



YUKON ENERGY CORPORATION

2021 GENERAL RATE APPLICATION
ROUND 1 INTERROGATORY REVISED RESPONSES FILED

August 24, 2021

Nathaniel YEE
(NY)

QUESTION:

- a) Please provide the stacking order for all thermal generation, YEC owned and rentals – for each site and for the integrated system.

ANSWER:

(a)

The stacking order for all thermal generation is as follows:

	Type/ Location	Units	Comment
1	YEC LNG	WG1, WG2 and WG3	
2	Whse rentals	YM-10, YM-11, YM-12, YM-13, YM-14, YM-15, YM-16, YM-17, YM-18, YM-19.	There is no particular stacking order for these units
3	Faro rentals	YM-20, YM-21, YM-22, YM-23, YM-24, YM-25 and YM26	There is no particular stacking order for these units
4	YEC Whse	WD4, WD5, WD6, WD7	
5	YEC Dawson	DD5, DD4, DD3, DD2, DD1	
6	YEC Faro	FD7, FD1	
7	YEC Mayo	MD1, MD2, MD3	

REVISED RESPONSE

Board Order 2021-10 Appendix B notes:

NY Submission: In the stacking order provided, YEC lists all 7 Faro rental diesels, and the installed FD1 and FD7 generators. This adds up to 18.4MW – while the most recent (2014/Current) YESAB shows only FD1 and FD7 for 8.15MW. How can all Faro capacity be in the stacking order?

YEC Response: For clarification it is noted that the Faro rental units are at the Faro site and are included in the formal stacking order; however, YEC can only run up to 10.6 MW of generation at Faro at any one time under its existing permits.

NY Reply: In this response, YEC acknowledges that the theoretical “formal stacking order” provided in response to the IR will never actually be used, due to a 10.6 MW generation limit at the Faro facility. Please provide the actual stacking order, given the 10.6MW limit, or the 8.15MW limit from the most recent 2014 YESAB (2014-0119) as requested.

Board Ruling: The Board considers the information requested to be of potential benefit. The Board directs YEC to provide a fulsome response to the NY reply; i.e., provide the actual stacking order.

YEC has updated the table giving consideration to the generation limits. The stacking order is subject to adjustment to reflect local conditions and periods when rental units are not available.

	Type/ Location	Units	Comment
1	YEC LNG	WG1, WG2 and WG3	
2	Whse rentals	YM-10, YM-11, YM-12, YM-13, YM-14, YM-15, YM-16, YM-17.	There is no particular stacking order for these units. There is a 14 MW air emission cap on the diesel generation at Whse. 10 available units but only 8 can be run at a time under non-emergency conditions under current air emissions permit (see note 1).
3	Faro rentals	YM-20, YM-21, YM-22, YM-23, YM-24, YM-25	There is no particular stacking order for these units. There is a 10.6 MW air emission cap on the diesel generation at Faro. 7 available units but only 6 can be run at a time under current air emissions permit (see note 2).
4	YEC Mayo	MD1, MD2, MD3	
5	YEC Dawson	DD5, DD4, DD3, DD2, DD1	

	Type/ Location	Units	Comment
Emergency conditions, in ability to meet system demand as a result of multiple generation failures			
6	Whse rentals	Remaining 2 rental units in Whse	3.6 MW (see note 1)
7	Faro rentals	Remaining 1 rental unit in Faro	1.8 MW (see note 2).
8	YEC Whse	WD4, WD5, WD6, WD7	Total 9.55 MW capacity.
9	YEC Faro	FD7, FD1	Total 5.8 MW capacity.

- 1 Notes:
- 2 1. Current permits allow up to 14 MW diesel capacity operation; an added 12 MW diesel
- 3 capacity can be operated under emergency conditions.
- 4 2. Yukon Energy has filed an application with Yukon Environmental and Socio-economic
- 5 Assessment Board in August 2021 for the purpose of increasing the allowed thermal
- 6 generation operation at the Faro Plant. Total permitted diesel operation is applied to
- 7 increase from 10.6 MW to 15.5 MW.

1 **QUESTION:**

2
3 a) What modifications have been made to the Faro diesel plant since the 2014
4 YESAB assessment? Please provide details and dates of any and all
5 changes/modifications to the Faro plant.
6

7 **ANSWER:**

8
9 **(a)**

10
11 Please see the summary provided below – which provides the modification to the plant
12 and the date of the modification since 2014.
13

14	S/N	Modification	Date
15	1	Moved FD5 Dawson	2014
16	2	FD0 plant RTU replacement	2017
17	3	Heating system UG leak replacement (FD7 to FD1)	2017
18	4	Faro plant repairs	2016

19
20 **REVISED RESPONSE**

21
22 Board Order 2021-10 Appendix B notes:
23

24 **NY Submission:** IR was for a list of all modifications/changes to the Faro plant
25 since the 2014 (most recent) YESAB assessment. YEC fails to list the 7 rental
26 generators. Is this an error, or is YEC claiming that the generators do not exist?
27 Please correct.
28

29 **YEC Response:** The IR requested that YEC provide “modifications have been
30 made to the Faro diesel plant since the 2014 YESAB assessment.” The Faro rental
31 diesels are not YEC assets and are not part of Faro plant rate base. The
32 infrastructure required for the diesel rental units is reviewed in detail in Section
33 5.2.1.2 of the Application [N-1 Capacity Shortage Faro Thermal Rental Site
34 Infrastructure].
35

36 **NY Reply:** Generating station, ownership status and rate base are not relevant,
37 but can be noted as part of the response if YEC prefers.

1 YEC's initial response was:

2 S/N Modification Date

3 1 Moved FD5 Dawson 2014

4 2 FD0 plant RTU replacement 2017

5 3 Heating system UG leak replacement (FD7 to FD1) 2017

6 4 Faro plant repairs 2016

7 and the revised answer is understood to be the following:

8
9 S/N Modification Date

10 1 Moved FD5 Dawson 2014

11 2 FD0 plant RTU replacement 2017

12 3 Heating system UG leak replacement (FD7 to FD1) 2017

13 4 Faro plant repairs 2016

14 5 Added seven rental generators (of 1.8MW each) 2020 (though YEC notes that
15 "the Faro rental diesels are not YEC assets and are not part of Faro plant
16 ratebase")

17 6 Added The infrastructure required for the diesel rental 2020 units reviewed in
18 detail in Section 5.2.1.2 of the Application [N-1 Capacity Shortage Faro Thermal
19 Rental Site Infrastructure].

20
21 If YEC agrees that this is what was meant, the answer is acceptable.

22
23 **Board Ruling:**¹ The Board directs YEC to confirm NY's understanding as stated
24 in his reply. If YEC does not agree with NY's understanding as stated in his reply,
25 the Board directs YEC to explain the discrepancy.

26
27 In response to the above direction, YEC agrees.

¹ As corrected by Board email dated August 18, 2021.

Utilities Consumers' Group (UCG)

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.

1 **REVISED RESPONSE**

2
3 Board Order 2010-21 Appendix A notes:

4
5 YEC did not respond to the questions posed by UCG which were to provide details
6 of specific instances where YEC reduced its ongoing costs, reduced waste, or
7 improved performance to address short term financial stability since the last GRA.
8 The Board does not agree that the IR is imprecise in nature, nor that the
9 information requested is available in YEC's application or Tab 3. The Board directs
10 YEC to respond to the IR at issue.

11
12 To be helpful to the Board, and to provide additional information on what was done to
13 ensure the necessary level of service is provided in a cost effective manner, the following
14 are noted:

- 15
16 • YEC has provided a revised response to YUB-YEC-1-43(a) in an effort to describe
17 efforts to reduce Administration costs.
18
- 19 • It is noted that Operations and Maintenance costs are reviewed using a similar
20 approach as for Administration costs. However, O&M costs can be more difficult
21 to reduce when they are directly related to growing operational demands of
22 increased generation.
 - 23 o An example of reducing costs while becoming more productive is the
24 approach of maximizing hydro generation to save variable costs related to
25 thermal generation.
26
 - 27 o As part of YEC's 2021 budget process Mechanical O&M costs (included in
28 Production Costs) were cut by \$105,000 and a subsequent \$112,000 by
29 reductions in thermal related maintenance costs, for a total of a 23%
30 reduction from original budget submission.
31
 - 32 o In addition, the Operators O&M costs (also included in Production Costs)
33 were reduced by \$239,000 (43%) from 2020 Forecast by reductions related
34 to lower thermal generation, such as less sparkplugs, oil and filters. Overall,
35 non-labour Production Costs, excluding the costs of the diesel rentals,
36 decreased by \$249,000 (11%) from 2020 Forecast.
37

- 1 • With regard to consultant costs, YEC has relied on the use of a Consultant
2 (InterGroup) to perform some of the analytical work related to regulatory matters.
3 Yukon Energy notes that in many cases it is more economic to use a consultant,
4 such as InterGroup, to perform this work rather than YEC. First, the consultant
5 provides specific expertise on regulatory matters not currently held by YEC
6 employees. Second, a YEC employee's cost (including benefits) is not that
7 different from the Consultant's rate so the task can typically be performed cost
8 effectively by the Consultant. Finally, YEC only pays the consultant for hours
9 worked rather than paying a full annual salary as for a YEC employee.

10
11 **(g)**

12
13 In UCG-YEC-1-19(c) from the 2008/09 GRA, Yukon Energy addressed this UCG concept
14 as follows:

15
16 As noted in response UCG-YEC-1-32 provided during the 2005 Required
17 Revenues and Related Matters proceeding, a multi-year performance based
18 regulatory framework is not currently in place in Yukon. Implementing this form of
19 regulation would likely require significant changes to the regulatory framework in
20 the Yukon that have not yet been assessed. Yukon Energy has not assessed
21 measures that the Yukon Government might adopt to bring in legislation or policy
22 related to performance-based regulation.

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 **REVISED RESPONSE**

2
3 Order 2021-10 Appendix A notes:

4
5 YEC has not stated that the UCG request is too onerous. Although YEC has
6 provided information, it is not fully responsive to the IR. Therefore, the Board
7 directs YEC to produce the requested information as a single document.

8
9 Please see Attachment 1 to this response that includes Yukon electricity map that shows
10 location and types of installed capacity as well as the table from Appendix A of YEC's 10-
11 Year Renewable Electricity Plan Technical Report with the list of installed capacity with
12 dependable capacity relied upon for N-1 capacity requirements.

13
14 **(c)**

15
16 AEY would be in a better position to provide the requested information. This information
17 as required for the N-1 capacity criteria is provided in Tab 2 of the Application.

18
19 **REVISED RESPONSE**

20
21 Order 2021-10 Appendix A notes:

22
23 YEC has not stated that the UCG request is too onerous. Although YEC has
24 provided information, it is not fully responsive to the IR. Therefore, the Board
25 directs YEC to produce the requested information as a single document.

26
27 Please see response to part b) above that provides an attachment with the map and list
28 of installed capacity by location on the YIS for both YEC and AEY.

29
30 **(d)**

31
32 Yes. When planning the system to the N-1 contingency criterion (used to determine the
33 requirement of system capacity and consequent diesel rentals), the mines are not included
34 in the analysis. Accordingly, the mines have no impact to the diesel requirements, as they
35 have their own diesel backup.

1.3 Yukon Integrated System

At present, the Yukon electrical system shown in Figure 1 comprises:

- » One (1) large hydroelectric based grid called the Yukon Integrated System (YIS);
- » One (1) medium-sized diesel-based grid serving Watson Lake; and
- » Three (3) smaller isolated communities with diesel generation (Beaver Creek and Destruction Bay/ Burwash Landing) and solar/diesel generation (Old Crow).

Figure 1: Yukon Electrical Systems



Appendix A: Existing Resources Technical Attributes

Location	Retirement Year	Original Unit #	Current Unit #	Prime Mover Type	Dispatchable	10 Year Renewable Energy Plan		2016 IRP Dependable Capacity (IRP Table 4.2.) [kW]
						Installed Capacity [kW]	Dependable Capacity [kW]	
Aishihik								
Hydro	2050	AH1	AH1	Hydro	Yes	15,600	15,000	15,000
	2050	AH2	AH2	Hydro	Yes	15,600	15,000	15,000
	2050	AH3	AH3	Hydro	Yes	7,000	7,000	7,000
Subtotal						38,200	37,000	37,000
Faro								
Diesel	2023	FD1	FD1	Diesel	Yes	5,150	3,000	4,000
	2050	FD7	FD7	Diesel	Yes	3,000	2,800	2,800
Subtotal						8,150	5,800	6,800
Dawson								
Diesel	2050	DD1	DD1	Diesel	Yes	800	650	720
	2023	DD2	DD2	Diesel	Yes	1,000	850	920
	2050	DD3	DD3	Diesel	Yes	1,000	850	920
	2050	DD4	DD5	Diesel	Yes	1,440	1,000	1,000
	2023	DD5	DD5	Diesel	Yes	1,500	1,350	1,400
	2050	YM1	FD6	Diesel	Yes	1,440	850	1,000
Subtotal						7,180	5,550	5,960
Mago								
Diesel	2050	MD1	FD2	Diesel	Yes	1,000	850	850
	2050	MD2	FD4	Diesel	Yes	1,000	850	850
	2050	MD3	FD3	Diesel	Yes	1,000	850	850
Subtotal						3,000	2,550	2,550
Hydro	2050	MH1	MH1	Hydro	Yes	2,550	1,500	1,400
	2050	MH2	MH2	Hydro	Yes	2,550		
	2050	MBH1	MBH1	Hydro	Yes	5,310	2,500	3,800
	2050	MBH2	MBH2	Hydro	Yes	5,310	2,500	3,800
Subtotal						15,720	6,500	9,000
Total						18,720	9,050	11,550
Whitehorse								
Hydro	2050	WH1	WH1	Hydro	Yes	5,800	3,500	3,000
	2050	WH2	WH2	Hydro	Yes	5,800	3,500	3,000
	2050	WH3	WH3	Hydro	Yes	8,400		
	2050	WH4	WH4	Hydro	Yes	21,327	20,000	18,500
Subtotal						41,327	27,000	24,500
Diesel	2015	WD1	WG1	Diesel	Yes	N/A	N/A	N/A
	2015	WD2	WG2	Diesel	Yes	N/A	N/A	N/A
	2019	WD3	WD3	Diesel	Yes	N/A	N/A	4,500
	2050	WD4	WD4	Diesel	Yes	2,500	2,250	2,500
	2050	WD5	WD5	Diesel	Yes	2,500	2,250	2,500
	2050	WD6	WD6	Diesel	Yes	2,500	2,250	2,500
	2050	WD7	WD7	Diesel	Yes	3,300	2,800	3,000
Subtotal						10,800	9,550	15,000
Natural Gas	2055	WG1	WG1	Natural Gas	Yes	4,400	4,200	4,400
	2055	WG2	WG2	Natural Gas	Yes	4,400	4,200	4,400
	2055	WG3	WG3	Natural Gas	Yes	4,400	4,200	N/A
Subtotal						13,200	12,600	8,800
Total						65,327	49,150	48,300

Location	Retirement Year	Original Unit #	Current Unit #	Prime Mover Type	Dispatchable	10 Year Renewable Energy Plan		2016 IRP Dependable Capacity (IRP Table 4.2.) [kW]
						Installed Capacity [kW]	Dependable Capacity [kW]	
Haeckel Hill								
Wind	2019	W/W2	W/W2	Wind	No	N/A	N/A	0
						0	0	0
Mobile Diesels								
Diesel	2050	YM2	YM2	Diesel	Yes	150	0	0
	2050	YM3	YM3	Diesel	Yes	125	0	0
	2050	YM4	YM4	Diesel	Yes	35	0	0
	2050	YM5	YM5	Diesel	Yes	125	0	0
				Subtotal		435	0	0
YECL								
Diesel	2050	CD1	CD1	Diesel	Yes	1,600	1,200	1,206
	2050	TD1	TD1	Diesel	Yes	1,500	1,200	1,130
	2050	RD1	RD1	Diesel	Yes	1,000	750	750
	2050	HD1	HD1	Diesel	Yes	1,750	1,500	1,320
	2050	Pelly G1	Pelly G1	Diesel	Yes	275	200	199
	2050	Pelly G2	Pelly G2	Diesel	Yes	600	400	446
	2050	Pelly G3	Pelly G3	Diesel	Yes	300	200	218
	2050	Stewart G1	Stewart G1	Diesel	Yes	150	100	104
				Subtotal		7,175	5,550	5,373
YEC								
				Hydro		95,247	70,500	70,500
				Diesel		29,565	23,450	30,310
				Natural Gas		13,200	12,600	8,800
				Wind		0	0	0.0
				Total		138,012	106,550	109,610
YECL								
				Diesel		7,175	5,550	5,373
				Total		7,175	5,550	5,373
Yukon Power System								
				Hydro		95,247	70,500	70,500
				Diesel		36,740	29,000	35,683
				Natural Gas		13,200	12,600	8,800
				Wind		0	0	0
				Total		145,187	112,100	114,983
Single Contingency (N-1) Dependable Capacity								
				Hydro		N/A	33,500	33,500
				Diesel		N/A	27,500	34,363
				Natural Gas		N/A	12,600	8,800
				Wind		N/A	0	0
				Total		0.0	73,600	76,663

Notes:

- Single Contingency (N-1) scenario dependable capacity excludes the dependable capacity for Aishihik (37 MW) and ATCO's Haines junction diesel generator (1.5 MW) as the community would be isolated by the loss of the transmission line between the Aishihik Generating Station and the Takhini substation.
- No dependable capacity assumed for Minto Mine diesel generators and YEC wind turbines and mobile generators with the exception of unit YM1.
- Excludes ATCO Fish Lake Hydro. The contribution of the ATCO Fish Lake Hydro plant was not included in the inventory of the existing resources as its contribution was deducted from the load forecast modelling.

