under this EPA are free and clear of all liens, claims, charges and encumbrances. Seller shall use commercially reasonable efforts to (i) provide information reasonably requested by Buyer in relation to such Environmental Attributes, including as may be required to allow Buyer to verify or certify that such Environmental Attributes exist or have been created and (ii) assist in having Seller's Plant certified, licensed, qualified or approved under any rules, regulations, programs or applicable Laws of any Governmental Authority or independent certification agency in respect of Environmental Attributes, provided that Buyer shall pay Seller all costs reasonably incurred by Seller in respect of the same. Any failure by Seller to exercise such commercially reasonable efforts under this Section 6.1 is a "material default" for the purposes of this EPA, and Buyer may terminate this EPA under Section 9.1(j).

ARTICLE 7 EPA ADMINISTRATION, RECORDS AND AUDITS

7.1 Records

Each of Buyer and Seller will prepare and maintain all Records, or duplicates of such Records, at Buyer's head office or local Yukon office or the Seller's Plant, as applicable, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed in writing between the Parties, for a period of not less than 7 years from the date on which each such Record is created. The Audit Parties may take copies of such Records for the purposes of an inspection or audit under Section 7.2.

7.2 Inspection and Audit Rights

For the sole purpose of verifying:

- (a) compliance with this EPA;

- (b) the accuracy of statements, supporting information and calculations delivered by a Party under this EPA;
- (c) the qualification of the Seller's Plant and the Energy for the Environmental Certification; or
- (d) the liability of Seller for System Upgrades Costs and New Interconnection Facilities Costs,

Buyer or Seller, as applicable, will, on reasonable prior written notice from either Party desiring to conduct an audit, provide the Audit Parties with prompt access during normal business hours to (i) in respect of Buyer, Buyer's records solely relating to this EPA, or (ii) in respect of Seller, Seller's Plant and all records relating to the Seller's Plant, including any Seller Confidential Information, as applicable, to enable the Audit Parties to conduct an inspection or audit thereof. The Audit Parties will exercise any access and audit rights under this Section in a manner that minimizes disruption to the operation of the Party subject to the audit. The audit rights contained in this Section 7.2 shall be subject to the limitations set forth in Section 5.3.

7.3 Seller Consents

Seller will promptly provide any consents required to enable any of the Audit Parties to make enquiries with any Governmental Authority or any Person administering the Environmental Certification concerning any or all of the following: (a) the qualification of the Seller's Plant and the Energy for Environmental Certification, the status of the Environmental Certification and copies of any audits, inspections or reports prepared in connection with the Environmental Certification; and (b) compliance by Seller with Laws and Permits applicable to the Seller's Plant.

ARTICLE 8 FIRST NATION CLAIMS

8.1 Notification of First Nation Claim

Given the ownership and location of the Project, Seller and Buyer do not expect any First Nation Claims. However, if Buyer or Seller receives or obtains evidence of a First Nations Claim, it will notify the other Party as soon as practicable.

8.2 Obligation to Consult

If Buyer receives, obtains evidence or becomes aware of a First Nations Claim, it may direct Seller, at Seller's cost, to:

- (a) consult with the First Nations making the First Nation Claim, or, if requested by Buyer, assist Buyer in the consultation process;
- (b) take any measures Seller deems necessary to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts provided the measures are consented to in advance by Buyer and the First Nations making the First Nation Claim; and
- (c) provide regular written reports to Buyer concerning Seller's compliance with this Section, as may be reasonably requested by Buyer.

8.3 Seller Termination for First Nation Claim

At any time prior to Buyer's COD, if:

- (a) within 60 days of Buyer receiving, obtaining evidence or becoming aware of a First Nations Claim, Buyer does not make a direction to Seller as contemplated in Section 8.2;
- (b) Buyer notifies Seller in writing that it will not make a direction to Seller as contemplated in Section 8.2; or
- (c) after consultation with the First Nations making the First Nation Claim it becomes clear that the measure(s) necessary for Seller to resolve the First Nation Claim or to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts would, in Seller's discretion, impose a commercially unreasonable cost on Seller, or would require the consent of Buyer under this EPA or agreement by Buyer to amend this EPA in order to address any Potential Impacts and such consent or agreement to amend is not provided within 60 days after Seller's request to Buyer,

then Seller may terminate this EPA on notice to Buyer. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. A termination by Seller under this Section will, for all purposes of this EPA, be treated in the same manner as a termination by Seller under Section 9.3(c) of this EPA (including the obligations of Seller under Section 9.7). The termination of this EPA is the exclusive remedy to which Seller may be entitled to if Seller elects to terminate this EPA under this Section.

8.4 Buyer Termination for First Nation Claim

At any time prior to Buyer's COD, if Buyer receives, obtains evidence or becomes aware of a First Nations Claim, Buyer may, at its sole discretion, terminate this EPA on notice to Seller. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. Upon a termination by Buyer under this Section 8.4, Seller shall reimburse Buyer for costs or liabilities described in Sections 9.7(a), (b) and (c). The reimbursement by Seller of such costs or liabilities, the indemnification by Seller contemplated in Section 8.5 and the termination of this EPA are the exclusive remedies to which Buyer may be entitled to if Buyer elects to terminate this EPA under this Section.

8.5 Seller Indemnity for First Nation Claim

Seller shall indemnify and hold Buyer and its Affiliates harmless from any and all claims, damages, costs, expenses, or liabilities whatsoever incurred by Buyer and its Affiliates in relation to such First Nation Claim and such indemnity shall survive termination of this EPA.

ARTICLE 9 TERMINATION

9.1 Termination by Buyer

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA by notice to Seller if:

- (a) Seller's COD does not occur within 730 days following Target Seller's COD for any reason whatsoever (including Force Majeure), provided that Buyer may terminate this EPA under this provision only if Buyer delivers a termination notice prior to Seller's COD; or
- (b) at any time after Buyer's COD, Seller fails to deliver at least an average of 25% of the aggregate Projected Monthly Energy as set out in Schedule "E" to Buyer over all hours in a period of 730 continuous days for any reason whatsoever (including Force Majeure, a Distribution/Transmission Constraint), but excluding a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or
- (c) at any time after Buyer's COD, Buyer is unable to accept delivery of Energy at the POI for a period of 730 continuous days due to Force Majeure invoked by Buyer or a Distribution/Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or
- (d) Seller breaches Section 4.5; or
- (e) Seller fails to complete any application, payment, filing, study, document or other step in the process for interconnecting the Seller's Plant to the Distribution System, Transmission System or New Interconnection Facilities, as applicable, in accordance with the requirements of, and within the time limits, including any cure periods, specified by Buyer, and such failure could reasonably be expected to have an adverse impact on Buyer or any third party; or
- (f) any System Interconnection Study Report completed after the Effective Date contains information that is inconsistent with the description of the Seller's Plant in Schedule "B" and Seller has not received Buyer's consent under Section 3.3 for the change to Schedule "B"; or
- (g) Seller is Bankrupt or Insolvent; or
- (h) Seller, as a result of an act or omission of Seller, ceases to be exempt from regulation as a "public utility" as defined in the *Public Utilities Act* with respect to the Seller's Plant and the sale of Energy to Buyer under this EPA, and the loss of such exemption could reasonably be expected to have an adverse effect on the benefit to Buyer of this EPA; or
- (i) an amount due and payable by Seller to Buyer under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Buyer has given notice of the default to Seller; or
- (j) Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Buyer to Seller of the default Seller has cured the default or, if the default cannot be cured within that 30 day period, Seller demonstrates to the reasonable satisfaction of Buyer that Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any purported Assignment of this EPA without the consent of Buyer.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Seller.

9.2 Notice of Termination Event

Seller will notify Buyer promptly if Seller is Bankrupt or Insolvent or if there is a material risk that Seller will become Bankrupt or Insolvent or if Seller has defaulted under any agreement with a Facility Lender or if any Permit or land tenure agreement for the Seller's Plant is terminated or expires.

9.3 Termination by Seller

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Seller may have under this EPA or at law or in equity in respect of any of the following events, Seller may terminate this EPA by notice to Buyer if:

- (a) after Buyer's COD, Buyer has not accepted delivery of Energy for a period of 730 continuous days due to an event described in Section 4.4 or any event of Force Majeure and Seller is not entitled to receive any payment pursuant to Section 4.8 in respect of that period; or
- (b) the Seller's Plant has suffered major damage where the cost to repair the damage exceeds the net present value (using the Present Value Rate) of the expected revenues under the EPA for the remainder of the Term less the net present value (using the Present Value Rate) of the estimated operating and maintenance costs for the Seller's Plant for the remainder of the Term; or
- (c) Seller has been unable to achieve Seller's COD for a period of 730 days after Target Seller's COD or has been unable to deliver Energy to the POI for a period of 730 continuous days after Seller's COD in either case solely as a result of Force Majeure invoked by Seller or a Distribution/Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or
- (d) Buyer is Bankrupt or Insolvent; or
- (e) except where an amount has been disputed in the manner specified in Section 5.3(a)(ii), an amount due and payable by Buyer to Seller under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Seller has given notice of the default to Buyer; or
- (f) Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Seller to Buyer of the default Buyer has cured the default or, if the default cannot be cured within that 30 day period, Buyer demonstrates to the reasonable satisfaction of Seller that Buyer is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Buyer.

9.4 Termination by Buyer for Convenience

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA for convenience upon 90 days prior notice to Seller.

9.5 Effect of Termination

Upon expiry of the Term or earlier termination of this EPA in accordance with its terms:

- (a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of this EPA and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination or that are stated to arise on termination of this EPA, subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA;
- (b) both Parties will remain bound by Section 3.5 with respect to the satisfaction of residual obligations for the period prior to termination or that are specified to arise on, or continue following, termination, and Sections 12.1 and 13.1 associated with Delivered Energy prior to termination of this EPA; and
- (c) Seller will remain bound by Sections 7.1 and 7.2 for a period of 36 months following expiry or termination of this EPA;

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

9.6 Buyer Payment on Termination

If Seller terminates this EPA under any of Sections 9.3(d), 9.3(e) or 9.3(f) or Buyer terminates this EPA for convenience under Section 9.4, Buyer will pay to Seller an amount equal to the applicable Termination Payment due at the time of termination determined in accordance with Schedule "F".

9.7 Seller Payment on Termination

If Buyer terminates this EPA on or before 90 days after Seller's COD or Seller terminates this EPA on or before Buyer's COD under any of Sections 9.3(a), 9.3(b) or 9.3(c), Seller will, within 30 days after receipt of an invoice from Buyer, reimburse Buyer for:

- (a) all System Upgrade Costs and New Interconnection Facilities Costs incurred by Buyer, or which Buyer has become contractually obligated to pay, prior to the termination of the EPA including System Upgrade Costs and New Interconnection Facilities Costs Seller would otherwise be responsible for under Section 3.5;
- (b) any incremental liability for System Upgrade Costs and New Interconnection Facilities Costs which Buyer will incur as a result of the termination of this EPA; and
- (c) any System Upgrade Costs and New Interconnection Facilities Costs which Seller is responsible for under any reimbursement agreement pursuant to Section 3.3.

9.8 Calculation and Payment

Buyer will pay any amount which it owes under Section 9.6 within 30 Business Days after the date of delivery of an invoice by Seller to Buyer. Any amounts owing by Seller to Buyer under this EPA will be netted against any amount owing by Buyer to Seller under Section 9.6.

9.9 Exclusive Remedies

Payment by Buyer of the amount determined under Section 9.6 is the exclusive remedy to which Seller is entitled, and Buyer's limit of liability, for termination of this EPA by Seller pursuant to any of Sections 9.3(d), 9.3(e) or 9.3(f). Subject to Section 9.4 and 9.7, termination of this EPA is the exclusive remedy to which Buyer or Seller, as the case may be, is entitled if Buyer or Seller elects to exercise its right to terminate this EPA under any of Section 9.1, 9.3(a), 9.3(b) or 9.3(c). For greater certainty, subject to Section 9.4 and 9.7, Seller will not be required to pay any termination payment on termination by Buyer of this EPA. Neither Party will have any right to terminate this EPA except as expressly set out herein.

ARTICLE 10 REPRESENTATIONS AND WARRANTIES

10.1 Seller's Representations

Seller represents and warrants to Buyer, and acknowledges that Buyer is relying on those representations and warranties in entering into this EPA, as follows:

- (a) Seller is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;
- (b) this EPA constitutes a valid and binding obligation of Seller enforceable against Seller in accordance with its terms; and
- (c) this EPA has been duly authorized, executed and delivered by Seller.

10.2 Buyer's Representations

Buyer represents and warrants to Seller, and acknowledges that Seller is relying on those representations and warranties in entering into this EPA, as follows:

- (a) Buyer is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;
- (b) this EPA constitutes a valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms; and
- (c) this EPA has been duly authorized, executed and delivered by Buyer.

ARTICLE 11 LIABILITY LIMITATIONS

11.1 Limit of Liability

Buyer's liability for damages for any failure to take or pay for Delivered Energy under this EPA is limited to the amount payable by Buyer for that Delivered Energy under Article 5, amounts owing under Sections 4.8 and any interest thereon calculated under this EPA.

11.2 Consequential Damages

Neither Party will be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages with respect to, arising out of, relating to or in any way connected with a Party's performance or non-performance under this EPA.

ARTICLE 12 DISPUTES

12.1 Dispute Resolution Procedure

Any dispute, controversy or claim arising out of or relating to this EPA ("**Dispute**") shall be exclusively and finally resolved in accordance with the dispute resolution procedure set forth in this Article 12 (the "**Dispute Resolution Procedure**").

12.2 Commencement of the Dispute Resolution Procedure

The Parties shall make reasonable efforts to first resolve any Dispute. If a Dispute cannot be resolved by the Parties, then either Party may initiate the Dispute Resolution Procedure by giving notice of the Dispute to the other Party (the "**Notice of Dispute**"). The Notice of Dispute shall contain a brief statement of the nature of the Dispute, set out the relief requested, and request that the Dispute Resolution Procedure be commenced.

12.3 Negotiations

Upon the submission of a Notice of Dispute pursuant to Section 12.2, each of the Parties shall refer the Dispute to a designated senior management executive with the authority to negotiate a settlement of the Dispute for that Party (the "**Senior Management Executives**"). The Senior Management Executives of the Parties shall attempt to resolve the Dispute within 30 days from the date on which the Notice of Dispute was issued, or such longer period as the Senior Management Executives may otherwise unanimously agree. If the Senior Management Executives unanimously agree upon a resolution of the Dispute, such resolution shall be memorialized in a written settlement agreement mutually acceptable to the Parties and shall be binding on the Parties.

12.4 Arbitration

If a Dispute is not resolved by Senior Management Executives within 30 days from receipt of a Notice of Dispute (or such longer period as the Senior Management Executives may otherwise agree in writing), the Dispute shall, at the request of either Party, be resolved by binding arbitration under the Rules of Arbitration of the International Chamber of Commerce (the "**ICC Rules**"), except to the extent of conflicts between the ICC Rules and the provisions of this EPA, in which

event the provisions of this EPA shall prevail. The following provisions shall apply to an arbitration commenced pursuant to this Section 12.4:

- (a) the number of arbitrators shall be one;
- (b) the place, or legal seat, of the arbitration shall be Whitehorse, Yukon;
- (c) the language to be used in the arbitral proceedings shall be English;
- (d) all awards issued by the arbitrator shall be final, non-appealable and binding on the Parties. Any award may be filed in any court of competent jurisdiction and may be enforced by a Party as a final judgment in such court. The Parties expressly waive, to the maximum extent permitted by law, any right of appeal of any award or reference of any matter to any court, other than as may be necessary to recognize or enforce an award;
- (e) the arbitrator shall be guided by the International Bar Association's Rules on the Taking of Evidence in International Commercial Arbitration;
- (f) the Parties shall request that the arbitrator render its final award within 12 months of the commencement of the arbitration, or as soon as possible thereafter, provided that no award shall be invalid if it is not rendered within the time period herein specified;
- (g) any award for monetary damages shall be made and payable in Canadian Dollars and may include interest from the date of any breach or violation of this EPA until paid in full at the rate determined by the arbitrator;
- (h) the Parties agree that any arbitration carried out hereunder shall be kept private and confidential, and that the existence of the proceedings and any element of it (including all awards, the identity of the Parties and all witnesses and experts, all materials created for the purposes of the arbitration, all testimony or other oral submissions, and all documents produced by a Party that were not already in the possession of the other Party) shall be kept confidential, except (i) with the consent of the Parties, (ii) to the extent disclosure may be lawfully required in bona fide judicial proceedings relating to the arbitration, (iii) where disclosure is lawfully required by a legal duty, and (iv) where such information is already in the public domain other than as a result of a breach of this clause. The Parties also agree not to use any information disclosed to them during the arbitration for any purpose other than in connection with the arbitration;
- (i) where a Dispute relates to the EPA, the Parties shall agree to consolidate the matters in Dispute under such agreements in a single arbitration;
- (j) the Parties agree that during the resolution of a Dispute pursuant to this Article 12, the Parties shall continue to perform their obligations under this EPA, provided that such performance shall be without prejudice to the rights and remedies of the Parties and shall not be read or construed as a waiver of a Party's right to claim for recovery of any loss, costs, expenses or damages suffered as a result of the continued performance of this EPA; and
- (k) each Party will be responsible for its own costs under this Article 12, subject to the award of an arbitrator.

ARTICLE 13 CONFIDENTIALITY

13.1 Confidentiality

- (a) **Additional Confidentiality Obligation** - During the Term and for two years thereafter:
 - (i) Buyer will treat as confidential, and will not disclose to any third Person, Seller Confidential Information, and
 - (ii) Seller will treat as confidential, and will not disclose to any third Person, Buyer Confidential Information.
- (b) **Disclosure of Confidential Information** - Notwithstanding Section 13.1(a) above:
 - (i) Seller may also disclose Buyer Confidential Information and Buyer may disclose Seller Confidential information in the following circumstances:
 - (A) disclosures expressly authorized under this EPA or otherwise set out in this EPA;
 - (B) disclosures to enable a Party to fulfill its obligations under the EPA;
 - (C) disclosure in any arbitration or legal proceedings for the enforcement of the EPA;
 - (D) disclosure to the Party's directors, officers, employees, Facility Lenders, consultants and advisors, and purchasers of the Environmental Attributes, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;
 - (E) subject to Section 13.1(b)(ii)(D), disclosure required to be made by a Party by an order of a court, a regulatory agency or a tribunal or under any law, regulatory requirements or any requirement of any stock exchange that is binding upon a Party, provided that (i) to the extent reasonably practicable, the Party intending to make such disclosure gives reasonable notice to the other Party before make the disclosure, and (ii) limits the disclosure to that required by the applicable order, Laws or regulatory or stock exchange requirement;
 - (F) disclosure to a third Person if such information was known by that third Person before disclosure by Buyer or Seller, as the case may be, provided the third Person did not know of the information as a result of a breach of the non-disclosure obligations in this EPA; or
 - (G) disclosure with the consent of Buyer, in the case of Buyer Confidential Information, or Seller, in the case of Seller Confidential Information.

- (ii) Buyer may disclose Seller Confidential Information in the following circumstances:
- (A) disclosure to Buyer's Affiliates or to a third Person, and their respective employees, consultants and advisors, for the purpose of reselling or marketing any Energy, including disclosure of Seller Confidential Information by such Affiliate or third Person to those who have purchased or may purchase the Energy;
 - (B) for purposes other than those described in Section 13.1(b)(i), to Buyer's Affiliates and to any directors, officers, employees, consultants and advisors of any Affiliates, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;
 - (C) to any ministers, deputy ministers, servants or employees of the Yukon or the federal government, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality; or
 - (D) disclosure in any regulatory proceeding, whether related to this EPA or not, to the extent that Buyer considers disclosure is necessary or desirable to support its position in such proceeding.

ARTICLE 14

FORCE MAJEURE

14.1 Force Majeure

- (a) If there is a Force Majeure affecting a Party's ability to perform an obligation under this EPA, and that Party wishes to declare a Force Majeure, that Party will promptly notify the other Party of the Force Majeure. The notice of Force Majeure must identify the nature of the Force Majeure, the date the Force Majeure commenced, the expected duration of the Force Majeure, and the particular obligations affected by the Force Majeure. If (i) a notice of Force Majeure is provided in accordance with this Section, (ii) the event in question is in fact an event of Force Majeure as defined in this EPA, and (iii) the event of Force Majeure commenced on the commencement date in the notice of Force Majeure, then the Force Majeure will be deemed to have been invoked as of the commencement date stated in the notice.
- (b) Neither Party will be in default of any obligation under this EPA if a Party is unable to perform that obligation due to an event or circumstance of Force Majeure, provided notice is delivered in accordance with this Section and the circumstances are, in fact, an event or circumstance of Force Majeure.
- (c) Subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure. The Party invoking Force Majeure will make commercially reasonable efforts to promptly remove the Force Majeure and will promptly respond to any inquiry from the other Party regarding the efforts

being undertaken to remove the Force Majeure and will give prompt notice of the end of the Force Majeure.

ARTICLE 15 GENERAL PROVISIONS

15.1 Independence

The Parties are independent contractors, and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

15.2 Enurement

This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

15.3 Assignment

- (a) Seller may not assign this EPA except with the prior consent of Buyer, which consent may not be unreasonably withheld, conditioned or delayed provided such Assignment is to a Facility Lender. Any Assignment (other than an Assignment to a Facility Lender) is subject to the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of Seller under this EPA arising both before and after the Assignment, and providing the representations and warranties set out in Section 10.1 effective as at the time of Assignment, and Seller not being in default under this EPA. Unless agreed to in writing by Buyer, Seller shall remain jointly and severally liable with the assignee for all obligations of Seller under this EPA.
- (b) Any request by Seller for Buyer's consent under Section 15.3(a) must be delivered to Buyer not less than 30 days before the date of the proposed Assignment. A request under this Section must be accompanied by such information as reasonably required by Buyer to assess the request for consent including the name, address and ownership structure of the assignee, details of any consultation with First Nations that may be impacted by the Seller's Plant or the Assignment with respect to the proposed Assignment, list of the directors and officers of the assignee and information concerning the assignee's operations, experience and financial status.
- (c) If Seller seeks consent to Assign this EPA to a Facility Lender, Buyer may require, as a condition of its consent to the Assignment, that Seller and the Facility Lender enter into a Lender Consent Agreement with Buyer containing customary provisions. If required by a Facility Lender, Buyer will enter into a Lender Consent Agreement with the Facility Lender and Seller containing customary provisions. Seller will reimburse Buyer for all costs reasonably incurred by Buyer in connection with any request by Seller for Buyer's consent pursuant to Section 15.3(a).

15.4 Entire Agreement

This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA.

15.5 Amendment

This EPA may not be amended except by an agreement in writing signed by both Parties.

15.6 No Waiver

Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

15.7 Notices

Any notice, consent, waiver, declaration, request for approval or other request, statement or bill that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address for that Party stated in Schedule "A" and:

- (a) notices under Section 14.1, Article 8 and Article 9 must be delivered by hand or by a courier service during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day;
- (b) all notices other than notices described in Section 15.7(a) may be delivered by email during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day; and
- (c) either Party may change its address for notices under Section 3 of Schedule "A" to this EPA by notice to the other Party.

15.8 Interconnection Notices

Nothing in the System Interconnection Guidelines and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA, except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the System Interconnection Guidelines will constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA.

15.9 Commodity Contract/Forward Contract

The Parties agree and intend that this EPA constitutes an "eligible financial contract" under the *Bankruptcy and Insolvency Act* (Canada) and *Companies' Creditors Arrangement Act* (Canada).

15.10 Further Assurances

Each Party will, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA including, in the case of Seller, completing any registration process required in respect of Environmental Attributes as requested by Buyer.

15.11 Severability

Any provision of this EPA which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

15.12 Counterparts

This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

[Signature Page Follows]

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA effective as of the date set out on page one of this EPA.

536774 YUKON INC.

YUKON ENERGY CORPORATION

Per:



Ben Power
Director

Per:

Andrew Hall
President and Chief Executive Officer

Per:



Michael Schultz
Director

Per:

Michael Brandt
Vice-President

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536774 YUKON INC.

Per: _____
Ben Power
Director

Per: _____
Michael Schultz
Director

YUKON ENERGY CORPORATION

Per: _____
Andrew Hall
President and Chief Executive Officer

Per: _____
Michael Brandt
Vice-President

SCHEDULE "A"

DEFINITIONS AND INTERPRETATION

1. DEFINITIONS

References in a Schedule to a section or Section mean a section or Section of this EPA, and not a Schedule, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

- 1.1 "Affiliate"** means, with respect to any Party or any third Person, any Person directly or indirectly Controlled by, Controlling, or under common Control with, such Party or the third Person.
- 1.2 "Annual Operating Plan"** means a 12-month operating plan for the Seller's Plant that includes for term of each operating plan, (a) a schedule of the expected total deliveries of Energy at the POI in each month and (b) a schedule of any Planned Outages of the Seller's Plant expected by Seller. The Annual Operating Plan will be consistent with Good Industry Practice and shall be substantially in the form attached hereto as Schedule "C", subject to such modifications thereto as may be reasonably required by Buyer.
- 1.3 "Application"** means the application and all supporting documents and information with respect to the Seller's Plant filed by Seller with Buyer in the Standing Offer Program.
- 1.4 "Assign" or "Assignment"** means to assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term and, without limiting the foregoing, each of the following is deemed to be an Assignment of this EPA by Seller:
- (a) any sale or other disposition of all or a substantial part of Seller's ownership interest in the Seller's Plant, or of all or any interest of Seller in this EPA or revenue derived from this EPA;
 - (b) any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant or Seller's ownership interest therein; and
 - (c) any change of Control, merger, amalgamation or reorganization of Seller.
- 1.5 "Audit Parties"** means the applicable Party conducting an audit under this EPA and its Affiliates, representatives, consultants, advisors and any other third Person retained in respect of the applicable audit.
- 1.6 "Bankrupt or Insolvent"** means, with respect to a Person:
- (a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it;
 - (b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law;
 - (c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy;

- (d) the Person has voluntarily suspended the transaction of its usual business; or
 - (e) a court of competent jurisdiction has issued an order declaring the Person bankrupt or insolvent.
- 1.7 **"Business Day"** means any calendar day which is not a Saturday, Sunday or Yukon statutory holiday.
- 1.8 **"Buyer"** means Yukon Energy Corporation and its successors and permitted assigns.
- 1.9 **"Buyer Confidential Information"** means technical or commercial information disclosed by Buyer to Seller that Buyer directs, and clearly marks, as confidential, including the System Interconnection Guidelines and this EPA but excluding information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Seller, or (ii) is known to Seller before disclosure to it by Buyer, or becomes known to Seller, thereafter by way of disclosure to Seller by any other Person who is not under an obligation of confidentiality with respect thereto.
- 1.10 **"Buyer's COD"** shall occur when the System Upgrades have been completed and Buyer provides a notice of completion of the same to Seller.
- 1.11 **"Change in Law"** means (a) the enactment, adoption, promulgation, modification or repeal of any applicable Laws or any change in the interpretation or administration of any applicable Laws resulting from a decision of a Governmental Authority which occurs after the Effective Date; but in each case excluding a Change in Law relating to income tax, or (b) the requirement for a new Permit (including due to a change in the circumstances in which a Permit is required), a change in the terms of any Permit after the date such Permit is granted, or any change in the interpretation or administration of any Permits resulting from a decision of a Governmental Authority.
- 1.12 **"Condition Date"** means the date specified as such in Schedule "B".
- 1.13 **"Conditions Precedent"** means those conditions precedent set out in Schedule "B".
- 1.14 **"Control"** of any Person means:
- (a) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or Persons performing similar functions;
 - (b) ownership of 50% or more of the equity or beneficial interest in that Person; or
 - (c) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.
- 1.15 **"CPI"** means the "Canada All Items (Not Seasonally Adjusted)" Consumer Price Index as published by Statistics Canada or any successor agency thereto.
- 1.16 **"Delivered Energy"** means in each month after Buyer's COD the amount of Energy delivered by Seller at the POI in that month as recorded by Buyer's Meter less the applicable Line Losses.

- 1.17 **"Development Progress Report"** means a report describing the progress of the financing, design, engineering, construction, Interconnection, and commissioning of the Seller's Plant, that is in form and content acceptable to Buyer, acting reasonably.
- 1.18 **"Discretion"** (whether or not capitalized) means sole, absolute and unfettered discretion unless this EPA expressly states otherwise.
- 1.19 **"Dispatch/Turn-Down"** means for Seller to turn down or shut off the Seller's Plant.
- 1.20 **"Dispatch/Turn-Down Deemed Energy"** has the meaning given to such term in Section 4.9(b)(i).
- 1.21 **"Distribution System"** means the distribution, protection, control and communication facilities in the Yukon that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35 kilovolts or less, and includes all additions and modifications thereto and repairs or replacements thereof.
- 1.22 **"Distribution/Transmission Constraint"** means any disconnection of the Seller's Plant from the Distribution System or Transmission System, or any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System preventing or limiting deliveries of Energy at the POI or within the Distribution System or Transmission System or any direction from Buyer to reduce generation of the Seller's Plant as a result of any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System.
- 1.23 **"Effective Date"** shall mean the date on which all Conditions Precedent have been satisfied or waived in accordance with Section 2.1.
- 1.24 **"Electrical Grid"** means the electrical grid into which the Seller's Plant will be interconnected, as identified in Schedule "B".
- 1.25 **"Eligible Clean Energy"** means wind, hydro, geothermal, biomass and solar energy sources permitted under the IPP Policy for the SOP generated by a Project located in Yukon which is directly connected into the YIS or the WLG through the New Interconnection Facilities.
- 1.26 **"Energy"** means all electrical energy expressed in kWh generated by the Seller's Plant, excluding electrical energy generated by the Seller's Plant which is required to service the Seller's Plant Load.
- 1.27 **"Energy Price"** has the meaning given to such term in Schedule "B".
- 1.28 **"Environmental Attributes"** means the following as attributable to Energy delivered to Buyer under this EPA:
- (a) all attributes directly associated with, or that may be derived from, the Energy delivered to Buyer under this EPA having decreased environmental impacts relative to certain other generation facilities or technologies including any existing or future credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradeable;
 - (b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to the actual or assumed reduction, displacement or offset of emissions at any location other than the

Seller's Plant as a result of the generation, purchase or sale of the Energy delivered to Buyer under this EPA;

- (c) any credit, reduction right, off-set, allowance, allocated pollution right, certificate or other unit of any kind whatsoever whether or not tradeable resulting from or otherwise related to the reduction, removal, or sequestration of emissions at or from the Seller's Plant; and
- (d) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing, but for certainty not including:
 - i. benefits or proceeds from environmental incentive programs offered by Governmental Authorities that do not require a transfer of the attributes in (a) to (c) above; and
 - ii. benefits or proceeds from social programs, including programs relating to northern or rural development, employment or skills training, or First Nations, that do not require a transfer of the attributes in Sections (a) to (c) above.

1.29 "Environmental Certification" means any certification Buyer requires Seller to obtain under Section 6.1.

1.30 "Facility Lender" means any lender(s) providing any debt financing or debt hedging facilities for the design, engineering, construction and/or operation of the Seller's Plant and any successors or assigns thereto and any Person taking any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant.

1.31 "Final Amount" means an amount owing by either Party to the other Party under this EPA, including as a result of a breach of this EPA, where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award under Section 12.1 of this EPA or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.

1.32 "First Nation Claim" means a legal claim or proceeding or written threat to commence a legal claim or proceeding from or on behalf of First Nations where such claim or threat alleges a breach or potential breach of, or an impact to: any First Nations' Treaty rights, rights under a Settlement Agreement (as that term is defined in the Yukon Umbrella Final Agreement), or rights under section 35 of the *Constitution Act*, 1982, by (a) this EPA, (b) the Seller's Plant, (c) the Interconnection or any works related to the Interconnection, or (d) any authorization granted by the Yukon or federal government relating to the Seller's Plant and its operations.

1.33 "First Nations" means any one of the 14 First Nations in the Yukon.

1.34 "Force Majeure" means any event or circumstance not within the control of the Party, or any of its Affiliates, claiming Force Majeure, but does not include:

- (a) any economic hardship or lack of money, credit or markets;
- (b) an event or circumstance that is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws;

- (c) a mechanical breakdown or control system hardware or software failure, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the breakdown or failure was caused by a latent defect in the design or manufacture of the equipment, hardware or software, which could not reasonably have been identified by normal inspection or testing of the equipment, hardware or software;
 - (d) an event or circumstance caused by a breach of, or default under, this EPA or a willful or negligent act or omission by the Party seeking to invoke Force Majeure;
 - (e) any Distribution/Transmission Constraint unless such event is caused by an event or circumstance not within the control of Buyer; or
 - (f) any acts or omissions of: (i) any Affiliate, employee, director, officer, agent or other representative of the Party invoking Force Majeure; (ii) any vendor, supplier, contractor, subcontractor, consultant or customer of or to the Party invoking Force Majeure; or (iii) any other Person for whom the Party invoking Force Majeure is responsible at law, unless the act or omission is caused by an event or circumstance that would constitute Force Majeure if the Person described above was a party to this EPA in place of a Party invoking Force Majeure.
- 1.35 **"Forced Outage"** means the immediate removal of one or more generating units of the Seller's Plant or transmission or distribution infrastructure of the Seller's Plant from service in response to equipment alarms or any damage identified during a Planned Outage or Maintenance Outage requiring extension of those Planned Outage or Maintenance Outage.
- 1.36 **"General Rate Application"** means any application, review, process, or procedure in which the YUB sets and approves rates to be charged by Buyer for the supply of the service for which it is franchised in accordance with the *Public Utilities Act*.
- 1.37 **"Good Industry Practice"** means:
- (a) in respect of Buyer, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the Yukon; and provided that Buyer shall be in compliance with Good Industry Practice in respect of any equipment comprising the Distribution System or Transmission System, if it operates such equipment in accordance with all applicable original equipment manufacturer guidelines and requirements provided to Buyer by supplier of such equipment; and
 - (b) in respect of Seller, any of the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others,

but rather to be acceptable practices, methods or acts generally accepted in Western Canada.

- 1.38 **"Governmental Authority"** means any federal, provincial, local or foreign government or any of their boards or agencies, or any regulatory authority other than Buyer and Seller and entities controlled by Buyer or Seller.
- 1.39 **"GST"** means the goods and services tax imposed under the *Excise Tax Act* (Canada) as that Act may be amended or replaced from time to time.
- 1.40 **"Interconnection"** means the POI.
- 1.41 **"IPP Policy"** has the meaning given to such term in the recitals to this EPA.
- 1.42 **"Joint Operating Procedure"** means the joint operating procedure attached as Schedule "H" as may be modified by Buyer from time to time.
- 1.43 **"KW"** means kilowatt.
- 1.44 **"kWh"** means kilowatt-hour.
- 1.45 **"Laws"** means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority in effect from time to time.
- 1.46 **"Lender Consent Agreement"** means a lender consent agreement in the form and substance acceptable to Buyer, acting reasonably.
- 1.47 **"Line Losses"** means losses of electricity associated with the transmission and transformation of Energy and other electricity, if applicable, from the Seller's Plant to the POI that are recorded by the Meter or reasonably estimated by Buyer.
- 1.48 **"Line Loss Methodology"** means the Line Loss Methodology set forth in the System Interconnection Study Report for the purposes of this Project.
- 1.49 **"Maintenance Outage"** means any outage of Buyer's Distribution System or Transmission System or the Seller's Plant that is not a Planned Outage or a Forced Outage that typically has a flexible start and end time and of shorter duration than a Planned Outage.
- 1.50 **"Meter"** means a meter owned by Buyer that is: (a) capable of accurately measuring the quantity of Energy generated by the Seller's Plant and delivered to the POI independent of all other generation equipment or facilities, (b) capable of being remotely interrogated; and (b) calibrated to measure on an hourly basis the quantity of Energy delivered by Seller to the POI.
- 1.51 **"Monthly Energy Shortfall Payment"** has the meaning given to such term in Schedule "E".
- 1.52 **"New Interconnection Facilities"** means those additions, modifications and upgrades required to interconnect the Project to the Electrical Grid which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any System Upgrades.

- 1.53 **"New Interconnection Facilities Costs"** means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the New Interconnection Facilities, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.
- 1.54 **"Non-Permitted Distribution/Transmission Constraint"** has the meaning given to such term in Section 4.8(a).
- 1.55 **"Outage"** means a Forced Outage, Maintenance Outage, or Planned Outage of Buyer's Distribution System or Transmission System or Seller's Plant.
- 1.56 **"Outage Notice"** means a notification of any Outage or revised notification of any Outage required to be delivered by Seller to Buyer or Buyer to Seller under this EPA that describes the timing, frequency, nature and duration of the Outage and that is in a format that may be prescribed by Buyer from time to time.
- 1.57 **"Party"** means Buyer or Seller, and **"Parties"** means both Buyer and Seller.
- 1.58 **"Permits"** means permits, certificates, licences, approvals and other authorizations issued by any Governmental Authorities as may be required for the design, construction, ownership, operation, maintenance and decommissioning of (i) the Seller's Plant and the delivery of Energy to the POI, and (ii) the System Upgrades and the New Interconnection Facilities.
- 1.59 **"Person"** means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.
- 1.60 **"Planned Outage"** means an outage that is scheduled well in advance for purposes of inspections, maintenance, or repair of Buyer's Distribution System or Transmission System or Seller's Plant, that typically has a predetermined duration and scope of work, occurs only once or twice per year, and may last for several days.
- 1.61 **"POI" or "Point of Interconnection"** means the point at which the Seller's Plant interconnects with the Distribution System or Transmission System, as identified on the Single Line Diagram.
- 1.62 **"Potential Impacts"** means any adverse or potentially adverse impact on the established or potential aboriginal rights (including title) of First Nations as a result of:
- (a) this EPA;
 - (b) the Project;
 - (c) the interconnection of the Seller's Plant to the Distribution System or Transmission System; or
 - (d) any activities directly related to the Seller's Plant that enable Seller to comply with its obligations under this EPA that are carried out by Seller, any Affiliate, consultant or contractor of Seller, or any other Person for whom Seller is responsible at law.
- 1.63 **"PPT"** means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.

- 1.64** **"Present Value Rate"** means the annual yield on a Government of Canada bond having a term and maturity date that most closely matches the remaining Term (as at the date of the applicable calculation) and expiry date of this EPA, plus 3%.
- 1.65** **"Prime Rate"** means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Whitehorse, Yukon, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.
- 1.66** **"Project"** means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.
- 1.67** **"Project Cluster"** means two or more existing or proposed Projects under the SOP Rules that Buyer determines in its Discretion are so closely related to each other that they should be considered a project cluster for the purposes of the Standing Offer Program.
- 1.68** **"Project Energy Volume"** (in kWh) means the maximum annual Energy which Buyer may sell to Seller from the Project in any calendar year as set out in Schedule "B"; provided that where the Term does not commence on January 1, such amount shall be prorated for the first and last contract year which do not reflect a full calendar year.
- 1.69** **"Project Standards"** means:
- (a) all applicable Laws;
 - (b) the terms and conditions of all Permits, including land tenure agreements, issued in connection with the Seller's Plant;
 - (c) Good Industry Practice;
 - (d) the description of the Seller's Plant in Schedule "B";
 - (e) the requirement that Energy must qualify as Eligible Clean Energy; and
 - (f) the terms and conditions of this EPA (including the System Interconnection Guidelines).
- 1.70** **"Public Utilities Act"** means the *Public Utilities Act* (Yukon) and any successor or replacement legislation.
- 1.71** **"Records"** means all records and logs required to properly administer this EPA, including:
- (a) Energy generation records and operating logs;
 - (b) Meter readings;
 - (c) maintenance reports;
 - (d) invoice support records;
 - (e) documents concerning compliance with Project Standards, but excluding any such documents that are protected by solicitor-client privilege;

- (f) records related to System Upgrade Costs and New Interconnection Facilities Costs;
- (g) all information reasonably required to establish the amount of Energy Seller could have sold during a Distribution/Transmission Constraint including logs of all Outages of the Seller's Plant and other reductions in Energy output (specifying the date, time, duration and reasons for each such outage and each reduction in Energy output); and
- (h) information relating to the Environmental Certification, information relating to the existence, nature and quality of Environmental Attributes, information required for the purposes of any Environmental Attributes or energy certification or tracking system, and any other information Buyer requires to enable it or any of its Affiliates to obtain and realize the benefit of the Environmental Attributes,

all consistent with Good Industry Practice.

1.72 "Regulatory Agency Authorizations" means the issuance of those Permits which are specified as required for the Project in the YESAB assessment report recommendation to proceed issued in respect of the Project.

1.73 "Seller" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

1.74 "Seller Confidential Information" means any of Seller's confidential technical or financial information provided by Seller to Buyer in confidence with express written notice to Buyer of the confidential nature of the information, but excluding:

- (a) this EPA; and
- (b) information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Buyer, or (ii) is known to Buyer before disclosure to it by Seller, or becomes known to Buyer thereafter by way of disclosure to Buyer by any other Person who is not under an obligation of confidentiality with respect thereto.

1.75 "Seller's COD" means the commercial operation date of Seller's Plant which is the date on which all of the following conditions have been satisfied in respect of the Seller's Plant:

- (a) Seller has obtained all Permits required for the construction, commissioning, and operation of the Seller's Plant and all such Permits are in full force and effect;
- (b) the Seller's Plant has been fully constructed in accordance with the Project Standards;
- (c) Seller is not: (A) Bankrupt or Insolvent; (B) in default of any payment obligation or requirement to post security under this EPA; (C) in material default of any of its other covenants, representations, warranties or obligations under this EPA; or (D) in material default under any Permit or Law applicable to the construction, commissioning or operation of the Seller's Plant or under any land tenure agreement for the site on which the Seller's Plant is located;
- (d) a Meter has been installed at the POI in accordance with Section 3.6 of this EPA;

- (e) Seller has delivered to Buyer a written notice together with certificate of Seller's professional registered engineer confirming that Seller's COD has been achieved; and
- (f) Buyer has delivered a Commission Notice to Operate, or such other document(s) of similar effect as may be substituted therefor, which evidences no material deficiencies, in respect of the Seller's Plant Capacity and Seller's Plant operations;

and for purposes of this EPA, Seller's COD will be deemed to have occurred at 24:00 PPT on the later of the dates set out above.

- 1.76 **"Seller's Plant"** means Seller's plant described in Schedule "B" and all assets required to interconnect that plant to the Distribution System or Transmission System; all rights, property, facilities, assets, equipment, materials, Permits and contracts required to design, engineer, procure, construct, commission, operate and maintain the plant described in Schedule "B" and to interconnect that plant to the Distribution System or Transmission System, whether real or personal and whether tangible or intangible including all land tenure and all books, Records and accounts with respect to the Seller's Plant described in Schedule "B"; and shall include replacement parts or equipment which are of the same or similar nature as the parts or equipment being replaced and which do not materially increase the amount of Energy available from Seller's Plant.
- 1.77 **"Seller's Plant Capacity"** means the electrical generating capacity of the Seller's Plant set out in Schedule "B".
- 1.78 **"Seller's Plant Load"** means any electrical energy consumed by Seller's Plant.
- 1.79 **"Single Line Diagram"** means the simplified electrical representations of the Seller's Plant, the Interconnection, the Distribution System and Transmission System attached hereto in Schedule "B".
- 1.80 **"SOP OIC"** means that Order in Council issued by the Government of Yukon on January 24, 2019 regarding, among other things, the Standing Offer Program.
- 1.81 **"SOP Rules"** means the Standing Offer Program Rules developed by the Government of Yukon which governed this EPA as at the date of this EPA.
- 1.82 **"Standing Offer Program"** or **"SOP"** means the Standing Offer Program as described in the IPP Policy.
- 1.83 **"System Interconnection Guidelines"** means those system interconnection guidelines in the form attached as Schedule "G" hereto, as amended or replaced by Buyer from time to time.
- 1.84 **"System Interconnection Study Report"** means the detailed interconnection study issued to Seller by Buyer which, among other things, (i) evaluates the impact of the Project on the reliability of Buyer's system, (ii) provides a planning-level estimate of the required System Upgrades and New Interconnection Facilities and associated costs, and (iii) establishes the Line Loss Methodology for this Project, a copy of which is attached as Schedule "D".
- 1.85 **"System Upgrades"** means additions, modifications and upgrades to the Distribution System, Transmission System or any portion of Buyer's generation system that are determined by Buyer to be required in order to facilitate the interconnection and to allow such Distribution System, Transmission System or any portion of Buyer's generation system to support the integration of the

Energy produced by the Seller's Plant in accordance with this EPA and the System Interconnection Guidelines, which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any New Interconnection Facilities.

- 1.86 "System Upgrade Costs"** means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the System Upgrades, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.
- 1.87 "Target Buyer's COD"** means the target date for achieving Buyer's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.
- 1.88 "Target Seller's COD"** means the target date for achieving Seller's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.
- 1.89 "Term"** has the meaning given to such term in Section 2.1.
- 1.90 "Termination Payment"** has the meaning given to such term in Schedule "F".
- 1.91 "Transmission System"** means the transmission, substation, protection, control and communication facilities owned and operated by Buyer, and includes all additions and modifications to those facilities and repairs or replacements of those facilities.
- 1.92 "Upgrade Costs Advance"** has the meaning given to such term in Section 3.5(a).
- 1.93 "Upgrade Costs Security"** has the meaning given to such term in Section 3.5(a).
- 1.94 "Utilities"** means both Yukon Energy Corporation or Yukon Electrical Company, doing business as ATCO Electric Yukon, as applicable.
- 1.95 "YESAA"** means the *Yukon Environmental and Socio-economic Assessment Act*, SC 2003, c 7.
- 1.96 "YESAB"** means the Yukon Environmental and Socio-economic Assessment Board.
- 1.97 "YUB"** means the Yukon Utilities Board and any successor thereto appointed from time to time under the *Public Utilities Act*.

2. INTERPRETATION

- 2.1 Headings** - The division of this EPA into Articles, sections, Sections, paragraphs and Schedules and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.
- 2.2 Plurality and Gender** - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.
- 2.3 Governing Law** - This EPA is made under, and will be interpreted in accordance with, the Laws of the Yukon. Subject to Section 12.1, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Yukon at Whitehorse, and those courts

have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.

- 2.4 Industry Terms** - Technical or industry specific phrases or words not otherwise defined in this EPA have the well-known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.
- 2.5 Statutory References** - Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.
- 2.6 Currency** - References to dollars or \$ means Canadian dollars, unless otherwise stated.
- 2.7 Reference Indices** - If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA will be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under Section 12.1 of this EPA.
- 2.8 Conversions** - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.
- 2.9 Additional Interpretive Rules** - For the purposes of this EPA, except as otherwise expressly stated:
- (a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Schedules attached to this EPA;
 - (b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular section, Section or other subdivision;
 - (c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto;
 - (d) the words "year" and "month" refer to a calendar year and a calendar month;
 - (e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;
 - (f) all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively; and

- (g) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, will be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

3. ADDRESSES FOR NOTICES

3.1 Notices to Buyer - Except as noted below, all notices addressed to Buyer will be delivered to the following address:

To: Yukon Energy Corporation
#2 Miles Canyon Road
Box 5920
Whitehorse, YT Y1A 6S7
Attention: IPP Manager
Email: ipp@yec.yk.ca

3.2 Notices to Seller - All notices addressed to Seller will be delivered to the following address:

To: 536774 Yukon Inc.
110 Titanium Way, Whitehorse, YT, Y1A 0E8
Attention: Ben Power
Email: bpower@solvest.ca

SCHEDULE "B"

PROJECT DESCRIPTION

CONTRACT PARTICULARS:

1. **Condition Date:**

Not Applicable.

2. **Conditions Precedent:**

None.

3. **Term:**

The "**Term**" of this EPA commences on the Effective Date and continues for a period of 25 years following Buyer's COD.

4. **Energy Price and Seasonal Adjustment:**

- (a) In each billing period, Seller shall pay to Buyer, for each kWh of Delivered Energy the "**Energy Price**" calculated as follows:

$$\text{Energy Price}_n = (.5 * \$0.158/\text{kWh} * \text{CPI}_{\text{January 1, } n} / \text{CPI}_{\text{January 1, 2020}}) + (.5 * \$\_\_\text{/kWh})$$

Where:

n = the year for which the relevant calculation is being conducted; and

$\text{CPI}_{\text{January 1, } n}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted.

- (b) For each hour, the Energy Price determined above for Delivered Energy during that hour will be adjusted to an amount (expressed in \$/kWh) equal to the percentage of that Energy Price applicable for that hour as set out in the table in Schedule "I".

SELLER'S PLANT

1. **Location of Control Building:** 60.946N -135.160W, being Lot 1297-02 on the North Klondike Highway.
2. **Eligible Clean Energy Type:** Solar Photovoltaic
3. **Seller's Plant Capacity:** 1MW AC
4. **Project Energy Volume:** 1,840,200 kWh per year
5. **Seller's Plant Description:**

Please refer to Seller's single line diagram in Exhibit B-1. *1.72 MW DC -1 MW AC Ground Mount solar farm located on the north Klondike highway consisting of 4000 x 430W bi-facial solar*

modules mounted on fixed 35-degree angle racking. Strings of 25 modules will connect to Huawei 50 kW inverters with an AC output voltage of 600V for combined capacity of 1 MW AC at Power Factor 1.0. The inverters will terminate at 1200A CDP + metering cabinet connecting to the low voltage side of the ATCO transformer.

Total AC Power:	1000 kW
Primary AC line voltage:	600V AC
Total AC line current:	962A
Total DC power:	1560 kW
Open-circuit DC voltage:	1500A
Operating DC voltage:	1100V
Total DC operating current:	1563A

6. **Target Seller's COD:** November 1st, 2020
7. **Electrical Grid:** Yukon Integrated System (YIS)

BUYER'S SYSTEM UPGRADES

1. **System Upgrades:**

No System Upgrades are required.

2. **New Interconnection Facilities:**

The Seller is connecting to YIS at ATCO Electric Yukon. Please see the System Interconnection Study Report attached as Schedule "D".

Please refer to Buyer's single line diagram in Exhibit B-2.

3. **Target Buyer's COD:** November 1st, 2020

BREAKERS/SWITCHES AND SYNCHRONIZATION

A SW Fusible HD 600V 1200A NEMA3R/Neutral and 60A 3P Type 3R 600VAC/DC Heavy Duty Non-Fusible Safety Switch will be used. The specifications of such switches are attached.

After voltage is restored after an outage no reconnections will be attempted until the Seller has permission to reconnect from the System Control Center (as identified in Schedule "H"). After permission is given, the Seller must check that voltage and frequency are stable and within 10% of nominal values before closing in to reconnect:

- A plus or minus 10% voltage range is acceptable; and
- A plus or minus 10% frequency range is acceptable.

Product availability : Stock - Normally stocked in distribution facility



Price** : 20,993.00 USD



Main

Product	Single Throw Safety Switch
Current Rating	1200 A
Certifications	UL listed file E2875
Enclosure Rating	NEMA 3R galvanized steel
Factory Installed Neutral	Neutral (factory installed)
Disconnect Type	Fusible disconnect
Short Circuit Current Rating	200 kA maximum L
Mounting Type	Surface
Number of Poles	3
Electrical Connection	Lugs
Duty Rating	Heavy duty
Voltage Rating	600 V AC/DC
Wire Size	AWG 3/0...750 kcmil copper or aluminium

Complementary

Width	36.62 in (930.15 mm)
Height	69.13 in (1755.90 mm)
Depth	17.75 in (450.85 mm)
Tightening torque	375 lbf.in (42.37 N.m) 0.13...0.59 in ² (85.01...380 mm ²) AWG 3/0...750 kcmil

Ordering and shipping details

Category	00054 - H&HU SW,NEMA3R,400-1200A
Discount Schedule	DE1
GTIN	00785901442479
Returnability	Yes

Country of origin	MX

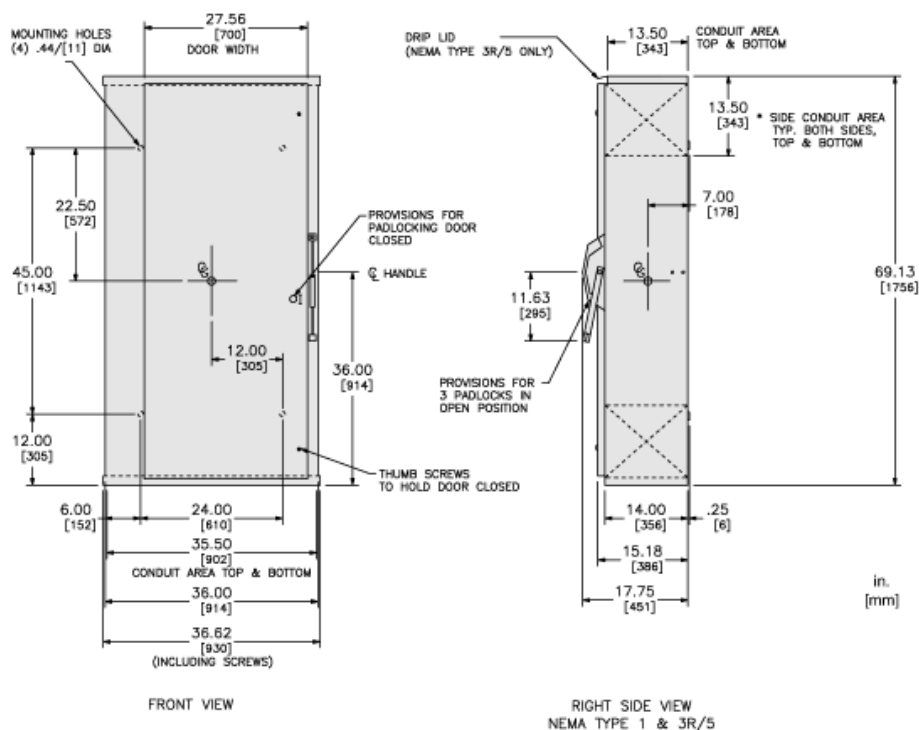
Offer Sustainability

Sustainable offer status	Green Premium product
California proposition 65	WARNING: This product can expose you to chemicals including: Lead and lead compounds which is known to the State of California to cause Carcinogen & Reproductive harm. For more information go to www.p65warnings.ca.gov
REACH Regulation	REACH Declaration
EU RoHS Directive	Compliant EU RoHS Declaration
Mercury free	Yes
RoHS exemption information	Yes
China RoHS Regulation	China RoHS declaration Product out of China RoHS scope. Substance declaration for your information.
Environmental Disclosure	Product Environmental Profile

Contractual warranty

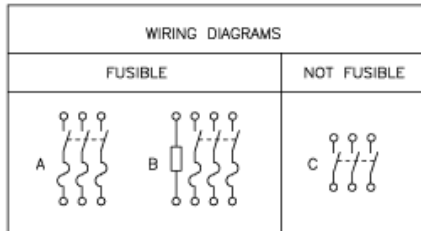
Warranty	18 months

Approximate Dimensions



CATALOG NUMBER	VOLTAGE RATINGS	WIRING DIAG.	3 PHASE HORSEPOWER RATINGS						DC HORSEPOWER RATINGS			
			240VAC		480VAC		600VAC		250VDC		600VDC	
			STD	MAX.	STD	MAX.	STD	MAX.	STD	MAX.	STD	MAX.
H32B	240VAC;250VDC	A	100	250	—	—	—	—	50	50	—	—
H32BR	240VAC;250VDC	A	100	250	—	—	—	—	50	50	—	—
H32BN	240VAC;250VDC	B	100	250	—	—	—	—	50	50	—	—
H32BNR	240VAC;250VDC	B	100	250	—	—	—	—	50	50	—	—
H36B	600VAC;600VDC	A	100	250	200	500	250	500	—	—	50	50
H36BR	600VAC;600VDC	A	100	250	200	500	250	500	—	—	50	50
H36BN	600VAC;600VDC	B	100	250	200	500	250	500	—	—	50	50
H36BNR	600VAC;600VDC	B	100	250	200	500	250	500	—	—	50	50
HU36B	600VAC;600VDC	C	100	100	—	500	—	500	—	—	50	50
HU36BR	600VAC;600VDC	C	100	100	—	500	—	500	—	—	50	50

Wiring Diagrams



TERMINAL LUGS			
AMPERES	MAX. WIRE	MIN. WIRE	TYPE
1200	(4)750 KCMIL	(4)#3/0 AWG	75°C AL OR CU

FUSE PROVISIONS			
AMPERES	TYPE	AMPERES	TYPE
1200	CLASS "L"	800	CLASS "L"



Main

Product or component type	Single Throw Safety Switch
Disconnecter device type	Non-fusible disconnect
Number of poles	3
Electrical connection	Lugs
Series name	Heavy duty

Complementary

Line Rated Current	60 A
Device composition	None
Device mounting	Surface
System Voltage	600 V AC/DC
AWG gauge	AWG 14...AWG 3 (copper or aluminium)

Environment

Product certifications	CSA
NEMA degree of protection	NEMA 3R galvanized steel

Offer Sustainability

Sustainable offer status	Green Premium product
RoHS (date code: YYWW)	Compliant - since 1313 - Schneider Electric declaration of conformity Schneider Electric declaration of conformity
REACH	Reference not containing SVHC above the threshold Reference not containing SVHC above the threshold
Product environmental profile	Available
Product end of life instructions	Need no specific recycling operations

EXHIBIT B-1

Seller's Single Line Diagram

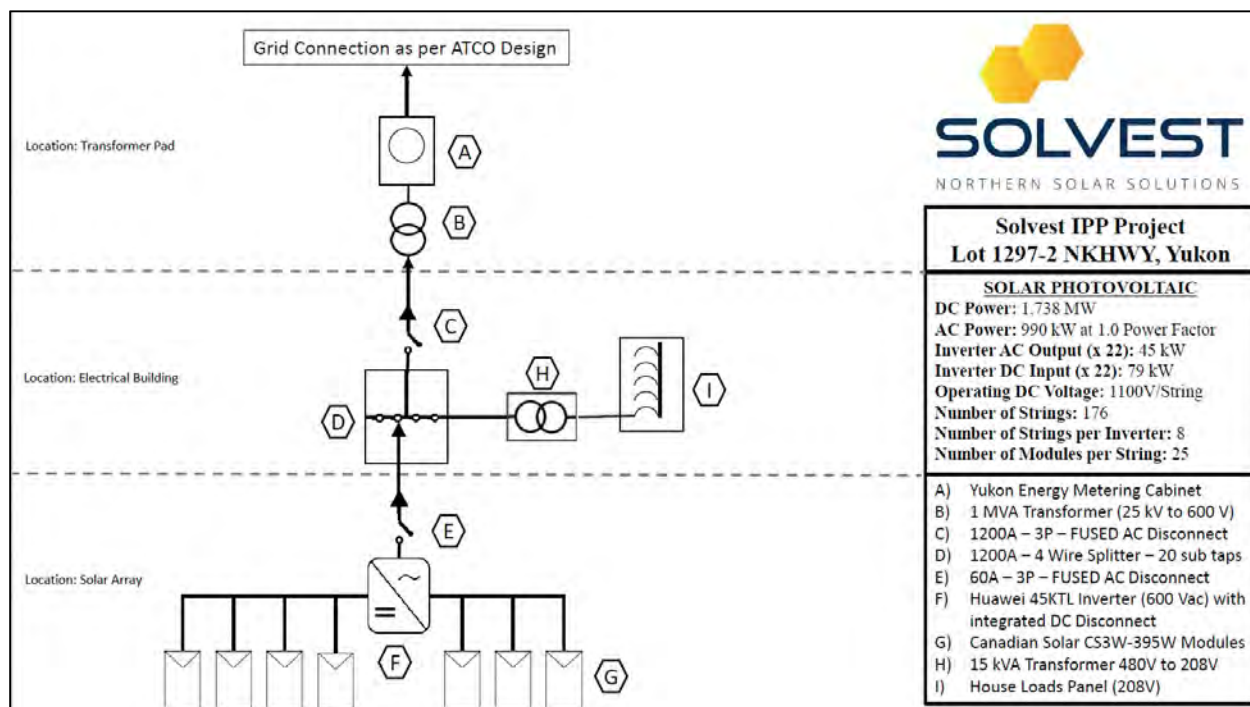
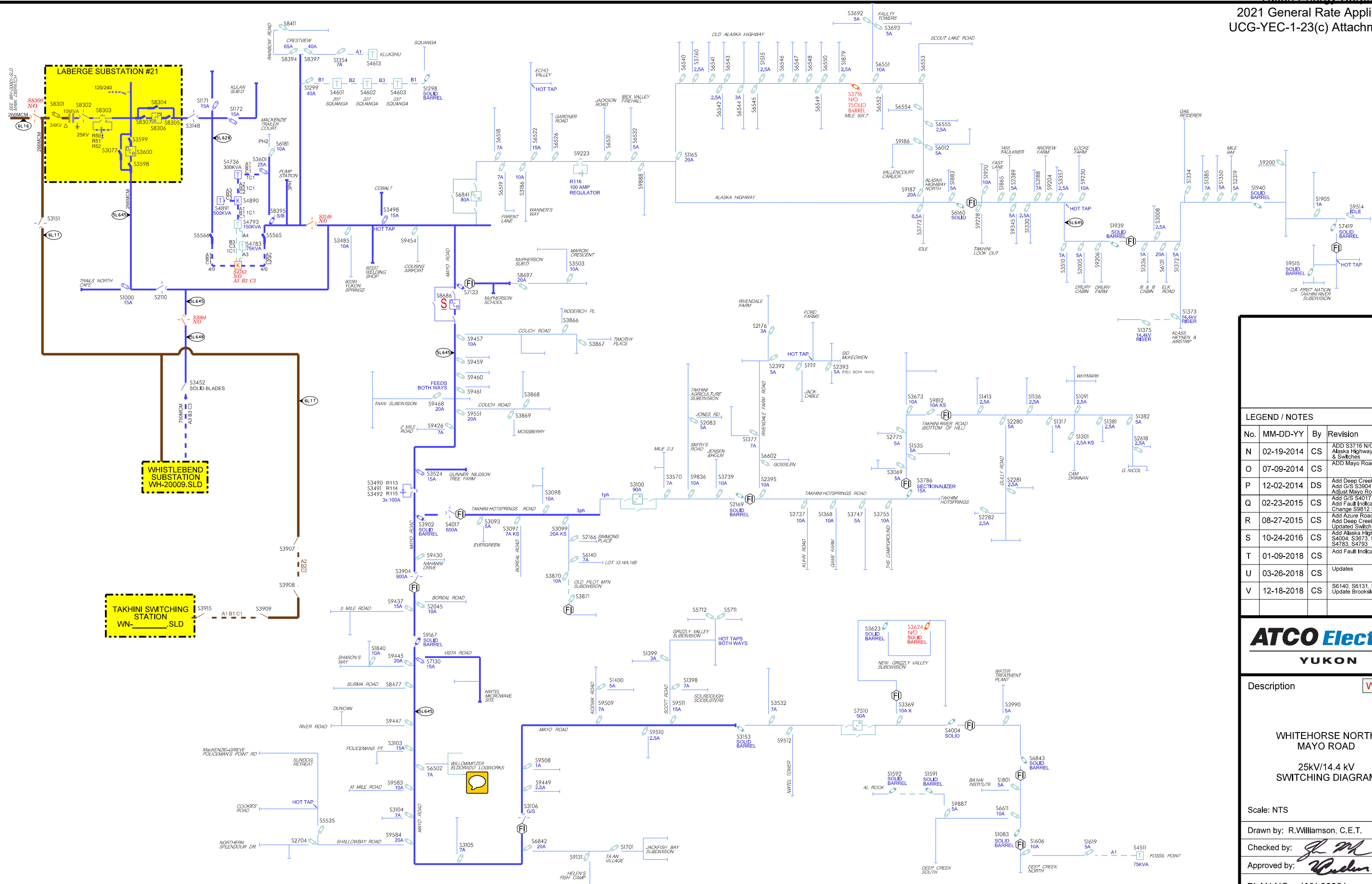


EXHIBIT B-2

Buyer's Single Line Diagram

(Please see attached)



LEGEND / NOTES			
No.	MM-DD-YY	By	Revision
N	02-19-2014	CS	ADD S3716 N/O SOLID, Alaska Highway Line & Switches
O	07-09-2014	CS	ADD Mayo Road Double Ch
P	12-02-2014	DS	Add Deep Creek, 34KV from Add G/S S3904
Q	02-23-2015	CS	Adjust Mayo Road 25KV Add G/S S4017
R	08-27-2015	CS	Add Fault Indicators Change S3612 S/B - 10A KS
S	10-24-2016	CS	Add Azure Road changes Add Deep Creek Changes Updated Switch Tag S5535
T	01-09-2018	CS	Add Alaska Highway S4004, S3673, S5931, S593 S4783, S4793
U	03-26-2018	CS	Add Fault Indicators
V	12-18-2018	CS	Updates S6140, S6131, S4890, S489 Update Brooksline

ATCO Electric
YUKON

Description	WN-2000

WHITEHORSE NORTH
MAYO ROAD
25kV/14.4 kV
SWITCHING DIAGRAM

Scale: NTS

Drawn by: R.Williamson, C.E.T.

Checked by:

Approved by: 

PLAN NO: WN-20001

File: WN-20001-SLD.dgn Rev: V

SCHEDULE "C"

FORM OF ANNUAL OPERATING PLAN

DATE: June 5, 2020.

TO: Yukon Energy Corporation ("Buyer")

RE: Electricity Purchase Agreement between 536774 Yukon Inc ("Seller") and Buyer dated the 5th day of June, 2020 (the "EPA")

The following sets out the Annual Operating Plan of Seller commencing on June 5, 2020 (the "**Applicable Period**").

- (a) The following (from Table E-1 of Schedule "E" of the EPA) is the schedule of the expected total deliveries of Energy at the POI in each month of the Applicable Period:

	Projected Hourly Energy (kWh/h) (A)	Projected Monthly Energy (kWh) (B)
January	400 kWh/h peak	21,000
February	779 kWh/h peak	100,800
March	850 kWh/h peak	198,300
April	801 kWh/h peak	251,600
May	821 kWh/h peak	263,300
June	814 kWh/h peak	241,100
July	815 kWh/h peak	231,600
August	818 kWh/h peak	216,200
September	862 kWh/h peak	155,400
October	836 kWh/h peak	108,400
November	692 kWh/h peak	40,200
December	347 kWh/h peak	12,500

- (b) The following is the schedule of any Planned Outages of the Seller's Plant expected by Seller for the Applicable Period:

The Seller has no Planned Outages for the Applicable Period.

- (c) The following is the schedule of operations and maintenance activities planned for the Seller's Plant expected by Seller for the Applicable Period:

The Seller will perform bi-annual maintenance on the Seller's Plant in the first week of March and last week of April. The Seller's Plant will not be shut down during this maintenance activity, however one inverter at a time may be brought offline for thermal scans. This would decrease the output of the Seller's Plant by no more than 45 kW ac.

Dated effective as of the date set forth above.

536774 YUKON INC.

Per: _____
Ben Power
Director

Per: _____
Michael Schultz
Director

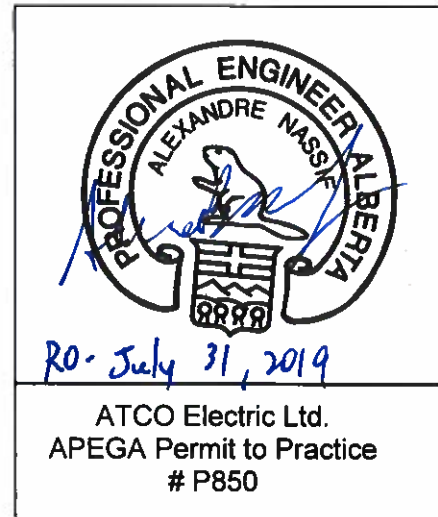
SCHEDULE "D"
SYSTEM INTERCONNECTION STUDY REPORT

(Please see attached)



DISTRIBUTED GENERATION FEASIBILITY RESULTS

Project #: n/a
Customer: Solvest Inc.
ISD: TBD
Location: Whitehorse
Substation: Laberge
Feeder: 5L645
Author: Alexandre Nassif, P.Eng.
Reviewed by: John Williams, P.Eng.
Revision: R0
Date: July 30, 2019



DG Description

Total Generation Requested	1 MW
Type of Generation	Solar
Maximum Allowable Generation	It is possible to accommodate up to 1MW of generation with required system upgrades. The solar farm will need to operate under constant unity power factor (100%)
Number and Size of Units	Eight (8) inverters, 125 kW each
Site Load	No
Transformer Ownership	It is assumed the customer will install a three-phase 1MVA transformer.
PCC Transformer Size and Winding Configuration	25kV-600V with a grounded wye winding configuration on ATCO's side.

DTT Assessment

DTT Required (Y/N)	Not required. It is a pre-requisite that the solar inverters meet all specifications of UL1741 SA

	and IEEE 1547-2018, including the provisions for anti-islanding and open-phase detection and disconnection. If these requirements are met, existing inline reclosers will not need to be retrofitted and no DTT scheme will be required.
Scope	N/A

AESO Requirement Assessment

SCADA Visibility Required? (Y/N)	It is assumed SCADA visibility is not required. The transmission authority must be consulted.

Distribution Assessment

Feeder and Conductor Size	From Laberge to the possible tie-in point, feeder 5L645 consists of: - 1km of 3 x 1/0 ACSR - 4.7km of 3 x #6 ACSR - 2km of 3 x #4 ACSR - 8.2km of 3 x 1/0 ACSR - 5.6km of 3 x 266ACSR It is assumed about 400m of new conductor will be required and will be 3x1/0 ACSR.
Substation rating	Laberge contains a 10MVA 35kV-25kV substation
Maximum generation without upgrades:	1 MW The existing Voltage Regulator (R113 R114 R115) must be reprogrammed to operate in co-generation model with forward settings of 124V (existing) and reverse settings of 122V. If the voltage regulator does not allow co-generation operation, it must be replaced.
Feeder 5L645 Loading	Feeder Loading: Max = 4,055 KW Average = 1,758 kW 10th percentile = 997 kW Min (1st percentile; excluding outages) = 745 kW
Substation (Laberge) Loading	Max = 5,512 kW Average = 2,480 kW 10th percentile = 1,446 kW Min (1st percentile) = 1,000 KW
Circuit Distance from the substation	About 22 km

Existing DG on this feeder? (Y/N)	There are other solar generators in the feeder. They are assumed to be very small.
Alternate Feed? (Y/N)	UNKNOWN. If supplied by an alternate feed, this generator will need to be directed offline by the control center.
New Build Required? (Y/N, distance and conductor)	It is assumed about 400m of new line (3 x 1/0 ACSR) will be required.
Reconductoring Required? (Y/N, distance and conductor)	No.
Consideration of ATCO's System's Power Factor	It is expected that the Solar generator will not negatively and substantially impact the substation power factor under peak load condition.
Upstream Regulator Setting Changes Required? (Y/N)	YES: - Voltage regulator R113 R114 R115 will need to be reprogrammed or upgraded to operate under co-generation mode. Forward settings can remain at 124V, but reverse settings need to be changed to 122V. - Voltage regulator R50R51R52 at Laberge will need to be reprogrammed or upgraded to operate under co-generation mode. Forward settings can remain at 126V, but reverse settings need to be changed to 125V
Upstream Distribution recloser equipment change? (Y/N)	No changes required, as long as the solar inverters comply with all anti-islanding and open-phase detection clauses of UL 1741 SA and IEEE 1547-2018.
Power Transfer to other feeders? (Y/N and amount)	YES Power transfer during feeder max/average/10th percentile /min loading are: Max = no transfer Average = no transfer 10th percentile = very small Min = 255 kW

Power Transfer to 35kV? (Y/N and amount)	Potentially. The minimum load is about 1MW, which is the size of the proposed generation.
Power Transfer to Transmission? (Y/N and amount)	No.

Distribution Scope of Work

Local Scope

1. Build about 400m (to be confirmed by field check) of 3 x 1/0 ACSR line to the PCC.
2. Tie customer transformer to the distribution system
3. Install Bi-Directional Meter with power quality meter
4. Install a three-phase fault interrupter with voltage sensors and a controller that allows for directional protection.

Upgrade Scope

1. Reprogram the existing Voltage Regulator (R113 R114 R115) to operate in co-generation mode. If the voltage regulator does not allow co-generation operation, it must be replaced.
2. Reprogram the existing Voltage Regulator (R50R51R52) to operate in co-generation mode. If the voltage regulator does not allow co-generation operation, it must be replaced.

Assumptions:

- DG will be operating at 100% power factor (unity)
- 25kV-600V transformer will be customer owned
- Routing is assumed

Transmission Assessment (to be completed by the Transmission Authority)

Revision History

Revision	Date	Comment	Initials
R0	July 31, 2019	First Release.	AN

SCHEDULE “D”

SYSTEM INTERCONNECTION STUDY REPORT

(Continued)

Line Losses

ATCO Electric Yukon has established that the only Line Losses will be transformer losses which will be fully quantified upon commissioning.

Initial estimated transformer losses based on the specifications of the transformer to be ordered is approximately 0.5%, but it has been recommend to use 0.75% for budgeting purposes.

SCHEDULE "E"

MONTHLY ENERGY SHORTFALL PAYMENT

Monthly Energy Shortfall Payments

In any calendar month in which there has occurred a Non-Permitted Distribution/Transmission Constraint then Buyer shall pay Seller Monthly Energy Shortfall Payment,

where:

"Monthly Energy Shortfall Payment" means the Monthly Constraint Shortfall multiplied by the price which is payable for Delivered Energy under Section 5.1 of the EPA; and

"Monthly Constraint Shortfall" (expressed in kWh) means, for each calendar month, means the aggregate of the duration of each Non-Permitted Distribution/Transmission Constraint (measured as a fraction determined as the aggregate number of minutes in such Non-Permitted Distribution/Transmission Constraint divided by 60) multiplied by the "Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy" set out in Table E-1 below for the applicable calendar month.

Table E-1

	Projected Hourly Energy (kWh/h) (A)	Projected Monthly Energy (kWh) (B)	Non-Permitted Distribution/Transmission Constraint Factor (F1)	Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy (kWh/h) (A x F1)
January	28.23	21,000	_%	
February	150.00	100,800	_%	
March	266.53	198,300	_%	
April	349.44	251,600	_%	
May	353.90	263,300	__%	
June	334.86	241,100	__%	
July	311.29	231,600	__%	
August	290.59	216,200	__%	
September	215.83	155,400	__%	
October	145.70	108,400	__%	
November	55.83	40,200	__%	
December	16.80	12,500	__%	

Revisions to Projected Hourly Energy and Projected Monthly Energy

Within 90 days following the end of the 2nd year after Buyer's COD, the Parties shall review and revise the values in Table E-1 above for Projected Hourly Energy and Projected Monthly Energy to reflect the average actual amount of Delivered Energy sold to Buyer in the 2 years following Buyer's COD for the applicable months.

SCHEDULE "F"

TERMINATION PAYMENT

The "**Termination Payment**" at any time shall be equal to (a) the Gross Termination Payment set out below for the Contract Year in which the termination occurred, less (b) the actual amounts paid or owing by Buyer to Seller for Delivered Energy for the Contract Year in which the termination occurred.

Table F-1

Termination Year	Gross Termination Payment
Year 1	\$3,252,880
Year 2	\$3,233,759
Year 3	\$3,210,258
Year 4	\$3,181,994
Year 5	\$3,148,552
Year 6	\$3,109,482
Year 7	\$3,064,300
Year 8	\$3,012,480
Year 9	\$2,953,453
Year 10	\$2,886,607
Year 11	\$2,811,275
Year 12	\$2,726,740
Year 13	\$2,632,223
Year 14	\$2,526,885
Year 15	\$2,409,815
Year 16	\$2,280,032
Year 17	\$2,136,470
Year 18	\$1,977,981
Year 19	\$1,803,321
Year 20	\$1,611,146
Year 21	\$1,400,000
Year 22	\$1,168,313
Year 23	\$914,384
Year 24	\$636,374
Year 25	\$332,296

SCHEDULE "G"
SYSTEM INTERCONNECTION GUIDELINES

(Please see attached)



Yukon Energy Corporation

Independent Power Producers Interconnection Technical Guide

Revision: 04b
Release Date: 2019 01 24

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP (“Teshmont”), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision History

Revision Number	Date Released	Prepared by	Reviewed by	Comments
00	May 14, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng Robert Baker, PEng	First Draft
01	May 30, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Second Draft
02	June 5, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Third Draft. Incorporated YEC Comments.
03	June 18, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fourth Draft. Incorporated YEC Comments.
04	September 17, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fifth Draft. Incorporated YEC Comments.

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Appendix C	Information Provided by the Utility
Appendix D	Applicable Codes and Standards
Appendix E	Sample Operating Agreement
Appendix F	Typical Interconnection Single Line Diagrams
Appendix G	Protective Settings Commissioning Document

Executive Summary

The purpose of the Interconnection Technical Guide is to provide guidelines for Independent Power Producers (IPP) who wish to interconnect a generation facility of greater than 50 kW and up to 10 MW to the Yukon Integrated System (YIS) via the Yukon Energy Corporation (YEC) or ATCO Electrical Yukon (AEY) distribution systems. The maximum allowable generation at the Point of Interconnection (POI) between the distribution system and IPP will depend on the results of a system impact study conducted by YEC. This guide details the technical and operational requirements of the facility and is not intended to be used as a design guide.

The purpose of this document is to:

- Provide technical specifications for the interconnection of IPP generation to the YIS (via YEC or AEY distribution systems).
- Clarify, where necessary, the technical requirements in CSA Standard C22.3 No. 9-08 (R2015) “Interconnection of Distributed Resources and Electricity Supply Systems” [1] and to provide an outline for how each section applies to interconnections with the YIS.

1. *Introduction and Scope*

1.1. *Purpose*

This guide establishes criteria and technical requirements for Independent Power Producers (IPP) who wish to interconnect generation, with a net capacity greater than 50 kW and up to 10 MW, to the Yukon Integrated System (YIS), at the distribution level (35 kV and below), or at the transmission level (above 35 kV). This guide has been developed considering CSA Standard C22.3 No. 9-08 (R2015) [1] and IEEE Standard 1547-2018 [2] and is subject to regular review and revision due to evolving standards.

The technical guide is intended to assist IPPs who apply to connect to the YIS through the Standing Offer Program, Call for Power, or through other unsolicited requests to connect.

1.2. *Limitations*

The criteria and technical requirements described within this section apply to the following generation interconnections:

- Interconnections to the Yukon Energy Corporation (YEC) and ATCO Electric Yukon (AEY) distribution systems at voltages of 34.5 kV and below, and
- Interconnections to the YEC transmission system at voltages over 34.5 kV by means of an existing or new substation. Transmission interconnections will require specific detailed review and approval by YEC and all interconnection costs will be borne by the IPP.

This Guide establishes the minimum requirements for the Point of Interconnection (POI). The IPP generation may be subject to additional requirements to ensure the project meets all applicable standards.

This Guide is not to be used:

- As an Operating Agreement and does not address the following:
 - o Joint operating agreements
 - o Costs
 - o Tariffs
 - o Other contractual issues
- As an Interconnection Process and Procedures Guide, and does not include the following:
 - o Protection of the IPP's generation facilities
 - o Transmission system impact and upgrades
 - o System planning and design
 - o Operation of the distribution system
 - o Other system related issues
- As a design handbook for a generation facility.
- For any IPP generation not connected indirectly or directly to the YIS, i.e. an island grid.

2. Terms, Definitions, and Abbreviations

2.1. Definitions

Accredited Certification Organization – An organization that has been accredited by the Standards Council of Canada to operate a certification program for electrical equipment, such as the Canadian Standards Association (CSA).

Anti-islanding – A means of detecting and preventing a DR from energizing a part of the distribution system that becomes disconnected from the grid.

ATCO Electric Yukon – A private investor-owned utility, and member of the ATCO Group of Companies.

Automatic Circuit Recloser (ACR) – An overcurrent protection device used by utilities to detect faults on distribution system feeders, which has the ability to open and then reclose after a specified time delay allowing adequate time for temporary faults to clear.

Bi-directional Meter – A meter that measures real and reactive power and energy in both directions.

Cease to Energize – The cessation of energy outflow capability.

Clearing Time – The time from the start of the abnormal condition to when the distributed resource ceases to energize the distribution system.

Dispensated Metering Equipment – Any metering equipment that has received Measurement Canada approval under Section 9(2) or 9(3) of the Electricity & Gas Inspection Act.

Disconnecting Means – A device or group of devices that allows the conductors of a circuit to be disconnected from their source of supply.

Distributed Generation (DG) – Small, decentralized electric power generation facilities, typically interconnected to the distribution system.

Distribution System – The portion of the electrical system that operates at a nominal voltage of 34.5 kV line to line and below, and which distributes electric power between distribution substations and customers.

Effectively Grounded Distribution System – Distribution facilities where the neutral conductor is solidly grounded and the ratio of the zero sequence reactance to the positive sequence reactance is less than or equal to 3 and the ratio of the zero sequence resistance to the positive sequence reactance is less than 1.

Electromagnetic Interference (EMI) – Any electromagnetic disturbance that interrupts, obstructs, or otherwise degrades or limits the effective performance of a device, equipment or system.

Exporting – supplying power into the distribution system through the POI.

Facilities – A physical plant including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery.

Flicker – The subjective impression of fluctuating luminance caused by voltage fluctuations.

Frequency – The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz (Hz).

Generation – The process of converting solar, thermal, wind, hydro, or chemical energy into electric energy.

Independent Power Producer (IPP) – An agency or individual other than a public utility (as defined by the Public Utilities Act) who generates electricity to sell (to the utilities). An independent power producer does not own transmission facilities and is dependent on the utilities to purchase and distribute the power it produces.

Interconnection – The physical connection of DG to YEC's distribution system so that parallel operation can occur.

Island Grid – A community power system which is energized solely by one or more local power producers and is separated electrically from the YIS.

Islanding – A condition where a portion of the utility's distribution system is energized exclusively by one or more power producers through their DR interconnection.

Operating Interface Point – See Point of Interconnection.

Parallel Operation – the simultaneous energization at a POI by the generating facility and the utility distribution system.

Point of Interconnection (POI) – The location of the electrical connection between an IPP facility and the utility's distribution system. This will be the point where the ownership changes from the utility to the IPP.

Power Factor – The ratio of active power to apparent power. It is the cosine of the phase angle difference between the current and voltage of a given phase.

Protection Scheme – The protection functions, including associated sensors, relays, and power supplies, intended to protect a distribution system or interconnection equipment.

Public Utility – As defined by the Public Utilities Act and Regulations (i.e., YEC and/or AEY).

Ride-through – The ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Secondary Injection Testing – A method in which low level signals obtained from current and voltage signal generators are injected into a power system protective device to test device response.

Stabilized – The state of the distribution system after voltage and frequency has returned to normal range for a period of at least five minutes (or another period of time, as agreed with YEC) following a disturbance.

Stand Alone – The state where a distributed generation can operate by controlling the frequency and voltage of their facility while in islanded or isolated mode.

Telemetry – Transmission of measurable quantities using telecommunications systems.

Total Demand Distortion (TDD) – The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the maximum demand current. Harmonic components of order greater than 50 may be included when necessary.

Total Harmonic Distortion (THD) – The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the fundamental. Harmonic components of order greater than 50 may be included when necessary.

Transfer Trip – A remote signal directed from an upstream device to command a DG to cease to energize the distribution system upon detection of an islanding condition and to prevent re-energization.

Transmission System – The portion of the system that operates above a nominal voltage of 34.5 kV line to line and transmits electric power between YEC substations.

Trip Time – The time between the start of the abnormal condition and the interconnection device ceasing to energize the distribution system.

Type Test – A test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance.

Utility – See Public Utility (i.e., YEC and/or AEY).

Visible-Break Disconnect – A switch or circuit breaker by means of which the generator and all protective devices and control apparatus can be simultaneously disconnected under full load entirely from the circuits supplied by the generator. All blades or moving contacts must be connected to the generator side, and the design of the disconnect switch must allow adequate visible inspection of all contacts in the open position.

Voltage Flicker – A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.

Yukon Energy Corporation (YEC) – A publicly-owned electrical utility that is the main generator and transmitter of electrical energy in Yukon.

Yukon Integrated System – The integrated Whitehorse-Aishihik-Faro and Mayo-Dawson electrical grids which are owned by YEC.

2.2. Abbreviations

ACR	Automatic Circuit Recloser
AEY	ATCO Electric Yukon
AEUC	Alberta Electrical Utility Code
CEA	Canadian Electricity Association
CEC	The Canadian Standards Association's C22.1-98 Safety Standard for Electrical Installations Part 1, also known as the Canadian Electrical Code
CSA	Canadian Standards Association
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IPP	Independent Power Producer
LTC	Load Tap Changer
NEMA	National Electrical Manufacturers Association
POI	Point Of Interconnection
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SIS	System Impact Study
YEC	Yukon Energy Corporation
YIS	Yukon Integrated System
YUB	Yukon Utilities Board

3. Party Responsibilities

Refer to the IPP Policy as released in January 2019 for the individual responsibilities of the Government of Yukon, utilities (YEC and AEY), Yukon Utilities Board and the IPP during the generation interconnection process.

3.1. IPP Responsibilities

The IPP is responsible to:

- Provide technical information to the utility as specified in Appendix A and Appendix B;
- Assume ownership of the facility including the design, installation, operation, and maintenance of all equipment, station and distribution line facilities from the POI to the IPP facility, unless otherwise agreed to in writing;
- Pay the costs of system interconnection in accordance with the commercial terms established by the utilities;
- Obtain all regulatory approvals, including environmental assessment approvals, if necessary, for the construction and operation of its facilities. The IPP facilities shall be designed, constructed, operated and maintained in compliance with the applicable statutes, regulations, by-laws, codes and technical requirements specified by the utility (e.g. remote monitoring etc.);
- Submit all specifications of its facilities and detailed plans to the utility for review prior to receiving permission to connect to their distribution system;
- Ensure the technical requirements given in the standards and codes in Appendix D are met;
- Ensure metering requirements are met (see section 12); and
- Negotiate the timing and any testing requirements for the commissioning process with YEC

3.2. YEC Responsibilities

YEC is responsible for the operation of the Yukon Integrated System (YIS) and for certain local distribution systems interconnected with the YIS. This guide applies to all transmission and YEC distribution system interconnections.

YEC is responsible for all system studies performed on the YIS. The IPP and AEY, in the case of an AEY interconnection, shall provide all necessary information to YEC for the interconnection of the IPP facility. The system studies conducted by YEC will be paid for by the IPP.

After receiving the application for interconnection, YEC shall provide the IPP, at the IPP's cost, the information specified in Appendix C.

3.3. AEY Responsibilities

AEY is responsible for the operation of certain local distribution systems interconnected with the YIS. This guide applies to these AEY distribution system interconnections.

After receiving the application for interconnection, AEY shall, in consultation with YEC, provide the IPP, at the IPP's cost, the information specified in Appendix C.

4. General Requirements

4.1. Standards

When planning, designing, and operating an IPP Generation Facility, the IPP shall meet all applicable national, territorial and local construction and safety codes and standards.

The interconnection facility must comply, as a minimum, with the following:

- All CSA Standards, including the Canadian Electrical Code (CEC),
- Applicable YEC and AEY standards and the requirements set forth in this Guide,
- National, Territorial and local Governing law, acts, by-laws and codes, and
- Alberta Electrical Utility Code (AEUC) [4].

Applicable standards are located in Appendix D, however not all may be applicable for the IPP facility and additional standards may apply.

The interconnection of new generation can adversely affect the electric service to existing or future customers. The IPP must work with the utility to mitigate any adverse effects.

The facility must be constructed and maintained to provide a safe environment for employees as well as the public. If the generation facility adversely affects other customers, the utility may disconnect it until such time as the concern has been mitigated. The IPP is responsible for any costs incurred as a result.

The IPP is required to install, operate and maintain the facility and to ensure it is in sufficiently good order and repair at all times. Maintenance shall conform to good electrical practice, adequate for safe parallel operation when connected to the YIS. The utility and the IPP shall share commissioning reports, operating procedures and annual shutdown, maintenance, and inspection reports.

4.2. Operating Requirements

A joint operating agreement template will be developed in conjunction with the utility. The agreement requirements are not included within the scope of this Guide. A sample operating agreement is located in Appendix E.

5. Site Specific Conditions and Capacity Limitations

During the preliminary stage of project development any limitations regarding the proposed interconnection, and any additional system upgrades required, will be determined in consultations between the IPP, YEC and AEY, if interconnected via an AEY distribution system.

A system impact study will be necessary to identify any site-specific conditions and capacity limitations of the distribution and/or transmission system. To facilitate the study, the utility and the IPP will exchange information concerning load, feeder characteristics, protection philosophies, station layouts, capacities, ratings and other relevant information of the distribution and/or transmission system. The utility controls reliability design and reliability standards.

Under certain circumstances, YEC and AEY may limit the size or reconfigure the proposed connection arrangement of the IPP facility in order to maintain the integrity of their system.

6. YIS Transmission and Distribution System Characteristics

6.1. YEC Transmission System

6.1.1. General System Configuration

The YIS is an 'Islanded grid' which has no interconnection with the main North American electric grid. The Yukon must produce all of its own power, and cannot generate more electricity than is there is load, since there are no neighboring markets into which to sell surplus energy.

The YIS includes the 138 kV Whitehorse – Aishihik – Faro (WAF) grid, the 69 kV Mayo-Dawson-Keno (MD) grid, and the 138 kV Carmacks-Stewart Transmission Line (CSTL) which interconnects the WAF and MD grids. YEC provides power to major industrial customers connected to the 69 kV and 138 kV grids.

A map of the YIS is shown in Figure 6–1.

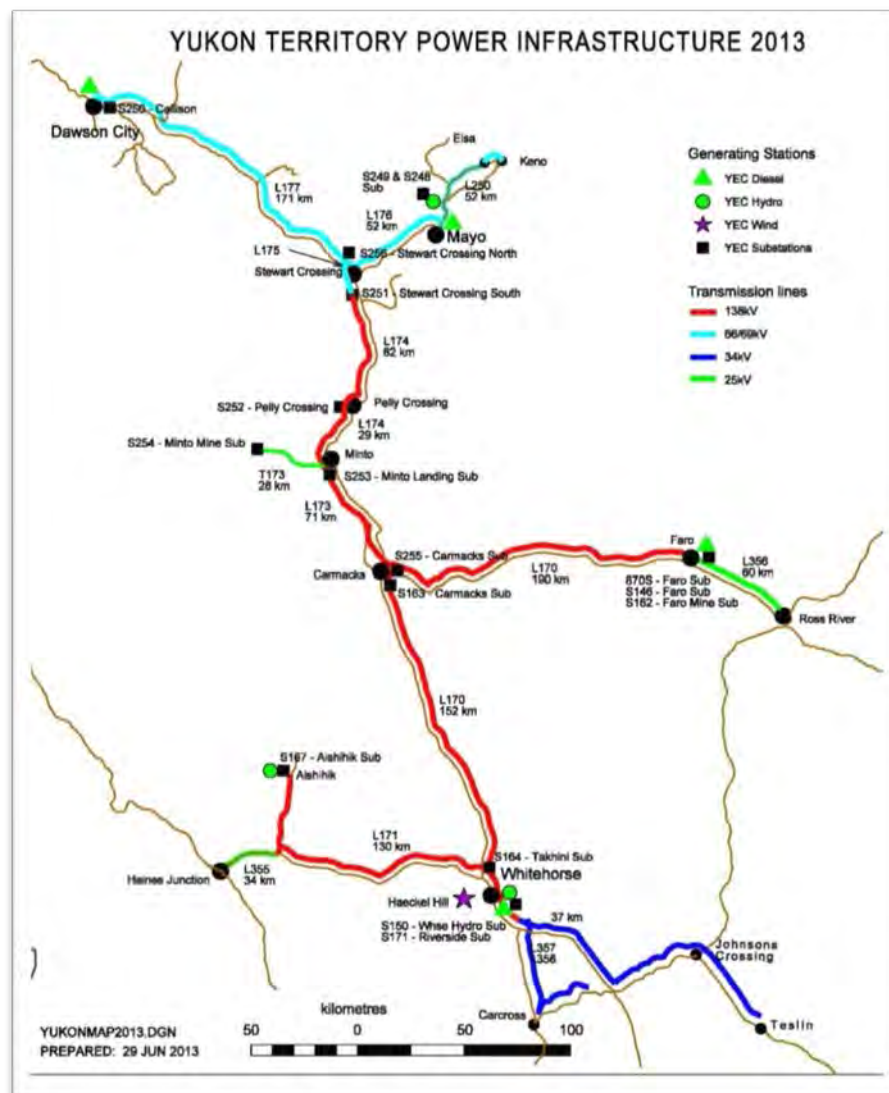


Figure 6–1: YIS Map

6.1.2. System Unbalance

Voltage unbalance on the transmission system is minimal during normal operation. The voltage unbalance under normal operating conditions will be less than three (3) percent. The IPP facilities may be subjected to voltage unbalance and negative sequence current during system disturbances. The generation connected to the transmission system must be able to withstand significantly unbalanced voltages with high negative phase sequence currents for short periods of time.