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 44.50</i>		<i>46.58</i>	<i>47.12</i>	<i>48.75</i>	<i>49.25</i>
<i>Engineering Services 15.00</i>		<i>13.03</i>	<i>15.16</i>	<i>5.63</i>	<i>15.50</i>
<i>Health, Safety & Environment 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	

REVISED RESPONSE

The question had requested that Yukon Energy provide a chart giving each of the YEC positions (management and non-management) pay grade/scale and performance bonus. The original response only provided union pay grants and had omitted providing information for management and non-management pay grade/scale. Table 1 and Table 2 provide additional information in response to the original question.

1

Table 1: Union Pay Grades & Positions (2019)

Level	Min	Max
Level 1	\$ 14.47	\$ 17.29
Level 2	\$ 16.74	\$ 19.99
Level 3	\$ 19.24	\$ 22.98
Meter Reader		
Level 4	\$ 22.30	\$ 26.61
Level 5	\$ 25.77	\$ 30.76
Plant Operator Temp x 2		
Customer Service Representative		
Administrative Assistant-Eng. Services		
Accounts Payable Clerk		
Level 6	\$ 29.74	\$ 35.52
Plant Operator Mayo x 2		
CMMS/Operations Administrator		
Procurement Administrator		
Warehouse Assistant		
Plant Operator Aishihik		
Level 7	\$ 34.53	\$ 41.23
Warehouse Administrator		
Plant Operator Whitehorse x 4		
Sr Office Administrator		
Financial Administrator x 3		
Level 8	\$ 40.11	\$ 47.89
Apprentice Trades Person		
Procurement Specialist		
Powerline Technician Mayo		
SCC Operator I x 4		
Maintenance Electrician x 4		
Powerline Technician Whitehorse		
Maintenance Mechanic x 4		
Sr Plant Operator		
Draftperson/Land Use Administrator x 2		
Powerline Technician Dawson		
Maintenance Electrician Mayo		
Communication Coordinator		

2

1

Table 1: Union Pay Grades & Positions (2019) – Continued

Level 9	\$ 44.05	\$ 52.61
Maintenance Job Planner		
Metering Coordinator Maintenance Electrician		
SCC Operator II		
Sr Powerline Technician Mayo		
Network/Systems Administrator		
Sr. Procurement Specialist		
Database Administrator		
Safety Coordinator		
Electrical Protection & Control Coordinator		
Sr Maintenance Mechanic		
Electrical Instrumentation Coordinator		
Sr. Powerline Technician Dawson		
Environment & Resource Analyst		
Sr Powerline Technician - Whitehorse x 2		
Operations Coordinator		
Coordinator Mechanical Projects		
Coordinator, Electrical Projects		
SQL/Sharepoint Administrator		
Distribution Coordinator		
Level 10	\$ 46.34	\$ 55.35
Leadhand, SCC		
Leadhand Electrical Maintenance		
Leadhand Transmission & Distribution		
Level 11	\$ 48.98	\$ 58.49
Leadhand Mechanical Maintenance		

2

1

Table 2: Management & Professional Pay Grades & Positions (2019)¹

2019 Rates	Min. Salary	Min. Hr	Max Salary	Min. Hr
Level 8	\$ 68,161.60	\$ 32.77	\$ 96,523.00	\$ 46.41
Payroll Analyst				
Level 9	\$ 73,797.84	\$ 35.48	\$ 104,564.88	\$ 50.27
Corporate Secretary				
Electrical Engineer-Engineer in Training				
Level 10	\$ 80,283.91	\$ 38.60	\$ 120,426.92	\$ 57.90
Sr. Regulatory Analyst				
Mechanical Engineer				
Electrical Engineer x 2				
Manager, Property & Risk Management				
Assistant Controller				
Level 11	\$ 87,872.37	\$ 42.25	\$ 131,808.56	\$ 63.37
Manager Communications				
Resource Planner x 3				
Project Manager x 2				
Protection & Systems Engineer				
Manager Health + Safety				
Manager Environmental Assessment & Licensing				
Asset Manager				
Level 12	\$ 96,231.71	\$ 46.27	\$ 144,346.52	\$ 69.40
Manager Human Resources				
Manager IT				
Controller				
Manager, Procurement				
Manager, Capital Projects				
Manager, Civil Engineering & Projects				
Level 13	\$ 103,049.95	\$ 49.54	\$ 154,574.93	\$ 74.31
Manager Operations				
Level 14	\$ 111,517.40	\$ 53.61	\$ 167,277.69	\$ 80.42
Level 15	\$ 131,314.35	\$ 63.13	\$ 196,971.52	\$ 94.70
VP, Engineering Services				
VP, Finance & Chief Financial Officer				
VP, Aboriginal & Government Relations				
VP, Resource Planning & Regulatory Affairs				
VP, Operations				
Level 16	\$ 142,861.77	\$ 68.68	\$ 214,293.19	\$ 103.03
VP, Business and Corporate Development				
Level 17	\$ 165,627.78	\$ 79.63	\$ 248,441.67	\$ 119.44
Level 18	\$ 201,040.89	\$ 96.65	\$ 301,561.34	\$ 144.98

2

3

4

5

¹ Table 2 does not include casual employees, the President's position nor the Records Management position as they are not covered by either the Union Collective Agreement or the M&P Terms & Conditions of Employment.

1 (i)

2
3 YEC does not have (management and non-management) pay grade/scale and
4 performance bonus information of other utilities in Canada to provide.

5
6 **REVISED RESPONSE Provided in response to UCG Motion**

7
8 UCG-YEC-1-24 notes as follows with respect to out of scope employee job evaluations:

9
10 Yukon Energy relies on Korn Ferry, an independent contractor, for the evaluation
11 of all jobs. Yukon Energy participates in the salary benchmarking service provided
12 by Korn Ferry whereby our jobs are compared against the market and our peers
13 (utilities), adjusted for our geographical location.

14
15 To provide greater clarity to the response to UCG-YEC-1-24 and UCG-YEC-1-26(i), it is
16 noted that YEC contracts with Korn Ferry, an independent contractor, to provide job
17 description evaluation services. "Salary benchmarking" is not a fulsome description of the
18 service provided to Yukon Energy by Korn Ferry.

19
20 Yukon Energy also participates in the salary benchmarking service provided by Korn Ferry
21 whereby YEC jobs are compared against the market and YEC peer utilities and adjusted
22 for geographic location.

23
24 For context, it is noted that Yukon Energy adopted an evaluation system, the Hay Plan, in
25 the early 2000's. This is a well-established and widely used proprietary evaluation
26 methodology now owned by Korn Ferry; and is used to help ensure consistency of
27 treatment both within the company and across other businesses (i.e., benchmarking).

28
29 The Hay Plan is a points-based system and is the primary approach to evaluation that
30 focuses on several universal factors including:

- 31
32 • Know how;
33 • Problem solving;
34 • Accountability; and
35 • Working conditions.

1 As part of the evaluation process Korn Ferry also enters job specifics into a proprietary
2 job evaluation model that looks at other YEC evaluations as well as global Korn Ferry job
3 evaluations as appropriate to arrive at an assessment. This is a computerized model that
4 looks at similar positions and provides a ranking against this average.

5
6 No specific benchmark compensation figures are reported to YEC, and YEC does not
7 have access to the background information used by Korn Ferry in its assessments.

8
9 **REVISED RESPONSE – AUGUST 24, 2021**

10
11 Board Order 2021-10 Appendix A notes:

12
13 YEC's IR response has made it difficult to understand the services being provided
14 by Korn Perry [sic]. On its face, it appears that YEC participates in a Korn Ferry
15 benchmarking process for the purpose of establishing that its management and
16 non-management pay scales and bonuses are reasonable and comparable [sic]
17 with other utilities in Canada. Yet, YEC's IR response indicates that it receives no
18 reporting of specific benchmark compensation figures nor does it have access to
19 the background information used by Korn Ferry in its assessments.

20
21 Accordingly, it is not clear why and how YEC "participates in the salary
22 benchmarking service provided by Korn Ferry whereby YEC jobs are compared
23 against the market and YEC peer utilities and adjusted for geographic location,"
24 yet is unable to establish where their compensation figures sit in comparison to
25 peer utilities whether by way of percentiles or some other measurement.

26
27 The Board requires YEC to confirm that it remains unaware of where its current
28 management and non-management pay grades and positions are in relation to
29 peer utilities. If confirmed, please explain how parties and the Board are to
30 ascertain the reasonableness of YEC's management and non-management pay
31 grades and positions as provided in response to the IR at issue.

32
33 Yukon Energy confirms that the Korn Ferry benchmarking process does not provide Yukon
34 Energy with specific information regarding where YEC's specific current management and
35 non-management pay grades and positions are in relation to peer utilities.

1 As noted in Yukon Energy's correspondence on July 12, 2021, the Hay Plan Evaluation
2 Method is the most widely used job evaluation system in the world and has been in
3 circulation for close to 80 years. Additionally, this approach has been deemed compliant
4 with both US and Canadian pay equity legislation.

5
6 The method is based on measuring a job description against 4 universal factors:

- 7
- 8 • Know-How
- 9 • Problem Solving
- 10 • Accountability
- 11 • Working Conditions

12
13 For each factor, the Hay Plan uses guide charts that assign points to each factor based
14 on the level of expertise required for the evaluated job; the sum of the points awarded then
15 determines the pay level.

16
17 While it is not possible for YEC to correlate a YEC job description against its peers using
18 this approach, the long history and general acceptance by the business community lends
19 strong credence to this approach.

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 **REVISED RESPONSE**

30
31 Board Order 2021-10 Appendix A notes:

32
33 The Board finds that the information being requested by UCG would be helpful.
34 The Board directs YEC to prepare a chart, commencing with the year 1998, that
35 provides the amount of rate base approved for any test year where a GRA was
36 submitted by YEC.

Please see table below that shows approved mid-year ratebase for YEC for each test year since 1997 test year.

Test Year	Mid-Year Rate Base, \$000	Reference
1997	116,321	YEC 2005 Required Revenues and Related Matters, Attachment to McMahon-YEC-1-29 a)
2005	140,793	2008/09 GRA Compliance Filing, Schedule 4A
2008	143,184	2008/09 GRA Compliance Filing, Schedule 4B
2009	147,969	2008/09 GRA Compliance Filing, Schedule 4C
2012	216,467	2012/13 GRA Compliance Filing, Schedule 4B
2013	226,684	2012/13 GRA Compliance Filing, Schedule 4B
2017	272,931	2017/18 GRA Compliance Filing, Schedule 4B
2018	287,478	2017/18 GRA Compliance Filing, Schedule 4B

(e)

As indicated in the Table, the amounts are mid-year balances, so they are not the actual amount of contributions received in the year. Also as indicated in the Table, the amounts are for assets in-service, so the Table does not include contributions received for assets that remain as work in progress. Finally, as these amounts are asset in-service, they include amortization of the contributions. The Table represents the balance of all current and historical contributions at their net book value. New contributions since 2018 include \$11.5 million from VGC Group to fund McQuesten Substation and system improvement capital costs. YEC is also forecasting \$23.7 million in 2020 and 2021 from the Federal government for the Mayo to McQuesten Transmission Line.

(f)

Actual vs approved rate base for 2018 simply reflects the extent that actual numbers varied from the forecast approved by the Board.

(g)

Existing vs proposed for 2021 mainly reflects the impact of adjusted depreciation rates. See working capital tables in Tab 7 for review of adjustments to this element.

1 **(h)**

2

3 The Application focuses on changes to rate base and identifies specific capital, deferred
4 and other rate base cost changes for review and approval. YEC is not able to respond to
5 the question as it seeks a broad review as to all costs approved in the past that would
6 require considerable effort to address without providing any assistance to the 2021 GRA
7 approvals sought in this application.

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.

16
17 **REVISED RESPONSE** to parts **d)** through **f)**

18
19 Board Order 2021-10 Appendix A notes:

20
21 The Board agrees with YEC that the parameters for the YEC benchmark against
22 [sic] FortisBC (Electric) have been established and agrees that no further response
23 is required for parts (a-c) of the IR. However, UCG may test any changes in
24 circumstances such as if risk was shifted from YEC to customers.

25
26 The Board considers that responses to parts (d-f) may be of potential benefit and
27 directs YEC to provide responses to these part.

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 YEC would like to highlight that it does not use “gross margin” in the regulatory or financial
2 reporting. In order to be responsive, YEC assumes that by “gross margin” UCG meant
3 percentage of net operating income compared to total revenues.

4
5 Table 1 compares 2019 and 2020 actual revenues and expenses for YEC as reported in
6 the annual report under the IFSR reporting standards⁴ compared to revenues and
7 expenses for Fortis BC. The table also calculates “gross margin” as indicated above.

8
9 Line 5 of Table 1 shows expenses excluding depreciation and amortization expenses as
10 well as property tax as requested in part e) of the IR.

11
12 The table validates the fact that YEC is much smaller compared to Fortis BC which was
13 taken into account when the Board awarded risk premium for smaller size in previous
14 proceedings. Yukon Energy is also a capital intensive utility compared to Fortis BC as
15 highlighted in Tab 8 of the Application with customer count at about 1.6% that of FortisBC
16 (Electric) while its rate base was approximately 22% that of FortisBC.

17
18 The table also shows that Fortis BC as investor-owned with largely distribution service
19 utility tend to focus on increasing net profit which is not the case for Yukon Energy which
20 is much smaller utility with generation and transmission service where the revenues are
21 subject to fluctuations in part due to connection and loss of industrial customers and its
22 lack of any interconnection with external electricity markets.

⁴ The IFRS reporting standards differ from regulatory reporting. For example, under IFRS the annual O&M expenses include \$8.3 million for 2019 and \$11.4 million for 2020 “regulatory account expenses” which are deferred costs under the regulatory reporting [please see notes 10 and 20 of the 2020 annual report, https://yukonenergy.ca/media/site_documents/FINAL_2020_Annual_Report_Yukon_Energy_web.pdf]. Also, the revenues include revenues related to Rider J1 [2017/18 GRA true-up rider] as well as revenues from Rider F rider. While under the regulatory reporting Rider J1 revenues are booked for the years where the revenue shortfall is calculated [2017-2019] and Rider F revenues are adjusted through the fuel costs.

Table 1: Revenues and Operating Income for YEC compared to Fortis BC Inc.

		YEC		Fortis BC Inc. (Electric)	
		2019	2020	2019	2020
1	Revenues (\$millions)	52.0	71.8	404.0	412.0
2	Expenses (\$millions)	57.7	67.5	281.0	289.0
2a	Power purchase costs	0.06	0.05	121.0	120.0
2b	Operating and maintenance expenses	44.0	53.3	81.0	91.0
2c	Property and other taxes	0.7	0.7	17.0	17.0
2d	Depreciation and amortization	13.0	13.4	62.0	61.0
3=1-2	Revenues less Expenses [before debt cost]	-6	4	123	123
4=3/1	Gross Margin [percentage of revenues]	-11%	6%	30%	30%
5=2a+2b	Expenses excluding depreciation and amortization, and property taxes	44.1	53.3	202.0	211.0

Notes:

1. The information for Yukon Energy is based on 2020 Annual Report, page 43 and reflect financial reporting under IFRS [available at https://yukonenergy.ca/media/site_documents/FINAL_2020_Annual_Report_Yukon_Energy_web.pdf; accessed on August 6, 2021]. Operating and maintenance costs for YEC include "regulatory account expenses" which are deferred costs under the regulatory reporting [please see note #10 in the annual report]. The revenues for 2020 exclude \$3.531 million insurance proceeds [please see note #19 in the annual report]. The revenues for YEC also include 2017/18 GRA true-up riders and Rider F rider revenues.

2. The information for Fortis BC is based on 2020 Financial Statements, page 5. Available at https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/audited-annual-financial-statements-electric-year-end-2020.pdf?sfvrsn=511b2169_2 [accessed on August 6, 2021].

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; WH4Upr.

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.

19
20 **REVISED RESPONSE**

21
22 Board Order 2021-10 Appendix A notes:

23
24 The Board agrees with the points brought up in the UCG submission. Providing
25 costs for each step in the process gives the Board a better understanding of
26 whether YEC has prudently incurred costs over the project time period. Continuity
27 schedules also allows the Board to confirm there is no duplication of costs being
28 requested to be added to the rate base.

29
30 Accordingly, the Board finds the information requested by UCG to be helpful and
31 directs YEC to provide continuity schedules of each capital project greater than \$1
32 million. This entails providing information outlined in UCG-YEC-1-34 and UCG's
33 motion. YEC is to provide these schedules in excel format with formulae intact.

34
35 To clarify YEC's earlier response, "stagegate" activities relate only to planning stages for
36 a project. The capital projects greater than \$1 million are construction projects so they do
37 not follow the stagegate process that planning projects go through. However, YEC is able

to provide the requested information by year to help show the costs incurred on a project over time. The following tables show the actual costs by project by year by cost element, detailing contractor costs. YEC costs are split into Labour, Travel, Materials, General and AFUDC. As 2021 is not yet complete, 2021 columns reflect the current forecast based on information available today. These forecasts may change as the project progresses forward.

The variance analysis are provided for the projects where 2020 actual costs are included [compared to forecast costs in the 2021 GRA] as well as updated 2021 forecasts compared to forecasts included in the GRA.

The McQuesten Substation Project was built by VGC Group and transferred to YEC – therefore YEC does not have cost breakdown by activities for this project (net cost to YEC of \$0.931 million (as agreed in the PPA) after VGC Group's asset contribution valued at \$10.688 million).

Table 1: LNG Third Engine Project Cost Breakdown, \$000

	2014	2015	2016	2017	2018	2019	Total
Labour				\$45	\$163	\$5	\$213
Travel				\$2	\$11	\$0	\$13
Materials				\$200	\$89	\$0	\$289
Contractors - Asher Engineering				\$95	\$360		\$455
Contractors - Enerflex (Gas Drive)				\$2,318	\$4,237		\$6,555
Contractors - Other	\$200			\$4	\$52	\$3	\$260
General				\$0	\$11	\$2	\$13
AFUDC		\$5	\$5	\$11	\$95	\$0	\$115
Subtotal	\$200	\$5	\$5	\$2,675	\$5,017	\$11	\$7,913
Spare Parts	\$64	\$185	\$17	\$5	-\$10	\$86	\$347
Total	\$264	\$190	\$22	\$2,680	\$5,008	\$97	\$8,260

Table 2: N-1 Capacity Shortage Whitehorse Thermal Rental Site, \$000

	2018	2019	Total
Labour	\$113.0	\$175.8	\$288.8
Travel	\$4.1	\$1.3	\$5.4
Materials	\$67.1	\$842.5	\$909.5
Contractors - Struthers Technical Solutions	\$18.9		\$18.9
Contractors - Finning		\$35.5	\$35.5
Contractors - Other	\$22.8	\$4.1	\$26.9
General	\$1.3	\$3.3	\$4.6
AFUDC	\$0.3	\$7.9	\$8.2
Total	\$227.5	\$1,070.3	\$1,297.8

Table 3: Transmission Line Refurbishment Project, \$000

	2018	2019	Total
Labour	\$172.8	\$48.1	\$220.9
Travel	\$18.0	\$3.7	\$21.7
Materials	\$1,445.0	\$755.6	\$2,200.6
Contractors - ACE Vegetation Control Service	\$344.0	\$368.2	\$712.2
Contractors - Arctic Arrow Powerline Group	\$3,236.9	\$2,455.9	\$5,692.9
Contractors - Castle Rock Enterprises	\$138.0		\$138.0
Contractors - Chimax Inc	\$22.7	\$28.0	\$50.7
Contractors - DNR Pressure Welding	\$293.6	\$308.5	\$602.2
Contractors - IBEX Construction	\$148.6	\$90.5	\$239.0
Contractors - J&B Contracting	\$47.6		\$47.6
Contractors - Meldon Construction	\$59.9		\$59.9
Contractors - Other	\$65.4	\$18.3	\$83.8
General	\$228.5	\$146.6	\$375.1
AFUDC	\$59.1	\$48.1	\$107.2
Total	\$6,280.2	\$4,271.6	\$10,551.8
Included in 2017/18 GRA	\$6,280.2	\$0.0	\$6,280.2
Not included in 2017/18 GRA	\$0.0	\$4,271.6	\$4,271.6
Total	\$6,280.2	\$4,271.6	\$10,551.8

Table 3 includes project components shown separately in Table 5.2-1: the portion included in the 2017/18 GRA under heading "Major Projects Reviewed in 2017/18 GRA [forecast

included in 2018 GRA rate base]” and the portion not included in the 2017/18 GRA shown under heading “Major Projects not in 2017-18 GRA Rate Base.”

Table 4: Transmission Line Refurbishment – L178 Project, \$000

	2021	Total
Labour	\$115.0	\$115.0
Travel	\$28.3	\$28.3
Materials	\$25.0	\$25.0
Contractors	\$115.0	\$115.0
AFUDC	\$17.0	\$17.0
Total	\$300.3	\$300.3
2021 GRA Forecast	\$1,300.0	\$1,300.0
Variance	-\$999.7	-\$999.7

This project did not proceed in 2021 as forecast in the GRA application. During the procurement process the market price came back much higher than YEC expected. YEC has reduced the project scope for 2021 to only \$0.3 million to reflect work completed by YEC power line crews, and this cost will be closed in 2021.

Table 5: Breaker Replacement Program Project, \$000

	2017	2018	2019	Total
Labour	\$39.4	\$173.0	\$234.3	\$446.7
Travel	\$2.8	\$12.5	\$21.7	\$36.9
Materials	\$20.5	\$617.9	\$580.5	\$1,218.9
Contractors - Struthers Technical Solutions	\$47.4	\$9.8		\$57.2
Contractors - FM Installations		\$230.3		\$230.3
Contractors - Orbis Engineering		\$85.0	\$132.0	\$217.0
Contractors - Valard Construction			\$640.6	\$640.6
Contractors - Taifa Engineering			\$103.3	\$103.3
Contractors - Other		\$17.6	\$20.4	\$38.0
General		\$11.9	\$32.4	\$44.2
AFUDC	\$0.5	\$9.4	\$15.4	\$25.3
Total	\$110.5	\$1,167.3	\$1,780.6	\$3,058.4
Included in 2017/18 GRA	\$110.5	\$688.0		\$798.5
Not included in 2017/18 GRA	\$0.0	\$479.4	\$1,780.6	\$2,259.9
Total	\$110.5	\$1,167.3	\$1,780.6	\$3,058.4

This table includes project components shown separately in Table 5.2-1: the portion included in the 2017/18 GRA under heading “Major Projects Reviewed in 2017/18 GRA [forecast included in 2018 GRA rate base]” and the portion not included in the 2017/18 GRA shown under heading “Major Projects not in 2017-18 GRA Rate Base.”

Table 6: N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure, \$000

	2020	Total
Labour	\$332.7	\$332.7
Travel	\$69.8	\$69.8
Materials	\$1,036.2	\$1,036.2
Contractors - Chimax	\$47.0	\$47.0
Contractors - FMInstallations	\$132.8	\$132.8
Contractors - Ibex Construction	\$151.8	\$151.8
Contractors - Maven Consulting Limited	\$118.3	\$118.3
Contractors - Orbis Engineering	\$165.3	\$165.3
Contractors - QED Technical Services	\$36.6	\$36.6
Contractors - RC Crane	\$39.0	\$39.0
Contractors - Taifa Engineering	\$182.4	\$182.4
Contractors - Other	\$118.4	\$118.4
General	\$4.2	\$4.2
AFUDC	\$11.0	\$11.0
Total	\$2,445.6	\$2,445.6
2021 GRA Forecast	\$2,036.9	\$2,036.9
Variance	\$408.6	\$408.6

Please see details in response to CW-YEC-1-26 (b) that provide explanation for cost variances.

Table 7: Mayo – McQuesten Transmission Line Upgrade Project, \$000

	2019	2020	2021	Total
Labour, Travel, Materials	\$109.5	\$1,486.9	\$375.9	\$1,972.3
Contractors - ATCO	\$52.1	\$211.2	\$644.0	\$907.3
Contractors - Challenger Geomatics		\$161.0	\$58.1	\$219.0
Contractors - Chimax		\$38.9	\$26.4	\$65.2
Contractors - Cobalt Construction		\$2,468.9		\$2,468.9
Contractors - HAPG			\$5,956.3	\$5,956.3
Contractors - Maven Consulting Limited	\$104.8	\$972.4	\$221.3	\$1,298.5
Contractors - METSCO Energy Solutions		\$172.1	\$103.5	\$275.6
Contractors - Midlite Construction		\$7,885.4	\$2,910.7	\$10,796.1
Contractors - Underhill Geomatics		\$39.0		\$39.0
Contractors - Valard Construction		\$2,785.4	\$1,834.5	\$4,619.9
Contractors - Other	\$29.1	\$288.4		\$317.5
General	\$205.6	\$476.5	\$1.4	\$683.5
Total	\$501.1	\$16,986.0	\$12,131.9	\$29,619.0
Estimated Contributions	-\$274.1	-\$12,105.3	-\$8,611.3	-\$20,990.7
Net Cost	\$227.0	\$4,880.7	\$3,520.6	\$8,628.3
2021 GRA Forecast [before contributions]	\$501.1	\$20,000.0	\$11,200.0	\$31,701.1
Variance	\$0.0	-\$3,014.0	\$931.9	-\$2,082.1
2021 GRA Forecast net cost [after contributions]	\$227.0	\$5,000.0	\$2,800.0	\$8,027.0
Variance	\$0.0	-\$119.3	\$720.6	\$601.2

The 2021 forecast costs and contributions are on forecast basis and subject to change.

Mayo – McQuesten Transmission Line Upgrade Project reflects project actual costs for 2020 and updated 2021 forecast based on information available now. Updated total cost at \$29.619 million is \$2.082 million lower than the GRA forecast reflecting \$3.014 million lower than the forecast costs for 2020 and \$0.932 million higher forecast costs for the 2021 test year.

YEC internal cost assessments have been made relative to a budget of \$30.317 million (\$1.384 million lower than the GRA forecast). The following are noted regarding the cost variances relative to the internal budget:

- Brushing and access road work was completed during Q3 2020. Final actual costs for this work are \$0.982 million higher than the forecast. Most of the additional costs were the result of access road construction, as this work wasn't identified in project scope or cost from inception. Extensive hand clearing of riparian areas and

1 additional temporary roads were also required to mobilize equipment around the
2 riparian areas.

- 3
- 4 • Transmission line construction work expected to be completed with about \$1.992
5 million below the forecast.
- 6
- 7 • Budget surpluses are also forecasted for project management, owner's engineers,
8 surveying work and YEC internal costs for transmission line portion of the project.
- 9
- 10 • During Q4 2020, unknown risks associated with field design and subsoil conditions
11 contributed to a higher cost with about \$0.898 million additional cost in substation
12 construction costs and unplanned aggregate supply costs also contributed \$0.064
13 million in overages to the project.
- 14
- 15 • Additionally, the STATCOM supply and installation contract exceeded the original
16 cost estimates by \$1.450 million. Several small design change requests and other
17 costs, such as communication upgrades at the substation have also led to a higher
18 costs increasing the project cost by about \$0.216 million.
- 19
- 20 • Multiple design interface issues also led to increased costs, including project
21 management, owner's engineers and YEC internal costs for STATCOM portion of
22 the project.
- 23
- 24 • Despite the cost increases relating to substation construction and STATCOM
25 installation, these cost increases are partially covered by contingency and further
26 offset by lower than expected costs for transmission line construction.
- 27
- 28 • Overall, the project is forecasted to be completed under budget.

Table 8: Replacement of the P125 Head Gate Project, \$000

	2019	2020	2021	Total
Labour	\$25.0	\$63.2	\$0.4	\$88.6
Travel	\$0.5	\$5.8	\$0.0	\$6.3
Materials	\$15.5	\$6.5	\$0.0	\$22.1
Contractors - FMInstallations		\$1,841.1		\$1,841.1
Contractors - SNC Lavalin	\$40.1	\$27.9	\$17.1	\$85.0
Contractors - Other	\$11.8		\$1.4	\$13.2
General		\$0.1		\$0.1
AFUDC	\$0.6	\$13.5	\$1.7	\$15.7
Total	\$93.5	\$1,958.1	\$20.5	\$2,072.1
2021 GRA Forecast	\$93.5	\$2,300.0	\$3,500.0	\$5,893.5
Variance	\$0.0	-\$341.9	-\$3,479.5	-\$3,821.4

The updated capital spending forecast for 2021 includes only \$0.02 million for this project, which is reduction of approximately \$3.5 million from the 2021 GRA forecast. The original scope of the project included work on WH1, WH2 and WH3 headgates with total project cost at \$5.893 million, including about \$3.5 million in 2021 for WH1 and WH3 headgates.

Yukon Energy completed the replacement of the WH2 headgate in 2020. As part of YEC's annual business planning process, team capacity was assessed and upon completion of the assessment it was determined that the replacement and refurbishment of the gates and related infrastructure for units WH1 and WH3 will be deferred to 2022 and 2023 respectively. Planning is currently underway for the replacement of the WH1 headgate which includes revision of the technical specifications based on learnings from the WH2 headgate replacement, as well as preparation and release of an RFP in advance of the 2022 project.