6.1.3. Frequency

The YEC transmission system operates at 60 Hertz (Hz) Alternating Current (AC) with equipment standard for this frequency. Frequency variations are typically in the range between 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, however variations between 58 Hz to 66 Hz or greater can occur for larger contingencies.

The frequency of the electric system is controlled by synchronous generator governor systems. Such governor systems respond automatically to changes in system frequency to prevent further deviation. These variations are system dependent and subject to change.

6.1.4. Steady State Voltage Levels

During normal steady state conditions, the 69 kV and 138 kV systems can vary between 90% and 105% of nominal voltage. However, under extreme conditions, the 69 kV and 138 kV systems can vary between 85% and 110% of nominal voltage with some 138 kV facilities designed to operate continuously up to 110% of nominal voltage.

6.1.5. System Fault Levels and System Impedances

The IPP generation facilities connecting directly to the transmission system shall be designed for operation at short circuit (fault) levels that take into account reasonable future development of the YIS transmission system. The short circuit levels to be used in the design depend on the point(s) of interconnection and future planned development and are available on request from YEC.

6.1.6. Fault Clearing and Automatic Reclosing

The YIS does not implement auto-reclosing at the transmission level.

6.1.7. System Grounding

The transmission system is effectively grounded.

6.2. YIS Distribution System Characteristics

6.2.1. General

Both YEC and AEY operate distribution systems in the Yukon which are interconnected with the YIS. The systems are predominantly three phase, wye connected, with nominal voltages of 4.16/2.4 kV, 6.9/4 kV, 12.5/7.2 kV, 13.8/8 kV, 25.00/14.4 kV and 34.5/20 kV.

AEY also operates a number of distribution systems which are not interconnected to the YIS, and are not covered by this Guide:

- Watson Lake
- Old Crow
- Beaver Creek
- Destruction Bay / Burwash Landing
- Swift River

For information on connecting to the AEY distribution systems which are isolated from the YIS, refer to AEY's document entitled, "ATCO Electric Yukon's Isolated Community Generation System Interconnection Guidelines".

6.2.2. Voltage Levels

The YEC and AEY distribution systems operate to meet CSA Standard CAN3 C235.83 – "Preferred Voltage Levels for AC Systems 0 to 50,000V" which defines the preferred operating voltage levels for normal and extreme operating conditions. The distribution system steady state voltage is typically maintained between + 5% to 7% and - 5% to 7%.

6.2.3. Power Quality (Harmonics and Voltage Flicker)

The YEC and AEY distribution systems operate to limit the maximum individual frequency voltage harmonics to 3% of the fundamental frequency and the voltage total harmonic distortion (THD) to 5% on the utility side of the POI.

6.2.4. Voltage Regulation

The operating voltages on the low voltage buses of YEC distribution substations are generally regulated by transformer automatic load tap changers (LTC), bus voltage regulators or feeder voltage regulators. YEC will provide set-points for the equipment upon request.

6.2.5. Voltage Unbalance

Distribution facilities are typically three-phase systems, incorporating single-phase distribution taps. The voltage unbalance on a distribution system under normal operating conditions may exceed 3%, due to the unbalanced loading and single-phase regulation. Voltage unbalance will be calculated using the following formula, as derived from CSA Standard C22.3 No. 9-08 (R2015) [1]:

Voltage Unbalance (%) = 100 x (negative sequence voltage of the fundamental frequency component) / (positive sequence voltage of the fundamental frequency component)

6.2.6. *Fault Levels*

Fault levels and maximum allowable fault currents vary significantly through the distribution system and must be considered in the design of the IPP interconnection.

6.2.7. *System Grounding*

The utility distribution facilities are typically three phase, four wire, multi-grounded systems that incorporate single phase distribution taps. The lines are normally operated as effectively (solidly) grounded with grounded-wye connected sources at the distribution substation secondary bus.

6.2.8. *Phasing*

The phase sequence on the utility system may vary, and must be confirmed between the IPP and the utility during the design phase of the installation.

6.2.9. *Fault and Line Clearing and Automatic Reclosing*

The YEC distribution systems do not currently include auto reclosing. The AEY distribution systems may have auto reclosing and this will be confirmed during the design phase of the application.

7. Power Quality Requirements for the System Interconnection

7.1. Harmonics

The following industry standards may provide guidance for appropriate performance.

- IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018 [2]
- IEEE 519-2014 – IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems [5]
- IEC 61000-4-15 – Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications [6]

The generation facility shall not inject harmonic currents such that will cause objectionable voltage distortion as per standard IEEE 519 Harmonic current injections cause intolerable voltage distortions on the distribution system and may damage equipment.

The Utility, at the IPP's expense, shall conduct a Power Quality Assessment of the distribution system in the immediate vicinity of the interconnection using a measurement technique compliant with IEC 61000-4-7.

When performing a Power Quality Benchmark, the measurements at the customer's POI shall be taken over a one week (168 hour) period during typical production load levels.

7.2. Flicker

The generation facility shall meet the requirements of Section 6.2.3 and shall not cause unacceptable levels of flicker on the distribution system. The utility, at the IPP's expense, shall measure the flicker level using a power quality measuring device that meets the requirements of the IEC Flickermeter Standard 61000-4-15.

When performing a Flicker assessment, the measurements at the customer POI shall be taken over a representative load cycle of one day or greater.

7.3. Speed Regulation and Frequency Control

The frequency of the YIS is controlled by the generators operated by YEC.

The YIS operates at 60 Hertz (Hz) Alternating Current (AC). The nominal frequency variations are typically 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, and the frequency may drop to 58 Hz or rise to 66 Hz or higher for larger contingencies.

The frequency of the YIS is automatically controlled by the governor systems of the generators operated by YEC, within the specified limits.

IPP generators rated at 1 MVA and greater are required to have a governor system, capable of operating in droop mode, to respond to system frequency changes. The droop setting of the governor will typically be in the range of 5%.

IPP generators rated less than 1 MVA may operate in base load mode rather than in frequency control mode.

The utility will define frequency requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC.

Equipment connected to the YIS shall be capable of withstanding the dynamic frequency performance criteria listed in Table 1.

Table 1: Transmission Minimum Frequency Performance

Under Frequency Limit	Over Frequency Limit	Minimum Time
60.0-59.0 Hz	60.0-61.0 Hz	N/A (continuous operating range)
58.9-58.5 Hz	61.1-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	Instantaneous trip

Under-frequency and over-frequency relaying that automatically disconnects generators from YIS must not operate for frequencies in the range of 59.0 to 61.0 Hz if no other abnormal system event is underway.

7.4. Voltage Regulation and Power Factor

The IPP is responsible for ensuring that the voltage levels at the POI are maintained within this guidelines prescribed by the utility. The IPP interconnection must maintain the voltage levels, under all feeder load conditions, at the same values as they were prior to the interconnection.

Synchronous generators connected to the distribution system must be equipped with adequate excitation controllers. The IPP shall operate generators with Automatic Voltage Regulators (AVR) adjustable from 95% to 105% of nominal bus voltage. The Generation should be run in Voltage control unless required to run in power factor (pf) mode by the Utility. Operation in MW or MVAR control is not acceptable. The AVR response should with no intentional delay when in Voltage Control mode.

Induction generators do not have voltage or reactive power control capability and consume reactive power (VAR). In this case, the generator must provide reactive compensation to correct the power factor to 0.9 lagging or better at the POI, unless other terms are specified by the utility.

Inverter type generating equipment can control the power factor over a wide range, typically ± 0.75 . An inverter type generator connected to the distribution facility must be capable of adjusting the power factor in the range of ± 0.9 . The IPP may operate outside that range only by prior agreement with the utility.

The utility will define voltage and reactive power requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC. The IPP and utility will identify and

agree on the exact transformer ratio to allow optimal voltage regulation on the system and the IPP will determine whether an on-load tap changer is needed.

In order to coordinate with its existing voltage control devices, the utility may require that the generator operate in a power factor control mode. This means operating within a constant power factor set point range. The voltage/power factor regulator must be capable of controlling the power factor of the generator. The utility shall determine the actual set point between these limits.

In power factor control mode, the voltage regulator must have a voltage override that causes it to reduce excitation if the voltage at the POI exceeds an upper limit to be specified by the utility. The normal upper limit is 105% of nominal; however, the voltage regulator shall have the provision to adjust this upper limit between 100% and 110% of nominal. The voltage regulator must also have provision for a time delay between sensing an excursion of the upper voltage and initiating control action. The power factor control equipment must have the capability to allow for the adjustment of this time delay from between 0 and 180 seconds. The utility will specify the required time delay for each project.

7.5. Voltage Unbalance

Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. Of particular concern is negative sequence voltage and the resulting effect, particularly on rotating generators and motors connected to the system.

To protect the utility and the IPP equipment, the 3-phase generation contribution at the POI should not cause a voltage unbalance greater than 1% or a current unbalance greater than 5%.

If the existing unbalance at the POI is shown to be already close to the maximum unbalance condition, the IPP contribution may cause the unbalance to exceed the specified amount. This will be considered on a case-by-case basis.

7.6. Voltage and Frequency Transients

The IPP is responsible for the cost of any necessary transient or dynamic stability studies, which must be performed in a manner approved by YEC.

7.7. Resonance and Self-Excitation of Induction Generators

The potential effects of resonance should be considered as part of the design of the generating facility.

The effects include:

- Ferro-resonance in the transformer,
- Sub-synchronous resonance due to the presence of capacitor banks, and
- Harmonic resonance with other customers when capacitors are being added as part of the installation.

When induction generators are used, the potential for self-excitation should be assessed and addressed as part of the system impact study and mitigated accordingly.

The IPP shall be responsible for the engineering analysis as part of the design process to evaluate the existence of, and to eliminate the harmful effects of resonance and the assessment of the self-excitation effects of induction generators. The engineering analysis of resonance and the assessment of the self-excitation effects of induction generators must be submitted to YEC for approval or further evaluation.

7.8. DC Current Injection

The IPP facility system shall not inject a dc current at the POI.

7.9. Fault Levels

The utility will provide the IPP with the anticipated fault levels or the data necessary for the IPP to calculate the distribution system fault contributions at the POI.

The IPP facility must not increase the fault levels on the utility distribution or transmission system above their design levels for maximum faults.

8. Physical Interconnection

8.1. Safety

The safety of the public, operating personnel and the environment is of primary concern in the design, construction, operation and maintenance of the interconnection facilities.

8.2. Point of Interconnection (POI)

The POI is the point at which the utility (YEC or AEY) distribution facilities or conductors are connected to the IPP's facilities or conductors, and where any transfer of electric power between the IPP and the utility takes place. The POI must be identified in the design and on the Single Line Diagram (SLD).

Depending on ownership, YEC or AEY will coordinate the design, construction, maintenance and operation of the facility on the distribution system side of the POI. The IPP is responsible to coordinate the design, construction, maintenance and operation of the facility on the generation side of the POI.

All voltage and frequency parameters specified in this section must be met at the POI unless otherwise stated.

The IPP is responsible for any incremental costs to the electric systems caused by the interconnection. The responsible utility will carry out the engineering, design and construction required for these installations and charges those costs back to the IPP. Ongoing O&M costs incurred on the distribution feeder side will also be recovered by the utility.

There may be cases where either the utility or the IPP may own equipment located on the other's side of the POI. For example, the utility may own and operate communications, supervisory, or metering equipment, which is located on the IPP side of the POI. The IPP must provide a site with the necessary space for utility to install current transformers, potential transformers, switching equipment, meters, and any other AC and DC auxiliaries, protection and controls, SCADA or communications equipment required to interconnect with the generating facility. The site is to be approved by the utility and a 120-volt AC power service is to be available for the use of portable tools.

8.3. Point of Disconnection

For transmission interconnections, the visible-break disconnect switch shall be located on the high voltage side of the interconnection transformer.

For distribution interconnections, the visible-break disconnect switch may be located on the high or low voltage side of the interconnection transformer.

The disconnect switch must be gang operated to simultaneously isolate all three phases.

If the IPP site interconnects multiple generators, one disconnect switch must be capable of isolating all of the generators simultaneously. There may be other means of meeting this requirement; however the approval of the utility must be obtained before using other means.

The IPP must follow the utility switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

8.3.1. High Side and Low Side Disconnect Switches

For transmission interconnections the disconnect switch on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

For distribution interconnections the disconnect switch, if on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the utility, and if on the low voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

8.3.2. Disconnect Switch Specification

The disconnect switch must be a manual, visible-break disconnect that provides safe isolation for the utility's personnel from the generators and all other possible customer sources of energy.

The disconnect switch must:

- Be adequately rated to break the connected generation/load;
- Be located within five meters (horizontal) of the POI, unless otherwise approved by the utility;
- Provide a direct, visible means to verify contact operation;
- Allow simultaneous disconnection of all ungrounded conductors of the circuit;
- Plainly indicate whether the switch is in the "open" or "closed" position;
- Be lockable in the "open" position;
- Be capable of being energized from both sides;
- Be readily accessible to the utility's operating personnel;
- Be externally operable without exposing the operator to contact with live parts;
- Be capable of being closed without risk to the operator while there is a fault on the system;
- Be labeled with utility's switch number;
- Meet all applicable CSA Part II standards and all applicable codes; and
- Undergo annual inspections and maintenance, with reports submitted to the utility for approval.

8.4. Interconnection Transformer

A generator step-up transformer boosts the voltage of the DG to match the voltage of the utility distribution feeder. The transformer winding configuration impacts how system faults are detected and what type of protection is required (see Section 9.10). The IPP must submit their transformer connection proposal to the utility for review and approval prior to placing an order for purchase.

8.5. Interconnection Grounding

The IPP facility must be grounded in accordance with the latest revisions of the CEC and AEUC. A ground grid of sufficient size to handle the maximum available ground fault current must be designed and installed in order to limit ground potential rise (GPR) step and touch potentials to safe levels as set forth in ANSI/IEEE Std. 80 IEEE Guide for Safety in AC Substation Grounding.

The ground grid will be designed for foreseeable future fault levels obtainable from the System Impact Study.

Grounding of the interconnection shall be designed to provide:

- Solid grounding of the distribution feeder neutral connection,
- Fault detection that isolates all sources of ground fault contribution,
- A circuit to block the transmission of harmonic currents and voltages, and
- Protection of the low voltage side from damage due to high side faults.

The preferred configuration, for an IPP owned interconnection transformer, is delta connection on the generator side of the transformer and a grounded-wye configuration on the utility's side of the transformer. If this configuration is not technically feasible, the configuration chosen must still address the above concerns. Grounding must conform to the AEUC [4].

Sample single line diagrams are shown in Appendix F.

8.6. *Phasing and Phasing Sequence*

Since phasing is not standardized across distribution facilities, the phase sequence must be coordinated between the IPP and utility's distribution system.

8.7. *Interrupting Device Ratings*

The design of the generation facility must consider the fault contributions from both the distribution system and the IPP generation facility, to ensure that all circuit fault interrupters are adequately sized. The utility will inform the IPP of the present and anticipated future fault contribution from the interconnected electric system.

9. Interconnection Protection

9.1. General

The purpose of the IPP facility protection is to reduce the risk of damage to IPP and utility equipment and maintain the reliability of supply.

The protection scheme shall be designed to detect the following conditions at the POI:

- Balanced and unbalanced system faults (i.e. line-ground, line-line and three phase faults)
- Frequency variations
- Voltage variations
- Reverse power flow
- Islanding conditions
- Out of synchronism

Depending upon location, the protection scheme may be required to detect additional conditions such as open phase, ferro-resonance, negative sequence voltage, or zero sequence currents.

The protection scheme must fully coordinate with any existing distribution system protective devices. The IPP must submit a complete protection design package, including all relay settings, tripping schemes and schematics, to the utility for review and approval prior to installation. Both existing and ultimate bus fault levels should be considered. A sample Protective Setting Commissioning Sheet with guideline limits is included in Appendix G.

The point of measurement for voltage and frequency shall be at the POI or as agreed upon with the utility.

The IPP must revise and re-submit the protection information for any proposed modification.

9.2. Device Ratings

Equipment shall be rated to carry and interrupt the fault levels that are, or will be, present at the IPP facility - this includes the ultimate fault currents specified by the utility. The IPP's equipment covers all station and distribution facilities, including but not limited to all protection equipment forming the entrance and distribution line protection: circuit breakers, current transformers, potential transformers, secondary cabling, dc system/battery charger, switchboard wiring and protective relays.

9.3. Minimum Protection Requirements

The following minimum protection requirements shall be provided for an interconnected IPP facility:

- Overcurrent
- Over-frequency
- Under-frequency
- Over-voltage
- Under-voltage

Additional protection requirements are dependent upon the transformer configuration and the distribution system characteristics.

9.4. Phase and Ground Fault Protection

The IPP must install utility grade protective devices to detect and promptly isolate the generation facility for faults occurring either in the DG facility itself or on the distribution system. Virtual devices (i.e., computer or programmable-logic controller systems) are acceptable provided they meet standard utility practice for system protection and they have been type tested and approved by an independent testing laboratory.

The protective devices in the IPP generation facility must fully coordinate with the protective relays on the distribution system unless otherwise agreed. The IPP must calculate the protective device settings and submit the relay characteristics and settings to YEC for review and approval.

The generation facility must be able to detect the following situations and isolate itself from the distribution system:

- A short circuit between any phase(s) and ground (if distribution system is a grounded system)
- A short circuit between phase(s)

9.5. Over-Frequency and Under-Frequency Protection

Each synchronous generator must be capable of continuous operation between 59.0 Hz and 61.0 Hz and of limited time operation for larger deviations from normal frequency, as shown in Table 1.

Over/under frequency relays are normally installed to protect the generators from extended off-nominal operation. It is expected that larger (> 1 MW) synchronous generators shall remain connected to the system during frequency excursions. To ensure that the generator is not tripped prematurely, YEC will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

9.6. Over-Voltage and Under-Voltage Protection

The IPP must operate its generation facility such that the voltage levels on the utility's system are not significantly altered by the connection of the generation facility. IPP facility paralleling shall not cause voltage fluctuations of more than $\pm 5\%$ at the POI.

The IPP must install necessary relays to trip the circuit breaker when the phase-to-ground voltage, measured on any one of the three phases, deviates outside predetermined limits. Under-voltage relays should be adjustable and should have a settable time delay to prevent unnecessary tripping of the generator on external faults. Over-voltage relays should be adjustable and may be instantaneous.

The interconnection facility must cause the generator to cease to energize the utility's system within the trip times indicated in Table 2. "Trip time" refers to the period of time between the start of the abnormal condition and the moment the interconnection device ceases to energize YEC's system.

To ensure that the generator is not tripped prematurely, the utility will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

Table 2: Response to Abnormal Voltages

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: $V < 50\%$	Trip time: Instantaneous

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: $50\% < V < 90\%$	Trip time: 120 cycles
RMS Voltage: $90\% < V < 105\%$	Normal Operation
RMS Voltage: $105\% < V < 120\%$	Trip time: 30 cycles
RMS Voltage: $V \geq 120\%$	Trip time: Instantaneous

The IPP may reconnect when the system is stabilized (i.e. voltage and frequency have returned to normal range for a time as identified by the utility).

9.7. Additional Protection

The utility may require additional protection on a case by case basis. Possible protection may include:

- **Unbalance or negative sequence protection:** The IPP generator is tripped on excessive current unbalance. This is important if fuse protection is used on the primary of the generator step-up transformer or for any other open phase condition
- **Broken delta protection (59G):** Using a grounded wye-broken delta potential transformer, this protection can facilitate detection of ground faults on ungrounded systems.
- **Rate of change of frequency:** Protection to detect a power island condition.
- **Reverse power protection:** Protection to detect a generator motoring condition.

9.8. Anti-Islanding Protection

Islanding is the condition where the generation facilities and a portion of the distribution system have become isolated from the rest of the system, and continue to operate in isolated mode. Unless agreed upon by the utility, generating facilities shall not be permitted to remain connected to an islanded system, i.e. islanding is not generally allowed. Generation facilities may continue to supply station service loads while disconnected from the interconnection system.

Anti-islanding protection is required to:

- Prevent power quality issues to customers connected to the island,
- Avoid out-of-phase reclosing between the utility and the DR facility, and
- Prevent safety hazards created as a result of back feeding isolated portions of the utility distribution system.

For rotating generators, the IPP must install a transfer tripping scheme using tele-protection signals from the system to separate the DG facility from the distribution system in the event of an islanding condition.

Transfer tripping requirements are also applicable to induction generators, unless the IPP can demonstrate that there is no potential for self-excitation. For inverter-based generation a detection scheme designed in accordance with the requirements of IEEE 1547 [2] may be acceptable.

The IPP is responsible for damage to the YIS caused as a result of failure to safely separate from the system during an islanding event or subsequently during reconnection to the system following the event.

9.9. Transformer Winding Configuration

The winding configuration of any three phase transformer will have an influence on the location of the protection measurement points and the level of protection required for the IPP interconnection. See Appendix F for examples for typical synchronous generator protection single line diagrams for different transformer configurations.

9.10. Conditions for Connecting to an Energized Distribution System

The IPP system must not energize the utility distribution system when the distribution system is de-energized or following the operation of any interconnection protection functions. The utility will inform the IPP facility when it is safe to reconnect to the distribution system.

Where transfer trip protection is installed, the transfer trip protection must ensure that the generator disconnects before a substation feeder breaker or intermediate automatic circuit reclose (ACR) operation. General requirements are:

- Generator lockout within 0.6 seconds of breaker or ACR opening; and
- Fail-safe lockout within 6 seconds of communication loss.

These conditions will be finalized via the operating agreement between the utility and the IPP.

9.11. Synchronization

Any DG facility able to generate voltage while disconnected from the YIS requires synchronization facilities before connection is permitted.

The IPP facility shall maintain in synchronism with the system while operating in parallel. The generating facility has the responsibility of maintaining synchronization with the system. The utility cannot synchronize to the generating facility. Any proposed synchronizing scheme must be submitted to the utility, prior to the installation.

For synchronous generators, an approved automatic synchronizing device must be provided in all cases where the plant is to be operated unattended. Automatic synchronizing shall be supervised by a synchronizing check relay. Synchronizing controls should satisfy the conditions in Table 3 for synchronous generators.

Table 3: Synchronization Criteria for Synchronous Generators

Aggregate Rating of Generators (kVA)	Frequency Difference (Hz)	Voltage Difference (%)	Phase Angle Difference (degrees)
0-500	0.3	10	20
>500 – 1500	0.2	5	15
>1500	0.1	3	10

Induction generators do not require synchronization since there is no generated voltage prior to connecting to the distribution system. The generator speed shall be brought to within 0.5% of its rated value. These units may be started as induction motors using power from the distribution system provided that these units do not cause unacceptable voltage flicker as specified in Section 7.2 on start - up or on connect/disconnect. The interconnection process of the induction generator shall not create a voltage drop pf greater than 5 percent.

Inverter-type or line-commutating voltage-following equipment does not require synchronization facilities. Operation of the interconnection (or disconnecting of the DR facility) shall not cause voltage drop greater than 5 percent and shall meet the flicker requirements

9.12. *Protection from Electromagnetic Interference (EMI)*

The influence of EMI must not result in a change in state or mis-operation of the interconnection facility.

9.13. *Surge Withstand Performance*

The interconnection facility must have the capability to withstand voltage and current surges in accordance with the environments described in IEEE/ANSI C62.41 or C37.90.1

9.14. *Batteries and Auxiliaries*

Batteries and auxiliaries shall have sufficient capacity to ensure the operation of all DC loads during loss of AC supply. Typically the batteries must be capable of supplying the substation DC load for 8 hours.

9.15. *Mitigation of Protection Scheme Failure*

Relays with self-diagnostic features, which provide information on the integrity of the protection scheme, should be used whenever possible.

The protection scheme must be designed by a qualified professional engineer, or a competent technical person working with the utility's engineers, to ensure that the self-diagnostic feature is integrated into the overall protection scheme for the safe and reliable operation of the system.

Depending on the scheme and its design, where relays with the self-diagnostic feature do not trip the appropriate breaker(s), sufficient redundant or backup protection must be provided for the system. The malfunctioning relay must also send a signal to notify operating personnel to investigate the malfunction.

9.16. *Instrument Transformers used for Protection*

Instrument transformers used for protection must comply with CAN/CSA-C60044-6 or IEEE C57.13 [8].

10. Remote Monitoring and Information Exchange

The IPP facility shall provide information in real-time to YEC SCC regarding:

- a. Connection or circuit breaker status,
- b. Real and reactive power output in kW and kVAR,
- c. Load Tap Changer (LTC) position of the interconnecting transformer,
- d. Communication and RTU failure alarm,
- e. Intelligent Electronic Device (IED)/Relay failed status, and
- f. Voltage at the POI.

The communication protocol and the equipment required will be specified by YEC.

The IPP facility shall log the operation of any protective device, including which protection elements operated, and the status of the DG facility including power output, voltage, and current waveforms.

YEC may have additional requirements on a case by case basis.

If it is determined that the IPP facility will have an impact on YEC's Transmission Network, the IPP will be required to provide a Remote Terminal Unit (RTU) or Data Link to a YEC RTU capable of exchanging Supervisory Control and Data Acquisition (SCADA) information with the YEC Control Centre. The protocol for data exchange via the RTU shall be compatible with that used for communications used by YEC. The communication protocol and the equipment required will be specified by YEC.

The IPP will be required to provide the following typical data needed by the (SCADA) system:

- a. Individual generator(s) MW and MVAR
- b. Individual generator(s) MWh and MVARh
- c. Generator(s) breaker status
- d. Individual generator on/off status, if no generator breaker exists
- e. Total station MW and MVAR
- f. Station service MW, MVAR, hourly MWh and MVARh
- g. Generator transformer(s) high voltage side breaker(s) and isolator(s) status
- h. Bus voltage at high voltage bus
- i. PSS status, if applicable
- j. AVR status, if applicable
- k. AVR voltage setpoint, if requested
- l. Total plant MW setpoint, if requested
- m. Generator step-up transformer tap setting, if requested

11. Construction

The construction and installation of the IPP's generating facility must meet all applicable statutes, regulations, by-laws and codes. The IPP is responsible for obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities. Copies of all permits, compliance reports and inspection documents must be provided to the utility prior to energizing the POI.

All single line diagrams provided to the utility must be drawn in accordance with IEEE standards and conventions, and must be stamped by a professional engineer assuming responsibility for the design.

12. Metering

12.1. General

Two meters, primary meter and backup meter, will be required at the IPP facility:

- The utility shall install, own, operate and maintain one meter (primary) necessary for measuring the energy and demand supplied to the YIS, unless otherwise specifically provided in a contract with the IPP. This meter shall remain the sole property of YEC. The meter will comply with Measurement Canada requirements and will be owned and maintained by YEC.
- The IPP shall install, own, operate and maintain the other meter (backup) which does not necessarily have to comply with Measurement Canada requirements.

Generators exporting power onto the distribution system shall be equipped with bi-directional meters with four-quadrant measurement capability. An appropriate number of channels are required for four-quadrant meters to separately record active and reactive power in both the export and the import directions.

The high voltage side of the interconnection transformer is designated as the Measured Billing Point for all energy imported and exported from the IPP facility.

The metering equipment will be:

- Suitable for use in the environmental conditions reasonably expected to occur at the installation site; and
- Appropriate for measuring the power system characteristics reasonably expected to exist at the installation under all power system conditions and events.

The IPP shall provide Measurement Canada Approved instrument transformers. Each meter shall be connected to its own individual core/winding. For the utility meter the IPP shall wire from the instrument transformers to the meter receptacle using CSA-approved tamper resistant conduit and accessories suitable for the utility meter or metering equipment.

For transmission interconnections the IPP will provide burden calculations for proposed instrument transformer secondary wiring, for approval by YEC. If necessary the wiring burden may have to be reduced, by increasing the CT secondary conductor size, to meet Revenue Meter requirements.

The IPP shall supply and install the meter base to meet the utility requirements. The utility will provide the specifications for the meter base during the design phase.

12.2. Meter Requirements

The primary meter supplied by the utility will:

- Be Measurement Canada Approved for revenue metering;
- Be dispensated, with accuracy class ratings for active and reactive energy management as per Table 4;
- Be verified and sealed in accordance with the Electricity and Gas Inspection Act;
- Be capable of maintaining the interval boundaries within 60 seconds of the hour and every quarter hour thereafter;

- Measure all quantities required to determine active energy and reactive energy transferred in the required directions at the Measured metering point;
- Provide a separate register to maintain the continuously cumulative readings of the active energy and reactive energy transferred in the required directions at the Measured metering Point;
- Retain readings and, if applicable, all clock functions for at least 14 days in the absence of line power;
- Be equipped with meter failure alarm and communication failure alarm;
- Communicate all metering and equipment status to the YEC system control centre via the IPP's communication equipment;
- Apply loss compensation (such as line losses) factors where applicable to the revenue meters; and
- The meter shall have an accuracy class of 0.2% or better.

The backup meter supplied by IPP will:

- The backup metering will be of the same accuracy class and capability as the primary metering and shall include all equipment to provide the necessary billing data.
- Be non- dispensated, with accuracy class ratings for active and reactive energy management as per Table 5;
- .

Table 4: Schedule of Accuracies for Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Points of Delivery	Points of Supply	Measurement Transformers Accuracy Class
10 and above	1.0%	1.0%	0.3%
10	1.0%	1.0%	0.3%

Table 5: Schedule of Accuracies for Non-Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Watt-hour Meter Accuracy Class	Var-hour Meter Accuracy Class
10 and above	0.2%	0.5%
10	0.5%	1.0%

12.3. Measurement Transformers

The applicable winding(s) of the current and potential instrument transformers supplied and installed by the IPP must:

- Be approved by Measurement Canada for revenue metering.
- Be burdened to a degree that does not compromise the accuracy required by this guideline.
- Have a minimum of two cores per instrument transformer. One core connection for the utility meter and the other core connection for the IPP meter.
- Be used solely for metering and not to be used for any other purposes.
- Have an accuracy class rating that equals or exceeds the values specified in Table 4.

12.4. Remote Communications Equipment

The remote communications equipment may or may not be an integral part of the meter or the recorder. However, it must incorporate protocol schemes that will prevent the corruption of data during interval data transmission. The protocol must be suitable for the communications equipment type and nature of the communications media and path.

12.5. Password Protection

Two or more levels of password protection will be required for each meter data collection agency. One level is for full access to set time functions and a second level is for read only access to interval data and event logs.

12.6. Safety Requirements

The facility installation must conform to:

- Measurement Canada Standard Drawings;

- AEUC [4];
- CSA Standard C22.2 General requirements - Canadian electrical code, part II [7] ; and
- ANSI/IEEE C57.13-2016 IEEE Guide for Grounding of Instrument Transformers [8].

13. Interconnection Tests

13.1. General Testing Requirements

The IPP must notify YEC (and AEY if the interconnection is via the AEY distribution system) in writing at least three weeks prior to the initial energization and start-up testing of the IPP generation facility. YEC may witness any testing of the equipment and protection schemes associated with the interconnection. Tests must align with the requirements specified in IEEE 1547 and CSA 22.3 No 9-08.

13.2. Type Testing

Type testing is considered an acceptable method of verification where suitable and applicable equipment standards exist, and must be performed once for each specific protection scheme. All interconnection equipment must include a type testing procedure as part of the documentation in order to determine the protection settings meet the requirements set forth within this technical guide. A type test may be performed on one device or a combination of devices. In a case of a combination of devices which comprise a system, the testing will demonstrate that the devices are able to operate as a system.

The type tests shall be performed on a representative unit or system, either in a factory, testing laboratory, or in the field. Results from a resource within a similar product family or design, including hardware or software, shall be acceptable as a representative within the same product family where ratings are within 50% to 200% of the tested resource.

The following type tests must be performed in accordance with IEEE 1547.1 [9]:

- Temperature stability
- Response to abnormal frequency
- Response to abnormal voltage
- Synchronization
- Interconnection integrity
- Unintentional islanding
- Open phase
- Reconnect following abnormal condition disconnect
- DC injection (for inverters without interconnection transformers)
- Harmonics

13.2.1. Temperature Stability

The temperature stability test verifies the interconnection equipment maintains measurement accuracy of parameters over its specified voltage range.

13.2.2. Response to Abnormal Frequency

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal frequency.

13.2.3. *Response to Abnormal Voltage*

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal voltage.

13.2.4. *Synchronization*

This test verifies the interconnected IPP facility will accurately and reliably synchronize with the utility as per IEEE 1547.1.

13.2.5. *Interconnection Integrity*

The interconnection integrity test verifies the IPP facility meets the surge withstand requirements as specified in Section 9.14 when tested in accordance with IEEE 1547.1.

13.2.6. *Unintentional Islanding*

Where YEC requires an anti-islanding protection function (other than transfer trip) or minimum import power levels, this test verifies that an IPP facility will cease to energize in accordance with IEEE 1547.1.

13.2.7. *Open Phase*

The open phase test verifies that the IPP facility will cease to energize the utility interconnection upon the loss of an individual phase on the distribution network when tested in accordance with IEEE 1547.1.

13.2.8. *Reconnect following Abnormal Condition Disconnect*

This test verifies the functionality of the IPP facility interconnection component or system reconnect timer, which shall delay the reconnection to the utility following a trip event prior to the distribution system stabilization, as specified in Section 9.11.

13.2.9. *DC Injection (for Inverters without interconnection transformers)*

This test verifies that an inverter-based IPP facility will comply with the DC current inject limit specified in Section 7.9 when tested in accordance with IEEE 1547.1.

13.2.10. *Harmonics*

The individual current harmonics and the total demand distortion (TDD) of the IPP facility shall be measured and recorded under normal operating conditions to ensure the values are within the limits specified in Section 7.1

13.3. *Production Tests*

Production tests shall be conducted on each IPP generating unit and interconnection equipment prior to delivery to verify they meet the applicable standards and verify the operability of every generating unit manufactured for customer use.

The tests assume the equipment has met the applicable interconnection and interoperability requirements of the applicable standards and may be conducted as a factory test or performed as part of an evaluation or commissioning test. Facilities with adjustable set points shall be tested at a single

series of test points specified by the manufacturer. The summary report must provide a list of normal and abnormal performance category capability, final function settings, and final operating mode settings.

The following production tests are specified within IEEE 1547.1:

1. Response to abnormal frequency
2. Response to abnormal voltage
3. Synchronization

14. Commissioning Tests and Verifications

14.1. General

Commissioning tests are tests and verification on the IPP facility equipment to confirm the system as delivered, designed, and installed meets the interconnection and interoperability requirements of this guide and the applicable standards. These tests include visual inspections, and may include operability and functional performance tests as required.

Prior to the energization of the IPP facility, or changes to the facility, verification testing must be performed and coordinated with the utility. After the equipment is installed and ready for operation, the testing must be performed by a qualified individual in accordance the manufacturer's published test procedures, or IPP developed procedures that have been approved by the utility. Qualified individuals include: licensed, professional engineers; factory-trained and certified technicians and licensed electricians experienced in testing protective equipment. The utility reserves the right to witness the verification test or to require written certification that the test was performed.

Verification testing must also be performed annually or when major system upgrades or modifications are carried out.

14.2. Interconnection Verifications and Inspections

The following commissioning tests and inspections shall take place:

- a. Final IPP facility protection settings shall be verified, recorded, and provided to the utility. A sample protective settings commissioning report is located in Appendix G.
- b. Visual inspection shall ensure the grounding coordination requirements in Section 8.5 have been met.
- c. Visual inspection shall ensure the presence of a disconnecting means in accordance with Section 8.3 has been met.
- d. The polarities, burdens, and ratios of field wired instrument transformers shall be verified as correct and in accordance with the design documentation.
- e. Field installed power and control wiring shall be verified to be in compliance with drawings and manufacturer requirements.
- f. For three-phase systems, the phase rotation of the distribution system and the IPP facility as installed shall be verified as compatible.
- g. All monitoring and information exchange provisions shall be verified as functional in accordance with Section 10.
- h. Calibration checks of each protective relay or the equivalent protection device shall be performed using injection of appropriate ac quantities, secondary injection, or set-point adjustment verification.
- i. Functionality of the protective relays or the equivalent protection device, circuit breakers, and telecommunications equipment shall be tested to verify the system operates as intended.
- j. Load tests of protective relays or the equivalent shall be conducted immediately after energization, where applicable.

- k. The ohmic value and connection of the transformer neutral impedance grounding device shall be verified as correct.
- l. Upon loss of DC power supply to the protective relays or the equivalent protection device, it shall be verified the protection scheme activates the interconnection circuit breaker.
- m. Upon loss of a communication signal, it shall be verified the fail-safe transfer trip occurs when required by the utility in accordance with Section 9.8.
- n. Inverter operation must be verified annually by operating the load break disconnect switch and verifying the generation facility shuts down and does not restart for five minutes after the disconnect switch has closed.
- o. Any system depending on a battery for trip power must be checked for proper voltage and logged monthly. Once every four years, the battery must be replaced or a discharge test performed.
- p. The IPP shall submit to the utility the station LAN design architecture for review during the conceptual design phase of the project.
- q. The IPP is responsible for all hardware design, RTU drawings, installation, testing and commissioning.
- r. The IPP shall prepare a preliminary but tested version of the RTU Configuration and a preliminary version of the Point Assignment, and send them to the YEC SCC, together with all RTU drawings, P&C drawings and DNP point lists of all LAN devices, at least ten weeks before the in service date.
- s. The IPP and YEC SCC shall jointly test all control, status and analog points and confirm visibility at the SCC.

14.3. Disconnection Means Operability

Prior to the operation of the IPP facility, the disconnecting means provided in accordance with Section 8.3 operates as intended.

14.4. Energization Cessation

Tests shall be conducted in accordance with IEEE 1547.1 to verify the functionality of the protection that ensures the IPP facility does not energize the utility under the following conditions described within this standard:

- 1. Abnormal frequency
- 2. Abnormal voltage
- 3. Protection scheme failure

Additional protection functions shall also be verified in accordance with IEEE 1547.1 as needed. The following protective functions must be verified if used at the IPP facility:

- 1. If available, the anti-islanding function must be checked by operating a load break disconnect switch and verifying that the IPP facility ceases to energize the output terminals and does not restart once the load break disconnect switch has reclosed.
- 2. If reverse power or minimum power function is used to meet the interconnection requirements, the functionality must be tested using secondary injection techniques. Alternatively, this

function can be tested by the means of a local trip test or by adjusting the IPP output and local loads to verify that the applicable non-export criterion are met.

14.5. Re-Verification

Re-verification of the interconnection and interoperability requirements may be required when any of the following occurs:

- Functional software or firmware changes have been made to the IPP facility equipment;
- Any hardware component of the facility has been modified in the field, been replaced or repaired with parts that are not substitutive components compliant with the applicable standards;
- Protection settings have been changed after factory testing; or
- Protection functions have been adjusted after the initial commissioning / verification process.

15. Maintenance

The IPP has full responsibility for the maintenance of its equipment, up to the Point-of-Interconnection, consistent with the Interconnection Agreement and this Guide. The IPP shall maintain the facilities in accordance with Rule 2-300 of the Canadian Electrical Code to ensure safe parallel operation with the YEC or AEY system. Failure to do so may result in disconnection of the IPP generation facility.

The IPP must present to the utility the planned maintenance procedures and a maintenance schedule for the interconnection protection equipment, and keep records of such maintenance.

The utility reserves the right to periodically inspect the interconnection protection system to verify that it meets the requirements outlined in this document.

Maintenance procedures up to the POI will be performed in accordance with good utility practice and the utility's policies and procedures.

16. Marking and Tagging

The disconnect switch must be clearly marked as the “IPP Disconnect Switch” and tagged with an identification number approved by the utility. The IPP must follow the utility’s switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

The IPP switchgear equipment must include the manufacturer name and the manufacturer’s serial number.

17. Modification of Installation

The IPP shall obtain written approval from the utility before commencing any modification to the generation facility. If the change requires the installation or modification of equipment, the IPP shall provide documentation that the new equipment meets the requirements of Type and Production tests.

If the changes require modifications to the protection and controls information the IPP must obtain approval from the utility for the proposed modifications. Whenever changes are made to interconnection hardware or software that can affect the functions listed below, the potentially affected functions must be retested:

- Over-voltage and under-voltage
- Over-frequency and under-frequency
- Non-islanding function (if applicable)
- Reverse or minimum power function (if applicable)
- Inability to energize dead line
- Time delay restart after utility outage
- Fault detection, if used
- Synchronizing controls (if applicable)

To ensure that commissioning tests are performed correctly, the utility may require the ability to witness the tests and receive written certification of the results.

18. Technical Data Requirements

The following outlines the minimum data required at various stages for planning, design and commissioning the IPP's project. This data is required by YEC (and AEY if connected to AEY distribution system) to ensure suitable steps are taken to interconnect the IPP facility to the YEC system. Expanded data requirements for the proposal and design stages are located in Appendix A and Appendix B. The IPP Policy (in development as of June 2018) shall apply.

18.1. Proposal Stage

During the proposal stage the IPP Facility conceptual design must be submitted before any further detailed studies is approved by the utility. The list of information to be provided for this approval may be the result of preliminary discussions with the utility. Based on the information provided by the IPP, the utility will provide their proposition, their commitment and their own requirements concerning the connection of the IPP facility.

The following list of drawings and data required for the proposal stage of the project includes, but is not limited to:

- A Single Line Diagram (SLD) showing the following :
 - o The proposed protection relays, circuit and fuses with fuse type and rating,
 - o The connections of all substation equipment with voltage levels and equipment ratings
 - o The location of the revenue metering equipment.
- Description of protection scheme
- Generating station site plan showing the layout and location (coordinates) of the generating plant and the location of lockable, "visible" disconnect device
- Based on the size of the project the utility may require more additional generator, exciter and speed governor data for a preliminary interconnection study.

18.2. Approval (Design) Stage

Once the project has been approved by the utility the IPP will proceed to submit the facility detailed design.

The following list of drawings and data required for approval stage of the project includes, but is not limited to:

- Single Line Diagram
- Description of protection scheme
- Control schematic
- Protection and control philosophy
- Major equipment nameplate schedules and statements
- Fuse and protective relay coordination study and settings
- Current transformer characteristic curve
- Measurement Canada approval numbers for instrument transformers

- Generating station site plan showing the layout and land location coordinates and legal description. The drawing should also show the proposed terminal pole or service manhole with the routing of aerial line or underground cables from utility to the generating station.
- SCADA Diagram
- Obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities.
- Proposed In-Service Date

18.3. Verified Stage

When the project is nearing completion, the IPP must submit the proposed testing, commissioning and start-up procedures to be performed before the facility is connected to the YIS.

The following list of drawings and data required for commissioning and verification stages of the project includes, but is not limited to:

- Commissioning report
- Copies of all permits, compliance reports and inspection documents
- Final Single Line Diagram
- Final protection scheme
- Final control schematic
- Protection and control philosophy
- Major equipment nameplate schedules, statements, test reports and data sheets
- Final fuse and protective relay coordination settings
- Current transformer characteristic curve
- Final generating station site plan showing the layout and land location coordinates and legal description

19. References

The technical guide was created using the following primary reference standards. Additional applicable standards are located within Appendix D.

- [1] CSA Standard C22.3 No. 9-08 (R2015) – Interconnection of Distributed Resources and Electricity Supply Systems, CSA Group, 2015.
- [2] IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018.
- [3] Energy Strategy For Yukon Independent Power Production Policy, Yukon Energy, Mines and Resources, 2018
- [4] Alberta Electrical Utility Code, latest Edition
- [5] IEEE Std 519-2014 - IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems
- [6] IEC 61000-4-15: Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications
- [7] CSA Standard CAN/CSA-C22.2 NO. 0-10 (R2015) - General requirements - Canadian electrical code, part II
- [8] IEEE Std C57.13-2016 (Revision of IEEE Std C57.13-2008) - IEEE Standard Requirements for Instrument Transformers
- [9] IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

Appendix A

Information Required from IPP (Proposal Stage)

Appendix A

Information Required from IPP (Proposal Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
<i>Commercial Contact</i>	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
<i>Engineering Contact</i>	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
<i>Operating Contact</i>	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Prime Mover Type	
Number of Generators	
Generator Nominal kW Rating	
Generator Nominal kVA Rating	
Generator Nominal kV Rating	
Power Factor, at Rated Output	
Annual Energy Production (MW-hr)	
Production Capacity Range(MW)	

Transformer Data

Transformer Rating (ONAN/ONAF, kVA)	
Transformer Voltage Rating (kV)	
Load Tap Changer steps	
Winding Connection	
Positive Sequence Impedance (% ONAN base)	
Zero Sequence Impedance (% ONAN base)	

Prime Mover Data

Prime Mover Type	

Drawings

General Site Map, Including IPP Generation Facility	
Preliminary Substation Layout Drawings	
Preliminary Protection & Metering Single Line	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

Appendix B

Information Required from IPP (Design Stage)

Appendix B

Information Required from IPP (Design Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
<i>Commercial Contact</i>	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
<i>Engineering Contact</i>	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
<i>Operating Contact</i>	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Number of Generators	
Manufacturer	
Model	
Nominal kW Rating	
Nominal KVA Rating	
Nominal kV Rating	
Power Factor at Rated Output	
Maximum Authorized Real Power (MARP)	
Leading and Lagging Reactive Power at MARP	
Generator Grounding (Resistive, Reactive, None)	
<i>Individual Generator Parameters - impedances in per unit, on nominal machine base</i>	
Speed (RPM)	
Inertia Constant, H (generator)	
Direct Axis Synchronous Reactance , X_D	
Direct Axis Transient Reactance , X'_D	
Direct Axis Subtransient Reactance , X''_D	
Quadrature Axis Synchronous Reactance , X_Q	
Quadrature Axis Transient Reactance , X'_Q	
Quadrature Axis Subtransient Reactance , X''_Q	
Open Circuit Direct Axis Transient Time Constant, T'_{DO}	

Short Circuit Direct Axis Transient Time Constant, T'_D	
Open Circuit Direct Axis Subtransient Time Constant, T''_{DO}	
Short Circuit Direct Axis Subtransient Time Constant, T''_D	
Quadrature Axis Transient Time Constant, T'_{QO}	
Quadrature Axis Subtransient Time Constant, T''_{QO}	
Saturation Factor (1.0 per unit flux)	
Saturation Factor (1.2 per unit flux)	
Armature Resistance, R_A	
Stator Leakage Reactance, X_L	
Negative Sequence Resistance, R_2	
Negative Sequence Reactance, X_2	
Zero Sequence Resistance, R_0	
Zero Sequence Reactance, X_0	
Armature Short Circuit Time Constant, T_A	
Governor Droop (%)	
Short-time unbalanced current factor (K)	
Continuous negative sequence current level (%).	
<i>Induction Generator Data (if applicable) - impedances in per unit, on nominal machine base</i>	
Rating (kVA)	
Rated Power Factor	
Speed (RPM)	
Inertia Constant, H (generator)	
Stator Resistance, R_s	
Stator Reactance, X_s	
Rotor Resistance, R_R	
Rotor Reactance, X_R	
Armature Magnetizing Reactance, X_M	
Other Attachments	
Reactive capability curve (D-curve) comes with	
a. Under excitation limiter	
b. Over excitation limiter	

Exciter nameplate	
VEE curves	
Single line diagram	

Power Factor Regulator

Reactive Power Limit - Lagging (out)	
Reactive Power Limit - Leading (in)	
Accuracy Tolerance (%)	

Voltage Regulator

Voltage Regulator Range (V)	
Accuracy Tolerance (%)	

Transformer Data

Transformer kVA Ratings	
Transformer kV Ratings	
Cooling Type (ONAN, ONAF)	
Winding Connection	
Transformer Grounding (Resistive, Reactive, None)	
Grounding Impedance in Ohms (if applicable)	
Positive Sequence Impedance (% ONAN base)	
Zero Sequence Impedance (% ONAN base)	
<i>Tap Details (if applicable)</i>	
On-Load Tap Range	
On-Load Tap Size	
Off-Load Tap Range	
Off-Load Tap Size	
Other Attachments	
Factory Test Reports (minimum requirements)	
No Load Loss & Exciting Current Measurements	
Measurement of Load Loss & Impedance Voltage and Zero Sequence Impedance Measurements	

Prime Mover Data

Prime Mover Type	
Prime Mover Rating	
Inertia Constant (prime mover)	
Manufacturer	
Model	
Other Attachments	
Elevation versus Output Curve	
Ambient Temperature versus Output Curve	

Drawings Required

General Site Map, Including IPP Generation Facility	
Complete and Accurate Protection Diagrams	

Single Line Diagrams	
AC / DC Schematics	
Wiring Diagrams	
Major Equipment Nameplates (Transformer, Generator, etc.)	

Protection Requirements

Proposed Protection Schemes Provided	
Verified Interconnection Functionality Provided	
Inertia Constant (prime mover) Provided	
Maintenance Plans for Protection Devices Provided	
Maintenance Plans for Interrupting Devices Provided	

Compliance with Electrical Inspector

Permit or Equivalent Compliance Provided (Yes / No)	

Metering Requirements

Element (2 Element, 3 Element)	
Metering Service Provider	
Metering Data Manager	
Asset ID Number	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

D.1 Modelling Information

In some cases, a generator (or the aggregate generation on a line) is large enough that adjacent customers or the dynamic stability of utility's distribution system could be affected. The IPP is responsible for the cost of any required transient or dynamic stability studies, and the studies must be done in a manner suitable to, and approved by, the utility.

IPPs are responsible for ensuring the data they submit provides an adequate mathematical representation of the facility's electric behavior. If the data is not available prior to purchasing equipment, it must be submitted as soon as it becomes available.

The studies must accurately determine:

1. The impact of the IPP's facility on adjacent customers of the utility.
2. The dynamic stability, in aggregate, of the utility system.

Data may be supplied by the manufacturer or acquired directly by testing. It must include generator characteristics (i.e., speed, reactance, resistance, excitation system etc.) and governor characteristics (i.e., lead time/lag time constants, valve or gate opening data etc.).

The information requirements vary for induction generators and inverter generators, and for hydro or thermal systems.

Appendix C

Information Provided by the Utility

Appendix C

Information Provided by the Utility

After receiving the application for interconnection, the utility will provide the following information to the IPP, if required:

- a. Single Line Diagram or maps of the system up to the POI.
- b. Minimum and maximum 60 Hz source impedances (positive-sequence, negative- sequence and zero-sequence) at the POI.
- c. Maximum and minimum normal and emergency system operating voltage ranges at the POI.
- d. Harmonic impedance envelope at the POI if available.
- e. Planning, operating and reliability criteria, standards and policies.
- f. The results of a planning study (e.g. the System Impact Study) documenting the availability of the requested amount of system capacity and any other specific technical issues to be addressed.
- g. Cost estimates and time schedule to build the upstream facilities.
- h. Characteristics and settings of protection on the distribution system.
- i. Costs to implement any required changes to the distribution system that are identified by the System Impact Study.

Some or all of this information will be required by the IPP to properly design the interconnection protection. The utility will identify when the costs of producing this information are to be assigned to the IPP.

Appendix D

Applicable Codes and Standards

Appendix D

Applicable Codes and Standards

D.1 Primary Standards

CSA Standard C22.3 No. 9-08 (R2015) Interconnection of Distributed Resources and Electricity Supply Systems

IEEE Standard 1547-2018 Standard for Interconnecting Distributed Resources with Electric Power Systems with Associated Electric Power Systems Interfaces

Power Quality Standards

ANSI C84.1-2016 American National Standards for Electric Power Systems and Equipment Ratings (60 Hertz). Establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems from 100 V through 1200kV.

IEEE Std. 493-2007 IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book).

IEEE Std. 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

IEEE Std. 1100-2005 IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).

IEEE Std. 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality.

IEEE Std. 1250-2011 IEEE Guide for Identifying and Improving Voltage Quality in Power Systems.

In addition to the power quality standards, the following standards are applicable to the interconnection of generation facilities to YEC's system:

IEEE Std. 100 - 2000 IEEE Standard Dictionary of Electrical and Electronics Terms.

IEEE Std 315-1975 (Reaffirmed 1993) ANSI Y32.3-1975 (R1989) CSA Z99-1975 Graphic Symbols for Electrical and Electronics Diagrams (including Reference Designation Letters).

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems.

C37.1-2007 ANSI/IEEE Standard Definitions, Specifications and Analysis of Systems Used for Supervisory Control, Data Acquisition and Automatic Control.

C37.2-2008 IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.

C37.18-1979 ANSI/IEEE Standard Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery.

C37.20.1-2015 ANSI/IEEE Standard for Metal-Enclosed Low-Voltage (1000 Vac and below, 3200 Vdc and below) Power Circuit Breakers Switchgear.

C37.20.3-2001 ANSI/IEEE Standard for Metal-Enclosed Interrupter Switchgear.

C37.24-2017 ANSI/IEEE Standard for Evaluating the Effect of Solar Radiation on Outdoor Metal-Enclosed Switchgear.

C37.27-2015 ANSI/IEEE Standard Application Guide for Low-Voltage AC (635 V and below) Power Circuit Breakers with Separately Mounted Current-Limiting Fuses.

C37.29-1981 ANSI/IEEE Standard for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C37.50-1989 ANSI Standard Test Procedures for Low-Voltage AC Circuit Breakers Use In Enclosures.

C37.51-1989 ANSI Standard Conformance Test Procedure for Metal Enclosed Low- Voltage AC Power Circuit-Breaker Switchgear Assemblies.

C.52-1974 ANSI Standard Test Procedures for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C57.12-2015 IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers.

C57.12.13-1982 Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations.

C57.13.1-2006 IEEE Guide for Field Testing of Relaying Current Transformers.

C57.13.2-2005 IEEE Standard Conformance Test Procedures for Instrument Transformers.

C37.58-2003 (R2010) ANSI Standard Conformance Test Procedures for Indoor AC Medium- Voltage Switches for Use in Metal-Enclosed Switchgear.

C37.90-2005 ANSI/IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

C37.90.1-2002 ANSI/IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems.

C37.90.2-2004 ANSI/IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

C37.95-2014 IEEE Guide for Protective Relaying of Utility Consumer Interconnections.

C37.98-2013 ANSI/IEEE Standard for Seismic Testing of Relays.

IEC 1000-3-3 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Less than 16A.

IEC1000-3-5 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Greater than 16A.

UL1008 Transfer Switch Equipment.

UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

IEEE P1547, DRAFT Standard for Distributed Resources Interconnected with Electric Power Systems.
Canadian Electrical Code, CSA no. C22-1, latest version.C22.2 No. 31- M89 (R2000) Switchgear Assemblies.

Can/CSA - C22.2 No. 1071 95Commercial and Industrial Power Supplies.

Can/CSA - C22.2 No. 1010.1-92 Safety Requirements For Electrical Equipment for Measurement, Control and Laboratory Use.

Can/CSA - C22.2 No. 144-M91 (R2015) Ground Fault Circuit Interrupters.

C22.2 No. 193-M1983 (R2014) High-Voltage Full-Load Interrupter Switches.

C22.2 No. 201-M1984 (R2014) Metal Enclosed High-Voltage Busways.

C22.2 No. 229-M1988 (R2014) Switching and Metering Centres.

CSA Standard CAN3 C235 83 Preferred Voltage Levels for AC Systems 0 to 50,000V.

Alberta Electrical and Communication Utility Code (formerly the Alberta Electrical and Communication Utility System Regulation 44/1976 or future amendments).

Measurement System Standard / Transmission Administrator Metering Standard GC301 Practices for Management and Transfer of Metered Data.

C37.04-1999 IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.06-2000 American National Standard for Switchgear--AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis--Preferred Ratings and Related Required Capabilities.

C37.09-1999 IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.010- IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.011-2011 IEEE Application Guide for Transient Recovery Voltage for AC High- Voltage Circuit Breakers.

C37.012-2014 IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V.

C37.013-1997 IEEE Standard for AC High-Voltage Generator Circuit Breaker Rated on a Symmetrical Current Basis.

C37.015-2017 IEEE Application Guide for Shunt Reactor Switching.

C37.081-1981 (R1988) Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.081a-1997 Supplement to IEEE Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.11-2014 IEEE Standard Requirements for Electrical Control for Electrical Control for AC High-Voltage (>1000 V) Circuit Breakers.

C37.13-2008 IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures.

C37.14-2015 IEEE Standard for DC (3200 V and below) Power Circuit Breakers Used in Enclosures.

C37.16-2009 IEEE Standard for Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage AC (635 V and below) and DC (3200 V and below) Power Circuit Breakers.

C37.20.2-2015 IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear.

C37.23-2015 IEEE Standard for Metal-Enclosed Bus.

C37.30-1997 IEEE Standard Requirements for High-Voltage Switches.

C37.32-2002 American National Standard for Switchgear--High-Voltage Air Switches, Bus Supports, and Switch Accessories--Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide.

C37.34-1994 IEEE Standard Test Code for High-Voltage Air Switches.

C37.35-1995 IEEE Guide for the Application, Installation, Operation, and Maintenance of High-Voltage Air Disconnecting and Load Interrupter Switches.

C37.36b-1990 IEEE Guide to Current Interruption with Horn-Gap Air Switches.

C37.37-1996 IEEE Standard for Loading Guide for AC High-Voltage Air Switches (in Excess of 1000 V).

C37.38-1989 IEEE Standard for Gas-Insulated, Metal-Enclosed Disconnecting, Interrupter, and Grounding Switches.

C37.42-2016 IEEE Standard Specifications for High-Voltage (>1000 V) fuses and Accessories.

C37.44-1981 (R1992) American National Standard Specifications for Distribution Oil Cutouts and Fuse Links.

C37.54-1996 American National Standard for Switchgear--Indoor Alternating-Current High-Voltage Circuit Breakers Applied as Removable Elements in Metal-Enclosed Switchgear Assemblies--Conformance Test Procedures.

C37.55-2002 American National Standard for Switchgear--Metal-Clad Switchgear Assemblies--Conformance Test Procedures.

C37.57-2003 (R2010) American National for Switchgear--Metal-Enclosed Interrupter Switchgear Assemblies-Conformance Testing.

C37.66-2005 American National Standard for Requirements for Oil- Filled Capacitor Switches for AC Systems (1 kV to 38 kV).

C37.81-2017 IEEE Guide for Seismic Qualification of Class 1E Metal- Enclosed Power Switchgear Assemblies.

C37.85-1989 (R1998) American National Standard for Switchgear--Alternating- Current High-Voltage Power Vacuum Interrupters-Safety Requirements for X- Radiation Limits.

ANSI/IEEE C37.90.1-2102 Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus.

120-1989 (Reaff-1997) IEEE Master Test Guide for Electrical Measurements in Power Circuits.

1291-1993 IEEE Guide for Partial Discharge Measurement in Power Switchgear.

IEEE Std C62.23-2017 Application Guide for Surge Protection of Electric Generating Plants.

ANSI /IEEE C62.41-1991 Recommended Practices on Surge Voltages in Low- Voltage AC Power Circuits.

C57.13-2016 IEEE Standard Requirements for Instrument Transformers.

C57.13.3-2014 IEEE Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases.

C57.98-2011 IEEE Guide for Transformer Impulse Tests.

C57.19.100-2012 IEEE Guide for Application of Power Apparatus Bushings.

C57.110-2008 IEEE Recommended Practice for Establishing Liquid-Filled and Dry-Type Power and Distribution Transformer Capability When Supplying Non-sinusoidal Load Currents.

C62.92.4-2014 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV – Distribution.

IEEE Std. 242-2001 Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems.

ANSI C12.20-2010 Electricity Meters 0.2 And 0.5 Accuracy Classes.

ANSI C62.1-1981 Surge Arresters for AC Power Circuits.

ANSI C62.11-2012 Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV).

NEMA CC 1-2009 Electric Power Connectors for Substations.

NEMA LA 1-2009 Surge Arresters.

NEMA MG 1-2016 Motors and Generators

Appendix E

Sample Operating Agreement

Appendix E

Sample Operating Agreement

1. Purpose

This agreement outlines the steps to take to ensure a reliable and safe interconnection between the IPP and YEC and/or AEY through a variety of circumstances.

2. Definitions

Operating Authority: The organizational unit assigned responsibility for operating a portion of the electrical system. For each utility the YEC System Control Center (SCC) operator is the operating authority. For the IPP, the <IPP Contact> is the operating authority.

Operational Boundary/Interface Point or Point of Interconnection: The location on the electrical system at which responsibilities between Operating Authorities meet. The breaker <Breaker ID> is the interface point between the IPP and the utility.

3. Operational Information

Circuit Breaker Identification

List circuit breakers providing interconnection between IPP and the utility.

3.1 Interlocks

List identified circuit breaker interlocks with sequence information

3.2 Contact Information

SCC – Phone (867) XXX-XXXX or (867) XXX-XXXX (recorded lines)

Contact Name	Title	Phone Number
<Utility Contact>	Leadhand SCC	(867) XXX-XXXX
<Utility Contact>	Operation Coordinator	(867) XXX-XXXX
<Utility Contact>	Manager Operations	(867) XXX-XXXX
<Utility Contact>	Director of Operations	(867) XXX-XXXX
<IPP Contact>	<Contact Position>	(867) XXX-XXXX

3.3 Normal Operation

Under normal operating conditions the IPP facility will be connected to the utility grid. The breakers status under normal operating conditions is as follows.

Breaker	Status
<Breaker ID>	Open/Closed
<Breaker ID>	Open/Closed
<Breaker ID>	Open/Closed
<Breaker ID>	Open/Closed

4. Operating Procedures

4.1. Line L### (<Utility Line> to <IPP Facility>) Isolation

L### isolation requires the minimum notification defined in section 4.3, with the exception of emergency repairs. The utility will provide a Condition Guarantee on breaker <Breaker ID>. The Condition Guarantee is used in communications between external parties. It is a formal method of communication that switching has been completed. It ensures the status of the breaker/device will not change until the work is complete, the lock out tag out is surrendered and all workers are clear.

4.2. Voltage Support

Based on the power quality conditions defined in Schedule <X> of the Power Purchase Agreement (PPA) and system security requirements, SCC may request voltage support. Voltage support can be accomplished by placing IPP generation on line, or other means such as capacitor banks or transformer tap changing. If such support is part of the operating agreement then:

- When the IPP has generation online, the generators regulate the generator bus voltage between 100 and 105% of nominal and the utility shall have control of this set-point. Generators reactive output will be adjusted by the utility in real time, to regulate the system voltage, by pulsing the AVR voltage set-points. The IPP sets the acceptable range within which the utility can adjust voltage.
- The utility must have full SCADA visibility of the IPP substation and control of critical elements.

4.3. SCC Remote Monitoring and Control

- SCC will have visual indication of the IPP breakers, generator status, capacitor status and electrical measurement information for the IPP facility.
- The utility control will be limited to:
 - Approving requests from the IPP to connect and disconnect from the utility system
 - Approving requests from the IPP for changes in generation output
 - Requesting the IPP to disconnect from the utility system for operational and safety reasons
- All IPP requests must be communicated and approved by the utility
- The utility shall have control (open and close) of incoming line breaker <Breaker ID> at the IPP facility.

5. Operational Notification

5.1. Daily Operating Communications

Under normal operating conditions IPP will be supplying <XXX> kW to the YIS. Generation changes of more than <XXX> kW must be communicated and approved by the utility.

5.2. The transition from winter to summer and conversely summer to winter generation levels must be established with SCC with a minimum of 30 days' notice.

5.3. IPP Facility Planned Maintenance and Scheduling

The IPP shall operate under the utility approved maintenance procedures established.

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours. Changes in the availability and capacity of the onsite generation need to be communicated to SCC. The utility and the IPP shall share annual shutdown/maintenance plans in February of each year.

5.4. Transmission and Distribution Maintenance and Scheduling

The utility performs annual line maintenance on its transmission and distribution lines, during which grid power to the IPP facility may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.

The utility will provide a minimum of 30 days' notice of the start date and expected duration of work that will curtail or otherwise interrupt the supply of grid power to the IPP facility.

6. Loss of Supply Procedures

6.1. Loss of Supply - Short Term

In the event of a disturbance that results in the loss of grid power to the IPP facility, SCC will make one attempt to re-energize the line to the IPP facility. If successful the following steps apply to resume the IPP facility operation with grid power.

- a) SCC will confirm the status of the breakers located at the IPP's POI.
- b) SCC will request closed breaker <Breaker ID>.
- c) Once complete and with confirmation from SCC the IPP facility may proceed with the restarting of their operation. The IPP will communicate to SCC on generation greater than <XXX> kW. The request to increase generation may be communicated verbally or via SCADA.

6.2. Loss of Supply - Long Term

In the event of a disturbance that results in the loss of grid power to the IPP facility and SCC is unsuccessful in re-energizing the line the following steps will apply.

- a) SCC will confirm the status of the breakers.
- b) At the direction of SCC the IPP personnel will start and stage their generation on line supplying power to the IPP facility.
- c) Once the line to the IPP facility has been re-energized, SCC will request the IPP synchronize and close its POI breaker.
- d) The IPP facility is now connected to YEC system. Once complete and with confirmation from SCC the IPP facility may proceed with resuming generation. The IPP will communicate to SCC on generation increases greater than <XXX> kW. The request to load up may be communicated verbally or via SCADA.

7. Revision and Approval

- 7.1. This Agreement comes into effect once it is signed by the IPP and the utility.
- 7.2. This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.
- 7.3. The Parties shall provide 90 days' notice in writing of the intention to modify the Agreement.
- 7.4. The Agreement may be revised upon mutual agreement of both Parties. The agreement will be formally reviewed every two (2) years.

Approved by: _____
Yukon Energy Corporation

Approval Date: _____

Approved by: _____
ATCO Electrical Yukon

Approval Date: _____

Approved by: _____
IPP

Approval Date: _____

Appendix F

Typical Interconnection Single Line Diagrams

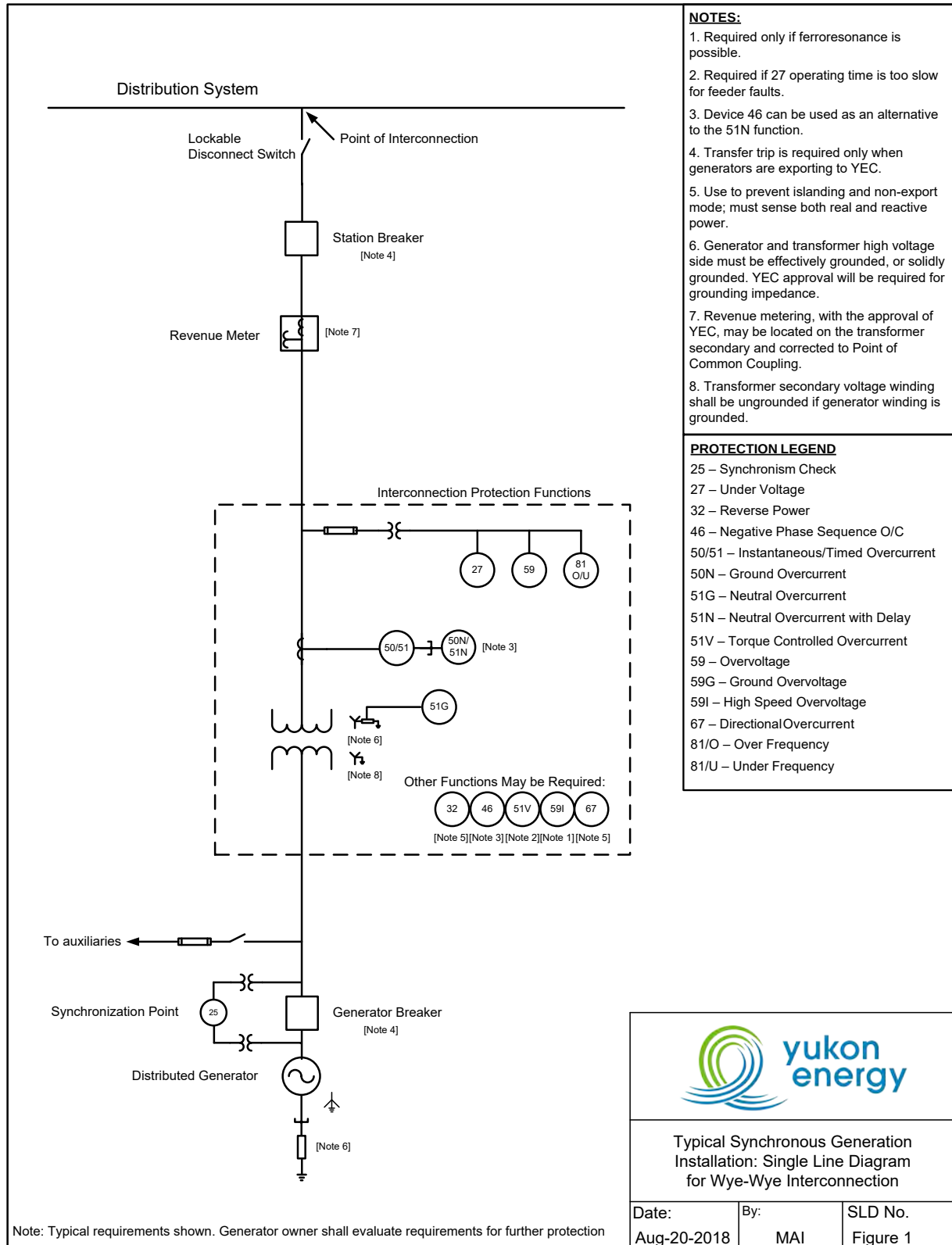


Figure F- 1: Single Line Diagram for Wye-Wye Interconnection

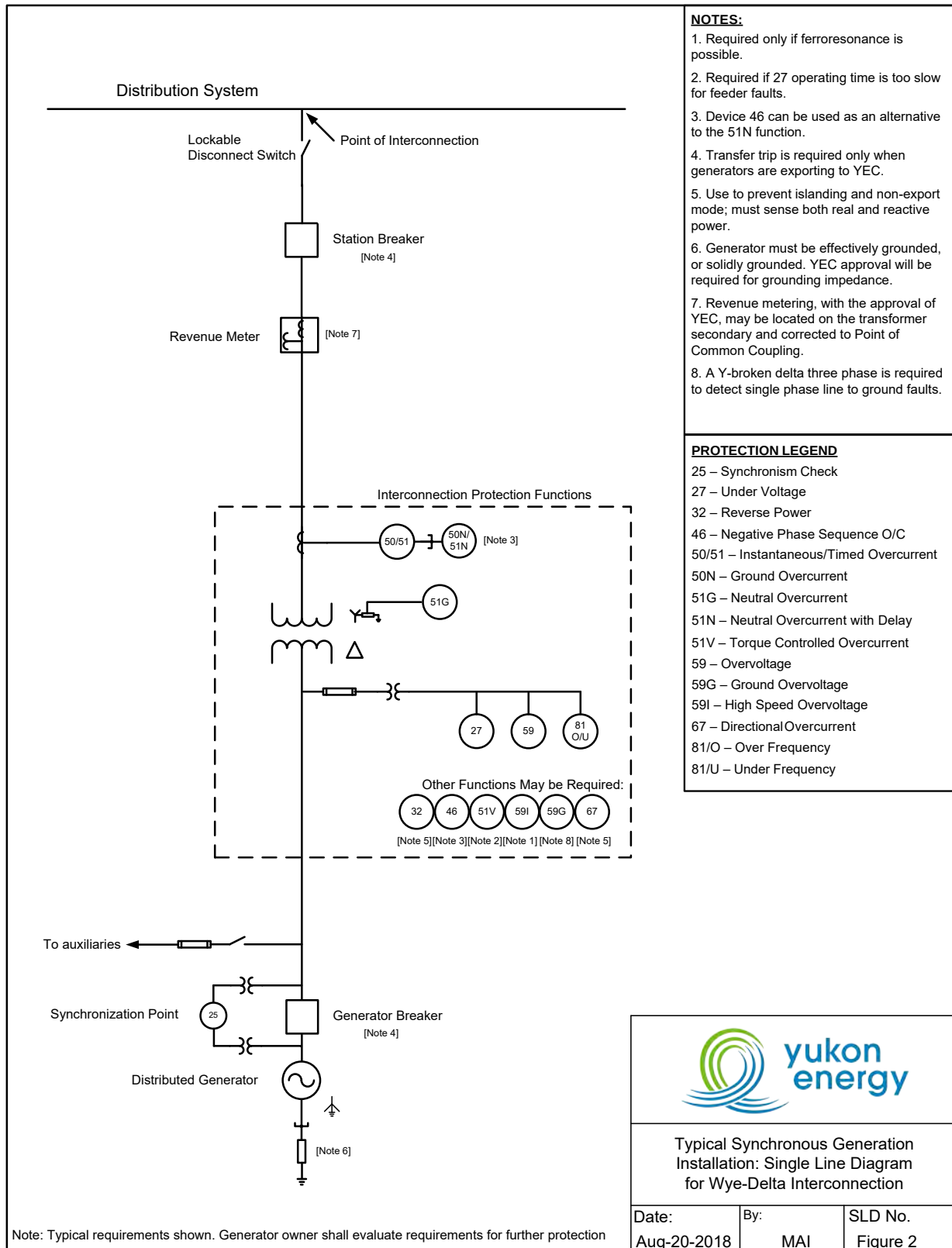


Figure F- 2: Single Line Diagram for Wye-Delta Interconnection

Appendix G

Protective Settings Commissioning Document

Appendix G

Protective Settings Commissioning Document

Over Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	106% - 120% 1% Increments						30 Cycles					
Fast Trip	144% - 120% 1% Increments						100 ms					

Under Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	50% - 90% 1% Increments						120 Cycles					
Fast Trip	Less than 50% 1% Increments						100 ms					

Non-Islanding Function Test

Loss of Utility Voltage	100 ms	
Generator Restart Delay	5 min Minimum	
Dead Bus Test	Fail to Start Successful (Yes/ No)	

Over Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	60.5 Hz - 61.5 Hz 1% Increments						3 minutes					
Fast Trip	61.5 Hz - 61.7 Hz 1% Increments						30 seconds					

Under Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	59.5 Hz - 58.5 Hz 1% Increments						3 minutes					
Second Trip	58.5 Hz - 57.9 Hz 1% Increments						30 seconds					
Third Trip	57.9 Hz - 57.4 Hz 1% Increments						7.5 seconds					
Fourth Trip	57.4 Hz - 56.9 Hz 1% Increments						45 cycles					
Fifth Trip	56.9 Hz - 56.5 Hz 1% Increments						7.2 cycles					
Fast Trip	Less than 56.4 Hz 1% Increments						100 ms					

Reverse AC Current Protection Function

	CURRENT TO TRIP						DURATION TO TRIP					
	DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED			DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip												

Synchronization Limits for Synchronous Generators

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Frequency Difference	+ 0.2 Hz		
Voltage Difference	5%		
Phase Difference	10° (degrees)		

Phase and Ground Fault Protection

	MAXIMUM CURRENT OR VOLTS TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Phase Current							200 ms					
Neutral Current							200 ms					

Transfer Trip Protection

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Generator Lockout	0.6 seconds		
Fail Safe Lockout	6 seconds		

Test Certification and Historical Data

Type Of Test	Original Commissioning Test		Protection System Re-Test	

Date of Test

Utility Representative Title

IPP Owner Representative

Signature

IPP Owner Representative Title

Date

Signature

SCHEDULE "H"
JOINT OPERATING PROCEDURE

(Please see attached)

	JOINT OPERATING PROCEDURE	DEPARTMENT:		INQUIRIES TO:		TOPIC:	
		Operations		Guy Morgan, Director, Operations		IPP / AEY / YEC Operating Agreement	
		ISSUED DATE:		REVIEW DATE:		APPROVED BY:	
		May x, 2020		May 3, 2021		_____ President & CEO	

1.0 Purpose

- 1.1 This agreement defines the operating arrangement between the **536774 Yukon Inc. dba Solvest Inc.** (IPP), ATCO Electric Yukon (AEY) and Yukon Energy Corporation (YEC). This agreement defines the roles and responsibilities for each entity to allow the IPP to operate reliably and safely on the Yukon Power System (YPS).

2.0 General Information

2.1 Breaker Identification

Breaker	Description
Switch #1	Connection between the IPP and AEY distribution

2.2 Definitions

- a) **Operating Authority** The organizational unit assigned responsibility for operating a portion of the electrical system.
- For YEC the SCC operator is the operating authority and is responsible for the system generation and security.
 - For AEY the Supervisor of Operations is the operating authority and is responsible for the distribution system and security.
 - For the IPP the Technical Coordinator is the operating authority of their generation and associated equipment.
- b) **Operator in Charge (OIC)** The worker designated by the Operating Authority to coordinate control of the power system or portion thereof, in accordance with the requirements of established operating standards and procedures.
- c) **Power Systems Work Standards (PSWS)** The standards that workers will utilize for establishing conditions on the power system that will, when combined with appropriate work standards, procedures and methods, provide a safe work area.

- d) **Condition Guarantee (COG)** Formal assurance to another Operating Authority or Operator in Charge (OIC) that identified devices are in the position requested and will not change status until the device status request is formally released by the requestor.
- e) **Point of Interconnection (POI)** The location on the electrical system at which responsibilities between Operating Authorities meet. The IPP Switch – S6359 is the interface point between IPP and AEY.

2.3 YEC Contact Information

- SCC (System Control Center) – phone 393-5355 or 393-5324 (recorded lines)
- Mike Hannah (Leadhand SCC) 393-5399, cell 334-6759
- Myles O’Brien (Operation Coordinator) 393-5352
- Ed Peake (Manager Operations) 393-5383, cell 334-6586
- Guy Morgan (Director of Operations) 393-5366, cell 334-6904
- YEC Group Email – SCC@yec.yk.ca

AEY Contact Information

- Tony Badry - Supervisor of Operations 633-7057, cell 335-4002
- Matt Johnson – Operator in Charge 633-7009, cell 334-3145

Control Room Desk

- Dispatch 633-7022
- Brock Kelsch 334-7239

IPP Contact Information

- Brock Kelsch bkelsch@solvest.ca

2.4 Normal Operation

Under normal operating conditions the IPP will generate into the Yukon Power Grid. The breakers status under normal operating conditions are as follows.

Breaker	Status
Switch #1	Closed

3.0 Operating Procedures

3.1 Planned 5L645 (IPP to AEY) Isolation

5L645 isolation requires the minimum notification defined in section 5.1, except for emergency repairs. AEY will provide a condition guarantee on S6359 - Condition Guarantee will be issued in accordance with **Section 800** of the PSWS – **Operating Interface Points**.

3.2 Planned 5L645 (AEY to IPP) Isolation

5L645 isolation requires the minimum notification defined in section 5.2, except for emergency repairs. IPP will provide a condition guarantee on S6359 - Condition Guarantee will be issued in accordance with **Section 800** of the PSWS – **Operating Interface Points**

3.3 SCC Remote Monitoring

SCC will have visual indication of IPP breakers, PV status, and electrical measurement information from the IPP site.

4.0 Power Quality Requirements

4.1 IPP will operate IPP Facilities in accordance with the power quality requirements of YEC as set out in the System Interconnection Guidelines (Schedule D).

5.0 Operational Notification

5.1 IPP Planned Maintenance and Scheduling

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC / ATCO OIC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours.

Planned changes in the availability and capacity of the onsite generation needs to be communicated to SCC / ATCO OIC at least 30 days in advance of such changes.

Unplanned availability should be conveyed as soon as possible.

The Parties will share annual shutdown/maintenance plans in February of each year and plan to minimize the impact on IPP generation potential by scheduling outages during off-peak generation months where practicable.

5.2 AEY Distribution Maintenance and Scheduling:

- a) AEY performs annual line maintenance on the distribution lines, during which connection to the IPP may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.
- b) AEY will provide a minimum of 5 working days' notice of the start date and expected duration of work that will curtail or otherwise interrupt the supply of IPP generation to the YPS.

6.0 Loss of Supply Procedures

6.1 Loss of Supply - Short Term

In the event of a disturbance that results in the loss of the grid connection to the IPP the IPP generation will remain off-line until approval from AEY and YEC.

The following steps apply to resume IPP operation with Grid Electricity.

- a) SCC will confirm the status of the breaker located at IPP site. If SCADA communications are down the switch status will be physically verified and reported to AEY before 5L645 will be energized.

Breaker	Expected Status
Switch #1	Open

- b) The following switching sequence will be followed to re-energize L### and synchronize IPP back to grid supply.

Step	Switch Sequence	Operation
1	Confirm 5L645 Energized	IPP/AEY
2	Switch #1 Closed	IPP
3	IPP starts system	IPP/YEC

- c) Once complete and with confirmation from SCC, IPP may proceed with the restarting of their operation. IPP Group will communicate to SCC once their system is back on line.

6.2 Loss of Supply - Long Term

In the event of a disturbance that results in the loss of the grid connection to the IPP the IPP generation will remain offline until approval from AEY and YEC.

- a) SCC will confirm the status of the breaker located at IPP site. If SCADA communications are down the switch status will be physically verified and reported to AEY before 5L645 will be energized.

Breaker	Expected Status
Switch #1	Open

- b) The following switching sequence will be followed to re-energize 5L645 and synchronize IPP back to grid supply.

Step	Switch Sequence	Operation
1	Confirm 5L645 Energized	IPP/AEY
2	Switch #1 Closed	IPP
3	IPP starts system	IPP/YEC

7.0 Revision and Approval

- 7.1 This Agreement comes into effect once it is signed by IPP, AEY and YEC.
- 7.2 This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.
- 7.3 The Parties will provide 90 days' notice in writing of the intention to modify this Agreement.
- 7.4 The Agreement may be revised at any time if operational needs require and are mutually agreed to by all Parties. This agreement will be formally reviewed every two (2) years.

8.0 Appendices

- 8.1 ATCO Electric's Power System Work Standards

Approved by: _____
Guy Morgan
Yukon Energy Corporation

Approval Date: _____, 2020

Approved by: _____
Tony Badry
ATCO Electric Yukon

Approval Date: _____, 2020

Approved by: _____
Ben Power
536774 Yukon Inc. dba Solvest Inc.

Approval Date: _____, 2020

SCHEDULE "I"

DELIVERY TIME ADJUSTMENT TABLE

Seasonal Adjustment is subject to change.

Month	Seasonal Adjustment
January	100%
February	100%
March	100%
April	100%
May	100%
June	100%
July	100%
August	100%
September	100%
October	100%
November	100%
December	100%

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application 3-8**

4
5 **TAB 3 - REVENUE REQUIREMENT**

6 1 Labour expense is generally a function of the following factors:

7 2 **Labour Rates** – This includes factors such as base pay, benefit cost, annual increments

8 3 (performance increments, cost of living adjustments), etc.

9
10 **QUESTION:**

11
12 a) Please explain how performance increments are assessed and valued.

13
14 **ANSWER:**

15
16 **(a)**

17
18 Yukon Energy Corporation employs two employee groups: In Scope and Out of Scope.

19
20 Performance increments are applied to these groups according to their applicable
21 agreement. In Scope employees' pay, performance and job evaluation are governed by
22 the Collective Agreement between Yukon Energy Corporation and P.S.A.C. Y024 as well
23 as Human Resource Policy HR-003 (excerpted below). Management and Professional
24 employees' pay and performance are administered according to the agreement between
25 Yukon Energy Corporation and Management and Professional Employees.

26
27 It is noted that both of these agreements expired December 31, 2019. The Union and
28 Yukon Energy Corporation agreement will be going to Interest Arbitration on April 6 – 7,
29 2021 to facilitate ratification of the contract.

30
31 In Scope (Unionized employees)

32
33 Yukon Energy relies on an established procedure within its Collective Agreement to guide
34 both the percentage and timing of performance increments. Article 14: Wage
35 Administration is the established agreement for these increments.

36
37 At time of hire, management offers a salary within the wage band of the position
38 evaluation, based on the individual's experience and time in the trade or industry they are

1 entering at Yukon Energy. Then, the Corporation stewards to the expectations of Article
2 14.02 (below) whereby an employee is advanced 3% in the wage range subject to
3 satisfactory performance. Then, 3% increments are earned every six months, based on
4 satisfactory performance, until the employee reaches the top of the pay band.

5
6 Once at the top of the pay band, an employee receives any yearly negotiated economic
7 increase.

8
9 Additional increments can occur when:

- 10
11 • An employee is promoted (see Article 14:04)
12
13 • A position is re-evaluated (see Article 22)
14

15 Yukon Energy reviews the performance of all employees on a yearly basis.

16
17 Out of Scope (Management and Professional Employees)
18

19 YEC relies on an established procedure within its Management and Professionals
20 Agreement to guide both the percentage and timing of performance increments. This is
21 found in Section 9 and Section 10 of the Management and Professionals Agreement
22 (excerpted below). Management and Professional Employees' performance is evaluated
23 based on the level of performance in relation to performance objectives and job
24 responsibilities.

25
26 **Job Evaluation**
27

28 In Scope
29

30 Yukon Energy relies on the procedures are set out in the collective agreement with respect
31 to Job Evaluation. This procedure is stated in Article 22: Job Evaluation (below).

32
33 Out of Scope
34

35 Yukon Energy relies on Korn Ferry, an independent contractor, for the evaluation of all
36 jobs. Yukon Energy participates in the salary benchmarking service provided by Korn
37 Ferry whereby our jobs are compared against the market and our peers (utilities), adjusted

1 for our geographical location.

2 The Korn Ferry Hay Job Evaluation Method relies on these principles in determining a job
3 profile:

- 4
 - 5 • Know-How
 - 6 o Practical / technical knowledge
 - 7 o Planning, organizing and integrating (managerial) knowledge
 - 8 o Communicating and influencing skills
 - 9 o Scope of knowledge required and the depth of understanding needed for
 - 10 the job
 - 11 • Problem Solving
 - 12 o Thinking environment – freedom to think
 - 13 o Thinking challenge – complexity of the problems encountered and the
 - 14 extent to which original thinking must be employed to reach decision
 - 15 • Accountability
 - 16 o Freedom to act
 - 17 o Nature of impact
 - 18 o Magnitude of impact
 - 19 • Working conditions
 - 20 o Physical demands
 - 21 o Mental pressures

22
23 **Article 14**
24 **Wage Administration**

25
26 **14.01** New employees entering the service of the Corporation will be appropriately placed
27 within the wage range at the discretion of the Corporation.

28
29 **14.02** On the first of the month following successful completion of the probationary
30 period, an employee will be advanced 3% in the wage range subject to satisfactory
31 performance. Thereafter, 3% increments reflecting progression through the range
32 will be semi-annually based on the employee's anniversary date, subject to
33 satisfactory performance.

34
35 **14.03** The Employer acknowledges the value and importance of timely performance
36 evaluations, and further agrees to maintain a performance evaluation policy
37 through the Joint Consultation Committee.

1 **14.04** When a promotion occurs, the employee concerned shall be placed in that position
2 within the new range which reflects an increase in wage which shall be no less
3 than 3% in the range from which they were promoted up to the maximum of the
4 new pay range.

5
6 **14.05** If an employee is accepted under a posting for a lower level job or is transferred at
7 their own request, they will be appropriately placed within the wage range for such
8 job at the discretion of the Corporation.

9
10 **14.06** An employee temporarily assigned, in writing, for a period of more than two (2)
11 continuous working days to a position of higher classification shall, from the first
12 day, be paid;

- 13 a) The minimum wage for the temporary position where that minimum is more
14 than four percent (4%) above their present wage; or
15 b) Receive four percent (4%) where their wage or temporary assignment does
16 not exceed the maximum of the range for the temporary position; or
17 c) Where the application of (b) above would provide for a temporary
18 assignment which would exceed the maximum of the range for the
19 temporary position, the employee would receive the maximum rate in the
20 range for the temporary position.

21
22 **Article 22**
23 **Job Evaluation**

24
25 **22.01** a) The parties agree the Job Evaluation Plan developed jointly and signed-off shall
26 form part of the Collective Agreement.

27 b) The Employer agrees that any changes to the Plan factor or factor weightings
28 shall be subject to agreement between the parties.

29
30 **22.02** a) When new positions are established, an independent consultant trained in job
31 evaluation and mutually agreed upon by both parties, shall evaluate the jobs
32 and shall notify the parties thereof within fifteen working (15) days of the
33 evaluation being completed.

34 b) When significant differences, or changes, in job content effect the existing job
35 evaluation to the extent that the Union or an employee request that the job be
36 re-evaluated, the following procedure shall be followed:

- 37 (i) An employee or the Union shall initiate a written request to HR for a job

1 to be re-evaluated within fifteen working (15) days of significant changes
2 in job content arising.

3 (ii) An employee initiating a written request for re-evaluation must file a copy
4 of the request with the Union.

5 (iii) An independent consultant trained in job evaluation and mutually agreed
6 upon by both parties shall complete the re-evaluation as soon as possible
7 but not later than ninety (90) working days upon receipt of the written
8 request for review.

9 (iv) HR shall notify the Union and the employee of the results of the re-
10 evaluation and provide a copy of the evaluation within fifteen (15) working
11 days of the completion of any evaluation.

12 (v) If the re-evaluation results in a higher pay level, it shall be retroactive to
13 the date that HR received the written request for review.

14 (vi) If the re-evaluation results in a lower pay level, the employee shall retain
15 their current rate of pay and any adjustments negotiated by the parties
16 for as long as they remain in that position.

17
18 c) When significant differences or changes, in job content affect the existing job
19 evaluation to the extent that the Employer requests that the job be re-
20 evaluated, the following procedure shall be followed:

21
22 (i) The Employer shall initiate a request for re-evaluation within fifteen (15)
23 working days of the significant changes in job content arising.

24 (ii) The Employer shall notify the Union of the initiation of the review.

25 (iii) An independent consultant trained in job evaluation and mutually agreed
26 upon by both parties shall complete the re-evaluation as soon as possible
27 but not later than ninety (90) working days upon receipt of the written
28 request for review.

29 (iv) HR shall notify the Union and the employee of the results and provide a
30 copy of the evaluation within fifteen (15) working days of the completion of
31 any evaluation.

32 (v) If the re-evaluation results in a higher pay level, it shall be retroactive to the
33 date the Employer initiated the request for re-evaluation.