Table 9: WH2 Uprate Project, \$000

	2018	2019	2020	2021	Total
Labour	\$39.1	\$126.2	\$129.5	\$452.2	\$747.0
Travel	\$1.0	\$11.9	\$8.3	\$13.0	\$34.1
Materials	\$0.0	\$68.8	\$104.2	\$261.6	\$434.5
Contractors - Litostroj Hydro		\$2,593.0	\$40.2	\$6,420.9	\$9,054.1
Contractors - SNC Lavalin	\$138.6	\$193.7	\$385.7	\$543.8	\$1,261.8
Contractors - Other	\$27.0	\$57.0	\$100.9	\$490.7	\$675.6
General	\$0.5	\$4.2	\$5.7	\$22.6	\$33.0
AFUDC	\$1.7	\$34.1	\$98.0	\$152.3	\$286.1
Total	\$207.9	\$3,088.8	\$872.5	\$8,357.0	\$12,526.3
2021 GRA Forecast					
Table 5.2-1	\$0.0	\$3,044.4	\$1,693.3	\$7,300.0	\$12,037.7
Tables 5.3-5.5	\$207.9	\$44.4	\$6.7	\$0.0	\$259.1
Total	\$207.9	\$3,088.8	\$1,700.0	\$7,300.0	\$12,296.8
Variance	\$0.0	\$0.0	-\$827.5	\$1,057.0	\$229.5

The 2021 cost breakdown is on forecast basis and subject to change. The total cost of \$12.526 million includes \$0.259 million reported in the deferred cost tables [please see Table 5.5 in Tab 5 of the Application]. The capital expenditures portion is \$12.267 million [\$12.526 - \$0.259].

WH2 Uprate Project reflects project actual costs for 2020 which was about \$0.827 million lower than the forecast and updated 2021 forecast which is about \$1.057 million higher than the forecast in the application to net project cost increase of \$0.230 million.

Once the WH2 unit was disassembled, assessments of both the embedded components as well as the removable components were undertaken. The condition of these components can only be assessed upon completion of disassembly. These assessments revealed in many cases that the condition of the components was worse than originally expected, and these components had to be refurbished as part of the project ensure proper operation and acceptable service life of the unit. In addition, during this inspection and assessment process certain components of the WH2 unit were found to be misaligned. This discovery resulted in the need for additional machining of several components to bring the items back into proper alignment.

Table 10: WH4 Uprate – Servomotor Replacement Project, \$000

	2018	2019	2020	2021	Total
Labour	\$2.4	\$15.9	\$28.2	\$82.1	\$128.6
Travel		\$1.6	\$21.9	\$4.0	\$27.5
Materials			\$0.1	\$61.4	\$61.5
Contractors - Andritz Hydro	\$30.3	\$50.3	\$184.1	\$574.0	\$838.6
Contractors - Other	\$18.9	\$8.8	\$12.5		\$40.3
General	\$0.1	\$0.1	\$0.0	\$93.7	\$93.9
AFUDC	\$0.1	\$2.2	\$7.2	\$9.8	\$19.3
Remaining forecast for 2021				\$190.0	\$190.0
Total	\$51.9	\$78.9	\$254.0	\$1,015.0	\$1,399.7
2021 GRA Forecast	\$51.9	\$78.9	\$400.0	\$1,000.0	\$1,530.8
Variance	\$0.0	\$0.0	-\$146.0	\$15.0	-\$131.0

The 2021 forecast cost breakdown is preliminary and subject to changes. It reflects actuals to date and forecast to completion.

WH4 Uprate – Servomotor Replacement Project reflects project actual costs for 2020 which was \$0.146 million lower than the forecast and updated forecast for 2021 which is \$0.015 million higher than the forecast in the application. Overall, the project expected to be completed with about \$0.131 million lower cost than the forecast in the GRA [mostly due to not used contingency provision].

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).

25
26 **REVISED RESPONSE**

27
28 Board Order 2021-10 Appendix A notes:

29
30 Similar to its reasons around UCG-YEC-1-34, the Board agrees that providing
31 costs for each step in the process gives the Board a better understanding of
32 whether YEC has prudently incurred costs over the project time period. Continuity
33 schedules allows the Board to confirm there is no duplication of costs being
34 requested to be added to the rate base.

35
36 Accordingly, the Board finds the information requested by UCG to be helpful and
37 directs YEC to provide continuity schedules of the WH4 Uprate Program. This

1 entails providing information outlined in UCG-YEC-1-43 and UCG's motion. YEC
2 is to provide these schedules in excel format with formulae intact.

3

4 The below table shows work done on the WH4 Uprate – Servomotor Replacement by
5 years completed and cost, reflecting updated actual costs for 2020 and forecast costs for
6 2021. None of these costs have previously been approved and placed in rate base.

7

	2018		2019		2020		2021		Total
(\$ million)	Actual		Actual		Actual		Forecast		Forecast
Project Management	\$	-	\$	0.000	\$	0.004	\$	0.030	\$ 0.035
Supplier	\$	0.018	\$	0.063	\$	0.187	\$	0.540	\$ 0.808
Owners Engineer	\$	-	\$	-	\$	0.047	\$	0.030	\$ 0.077
YEC Cost	\$	0.034	\$	0.016	\$	0.013	\$	0.215	\$ 0.278
Balance of Plant	\$	-	\$	-	\$	0.003	\$	0.200	\$ 0.203
	\$	0.052	\$	0.079	\$	0.254	\$	1.015	\$ 1.400

8

9

10 Balance of Plant consists of a monorail lifting beam to remove/install the servomotors, the
11 piping modifications and the new governor parts and tuning.

**Yukon Utilities Board
(YUB)**

1 **REFERENCE:** Application - Overview, Energy & Peak Load Changes, pages 1
2 to 4

4 **ISSUE:** Energy and Peak Load Changes (8.4% of revenue shortfall)

6 **QUOTE:** "Dependable capacity requirements caused by peak load growth for
7 non-industrial sales drives diesel rental costs that account for \$3.8
8 million (34.9%) of the 2021 GRA revenue shortfall."
9

10 **QUESTION:**

- 11
- 12 a) Based on the current load forecast, please provide the incremental costs on a per
13 kWh basis for the diesel rental units using only the rental and set-up costs.
14
- 15 b) Based on the current load forecast, please provide the incremental variable costs
16 on a per kWh basis for the diesel rental units.
17
- 18 c) Considering YEC's current load forecast, does the sum of the rental costs
19 (response to part (a)) and the variable costs (response to part (b)) equal YEC's
20 incremental cost of generation? If not, please explain and provide the incremental
21 cost for generation, separately identifying the portion based on fixed costs, variable
22 costs and total costs on a per kWh basis.
23

24 **ANSWER:**

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

28 Dependable capacity requirements caused by peak load growth lead to requirements for
29 dependable capacity to be in place during the critical winter grid peak period. Options to
30 meet this requirement are assessed based on fixed costs (capital and fixed non-fuel O&M
31 costs) without any focus on variable fuel costs, i.e., the facilities are primarily in place to
32 provide for the N-1 contingency event and would not normally be called upon to use fuel
33 in order to generate electricity. Accordingly, dependable capacity options are assessed
34 based on cost per kW of dependable capacity rather than based on costs per kWh of
35 possible generation.

36 The identified \$3.8 million of diesel rental costs for 2021 represent the incremental rental
37 costs for 17 units (15 units, each 1.8 MW to provide 27 MW as required for the N-1

dependable capacity shortfall, plus 2 spare units for reliability). These are fixed costs, i.e., they remain regardless of any generation; however, the units are rented and therefore the costs can be removed when the rental period ends.

Please also see response to NY-YEC-1-3 (a) and CW-YEC-1-17 for details on diesel rental unit costs.

REVISED RESPONSE

Board Order 2021-10 Appendix C notes:

The questions asked for the fixed and variable costs for the next incremental unit of generation which would, at a minimum, necessitate a calculation to spread the fixed costs over the total production. YEC did not provide those costs stating that it assesses fixed costs without any focus on variable fuel costs. Notwithstanding this statement, the Board directs YEC to provide each of the full fixed cost and the full variable cost on a per kWh basis for the diesel rental units for the next unit of generation. The information being provided should address the real costs to YEC of the diesel rental units based on its current load forecast.

(a)

The 17 rental units (including the two spares) in the test year are secured to provide N-1 dependable capacity back-up as required for the YIS. During the 140-day period when these units are connected for this purpose, Yukon Energy then also relies upon rented diesel units to support peak demand [for example, please see revised response to NY-YEC-1-6 Revised that shows stacking order for the YEC thermal units where rental units are dispatched after the LNG units] as it is cheaper to run rental diesel units compared to the permanent units and it also saves engine lives for the permanent diesel units.

Due to higher than long-term average water conditions expected for the 2021 test year total diesel generation for 2021 is forecast at 2.951 GW.h as shown in Table 2.2 of the Application, including 2.107 GW.h in Whitehorse and Faro. With \$3.8 million fixed rental cost for the test year, the average unit cost per kW.h for the fixed cost would then be equal to \$1.8/kWh [\$3.8 million divided by 2.107 GW.h, assuming, per NY-YEC-1-6 Revised, that all forecast diesel generation at Whitehorse and Faro is from rented diesel under non-emergency conditions].

1 **(b)**

2
3 The main purpose of the diesel rental units is to provide N-1 dependable capacity back-
4 up as required for the YIS. However, Yukon Energy also relies upon rented diesel units to
5 support peak demand as it is cheaper to run rental diesel units [YEC only responsible for
6 fuel costs and costs for oil changes].
7

8 The incremental variable costs forecast in the Application for the diesel rental units in the
9 test year are the diesel fuel costs at \$0.2010/kW.h for Whitehorse location and
10 \$0.2106/kW.h for the Faro location based on fuel prices and efficiencies proposed in the
11 2021 GRA. YEC does not have breakdown of required oil changes to estimate variable
12 cost per kW.h for the oil changes, however, it is expected to be not significant.
13

14 **(c)**

15
16 No – the sum of “a” and “b” above would not equal “YEC’s cost of incremental generation”
17 in any normal sense for such terms.
18

19 The rental units are secured to provide N-1 dependable capacity back-up as required for
20 the YIS rather than to provide incremental thermal generation in response to load growth
21 or reduced hydro generation availability. Accordingly, fixed capital costs for these units
22 are not relevant as costs for “incremental generation”, i.e., costs added when use units to
23 provide an added kWh of thermal generation. As reviewed below, this understanding
24 conforms with YEC reporting of costs of incremental generation for owned diesel and LNG
25 generation units.
26

27 YEC’s costs for incremental thermal generation fuel costs are provided in the Application,
28 separately for LNG and diesel units as well as for different diesel unit locations. YEC has
29 not provided a specific non-fuel variable thermal generation cost. “Fixed thermal
30 generation costs” as such are assumed not to be affected by short-term (test year
31 variances) incremental generation requirements, i.e., there is zero incremental fixed cost
32 incurred due to incremental generation requirements.
33

34 YEC’s costs of incremental generation for rented diesel units have been shown to be less
35 than incremental cost for owned units – resulting in YEC electing in recent years to run
36 the rental units (when available) ahead of permanent diesel units.
37

- 1 Please see response to YUB-YEC-2-3(a).

1 **REFERENCE:** Application, Tab 2, page 2-3, line 19

2
3 **ISSUE:** Independent Power Production

4
5 **QUOTE:** "Independent Power Production (IPP) renewable generation is forecast
6 to commence in November 2020 with less than 0.4% of forecast
7 generation impact for 2021."
8

9 **QUESTION:**

10
11 a) What is YEC's level of certainty regarding the forecast IPP amounts for 2021?
12 Please explain.

13
14 b) How have IPP projects been affected to date by the COVID-19 pandemic? Did the
15 IPP commence in November 2020, as scheduled?
16

17 **ANSWER:**

18
19 **(a)**

20
21 YEC has considerable uncertainty as to timing for forecast IPP amounts for 2021. The first
22 project that was to be operational in November 2020 has been delayed into spring 2021.
23

24 **REVISED RESPONSE**

25
26 Board Order 2021-10 Appendix C notes:

27
28 YEC was asked to explain what was YEC's level of certainty regarding the forecast
29 IPP amounts for 2021. YEC did not provide this explanation. The Board directs
30 YEC to explain why they have a considerable uncertainty as to timing for forecast
31 IPP amounts for 2021 and why the first project that was to be operational in
32 November 2020 was delayed into spring 2021.
33

34 The "uncertainty" referenced in YEC's initial response refers to commitments by the IPP
35 proponents that are largely beyond YEC control and pre-date COVID-19. Typically, a
36 proponent will require an executed Electricity Purchase Agreement well in advance of
37 being in-service (Commercial Operations Date – "COD") in order to secure financing and

1 the agreement includes a forecasted COD. All the risks of construction (e.g., supply chain,
2 market restrictions, site condition risk, permitting, etc.) are wholly within the control of the
3 proponent. In YEC's experience, the proponents struggle to meet their commitments and
4 COD tends to be delayed. YEC has no reasonable means to estimate if these delays will
5 materialize or how long delays can last.

6
7 The proponents of the projects provide regular updates of the COD to YEC. The number
8 of updates (and delays) are indicative of the realization of different challenges that arise
9 during the various stages of financing, procurement and construction of the projects.

10
11 **(b)**

12
13 We do not know how IPP projects have been affected to date by the COVID-19 pandemic.
14 The IPP did not commence in 2020 as scheduled.

1 **REFERENCE:** Application, Tab 2, page 2-4, line 2

2
3 **ISSUE:** Forecast Renewable Generation

4
5 **QUOTE:** “This impact is starting to be offset by new renewable generation
6 planned as part of Yukon Energy’s 10 Year Renewable Electricity Plan,
7 commencing with the new IPP generation forecast to provide 0.06
8 GW.h of solar generation in 2020 and 2.0 GW.h of new renewable
9 generation in 2021 based on information available at the time of filing.”

10
11 **PREAMBLE:** The Board requires additional information with respect to YEC’s
12 forecasts being based on “information available at the time of filing.”

13
14 **QUESTION:**

- 15
16 a) What specific information did YEC rely on to forecast the new renewable
17 generation?
18
19 b) To what date was information available in preparing these forecasts?

20
21 **ANSWER:**

22
23 **(a) and (b)**

24
25 The information available on IPPs when the generation forecasts were finalized for the
26 2021 GRA Application in September/ early October 2020 was the forecast IPP deliveries
27 and target dates noted in the following two agreements signed with potential IPP projects:

- 28
29 • North Klondike Highway Solar PV Project with target commercial operation date of
30 November 1, 2020 with 1,840 MWh annual energy delivered.
31
32 • Mount Sima Solar Project with target commercial operation date of June 1, 2021
33 with 270 MWh annual energy delivered.

34
35 **REVISED RESPONSE**

36
37 Board Order 2021-10 Appendix C notes:

YEC did not fully answer this question. The Board directs YEC to provide a complete answer that includes further details of the specific information that YEC relied on to forecast the new renewable generation and to what date was information available in preparing these forecasts.

The IPP generation forecasts and expected connection dates come directly from the EPA contracts signed with the two proponents; the monthly generation for each contract is below:

North Klondike Highway Solar PV Project (EPA signed June 2020)

	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

Mount Sima Solar Project (EPA signed August 2020)

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

The GRA assumes the North Klondike project was on the grid for the entirety of 2021 (1.8 GWh); Sima was forecast to be on the system June 2021 (~0.1 GWh). This accounts for the 1.9 GWh forecast for this application (Tab 2, Table 2.2, Row 12).

At the time the GRA was prepared in fall of 2020, there was minimal update information available on these IPPs. Delay risks seemed likely on at least the North Klondike Highway Solar Project, but YEC had no updated schedule to utilize for the project.

REFERENCE: Application, Tab 2, page 2-8, line 21

ISSUE: Loses

QUOTE: "Total generation is based on the sum of total sales plus losses. The 2018 approved forecast losses were 8.8%. Actual losses were 9.2% in 2018 and 2019, and full year forecast for 2020 is 9.1%. The losses are forecast at 8.8% for the 2021 test year which is the same as the 2018 approved level in the 2017/18 GRA and also within the range of historical losses for last three years, from 2017 (at 8.1%) through 2018 and 2019 (each at 9.2%)."

QUESTION:

- a) Please provide the detailed working document, with formulas intact, used to determine and justify YEC's forecast for losses in the test year.

ANSWER:

(a)

The losses for the 2021 test year are forecast at 8.8% which is the same as the 2018 approved level in the 2017/18 GRA. It is also within the range of historical losses for the last three years as illustrated in Table 1 below. Attachment 1 to this response provides an excel copy of the calculations.

Table 1: Line Losses for 2017, 2018 and 2019 Years (GWh)

Year	Firm Generation (GWh)	Firm Sales (GWh)	Losses (GWh)	Losses as % of Sales
2017	446.5	413.2	33.3	8.1%
2018	450.1	412.2	37.9	9.2%
2019	440.7	403.5	37.2	9.2%

Average 8.8%

1 **REVISED RESPONSE**

2
3 Board Order 2021-10, Appendix C notes:

4
5 YEC did not provide a working document with formulas intact in response to this
6 IR; rather, it only provided a copy of an excel document. The Board directs YEC to
7 provide a detailed working document with formulae intact. YEC is also directed to
8 confirm which numbers are correct, i.e., the Line Losses in Table 1 or in
9 Attachment 1 of this IR response, as the numbers do not match.

10
11 Correspondence provided to the Board on August 12, 2021 notes that the excel file with
12 formulae intact was provided as an attachment to the PDF IR consolidation provided to
13 the Board. The excel document is consistent with Table 1 in the IR response. YEC
14 confirms these are the correct numbers.

15
16 The Attachment 1 pdf document included in the IR consolidation is in error. A revised
17 Attachment 1 is provided with this response.

Table 1: Line Losses for 2017, 2018 and 2019 Years

Year	Firm Generation (GWh)	Firm Sales (GWh)	Losses (GWh)	Losses as % of Sales
2017	446.5	413.2	33.3	8.1%
2018	450.1	412.2	37.9	9.2%
2019	440.7	403.5	37.2	9.2%
Average				8.8%

1 **REFERENCE: Application, Section 3.3.1, Non-Fuel Operating and Maintenance**
2 **(O&M) Expenses, pages 3-8 to 3-13**

3
4 **ISSUE: Labour Costs (Section 3.3.1)**

5
6 **QUESTION:**

- 7
- 8 a) Please clarify how many employees will report to YEC's proposed "1.00 position
9 increase in 2021 due to ... a Vice President, First Nation Relations." (page 3-10)
- 10
- 11 b) Please confirm whether "Yukon Energy's 5-Year Strategic Plan, published in 2019,
12 confirmed YEC's commitment to establishing mutually beneficial and strategic
13 partnerships with Yukon First Nations governments" (page 3-9) and is intended to
14 be subject to testing in the current GRA. If confirmed, please explain fully why this
15 is the case.
- 16
- 17 c) Please explain whether it is YEC's understanding that it is responsible for fulfilling
18 consultation obligations where they arise with respect to potential impacts on s. 35
19 rights (Section 35 of the Constitution Act, 1982).
- 20
- 21 d) Please elaborate on YEC's new position (Vice President, First Nation Relations)
22 and how it will expand YEC's current ability to move projects forward.
- 23
- 24 e) Given that the name for the "Finance, Customer Billing/Accounting and
25 Purchasing" category (page 3-11) continues to reference the words "Customer
26 Billing/Accounting," please clarify whether any "Customer Billing/Accounting"
27 personnel remain in the originating group after the 2020 transfer of 2.10 positions
28 to the "Communications, Customer Accounting" (page 3-10) category.
- 29
- 30 f) Referring to the categories identified in Table 3.4 (page 3-8) and including the
31 proposed "1.00 position increase in 2021 due to the addition of a new full-time
32 position, Senior Communications Advisor" (page 3-10), please clarify how many
33 communication personnel in total will be employed by YEC and in which Table 3.4
34 category or categories these employees reside.
- 35
- 36 g) Please clarify the role of YEC's communication personnel in relation to YEC's
37 internal versus external communication requirements.
- 38
- 39 h) Please quantify how many external communication issues, such as customer
40 complaints, were submitted to YEC for resolution during each of the years 2018-

1 2020. Of these submissions, please quantify how many were resolved in each year
2 by YEC and how many were forwarded to the YUB for resolution.

3

4 i) With respect to YEC's Resource Planning and Environment category, please
5 clarify what is referred to as the "backlog of planning work designation for
6 completion" (pages 3-10 and 3-11) for which YEC has proposed to add a two-year
7 resource planning engineer position to assist with. In the response, please also
8 clarify which capital projects have been delayed as a result of the referenced
9 planning work backlog.

10

11 j) With respect to YEC's Resource Planning and Environment category, please
12 clarify if YEC's "2020 10-Year Renewable Electricity Plan" (pages 3-10 and 3-11)
13 is intended to be considered by the Board in the current GRA. If confirmed, please
14 explain fully why this is the case. Please provide a reference to where YEC's
15 Electricity Plan has been provided in its application; otherwise, please submit a
16 copy of the report in response to this IR.

17

18 k) With respect to YEC's Resource Planning and Environment category, please
19 identify the priority initiatives recommended in the "2020 10-Year Renewable
20 Electricity Plan" (pages 3-10 and 3-11) which YEC has proposed to address by
21 adding a senior project manager. In the response, please also quantify how many
22 employees are currently engaged in any of the priority initiatives and whether any
23 are proposed to now report to the new senior project manager.

24

25 l) Please explain whether procurement personnel have historically been within the
26 "Finance, Customer Billing/Accounting and Purchasing" group and provide the
27 quantity of employees responsible for procurement in that or any other group up
28 to the year 2020. Will YEC's proposed "1.00 position increase ... of a new full-time
29 position, Procurement Administrator" (page 3-11) result in less work for those
30 employees previously responsible for procurement work up to the year 2020? If
31 so, please explain where YEC has incorporated the incremental benefits of hiring
32 a full-time procurement administrator in its revenue requirement.

33

34 m) In relation to YEC's procurement activities, please provide quantifiable evidence
35 that YEC has experienced "increased workload in the department due to greater
36 volume of high dollar projects" (page 3-11) during each of the years 2018-2020 on
37 an actual basis.

38

39 n) In relation to YEC's procurement activities, please explain why there are
40 "increasingly complex contracting strategies for some capital projects, including
41 the additional requirements of the First Nation procurement policy, which has
42 increased the complexity and administrative support required for large project

procurement.” (page 3-11) In the response, please confirm that it is the Yukon Government First Nation Procurement Policy being referred to, whether that policy applies to Yukon Energy, and also identify the additional requirements of YEC to follow that policy.

o) In relation to YEC’s procurement activities, please explain and provide context with respect to “the need to allow departmental management to concentrate on policy renewal and development and education for client managers new to YEC.” (page 3-11).

p) In relation to YEC’s operations, please confirm that the “1.00 position increase in 2018 due to the addition of a new full-time position, Maintenance Mechanic to address additional responsibilities (e.g., LNG assets)” was contemplated in YEC’s original LNG project business case. If confirmed, please provide a reference to the business case where an increase in employee complement was identified as being required.

q) In relation to YEC’s operations, please provide the per cent increase over 2020 actual plant operator personnel that the total 1.75 position increase in plant operators will represent. (page 3-12)

r) In relation to YEC’s engineering services, please confirm that the “1.00 position increase in 2020 ... of a new full-time position, Electric Engineer” (page 3-12) occurred on an actual basis during the year 2020.

s) Please provide YEC’s capital to maintenance allocation ratios on an actual basis for the years 2018-2020. (page 3.13)

ANSWER:

(a)

YEC is not proposing any direct reports to this position at this time. The VP will be the primary liaison with First Nations and will work through other departments as required depending on the nature of the issue (e.g., planning, engineering, operations, finance).

(b)

In this context, the reference to the 2019-24 strategic plan was intended to demonstrate the Corporation’s commitment to working with First Nations. It is self-evident that YEC

1 owes a duty to Yukon First Nations as a landowner and further, as a legal obligation under
2 various treaty agreements.

3
4 **(c)**

5
6 YEC is not directly responsible for fulfilling the Crown's duty to consult and accommodate
7 Yukon First Nations with respect to a potential impact on s. 35 rights. However, the Crown
8 has given effect to its duty to consult, in part, through the framework established under
9 YESAA, and YEC has duties as a proponent under that framework, including statutory
10 consultation obligations, with respect to the environmental and socio-economic
11 assessment of YEC projects. In addition, in certain circumstances, YEC may have further
12 consultation duties arising directly under the provisions of Yukon First Nation Final
13 Agreements (e.g., under Specific Economic Measures provisions included in Chapter 22).

14
15 **(d)**

16
17 Any significant project that occurs in the Traditional Territory of a Yukon First Nation
18 requires the proponent to engage and consult with that First Nation. In YEC experience,
19 the consultation process is most effective when an established relationship already exists
20 with the affected First Nation. The Vice President First Nation Relations will be responsible
21 for establishing and maintaining relationships with First Nations in Yukon Energy's service
22 area. As well, when a project is identified, the Vice President will lead the negotiations of
23 the benefits agreements thereby capitalizing on the relationship.

24
25 **(e)**

26
27 No Customer Billing/Accounting personnel remain in the group after the 2020 transfer. To
28 be clear, certain aspects of customer accounting is retained by the core Finance group
29 (e.g., account reconciliation, cash management) but staff who are responsible for direct
30 interactions with customers, account set up and maintenance, bill preparation and
31 distribution, account collection, etc. have transferred out of Finance.

32
33 **(f)**

34
35 There will be two communication personnel in total employed by YEC and both are in the
36 category labelled Communications, Cust. Acctg.

1 (g)

2
3 Yukon Energy communications personnel are responsible for developing and delivering
4 the Corporation's external communications and supporting company-wide internal
5 communications on key topics and projects. The latter can include writing and reviewing
6 company-wide messages, presentations, campaigns and other collateral.
7

8 (h)

9
10 Yukon Energy does not track all external issues and complaints in one central repository.
11 External issues and complaints are addressed and actioned by individual departments, as
12 required. Yukon Energy is not aware of how many external issues or complaints were
13 forwarded to the YUB.
14

15 In terms of specifics, YEC offers the following as indicative of increased workload:
16

- 17 • Weekly briefings for the Minister and YDC started in Q4 2019 and have continued
18 since.
19
- 20 • We started tracking the number of media calls, Ask Steph (online) emails and
21 social media comments/questions we receive in 2020.
22
 - 23 o 84 media calls were received in 2020;
 - 24
 - 25 o 44 Ask Steph inquiries in 2020; and
 - 26
 - 27 o More than 200 questions and comments on Facebook and Twitter in 2020.
28
- 29 • Table 1 below highlights the impact of additional duties with respect to increased
30 communications involvement in capital works and customer service.
31

32 **Table 1: Allocation of Manager of Communications Time, 2018-2020 (Year-to-date)**

Year	Communication Admin.	Customer Billing Admin.	Capital
2018	99.24%	0.0%	0.76%
2019	66.43%	0.0%	33.57%
2020	44.13%	15.53%	40.34%

1 Additionally, as a one-position department with critical responsibilities during unplanned
2 events, the Manager Communications is effectively on call 24/7, 365 days a year. The
3 extra position will help provide an additional resource for this important function.

4
5 **(i)**
6

7 The general challenge is that YEC is unable to advance concurrently, as required, all of
8 its projects given limited internal planning resources. The planning projects which are
9 currently designated for completion include the ones listed below. It's difficult to clarify
10 which projects have been delayed due to insufficient internal resources – all projects tend
11 to be adversely impacted in this situation, and YEC has had to address delays in dealing
12 with almost all of the active projects listed below. The concern looking forward is that the
13 upcoming work requirement is expected to be even more challenging than that
14 experienced to date.

- 15
16 • Aishihik Generating Station Water Use 25 Year License Renewal;
17
- 18 • Whitehorse Rapids Generating Station Water Use License Renewal;
19
- 20 • Mayo Generating Station Water Use License Renewal;
21
- 22 • Diesel Retirement Replacement;
23
- 24 • Southern Lakes Storage;
25
- 26 • Mayo Lake Storage Enhancement Project;
27
- 28 • Battery Energy Storage System;
29
- 30 • Pumped Storage;
31
- 32 • Southern Lakes Transmission Line; and
33
- 34 • Demand Side Management Programs.

1 **(j)**

2
3 YEC's "2020 10-Year Renewable Electricity Plan" is intended to be considered by the
4 Board in the current GRA in that it is included as a deferred cost Regulatory project added
5 to rate base, as disclosed in Section 5.3.2 of the Application (page 5-26) as well as in
6 Table 5.5. The Plan, however, generally addresses project planning for development
7 beyond the 2021 test year. Please see CW-YEC-1-36(a) Attachment 1 for a copy of the
8 10-Year Renewable Electricity Plan.

9
10 **(k)**

11
12 YEC anticipates the Senior Project Manager will lead the completion of the Southern
13 Lakes Transmission Line and Pumped Storage projects (each of which remain in WIP in
14 2021). Current employees are engaged on these projects on an ad hoc basis given limited
15 resource capacity, and the focus on securing federal funding before advancing either
16 project. YEC does not anticipate any employees will report to the new senior project
17 manager.

18
19 **(l)**

20
21 Procurement personnel have been within the "Finance, Customer Billing/Accounting and
22 Purchasing" group for many years (i.e., > 10 years). The number of full time equivalent
23 employees responsible for procurement in the group for year 2020 is 3.5. The addition of
24 the Procurement Administrator will not result in less work for other staff. YEC recognized
25 that the volume of purchasing was exceeding the capacity of the department to the point
26 where some projects were delayed due to backlogs in procurement. As well, procurement
27 volumes have increased (see (m) below) and other managerial tasks were not being
28 addressed on a timely basis (see (o) below).

29
30 **(m)**

31
32 See Table 1 below for the volume of purchase orders processed at YEC back to 2018,
33 demonstrating the greater volume of high dollar projects.

Table 1: Volume of Purchase Orders: 2018 to 2020

Fiscal Year	Count of PO Number	Sum of Originating Subtotal
2018	586	27,855,025.96
2019	630	33,480,891.75
2020	765	62,313,928.33

(n)

YEC has had to address, or is addressing, a number of complex procurements. This includes the following examples:

- BESS – new technology both for YEC and the Canadian industry, international vendors, long lead time;
- EAM – software acquisition, high dollar, US vendor, acquisition of licences implementation and post-go live support; and
- MMTP – high dollar, large number of contracts, federal funding requirements, large FN components.

YEC approved a First Nation Procurement Policy in 2016, although implementation has occurred gradually since that time. YEC was aware that YG was working on a similar policy since 2019. While YEC is not obligated to follow YG policy, the shareholder expects that our policy approach should not materially diverge from YG.

REVISED RESPONSE

Board Order 2021-10 Appendix C notes:

YEC's response refers to an approved First Nation Procurement Policy. The Board requires clarification whether the First Nation Procurement Policy referred to is in addition to any other YEC procurement policies. The Board directs YEC to provide its First Nation Procurement Policy and any other approved procurement policies.

1 In response to the direction provided - it is noted that YEC has two procurement policies:

2
3 1. **FA-009 – Purchasing policy** – This is our standard procurement policy that
4 defines thresholds and requirements for purchasing; and

5
6 2. **PP-002 – First Nation Procurement** – Provides guidance on procurement
7 specifically where FN participation is required or otherwise desirous.

8
9 Copies of these policies are provided as Attachment 1 and Attachment 2 to this response.

10
11 **(o)**

12
13 The department includes one manager who has responsibility for providing supervision
14 and leadership to the team. In addition, this position is responsible for advising
15 management on complex transactions, conducting market research, developing and
16 maintaining long-term vendor relationships, policy update/development, procurement
17 system access and functionality and training for client staff.

18
19 With respect to procurement policy, there is a recognized need to adapt current policy for
20 external factors e.g., Canadian Free Trade Agreement, YG FN Procurement Policy. As
21 well, policies are over 10 years old and need to be updated for industry best practice and
22 general improvement for efficiency and effectiveness.