34 (vi) If the re-evaluation results in a lower pay level, the employee shall retain
35 their current rate of pay and any adjustments negotiated by the parties for
36 as long as they remain in that position.

- 1 d) Where an employee and the Union are not satisfied with the independent
2 consultant's evaluation decision, and the Union agrees to represent the
3 employee, the Union may refer the independent consultant's decision to
4 arbitration by letter within thirty (30) working days of receipt of the re-evaluation
5 decision. The letter shall state the matter sought to be arbitrated and the names
6 of proposed arbitrators. The Corporation shall, within thirty (30) days of the
7 receipt of such letter notify the first party in writing of the acceptance of one of
8 the arbitrators named or propose others. The Corporation also has the right to
9 appeal under this process.
10
11 e) An independent Arbitrator trained in job evaluation, mutually agreed upon by
12 both parties, will hear appeals of the independent consultant's decisions within
13 one hundred and twenty (120) working days or at the earliest mutually agreed
14 upon date by both parties. A decision of the Arbitrator is final and binding. Each
15 party shall pay one half (1/2) of the fees and expenses of the Arbitrator.
16
17 f) The Union may withdraw the appeal from the arbitration process at any time.
18
19 g) Unless the parties agree otherwise, the time lines in this article are mandatory.
20

21 **Human Resource Policy HR-003**

22
23 1.1 Performance management is intended to be an ongoing process of communication
24 between the immediate supervisor and the employee, focused on helping the employee
25 achieve their best workplace results. An effective performance management system
26 accomplished the following goals:

- 27 • Provides direction and clarifies performance expectations;
- 28 • Provides feedback and coaching to employees concerning job performance,
29 identifying both what is being done well and what needs improvement;
- 30 • Identifies training and professional development needs;
- 31 • Documents performance; and
- 32 • Substantiates performance increments.

34 **2.0 Policy Guidelines**

35 2.1 Yukon Energy supports a performance management system that should include
36 the four components listed below:

- 37 1) Performance Planning:

1 Clear performance expectations should be communicated to the employee.
2 These expectations should provide the employee with a clear understanding
3 of what is required for the employee to successfully fulfill job responsibilities.
4 These expectations should also help the employee align individual goals and
5 objectives with those of the department and Yukon Energy.

6 2) Coaching:

7 Coaching employees for improved performance is an integral part of
8 performance management. Coaching should occur on a regular basis and may
9 take various forms, from observation and informal direction to formal meetings
10 and written documentation.

11 3) Multiple Sources of Feedback:

12 To increase the potential for improvement, in some cases, it may be helpful to
13 receive feedback from customers, peers, and direct reports.

14 4) Performance Review:

15 This is the culminating communication of the performance cycle, focusing on
16 areas of achievement, areas for improvement and goals for the future.

17 **3.0 Performance Review Guidelines**

18 3.1 All probationary employees should have their performance reviewed with them
19 prior to the final thirty (30) days of the probation period.

20 3.2 All employees should have their performance reviewed with them semi-annually,
21 based on their anniversary date if there is room for an increment in the salary range
22 for their position. All other employees should have their performance reviewed at
23 least once a year.

24 3.3 Performance Reviews should have the following characteristics:

- 25 • Results Oriented – Goals should specify an end result to be accomplished. For
26 goals to be evaluated there must be a clear understanding of what is to be
27 achieved.
- 28 • Measurable – Goals should contain appropriate measurement criteria such as
29 quantity, quality, time or cost. These criteria are necessary for the monitoring
30 of progress toward or accomplishment of the goals. Where the goals cannot
31 be measured in quantitative terms, there should be a statement specifying
32 what constitutes acceptable performance.
- 33 • Clear and Concise – Goals should be written so as to eliminate
34 misunderstanding between the employee and the supervisor. The commitment
35 to action is basic to the formulation of goals and therefore, the expectation
36 should be prefaced with an action verb whenever possible.
- 37 • Timeframe – Goals should specify a target date for completion.

- Realistic – Goals should take into account both the abilities and competence of the employee, and the goals of the department.

3.4 Performance review forms should be discussed and signed by both the supervisor and employee. An employee's signature indicates only that the form has been reviewed and discussed with them. It does not imply agreement with the review.

3.5 Employees submitting concerns relating to their performance review will receive a written response from their supervisor in a timely manner. A copy of the employee's concerns and the supervisor's response will be placed on the employee's personnel file.

3.6 The original performance review must be forwarded to Human Resources and placed on employees' personnel file. Employees should receive a copy of the form, and other copies should be retained at the supervisory level.

3.7 Human Resources will process authorized performance increments in accordance with the terms set out in the collective agreement.

Management and Professional's Agreement

Section 9

Performance Reviews

9.1 The Corporation recognizes that performance reviews provide feedback to employees on their job performance and assists them in becoming more effective in their jobs.

9.2 Performance reviews will be conducted at least once each year. Completed performance reviews will be retained in the employee's personnel file.

Section 10

Performance Increments

10.1 Following the successful completion of the probationary period and on January 1st of each year thereafter, the employee may be awarded a performance increment based on the supervisor's assessment of their performance during the previous year, up to the maximum of their salary range. When an employee has received a performance increment following their probation, and that increment occurs at any time other than January 1st, the performance increment on the following January 1st will be prorated to reflect the number of months since the last increase.

10.2 Performance increments for Management & Professional employees will be based on the level of performance in relation to performance objectives and job responsibilities. The annual increment will not exceed 9% of current salary and will be guided by the following table. The maximum of the salary range applicable to the position shall not be exceeded.

Rating	% Performance Reward
Unacceptable	0%
Needs Development	0%
Meets Expectations	1% - 3%
Occasionally Exceeds Expectations	4% - 6%
Consistently Exceeds Expectations	7% - 9%

10.3 An employee who is rated as “Unacceptable” or “Needs development” is expected to improve their performance. The employee’s supervisor along with the employee will create an appropriate development plan to assist the employee with improving their performance. Unacceptable performance will not be permitted to continue and appropriate steps up to and including termination will be taken.

10.4 The completed performance review and recommended salary adjustment must be approved by the President & CEO prior to communication to the employee by the immediate supervisor.

10.5 Performance increments will be rolled into base salary.

Collective Agreement between Yukon Energy and P.S.A.C. Y024 - Article 14: Wage Administration.

- Collective Agreement between Yukon Energy and P.S.A.C. Y024 - Article 14: Job Evaluation
- Management and Professionals’ Agreement Section 9
- Management and Professionals’ Agreement Section 10
- Yukon Energy Human Resource Policy HR-03

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application 3-8**

4
5 9 **Head Count** – This relates to the number of full time equivalent positions. The Yukon Energy
6 10 employee complement is shown in Table 3.4.
7 11 Of the total labour expense increase from 2018 approved, approximately \$0.882 million relates to
8 12 additional headcount and \$0.740 million relates to labour rate increases. The balance is made up of other
9 13 factors impacting labour costs such as changes in overtime, vacancies and capital allocation.

10
11 **QUESTION:**

12
13 a) Since labour head count costs are proposed to increase more than \$1.6 million,
14 explain.

15
16 **ANSWER:**

17
18 **(a)**

19
20 Breakdowns of expenditures for all labour forecast costs are provided in the Application,
21 starting at section 3.3.2 (page 3-13) through 3.3.8 (page 3-20). Reasons for the increase
22 are provided in the Application at Section 3.3.1.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application 3-8

Table 3.4:

**Employee Complement History 2018 Approved Actual 2018 Actual 2019 Forecast 2020
Proposed 2021**

<i>President</i>	<i>4.16</i>	<i>5.14</i>	<i>4.82</i>	<i>4.01</i>	<i>4.16</i>
<i>First Nation Relations - - -</i>				<i>1.00</i>	
<i>Communications, Cust. Acctg. 1.00</i>		<i>1.00</i>	<i>1.00</i>	<i>3.10</i>	<i>4.60</i>
<i>Human Resources & Info. Mgmt. 5.25</i>		<i>5.27</i>	<i>5.34</i>	<i>5.32</i>	<i>5.25</i>
<i>Resource Planning and Environment 5.00</i>		<i>5.00</i>	<i>5.75</i>	<i>5.51</i>	<i>7.05</i>
<i>Finance, Cust. Acctg. & Purchasing 16.79</i>		<i>16.89</i>	<i>17.24</i>	<i>13.54</i>	<i>14.79</i>
<i>Operations</i>	<i>44.50</i>	<i>46.58</i>	<i>47.12</i>	<i>48.75</i>	<i>49.25</i>
<i>Engineering Services</i>	<i>15.00</i>	<i>13.03</i>	<i>15.16</i>	<i>5.63</i>	<i>15.50</i>
<i>Health, Safety & Environment</i>	<i>2.00</i>	<i>2.00</i>	<i>2.00</i>	<i>2.00</i>	<i>2.00</i>
<i>Total</i>	<i>93.70</i>	<i>94.91</i>	<i>98.44</i>	<i>97.86</i>	<i>103.60</i>

Note:

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

2. Customer Accounting was transferred from Finance to Communications in 2020.

Table 3.4 shows that the total position count is forecast to increase by 9.90 positions since 2018 approved to 2021 test year.

QUESTION:

- Why are Approved 2018 compliments different from Actual 2018?
- Explain what positions make up the four employee complement with job description in the presidents office.
- Explain why the vice president cannot do the job of FN relations?
- What exactly is the VP job description?
- Explain the 3.6 positions added in communications, customer Acctg.
- Explain the 2 positions added in resource planning and environment.

1 g) Explain why environment is in two locations in this above chart.

2
3 h) Provide a chart giving each of the YEC positions (management and non-
4 management) pay grade/scale and performance bonus.

5
6 i) Explain how each of these compare with other utilities in Canada.
7

8 **ANSWER:**

9
10 **(a)**

11
12 Approved 2018 compliments are what was approved by the YUB for rate-setting purposes.
13 Actual 2018 compliments represent what YEC required operationally.
14

15 **(b)**

16
17 The employee complement of the President category consists of the following:
18

- 19 • **President and Chief Executive Officer** - The President and CEO has the
20 authority, and is accountable to the Board of Directors, for the Yukon Energy
21 Corporation's achievement of corporate goals and objectives within the
22 established authority delegated by the Board. This includes providing leadership
23 and direction regarding the following daily organizational activities of the Yukon
24 Energy Corporation to ensure the achievement of reasonable organizational
25 results, benefits and cost effectiveness within the established corporate goals,
26 objectives and priorities; and to ensure the avoidance of unacceptable conditions
27 and actions.
28

- 29 • **Vice-President, Business and Corporate Development** - In conjunction with the
30 President, liaises with key stakeholders to promote positive relationships and
31 strong partnerships for the benefit of the corporation. Ensures that the Human
32 Resources, IT, Health and Safety and Communications departments corporate
33 objectives are met and in line with Yukon Energy's mission and vision. Contributes
34 in the development of corporate goals, business plans, and strategies to ensure
35 the effective planning and delivery of programs and services to achieve the
36 Corporate mandate Contributes to the vision, mission and values of Yukon Energy
37 through responsible, accountable and effective work performance. As a key

1 member of the senior management team is accountable for overall organizational
2 performance.

- 3
- 4 • **Corporate Secretary** - This position provides executive support to Yukon Energy's
5 Board of Directors (Board), the President and CEO (President) and the Sr.
6 Management Team, and is responsible preparation of board meetings including
7 the drafting of agendas, resolutions, and board material as well as the drafting of
8 board and committee minutes in accordance with Yukon Energy's policies,
9 guidelines and procedures. The position is responsible for all Access to Information
10 and Protection of Privacy (ATIPP) matters on behalf of the corporation.
11
 - 12 • **Records Management Analyst** - Performs a range of records management
13 activities for the Corporation. Maintains and controls the use, protection and
14 disposition of corporate records and information and provides library support
15 services in accordance with Yukon Energy's policies, guidelines and procedures.
16

17 **(c) and (d)**

18

19 The questions are unclear; each department at YEC has a vice president as the
20 department head. The question is not clear which vice president is being referred to.
21

22 **(e)**

23

24 The explanation for the 3.6 positions added in Communications, Customer
25 Billing/Accounting is provided in the Application under the heading Communications,
26 Customer Billing/Accounting on page 3-10.
27

28 **(f)**

29

30 The explanation for the 2.0 positions added in Resource Planning and Environment is
31 provided in the Application under the heading Resource Planning and Environment
32 starting on page 3-10.

(g)

For the years provided in Table 3.4, there are no Environmental employees allocated to the Health & Safety department. Therefore, it would be more appropriate for the department labelled "Health, Safety & Environment" to be changed to "Health & Safety".

(h)

Please see the Table below.

Table 1: Union Pay Grants (2019)

2019 Rates	Steps	1	2	3	4	5	6	
Level	Hourly Min	0.5 Year	1 Year	1.5 Year	2 Year	2.5 Year	3 Year	
Level 1	14.47	14.91	15.35	15.82	16.30	16.78	17.29	* Annual Economic Increase 2.0%.
Level 2	16.74	17.25	17.77	18.30	18.84	19.41	19.99	* Performance Increase 3% up to max of pay grade.
Level 3	19.24	19.83	20.42	21.02	21.65	22.31	22.98	
Level 4	22.30	22.97	23.65	24.36	25.09	25.84	26.61	
Level 5	25.77	26.53	27.34	28.15	29.00	29.87	30.76	
Level 6	29.74	30.64	31.57	32.52	33.49	34.49	35.52	
Level 7	34.53	35.57	36.63	37.73	38.86	40.02	41.23	
Level 8	40.11	41.31	42.55	43.82	45.15	46.49	47.89	
Level 9	44.05	45.38	46.75	48.14	49.59	51.08	52.61	
Level 10	46.34	47.73	49.16	50.64	52.17	53.73	55.35	
Level 11	48.98	50.45	51.95	53.52	55.12	56.78	58.49	

(i)

YEC does not have (management and non-management) pay grade/scale and performance bonus information of other utilities in Canada to provide.

1 **TOPIC: Revenue Requirement Requests**

2
3 **REFERENCE: November 2020 Application**

4
5 **SUPPORTING DOCUMENTS PAGE 3-9**

6 **TAB 3 - REVENUE REQUIREMENT**

7 At the historic staff level, 1 employees were finding it difficult to keep pace with increased demands, more
8 2 so as additional assets are added and increasing burden for planning and executing capital works.

9
10 **QUESTION:**

11
12 a) Please identify any/each consultant/contract hiring and cost amounts for planning
13 and executing capital works.

14
15 **ANSWER:**

16
17 **(a)**

18
19 The request is unreasonably broad. YEC is not able to provide the detailed information
20 requested given the considerable time and effort it would take to collect and summarize
21 this information.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application

SUPPORTING DOCUMENTS PAGE 3-9

TAB 3 - REVENUE REQUIREMENT

There are a number of corporate factors that directly affect employee complement:

* Increasing assets;

* Strategic importance of improving First Nation and public engagement, relationships and

communications;

Steady growth in customer accounts;

Increased planning requirements for projects recommended through the 2020 Ten Year

Renewable Electricity Plan; and

Continuing high capital demands to maintain existing aging assets.

To combat the above issues, YEC is forecasting an increased employee complement. The increase in employee complement has resulted in a significant decrease in forecast overtime costs for 2021. Also, the increased employee complement in 2019 through 2021 is due to an effort, where possible, to do more work internally as opposed to hiring outside consultants and contractors. YEC has made a conscience effort to limit increases to only those areas where required as reviewed below.

QUESTION:

a) Please identify the decrease in actual and forecast overtime costs for each of the years since 2018.

b) Please identify all cost savings for doing work internally as opposed to hiring outside consultants and contractors.

ANSWER:

(a)

YEC did not state that overtime costs decreased for each of the years since 2018; YEC stated "the increase in employee complement has resulted in a significant decrease in forecast overtime costs for 2021. For details of overtime costs, see CW-YEC-1-14 (b).

1 **(b)**

2

3 It is not possible to identify all cost savings for doing work internally as opposed to hiring
4 outside consultants or contractors. As indicated in the Application, some new positions
5 are being created to help reduce external costs in 2021 and the future such as those
6 mentioned for Operations and Engineering. In reality, almost all work could be outsourced
7 so all labour costs contribute to reduced outside consultants or contractors.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application Tab 3

6 3.3.6 Administration

7 As shown in Table 3.9, Administration expense is forecast to increase \$1.640 million (18%) in 2021 over 2018 approved primarily due to increase in labour costs by \$0.783 million (13%) in 2021 over 2018 approved reflecting labour cost changes as well as functional changes noted in section 3.3.1. Non-labour costs are forecast to increase \$0.856 million (29%) in 2021 over 2018 approved.

Table 3.9:12 Administration (\$000) 2018 Approved Actual 2018 Actual 2019 Forecast 2020 Existing 2021 Proposed 2021

Labour	\$ 5,916	\$ 5,949	\$ 5,835	\$ 6,113	\$ 6,699	\$ 6,699
Resource Planning	48	48	29	174	84	84
Communications	130	126	129	125	155	155
Customer Accounting	225	208	244	206	240	240
Environmental Mgmt	238	184	197	259	535	535
General	662	688	742	620	790	790
Information Systems	645	555	771	803	741	741
Fish Hatchery	168	158	169	200	210	210
Safety	182	210	168	168	226	226
Training	175	173	131	124	200	200

Recruitment	229	245	379	323	255	255
Board of Directors	182	246	280	274	252	252
Union	20	119	60	148	90	90
Regulatory Affairs	33	26	11	15	20	20
Material Management	37	9	31	32	32	32
Contracting	12	5	7	12	12	12
Professional Development	15	15	17	7	15	15
Total Administration	\$ 8,917	\$ 8,966	\$ 9,201	\$ 9,603	\$ 10,557	\$ 10,557

The increase in Administration costs reflect ongoing cost pressure [sic] related to recruitment, training, safety and other cost categories, including: Environmental Management expenses are forecast to increase by \$0.297 million (124%) in 2021 over 2018 approved due to increased environmental monitoring activities associated with the new 3 year water license of the Aishihik Generating Station.

General administration expenses are forecast to increase by \$0.129 million (19%) in 2021 over 2018 approved primarily due to new licenses required for the new asset management software.

Information Systems expenses are forecast to increase by \$0.096 million (15%) in 2021 over 2018 approved due to increased costs for data circuits.

Union expenses are forecast to increase by \$0.070 million (350%) in 2021 over 2018 approved but is \$0.029 less than 2018 actual. Fluctuations in Union expenses are due to cyclical renegotiation of the Collective Bargaining Agreement, which expired December 31, 2019.

Board of Directors expenses are forecast to increase by \$0.069 million (38%) in 2021 over 2018 approved due to additional training and increased meeting costs, as reflected in 2018 actuals.

1 **QUESTION:**

- 2
- 3 a) Please explain what is meant by administration labour costs and breakdown the
- 4 cost for each of these admin labour costs.
- 5
- 6 b) Was/were outside consultants hired for resource planning. If so, please name the
- 7 contractor/s and provide costs?
- 8
- 9 c) Was/were outside consultants hired for environmental management. If so, please
- 10 name the contractor/s and provide costs.
- 11
- 12 d) Breakdown general administration expenses with costs.
- 13
- 14 e) Provide each new license required and final costs for the new asset management
- 15 software.
- 16
- 17 f) Explain what function the communications have and how they are cost/accounted.
- 18
- 19 g) Explain what material management is and how it is cost/accounted.
- 20
- 21 h) Explain how you know you will need new data circuits until need?
- 22
- 23 i) If you do not have to purchase any/some of new circuit boards how will this
- 24 discrepancy be accounted?
- 25

26 **ANSWER:**

27

28 **(a)**

29

30 Administration labour costs means the cost of YEC employees to perform work

31 categorized as Administration. A breakdown of Administration labour costs forecast for

32 2021 is provided in the table below:

	(\$M)
Engineering Services	\$ 1.008
Board of Directors	0.083
President's Office	0.899
Corporate Communications	0.125
Corporate Services	0.193
Customer Billing	0.318
Environment	0.202
Finance & Regulatory Affairs	1.267
Health & Safety	0.317
Human Resources	0.304
Information Technology	0.662
Materials Management	0.264
Procurement	0.583
Resource Planning	0.473
	<u>\$ 6.699</u>

(b)

In 2020, the Resource Planning department spent \$90,000 on outside consultants (Sussex Group).

(c)

In 2020, the Environmental department spent \$176,000 on outside consultants, including \$113,000 paid to Environmental Dynamics, \$25,000 paid to Canadian Wildlife Federation and \$20,000 paid to Hemmera Envirochem.

(d)

Below is a breakdown of general Administration costs forecast for 2021:

	(\$M)
Engineering Services	\$ 0.287
President's Office	0.109
Corporate Services	0.136
Finance & Regulatory Affairs	0.258
	<u>\$ 0.790</u>

1 (e)

2
3 Forecast 2021 license cost relating to the new asset management software is \$0.108
4 million. The \$0.108 million can be broken down as follows:

- 5
6
 - \$0.093 million for annual vendor support and software upkeep.
 - \$0.015 million for User Acceptance Platform software. This software is used for
7 training and testing; it is used to test scenarios and to train others through a view
8 and walkthrough process, and will also support onboarding of new employees in
9 the future.

10

11
12 (f)

13
14 See also the response to YUB-YEC-1-39(g). The function includes the following activities:

- 15
16
 - **Corporate/ strategic communications** - includes activities to build and protect
17 Yukon Energy's corporate reputation;
 - **Engagement** - includes providing communications support and direction on all
18 Yukon Energy major capital projects; and
 - **Leading the customer service team** - includes directly supervising Yukon
19 Energy's Customer Service Team in Dawson City, and managing Yukon Energy
20 customer accounting and billing function.

21
22
23

24 Costs are accounted for in accordance with International Financial Reporting Standards.

25
26 (g)

27
28 Materials Management represents costs to operate the inventory at the warehouse in
29 Kulan Industrial Park in Whitehorse. Operations include supply chain management,
30 receipt, stocking and issuance of materials to O&M and capital jobs throughout the YEC
31 franchise area. Material management¹ also indirectly supports materials warehousing in
32 the communities of Faro, Mayo and Dawson. Costs to manage the warehouse include
33 materials, contractors (e.g. snow removal) and utilities. Costs are accounted for in
34 accordance with International Financial Reporting Standards.

¹ Note currently "materials" relates almost exclusively to transmission and distribution line poles, wire, transformers and hardware.

1 **(h)**

2
3 Data circuits are required primarily for SCADA (system Control and Data Acquisition),
4 Corporate applications, grid protection (Remedial Action Scheme), Revenue Metering and
5 voice services. The number of devices and the volume of data moving over the network
6 is driven by new assets, locations and services. Communications requirements are a
7 common element. This necessitates additional data circuits as the service provider
8 (Northwestel) does not offer bulk (dark fiber) communications service.

9
10 **(i)**

11
12 The circuits are purchased in response to growing needs in volume and speed of data.
13 The data circuits are a service paid monthly (not hardware or an asset) and are a growing
14 O&M line item. Communications requirements are assessed on a long term basis to
15 standardize technology and make the best capital investments possible to support current
16 and future needs. Communications are also assessed on a case-by-case basis in
17 response to equipment or facility upgrades or new capital projects.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application, Table 3.13:

5 Mid-Year Net Rate Base⁶ (\$000)

Approved 2018 Actual 2018 Actual 2019 Forecast 2020 Existing 2021 Proposed 2021

Year-End:

Net plant in service¹ \$ 278,702 \$ 287,713 \$ 293,199 \$ 303,158 \$ 323,642 \$ 322,649

Mid-Year:

Net plant in service

Before contributions \$ 445,367 \$ 449,441 \$ 458,678 \$ 475,781 \$ 498,719 \$ 498,223

Less contributions 167,112 166,677 168,222 177,603 185,319 185,319

Net plant in service 278,255 282,764 290,456 298,178 313,400 312,904

Mid-year regulatory deferral² 3,879 3,805 3,009 2,484 2,732 2,732

Working capital 5,344 5,617 5,935 6,592 6,985 7,141

Net Rate Base \$ 287,478 \$ 292,186 \$ 299,399 \$ 307,255 \$ 323,117 \$ 322,777

Notes:

² This reflects the regulatory deferred costs, excluding DSM and the balance of the hearing reserve account.

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.

Forecast

⁸ Yukon Energy's 2021 mid-year forecast rate base in this Application is \$322.777 million (an increase of

⁹ \$35.3 million or 12% from 2018 approved mid-year rate base of \$287.5 million).

QUESTION:

a) Is this proposed \$35.3 million increase in rate base since the last GRA only for plants that are now providing a service?

b) If no, identify cost amounts separating plants now providing a service from other costs not providing a service.

c) Explain what mid-year regulatory deferral means.

d) Please provide a chart identifying the approved rate base for each GRA year since 1998.

e) Identify and explain each separate contribution donor and amount for all years in chart.

1 f) Explain why 2018 actual rate base is different from 2018 approved?

2
3 g) Explain why difference between existing 2021 and proposed 2021?

4
5 h) Since \$11.861M 2019 increase, \$7.856 M 2020 increase, \$35.3M increase in rate
6 base since 2018 approved, identify amounts for each year already approved.
7 Identify where and when these were approved.

8
9 **ANSWER:**

10
11 **(a) and (b)**

12
13 \$35.3 million is the increase in mid-year rate base in 2021 test year over 2018 test year.
14 This includes increase in property, plant and equipment [in-service or forecast to be in-
15 service by end of 2021], closed deferred project costs as well as provision for working
16 capital requirements. Please see Schedule 1 in Tab 7 for details.

17
18 **(c)**

19
20 The mid-year balance of regulatory deferred projects [e.g., Resource Plan, IFRS transition
21 costs, etc.].

22
23 **(d)**

24
25 This question is unclear as to what chart is being requested, as well as to any relevance
26 to the current 2021 GRA of charting approved revenue requirements for prior years going
27 back to 1998. Accordingly, YEC has not provided the requested information.

28
29 **(e)**

30
31 As indicated in the Table, the amounts are mid-year balances, so they are not the actual
32 amount of contributions received in the year. Also as indicated in the Table, the amounts
33 are for assets in-service, so the Table does not include contributions received for assets
34 that remain as work in progress. Finally, as these amounts are asset in-service, they
35 include amortization of the contributions. The Table represents the balance of all current
36 and historical contributions at their net book value. New contributions since 2018 include
37 \$11.5 million from VGC Group to fund McQuesten Substation and system improvement

1 capital costs. YEC is also forecasting \$23.7 million in 2020 and 2021 from the Federal
2 government for the Mayo to McQuesten Transmission Line.

3
4 **(f)**

5
6 Actual vs approved rate base for 2018 simply reflects the extent that actual numbers varied
7 from the forecast approved by the Board.

8
9 **(g)**

10
11 Existing vs proposed for 2021 mainly reflects the impact of adjusted depreciation rates.
12 See working capital tables in Tab 7 for review of adjustments to this element.

13
14 **(h)**

15
16 The Application focuses on changes to rate base and identifies specific capital, deferred
17 and other rate base cost changes for review and approval. YEC is not able to respond to
18 the question as it seeks a broad review as to all costs approved in the past that would
19 require considerable effort to address without providing any assistance to the 2021 GRA
20 approvals sought in this application.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application, Appendix 3.1 2017-19 KPI Report:

Generation Source

Hydro 441,048 413,052 370,819

% of Total 96.8% 91.7% 84.1%

Diesel 4,618 7,186 3,793

% of Total 1.0% 1.6% 0.9%

LNG 9,856 30,130 66,065

% of Total 2.2% 6.7% 15.0%

Wind 32.582 0 0

% of Total 0.0% 0.0% 0.0%

QUESTION:

a) Is the LNG still classed as back-up with this amount of usage? Explain.

b) How much is wind expected to replace diesel and LNG in 2021?

c) Identify how each SAIDI, SAIFI and CADI compare to Fortis BC (Electric) in 2019.

ANSWER:

(a)

Yes; LNG is available to support grid load under unusual circumstances, e.g., low water, cold temperature, loss of renewable generation. The high loads in 2018 and 2019 are examples of higher generation due to low reservoir conditions.

(b)

No wind generation is forecast for 2021 as shown in Table 2.2.

(c)

YEC was not able to find CAIDI for Fortis (BC). Other stats are below:

	SAIFI	SAIDI	CAIDI
Yukon Energy	12.39	6.88	0.56
Fortis BC	1.21	2.45	Not reported

1

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application, Return on Common Equity Tab 3-27

16 Risk Premium Adder for YEC: Order 2018-10 established a 45 basis point risk premium for YEC over the BCUC benchmark ROE. A 45 basis point risk premium for YEC was considered to be fair and reasonable based on: (1) recognition of small size and principles established for AEY in Order 2017-01;7 and (2) recognition of YEC risk related to generation, isolated grid, and customer diversity.⁸ As noted in Tab 8, there are no new issues or material changes in circumstance at this time that would alter the basis for approving a risk premium of 45 basis points for Yukon Energy

QUESTION:

- a) Does Fortis BC (Electric) borrow the majority of its' money/debt from a government mother corporation?
- b) Does Fortis BC (Electric) receive federal and provincial contributions for various programs? Explain.
- c) Does Fortis BC (Electric) have a rider or mechanism for Fuel price changes, a Low Water Reserve Fund/ similar mechanism, or any other mechanism for stabilizing rates?
- d) Identify the gross margin for YEC in 2019 and 2020.
- e) Identify the earnings before interest, taxes and amortization for YEC in 2019 and 2020.
- f) Compare the numbers in 113 [d] and 114 [e] for the YEC to those of Fortis BC (Electric).

ANSWER:

(a) through (f)

Tab 8 of the GRA Application provides information relevant to the Board's assessment of comparative ROE risk for YEC and Fortis BC (Electric). The GRA also provides detailed

1 reporting on YEC's actual earnings in 2019 and forecast earnings in 2020, summarized
2 as regards ROE in Table 1-1. The comparative risks of YEC and Fortis BC (Electric) (FBC)
3 were extensively reviewed during the 2017-18 YEC GRA proceedings, with follow up
4 questions on YEC Undertakings [YUB-YEC-3-5] providing additional detail related to
5 FBC's power supply context and arrangements with BC Hydro and information showing
6 that the context for FBC is very different and less risky than YEC. The power supply
7 context for FBC was also reviewed in the 2017-18 GRA Undertaking #38 and Undertaking
8 #39 as well as the following follow-up questions on YEC Undertakings: YUB-YEC-3-3,¹
9 YUB-YEC-3-4,² and YUB-YEC-3-6.³ In summary, it has been well documented in YEC
10 proceedings that FBC is not on an isolated grid, and is not exposed to the same thermal
11 cost risks that YEC is exposed to given that FBC has access to renewable generation
12 resource options available on BC's integrated grid system.

13
14 Additional information requested by UCG in this information request will not change the
15 assessments already provided, or assist the Board in this proceeding.

¹ Reviews the Power Purchase Expense Variance Deferral Account [PPEVDA] and clarifies that the relevant provisions continue to operate in non-test years. The response notes that the account was discontinued by Decision G-138-14, but that per the Decision, the expenses and revenues related to the PPEVDA would continue to be flowed through to ratepayers each year through the annual flow-through mechanism.

² In addressing variances due to water variability for FBC, it is necessary to understand the context of FBC's hydro power supply arrangements with BC Hydro, the BCUC-approved cost flow through mechanisms and the extent that these arrangements collectively remove risk from FBC related to water variability cost impacts.

³ Notes that FBC is not exposed to water risks that would merit or require a specific and separate deferral or contingency account mechanism similar to the DCF. Accordingly, the absence of a specific FBC deferral account similar to the DCF is of no importance when comparing risks for FBC relative to YEC.

1 **TOPIC: Capital Projects**

3 **REFERENCE: November 2020 Application, p. 5-1**

5 21 Total spending on PP&E projects in the 2021 test year as shown in Table 5.1 totals \$61.767 million, with
6 22 91% of this spending in major projects over \$1 million (\$56.266 million) and 48% (\$29.801 million, Table
7 23 5.2-1) included in 2021 rate base. Total PP&E spending was \$21.300 million in 2018, \$31.154 million in
8 24 2019, and is forecast at \$36.171 million in 2020. Overall, PP&E transfers to rate base since the end of
9 25 2018 approximate \$92 million. Contributions transferred to rate base to offset some of these
10 26 expenditures since the end of 2018 approximate \$37 million (Table 5.1).
11 27 Deferred cost capital spending (including Work in Progress [WIP] and after contributions) was \$4.3
12 28 million in 2018 (Table 5.3), \$3.7 million in 2019 (Table 5.4), and is forecast at \$5.4 million in 2020 (Table
13 29 5.5) and \$10.5 million in 2021 (Table 5.6). The current GRA results in approximately \$7.4 million of
14 1 Deferred costs being brought into rate base in the current GRA (including relevant test year spending and
15 2 before transfers to the Hearing Reserve Account). with approximately \$1.5 million for 2019, \$4.0 million
16 3 for 2020, and \$1.9 million for 2021.
17 4 Actual and forecast intangible asset spending (including WIP) over 2018 to 2021 is \$6.062 million, all of
18 5 which is forecast to be brought into rate base by 2021, as illustrated in Table 5.7

20 **QUESTION:**

- 22 a) Are PP&E spending for 2018, 2019 and 2020 assumed approved or will they have
23 to wait the outcome of this hearing?
- 25 b) Do the PP&E requested transfers to rate base since the end of 2018 approximate
26 \$92 million include the 2021 test year? Explain.
- 28 c) Are total deferred capital costs for 2018, 2019 and 2020 assumed approved or will
29 they have to wait the outcome of this hearing?
- 31 d) If only \$7.4 million of deferred capital costs requested into rate base, would the
32 remaining \$7.5 million go into WIP? Explain.
- 34 e) Provide a table identifying (PP&E, deferred and intangible) approved capital costs
35 that were placed into rate base for each GRA year since 1990, including requested
36 2021 amounts.

1 **ANSWER:**

2
3 **(a) and (c)**

4
5 The GRA provides PP&E, deferred cost and other cost forecasts for the Board's approval
6 of the revenue requirement used to determine changes to rates.

7
8 **(b)**

9
10 The \$92 million includes transfers to rate base (actual or forecast) for 2019, 2020 and
11 2021 as documented in Table 5.1.

12
13 **(d)**

14
15 The referenced information indicates \$19.6 million of (actual or forecast) deferred cost
16 capital spending (including WIP, and net of contributions) for 2019, 2020 and 2021 with
17 approximately \$7.4 million being brought into rate base. The balance of \$12.2 million
18 would remain in WIP.

19
20 **(e)**

21
22 YEC is not able to provide the detailed information requested given the considerable time
23 and effort it would take to collect and summarize this information and its limited relevance
24 to the current review process.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: November 2020 Application, 5-1 Capital Projects**

4
5 2 Capital project investments in rate base are generally grouped in one of three categories: capital works
6 3 on property, plant and equipment; deferred cost studies (including new supply and other feasibility
7 4 studies, studies required by regulation or relicensing and dam safety works); and intangible assets.

8
9 **QUESTION:**

10
11 a) Provide all related stages a capital project undergoes from concept planning to a
12 plant in use. Include all regulatory stages as well.

13
14 b) Identify how each stage cost is accounted for.

15
16 c) Provide a table/chart demonstrating stages for each capital project greater than \$1
17 million applied for in this application rate base¹ since 2017/18 approved. On this
18 chart for each stage, identify all consultant firm/s name and cost, all contract firm
19 name and cost, all in-house costs with reason, a total of each stage cost. Provide
20 and identify all contributions amounts (government, mining, others) for each stage.

21
22 d) Identify any cost overruns and amounts for each stage of each project in #8 above.

23
24 **ANSWER:**

25
26 **(a)**

27
28 YEC follows a stagegate process. Depending on the complexity of the project, multiple
29 gates may be initiated. Each stage has deliverables, timelines and responsibilities
30 assigned as well as an estimated cost to reach the next stagegate. Upon successful
31 completion of deliverables through each gate, a final project charter is drafted which
32 encompasses the construction aspect of the project and is approved by Sr Management

¹ Capital Projects > \$1 million to include: LNG 3rd Turbine; N-1 Capacity Shortage Whitehorse site; N-1 Capacity Shortage Faro site; Mayo to McQuesten Transmission Line; McQuesten Sub-Station; Transmission Line Refurbishment; Transmission Line 178 Refurbishment; Breaker Replacement Program; Replace P125 Headgate; WH2 Uprate; WH4 Upr.

1 as well as the Board of Directors. The project is executed and when completed is
2 transitioned to Operations for operation and maintenance.

3
4 Regulatory tasks may or may not have separate stagegates. They are typically combined
5 with other deliverables within a gate however treated like any other deliverable such that
6 should the regulatory task not be completed, the project will not pass through the
7 associated gate.

8
9 **(b)**

10
11 Costs for each stagegate are tracked separately and are included in the total project cost
12 upon completion.

13
14 **(c) and (d)**

15
16 The detailed information requested cannot be reasonably provided in the time available.
17 Information regarding project costs breakdowns for major capital projects is provided in a
18 number of information requests, including the response to YUB-YEC-1-49.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 21 **LNG Third Engine/ Critical Spares** – actual cost of approximately \$8.261 million,
6 22 completed and in service in 2018, but not included in rate base approved in 2017/18
7 23 GRA.

8
9 **REFERENCE:** June 22, 2017 Application, page 5-26

10
11 **LNG Third Engine (\$6.2 million)**

12
13 **QUESTION:**

- 14
15 a) Is \$8.261million actual cost or approximate cost?
16
17 b) Exactly what was the projected cost for this project from the 2017/18 GRA.
18
19 c) If different from the above \$8.261 million, explain cost overruns.

20
21 **ANSWER:**

22
23 **(a) to (c)**

24
25 As noted in Tab 5, Section 5.2.1.1 the project was completed and in service in 2018. Page
26 5-6 of the GRA specifically notes, “the project was completed on schedule with total actual
27 project costs for the LNG Third Engine of \$8.261 million. This was below the 2017/18
28 forecast budget of \$8.9 million.”

1 **TOPIC: Capital Projects**

3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5 1 5.2.1.2 N-1 Capacity Shortage Thermal Rental Site Infrastructure
6 2 N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure6 (\$0.227 million in
7 3 WIP at end of 2018 and \$1.070 million in 2019)
8 4 The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under
9 5 its single contingency (N-1) capacity reliability criterion that approximated 6 MW in 2017, increasing to
10 6 10-11 MW by 2019. Yukon Energy is required to provide sufficient dependable winter capacity to meet
11 7 the single contingency capacity reliability criterion, i.e., there is no acceptable “do nothing” option given
12 8 the need to maintain reliable service and to address an ongoing and growing dependable capacity
13 9 shortfall.
14 10 The project involved the design of infrastructure to accommodate temporary rented thermal generators
15 11 at Whitehorse substation to address the capacity shortfall projected under the N-1 for 2018/19 and
16 12 2019/20 winters.
17 13 In winter 2018/19 six temporarily rented 1.8 MW units were installed in the proximity of S150 Whitehorse
18 14 Rapids Substation. The 2019 project included installation of two additional temporarily rented 1.8 MW
19 15 units in the area between P126 Whitehorse Diesel and S150 Whitehorse Substation. The project scope
20 16 included planning support, limited engineering design assistance, protection settings and installation
21 17 support temporary seasonal diesel power generators to meet seasonal N-1 load requirements and assist
22 18 with meeting winter system peaks. Total project cost was approximately \$1.298 million.
23 19 **N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure7 (\$2.037 million forecast in**
24 20 **2020)**
25 21 The project involves the design and installation of temporary rental site electrical infrastructure at Faro
26 22 (870S) to ensure Yukon Energy can continue to meet its N-1 capacity planning requirements.
27 23 The project scope includes engineering and design, procurement of materials, installation and
28 24 construction and other internal and project management costs. Specifically, the major scopes of work
29 25 include:
30 26 Preliminary design and feasibility studies (system impact study and grounding studies); and
31 6 Table 5.2-1 references this project as “N-1 Capacity Shortage Mobile Genset.”
32 7 Table 5.2-1 references this project as “N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure”.
33 Faro 870S 1 temporary diesel generator infrastructure – design, procurement, construction and
34 2 commissioning, including: civil/ structural work; 138 kV line tap and substation work; 4160V
35 3 collection system; fuel system; stations service power; protection, control, communication and
36 4 SCADA integration.
37 5 The project is expected to be completed in 2020 at an estimated budget of \$2.037 million. The project is
38 6 on track for a mid-November 2020 in service date.

40 **REFERENCE: YUB’s Order 2009-8 directions to YEC**

42 “In future GRA applications, YEC to include business cases for major capital projects that
43 included the following information: • descriptions of the project • economic analysis

1 including preliminary engineering estimates • discussion of alternatives and how the
2 chosen option was determined • discussion of the risks of proceeding with the chosen
3 alternative • discussion of risks of not proceeding with the chosen alternative; and •
4 discussion of assumptions included in the business case including escalation factors,
5 loading, financial measures, term of project and associated ancillary costs.”
6

7 **QUESTION:**
8

9 a) Chart all YEC diesels with capacity amounts available in Whitehorse, Faro, Mayo,
10 Dawson, and other towns. Identify for each unit when last retrofitted and at what
11 cost. Identify for each unit when end of life.
12

13 b) Chart all ATCO Electric Yukon diesels with capacity amounts, on the grid.
14

15 c) Chart natural gas units with each unit capacity.
16

17 d) Since these two project are jointly concerned and YEC is now requesting to place
18 costs of over \$3 million onto the rate base for 2021 test year, with the very limited
19 information for each of these projects, provide the businesses case for each
20 following the above Board directives.
21

22 e) In which year did YEC first rent gensets? How many?
23

24 f) Explain when and why YEC chose to move 7 generators to Faro.
25

26 g) Explain precisely why so much was expended to accommodate these rentals.
27

28 **ANSWER:**
29

30 **(a) and (c)**
31

32 Please see page 11 of 10-Year Renewable Electricity Plan provided in CW-YEC-1-36 (a)
33 Attachment 1 for the map that shows generation facilities and Appendix A for the list of
34 generation facilities with capacity information.
35

36 Please see table below for overhauls.

	2012 (+)	2013 (+)	2014 (+)	2015 (+)	2016 (+)	2017 (+)	2018 (+)	2019 (+)	2020 (+)
(P09-092) DD5 Bottom End Overhaul - (-)	696,893.47	358,797.07	39,843.64	24,819.12	24,508.20	.00			
(P11-008) DD2 Engine Overhaul - (-)	338,707.43	362,386.95	13,236.00	8,254.30	8,070.72	.00			
(P11-009) WD4 Engine Overhaul - (-)			506,717.60	12,348.98	12,074.04	.00			
(P11-012) DD3 Engine Overhaul - (-)			374,408.12	9,174.70	8,970.60	.00			
(P13-004) WD-5 Engine Overhaul - (-)		348,387.19	16,618.11	8,400.36	8,213.52	.00			
(P13-070) Whitehorse Spillway Diesel Overhaul - (+)			145,025.18						
(P13-088) Faro FD7 - 16K Hours Overhaul - (-)					120,657.77	.00			

(b)

AEY would be in a better position to provide the requested information. This information as required for the N-1 capacity criteria is provided in Tab 2 of the Application.

(d)

As reviewed in the referenced Tab 5 information on each of these projects, YEC must provide reliable firm capacity to the Yukon. New firm capacity requirements are assessed based on a "N-1" contingency, meaning the generating capacity must supply the Yukon load in the event that its largest generating facility is lost. YECs largest facility is Aishihik and has a capacity of 37MW.

Available information and forecasts since YEC's 2016 Resource Plan have documented an N-1 dependable capacity shortfall. Section 2.4 of the 2021 GRA updated this information for 2021, showing the determination of a forecast N-1 dependable capacity shortfall of 25.75 MW in 2021 without the rented diesels and a surplus of 1.25 MW with the 15 rented diesel units (27 MW).

YEC continues to examine and pursue a range of non-rental options to address the forecast N-1 dependable capacity shortfall, including diesel retirement replacement, the Battery Energy Storage System project, the Atlin Hydro EPA, and pumped storage. Until such time as sufficient new dependable capacity can be developed through one or more of these non-rental options, rented diesel units continue to be the only cost effective option for YEC to adopt to ensure that sufficient dependable capacity is connected to the Yukon Integrated System to meet firm reliability standards during the peak load winter months. The referenced diesel rental infrastructure is required to accommodate the required diesel rental units.

1 **(e)**

2
3 2017/2018 - 4 rentals
4 2018/2019 – 6 rentals
5 2019/2020 – 9 rentals
6 2020/2021 - 17 rentals

7
8 **(f)**

9
10 When YEC determined that 17 rentals would be required for 2020/21, it was concluded
11 that some of these additional rentals would be located at Faro. This decision reflected the
12 following:

- 13
14 • Whitehorse is at capacity and could not accept any more rentals.
15
16 • Faro has established diesel infrastructure from the time of the Faro mine, and could
17 accommodate cost effectively the required diesel rental units, i.e., the Faro facility
18 air emission permit allowed for added generation; transformation, control and
19 communication was available; and YEC owned land accommodated the
20 infrastructure and rentals.

21
22 **(g)**

23
24 This was the least cost option considering the available infrastructure at Faro and the
25 existence of the air emission permit that allowed for the addition of the rental fleet.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: Mayo to Keno Transmission Line and McQuesten Sub- Station**

4
5 **QUESTION:**

6
7 a) Identify forecast 2021 kWhr. usage for all non-government and government
8 residential and commercial ratepayers on grid from Mayo to Keno (do not include
9 Mayo).

10
11 b) Identify forecast 2021 kWhr. usage for each of the two mines, VCG and Alexco.

12
13 **ANSWER:**

14
15 **(a)**

16
17 The load forecast is prepared at the community level. YEC does not prepare forecast sales
18 at non-government and government customer level, and therefore is unable to provide the
19 requested information.