23
24 Training is becoming a critical issue as YEC has experienced significant turnover in recent
25 years. While the company has been successful at attracting skilled replacements, it is
26 normal for new project managers to require training on the specific rules of procurement
27 at YEC. Prior to the addition of an additional position, the manager was required to
28 participate in the preparation and management of procurement processes to the point
29 there was no time available to other matters as described.

30
31 **(p)**

32
33 The “1.00 position increase in 2018 due to the addition of a new full-time position,
34 Maintenance Mechanic to address additional responsibilities (e.g., LNG assets)” was not
35 specifically contemplated in YEC’s original LNG project business case. The position was
36 required to address the workload of all generation assets based on the workload at that
37 time, which changed from the time when the LNG business case was prepared. The

1 process to justify the additional position was done using a spreadsheet that assigned
2 annual tasks at each facility. This process determined the staff complement against the
3 work. The latest iteration of the work indicated a deficit in mechanical trades staff. With
4 the addition of the LNG facility there was an obvious lack of person hours to complete the
5 suggested maintenance.

6
7 **(q)**

8
9 The 1.75 position increase represents a 16% increase in plant operators.

10
11 **(r)**

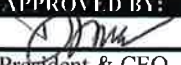
12
13 Confirmed.

14
15 **(s)**

16
17 YEC's capital to maintenance allocation ratios on an actual basis for the years 2018-2020
18 is provided in Table 2 below:

19
20 **Table 2: Capital to Maintenance Allocation Ratios**

	Capital	Maintenance
2018	14.7%	85.3%
2019	16.0%	84.0%
2020	18.2%	81.8%

	FINANCE POLICY FA-009	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Finance	Purchasing Policy
		ISSUED:	REVIEW DATE:	APPROVED BY:
		September 2006	August 2009	 President & CEO

1.00 Purpose

- 1.01 To control, manage and provide guidance to the various departments in the procurement of goods and services and to obtain optimum economic benefit for the corporation. These goals will be achieved through the promotion of ethical business practices, application of appropriate purchasing techniques and compliance with all applicable legislation.
- 1.02 All purchasing activities will be executed in a confidential and timely manner with all legal, safety and risk management issues addressed.

2.00 Principles

- 2.01 To promote ethical business practices accessibility and openness (as appropriate) throughout the purchasing process.
- 2.02 To promote favorable vendor and department relationships with the goal of long-term partnerships that achieves mutual long-term value.
- 2.03 To promote competitive bidding practices, when possible, while ensuring that vendors are provided an equal opportunity to offer their goods and services.
- 2.04 To promote and encourage the appropriate use of specific criteria and financial thresholds to determine the level of competition for the supply of goods and services. Under certain circumstances, non-competitive purchases may be justified.
- 2.05 To promote and ensure that evaluation criteria and standards used to evaluate bids and proposals are fully and clearly described in "Request" documents, and that only those evaluation criteria are used to evaluate any bids or proposals received.
- 2.06 To promote standardization where possible, to enable cost effectiveness through the volume amalgamation, and reduced support and maintenance costs.
- 2.07 Promote consistency of quality and added value in all purchases.

3.00 Policy

- 3.01 Corporate Services solicits competitive bids and makes the final award for purchases. All requesters are consulted on a purchasing partnership basis, as required, before any awards are made.

- 3.02 Corporate Services will make best efforts to purchase and/or contract for goods and services in the community in which they are used, to the extent that doing so reasonably conforms to the objectives of Yukon Energy’s Corporate Purchasing Guidelines, and to the extent that their needs can be met by community-based businesses.
- 3.03 Corporate Services requests pricing, product and market information through various “Request” documents.
- 3.04 All pricing and supplier information received will be kept confidential unless specified in the bid and in the case of the formal public bid process.
- 3.05 All purchases are made on credit terms (wherever possible) using a variety of methods such as: Contracts, Purchase Order, Corporate Procurement Cards, Local Purchase Orders, Standing Agreement etc.
- 3.06 The Corporation will only honor purchases issued by Corporate Services or properly authorized delegated purchasing authorities.
- 3.07 a) The President & CEO may waive any provision of this policy when it would be in the best interest of Yukon Energy to do so.
- b) Directors may award non-competitive contracts up to a maximum value of \$25,000.00. The President & CEO must approve all other non-competitive contracts. The criteria as set out in the Non-Competitive Guideline (GS-005) shall be adhered to.
- c) In all other cases, competitive bidding will be applied as follows:

<i>Purchase Value Threshold</i>	<i>Competitive Bid Application</i>
Up to \$5,000	Competitive bids not required; delegated purchasing/contracting authorities may enter into a Purchasing Agreement (minor works contract, Consulting Contract, Purchase Order, LOP, Visa, Standing Agreement, etc.)
\$5,001 to \$25,000	Competitive bids required – a minimum of two (2) phone vendor quotations are required.
\$25,001 to \$50,000	Competitive bids required – a minimum of three (3) written vendor quotations are required
\$50,001 to \$100,000	Competitive bids required – Corporate Services solicits bids from a minimum of three vendors.
More than \$100,000	Competitive bids required – Corporate Services releases a public bid where any number of vendors can compete. A minimum of three vendors must be invited.

4.00 Roles and Responsibilities

4.01 Corporate Services:

Corporate Services has the responsibility for the overall administration and performance of purchasing, bidding, tendering and contract awards and ensures adherence to Yukon Energy's purchasing policies and guidelines.

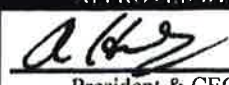
- Ensures that all vendor and cost information is kept confidential and not released to any other vendor, party or other employee unless specified in the bid;
- Oversees the procurement of goods and services;
- Develops and prepares purchasing documents such as: bids, tenders, addendums, evaluations, awards, contracts, amendments, etc.;
- Coordinates the evaluation of the bids in accordance with pre-established evaluation criteria. If necessary, arranges and coordinate vendor interviews and structures the process and evaluative selection methodology;
- Performs due diligence (i.e. legal, safety and risk management);
- Participates in the evaluation, supplier interviews or any other evaluative methodology used in determining the successful supplier;
- Awards, issues, receives and manages all Purchase Orders for non-stock items;
- Maintains and monitors the procurement card system;
- Receives and ships goods or forwards the shipment to the appropriate individual for receipt and acceptance;
- Develops, maintains and monitors vendor alliances;
- Coaches and guides employees and client departments;
- Liaisons with the vendor community providing information and responding to their inquiries and requests for information;
- Oversees and maintains the pre-qualification process for vendors;
- Responsible for records management of contract documents, pre-qualification documents and contractor(s)/consultant(s) database; and
- Maintains and reconciles purchasing logs.

4.02 Requestor:

- Ensures that all vendor and cost information is kept confidential and not released to any other vendor, party or other employee unless specified in the bid;
- Ensures that the proper approval for expenditure has been obtained prior to the work being bid;
- Provides a detailed scope for work to be bid;
- Provides any technical drawings or specifications that will need to be adhered to in the performance of the work;
- Provides timetable for start and completion of the work;
- Provides evaluation criteria for selection of vendor (if required); and
- Participates in the evaluation, vendor interviews or any other evaluative methodology used in determining the successful supplier.

4.03 Corporate Services & Requestor will work in partnership to determine:

- a) Decide the type of purchase agreement that is required. Determining factors to include:
 - Amount of risk;
 - Dollar value for material, goods or services; and
 - Type of service or purchase agreement being requested.
- b) Decide the appropriate type of "Request" Document that will be sent out (e.g. Request for Bid; Request for Quote; Request for Proposal; Request for Information; Request for Expression of Interest, etc.).
- c) Decide whether the bid should be competitive or non-competitive. See Competitive Bid Guideline GS-004 and/or Non-Competitive Purchases Guideline GS-010.
- d) Decide what type of evaluation criteria to use. See Evaluation Criteria Guideline GS-007.
- e) Evaluate the responses received.
- f) Negotiate new contacts.

	First Nation Procurement Policy PP-002	DEPARTMENT:		
		INQUIRIES TO:		
		TOPIC:		
		ISSUED:		
		REVIEW DATE:		
		All	Manager, Procurement	First Nation Procurement
		December 2016	January 2020	 President & CEO

1.0 Purpose

Yukon Energy Corporation (YEC) operates on Yukon First Nation (YFN) Traditional Territories and strives to meet or exceed the “spirit and intent” of land claim obligations. We recognize First Nations as Governments and potential energy proponents, partners and investors. In our daily operations, planning and project work, we will work proactively with First Nations to create opportunities for investment, contracting, employment and training. This policy specifically addresses the company’s intent with respect to procurement of goods, services and construction.

2.0 Principles

Yukon Energy has applied the following principles in developing this policy:

- The focus will be on offering contracting opportunities to existing YFN businesses with demonstrated capacity to execute the contract successfully;
- YEC must continue to demonstrate value for money as part of its mandate to provide Yukoners with affordable electrical service; and
- As with all procurement processes, YEC must ensure all activities contribute to a transparent, open and fair process.

3.0 Definitions

“**Sole Source**” means a non-competitive purchase order or contract for goods, services or construction waving a competitive process due to special circumstances deemed as an exception and approved by a Director for purchases <\$25K and the President and CEO for purchases >\$25K as per YEC Guideline GS-010.

“**Select/Invitational Tender**” means, a competitive process where specific vendors are invited to bid on a tender.

“**RFx**” means, a YEC procurement process such as a Request for Proposal (RFP), Request for Quotation (RFQ), Request for Information (RFI) or Request for Tender (RFT) for a corresponding public competitive demand.

“**Traditional Territories**” means, the Yukon First Nations Traditional Territories as identified in the following link. [“Traditional Territories”](#)

4.0 Procedure

- 4.1. Through YEC leadership, a YFN specific vendor registry will be created on the YEC website to promote registration of YFN-owned businesses, ultimately leading to the creation of a Yukon wide YFN Business Directory. YEC will also actively promote a link being shared for ease of registration on all member YFN websites to promote inclusivity. This Directory will be a key tool to inform the YEC Procurement Department and Project

Managers (PM's) of actual YFN-owned businesses that could offer goods and services to meet specific YEC needs.

- 4.2. YEC project managers, where possible, will identify opportunities as part of the project planning process to ensure that opportunities are provided to the First Nation community through information sharing, engagement and the scoping of opportunities. In addition, project managers will engage procurement to ensure practices such as set-asides, direct awards, select/invitational tenders, tender dis-aggregation, partnering or specified YFN content in bid evaluation criteria are considered, once again to ensure, where possible, YFN participation. Appendix A attached is a graphic representation of this process.

4.3. **Procurement Vehicles**

Procurement approaches that may be used to achieve the policy objectives include:

Project Agreement – applies to large projects; covers all aspects of YEC commitment to the affected FN:

Contracting opportunities;

Investment;

Apprenticeship; and/or

Cash or in-kind compensation.

Competitive Bid – Two alternatives are available:

RFP/Tender – traditional two envelope bid process where proponents can earn additional qualitative points based on FN participation (e.g. ownership, employment, etc)

Invitational Tender – where more than one qualified YFN-owned business exists, YEC will restrict participation in a competitive bid process to those businesses.

Sole Source – Where only one qualified YFN-owned business exists and subject to dollar limits and proof of value, YEC can award directly to that business through a sole source contract award.

- 4.4. **Criteria** – In assessing a project for FN procurement opportunities, PM's will assess the following factors:

- Traditional Territory location;
- Identified FN Capacity;
- Project criticality/urgency;
- Administrative burden;

Note this list should not be considered exhaustive; PM's should be aware of unique characteristics of the individual project that may inform the FN Procurement decision.

4.5. **Transparency** – YEC will publish via its website and otherwise make available to the public and stakeholders the following information:

- First Nation Procurement Policy;
- Competitive bids;
- Contract awards.

5.0 Implementation

YEC Management will develop and execute a plan for implementation of this policy in 2017. The implementation plan will include the following steps and deliverables:

- Complete policy roll-out and education with Yukon First Nations and Development Corporations
- Develop/Facilitate a First Nations Business Directory, including a web-based tool allowing YFN-owned businesses to self-register
- Provide FN Procurement orientation and training to YEC Project Managers, including processes for identifying and evaluating FN procurement opportunities.
- Update internal Project Management documentation to embed the analysis of FN Procurement opportunities into project planning
- Communicate with First Nations Development Corporations and businesses on potential project and contracting opportunities
- Establish Reporting Metrics
- Integrate with YEC's Purchasing Policy

References

Yukon First Nations

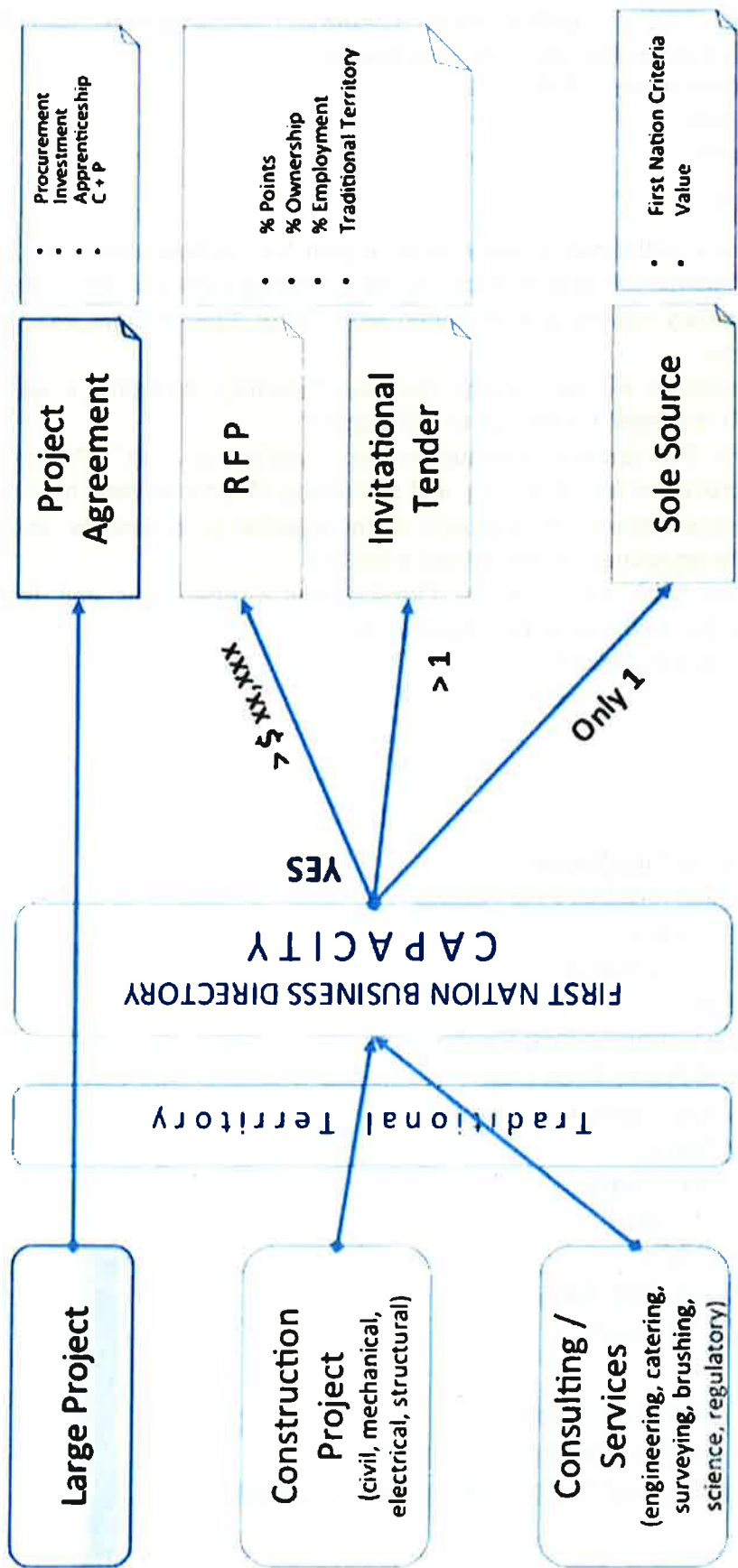
- [Carcross Tagish First Nation](#)
- [Champagne and Aishihik First Nations](#)
- [Kluane First Nation](#)
- [Kwanlin Dūn First Nation](#)
- [Liard First Nation](#)
- [Little Salmon Carmacks First Nation](#)
- [First Nation of Nacho Nyak Dun](#)
- [Ross River Dena Council](#)
- [Selkirk First Nation](#)
- [Ta'an Kwāch'ān Council](#)
- [Teslin Tlingit Council](#)
- [Tr'ondëk Hwëch'in](#)
- [Vuntut Gwitchin First Nation](#)
- [White River First Nation](#)

Additional Resources

- [Council of Yukon First Nations](#)
- [Yukon First Nations Chamber of Commerce](#)
- [Aboriginal Affairs and Northern Development Canada](#)

APPENDIX A

FIRST NATION PROCUREMENT PROCESS



1 **REFERENCE: Application, Section 3.3.6, Administration, pages 3-17 and page**
2 **3-18**

3
4 **ISSUE: Administration Costs**

5
6 **QUESTION:**

7
8 a) Please detail any measures taken by YEC to control or reduce its overall
9 administration costs forecast for 2021.