20
21 **(b)**

22
23 Victoria Gold forecast load at 43.1 GW.h for 2021 and Alexco forecast load at 24.1 GW.h
24 for 2021 as provided on page 1-7 of the Application.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5-11

11 Table 5.2.1-2: Project Cost and Contributions

	<i>Actual2018</i>	<i>Actual2019</i>	<i>Forecast2020</i>	<i>Forecast2021</i>
MMTL Upgrade (\$000)	0	501	20,000	11,200
MMTL Contribution (\$000)	0	274	15,000	8,400
Net Expense	0	227	5,000	2,800

The total spending of \$20.501 million for 2019 and 2020 is offset by \$15.274 million in contributions [net \$5.227 million] and is forecast to be closed and included in rate base in December 2020; the spending of \$11.200 million in 2021 is offset by \$8.400 million in contributions [net \$2.800 million] and is forecast to be closed and included in rate base in December 2021.

QUESTION:

- a) Identify contribution amount and contributor for each year and explain precisely what used for. (Not adequately explained in business profile).
- b) If none of these contributions were from Alexco please explain why not?

ANSWER:

(a)

See Tab 5, Section 5.2.1.3 of the Application. As noted at Tab 5, page 5-11, the project received a Federal Government contribution of \$23.674 million which covers 75% of the eligible project budget. The contributions for 2019 (of \$0.274 million), 2020 (of \$ 15 million) and 2021 (of \$8.4 million) total to this amount. Contributions are applied against total project costs in each year in order to reduce the impact on rates.

(b)

Industrial mine connections are subject to Power Purchase Agreements (PPAs) as approved by the Board. The PPA for Alexco Resources (as well as the PPA for VGC Group) sets out when contributions are required up front from the customer to cover all costs for the installation of transmission facilities used only for each mine. No such up

1 front contributions are required for transmission facilities (such as the Mayo-McQuesten
2 new transmission) that also service other customers on the Yukon Integrated System.

3
4 The Alexco and VGC Group PPA provisions also provide for industrial customers that
5 connect to the Mayo to Keno common transmission facilities that service this region to
6 make significant contributions (i.e., 85%) through the Fixed Charge towards the annual
7 YEC depreciation and return expenses related to the rate base cost for these
8 Transmission Facilities. These provisions will result in these two industrial customers
9 paying for 85% of the annual depreciation and return expenses for the new Mayo-
10 McQuesten transmission facilities

11
12 Yukon Energy has been pursuing the SKTP to improve electrical transmission
13 infrastructure in central Yukon between Stewart Crossing and Keno City; reinforce and
14 strengthen the grid between Stewart Crossing and Mayo; and replace and remove
15 deteriorated and “end of life” transmission infrastructure between Mayo and Keno City.
16 With regard to the line segment between Mayo and Keno City, it has been well
17 documented that the line facilities are significantly deteriorated and need to be rebuilt due
18 to safety and reliability concerns. As such, recent capital costs related to these facilities
19 are not directly due to the VGC Group Mine or the Alexco mine facilities.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5-12**

4
5 **22 5.2.1.4 McQuesten Substation (including Asset Contribution) – (\$0.123 million in 2018 and**
6 **23 \$11.496 million in 2019; with \$10.688 million contribution)**

7
8 **QUESTION:**

9
10 a) Identify contribution amount and contributor for each year and explain precisely
11 what each was used for. (Not adequately explained in business profile).

12
13 b) If none of these contributions were from Alexco please explain why not?

14
15 **ANSWER:**

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

18
19 See Tab 5, Section 5.2.1.4 of the Application. Pursuant to the VGC Group PPA, the
20 McQuesten Substation was developed by VGC Group and YEC, with the intention that it
21 would be owned and operated by YEC. Except as otherwise specified in the PPA, VGC
22 Group was responsible for all capital costs related to the McQuesten Substation
23 development.

24
25 YEC has received an asset contribution from VGC Group valued at \$10.688 million, and
26 has incurred a net cost of \$0.931 million (related to added facilities to enable future 138
27 kV service operation if required).

28
29 Development of this facility did not involve Alexco.

1 **TOPIC: Capital Project**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **5.2.1.5 Transmission Line Refurbishment - L70, L171 and L172 in 2018 and 2019 (\$4.272**
6 **15 million in 2019)**

7 16 Yukon Energy's 138 kV Whitehorse-Aishihik-Faro (WAF) transmission system was constructed in the late
8 17 1960's and early 1970's, and plays a critical role linking key hydro generation sources to load centres in
9 18 Whitehorse and on the northern grid. Recent studies as well as a detailed line assessment in 2017
10 19 indicated that key components of the WAF system were at end of life, in poor condition, and required
11 20 replacement.

12 21 This project was initiated to address replacement of key components of the following YEC transmission
13 22 lines which are approaching the end of their economic life.

14 25 At the time future Step Down transformer costs were estimated at \$1.34 million.

15
16 **QUESTION:**

17
18 a) Who made and why was the decision made to expense this money all at once
19 rather than stepping-up the yearly maintenance program utilizing in-house
20 personnel?

21
22 b) Does this \$4.272 million cost in 2019 include the \$1.34 costs for Step Down
23 transformers.

24
25 c) If yes, demonstrate that this work was done.

26
27 **ANSWER:**

28
29 **(a)**

30
31 The project review committee made the decision. The results from the transmission test
32 and treat and line assessments defined the scope of work. The scope of the work and
33 YEC's capacity to perform the work in house dictated the decision to make TLR a large
34 project. YEC has one line crew consisting of four personnel.

35
36 The assessment determined that a number of transmission line components were end of
37 life. There is no accepted practice to life extending these components (e.g., cracked
38 laminar beams, cracked ceramic insulation).

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

2

3 TLR did not include any work on stepdown transformers.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **5.2.1.6 Transmission Line Refurbishment – L178 (forecast \$1.3 million in 2021)**

6 12 The final phase of the Transmission Line Refurbishment Project will commence in 2021 for the Carmacks
7 13 to Faro Transmission Line (L178), as refurbishment has been completed for L170, L171 and L172 (see
8 14 Section 5.2.1.5).

9 15 Outages on the L178 currently trip at S164 (Takhini Substation) and can result in an outage on the
10 16 Takhini-Carmacks L170 transmission line. Failure to complete this element of the refurbishment project
11 17 would increase the risk of component failure on L178 resulting in a split in the North-South grid and
12 18 significant thermal generation costs in the northern grid to maintain supply to all customers

13
14 **QUESTION:**

15
16 a) Has outages of the L178 line ever caused a failure on the grid?

17
18 b) If so, how often and when?

19
20 c) Has utilizing the yearly maintenance in-house team considered as a viable
21 alternative. If not, why not?

22
23 **ANSWER:**

24
25 **(a)**

26
27 Yes. Outages of the L178 line have caused multiple events. See also response to YUB-
28 YEC-1-54.

29
30 **(b)**

31
32 See response to YUB-YEC-1-54(a).

33
34 **(c)**

35
36 YEC has one transmission crew comprised of four staff. The primary responsibility of the
37 in house crew is minor transmission maintenance, outage response and customer
38 connects. Work on the transmission system requires the line to be isolated, and this results

1 in customer outages and diesel generation for the duration of the work. Operating
2 agreements with commercial customers typically allow for two weeks disruption (off grid
3 power). Due to the quantity of work and the short timelines to complete the work, YEC
4 must supplement the YEC crew with contractors or project manage the work of the
5 selected contractor.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **5.2.1.8 Replacement of P125 Head Gate (\$0.093 million in 2019, \$2.300 million forecast in**
6 **8 2020, and \$3.500 million forecast in 2021)**

7
8 **QUESTION:**

9
10 a) If an adequate response charting breakdown is met in UCG-IR Capital 8 and 9
11 includes this project, then UCG has no further questions for now.

12
13 **ANSWER:**

14
15 **(a)**

16
17 No question is being posed above and no response appears to be required. A cost
18 breakdown for the P125 Head Gate Project is provided in YUB-YEC-1-49.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 13 5.2.1.10 WH4 Uprate - Servomotor Replacement (\$0.052 million in 2018; \$0.079 million in
6 14 2019; \$0.400 million forecast in 2020; and \$1.000 million forecast in 2021)

7 The total project budget is \$1.531 1 million and includes work from 2018 through to project completion
8 2 (expected in Q3 2021).

9
10 **QUESTION:**

- 11
12 a) Provide all prior work done on WH4, years work completed, along with each cost
13 for the WH4 Uprate program, that have been already been approved and placed
14 in rate base.

15
16 **ANSWER:**

17
18 **(a)**

19
20 In 2017, YEC performed a major overhaul on hydro unit #WH4 including replacement of
21 both the exciter and rotor spider. This work was unrelated to the current servomotor
22 replacement uprate project. The Hydro Unit #WH4 Overhaul was reviewed as part of the
23 2017/18 General Rate Application (see Tab 5, Section 5.2.1.5 of the 2017/18 GRA and
24 Board Order 2018-10, paragraph 421).

1 **TOPIC: Capital Projects**

3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5 **5.3.1 Major Projects >\$1 Million – Rate Base Additions**

6 12 **Aishihik Relicensing (Three Year Licence Renewal)** - (\$1.004 million net increase
7 13 in rate base by the end of 2021, excluding reductions due to amortization).

8 **5.3.1.1 Aishihik Generating Station Three Year Licence Renewal – (\$0.805 million to end of**
9 **23 2019; and \$0.200 million in 2020)**

10 16 Costs for the 3-year AGS licence renewal were incurred from January 2019 through to end of February
11 17 2020 (when the 3-year licence renewal was obtained). Costs over this period include regulatory costs for
12 18 the Designated Office review; costs related to the preparation of the Yukon Water Board Application for
13 19 the 3-year renewal and for the 60-day renewal and for the related review processes; and costs related to
14 20 preparation of an application to extend the DFO Fisheries Act Authorization and related review
15 21 processes;

16 22 and costs related to negotiations with CAFN and for negotiation of compensation with claimants pursuant
17 23 to the Waters Act .

18 29 The DFO evaluation concluded in August 2019 with the issuance of an Evaluation Report. Decision
19 30 Documents were
20 31 issued in September 2019.

21 32 Issued December 24, 2019.

22 33 A 60-day renewal was issued in December 2019 extending the licence to February 29, 2020, and a 3-
23 34 Year renewal was
24 35 issued on February 19, 2020.

26 **QUESTION:**

28 a) Provide all costs allocated for AGS YESAB review (each consultant name, work
29 done and cost for each. Provide all inhouse costs with work done.

31 b) Provide all costs allocated for AGS Water Board review (any and all consultant
32 costs and in-house costs).

34 c) Were both these licenses granted?

36 d) How much did it cost for FN negotiations and compensation and how was this
37 accounted for?

ANSWER:

(a) and (b)

Please note AGS YESAB review and AGS Water Board review costs cannot be readily broken out in the time available. Both cost items were included in permitting activities for this project. Permitting activities broken out by consultant are summarized in Table 1 below. Table 2 provides YEC internal costs.

Table 1: AGS Three Year Licence Renewal Permitting Activities Costs by Consultant

Consultant	2019	2020
DLA Piper (Canada) LLP	148,265.52	
Environmental Dynamics Inc.	52,869.26	7,588.09
Intergroup Consultants Ltd.	109,017.75	77,819.75
Morrison Hershfield Limited	48,293.25	
	<u>358,445.78</u>	<u>85,407.84</u>

Table 2: YEC Internal Costs for AGS Three Year Licence Renewal

Internal Costs	2019	2020
Internal Labour	17,236.99	
Other Internal Costs	667.74	3,062.09
AFUDC	122.47	2,314.17
Grand Total	<u>18,027.20</u>	<u>5,376.26</u>

(c)

All regulatory authorizations required to operate the project until December 31, 2022 were issued. The YESAA Designated Office review was completed in 2019 with issuance of the YESAA Report and Recommendations on September 4, 2019. Decision Documents were issued October 21, 2019. The Fisheries Act Authorization extension was issued December 20, 2019 and the three year Water Use Licence renewal was issued February 19, 2020.¹

(d)

See response to YUB-YEC-1-59(a) which provides a breakdown Three-Year Licence Renewal Project Costs.

¹ A 60-day renewal was also issued on December 19, 2019 [Water Use Licence HY-19-057].

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: June 22, YEC 2017 Application, page 5-31 and Table 5.3, page 5-**
4 **56Aishihik**

5
6 Relicensing (\$2.899 million) \$2.899 million cost identified at page 5-31 and \$8.9 million
7 cost identified on Table 5.3 at page 5-56.

8
9 **QUESTION:**

- 10
11 a) Identify which amount was approved as a WIP for 2017/2018 GRA.
12
13 b) What portion of these costs allocated from WIP to rate base?
14
15 c) Identify how these costs were different from the ones now requested to place into
16 rate base.
17
18 d) Identify any and all consultant firms, work performed and each cost for this phase
19 of the relicensing.
20
21 e) Please confirm that costs related to the Aishihik Relicensing will not be recovered
22 in rates until approved by the YUB this general rates application process.

23
24 **ANSWER:**

25
26 **(a) through (e)**

27
28 The Board approves costs that affect rates – and costs allocated to WIP in the last GRA
29 did not affect rates. All cost forecast to be added to rate base in the current GRA will not
30 be recovered in rates until approved by the Board in the GRA process.

31
32 Please see response to YUB-YEC-1-90 for review of this project's changes since the
33 2017-18 GRA.

1 **TOPIC: Capital Projects**

3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5 17 o Demand Side Management (DSM) – (\$1.737 million net increase in rate base by the
6 18 end of 2021, excluding reductions due to amortization).

7 5.3.1.2 Demand Side 1 Management – (\$0.833 million to the end of 2019; \$0.375 million
8 2 forecast in 2020 and \$0.894 million forecast in 2021, with contributions of \$0.365

9 3 million).

10 The Board made the following DSM related determination in Board Order 2018-10
11 6 (paragraph 482):

12 7 “The Board is not persuaded that YEC should continue to operate DSM projects. YEC has
13 8 indicated the benefits of expanding the program and submitted that its programs have
14 9 met or exceeded key performance indicators. However, the Board notes that the Yukon
15 10 government has DSM incentive programs in place, and the Board is of the view that it is
16 11 better to leave DSM projects to government, rather than having ratepayers fund these
17 12 projects. For these reasons, the Board is of the view that continuation of DSM programs
18 13 by YEC is not necessary.”

19 22 DSM Program Development

20 A Capacity DSM Feasibility Study and an updated CPR model,³⁵ to design 1 a suite of new DSM
21 2 programs to complement the existing inCharge program. This work was completed in early 2019. Minimal
22 costs to provide
23 brand and education continuity have also been incurred since early
24 5 2019 to maintain the inCharge program in the local market. Project expenditures to be included in rate
25 6 base of \$1.279 million (\$0.385 in 2019 and \$0.894 million in 2021) are amortized over 10 years.

27 Board Order 2013-01 Appendix A determined:

29 “that it was not approving the DSM program for the five-year term and that YEC was to
30 make a formal application to the Board before expanding the DSM program elements
31 beyond that approved or beyond 2015.”

33 **QUESTION:**

35 a) Has there been a court determination on the YEC request to Review and Vary
36 Board Decision 2018-10?

38 b) If the courts have not rendered a favourable decision on this matter, why is YEC
39 still proceeding with DSM expenditures?

1 c) Did YEC get prior authorization from the Board to proceed with new DSM
2 programming as directed by the Board to undergo these studies and models with
3 costs of \$1.279 million?

4
5 d) What are the programs complementing the inCharge that have been
6 implemented?

7
8 e) Confirm that YEC requires acceptance from the YUB before rates can be set which
9 recover any expenditures for energy efficiency or conservation (DSM measures).

10
11 **ANSWER:**

12
13 **(a), (b) and (c)**

14
15 The Court of Appeal of Yukon dismissed the appeal in a written decision on February 5,
16 2021. The Appeal addressed historic DSM costs (2016-2018) and in no way precluded
17 YEC from advancing new DSM programming. With respect to the balance of the
18 referenced questions, please see response to YUB-YEC-1-46 (a to f).

19
20 **(d)**

21
22 YEC has not yet initiated the implementation of any complimentary DSM programs.
23 Continued work on DSM programming, including potential complimentary programs, will
24 now be advanced given OIC 2021/16 directions enabling YEC to recover through rates
25 the costs reasonably incurred to provide or participate in a demand side management
26 program.

27
28 **(e)**

29
30 YEC confirms that rates cannot be adjusted without prior authorization from the YUB.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 17 **Demand Side Management (DSM)** – (\$1.737 million net increase in rate base by the
6 18 end of 2021, excluding reductions due to amortization).

7 **7 DSM Residential Demand Response Pilot**

8 20 Yukon Energy has pursued a pilot program testing internet connected, wifi enabled
9 21 demand response technology designed to control residential baseboard and hot water heating during
10 22 winter peak periods to help reduce system peak and reduce reliance on thermal generation such as
11 23 diesel
12 23 or natural gas.

13 34 Yukon Energy also noted plans to undertake a Capacity DSM Feasibility Study to quantify the potential
14 35 cost and
15 36 achievable uptake
16 37 of capacity-focused DSM programs such as demand response, behaviour change and other demand-
17 38 focused measures.

18 39 At the time Yukon Energy also noted plans to update the Conservation Potential Review (CPR) model
19 40 used to inform DSM
20 41 program design, to better match the inputs needed for resource planning; and to develop in house capacity
21 42 to use the CPR
22 43 model
23 44 to extract data for resource planning and program design purposes.

24 45 The objective of the program is to: 1 evaluate the technical feasibility of the demand response technology;
25 46 2 model and test the peak shifting effect of the pilot; test the reliability of the peak shifting effects of the
26 47 3 pilot; and evaluate customer acceptance of the demand response events.

27 48 4 The project is managed by Yukon Energy with funding support from Atco Electric Yukon (AEY), Yukon
28 49 5 Development Corporation (YDC) and Natural Resources Canada (NRCan). Project expenditures of \$0.809
29 50 6 million (\$0.434 million in 2019 and \$0.375 million in 2020) are to be included in rate base, offset by
30 51 7 contributions of \$0.365 million in 2019, are amortized over 10 years.

31
32 **REFERENCE:** [https://www.yukon-news.com/news/smart-grid-pilot-project-](https://www.yukon-news.com/news/smart-grid-pilot-project-announced/)
33 [announced/](https://www.yukon-news.com/news/smart-grid-pilot-project-announced/)

34
35 “It’s worth \$1.3 million, with the federal government chipping in \$650,000 and the Yukon
36 37 government contributing \$250,000.

37 38 ATCO and Yukon Energy cover the rest — \$300,000 and \$100,000, respectfully.”

39 **QUESTION:**

40
41 a) Explain precisely what the \$0.809 million costs are for?

1 b) How much exactly is YEC requesting to rate base?

2
3 c) Why is YEC costing any of this to the ratepayer rate base when all of the costs
4 were to be recovered from contributions (see above)?

5
6 d) Confirm that YEC requires acceptance from the YUB before rates can be set which
7 recover any expenditures on this demand response program.

8
9 **ANSWER:**

10
11 **(a)**

12
13 Please see response to YUB-YEC-1-59.

14
15 **(b) and (c)**

16
17 As quoted in the preamble, the DSM net addition to rate base (after contributions) is
18 \$1.737 million. The quoted announcement did not reference all of the DSM activities
19 included in this project.

20
21 **(d)**

22
23 The Board must approve costs prior to such costs being included in rates.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **8 LED Streetlight Retrofit Program**

6 The 2017/18 GRA outlined the basis for
7 13 the LED Streetlight Replacement program noting that Yukon Energy decided to move forward with the
8 14 retrofit of streetlight assets with LEDs. 37 Streetlights in downtown Dawson and Mayo were retrofit in 2016
9 15 with plans to retrofit the remaining streetlights in Faro, Mendenhall and Champagne in 2018. As
10 16 illustrated in Table 5.3, \$0.273 million was added to rate base in 2018.

11
12 **REFERENCE: Appendix A to Board Order 2018-10 Reasons, p.91 #480 and 481**

13
14 Board determined as a result of above: "The Board considers that retrofitting streetlights
15 at end of life with LED lights were prudent expenditures. Any LED installations that are
16 not end-of-life conversions are not to be included in rate base."

17
18 **QUESTION:**

- 19
20 a) Did YEC receive prior authorization from the Board to spend the \$0.273 million
21 demonstrating end-of-life conversions?
22
23 b) Confirm that YEC requires acceptance from the YUB before rates can be set which
24 recover any expenditures on this streetlight conversion.
25

26 **ANSWER:**

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

29
30 The Board must approve costs prior to their inclusion in rates. The Board does not provide
31 "prior authorization" for project costs, and YEC did not therefore seek or receive any prior
32 authorizations for the referenced costs.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.4-1: FEASIBILITY STUDIES – POTENTIAL RENEWABLE GENERATION OPTIONS

IPP Standing Offer Program Implementation

2018WIP	2019 Addition	2020Addition 2	021Addition

\$48,127	\$183,912		

Yukon Energy and ATCO Electric Yukon (AEY) are responsible for implementing the Yukon Government's Independent Power Producers (IPP) Policy. The Standing Offer Program (SOP) was developed based on the model used in British Columbia.

The utilities were directed to implement the policy by the Yukon Government and are required to execute the policy.

OIC 2019-25 requires that utility costs be recovered in rates. With total expenditures of \$232,039 to be amortized over five years.

QUESTION:

- a) If the YEC model was based on one produced in British Columbia, explain why a quarter million dollars in cost be needed to re-invent the template?
- b) Identify the section of OIC 2019-25 that states precisely that the utilities costs be recovered from rates for developing an IPP standing offer program.
- c) Why could not the Yukon Energy staff implement this policy in-house?

ANSWER:

(a)

YEC received formal permission from BC Hydro to utilize their Standing Offer Program documents as a starting point for Yukon's program. The permission came with the full recognition that significant changes would be required to be make it useful in the Yukon context. The number of documents required to launch the Standing Offer Program is significant. The program was a collaboration between YEC and ATCO Electric Yukon which required shared learning to firstly understand the BC program and then make

1 modifications that would work with Yukon Government policy and the Yukon context. This
2 was a daunting task for both Utilities to understand a model Standing Offer Program and
3 then customize it for the Yukon.

4
5 There are significant differences between BC's and Yukon's Standing Offer Program.
6 However, it was much more efficient to start from a working model than try developing this
7 program "from scratch".

8
9 **(b)**

10
11 The utilities were directed to implement the IPP policy by the Government of Yukon.

12
13 While the costs for developing an IPP standing offer program are not specifically
14 referenced in OIC 2019/25 – the OIC specifies costs that the Board must allow the utility
15 to recover in relation to electricity purchase agreements which include: (a) the cost of
16 purchasing electricity under an electricity purchase agreement; (b) third party consultant
17 costs, including legal fees, incurred by an electrical utility in relation to the development
18 and implementation of the agreement; and (c) the cost of maintaining or replacing
19 equipment or infrastructure necessary to purchase electricity under the agreement.

20
21 **(c)**

22
23 YEC and ATCO Electric Yukon are both signatories to the Standing Offer Program. The
24 sheer volume of documents required to implement this policy is a testament to the
25 technical and legal work that was required to develop it. Compounded by the need to
26 collaborate and the significance of contracting for 20 GWh (now expected to increase to
27 40 GWh) of renewable electricity from Independent Power Producers for 25 years, the
28 investment in third party legal and technical support was necessary.

1 **TOPIC: Capital Projects**

3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab**

5 **FACTORS DRIVING THE 2021 RATE INCREASE REQUIREMENT**

6 16 **Other Cost Changes (\$0.7 million impact, 6.0% of shortfall):** Other cost changes
7 17 affecting the 2021 GRA revenue shortfall include depreciation rate changes (\$0.6 million
8 18 increase), Reserve for Injuries and Damages (RFID) updates (\$0.4 million increase), and new
9 19 Independent Power Production (IPP) costs (\$0.3 million).

11 **QUESTION:**

- 13 a) Explain the difference in the business case cost of \$232,039 million for IPP and
14 the impact to rates of \$0.3 million for new IPP costs.
15
16 b) Which is relevant and how is this reflected in application costs?

18 **ANSWER:**

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

22 The question references two different IPP cost items included in the 2021 test year:

- 24 1. Costs for power purchased from IPPs (per Table 3.2 in Application, and page 3-6,
25 lines 8 to 12) – this is \$0.314 million forecast for 2021 purchase cost for 1.983
26 GWh forecast to be supplied by IPPs. All of this cost is included in 2021 revenue
27 requirement.
28
29 2. Costs for IPP Standing Offer Program Implementation (per Appendix 5.4, section
30 5.4-1, page 5.4-2) – deferred studies cost of \$232,039 (not \$232,039 million as
31 shown in question) incurred in 2018 and 2019, that was closed and included in rate
32 base in 2020 and is being amortized over five years. The 2021 revenue
33 requirement includes annual amortization costs plus return on 2021 mid-year rate
34 base amount.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab**

4
5 **Mt Sumanik Wind Feasibility Studies**

6 2018WIP	2019Addition	2020Addition	2021Addition
7 \$694,427	\$31,155	\$50,000	

8
9 Mt Sumanik was identified as a particular site of interest for wind development given the advantages of its
10 proximity to Whitehorse. From 2014 to 2015, work on this project focused on the siting, engineering,
11 environmental assessment, permitting and installation of wind monitoring equipment at Mt Sumanik. This
12 included completion of applicable studies such as a grid impact study and wind integration study. A Lidar unit
13 and power supply system was installed on Mt Sumanik to track wind data.

14
15 From 2016 to 2017, the project work consisted mostly of data collection and management, as well as
16 evaluating upgrades to the power system for the monitoring equipment which experienced difficulties. In 2018
17 work was conducted to repair the laser of the Lidar unit as the equipment was malfunctioning. Yukon Energy's
18 2016 Resource Plan identified a potential energy gap under the High Industrial Activity scenario. The Action
19 Plan identified one wind supply option under this scenario. Accordingly, as wind was still a resource of interest,
20 Yukon Energy considered whether further data monitoring should be conducted given missing data from the
21 malfunctioning equipment. The need for Yukon Energy to directly conduct resource wind monitoring and site
22 assessments has since been eliminated due to the high likelihood that future wind resources will be developed
23 by Independent Power Producers. As such, the project was decommissioned in 2020 with total expenditures
24 of \$775,581 to be amortized over five years.

25
26 **QUESTION:**

- 27
28 a) Breakdown all costs associated, including consultant firms and costs for each; i.e.
29 for siting, engineering, environmental assessment, permitting and installation of
30 wind monitoring equipment on Mt. Sumanik.
31
32 b) In what year was IPP policy presented by YTG to Yukon Energy for
33 implementation?
34
35 c) In what year was YEC first made aware that Northern Energy was planning a wind
36 farm in the Whitehorse area?

1 **ANSWER:**

2

3 **(a)**

4

5 Please see YUB-YEC-1-96.

6

7 **(b)**

8

9 The current IPP policy was implemented in 2019 through OIC 2019/25 and 2019/26.

10

11 **(c)**

12

13 2018.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **WH2 Uprate Engineering1**

6 2018WIP	2019Addition	2020Addition	2021Addition
7 \$207,944	\$44,448	\$6,679	

8
9 In 2016, Hatch assessed the uprate options at the WRGS. Uprate of the WH2 was considered the most
10 economically attractive option. The WH2 Uprate project would include completion of the WH2 unit's
11 rehabilitation, replacement of the turbine runner and stator rewind and rotor refurbishment. The WH2 uprate
12 engineering study was the first stage of a multi-year, phased project. The initial stage involved selection of an
13 Owners Engineer to conduct preliminary design work (commenced in 2018 and completed in 2020). An
14 external engineer was required to undertake this work as uprate studies are a specialized skillset that YEC
15 does not employ internally. By end of 2021 WH2 Uprate Engineering costs will be transferred to Property,
16 Plant and Equipment and added to WH2 Uprate total cost [amortized over 72 years starting in 2022]. However,
17 this requires replacement of the existing stator winding and refurbishment of the rotor field poles and windings.
18 before the end of 2021. The project is to be closed in 2021 with total expenditures of \$259,072 to be amortized
19 over 72 years.

20
21 **QUESTION:**

- 22
23 a) Was the total cost of \$250K for work given to Hatch?
24
25 b) If not, which engineering firm did study and at what cost?
26
27 c) If not, were there additional costs?
28
29 d) Confirm that existing WH2 stator has been replaced, winding and refurbishment of
30 rotor field poles and windings complete.
31
32 e) At what cost?

1 **ANSWER:**

2
3 **(a)**

4
5 The assessment work completed by Hatch in 2016 was prior to the WH2 Uprate project.
6 Hatch did not complete any work included in the \$259,071 spent on WH2 Uprate
7 Engineering between 2018 and 2020.
8

9 **(b)**

10
11 In 2018, YEC spent \$165,646.78 on consultants (SNC Lavalin). The remainder was
12 internal labor, legal fees (for contract negotiation), AFUDC and materials.
13

14 **(c)**

15
16 There were no other additional costs.
17

18 **(d)**

19
20 The original stator has not been replaced, nor have the refurbishment of rotor poles and
21 windings. This work is a part of the WH2 uprate project.
22

23 **(e)**

24
25 The cost of the stator rewind and refurbishment of the rotor poles are part of the overall
26 project cost of \$12,257,000. The cost of the rewind is \$601,857. Refurbishment of the
27 stator frame is \$24,457. Overall, YEC is spending \$972,440 on the WH2 generator
28 rewind/refurbish during the WH2 Uprate. This is included in the overall project budget of
29 \$12.257 Million.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: 5.2.1.9 WH2 Uprate (\$3.044 million in 2019, \$1.693 million forecast**
4 **in 2020, and \$7.300 million forecast in 2021)**

5
6 In 2017, Hatch completed an economic assessment of various uprate options at the Whitehorse Rapids
7 24 Generating Station (WRGS).

8 28 The project is planned to be implemented over a three year period (2019-21).

9 The WH2 uprate scope 1 of work will include unit rehabilitation, runner replacement, generator stator and
10 2 rotor re-winding, governor replacement, exciter replacement and upgrading of the control and condition
11 3 monitoring systems.

12 4 Yukon Energy contracted Litostroj Power to undertake the runner fabrication with the following
13 5 concurrent activities planned for 2020: governor fabrication, balance of plant civil construction; balance of
14 6 plant P&C design completion, relace of balance of plant request for proposal, and delivery of materials to
15 7 Whitehorse. The balance of plant civil scope work included rehabilitation of the tailrace crane
16 8 superstructure and concrete piers. Due to significant new damage to the WH1 and WH2 penstocks
17 9 discovered in 2020, the planned penstock work was cancelled and will be completed as part of the
18 10 penstock repairs.

19 11 The WH2 uprate project is currently expected to be delivered on time with total project cost of \$12.038
20 12 million.²⁸

21
22 **QUESTION:**

23
24 a) Further to reference above giving WH2 business plan, is the first reference
25 engineering costs of \$259,039 included in this business plan?

26
27 b) If not, why not?

28
29 c) WH2 scope of work include unit rehabilitation, runner replacement, rotor re-
30 winding, governor replacement, exciter replacement and upgrading of the control
31 and condition monitoring systems. Did Listostroj Power do all the work in scope
32 above and at what cost.

33
34 d) If Listostroj Power did not do all the work outlined above to the cost of \$12,038
35 million, identify which firm/s was/were hired, what work done and at what cost.

36
37 e) Identify work done in-house and at what cost.

38
39 f) Identify any costs above associated with the balance of work identified above
40 including rehab of tail race crane and concrete piers.

1 g) Identify all costs and for what work completed to WH2 for 2018 and any prior years.

2
3 h) Confirm that \$12.038 million is the total amount for overhaul of WH2.

4
5 **ANSWER:**

6
7 **(a)**

8
9 No, the costs are not included in the 2019-21 spending identified in Tab 5, Section 5.2.1.9.

10
11 **(b)**

12
13 These costs were considered a Feasibility Study before the actual fix was determined. In
14 accordance with YEC's policy, the project will be kept open and added to the 'Asset' when
15 in-service.

16
17 **(c) and (d)**

18
19 This work has not yet been completed.

20
21 Litostroj has been contracted to complete all of the aforementioned deliverables at a
22 contract value of \$6,806,558.

23
24 **(e)**

25
26 Internal work includes: YEC engineering, Project Management, procurement, health and
27 safety, operations, and site construction monitoring support. The estimated cost of YEC
28 internal support is \$500,000.

29
30 **(f)**

31
32 There is no additional work outside what has been defined above. Rehab of tailrace
33 cranes and concrete piers are not a part of this Project.

1 **(g)**

2
3 No WH2 Uprate project work was completed prior to 2018. The 2018 work included
4 developing project specifications and tendering as well as internal PM and engineering
5 work.

6
7 **(h)**

8
9 Total Amount for this project is \$12.297 million as per footnote 28 on Tab 5, page 5-19 of
10 the Application, i.e., this includes the engineering related costs shown in Appendix 5.4 of
11 \$0.259 million.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

13 5.2.1.10 WH4 Uprate - Servomotor Replacement (\$0.052 million in 2018; \$0.079 million in 2019; \$0.400 million forecast in 2020; and \$1.000 million forecast in 2021)

15 The project involves detailed design, procurement and installation of two new Servomotors for
16 Whitehorse Hydro Unit 4 (WH4) wicket gate operation.
19 Contracts with Andritz (OEM), L&S Electric (to review documentation and develop a governor
20 commissioning plan) and Hatch (owners engineer) have been finalized. Procurement has not yet been
21 undertaken for testing services and installation of a lifting device.
22 Yukon Energy entered into a contract with ANDRITZ Hydro for the design and supply of two new servo
23 motors. Final design is nearing completion and manufacturing is expected to commence in Q3 2020.
24 Other work is proceeding in parallel including planning for changes to the governor, signature testing and
25 characteristic testing with assistance from Hatch and L&S Electric. Delivery of the Servos is expected by
26 January 2021. Contractor mobilization and installation, testing and commissioning is expected to occur in
27 June 2021. The project is expected to be in service in June 2021.

QUESTION:

- a) Detail which contracts and work performed with costs to Andritz(OEM), L&S Electric, and Hatch.
- b) Identify any other contracts with work performed and costs.
- c) Identify all work performed and costs for in-house.
- d) Identify all costs and for what work completed to WH4 for 2018 and prior years.
- e) Give total cost of WH4 overhaul to date.

ANSWER:

(a)

This project is not yet complete. YEC currently has a contract with Andritz for \$744,000. L&S Electric will support with governor work, tuning and commissioning at a cost of \$70,000. Hatch is acting as owner's engineer at a cost of \$35,000.

1 **(b)**

2
3 No additional contracts have been put in place at this point in time.
4

5 **(c)**

6
7 This project is not yet complete. The work YEC will be performing includes, Engineering,
8 Operations, Procurement, Health and Safety, and Project Management support. It is
9 estimated that YEC internal cost will be \$153,000.
10

11 **(d)**

12
13 Total costs for 2018 and prior were \$51,894.08. This covered initial feasibility studies and
14 specification development.
15

16 **(e)**

17
18 Total costs up to December 31st, 2020 are \$385,000.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

5.2-1: GENERATION PROJECTS

Dam Safety Review

Dam Safety Program

2019Actual	2020Forecast	2021Forecast
		\$300,000

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA).

A DSR was completed in 2020 and included an extensive inspection of all water control facilities, underwater inspection of structural elements by divers, geotechnical investigation of the Whitehorse power canal, and research into historical records of YEC assets. The 2020 DSR resulted in a detailed report that prioritized recommendations for work to be completed in future years. Spending in 2021 is required to address 2020 DSR outcomes and priorities identified for 2021. Some of the high priority items that will be addressed include:

- Wareham dam spillway design
- Warning and danger signage around the six dams
- Public safety around Marsh Lake

Dam Safety Recommendations 2017/18

2019Actual	2020Forecast	2021Forecast
\$272,000	\$300,000	

The 2015 DSR resulted in a detailed report that outlined a list of observed deficiencies and corresponding recommended actions to address identified deficiencies and eliminate hazardous conditions which could adversely affect the safety of the public and YEC staff. 2019 spending included required maintenance around the Marsh Lake control structure, and replacement of Whitehorse piezometers; while planned 2020 activities include replacement of the Mayo Lake Dam wood planking, Wareham Dam seismic upgrades, and the implementation of a public safety plan at the Marsh Lake control structure.

QUESTION:

- Confirm all projects listed in Appendix 5.2 need to undergo a prudence test and approval from the Board before any/all can be entered into rate base.
- Confirm the last DSR was done in 2015.
- Confirm each project must be confirmed to be 'used and useful' before it can be entered into rate base.

1 d) Why were the 2015 recommendation of DSR not done until 2019 and forecast
2 2020, if they are so hazardous?

3
4 e) Are not some of the forecast work for 2021 the same as the 2021 safety
5 recommendations?

6
7 **ANSWER:**

8
9 **(a) and (c)**

10
11 Projects are included in rate base the year they are completed and in service. Project
12 costs must be reviewed and approved by the Board before being included in rates. The
13 Board's review and approval process includes assessment of cost prudence and that
14 assets are used and useful.

15
16 **(b)**

17
18 The last DSR was performed in 2015.

19
20 **(d)**

21
22 YEC plans and prioritizes projects throughout the year, taking into account any actions
23 needed to reduce or remove hazardous conditions that could potentially pose a threat to
24 the public, YEC staff, or property. At times, projects are shifted due to unforeseen events
25 which results in project deferral.

26
27 **(e)**

28
29 Forecasted 2021 work was driven from the 2020 Dam Safety Reviews. The 2015 Dam
30 Safety recommendations and the 2020 Dam Safety review both flagged work to be
31 undertaken to address public safety at Marsh Lake – this appears to be the only common
32 element between the 2017/18 Dam Safety Recommendations and the 2020 Dam Safety
33 Review. The response to YUB-YEC-1-75 provides an update the 2017/18 Dam Safety
34 Recommendations Project. This response notes that the Public Safety Plan was not
35 completed due to the fact that YEC was waiting for results from the 2020 Dam Safety
36 Review for inclusion into the Public Safety Plan.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

P126 LNG Boil-Off Gas Heat Exchanger

2019Actual	2020Forecast	2021Forecast
\$194,000		

Prior to decommissioning of the Mirrlees diesel generators, LNG boil off gas was piped to P126 and burned in the P126 plant boiler and/or dissipated through the WD1 jacket water heat exchanger. With retirement and removal of the three Mirrlees gensets at the Whitehorse Diesel Plant (P126) there was a requirement to replace this heat dissipation function and to design, supply and install a new heat exchanger at the plant to dissipate extra heat from the combustion of LNG boil off gas. Work related to the installation of the heat exchanger included hiring an owners engineer to prepare design, drawings and specifications for the new heat exchanger, piping, a new pump with VFD, and a temperature sensing device, and provide mechanical and electrical drawings and technical specifications for equipment and piping installation for tendering the construction work.

QUESTION:

- a) Confirm this work has been completed and operational.
- b) Why is this extra heat not utilized to heat buildings or some other cross purpose?

ANSWER:

(a)

This work has been completed.

(b)

The extra heat is typically available only during summer months (when the LNG plant is offline). The heat can be used for building heat or dyke heat if needed, but this is rarely the case.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 5.2-1: GENERATION PROJECTS

6
7 Wareham Gate Heater

8 2019Actual	2020Forecast	2021Forecast
9 \$574,000	\$100,000	

10
11 The Wareham Gate Heating project replaced an old and ineffective heating system on both Wareham Spillway
12 Gates. The new system is designed to keep both spillway gates operational through the winter. Passing flows
13 during outages and times of high inflows is a critical function of the spillway.
14

15 **QUESTION:**

16
17 a) Confirm this work has been completed and operational.
18

19 **ANSWER:**

20
21 **(a)**

22
23 The project is complete and operational.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 5.2-1: GENERATION PROJECTS

6
7 Wareham Gate Refurbishment

8 2019Actual	2020Forecast	2021Forecast
		9 \$250,000

10 The Wareham Dam impounds Wareham Lake and is classified as an extreme hazard Dam.¹ The Wareham
11 Spillway Gates have been in service since 1953 and are critical infrastructure for the Wareham Dam. The
12 spillway gates at Wareham Dam have had significant leakage problems over a number of years, primarily due
13 to age-related wear and corrosion. Recent observations, including an external engineering assessment,
14 indicated that the gates were deteriorating in several ways. Specifically, the skinplates were experiencing
15 pitting corrosion² and needed to be repaired by sandblasting, adding additional plates and plug welding and
16 seal welding the plates in an array to add strength. During testing of the hoist following repairs in 2019,
17 extremely high friction forces were also observed acting on the gate; the wheel bushing was worn; and there
18 was evidence of fretting wear on the wheel paths. Side seals were also leaking at a high rate at times; and
19 copper staunching rod links and retaining clips required refurbishment with new self lubricated bushings to
20 allow them to seal smoothly. Spending in 2020 was focused on undertaking work as identified above to
21 address each of these issues.

22
23 **QUESTION:**

24
25 a) Confirm this work has been completed and operational.

26
27 **ANSWER:**

28
29 **(a)**

30
31 This work has not been completed.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 5.2-1: GENERATION PROJECTS

6
7 Whitehorse Diesel System Grounding for Generators

8 2019Actual	2020Forecast	2021Forecast
9 \$218,000	\$10,000	

10
11 This project prepared grounding calculations and installed acceptable grounding equipment for all Whitehorse
12 diesel generators in order to address the following issues: (1) WD4 and WD5 generators were ungrounded
13 and in the case of a ground fault there was risk of significant damage to this equipment; and (2) the grounding
14 for WD6 and WD7 generators was not identical, and this was an inadequate configuration when several
15 generators were running in parallel.

16
17 a) Confirm this work has been completed and operational.

18
19 b) Why would Yukon Energy have any facility that is not properly grounded?

20
21 **ANSWER:**

22
23 **(a)**

24
25 This work has been completed and is operational.

26
27 **(b)**

28
29 Standards and system site conditions change over time. It is prudent for YEC to
30 continuously assess its grounding systems to ensure design functionality is being realized
31 as expected. YEC determines if there are any issues resulting from the assessments and
32 puts a plan in place to fix.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 5.2-1: GENERATION PROJECTS

6
7 WH1 and WH2 Design and Install Dewatering System

8 2019Actual 2020Forecast 2021Forecast

9 \$137,000

10
11 A suitable system was not in place to automatically control the water levels in the WH1 and WH2 draft tube
12 during dewatering activities. This project installed a redundant and automatic dewatering system integrated
13 with the station PLC to provide visibility and status alarms to increase safety and reduce the risk of a flood in
14 the P125 plant. Prior to implementation of the project, the existing system was oversized, and required large
15 volumes of makeup water to be.

16
17 a) Confirm this work has been completed and operational.

18
19 b) Why would the existing system be oversized in the first place?

20
21 **ANSWER:**

22
23 **(a)**

24
25 The project is completed and is operational.

26
27 **(b)**

28
29 It is unknown as to why the existing system is oversized.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 5.2-1: GENERATION PROJECTS

6
7 WH4 Ventilation

8 2019Actual	2020Forecast	2021Forecast
		9 \$750,000

10
11 The WH4 plant is overheating during the summer. Given that YEC is adding additional capacity to the WH4
12 hydro unit with new servo motors in 2021, removing the restriction placed on output by the overheating issue
13 will enable the extra capacity to be used reliably throughout the year.

14
15 **QUESTION:**

16
17 a) Why is this program not included in the WH4 overhaul?

18
19 b) Confirm this work has been completed and operational.

20
21 **ANSWER:**

22
23 **(a)**

24
25 Both the ventilation and uprate projects are different in nature and as a result YEC decided
26 to keep them separate.

27
28 **(b)**

29
30 This project has not started. Engineering, estimating and planning will occur in 2021 with
31 project commencement and completion in 2022.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **5.2-2: TRANSMISSION PROJECTS**

6
7 **Alexco Mobile Substation Connection**

8 **2019 Actual 2020Forecas 2021Forecast**

9 \$178,000

10 (\$178,000contribution)

11
12 Alexco plans to use a 3 MVA, 69 kV/4.16 kV mobile self-contained substation to feed their Birmingham site at
13 Keno. The substation must be connected to the McQuesten-Keno 69 kV line. The project includes supply,
14 installation and commissioning of the new line tap including connection to existing 69 KV line, engineering and
15 commissioning support for the new mobile substation. YEC has engaged Chimax to complete a 69 kV line tap
16 design to connect the Alexco mobile substation to the McQuesten-Keno 69 kV line. The actual project costs
17 will be fully recovered from the customer.

18
19 **QUESTION:**

20
21 a) Is this to be included in the rate base account and how is this accommodated?

22
23 **ANSWER:**

24
25 **(a)**

26
27 This project is included in rate base. With the contribution there is no net impact to rate
28 base. Costs are not included in rates until approved by the Board.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

Line 177 Re Route

2019Actual	2020Forecast	2021Forecast
	\$105,000	\$250,000

Some areas of L177 are on the border, or within, the highway right of way (ROW). The Yukon Highways Department is undertaking road construction upgrades; and the design will have cuts for a new ditch starting where some YEC poles are currently located. Three poles fall within a highway cut and at least one will be within 2 m of a highway cut. As a condition of our permit with YG, YEC is required to move the affected poles, and poles adjacent, in order to meet Yukon Government's construction requirements.

QUESTION:

- a) Why would Yukon Energy not be liable for this error?
- b) Should not Yukon Energy or their contractor absorb this cost?
- c) Confirm this work completed and operational.

ANSWER:

(a) and (b)

Portions of L177 are within the highway ROW and the terms and conditions of the YEC permit require YEC to move assets at YEC's expense when directed to by YG. This is a regulatory requirement. As such, Yukon Energy considers it a prudent expenditure that should be considered recoverable in rates.

The existing location of the L177 reflects assessments and action done when the facilities were originally installed, and does not confirm any "error" or liability as assumed in the question.