10
11 b) Please clarify whether YEC's forecast increase in general administration expense
12 related to new asset management software was contemplated in any related
13 business case and, if so, please provide a reference to the cost benefit analysis
14 conducted in that business case.

15
16 c) Please clarify why YEC's general administration expense forecast for 2021 is
17 anticipated to increase over 2020 forecast costs given the explanation for the
18 increase between 2018 and 2021 costs as noted in part (b) above.

19
20 d) Please explain why YEC's Board of Directors expenses have not decreased given
21 restrictions related to the COVID-19 pandemic and requirements to conduct
22 meetings virtually.

23
24 e) Please quantify the number of Board of Directors meetings held during the year
25 2020 on an actual basis and forecast for the year 2021.

26
27 f) Please describe the nature of and reason for any training proposed for YEC's
28 Board of Directors.

29
30 **ANSWER:**

31
32 **(a)**

33
34 YEC has an intense budget process where budget owners build a budget based on a
35 blank template. Budgets are scrutinized by Finance, Senior Management and the Board
36 of Directors. Budgets are adjusted as considered necessary.

1 **REVISED RESPONSE**

2
3 Board Order 2021-10 Appendix C notes:

4
5 YEC was non responsive to the question asked which was to detail any measures
6 taken by YEC to control or reduce its overall administration costs forecast for 2021.
7 The Board directs YEC to respond with the detail requested.
8

9 As part of the intense non-labour budget process, budget owners are required to justify
10 each cost they request in their budget. Budget requests that are not justifiable are rejected.
11 Administration budgets are done on a line item basis so there is a very detailed low-level
12 review of the budget requests. At a high-level, if there are required increases in any
13 budgets YEC attempted to find offsets to reduce the overall impact.
14

15 Below is a list of some cuts performed as part of the budget review for 2021 administration
16 costs:
17

- 18 • Board of Directors costs were cut \$13,000 (5%) from 2020 BP (8% from 2020
19 Forecast) by reducing consulting costs.
20
- 21 • President & CEO costs (included in General) were cut \$32,000 (32%) from original
22 budget submission by removal of all consulting costs.
23
- 24 • Human Resources costs (included in Recruitment and Union) were cut \$50,000
25 (13%) from original budget submission and \$125,000 (27%) from 2020 Forecast
26 by reducing consulting and legal costs.
27
- 28 • Training costs were cut by \$25,000 (11%) from original budget submission by
29 reducing contractor costs.
30
- 31 • Prior to the addition of \$272,000 costs required as a result of the Aishihik license
32 renewal process, Environment was cut \$28,000 (10%) from original budget
33 submission by reducing consulting costs.

1 **(b)**

2
3 The business case is reviewed in YUB-YEC-1-64, and includes consideration of managing
4 ongoing software management costs. The estimated ongoing annual costs start in 2021
5 and are used in the business case and NPV calculations.

6
7 **(c)**

8
9 The primary reason for the increase in general administration expense for 2021 over 2020
10 are the costs related to the new asset management software as noted in part (b), as the
11 system is to be implemented in 2021.

12
13 **(d)**

14
15 Travel cost was not a significant cost of the Board of Directors budget prior to the
16 pandemic; therefore, there is no significant savings on this budget due to pandemic
17 restrictions.

18
19 **(e)**

20
21 In 2020, YEC had 14 Board meetings and 24 Committee meetings. Of the 14 Board
22 meetings, 5 were scheduled and the other 9 were Special Meetings. YEC has scheduled
23 4 quarterly meetings, 2 special meetings for strategic planning and business plan approval
24 for 2021. There is a possibility that additional unscheduled meetings will be required for
25 time sensitive issues.

26
27 **(f)**

28
29 YEC's Board of Directors are looking at focusing their training on finance and oversight
30 for the Audit Committee (and possibly expanding to the full Board) for 2021. This is based
31 on the outcome of a Director Evaluation that was completed in 2020 and identified
32 oversight of financials and strategic priorities as a key focus area for the Board.

1 **REFERENCE:** Application, page 5-23

2
3 **ISSUE:** Section 5.3.1.2, Demand Side Management

4
5 **QUOTE:** “The context within which Yukon Energy has approached Demand Side
6 Management (DSM) has materially changed since the Board made the
7 following DSM related determination in Board Order 2018-10
8 (paragraph 482):

9
10 The Board is not persuaded that YEC should continue to operate DSM
11 projects. YEC has indicated the benefits of expanding the program and
12 submitted that its programs have met or exceeded key performance
13 indicators. However, the Board notes that the Yukon government has
14 DSM incentive programs in place, and the Board is of the view that it is
15 better to leave DSM projects to government, rather than having
16 ratepayers fund these projects. For these reasons, the Board is of the
17 view that continuation of DSM programs by YEC is not necessary.

18
19 Since that determination the Yukon Government has put in place a
20 Climate Change policy initiative called “Our Clean Future: A Yukon
21 Strategy for Climate Change, Energy and a Green Economy” which
22 emphasizes the importance of DSM as a valuable resource to reduce
23 the Yukon’s energy and capacity requirements. As part of that policy
24 the government fully expects Yukon Energy to pursue a cost-effective
25 DSM program.

26
27 Pursuant to this policy initiative and the Government’s expectations,
28 and further given DSM remains a cost-effective means of reducing
29 energy and capacity requirements, Yukon Energy has included in the
30 proposed 2021 rate base the expenditures for the programs and
31 activities as reviewed below. (footnotes removed)

32
33 **QUESTION:**

- 34
35 a) What is meant by the statement “the context within which Yukon Energy has
36 approached Demand Side Management (DSM) has materially changed”?

- 1 b) Given your response in part (a), how should the Board evaluate whether there is
2 a “material change” in the context (i.e., circumstances) since Board Order 2018-
3 10 was issued?
4
- 5 c) To the extent that the content of discussions can be disclosed, please describe
6 Yukon government discussions with YEC regarding the DSM programs YEC has
7 applied for in this proceeding, particularly in light of the Board’s finding in
8 paragraph 482 of Appendix A of Board Order 2018-10 that the continuation of DSM
9 programs by YEC was not necessary. Please also summarize any discussions on
10 scope, quantum, and timing of the applied-for DSM programs.
11
- 12 d) Please explain to what extent policy directions stated by Yukon Government in the
13 climate change policy initiative “Our Clean Future: A Yukon Strategy for Climate
14 Change, Energy and a Green Economy” are binding on the Yukon Utilities Board.
15 If these directions are not binding, please explain how the Yukon Utilities Board
16 should consider those policy directions in its review of YEC’s applied-for DSM
17 programs.
18
- 19 e) Please explain why policy initiatives supported by Yukon Government should be
20 funded by ratepayers through their utility bill, as opposed to through government
21 supported initiatives such as taxation or other means. In addition, please provide
22 YEC’s view on how the two options might differently affect low-income households.
23
- 24 f) Please explain how YEC considered rates and rate base provisions of the Public
25 Utilities Act in its proposal for demand-side management. In your response, please
26 specifically identify how the DSM programs are the property of a public utility used
27 or required to be used to provide service to the public.
28
- 29 g) On November 19, 2020, the Court of Appeal of Yukon heard an appeal regarding
30 Board Order 2019-05 (in which the Board dismissed YEC’s request to review
31 Board Order 2018 10) in relation to DSM costs. What impact, if any, is there on the
32 Board’s consideration of the applied-for DSM costs in this proceeding given that
33 the outcome of the Court of Appeal of Yukon’s decision on the appeal remains
34 outstanding?

1 h) Please explain YEC's management decision to include the DSM policy initiatives
2 in the current application rather than in its next GRA? Please explain why these
3 initiatives are required to be completed in 2021.

4
5 **ANSWER:**

6
7 **(a) through (f)**

8
9 Since the last rate application, the Yukon Government released a climate change strategy
10 – “Our Clean Future: A Yukon strategy for climate change, energy and a green economy”.
11 More specifically, YG drafted the action below in the policy:

12
13 53. Direct the Yukon Utilities Board to allow Yukon's public utilities to pursue cost-
14 effective capacity demand-side management measures.

15
16 This is a material change to how YEC approached DSM. The YG has clearly stated that
17 DSM is a valid supply option for Yukon utilities and that they expect YEC to actively
18 consider and implement prudent DSM programs. They also indicated their intention to
19 direct the YUB to support cost-effective programs administered by YEC and AEY.

20
21 In keeping with action item number 53 the YG enacted OIC 2021-16.

22
23 OIC 2021/16 directs the Board to include in rates provision to recover costs that a public
24 utility (i.e., YEC or AEY) reasonably incurs to provide or participate in a demand side
25 management program.

26
27 Based on YG's DSM policy and also considering growth in electrical load on the system,
28 Yukon Energy DSM planning was undertaken; this planning includes coordination with the
29 Yukon government's DSM programs to meet the overall policy objectives in a cost
30 effective manner.

31
32 DSM program costs of Yukon Energy have been approved by the Board in the past as
33 deferred costs that are included in rate base, consistent with the rate and rate base
34 provisions of the *Public Utilities Act* (“PUA”). The Board can continue to deal with these
35 costs in the future in the same manner.

1 **REVISED RESPONSE – Parts c-e**

2
3 Board Order 2021-10 Appendix C notes:

4
5 YEC did not provide answers to parts (c), (d) and (e) in response to this IR. The
6 Board directs YEC to provide complete responses to parts (c), (d), and (e).

7
8 As part of the response to part (c), please identify and detail the decision-making
9 criteria YEC relies on to determine whether and which DSM programs should be
10 applied for. Please also include a discussion of whether the criteria relied on
11 includes a specific assessment of a program and its costs as it would relate to the
12 benefits and costs to low income ratepayers.

13
14 In addition, in OIC 2021-16, Section 10(3) states: “(3) In determining whether costs
15 are reasonably incurred by a public utility to provide or participate in a demand-
16 side management program, the Board must consider the extent of any duplication
17 between the program for which costs are incurred and a demand-side
18 management program provided by the Government of Yukon or in which the
19 Government of Yukon is a participant.”

20
21 For the DSM programs applied-for in the application, please explain how a decision
22 was made as to whether a DSM program should be undertaken by YEC, by the
23 Yukon government, or both.

24
25 **(c)**

26
27 The updated DSM costs included in the GRA are to complete the design of a new portfolio
28 of DSM programs and the Residential Demand Response Pilot. The design of these new
29 DSM programs has not been completed and as such, no specific programs have been
30 selected and ready for implementation to the Yukon public during the test year.

31
32 In selecting which DSM programs are implemented, YEC will consider the energy and
33 capacity provided by each potential program and conduct the standard cost effectiveness
34 tests. Yukon Energy does not have visibility on the income levels of individual rate payers
35 in Yukon. It may be that programs selected will benefit low income ratepayers but YEC is
36 not intending to specifically design the program for that purpose. YEC will also ensure,
37 through discussion with Yukon Government, that YEC's DSM programs are not duplicative

1 of Yukon Government DSM programs. YEC considers the direction in OIC 2021-16 to be
2 a confirmation that YEC is able to include DSM alongside supply side options in its
3 resource planning, subject to the assessments noted above.

4
5 YEC shared a preliminary draft of the DSM program design report with Yukon Government
6 for their comment as well as discussions on how to best work collaboratively on these
7 programs. After receiving Board Order 2018-10, YEC stopped work on the DSM program
8 design report, and it was not finalized. With the receipt of the OIC 2021-16, Yukon Energy
9 has commenced work to finalize the DSM program design report. Yukon Energy intends
10 to continue to work with the Yukon Government and other energy stakeholder in Yukon to
11 ensure that there is no duplication of programs.

12
13 See also the response to YUB-YEC-2-31(d).

14
15 **(d)**

16
17 YEC assumes that the Board would consider (rather than reject without assessment)
18 Yukon Energy programs carried out in accordance with Yukon Government policy
19 directives and OIC 2021-16, and this consideration would assess such programs based
20 on standard cost effectiveness tests applied to the energy and capacity expected to be
21 provided by each potential program.

22
23 As noted in the initial response to YUB-YEC-1-46 (and in response to YUB-YEC-2-31(b)),
24 the policy directions stated by Yukon Government in the climate change policy initiative
25 “Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy”
26 included a commitment to provide a binding directive to the YUB on DSM program-related
27 rate determinations as allowed under the PUA Section 17. Yukon Energy was aware of
28 this commitment when the GRA was prepared. This commitment was subsequently
29 implemented through OIC 2021/16 with respect to DSM programming.

30
31 **(e)**

32
33 Yukon Government has clearly directed the YUB through OIC 2021/16 to fund DSM
34 through rates that meet certain tests, so on one level this question that was provided prior
35 to this OIC is moot with respect to this program.

1 DSM as such is a legitimate, cost-effective energy and capacity resource for electric
2 utilities. This opinion is supported in numerous resource planning reports where DSM
3 compares favorably when evaluated against other supply options, as well as by utility
4 experience and practice in other Canadian jurisdictions. Absent OIC 2021/16 direction,
5 Yukon Energy understands that ratepayer funding decisions on YEC DSM programs
6 should be based on standard cost effectiveness tests applied to the energy and capacity
7 expected to be provided by each potential DSM program. OIC 2021/16 also directs that
8 YEC programs are not duplicative of Yukon Government programs.

9
10 Beyond the above considerations affecting YEC selection of DSM programs, Yukon
11 Energy is not aware of any basis for assessing which DSM programs should be done by
12 the Yukon Government versus the utilities - or on how these two options might differently
13 affect low-income households.

14
15 **(g)**

16
17 YEC notes the Court of Appeal ruled on this proceeding on February 5, 2021 and the
18 appeal was dismissed. The Court of Appeal proceeding including the decision does not
19 affect the 2021 GRA Application as none of the costs that were covered by the appeal are
20 included in this Application.

21
22 **(h)**

23
24 As stated above, YG has publicly confirmed its support for utility-driven DSM programming
25 and further they indicated that they expect YEC to undertake such programming. Based on
26 YG's clear expectation (now confirmed by OIC 2021/16) and with the knowledge that a
27 significant capacity shortfall exists on the Yukon integrated system, YEC believed it was
28 timely and prudent to include these programming costs in the 2021 application.

1 **REFERENCE:** Application, Tab 5.2.1.3, pages 5-8 to 5-10

2
3 **ISSUE:** The Mayo-McQuesten Transmission Line Upgrade Project

4
5 **QUOTE:** From page 5-8 of the Application:

6
7 “The Mayo – McQuesten Transmission Line (MMTL) project involves
8 the construction of a new 138 kV framed transmission line from the
9 Mayo to McQuesten substations as well as the installation of electronic
10 voltage support equipment (Statcom) at Stewart Crossing South
11 substation that will improve overall reliability and power quality in the
12 system. The [Mayo – McQuesten Transmission Line Upgrade Project]
13 transmission will initially be operated at 69 kV.