(c)

Work is complete and operational.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **Minto Mine Substation – Neutral Ground Resistor**

6 **2019 Actual 2020Forecast 2021Forecast**

7 \$105,000

8 (\$184,000 contribution3)

9
10 The Minto mine requires that the following equipment be installed at the S254 Minto mine substation to be in
11 compliance with regulatory direction: 25 kV recloser c/w bypass switch, instrument transformers, protection
12 and controls; and 5 kV NGR c/w instrument transformers, protection and control. As this equipment is being
13 installed at the customer's request, the full cost of the work will be recovered from the customer.

14
15 **QUESTION:**

16
17 a) Is this to be included in the rate base account and how is this accommodated?

18
19 **ANSWER:**

20
21 **(a)**

22
23 Projects are included in ratebase the year they come into service. The project was
24 completed in 2019. The project includes a contribution amount that exceeds the cost
25 incurred in 2019 due to the contribution also addressing a cost incurred in a prior year –
26 the net impact will therefore reduce rate base. Project costs are not included in rates until
27 reviewed and approved by the Board.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

5.2-1: GENERATION PROJECTS

Line 177 Re Route

Protection and Control Program

2019 Actual	2020Forecast	2021Forecast
		\$300,000

The protection and control program is a capital replacement program under development as part of the Asset Management Framework. YEC has engaged SNC to conduct an asset condition assessment for all protection and control equipment in all generating plants and substations throughout the YEC system. The protection and control review will develop a 20-year capital plan to prioritize the replacement of aging protection and control assets throughout the YEC grid. The program is being undertaken to improve system reliability, protect generating and transmission assets, and reduce outage frequency.

QUESTION:

- a) Since the YEC has spent millions on a Asset Management Program, explain why Yukon Energy would need to hire an outside consultant to do this work?

ANSWER:

(a)

This is an output of the Asset Management Program. Protection and Control is a specialized industry and as a result, consultants with this expertise are required to support YEC in development and implementation.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

Line 177 Re Route Transmission Line Access

2019 Actual	2020Forecast	2021Forecast
\$324,000	\$300,000	

YEC requires access to transmission lines for maintenance, inspection, and brushing activities. A number of temporary access points lacked the necessary permitting and were potentially not constructed to an acceptable standard. The Yukon government authority has indicated this situation is no longer acceptable and must be rectified. The project included the completion of a management plan for transmission access points including current condition, work and permits required, and estimated costs, specifically for accesses required to complete the Transmission Line Refurbishment project (see Section 5.2.1.5). It also included construction of new accesses and upgrades to existing accesses. Completion is expected to result in faster response times for emergency line work, avoidance of potential YG penalties and reliable access to key YEC assets.

QUESTION:

a) Is this not included in another area of capital works?

b) Since the YEC has spent millions on a Asset Management Program, explain why Yukon Energy would need to hire an outside consultant to do this work?

ANSWER:

(a)

No. It is not included in any other area of capital works.

(b)

This requires the support from a consultant with the expert skillset to develop a program which will be a component of the Asset Management system.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

Van Gorda Substation

2019Actual	2020Forecast	2021Forecast
\$54,000	\$199,000	
(\$188,000 contribution)		

Crown Indigenous Relations and Northern Affairs Canada (CIRNAC) is responsible for the Faro Mine Site; they are working to design, supply, install and commission a substation at the Van Gorda mine which is part of the Faro mine complex. CIRNAC has also expressed interest in transferring ownership of an existing stepdown transformer (138kV: 4.16 kV / 12 MVA) at the Faro substation which is currently out of service. CIRNAC has requested that Yukon Energy support their project. Yukon Energy's role in the project would be to support CIRNAC and its technical consultants with respect to technical and operational matters, support transfer of ownership of the T1 Transformer, supply YEC approved meters, complete SCADA works for YEC monitoring, and monitor commissioning activities. YEC will witness all commissioning and start up activities.

QUESTION:

- a) Why is this not fully recovered from CIRNAC?
- b) Is this to be included in the rate base account and how is this accommodated.

ANSWER:

(a)

CIRNAC is making a full contribution for costs related to YEC supporting CIRNAC and its technical consultants with respect to technical and operational matters, support transfer of ownership of the T1 Transformer, supply YEC approved meters, complete SCADA works for YEC monitoring, and monitor commissioning activities. The application included a forecast contribution of \$188k for this work in 2020 in error. It should have shown a contribution of \$54k in 2019 and \$134k in 2020 (total forecast contribution for both years of \$188k).

The variance in forecast costs in 2020 of \$65k (\$199k forecast spending -134k contribution from CIRNAC) relates to additional costs incurred by YEC to complete SCADA works for

1 YEC monitoring that were not part of the CIRNAC scope of work. The scope of this work
2 included the following:

- 3
- 4 • Installation/commissioning of radio communication equipment at the Faro diesel
5 plant and the CKRW tower to ensure YEC has the ability to send and receive
6 SCADA information from Vangorda substation and Faro mine;
7
- 8 • A new revenue meter and CTs for the revenue meter purchased and installed at
9 Faro mine; and
10
- 11 • Replacement of the revenue meter PTs at Vangorda to meet ATCO's metering
12 system requirements.
13

14 **(b)**

15

16 The project was completed in 2020 and included in rate base. Contributions would reduce
17 the impact on rate base. Costs are not included in rates until approved by the Board.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **WAF Transmission Upgrades**

6 2019Actual	2020Forecast	2021Forecast
7 \$793,000		

8
9 The WAF transmission system allows low cost hydro generation supplied from Aishihik, Whitehorse, or Faro
10 to be transmitted to other locations on the grid. Failure of a transmission line structure would interrupt this
11 supply, potentially resulting in a wider grid collapse. The structures on this transmission line were built in the
12 1960s through 1970s and were in various stages of deterioration. 2019 project work focused on L178
13 (Carmacks to Faro). The remainder of the WAF line was addressed as part of the Transmission Line
14 Refurbishment (TLR) project (see Tab 5, Section 5.2.1.5); and the remainder of the deficient L178 structures
15 will be replaced as part of the L178 portion of the TLR project (see Tab 5, Section 5.2.1.6).

16
17 **QUESTION:**

18
19 a) Appears to be a duplicate of the L178 capital request? Explain.

20
21 **ANSWER:**

22
23 **(a)**

24
25 The 2019 WAF Transmission Upgrades project work focused on L178 (Carmacks to Faro).
26 This work was completed separately from the L178 portion of the TLR project.

27
28 The excerpt referenced in the preamble to this question specifies that the remainder of the
29 WAF line upgrade work (not included in the WAF Transmission Upgrades) was addressed
30 as part of the Transmission Line Refurbishment (TLR) project (see Tab 5, Section 5.2.1.5);
31 and the remainder of the deficient L178 structures will be replaced as part of the L178
32 portion of the TLR project (see Tab 5, Section 5.2.1.6). Table 5.2-1 in Tab 5 of the
33 Application does not show spending on the L178 portion of the TLR project prior to 2021.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **5.2-3: DISTRIBUTION PROJECTS**

6
7 **Customer Extensions**

8 2019Actual	2020Forecast	2021Forecast
9 \$626,000		
10 (\$698,000 contribution)		
	11 \$600,000	
	12 (\$426,000 contribution)	
		13 \$600,000
		14 (\$400,000 contribution)

15
16 Yukon Energy is required to provide service to new customers connecting to the grid system. Customer
17 extensions are forecast and budgeted as capital items without identifying specific projects. Most costs of
18 customer extensions are covered by customer contributions pursuant to the Terms and Conditions of Service.

19
20 **QUESTION:**

21
22 a) Explain how you forecast extensions and contribution?

23
24 **ANSWER:**

25
26 **(a)**

27
28 YEC uses a rolling average for the customer extensions budget. It is difficult to predict the
29 number and type projects YEC may see on an annual basis (e.g., commercial projects
30 where contributions can be quite high). The number of customer connects can be quite
31 variable year to year.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 L355 Voltage Regulator

6 2019Actual	2020Forecast	2021Forecast
7 \$144,000	\$35,000	

8
9 Atco Electric Yukon (AEY) has reported low voltage levels (below CSA standards) at the AEY Haines Junction
10 substation, which is supplied from Aishihik via distribution line L355. The project identified the voltage profile
11 of L355, determined the appropriate location and settings of voltage regulators, and completed all installation
12 and commissioning work.

13
14 **QUESTION:**

15
16 a) Were these new voltage regulators and are they now in use?

17
18 b) What is the forecast work for 2020? And why to rate base?

19
20 **ANSWER:**

21
22 **(a)**

23
24 These are new voltage regulators and are now in use.

25
26 **(b)**

27
28 The forecast work in 2020 was to install additional ground conductor and to commission
29 once complete. This was a capital expenditure.

TOPIC Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

System Improvements for Eagle Gold Mine

2019 Actual	2020Forecast	2021Forecast

\$487,000		

(\$487,000		

Contribution)		

The VGC Group PPA provides for development on the Yukon grid of the McQuesten Substation plus the Initial YEC Facilities Improvements, as described in Schedule C of the VGC Group PPA, prior to Commencement of Delivery to the Eagle Gold Mine. These Yukon grid enhancements and facilities are required to connect the Mine to the existing transmission grid, to maintain acceptable system voltages while supplying this new load, and to address potential contingent operating conditions such as loss of generation at Mayo or loss of the transmission connection between Mayo and Whitehorse. The VGC Group PPA provides in Section 6.1 for YEC to recover from the mine the reasonably incurred capital costs for the Initial YEC System Improvements as set out in Schedule C of the PPA.

QUESTION:

a) How is this accounted for in the rate base?

ANSWER:

(a)

Project costs are included in rate base the year the project is completed. With the contribution there is no net addition to ratebase. Costs are not included in rates until approved by the Board.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

5.2-4: GENERAL PLANT AND EQUIPMENT PROJECTS

Communications Upgrades

2019Actual	2020Forecast	2021Forecast

\$801,000		

The project completed a number of recommendations that resulted from a Communications Needs Assessment undertaken by an independent consultant that were required to achieve necessary improvements in security, integration, performance and redundancy. The project was reviewed in detail in the 2017/18 GRA.4 YEC noted at the time that the project was planned to be executed over multiple years – "The 2017/18 review noted that satellite installations for SCADA and fibre communications upgrades were required to create redundancy for disaster planning; network access controls were needed due to changes resulting from the satellite installations, and that the SCADA communications upgrades would facilitate satellite communication at YEC's various sites. Key projects completed in 2019 included: fibre communication upgrades; SCADA upgrades, the Takhini Redundant Datacentre; Satellite installations for SCADA.

QUESTION:

- a) Identify the independent consultant for the Communications Needs Assessment, work completed and cost.
- b) Identify the contractor/s who did the upgrades, work completed and costs.
- c) Are all these upgrades now operating efficiently?

ANSWER:

(a)

The Communications Needs Assessment was completed by BBA to provide a holistic assessment of YEC's communications infrastructure and a guide to evolving it to meet future needs and requirements. The BBA assessment was completed in 2016 at an approximately cost of \$60,000. A review/ update of this work was undertaken in 2018 to finalize the scope of the capital project at a cost of \$10,788.

1 The study looked at both information technology and operations technology and
2 addressed the following:

- 3
- 4 • SCADA and remote data collection
- 5 • Corporate data, voice and video communications
- 6 • Cost Effectiveness over life-cycle
- 7 • Reliability and Redundancy
- 8 • Security
- 9 • Safety
- 10 • Accessibility and availability
- 11 • Future needs: new plants, future data collection strategies, bandwidth
- 12 requirements, protocol migration, backup control center, disaster recovery, etc.
- 13 • Review of current network topography
- 14 • Review of existing SCADA, data, voice and video communications infrastructure
- 15 • Risk identification and qualification
- 16 • Identification of gaps with equipment capabilities
- 17 • Maintenance requirements and life cycle estimates
- 18 • Limitations and risks summary
- 19 • Available Technology, options.
- 20 • Simple cost/benefit/risk analysis.
- 21 • Office and mobile workforce equipment requirements.
- 22 • Substation and plant equipment requirements.
- 23 • Bridging strategies in existing facilities and requirements in new plant.
- 24 • Overall Data Communications strategy.
- 25 • Opportunities for improvement.
- 26 • Opportunities for joint-ventures (Government, First Nations, Northwestel, Private)
- 27 • Growth strategy including an examination of maintenance workforce requirements.

28
29 **(b)**

30
31 The project was completed at a total cost of \$1.152 million.¹ 2019 actual spending was
32 \$0.801. million.

¹ \$0.351 million was included in ratebase as part of the 2017/18 GRA Application; and \$0.801 million was incurred in 2019. The project was completed in 2019.

A summary of costs by contractor is as follows:

Table 1: Project Cost by Contractor

<u>Vendor</u>	<u>Note</u>	<u>Activity</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>Total</u>
Charter Telecom	A	Data Centre materials and some network programming	25,097	145,072	354,611	524,780
Northwestel Inc.	B	Fiber work for Takhini and Mayo			208,350	208,350
Total North Communications	C	Satellite equipment and installations (includes costs related to UPH Networks)			49,596	49,596
Dell Computer Corporation	D	Dawson and Mayo Community Servers	30,415			30,415
Westower Communications Ltd	E	New Ashihik Headgate Tower			26,490	26,490
BBA Engineering Ltd.	F	Update to original communications needs assessment		10,953		10,953
McWatters Network Engineering LTD	G	Nwtel Service Upgrade Project Management and Fiber Design consulting	5,700	17,550		23,250
Alpha Technologies	H	Radio equipment for Ashihik	189		7,348	7,537
CDW Canada	I	Radio equipment for Ashihik			7,517	7,517
Walters Construction & Industrial Corp	J	Aishihik Tower pad construction costs			6,670	6,670
Teshmont Consultants LP	K	Aishihik Tower erection costs			4,708	4,708
R.C. Crane and Construction	L	Aishihik Tower erection costs			4,130	4,130
IBEX Construction Ltd.	M	Aishihik Tower erection costs			1,487	1,487
Maven Consulting Limited	N	Aishihik Tower engineering costs			1,063	1,063
			61,401	173,574	671,971	906,946
YEC Materials, Overhead and Other		Labour, design, materials , and Mayo Communications Shack	34,463	81,175	129,324	244,961
Total			95,864	254,749	801,294	1,151,907

(c)

Yes, these upgrades have been installed successfully and are delivering the functionality and benefits as per the objectives of the program.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **Building Upgrades**

6 2019Actual	2020Forecast	2021Forecast
7 \$370,000	\$275,000	

8
9 In 2016, an external consultant was hired to perform an asset assessment on YEC-owned buildings and
10 facilities, mainly consisting of staff houses and administration buildings.

11
12 2019 work included: exterior works,7 HVAC retrofits,8 flooring replacement,9 electrical panel replacements,10
13 and equipment replacement. 2020 costs relate to replacement of the WH4 hydro plant (P127 roof). During
14 2019 the roof membrane failed, and an interim patch was installed to address a leak. If the roof was not
15 repaired additional leaks would develop and need to be addressed at a much higher cost.

16
17 **QUESTION:**

18
19 a) Identify the external consultant hired to perform asset assessment and costs
20 associated.

21
22 b) Is all the work now completed?

23
24 c) Does Yukon Energy have a maintenance person for its buildings?

25
26 **ANSWER:**

27
28 **(a)**

29
30 Golder Associates Ltd was hired to perform the asset assessment. The cost for this work
31 was \$131,350 + GST.

32
33 **(b)**

34
35 Work was completed as per priorities identified and budgeting, another assessment was
36 due to be done in 2020 as part of a 5 year renewal plan. This has yet to occur as there
37 are still some outstanding deficiencies being addressed in 2021.

1 (c)

2

3 A property manager is in place. There is no maintenance personnel dedicated to
4 buildings, and the work is primarily outsourced.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **Compact Digger Truck**

6 2019Actual	2020Forecast	2021Forecast
		7 \$185,000

8
9 The purchase of a 4 to 5 ton chassis compact digger truck for use in Dawson...

10
11 **QUESTION:**

12
13 a) Is this digger truck now purchased and operating in Dawson?

14
15 **ANSWER:**

16
17 **(a)**

18
19 No. Procurement will happen in 2021.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **Crane Inspection**

6 2019Actual	2020Forecast	2021Forecast
	\$165,000	\$400,000

7
8
9 During an annual crane inspection, three YEC cranes (Aishihik service building, P127 powerhouse, & P127
10 stop log hoist) were identified as needing significant structural, electrical, and mechanical repairs in order
11 remain in acceptable working condition. 2020 spending will provide for a detailed assessment of each crane
12 to determine an engineered plan for replacement or refurbishment as required. Actual construction activities
13 are planned for 2021.

14
15 **QUESTION:**

16
17 a) Has this inspection and construction been completed and now operating?

18
19 **ANSWER:**

20
21 **(a)**

22
23 The inspection has been completed and the cranes are functional. However, there is
24 work still to be completed.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

5.2-4: GENERAL PLANT AND EQUIPMENT PROJECTS

Mayo Earthworks

2019Actual	2020Forecast	2021Forecast

\$300,000		

A number of issues at and around the Mayo Hydro facilities have been identified. These include slope instability and erosion issues near access roads (Mayo A, Mayo B, and Wareham dam), both powerhouse buildings, surge tank, and both substations. During 2019 a complete site inventory of civil issues was undertaken to identify and prioritize embankments. 2020 spending developed a detailed work plan for identified issues including a geotechnical assessment, topographic survey, detailed engineering design (including drawings and specifications), construction methodology, and project scope, schedule & budget development.

QUESTION:

a) Is this earthworks all completed or was this just for the assessment work?

b) Identify contractor, work completed and cost for each job.

ANSWER:

(a)

Only assessment work has been completed.

(b)

Assessment and engineering work was completed by CAP Engineering at a total cost of \$101,985.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 5.2-4: GENERAL PLANT AND EQUIPMENT PROJECTS

6
7 New Mobile Office Unit – IT

8 2019Actual	2020Forecast	2021Forecast
		9 \$230,000

10
11 The existing IT trailer houses five offices and a closed storage space. It is aging and requires additional O&M
12 support each year. The project involves replacement of the aging, undersized IT trailer with a larger unit able
13 to accommodate eight office spaces and storage. Additional office spacing would allow for staff expansion as
14 a less costly solution than building onto the main building.

15
16 **QUESTION:**

17
18 a) Has this IT trailer been bought, set up and operational?

19
20
21 **ANSWER:**

22
23 **(a)**

24
25 No. The procurement process has not started for the new IT trailer.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **Vehicle Purchases**

6 2019Actual	2020Forecast	2021Forecast
7 \$258,000 \$	476,000	\$580,000
8 Fleet vehicles...		

9
10 **QUESTION:**

11
12 a) Identify which vehicles have been purchased and are operational?

13
14 **ANSWER:**

15
16 **(a)**

17
18 Please see response to YUB-YEC-1-85.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **Water Improvement Upgrades**

6 2019Actual	2020Forecast	2021Forecast
7 \$150,000		

8
9 The cooling water and potable water systems in the YEC main corporate office have experienced pre-mature
10 piping failure and select cooling coil leaks for at least the past 10 years. An external engineering firm was
11 engaged to assess the current systems and provide recommendations to address the issues. The project will
12 implement those recommendations including the installation of a particulate filter, a VFD drive for the existing
13 pump, a heat exchanger, new cooling water piping and valves, and fan coil drip pans with leak detection.

14
15 **QUESTION:**

16
17 a) Which firm did assessment, and at what cost?

18
19 b) Are the necessary changes made and operational?

20
21 **ANSWER:**

22
23 **(a)**

24
25 Stantec Architecture Ltd. was retained to do the assessment at a cost of \$7,450.00 + GST.

26
27 **(b)**

28
29 With the exception of an exchanger all changes have been made, and the water system
30 is currently functional.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 5.2-5: OVERHAULS & RESERVE FOR SITE RESTORATION PROJECTS

6
7 FD7 Overhaul

8 2019Actual	2020Forecast	2021Forecast
		\$580,000

9
10
11 Faro Diesel #7 (FD7) is located at the Faro Diesel Plant and uses as 12-cylinder Caterpillar Model 3612 diesel
12 engine as its prime mover (vintage 1992).

13
14 **QUESTION:**

15
16 a) Is FD7 overhauled and now operational?

17
18 **ANSWER:**

19
20 **(a)**

21
22 FD7 has not been overhauled. It is operational.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 5.2-5: OVERHAULS & RESERVE FOR SITE RESTORATION PROJECTS

6
7 Decommissioning on WD3

8 2019Actual	2020Forecast	2021Forecast
		9 \$999,000

10
11 After removing the third Mirrlees engines from service, all three units were fully decommissioned.
12 Decommissioning included disassembly and removal of all ancillary equipment and piping, asbestos
13 abatement as required, separation and hoisting of major engine components, and backfill and compaction of
14 the engine pits. All decommissioned equipment was removed from site and appropriately disposed of.

15
16 **QUESTION:**

17
18 a) Is this work complete or is it forecast?

19
20 b) Identify contractor and cost for each project.

21
22 **ANSWER:**

23
24 **(a)**

25
26 This work is complete.

27
28 **(b)**

29
30 The contractor for this project was Klondike Welding and the total cost for the project was
31 \$999,000.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

4
5 **Site Restoration Transmission Lines**

6 **2019Actual 2020Forecast 2021Forecast**

7 \$174,000

8
9 The Utility maintains a regulatory provision for future removal and site restoration related to property, plant
10 and equipment. Costs of dismantling capital assets, including site remediation, are applied to this account. In
11 2019, YEC spent \$0.174 million on site remediation relating to the L178 and L355 Transmission Lines.

12
13 **QUESTION:**

14
15 a) Identify contractor/s work completed and costs.

16
17 **ANSWER:**

18
19 **(a)**

20
21 In 2019, YEC spent \$0.174 million on site remediation relating to the L178 and L355
22 Transmission Lines. Work included site restoration after the structure repairs and or
23 replacement. Some of the work was related to failed test and treat structures where the
24 pole shell thickness was less than 2 inches, this requires a pole change out. Work on
25 structures included:

- 26
27
 - 61 structures L178
 - 15 structures L355

28
29
30 Costs were allocated as follows:

- 31
32
 - Ibex Construction performed the work on L178 (\$122,436);
 - YEC performed the work on L355 (approximately \$52,000).

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

1. Aishihik Generating Station (AGS) Long Term Year Water Use Licence Renewal

2018 WIP	2019Additions	2020Additions	2021Additions
\$4,957,199	\$512,755	\$1,488,000	\$960,000

The planned long term AGS Water Use Licence renewal project and related costs were initially reviewed as part of the 2017/18 GRA. At that time, it was noted that the total forecast budget for the project was \$3.569 million spread over five years (2015-2019). Project expenditures to support the long term licence renewal were reviewed in detail in the 2017/18 GRA (See Section 5.3.1.2 and response to YUB-YEC-1-77 in that GRA). Total deferred costs to the end of 2018 were forecast at \$2.899 million.

In 2018, Yukon Energy prepared a long-term Project Proposal application for filing with YESAA Designated Office in December 2018, prior to Yukon Energy's decision in early 2019 to secure a three-year licence renewal.¹ The longterm Project Proposal document was updated over Q1 and Q2 2020 and filed with the Haines Junction Designated Office in July 2020. It is expected that the Designated Office review process will be completed in Q2 2021. Yukon Energy expects to prepare and file its long term water use licence renewal application with the Yukon Water Board in early 2021, and that a hearing regarding the licence renewal would occur sometime in 2022. The deferred costs forecast in the Application include spending in WIP increasing from \$4.957 million at the end of 2018 to \$7.918 million by the end of 2021. The project is forecast to be complete by the end of 2022. A three-year licence renewal was secured in February 2020, extending the licence to December 31, 2022.

QUESTION:

- a) Outline project related work completed, costs and contracts awarded, as prepared for 2017/18 GRA.
- b) Were these approved? If so, give relevant Board decision.
- c) If forecast cost to end of 2018 were forecast at \$2.899 million, why is the 2018 WIP listed at \$4.957,199 million.
- d) Identify firms hired, contract amount and work completed for the \$512,755, 2019 additions.
- e) Identify in-house work completed and costs for 2019 additions.

1 f) Identify firms hired, contract amount and work completed for the \$1.488 million
2 2020 additions.

3
4 g) Identify in-house work completed and costs for 2020 additions.

5
6 h) Identify firms hired, contract amount and work completed for the \$0.966 million
7 2021 additions.

8
9 i) Identify in-house work completed and costs for 2021 additions.

10
11 **ANSWER:**

12
13 **(a)**

14
15 In the 2017/18 GRA, the total budget for the project was forecast at \$3.569 million spread
16 over five years (2015 – 2019). The information prepared for the 2017/18 GRA with regards
17 to the work is detailed in YUB-YEC-1-77 from the 2017/2018 GRA (see Attachment 1 to
18 this response).

19
20 **(b)**

21
22 This was a deferred project in the 2017/18 GRA. The project was not forecast at that time
23 to be completed until the end of 2019. As such these costs were not approved as part of
24 that prior proceeding.

25
26 **(c)**

27
28 The 2018 costs were forecast costs at the time of the GRA filing; actual 2018 costs as
29 reported in the 2021 GRA are higher than the 2017-18 GRA forecast. In both GRA's, these
30 costs remain in WIP.

31
32 **(d)**

33
34 Table 1 below provides the contractors, work completed, and costs incurred in 2019 for
35 the project. YEC internal costs incurred in 2019 are addressed in response to part (e).

Table 1: Contractor Costs and Work Completed (2019)

Contractor	Cost	Work Completed
Ecofor Consulting Ltd	\$90,923	Archaeological and heritage resources technical support
Environmental Dynamics Inc.	\$80,631	Support of YESAB DO Assessment Project Proposal development, Biophysical technical work, Canyon Lake monitoring
InterGroup Consultants Ltd.	\$113,479	Project management, Preparation of YESAA Project Proposal, YESAB DO Assessment Support, Preparation of Monitoring & Adaptive Management Plan, Participation in technical working group, support to compensation and other project negotiations
Morrison Hershfield Limited	\$85,124	MAMP Technical Development, YESAB DO Assessment Support, Responses to Information Requests, Downstream technical work.
Total	\$370,157	

(e)

Table 2 below provides YEC internal costs incurred in 2019 for the project.

Table 2: Yukon Energy Internal Costs (2019)

Element	Cost	Description
Internal Labour	\$4,023	Project Management, Development of Project Proposal
Other Internal Costs	\$3,046	Materials, travel, communications
AFUDC	\$135,528	Accrual of AFUDC
Total	\$142,597	

(f)

Table 3 below provides the contractors, work completed, and updated costs incurred in 2020 for the project (the updated costs are higher than the forecast in the Application).

1

Table 3: Contractor Costs and Work Completed (2020 Forecast)

Consultants	Cost	Work Completed
Aasman Brand Communications Inc.	11,469	Communications and materials development, graphic design
Daryn R. Leas Law Corporation	87,211	Consulting and advisory services for Project Agreement negotiation
DLA Piper (Canada) LLP	172,305	Legal support
Ecofor Consulting Ltd	18,705	Archaeological and heritage resources technical support
Environmental Dynamics Inc.	175,238	MAMP Technical Development, YESAB DO Assessment Support, Biophysical technical work, Canyon Lake monitoring,
InterGroup Consultants Ltd.	340,517	Project management, Preparation of YESAA Project Proposal, YESAB DO Assessment Support, Preparation of Monitoring & Adaptive Management Plan, Participation technical working group, support to compensation and other project negotiations.
Morrison Hershfield Limited	303,389	MAMP Technical Development, YESAB DO Assessment Support, Responses to Information Requests, Downstream technical work, Technical Support for Water Board Application
Champagne & Aishihik First Nations	770,510	Contributions to support technical review of project; Chemi narrows payment from 2002 relicensing process
Total	\$1,879,433	

2

3 (g)

4

5 Table 4 below provides updated YEC internal costs incurred in 2020 for the project.

Table 4: Yukon Energy Internal Costs (2020 Forecast)

Element	Cost	Description
Internal Labour	67,201	Project Management, Development of Project Proposal, Attendance at Technical Working Group meetings, Attendance at Technical Subgroup Meetings, Attendance at Steering Committee Meetings, disbursements for printing, venue rental, telecommunications, etc.
Other Internal Costs	27,594	Materials, printing, travel, communications
AFUDC	164,665	Accrual of AFUDC
Total	\$259,460	

(h) and (i)

Table 5 below provides the costs for the 2021 current contracts budgeted to the end of March 2021. Additional work for the remainder of 2021 has not been contracted or completed.

Table 5: Contractor Costs and Work Budgeted to end of March 2021 (Forecast)

Contractor	Cost	Work Anticipated
Morrison Hershfield Limited	\$59,945	MAMP Technical Development, YESAB DO Assessment Support, Responses to Information Requests, Downstream technical work, Technical Support for Water Board Application
Environmental Dynamics Inc.	\$89,528	MAMP Technical Development, YESAB DO Assessment Support, Responses to Information Requests, Biophysical technical work, Technical support for Fisheries Act Authorization
InterGroup Consultants Ltd.	\$129,320	Project management, YESAB DO Assessment Support, Preparation of Monitoring & Adaptive Management Plan, Participation in technical working group, Support for Water Board Application development; support to compensation and other project negotiations
Ecofor	\$6,600	Heritage and socio-cultural technical support
Champagne & Aishihik First Nations	\$90,000	Contributions to support technical review and participation in project committees

- 1 To date, YEC has incurred \$18,389 of internal labour costs in 2021 for project
2 management and technical resources to support the YESAB DO Assessment
3 development of the Monitoring and Adaptive Management Plan.
4
5 Please see response to YUB-YEC-1-90 for a review of updated project costs by activity
6 through to forecast completion at the end of 2022.

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TOPIC: Aishihik Generating Station Water Use Licence Renewal, Section 5.3.1.2

REFERENCE: Application, pages 5-33 to 5-34. PDF pages 204 to 205

QUOTE: “A licence renewal is required for the continued operation of the 37 MW hydro facility, which provides the only multi-year hydro storage and the largest winter peak hydro generation capability on the Yukon Integrated System. Yukon Energy plans to seek a 25-year licence renewal (the maximum allowed term).

“The total budget for the project is forecast at \$3.569 million spread over five years (2015 – 2019). Total deferred costs to the end of 2018 are forecast at \$2.899 million. The last Aishihik licence renewal project cost approximately \$8.791 million.

“The licence renewal process will include undertaking environmental and socio-economic studies required to support a YESAA Project Proposal (currently targeted for a Designated Office filing in mid-2018), followed by the development and securing of a Yukon Water Board Application and an application for a Fisheries Act Authorization.”

QUESTION:

- a) Please provide a detailed breakdown and explanation of the actual costs from 2015 and 2016 and forecast costs from 2017 onwards for the Aishihik licence renewal project.
- b) Considering that the above is a five-year project, please describe and explain what has been accomplished from 2015 to date, with respect to this project.
- c) Please explain what is meant by a “Designated Office filing”.
- d) Have issues arisen as a result of working with the Champagne and Aishihik First Nations (CAFN) towards a water license use renewal? If so please explain.

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1 e) Considering that YEC is almost three years into the project, are there updates to
2 the total forecast cost of \$3.569 million for this project?

3
4 **ANSWER:**

5
6 **(a)**

7
8 Table 1 provides a breakdown of the actual and forecast expenditures per spending
9 category for the Aishihik water use license renewal project. The actual expenditures for
10 2015 and 2016 are combined since the expenditures were minimal in 2015 due to a delay
11 in the project start. The delay was caused by longer than expected negotiations with the
12 Champagne and Aishihik First Nations (CAFN) related to the novel co-management
13 approach in developing the regulator submissions. The co-management approach is
14 discussed in more detailed in answer to YUB-YEC-77(b).

15
16 The total project expenditure forecast, as presented in column 2015-2019 in Table 1, is
17 based on the budget approved by YEC's Board of Directors in September 2015. As
18 discussed in more details in the answer to YUB-YEC-77(e), the 2015-2019 forecast is
19 expected to increase.

20
21 The project management costs are YEC internal costs related to the work on planning and
22 executing the project.

23
24 The CAFN and stakeholder engagement costs are related to: 1) engagement with the
25 CAFN, including funding the Champagne and Aishihik Community Advisory Committee
26 (CACAC) and traditional knowledge project, discussed in more details in the answer to
27 YUB-YEC-77(b); and 2) public engagement, discussed in more details in the answer to
28 YUB-YEC-77(b).

29
30 The Aishihik Advisory Committee (AAC) costs are related to the activities of AAC
31 discussed in more details in the answer to YUB-YEC-77(b).

32
33 The Impact assessment studies costs are related to the planning and execution of the
34 environmental and social impact assessment studies discussed in more details in the
35 answer to YUB-YEC-77(b).

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The permitting process costs are related to development of: 1) the project proposal to the Yukon Environmental and Socio-economic Assessment Board (YESAB); 2) regulatory application to the Department of Fisheries and Oceans (DFO); and 3) regulatory application to the Yukon Water Board (YWB).

The CAFN compensation costs are related to: 1) the compensation to the CAFN due to the loss of use of the lake for the duration of the future water use license; and 2) negotiation costs to reach a compensation agreement with the CAFN.

Table 1: Actual and Forecast Expenditures for the Aishihik Water Use License Renewal Project

Expenses in \$'000	Actual 2015-2016	Actual Jan - Jun 2017	Forecast Jul 2017 - Dec 2019	Forecast 2015-2019
Project management	79	34	440	553
CAFN and stakeholder engagement	126	36	222	384
Aishihik Advisory Committee (AAC)	81	6	66	153
Impact assessment studies	703	426	630	1759
Permitting process			300	300
Total	989	502	1658	3149

In addition to the above forecast, YEC anticipates payment of compensation to affected lake users, however, the quantum is not known at this time.

(b)

Project accomplishments since its inception until the end of August 2017 are presented in the following categories: establishment of co-management framework; establishment and activities of the AAC; planning and execution of environmental and social impact assessment studies; public engagement; and building relationship with the CAFN. Each of those categories is discussed in the following paragraphs.

Establishment of co-management framework.

Considering the importance of the Aishihik Generating Station (AGS), the fact that the facility is located at the CAFN traditional territory, and complexities encountered during the previous water use licence renewal process due to misaligned expectations between the CAFN and YEC, YEC deemed it prudent to engage the CAFN at the beginning of the

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1 current water use license renewal process. The objective of engagement was to increase
2 participation by the CAFN in the water use relicensing regulatory process, increasing
3 collaboration between YEC and CAFN and reducing the risk of conflict and/or adversarial
4 legal action during the formal regulatory proceedings. As a consequence, CAFN and YEC
5 signed the Aishihik Hydroelectric Power Generation License Renewal Co-Management
6 Protocol Agreement that provided a formal framework for the co-management of the water
7 use licence renewal process between CAFN and YEC. The document stipulates the roles
8 and responsibilities of the parties in the relicensing process, as well as the governing and
9 advisory bodies, such as the Steering Committee, AAC, and CACAC. As a part of the co-
10 management process to develop the assessment and permitting regulatory submissions,
11 CAFN set up the CACAC to provide advice on the introduction of CAFN's values and
12 traditional knowledge to the process to influence the scope and interpretation of the
13 environmental and social impact assessment studies. In the spirit of the co-management
14 agreement, YEC provided funding for the CACAC, as well as the CAFN-led traditional
15 knowledge project that will be a part of the regulatory submissions.

16
17 **Establishment and activities of AAC.**

18 Since, in addition to CAFN, the water use licence renewal process includes external
19 stakeholders, YEC also engaged the major stakeholders in the process through the AAC.
20 The AAC is co-chaired by the CAFN and YEC.

21
22 The AAC's role is to provide ongoing advice and feedback as Yukon Energy and CAFN
23 develop a project proposal targeted for submission to the Yukon Environmental and Socio-
24 economic Assessment Board (YESAB), as well as regulatory applications to the
25 Department of Fisheries and Oceans (DFO) and Yukon Water Board (YWB). In addition,
26 the AAC reconciles potential opposing interests and values of the YEC, CAFN, external
27 stakeholders, and public related to the use of Aishihik Lake.

28
29 Eight AAC meetings have been held since the beginning of the project until the beginning
30 of August 2017, and all the major project activities have been proposed, discussed and
31 approved at AAC meetings.

32
33 The activities of the AAC included:

- 34
35 1. Consideration of the Federal and Yukon Government policies and regulations
36 related to the water use license renewal process;

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- 1 2. Building a common understanding of inputs, analysis methodologies, and
- 2 deliverables related to the water use license renewal process;
- 3 3. Development of potential AGS operational alternatives;
- 4 4. Identification of potential information gaps to define required environmental and
- 5 social impact assessment studies and their scopes, impact assessment planning,
- 6 mitigation and monitoring plans;
- 7 5. Development of the list of the environmental and social impact assessment studies
- 8 required for the regulatory submissions;
- 9 6. Development of the list of valued components to be used to evaluate operational
- 10 alternatives; and
- 11 7. Preliminary evaluation of the operational alternatives.
- 12

13 **Planning and execution of environmental and social impact assessment studies.**

14 As a consequence of the AAC activities, environmental and social impact assessment
15 studies are being executed. To inform the execution of the impact assessment studies,
16 three technical groups were established to execute the decisions made by the AAC. The
17 activities of the technical groups are related to lake issues, downstream river issues and
18 the traditional knowledge project, all of which create a base for development of the
19 documents needed for the regulatory submissions. The technical groups consist of
20 members from YEC, CAFN, and subject matter experts.

21
22 **Public engagement.**

23 As a part of the public engagement strategy, two public meetings, one in Whitehorse,
24 another in Haines Junction, were jointly planned, organized and held by YEC and CAFN.
25 The goal of the meetings was to inform public on the objectives and progress of the project,
26 co-management process and to solicit feedback.

27
28 **Building relationship with the CAFN.**

29 In addition to joint YEC and CAFN activities discussed in paragraphs on establishment of
30 co-management framework, establishment and activities of AAC, planning and execution
31 of environmental and social impact assessment studies, and public engagement, as a part
32 of building relationship with the CAFN, YEC participated in two culture camps organized
33 by the CAFN. The objective of the participation was to familiarize with CAFN values related
34 to water, land and fish.

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1 **(c)**

2

3 A 'Designated Office Filing' refers to a project proposal submitted to a Designated Office
4 for an assessment pursuant to the Yukon Environmental and Socio-economic Assessment
5 Act (YESAA). In this case, the Haines Junction Designated Office is expected to conduct
6 the project evaluation. This level of assessment differs from a project proposal required to
7 be submitted to the more intensive Executive Committee Screening or Panel Review
8 processes of Yukon Environmental and Socio-Economic Assessment Board.

9

10 **(d)**

11

12 Please refer to the answer to YUB-YEC-77(b) for details related to relationship with the
13 CAFN.

14

15 **(e)**

16

17 Largely due to the known increased quantum and scope of the impact assessment studies
18 required for the project proposal to YESAB, as well as the funding of the CACAC and
19 CAFN traditional knowledge project, the project is expected to exceed the initial budget of
20 \$3.569 million. Due to unknown costs related to potential increase in the scope of
21 regulatory proceedings, and compensation to the CAFN, the final project cost cannot be
22 accurately estimated at this time. YEC will continue to monitor the development of costs
23 related to unknowns and adjust the budget accordingly.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 2. Whitehorse Generating Station Water Use Licence Renewal

6 2018 WIP	2019Additions	2020Additions	2021Additions
			7 \$260,000

8
9 The existing water use licence for the Whitehorse Rapids Generating Station (WRGS) expires at end of 2025
10 and must be renewed in order to ensure ongoing, lawful operation of the WRGS hydro facilities. This is a multi-
11 year project to renew the existing long-term project authorizations for the WRGS Hydro Plants and associated
12 infrastructure. Project activities include conducting required baseline studies (e.g., environmental, socio-
13 economic, engineering), and undertaking environmental and socio-economic effects assessment, First Nation
14 engagement and consultation, other stakeholder engagement as required to submit a YESAA project proposal
15 to the Whitehorse Designated Office. Project activities will also include completing the YESAA review process,
16 the water use renewal process with the Yukon Water Board, and Fisheries Act Authorization (DFO) regulatory
17 process.

18
19 **QUESTION:**

20
21 a) Identify firms hired, contract amount and work completed for the \$0.260 million
22 2021 additions.

23
24 b) Identify in-house work completed and costs for 2021 additions.

25
26 **ANSWER:**

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

29
30 No work on this project has been initiated to date.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

Diesel Retirement Replacement (12.5 MW)

2018 WIP	2019Additions	2020Additions	2021Additions
\$41,007	\$554,224	\$800,000	\$5,000,000

it was determined that considering the results of the technical, environmental and socio-economic research, as well as public feedback, YEC would focus potential options to add or replace capacity at existing generation facilities on an incremental basis as diesel engines are retired. This includes consideration of the following near term activities:

- Installation of 5 MW of thermal capacity at the Whitehorse Diesel Plant (P126);
- Replacement of 5.1 MW of diesel to be retired at the Faro Diesel Plant with a 5 MW diesel unit;
- Retirement of the existing 2.5 MW of diesel capacity in Dawson City with installation of 2.5 MW of diesel capacity at the Callison Substation.

Efforts in 2020 have focused on preliminary engineering and finalizing a procurement strategy, defining vendor contracts and milestones, and updating the overall project schedule.

The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from \$0.041 million at the end of 2018 to \$6.395 million by the end of 2021. Dependable capacity from these projects is expected to be available by winter 2023/24. In the interim, Yukon Energy will continue to rent diesel generators each winter to ensure an adequate supply of back-up power in case of an emergency.

QUESTION:

- Identify all diesels with capacity now retired.
- Identify all consultant firms hired, work performed and each cost for 2018WIP, 2019 and 2020 years totaling \$1,395.231 million.
- Identify all in house work performed and cost for these years.
- Is the \$5 million for 2021 for a new diesel generator? Explain.

ANSWER:

(a)

WD3 in Whitehorse was retired in March 2019. In addition, Yukon Energy plans to retire the following diesel units as follows:

- Faro Diesel 1 (FD1) - March 2022;
- Dawson Diesel 2 (DD2) - March 2023; and
- Dawson Diesel 5 (DD5) - March 2023.

(b)

Please see Table 1 below.

Table 1: Summary of Consultant Firms Hired and Work Performed - 2018 to 2020

Consulting Firm	Work Conducted	2018 Costs	2019 Costs	2020 Costs
Aasman Brand Communications Inc.	Consulting for public communications and engagement		\$89,931.57	
ArticCan Energy Services	GHG Lifecycle Analysis		\$31,130	
Asher Engineering Ltd.	Initiation work for generator technical specification engineering			\$4,749.76
Associated Engineering	Road upgrade estimates		\$4,930	
Associated Environmental Consultants Inc.	YESAA DO Level Assessment preparation for Dawson project			\$8,777.64
BBA Engineering Ltd.	P126 Building Retrofit engineering		\$12,423.37	\$60,067.16
Core Geosciences Services	Air Quality Modeling			\$1,757.50
DLA Piper (Canada) LLP	Legal support			\$3,576.64
Environmental Dynamics Inc.	Environmental Attributes desktop review			\$10,344.85
Geotech Drilling Services Ltd.	P126 geotechnical drilling			\$50,403.93
Hatch Ltd.	Technical study support		\$44,800	\$19,200
Hemmera Envirochem Inc.	Noise monitoring for Whitehorse project			\$38,000
IBEX Construction Ltd.	Construction support for geotechnical drilling			\$3,784.5
InterGroup Consultants Ltd.	Socioeconomic Attributes report support and project regulatory analysis		\$18,611.5	\$12,905

Consulting Firm	Work Conducted	2018 Costs	2019 Costs	2020 Costs
Laberge Environmental Services	Vegetation mapping and rare plant survey		\$7,670.56	
Maven Consulting Limited	Procurement scope development support			\$1,537.5
Midgard Consulting Inc.	Feasibility engineering	\$6,775	\$221,659.70	\$117,566.30
Orbis Engineering Field Service Ltd.	Public engagement technical support		\$2,572.50	
Teshmont Consultants LP	System Impact Study support		\$9,017.25	
Tetra Tech Canada Inc.	Geotechnical reporting		\$7,152.36	
Vector Research	Participation on Advisory Committee		\$1,837.5	
WSP Canada Inc.	Air quality and plume modeling		\$12,870	\$16,330

(c)

In-house work conducted on the project consisted primarily of project management for the feasibility engineering and support of the public engagement activities. Internal labour costs for the project are summarized in the table that follows:

Table 2: Internal Labour Costs

2018	2019	2020
\$19,533.50	\$108,294.96	\$61,131.57

(d)

Please response to YUB-YEC-1-92.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.2-3: SPENDING TO MAXIMIZE RENEWABLE GENERATION FROM EXISTING FACILITIES

4. Southern Lakes Enhanced Storage (Marsh Lake Storage Project)

2018 WIP	2019 Addition	2020 Additions	2021 Additions
\$7,319,000	\$374,899	\$485,000	\$1,200,000

Forecast MLSEP project costs and actual expenditures were reviewed in detail in the 2012/13 and the 2017/18 GRAs. The 2012/13 GRA, identified the project as a relatively small project, with earliest in-service assumed in 2014 (first full year 2015) at a capital cost (2010\$) of \$10.5 million, with mitigation design (shoreline erosion and surface water) expected to comprise about one-half of this total cost (actual costs for mitigation were stated in the 2012/13 GRA as an item that at that time could not be known with any certainty). In the 2017/18 GRA, forecast total project costs increased to \$15.377 million (\$9.795 million forecast for effects assessment; \$0.300 million forecast for YESAA assessment and permitting; and \$7.127 million forecast for mitigation implementation).³ Annual incremental hydro generation was estimated at 6.4 GW.h on average, focused in winter months at the current Whitehorse plant. Annual operating cost (2010\$) was estimated at \$8/MW.h. Full Utilization LCOE (2010\$) was estimated at 8.5 cents/ kW.h. Marsh Lake Storage was also assumed in the 2012/13 GRA.

Project Update

During the 2017/18 GRA, Yukon Energy indicated that the next major milestone was obtaining First Nation support for the project in order to progress to the YESAB assessments stage. The deferred costs forecast in the Application assumes that the project continues, with spending in WIP increasing from \$7.319 million at the end of 2018 to \$9.379 million by the end of 2021. Potential in service for the Project is 2023.

QUESTION:

- a) Does Yukon Energy now have all involved First Nations and Southern Lakes property owners on board with this project. Provide documents demonstrating this.
- b) Identify all consultant firms hired, work performed and each cost for 2018WIP, 2019, 2020 and 2021 years totaling \$9.319 million.
- c) Identify all in-house work performed and cost for these years.
- d) What is the new estimated cost to do the construction and mitigation for this project?

e) What would be the updated LCOE?

ANSWER:

(a)

YEC is committed to continuing to work with all affected First Nations and impacted property owners as part of advancing the project. Engagement with First Nations and impacted property owners will be a key element of the workplan in drafting of a YESAA Designated Office Project Proposal in 2021. The outcomes of the engagement will inform YEC's Board of Directors on its decision on whether to submit the Project Proposal to YESAB.

(b)

The consultant firms, work performed, and cost for 2018WIP, 2019 and 2020 are shown in the table below. Costs for the project have not yet been incurred in 2021.

Table 1: Southern Lakes Enhanced Storage Costs: 2018 to 2020

Contractor	2018 WIP Cost	2019 Costs	2020 Costs	Work Performed
1140609 Alberta Ltd.	6,600			Consultant engaged by TKC to conduct technical review on items including ice hydraulics and downstream impacts in Yukon River of project.
Aasman Brand Communications Inc.		65,313	7,491	Communications support, development of ads, development of online and print materials, graphic design.
AECOM Canada Ltd.	1,133,551			Prime project consultant 2009 through 2013. Baseline biophysical and engineering studies, preliminary effects assessments, conceptual mitigation design and comparative analysis, support for community/government engagement and consultation.
Ben's Electric	935			Army Beach pump
Bill Slater Environmental Consulting	2,220			Technical consultant engaged by TKC to review Project

Contractor	2018 WIP Cost	2019 Costs	2020 Costs	Work Performed
Brimar and Associates Survey Ltd	20,013			Army Beach Drainage/Ditch mitigation design
Canada Post Corporation		2,837		Mailouts
Carcross Tagish Renewable Resource Council	5,500			Contribution for Cisco Fish Study
Carcross/Tagish First Nation	41,207			Contribution Agreement for workshops, meetings, and consultation in support of technical review of project.
DataPath Systems			600	Hosting of Southern Lakes Water Level Committee's website
Dexter Kotylak	160			Army Beach honorarium
Environmental Dynamics Inc.	27,201			Lake trout beach seining data collection, miscellaneous mapping of Southern Lakes, Army Beach draining frog salvage
GW Solutions Inc.	7,998			Groundwater technical support
Hemmera Envirochem Inc.	1,437,068	14,977	21,434	Technical support, workplan development, erosion/groundwater/other technical studies, First Nations engagement support, technical reviews, support of public engagement sessions
Horizon Helicopters	2,278			Helicopter for Southern Lakes erosion recon
Industrial Electric Services Ltd.	133			Technical contractor work on the mitigation trial of the drainage control valve and water pump at the end of the Army Beach Road.
Keith' Plumbing & Heating Co. Ltd	42,810			Sump pump and related hardware supply and installation
Kwanlin Dun First Nation	25,104			Contribution Agreement for workshops, meetings, consulting services for technical reviews
M.Miles & Associates Ltd	34,640			Technical advisory services for Water Level Committee, technical review of river geomorphology
Morrison Hershfield Limited	4,994			Minor consulting services to transition from AECOM to new prime consultant

Contractor	2018 WIP Cost	2019 Costs	2020 Costs	Work Performed
Northwest Hydraulic Consultants			2,425	Follow up questions and request for information on previous technical work NHC completed on the project related to erosion impact assessment and mitigation design.
Nunatak Contracting & Construction	270			Installation of Army Beach pump
Stantec Consulting Ltd. (Vancouver)		51,746	25,728	Technical consulting services; Public Engagement planning, facilitation and support, preparation of What We Heard report
Toews, Don	1,500			Senior review of Project Proposal
Wildstone Industrial Ltd	52,307			Mash Lake Army Beach Drainage Mitigation
Yukon Bureau of Statistics		46,170		Southern Lakes and Yukon-wide surveys
Yukon Conservation Society	117,697			SLWLC contribution agreement funding and acting as treasury for Committee
Earlier work without easy record access*	2,684,603			
Grand Total	5,648,788	181,043	57,677	

*Earlier work done prior to current financial reporting. Given that this project remains in WIP for the 2021 GRA, the effort to try and secure information from prior records was not feasible for the current IR response process.

(c)

Internal costs for 2018 WIP, 2019, 2020, and 2021 to date are provided in Table 2 below.

Table 2: Southern Lakes Enhanced Storage Internal Costs

	2018 WIP	2019	2020	2021
1-Labor	294,331	32,601	10,733	935
2-Travel Exp	5,988	74	11	-
3-Matl, Supl, Inv	165,893	-	-	-
5-Rental	2,174	-	-	-
6-General	67,023	-	-	-
7-Fuel & Util	2,900	908	967	87
8-AFUDC	1,131,979	160,262	175,572	-
Total	1,670,289	193,846	187,283	1,022

(d)

Please see response to YUB-YEC-1-93.

(e)

Please see response to YUB-YEC-1-93.

TOPIC: Capital Projects

REFERENCE: 5. Mayo Lake Storage Enhancement Project – including Mayo Lake Outlet Dredging

2018 WIP	2019Additions	2020Additions	2021Additions
\$3,373,374	\$262,379	\$460,000	\$525,000
E (2010\$) of 6.3 centres/kWh			

⁶ Section 5.3.1.4 of the 2012/13 GRA Application reviewed the project concept, work completed to date (including environmental and socio-economic fieldwork activities, analysis and assessment, project proposal preparation, engineering support, and public consultation), and project risks, costs and benefits. The project was included in the 2012/13 GRA under Relicensing rather than Feasibility Study deferred cost projects, reflecting the central objective to modify the current water licence affecting water storage at Mayo Lake.

⁷ Section 5.3.1.9 of the 2017/18 GRA provided an update on the project progress, costs, and potential in service. Further detail was provided in response to YUB-YEC-1-85 in the 2017/18 GRA. In Order 2018-10, the Board noted that it had approved the Mayo Lake storage enhancement in Order 2013-01, and that given that sediment removal was necessary to realize any benefits from this project it was prudent to expand the scope of work for this project accordingly.

Project Update

In 2018, Northwest Hydraulic Consultants (NHC) was retained to provide a technical assessment regarding whether sediment remediation steps in the Mayo Outlet Channel were feasible and cost effective. The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from \$3.373 million at the end of 2018 to \$4.621 million by the end of 2021.

QUESTION:

- a) Confirm the N'acho Nyak Dun has been in favour of this proposal from the start and continuing until this day. Provide documents demonstrating this.
- b) What is the estimated total cost to complete this project?
- c) What is the updated LCOE?

1 **ANSWER:**

2
3 **(a)**

4
5 YEC continues to work with the First Nation of Na-Cho Nayak Dun to obtain their feedback
6 on the project and their specific input into the YESAA Project Proposal and the Monitoring
7 and Adaptive Management Plan. The FNNND supported the prior YESAA Project
8 Proposal submission on this project that YEC had to withdraw to address Mayo outlet
9 channel dredging planning. Obtaining FNNND's support to move forward to a YESAA
10 Designated Office assessment is an objective of YEC's project plan.

11
12 **(b)**

13
14 Please refer to YUB-YEC-1-94.

15
16 **(c)**

17
18 Please refer to YUB-YEC-1-94.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

6
7 **Building Condition Reports 2020-2024**

8 2018WIP	20192020Addition	2021Addition
		9 \$175,000

10
11 Building condition reports are required to formally document the structure and fabric of a property, describe
12 the construction of the building and its current condition, and outline work required, timing and costs for
13 completion.

14
15 An external engineering firm will undertake site visits for all owned YEC properties and provide an assessment
16 of the condition of each site that outlines requirements for immediate maintenance and repairs; maintenance
17 and repairs required over the next five years; code violations; and cost estimates for required work. The
18 building condition report will be used to forecast O&M projects building condition assessment capital works
19 over 2020-2024. The project is to be closed in 2021 with total expenditures of \$175,000 to be amortized over
20 five years.

21
22 **QUESTION:**

- 23
24 a) Why does Yukon Energy not simply get a building inspector from the YTG or
25 Whitehorse to building inspections as that is what they do, instead of hiring an
26 expensive engineer, most of who are even not qualified to do all the necessary
27 tasks.
28
29 b) Identify which engineering firm received contract.

30
31 **ANSWER:**

32
33 **(a)**

34
35 Regulatory building inspectors only review assets for compliance with code; YEC required
36 an asset health assessment which is not a service offered by compliance authorities.

37
38 **(b)**

39
40 Please see response to UCG-YEC-1-73.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **Business Continuity Plan**

6 2018WIP	2019Addition	2020Addition	2021Addition
		\$80,000	\$75,000

7
8
9 A gap analysis was undertaken by a third party consultant regarding Yukon Energy's current Business
10 Continuity Plan (BCP). This identified substantial work required to address the identified gaps in order to meet
11 current industry standards. This includes development of technical recovery procedures, based on identified
12 Recovery Time Objectives (RTO) for the various business processes related to IT applications and
13 infrastructure components; developing a defined methodology for evaluating the criticality of vendors,
14 establishing vendor Business Continuity/Disaster Recovery (BC/DR) requirements, and monitoring vendor
15 BC/DR compliance; and developing a formal BC/DRP/Emergency Response Planning training program or
16 exercise and testing program. If the current BC/DR program deficiencies are not addressed, YEC will face a
17 number of risks in the event of an actual emergency. This includes delays in poorly defined Incident Command
18 System, unclear priorities for returning critical support systems to service, lack of adequate employee training
19 or potential communication breakdowns. The project is to be closed in 2020 and 2021 with total expenditures
20 of \$155,000 to be amortized over five years.

21
22 **QUESTION:**

- 23
24 a) How did Yukon Energy identify this was a problem?
- 25
26 b) Identify which consultant firm/s got contracts for what work and what cost.

27
28 **ANSWER:**

29
30 **(a)**

31
32 Historically, YEC has run formal disaster recovery scenarios to ensure appropriate
33 response procedures were in place and staff understood their responsibilities in various
34 emergency situations. These scenarios tended to focus on front-line operational readiness
35 especially IT systems to deal with a given situation in a short time. In working with
36 consultants and discussing with peer organizations, it was concluded that a
37 comprehensive BCP/DRP program is a normal risk management tool used by entities
38 similar to YEC and that YEC could improve its current approach.

1 **(b)**

2

3 The work planned for 2020 was delayed due to internal resource constraints. As a result,
4 no contractors were awarded for this work. The timeline for completion will slip to 2021/22
5 so there is no impact to rates from this project in 2021.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

Mayo and Aishihik Hydro Climate Change

2018WIP	2019Addition	2020Addition	2021Addition
	\$474,313	\$124,249	\$40,000

A partnership was developed in 2016 between Yukon College and INRS, a university institution which developed a successful joint ARD/CRD proposal to leverage funding from NSERC. The project is to be closed in 2020 with total expenditures of \$638,562 to be amortized over five years.

QUESTION:

- a) Does Yukon Energy have engineers in their personnel?
- b) Does Yukon Energy have a hydrologist in their personnel?
- c) If Yukon Energy aligned with Yukon College and INRS why would YEC need an expensive independent consultant?
- d) Identify which consultant firm/s received contracts for this study and at what cost.

ANSWER:

(a)

Yes.

(b)

No.

(c)

Yukon Energy's alignment with Yukon College and Institut national de la recherche scientifique (INRS) included funding the work conducted by both academic institutions, which made up the majority of the external costs. An independent consultant was also

engaged to verify the study methodology and review the model to ensure it was of appropriate quality and standards for YEC's continued future use.

(d)

See Table 1 below.

Table 1: Mayo and Aishihik Hydro Climate Change Study Costs

Contractor	Total Cost
Aasman Brand Communications Inc.	849.49
INRS	316,073.77
Rousseau, Alain	1,761.10
Smith, Douglas Ian	25,652.26
Yukon University	112,500.00
Total	456,836.62

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **PMF Flood Study**

6 2018WIP	2019Addition	2020Addition	2021Addition
			7 \$150,000

8
9 A Probable Maximum Flood (PMF) study is required for Aishihik Lake and Canyon Lake. The project is to be
10 closed in 2021 with total expenditures of \$150,000 to be amortized over five years.

11
12 **QUESTION:**

- 13
14 a) Does Yukon Energy have a hydrologist on staff?
15
16 b) Why would this project not be included in the Aishihik Water License costs?
17
18 c) Which consultant firm/s did this project work and at what cost?
19
20 d) Provide latest Hydrology Report.

21
22 **ANSWER:**

23
24 **(a)**

25
26 YEC does not have a hydrologist on staff.

27
28 **(b)**

29
30 The PMF study is a separate project related to dam safety.

31
32 **(c)**

33
34 YEC will be hiring a consultant in 2021 through a competitive process to perform the study.

35
36 **(d)**

37
38 Please see Attachment 1 to this response.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **Transmission Access Road Program Study**

6 2018WIP	2019Addition	2020Addition	2021Addition
		\$132,787	\$200,000

7
8
9 Yukon Energy does not have a proper inventory of all the road accesses for transmission line access; and
10 does not know the status of all the accesses that are required to maintain approximately 1,110 km of
11 transmission line. The objective of the study is to engage an external consultant to provide a GIS database
12 outlining access locations; the current status of accesses; and to prepare a GIS data base and report that
13 includes a gap analysis of what needs to be addressed to complete the GIS database. The project is to be
14 closed in 2020 and 2021 with total expenditures of \$332,787 to be amortized over five years.

15
16 **QUESTION:**

- 17
18 a) Does Yukon Energy personnel not routinely inspect and work on all transmission
19 line locations?
20
21 b) Why would these staff workers not be able to inventory locations, need and GPS
22 these locations?
23
24 c) Which consultant firm/s did this expensive work and at what cost?

25
26 **ANSWER:**

27
28 **(a)**

29
30 YEC routinely inspects all of its transmission lines both aerially and by use of Snow
31 machines, UTVs, trucks and on foot. These various types of inspections drive the
32 maintenance program. Lines receive maintenance based on priority and available budget.
33 Not every line gets worked on every year as it much more efficient to focus work in a
34 particular area.

1 **(b)**

2
3 An initial assessment was completed by YEC staff to inventory existing access trails along
4 transmission lines that were coming up for priority maintenance. To maintain or modify
5 these trails in any way requires proper permitting and many of them require modification
6 to make them suitable for YEC equipment. Due to the level of assessment needed to meet
7 highways permitting requirements and due to the amount of permitting required, outside
8 support was needed. Additionally, this assessment identifies gaps where we do not have
9 appropriate access which can be due to a variety of reasons including sensitive lands
10 interests. This level of assessment gives us a comprehensive data base that will help us
11 assess future maintenance programs.

12
13 **(c)**

14
15 The firm that did this work is Tetra Tech. The final invoice was \$87,526.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

6
7 Whitehorse Diesel Rental Substation Improvements

8 2018WIP	2019Addition	2020Addition	2021Addition
		\$100,000	

9
10
11 The temporary substation behind the diesel plant is the grid connection point for the rental diesel fleet, was
12 built using repurposed/ salvaged equipment, and has temporary fencing. The cables for the temporary
13 substation were reused from the WD1 and WD2 units and are aged. Cabling from this substation to S150 is a
14 direct connection, and a cable fault will result in the shutdown of S150, which is the primary generating and
15 distribution station on the grid. In order to prevent risk of such a failure, the cables, breakers, and enclosures
16 must be replaced and a permanent fence must be installed. The natural gas pipe and regulator must also be
17 relocated and cable protection at S150 must be installed. Spending in 2021 relates to developing an
18 engineered solution, including a budget and risk analysis. The project is to be closed in 2021 with total
19 expenditures of \$100,000 to be amortized over 45 years.
20

21 **QUESTION:**

22
23 a) From Yukon Energy preamble above it appears as if YEC knew all of the relevant
24 problems existed from their own staff and engineers. As such, explain why an
25 independent study was necessary?
26

27 b) Which firm received this study contract?
28

29 **ANSWER:**

30
31 **(a)**

32
33 An engineered solution is required to validate what has been identified and detect any
34 additional items that were not previously discovered.
35

36 **(b)**

37
38 The IR “quote” above shows the project cost in 2020, which is not accurate – Section 5.4-
39 2 of the application shows this cost in 2021. At this time, it has not been determined which
40 firm will receive this study contract.

1 **TOPIC: Capital Projects**

3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5 5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

7 10 Year Renewable Energy Plan

8 2018WIP 2019Addition 2020Addition 2021Addition

9 \$310,842 \$402,125

10 A desktop update of the 2016 Resource Plan was completed with additional renewable energy project
11 considerations. The update consisted of a new long term load forecast, expansion of existing hydro inventory,
12 update of financial resource attributes, portfolio analysis and an action plan charting the path for resource
13 development and implementation over the next 10 years. The outcome of this project and its acceptance will
14 allow YEC to establish and follow a plan to ensure that reliability criteria are met. The project is to be closed
15 in 2020 with total expenditures of \$712,967 to be amortized over five years.

16 27 The Tab 5 test year forecasts include capital costs for the Ten Year Renewable Energy Plan which
17 28 addresses resource planning updates as required for current YEC resource planning. This includes
18 29 consideration of impacts on future peak load growth and energy generation requirements as a result of
19 30 Yukon's strategy for climate change, energy and a green economy, particularly as regards IPP policy
20 31 resource project development impacts on energy and capacity resource balances, and policy impacts on
21 32 future peak loads related to ongoing initiatives for electrification, electric vehicles, and heat pumps.

22 19 Directive #62 (paragraph 490) – Resource Plan Update

23 20 * However, the Board is of the view that it is not prudent for YEC to continue with
24 21 these significant expenses to update the resource plan every five years. Accordingly,
25 22 the Board directs YEC to seek Board approval prior to any future updates of its
26 23 resource plan. Any such application must be accompanied by a detailed proposal for
27 24 both costs and scope of work, including a description of work to be carried out
28 25 internally and by consultants. YEC must also include an explanation of why any work
29 26 to be done by consultants cannot be carried out by internal staff.

31 **QUESTION:**

- 32
- 33 a) Did Yukon Energy seek prior approval of the Board and was this approval given?
34 Identify Board decision
- 35
- 36 b) If no, as this was almost three quarters of million dollars update, should not Yukon
37 Energy have followed Board directions?
- 38
- 39 c) Identify which consultant firm/s received contracts, for what work to be done and
40 at what cost.

ANSWER:

(a) and (b)

The Board's mandate relates to approval of rates, and does not include approval of public utility programs, plans or projects. Yukon Energy did not seek prior Board approval to update its resource plan in response to new conditions and Yukon Government policy requirements related to its Climate Change policy initiative. The expenditures for this resource plan update were prudently incurred and modest compared with the 2016 Resource Plan costs.

(c)

Please see Table 1 below for a summary of work completed by consultant and costs.

Table 1: Summary of 10-Year Renewable Energy Plan Costs by Consultant

Consultant	Work Completed	Total Cost
Aasman Brand Communications Inc.	Communications & engagement materials; Graphic design & formatting	\$ 52,842.81
Campbells North Consulting	Technical and project management support	\$ 3,822.50
DLA Piper LLP	Legal support	\$ 44,706.99
Itron Canada Inc.	Load Forecast Modeling; Electric Vehicle Load Update	\$ 36,646.10
InterGroup Consultants	Strategic studies, Southern Lakes Transmission Investment and development options	\$ 59,487
Knight Piesold Limited	Technical Attribute & Cost Studies for Resources	\$ 99,064.62
Midgard Consulting Inc	Resource Options & Market Assessment Update; Technical Report	\$ 129,751.95
Northern Governance Institute (nGI)	Public engagement facilitation and organization; What We Heard Report	\$ 70,576.06

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

4
5 **Atlin Hydro EPA Preparation**

6 2018WIP	2019Addition	2020Addition	2021Addition
			7 \$200,000

8 The Atlin (Pine Creek) Hydro Expansion project was selected as a key project in the 10 Year Renewable
9 Electricity Plan, given its relatively advanced stage of development as a brown-field expansion project, when
10 compared to other potential greenfield hydro developments. The project also has a lower Levelized Cost of
11 Energy (LCOE) than the Drury Lake project. In 2020, YEC engaged in discussions with Xeitl Limited
12 Partnership (Xeitl LP) (Taku River Tlingit development corporation) regarding the Atlin project being planned
13 by Xeitl LP, and key principles and terms for an Agreement-in-Principle (AIP), as well as potential IPP contract
14 provisions. An AIP has been signed, and discussions towards an EPA are underway. The project is to be
15 closed in 2020 with total expenditures of \$200,000 to be amortized over five years.

16
17 **QUESTION:**

- 18
19 a) Explain exactly what study is needed here?
20
21 b) Identify which consultant firm/s performed tasks, what work done and costs.

22
23 **ANSWER:**

24
25 **(a)**

26
27 As noted, the project relates to negotiation key principles and terms for an Agreement-in-
28 Principle (AIP) and IPP contract provisions with Xeitl Limited Partnership (Xeitl LP) (Taku
29 River Tlingit development corporation) regarding the Atlin project being planned by Xeitl
30 LP. An AIP has been signed, and discussions towards an EPA are underway.

31
32 **(b)**

33
34 The work is forecast to occur in 2021 and has not been completed. Consultant work to
35 date has primarily been undertaken by DLA Piper and InterGroup Consultants Ltd.
36 InterGroup has provided support related to financial analysis and EPA development; and
37 DLA Piper has provided support related to EPA development and negotiation. Costs to
38 the extent that they are readily available are provided in UCG-YEC-1-104.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

Dam Safety Review

2018WIP	2019Addition	2020Addition	2021Addition
			\$315,000

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA). Reporting on outcomes of this review is also required by each Yukon Energy generating facility water use licence. The DSR includes a comprehensive review of all of Yukon Energy's dam structures, and includes consideration of all civil, structural, geotechnical, electrical, mechanical and safety issues that may affect YEC personnel and the general public. The review identifies hazards and potential problems of high risk that require immediate attention (within one year) as well as lower risk items that can be performed over time. The project is to be closed in 2020 with total expenditures of \$315,000 to be amortized over five years.

QUESTION:

a) Identify which firm/s performed these reviews, work performed and what cost.

ANSWER:

(a)

Encora performed this work at a cost of \$139,510.

1 **TOPIC: Capital Projects**

3 **REFERENCE: 5.4 INTANGIBLE ASSETS**

5 12 Intangible assets are reviewed in Table 5.7 and include financial software, customer service costs and
6 13 costs related to development of an asset management framework (i.e., Enterprise Asset Management
7 14 Purchase and Implementation).

8 **5.4.1.1 Enterprise Asset Management (EAM) System Purchase 1 and Implementation –**

9 **2 (\$0.809 million in 2019, \$3.854 million forecast in 2020, and \$0.275 million forecast in 2021)38**

10 4 The 2017/18 GRA included feasibility costs for development of an Asset Management Program that would
11 5 document plans to systematically assess major asset groups (hydro, substations and transmission and
12 6 distribution) and manage the planning of investments to meet overall corporate goals.39

13 16 The existing Computerized Maintenance Management System (CMMS) does not meet Yukon Energy's
14 17 current or future asset management needs. An EAM system is an enterprise level software application
15 18 that enables an organization – particularly an asset intensive organization – to manage and optimize its
16 19 assets throughout the entire asset lifecycle including asset needs identification, asset investment planning
17 20 and prioritization, advanced asset maintenance management and asset performance tracking.

18 21 EAM project activities since 2018 relate to the selection, purchase, planning and implementation of an
19 22 EAM system. A procurement process to evaluate and select a replacement system was initiated in 2018;
20 23 and selection of a replacement EAM system was completed in 2019. The tool will be integrated with the
21 24 Microsoft Dynamics GP, YEC's financial management solution, and other legacy applications to provide
22 an

23 25 integrated solution that ties to YEC's financial and inventory management systems.

24 26 The following project activities have been completed:

25 38 \$0.276 million was spent in 2018 under PP&E and transferred to Intangibles in 2019. The 2019 spending
26 was \$0.533 million to total 2019 cost to rate base at
27 \$0.809 million.

28 39 2017/18 GRA, Appendix 5.4, page 5.4-2 provides a summary of this project, with forecast spending of
29 \$0.200 million in 2017 and \$0.150 million in 2018. In

30 Order 2018-10, the Board found the project reasonable and the associated costs prudent and approved the
31 deferred costs as filed.

32 40 The ISO 55000 standard is an international standard covering management of assets of any kind.

33 **Procurement of Project 1 Management Services:** In 2019, YEC issued a Request for

34 2 Proposals (RFP) for project management of the EAM implementation, and KPMG was selected as
35 3 the proponent for this work. The KPMG team is well qualified and experienced and its team
36 4 members successfully implemented a similar EAM system at NTPC (demonstrating knowledge and
37 5 competence to deal with issues faced by small, northern Crown utilities).

38 **6 Procurement of Software Solution:** A multi-stage competitive procurement was administered

39 7 in 2018. A total of 27 potential suppliers were invited to participate in a request for information
40 8 process. From this, 8 vendors were invited to a full request for proposal (RFP) process. As a final
41 9 step, three vendors were invited to participate in vendor presentations and site visits and full cost
42 10 work up. Based on this extensive process, YEC awarded a time and materials contract to Infor
43 11 ERP Software.

44 12 Over 2020, YEC has worked towards implementation of the software solution provided by Infor. This has

13 included the following:

14 Inception (completed in 2020): Undertaking activities related to project kickoff; training

15 workshops by vendor (Infor) with YEC team members; workshops conducted by Infor to define
16 as-is process models, technical strategy and architecture and KPIs as a basis for the EAM
17 solution; workshop conducted by KPMG (OCM lead) to gather YEC executive input on expected
18 organizational challenges and ensure alignment project objectives; and prioritization
19 requirements for next phase.

20 Elaboration (commenced in 2020 and ongoing): Involves detailed scoping and finalization

21 of business requirements and integration design, advanced training for core team members,
22 development of a testing strategy, scope and defining data structures and plan integration
23 strategy and requirements.

Construction (commenced in Q2 2020 and Completed in Q4 2020): Development of user

25 acceptance testing plan, initial testing and final data conversion preparation by vendor. This
26 includes development of training curriculum and methodology and approach; assessment of
27 impact of EAM project on YEC; test all modules of AEM solution, going through business
28 processes and verifying functionality; determine if designed and configured solution meets YEC's
29 requirements and specifications; build EAM integrations with YEC legacy systems; local testing of
30 integrations developed; and end to end system testing of AEM system and integrations.

Transition (commenced in Q4 2020 and ongoing): Finalization 1 of EAM solution and

2 preparation to launch into production; including preparing for training for broader YEC users;
3 outline and convert data from non-EAM systems to EAM systems and checking redundancies
4 involved while going live; change impact assessment based on enhanced understanding of
5 project; assessment of readiness for launch and finalize EAM for users and convert to production
6 'live' environment.

7 Optimize (commence late Q4 2020 and complete early 2021): After launch into

8 production review of project successes and lessons learned, including limited support work from
9 vendor as required.

10 Total costs to complete the project are currently estimated at \$4.938 million. The project is expected to
11 be fully implemented in early 2021.

QUESTION:

- a) Identify which firm did the feasibility plan and at what cost.
- b) Identify where Yukon Energy received approval to add 2019 costs of \$0.809 million to rate base.
- c) Reconcile the difference in the approved 2017/18 deferred costs of \$0.350 million and the \$0.276 million 2018 spending and transfer to intangibles.
- d) Provide breakdown of 2019 spending of \$0.533 million, i.e. job description, consultant/s firms hired and cost for each.

- 1 e) Identify which firm/consultant received contract for project management services
2 and at what cost.
3
4 f) Provide cost for actual Enterprise Asset Management System and related
5 software.
6
7 g) Provide breakdown of costs for Inception project kickoff, various training
8 workshops, etc.
9
10 h) Provide costs for Elaboration finalization, integration, advanced training, etc.
11
12 i) Provide a breakdown of all costs with reasons for Construction, Transition and
13 Optimize phases of program.
14
15 j) Provide any in-house costs for all of this project phases.
16
17 k) Is this new model of EAM now fully implemented and operational?
18
19 l) If some of total cost of \$4.938 million for EAM already on approved rate base?
20
21 m) If yes, identify amount and Board reference decision.
22

23 **ANSWER:**

24
25 **(a)**

26
27 Hatch was retained to undertake a CMMS current state assessment and market survey at
28 a total cost of \$46,400.
29

30 **(b)**

31
32 The 2019 costs are included in the Application for approval with the 2021 GRA.

(c)

The actual costs in 2018 were \$0.276 million. The \$0.350 million cost was an early estimate in 2017 to perform the work.

(d)

Please see the information provided in the table below for break out of the \$0.533 million cost for the project.

UCG-YEC-1-97 Section C: #172 (1 of 2)

Cost Code	Sum of Amount
1-Labor	\$ 80,561.03
2-Travel Exp	\$ 22,279.64
3-Matl, Supl, Inv	\$ 172.49
4-Contractors	\$ 419,568.83
5-Rental	\$ 240.00
8-AFUDC	\$ 10,691.33
Grand Total	\$ 533,513.32

A summary of contractors hired and description of work and costs is as follows:

Vendor	Sum of Amount
Charter Telecom	\$ 1,080.00
eCorall Solutions Inc.	\$ 7,412.80
Hatch Ltd.	\$ 77,662.72
Infor (Canada) Ltd.	\$ 100,000.00
KPMG LLP (Vancouver)	\$ 233,413.31
Grand Total	\$ 419,568.83

(e)

KPMG received the contract for PM services, at a cost of \$133,972. As noted in part (d) final costs for KPMG were \$233,413. Added costs for KPMG relate to an expansion of scope to establish more firm pricing of the implementation estimate, and extensions to the project deadline.

1 **(f)**

2
3 The Cost of the EAM Software System at time of purchase is as follows:

4
5 1. \$464,789 – Software; and

6
7 2. \$113,450 (annual Licensing and upkeep fees).

8
9
10 **(g), (h) and (i)**

11
12 There is no specific breakdown of costs to this detail. For a project cost breakdown please
13 see response to YUB-YEC-1-64(c).

14
15 **(j)**

16
17 The YEC internal costs are estimated to be \$462,000.

18
19 **(k)**

20
21 The EAM system is not yet in service. The system will be in service Q1 2021.

22
23 **(l) and (m)**

24
25 No costs for the EAM project as presented in the Application are currently included in rate
26 base or approved by the Board to include in rates.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.5: DEFERRED STUDIES

Deferred cost projects with total spending since 2018 greater than \$100,000 million and less than \$1 million that remain in WIP in 2021, excluding General Rate Application costs in WIP, have total expenditures of \$0.400 million and EV Infrastructure Project

2018WIP	2019Addition	2020Addition	2021Addition
			\$200,000

Strategy development will assess the potential impact of electric vehicles on the Yukon electrical system and identify a path forward for YEC to meet these challenges.

QUESTION:

a) Has this assessment been completed?

b) If this cost is for strategy development why is this not done inhouse with the many personnel on staff?

c) Identify which firm/s performed tasks concerning this assessment, what work was done and at what cost?

ANSWER:

(a)

No.

(b)

The costs of internal labour and consulting for the project have not yet been determined. Limited resources are available to complete this work, as a result of the large number of ongoing projects outlined in YUB-YEC-1-39.

(c)

The work has not been initiated and is no longer planned to be done in 2021.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.5: DEFERRED STUDIES**

4
5 P125 Trashrack Study

6 2018WIP	2019Addition	2020Addition	2021Addition
		\$200,000	

7
8 The P125 intake is becoming blocked with debris and frazil ice. These blockages are currently being removed
9 manually by divers and plant operators. This results in multiple outages each year to address blockages. Not
10 addressing this issue will mean continued outages and requirement for divers to address the issue manually.
11 A track rack must be installed that can permanently address the variety of debris encountered at the intake.
12 The study will confirm the deck structural capacity and other details such as power supply and trash rack
13 geometry.
14

15 **QUESTION:**

16
17 a) Confirm that this cost and work is not identified in another area of work to be
18 performed.
19

20 b) Has this work been completed and finalized?
21

22 **ANSWER:**

23
24 **(a)**

25
26 This is a standalone project. The cost and work is not identified in any other area of work
27 to be performed.
28

29 **(b)**

30
31 This work is in the assessment phase and has not been completed nor finalized.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.6: INTANGIBLE ASSETS >\$100,000 AND<\$1 MILLION**
4 **ADDED**

5
6 **TO RATE BASE**

7 **ERP System Upgrades**

8 **2019Actual 2020Forecast 2021Forecast**

9 \$200,000

10
11 Given Yukon Energy's role as the primary generator of electricity for an isolated grid, it is critical to maintain a
12 modern and robust Enterprise Resource Planning (ERP) system. ERP system refers to a type of software that
13 organizations use to manage day-to-day business activities such as accounting, procurement, project
14 management, maintenance management and supply chain operations. Best practice is to update systems
15 regularly to ensure that the systems are up to date. The project involves upgrades to the ERP system
16 components to the recommended latest stable versions. System experts are contracted to help with individual
17 components as these are critical systems and Yukon Energy has no inhouse expertise.

18
19 **QUESTION:**

- 20
21 a) Given the cost of this program upgrade, will Yukon Energy now use this in-house
22 capability instead of hiring your consultant?

23
24 **ANSWER:**

25
26 **(a)**

27
28 To be clear, this is not a new system with new in-house capabilities.

29
30 As described in the Application, this is an upgrade to the existing system. YEC performs
31 upgrades as considered necessary. As with any software, external consulting will be used
32 as necessary. As noted in YUB-YEC-1-103, one of risks of not doing an upgrade is that
33 there will be no support for the software.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: Feasibility Study**

4
5 Table 5.4 2017-18

6 Total Feasibility Study WIP 8,589,838 1,090,716 (132,667) 9,547,887

7 Table 5.6 2021

8 Total Feasibility Study WIP 9,833,270 7,370,000 (979,072) 16,224,199

9
10 **QUESTION:**

11
12 a) Confirm increase in WIP Feasibility Studies from 2017-18 to 2021 is \$6,676,312.

13
14 b) Confirm increase in Total WIP from 201-18 GRA to 2021 is \$11,394,258.

15
16 **ANSWER:**

17
18 **(a)**

19
20 The increase in feasibility study WIP noted in the question [\$6.676 million] is the increase
21 in 2021 test year over 2018 actuals. The feasibility study WIP in 2021 test year is reduced
22 from the 2018 test year by \$5.565 million mostly due to delays with Energy Storage
23 System Assessment and YEC's decision not to go ahead with 20 MW thermal plant
24 assessment assumed in the 2017/18 GRA.

25
26 **(b)**

27
28 The increase in total WIP in 2021 test year over 2018 test year is \$9.468 million [net of
29 contributions] that reflects increase PP&E WIP by \$29.769 million plus increase in
30 deferred cost WIP by \$0.475 million offset by increase in contributions WIP by \$20.776
31 million as illustrated in Tab 7, Schedule 1.

1 **TOPIC: Capital Projects**

2
3 **REFERENCE: APPENDIX 5.3: DEFERRED PROJECTS >\$1 MILLION NOT ADDED**
4 **TO RATEBASE**

5
6 Deferred expenditure test year spending on major projects (i.e., expenditures over \$1 million) retained in WIP
7 is focused on projects required to address sustaining capital requirements (i.e., required to replace, repair or
8 enhance/ improve components of the existing system to ensure continued reliability, safety and environmental
9 or regulatory compliance), investments to ensure sufficient dependable capacity for the integrated grid, and
10 continued planning expenditures to meet other potential future generation and transmission requirements.

11 Approximately \$28.573 million of deferred costs are forecast to be incurred in WIP for major projects by the
12 end of 2021. Details on actual and forecast expenditures by year are reviewed in Tables 5.2 to 5.6.

13 Spending on Sustaining Capital: Net deferred costs in WIP by end of 2021 of approximately \$8.178 million:

14 1. Aishihik Generating Station Water Use 25 Year Licence Renewal – (forecast WIP

15 cost of approximately \$7.918 million by end of 2021 - project planned for completion in 2022).

16 2. Whitehorse Rapids Generating Station Water Use Licence Renewal - (forecast Spending to address
17 Capacity

18 Planning Requirements: Net deferred costs in WIP by end of 2021 of approximately \$6.395 million:

19 3. Diesel Retirement Replacement (12.5 MW) – (forecast WIP cost of approximately

20 \$6.395 million by end of 2021 planning, engineering, permitting, long-lead equipment

21 procurement – total project planned for completion by 2024, with certain portions

22 completed and in service starting in 2022).

23 **Spending on planning to maximize renewable energy generation from existing**

24 **facilities:** Net deferred costs in WIP by end of 2018 of approximately \$14.000 million:

25 4. Southern Lakes Storage (Marsh Lake Storage Enhancement Project) – (forecast

26 WIP cost of approximately \$9.379 million by end of 2021 - project subject to ongoing

27 review, potential in-service by 2023).

28 5. Mayo Lake Storage Enhancement Project (including Mayo Lake Outlet Channel) – (forecast WIP cost of
29 approximately \$4.621 million

30
31 **QUESTION:**

32
33 a) Although it appears Yukon Energy will not place these projects onto the rate base
34 for the test year, is Yukon Energy now using this process to get regulatory approval
35 for all of these projects lining up for \$28.573 million in the WIP? Explain.

36
37 b) As Aishihik relicensing is lining up for almost \$8 million in the WIP, explain how
38 Yukon Energy justifies this cost?

39
40 c) Identify which firm/s managed/is managing this Aishihik license renewal from the
41 beginning until now, what work was performed and at what cost

1 d) Identify which firm/s managed/is managing the Whitehorse Station license renewal
2 from the beginning until now, what work was performed and at what cost.

3
4 e) Does the Diesel Retirement Replacement cost of \$6.395 million include the
5 purchasing of any new generators? Explain.

6
7 f) Justify the costs for Southern Lakes Storage and Mayo Lake Enhancement, for
8 each, including discussion of risks of not proceeding with these projects as well as
9 discussion of assumptions included in the business case for escalation factors,
10 loading, financial measures, term of project and associated ancillary costs, as per
11 Board Order 2009-8.

12
13 **ANSWER:**

14
15 **(a)**

16
17 The projects identified in Appendix 5.3 are forecast to remain in WIP during the 2021 test
18 year. As noted in the response to YUB-YEC-1-89 the purpose of this appendix is to identify
19 major projects with costs that will not affect forecast test year rate base and therefore do
20 not require detailed review at this time for the purpose of the 2021 GRA Application. As
21 such, Yukon Energy is not using this process to get regulatory approval for these projects.
22 They will be brought to the regulator for a prudence review at a later date.

23
24 **(b)**

25
26 The Aishihik hydro facility is a key power plant in Yukon's electricity system, providing
27 25% of the renewable electricity available on the Yukon grid. It also plays an important
28 role in winter months, providing 40% of the energy Yukoners need when demand for
29 electricity is greatest. Although the 40-megawatt Whitehorse Rapids hydro facility is larger
30 than Aishihik, the effective capacity of the Whitehorse plant is reduced by close to half
31 during the coldest months of the year because of reduced water flow on the Yukon River.
32 Aishihik is the only hydroelectric facility in Yukon that can store energy in the summer
33 when demand is low to be used in the winter when demand is high. It can also store energy
34 during wet years to be used in dry years when the levels of the lake water are lower.
35 Replacement of the energy and capacity provided by the Aishihik facility would cost
36 significantly more than the referenced \$8 million for the 25 year relicensing process.
37 Please see response to YUB-YEC-1-90 (b through e) for added detail.

1 (c)

2
3 Morrison Hershfield, working with other consultants (InterGroup, EDI, Palmer, Ecofor) was
4 the lead consultant through 2018. Since then, YEC has contracted each firm separately
5 to carry out the required work, and InterGroup has been the key technical leading
6 consulting firm. Please refer to UCG-YEC-1-83 for cost information.

7
8 (d)

9
10 Work on this project has not commenced.

11
12 (e)

13
14 Please refer to YUB-YEC-1-92.

15
16 (f)

17
18 The project justifications are based on an incremental savings on an LCOE basis
19 compared to the next best alternative (thermal energy generation). Both of these projects
20 remain in WIP and are not part of forecast revenue requirement for 2021.

21
22 Please see responses to YUB-YEC-1-93 and YUB-YEC-1-94 for more detailed
23 information on updated justification for continuing to pursue each of these projects.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.1: CAPITAL PROJECTS > \$1 MILLION NOT IMPACTING RATE BASE

Appendix 5.1 provides project summaries for capital projects with spending over the period from 2019 to 2021 exceeding \$1 million that remain in WIP at the end of 2021 (and therefore do not affect the 2021 GRA revenue requirement). Total forecast spending on these projects is forecast to grow from \$1.129 million in 2019, to \$2.860 million in 2020 to \$31.966 in 2021. The forecast material increase in 2021 spending relates largely to the Battery Energy Storage System project which has \$25 million forecast spending in 2021. However, it is noted that spending for this project will be offset by a \$16.5 million contribution. Further details on annual spending are summarized in Table 5.2-2.

As outlined below, spending for these projects is largely focused on: (1) capital works to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance); (2) investments to ensure sufficient dependable capacity for the integrated grid; and other projects.

Capital Works to Address Sustaining Capital Requirements:

1. Dawson Voltage Conversion
2. MH0 (Mayo A) Generating Station Slope Stability
3. Replacement of Mayo A Surge Chamber
4. Stop Log Crane WH Main Spillway
5. Asset Management Framework

Investments to Ensure Dependable Capacity:

6. Battery Energy Storage System (transfer from Feasibility)
7. Pumped Storage
8. Southern Lakes Transmission Line
9. Whitehorse Interconnection

Other:

10. Aishihik Contract Dispute WIP cost of approximately \$0.260 million by end of 2021 - project planned for completion in 2025)

QUESTION:

- a) Is the total spending requested to go in WIP \$31.966 million, or is this just forecast 2021?
- b) Although it appears Yukon Energy will not place these projects onto the rate base for the test year, is Yukon Energy planning to use this process to get regulatory approval for all of these projects lining up for at least \$31.966 million in the WIP? Explain.

1 c) Does Yukon Energy consider this a complete final capital review for each of these
2 these above projects, to then transfer into rate base next rate hearing?

3
4 **ANSWER:**

5
6 **(a)**

7
8 Projects included in Appendix 5.1 are currently in WIP will remain in WIP at the end of
9 2021. The total includes actual amounts incurred to the end of 2019 and forecast amounts
10 for 2020 and 2021.

11
12 **(b) and (c)**

13
14 See YUB-YEC-1-89 (a) to (c). Appendices 5.1 and 5.3 review Major Projects (i.e., projects
15 with forecast costs exceeding \$1 million) for PPE (Appendix 5.1) and deferred costs
16 (Appendix 5.3) that are forecast to remain in WIP during the 2021 test year. The purpose
17 of these appendices is to clearly identify major projects with costs that will not affect
18 forecast test year rate base and therefore do not require detailed review at this time for
19 the purpose of the 2021 GRA Application. Accordingly, it is confirmed that no costs for
20 projects listed in these appendices have been added to rate base or revenue requirement
21 for 2021.

22
23 Costs for these projects will be fully reviewed at a subsequent proceeding when YEC
24 applies to have the costs included in rates.

TOPIC: Capital Projects

REFERENCE: Sole-Sourced Contracts

QUESTION:

- a) Since 2018, including the 2017-18 regulatory proceedings before the Yukon Utilities Board, identify all expenditures related to work completed by InterGroup Consultants Ltd. on behalf of Yukon Energy Corporation.
- b) Identify any of the above contracts given through a request for proposal or tender/bidding process.
- c) Since 2018, including the 2017-18 regulatory proceedings before the Yukon Utilities Board, identify all expenditures related to work completed by John Landry LLB /DLAPiper on behalf of Yukon Energy Corporation.
- d) Identify any of the above contracts given through a request for proposal or tender/bidding process.

ANSWER:

(a)

Department/Project	Amount
Aishihik Generating Station Water Use Licence Renewal	814,564.82
General Rate Application 2019-2020	273,326.93
Mayo Lake Storage	121,208.71
Atlin Hydro EPA Preparation	79,693.27
10 Year Renewable Energy Plan	59,487.97
BESS	48,847.50
Finance	42,190.59
Thermal Replacement	31,516.50
Resource Planning	4,532.75
Vista Integration	3,614.07

(b)

Formal tender processes were issued for the original contracts awarded for involvement in the largest projects:

- Aishihik Generating Station Water Use Licence Renewal; and
- General Rate Application 2019-20.

Note these tenders do not explicitly cover all spending to date; extensions to scope and budget occurred in both cases as project plans were developed and changed based on circumstances. YEC issues extensions for work based on successful delivery to date and reasonable estimates for the expanded scope.

(c)

Department/Project	Amount
AH3 Legal Defense	496,919.05
Aishihik Relicensing	421,626.21
Human Resources	292,571.83
Finance	237,013.25
Executive	91,726.97
2017/18 GRA R&V	91,556.50
Atlin Hydro EPA	71,673.00
IPP Program Implementation	76,984.88
MMTP	41,106.93
Ten Year Renewable Energy Plan	44,706.99
2021 GRA	25,508.00
WH2 Uprate	21,332.67
IPP - Other	18,995.50
WH4 Uprate	12,117.77
Victoria Gold PPA Review	9,122.60
EAM	7,170.45
BESS	6,247.50
LNG Third Engine	4,075.40
Thermal Plant	3,576.64
Corporate Administration	2,046.56
Residential Demand Response Pilot	1,984.50
Communications	1,682.00

(d)

YEC does not tender legal services.