14
15 The existing 69 kV transmission line from Mayo to Keno constructed by
16 the Northern Canada Power Commission (NCPC) in 1951 is at end of
17 life and in need of replacement. The transmission line has experienced
18 both reliability and power quality issues with an increasing number of
19 outages on the line affecting customers on a system wide basis. Key
20 requirements under the VGC Group PPA include development of the
21 McQuesten Substation plus new transmission to replace the existing
22 69 kV facilities between at least Mayo and McQuesten by
23 approximately summer of 2020.” (footnote removed)

24
25 From page 5-9 of the Application:

26
27 “Later stages will proceed only when loads in the area justify increasing
28 the operating voltage to 138 [kV], and when additional federal funding
29 becomes available ... Increased power transfer/ capacity will also
30 support economic development in central Yukon, as well as connection
31 of renewable energy sources such as hydro, wind and solar.”

32
33 “Effects assessment and stakeholder engagement development
34 activities for all project stages were undertaken in 2015 and 2016. As
35 reported during the 2017-18 GRA, all project permits were in place,
36 including the land use permit, access permits and highway permits. No

1 additional permitting was anticipated to be required.” (footnote
2 removed)

3
4 From page 5-10 of the Application:

5
6 “Decommissioning of the old 69 kV line is expected to occur between
7 November 2020 and December 2020. Substation construction at
8 Stewart Crossing commenced in August 2020 and is expected to be
9 completed by June 2021. An order has been placed for the Statcom
10 and it is in manufacturing. Statcom delivery is expected to occur by
11 August 2021, with installation in September 2021 and commissioning
12 completed by October 2021.”

13
14 **QUESTION:**

- 15
- 16 a) Please provide the reliability criteria YEC utilizes in assessing the viability of its
17 electric system (e.g. the thermal limit ratings and acceptable voltage range on
18 transmission lines).
- 19
- 20 b) Please provide and explain the studies that were conducted to show that the
21 existing 69 kilovolt (kV) transmission line had reliability and power quality issues.
22 For example, did YEC carry out a contingency analysis that showed this line
23 exhibited reliability criteria violations?
- 24
- 25 c) Please explain how often YEC carried out studies and assessed the reliability of
26 the existing 69 kV transmission line in the past.
- 27
- 28 d) Please explain why YEC proposed to install STATCOM in this project. Were any
29 other alternatives to STATCOM explored (e.g. static VAR compensators or
30 synchronous condensers)? If other alternatives were explored, please provide the
31 costs of these alternatives and the reasons these alternatives were dismissed.
- 32
- 33 e) Please provide the number and duration of outages experienced on the line in the
34 last 10 years, on a per annum basis, and the costs incurred due to these outages.

- 1 f) Please provide and explain the studies that were conducted to show the Mayo-
2 McQuesten Transmission Line Upgrade Project resolved reliability and power
3 quality concerns.
4
- 5 g) Please explain if any other alternative solutions were proposed and explored. If
6 applicable, please provide and explain the studies conducted on these alternatives
7 and provide the costs of these alternatives.
8
- 9 h) Given that YEC plans to operate this new line initially at 69 kV and future load will
10 need to justify an operating voltage of 138 kV, please explain why YEC considered
11 it prudent to spend capital on infrastructure designed for 138 kV.
12
- 13 i) Please explain if there were any concerns brought up during stakeholder
14 engagement sessions and if there are any outstanding concerns to date.
15
- 16 j) Please provide details on the selection process of contractors for this project,
17 including how contracts were awarded for this project.
18
- 19 k) Based on the information provided in page 5-10 of the Application, please provide
20 an update on the project. For example, did YEC decommission the old 69 kV line?
21

22 **ANSWER:**

23
24 **(a)**
25

26 Attachments 1 this response provides Transmission Line Design Criteria Stewart to Keno
27 Transmission Project 138 kV Transmission Lines which is relevant to the MMTL Project.
28 Attachment 2 provides YEC L170 Transmission Line – Clearance and Structural
29 Evaluation Criteria” – this document defines YEC’s evaluation criteria for all structures,
30 and is also relevant to the MMTL project.
31

32 **REVISED RESPONSE**
33

34 Board Order 2021-10, Appendix C notes:
35

36 In the Attachment 1 version provided by YEC, there is no information provided
37 under Appendix A – Site Location Plan, Appendix B – Code & Regulation List,

1 Appendix C – Cables and Insulators Catalogue Information, Appendix D – Climate
2 Data Reference Data, and Appendix F – IEEE Std. 738 Ampacity Calculation
3 Program Output. The Board directs YEC to upload a version of this attachment
4 that includes information within these appendices.
5

6 YUB-YEC-1-51(a) REVISED Attachment 1 provides the requested revised attachment.
7

8 **(b), (c) and (e)**
9

10 As noted in Tab 5, Section 5.21.3 of the Application, a new line from Mayo to the Keno
11 City region is required at this time to replace the end of life existing 69 kV line constructed
12 in the 1950's. This line is in poor condition and there has been a significant degradation in
13 reliability. This was reviewed previously during the 2017 VGC Group PPA proceeding and
14 the 2017/18 GRA,¹ and is also supported by data collected from inspections.
15

16 In the early 1990s, Yukon Energy noted that the line was significantly deteriorated and
17 needed to be rebuilt or abandoned due to safety and reliability concerns;² however, at the
18 time a rebuild could not be justified due to the closure of UKHM. As an alternative, minimal
19 capital improvements were undertaken at that time to maintain the line and ensure
20 continued service to existing non-industrial customers;³ and over the past 15+ years
21 transmission line repairs have been required on an ongoing basis to address reliability
22 concerns.
23

¹ See for example, YEC's 2017 VGC Group PPA Application, section 4.3; and 2017/18 GRA Section 5.3.1.1; and response to YUB-YEC-1-78.

² The Yukon Energy 1992 Resource Plan notes "This line was built in 1952 with untreated native poles, which have long since rotted at ground level. Virtually every pole on this line has been stubbed (a small pole attached at ground level) or cribbed (a rock filled culvert or container added) over the last forty years. The line was identified as a severe safety hazard for Company employees and the general public."

³ In its 1992 Resource Plan, Yukon Energy noted that "it was recognized for many years, by both NCPC and YEC, that the Mayo-Elsa-Keno City transmission line urgently needed to be either re-built or abandoned." At the time, it was noted that "this project just could not continue to be deferred indefinitely," and "essential work had to be performed to ensure the safety of the line." The option of abandoning the transmission line was considered and discarded at the time for the following reasons: (1) Additional loads are also supplied from this line, via Keno City, CBC and NWTel tower sites, Silver Trail Lodge and a number of YTG Highways heat traces in culverts; and (2) The cost of diesel generation would be at least \$250,000 per annum based on approximately 2.5 kWh consumption at 10 cents per kWh by UKHM.

1 More specifically, the Stewart- Keno Transmission Line Project Proposal filed with YESAA
2 in 2015 noted:⁴

3
4 Transmission line repairs have been required over the past fifteen years to address
5 ongoing reliability concerns. Line reliability has also become a more significant
6 issue and line outages have increased, affecting customers on the Integrated Grid
7 (including local customers as well as customers as far away as Dawson City and
8 Whitehorse). For example, outages on the Mayo to Keno line have increased from
9 4 outages in 2012, to 6 outages in 2013, to 19 outages in 2014 to 20 outages (to
10 the end of Q3 2015) – outages for 2015 are forecast to be 27. Further, in 2011,
11 35% (or 188 of 535) of the structures on L250 failed the test and treat assessment
12 undertaken at that time and were considered unsafe to climb, limiting the
13 maintenance work that can be safely undertaken on these structures. The
14 remoteness of the line as well as terrain and access challenges also magnify the
15 costs and difficulties involved in managing maintenance and reliability of this asset.
16

17 No power quality studies were performed for the existing 69kV transmission line due to
18 the fact that the numerous outages were the assumed to be the cause of power quality
19 issues experienced.
20

21 The following is noted regarding past inspections/ assessments for L250:
22

- 23 • A Line inspection was performed on L250 in 2002.
- 24
- 25 • A detailed Line inspection was performed on L250 in 2008.
- 26
- 27 • Wood pole test and treat was performed on the line on L250 in 2011.
- 28
- 29 • Outage statistics on L250 are updated as they occur.
30

31 Yukon Energy performs overhead line inspections and wood pole test and treat
32 inspections to determine the condition of the line and poles. Outage reports are also
33 reviewed annually to identify reliability issues.

⁴ Stewart-Keno Transmission Line Project Proposal, Chapter 6, page 6-3.

See Table 1 below for a summary of the outages from 2011 to 2020 mid-year. Total cost to respond to outages (planned and unplanned) are about \$320,900 (2012 to date) with an average annual cost of roughly \$35,655. Additionally, capital investment in this line over the same period totaled \$963,700.

Table 1: Number and Duration of Outages: 2011 to 2020

Year	Unplanned Outages	Planned Outages	Total Outages	Outage Hours
2011	8	0	8	16.19
2012	4	0	4	5.91
2013	6	0	6	3.78
2014	14	5	19	126.24
2015	23	7	30	105.1
2016	9	1	10	0.6
2017	14	0	14	8.2
2018	4	3	7	9.62
2019	20	0	20	14.42
2020	1	3	4	4.19

(d)

YEC explored three alternatives: the STATCOM (Static synchronous compensator); SVC (static VAR compensator); and the synchronous condenser.

The synchronous condenser was proposed as the best solution as it provided reactive power support while also being able to recover the system frequency with excursions below 64Hz in a large load loss such as Eagle Gold Mine. However, due to the associated costs the STATCOM was chosen as a compromise as its more responsive than the SVC solution.

See Table 2 below for further details.

Table 2: Stewart Crossing Potential FACTS Solutions

	STATCOM	SVC	Synchronous Condenser	BESS plus STATCOM
Pros	Fastest response for reactive power support.	The most economical solution for reactive power support.	Provides frequency stability enhancement in addition to reactive power support. This may avoid predicted and future review/changes for frequency protection relays or RASs.	Potentially addresses frequency issues.
Cons	There are no cons associated with the STATCOM solution, for providing the required reactive power support	It is considered as a harmonic source, and doesn't have a quick response time compared to the STATCOM (e.g. flicker).	No-load running losses; may require additional maintenance when compared with the STATCOM or SVC solution.	Not commercially available. Would require custom design and assembly.
Relative Budgetary Cost *	1.0	0.90 - 0.95	1.4 – 2.0	Unknown. Costs would need to be determined via communication with the potential suppliers.
Other Notes	For low inertia systems, the addition of a STATCOM (as a solution for the deficient reactive power support) is a fix for only one issue. However, the wide swing of frequency may impact the evaluation of the required reactive power support.	This technology is fading in popularity. A STATCOM would be the preferred solution for reactive power support.	Synchronous condensers (synchs) are the solution for both reactive power deficiency and frequency instability. Synchs will provide long term operational easiness. They will also reduce or eliminate the need for future frequency RASs. YEC personnel have O&M synchronous condenser experience.	This solution would require significant research/study, consultation/coordination with suppliers, etc. which would result in additional time and cost for the project. Ongoing costs associated with battery life would need to also be considered.

NOTE: * The above relative budgetary costs are provided based on Teshmont's in-house information. Supplier input was not obtained.

(f), (g) and (h)

As noted in part (b) a new line from Mayo to the Keno City region is required to replace the end of life existing 69 kV line constructed in the 1950's. This fundamental requirement necessitated the project as a key element of the PPA as approved by the Board.

Please see Attachment 1 to this response which provides the Chimax Inc Transmission Line preliminary design report; and Attachment 2 which provides the Chimax Inc Transmission Line Scope Extension Report which reviews overall project cost comparisons between Mono Pole and H-Frame transmission structures.

As reported on and reviewed during the VGC Group PPA proceeding, an assessment was also carried out to determine the transmission upgrades required to supply the proposed Eagle Gold facility (EG) from the Yukon Energy Corporation (YEC) power system while providing acceptable service and reliability to EG and existing YEC customers. This study confirmed the system upgrades required (as provided for in the PPA), and the STACOM requirement as part of the overall system improvements.

The decision to complete the design of the project using a 138 kV standard was made in March 2017 as a result of completion of the detailed design of the powerlines and

substations and comparative pricing using 138 and 69 kV design standards. Table 3 below provides a cost comparison. Cost reductions shown in Table 3 are in comparison with the 138 kV H-frame design. For L180 line the cost reduction to use a 69 kV design compared to 138 k was less than 10% (between 3.8% and 9.4%).

Table 3: Preliminary Cost Estimates SKTP

	L180				L250		
Voltage	138kV		69kV		138kV	69kV	
Pole Framing	H-Frame	Mono Pole	Mono Pole		H-Frame	Mono Pole	
Tangent Insulator Type	Suspension	Braced Post	Braced Post	Post	Suspension	Braced Post	Post
Fiber Configuration	OPGW	OPGW	OPGW	OPGW	OPGW	ADSS	ADSS
No. Structure	162	218	255	255	118	175	175
No. Pole	354	230	266	266	227	178	178
Cost Item							
Procurement	\$3,200,315.77	\$3,317,249.23	\$3,261,908.91	\$2,838,233.03	\$1,935,469.37	\$1,842,557.06	\$1,497,569.84
Construction	\$6,515,800.56	\$5,605,689.15	\$5,839,587.50	\$5,651,915.12	\$4,090,160.91	\$3,578,987.53	\$3,447,030.38
Engineering Support	\$68,790.00	\$83,910.00	\$93,900.00	\$93,900.00	\$56,910.00	\$72,300.00	\$72,300.00
Construction Management	\$950,400.00	\$950,400.00	\$950,400.00	\$950,400.00	\$799,000.00	\$799,000.00	\$799,000.00
Additional Cost Provision	\$281,029.86	\$399,254.44	\$447,979.30	\$447,979.30	\$159,717.42	\$301,112.00	\$301,112.00
Sub-Total	\$11,016,336.19	\$10,356,502.82	\$10,593,775.71	\$9,982,427.45	\$7,041,257.70	\$6,593,956.59	\$6,117,012.22
Contingency (10%)	\$1,101,633.62	\$1,035,650.28	\$1,059,377.57	\$998,242.75	\$704,125.77	\$659,395.66	\$611,701.22
Estimated Cost	\$12,117,969.81	\$11,392,153.10	\$11,653,153.28	\$10,980,670.20	\$7,745,383.47	\$7,253,352.25	\$6,728,713.44
cost per km	\$390,902.25	\$367,488.81	\$375,908.17	\$354,215.17			
Comparison							
Cost Differences		(\$725,816.71)	(\$464,816.53)	(\$1,137,299.61)		(\$492,031.22)	(\$1,016,670.03)
% Reduction		-5.99%	-3.84%	-9.39%		-6.35%	-13.13%
Assumptions:							
All mono pole embedments are based on 10% pole length plus 6ft (from grade). Actual embedment requirement will vary, require additional engineering in final design.							
For 138kV mono pole, average pole span is approximately 150m (cable galloping governed)							
For 69kV mono pole, average pole span is approximately 120m (cable galloping governed)							
Remarks:							
The increased structure count and combined with higher Braced Post Insulator cost, the mono pole option with braced post insulator would not provide significant saving compared with H-Frame structure. The reduced 69kV span allow utilization of post insulator which can significantly reduce the overall cost.							

The decision to utilize a 138 H-frame design was based on the following factors:

- For an increase in initial capital cost of between 4 % and 10% (for L-180 this would amount to between \$0.5M and \$1.0M) from 69 to 138 kV.
- The benefits of prebuilding to a 138 kV standard are an increase in the ultimate line capacity of up to 400%.
- The existing powerline is at its end of life and must be replaced in order to continue to serve existing customers in this region and new industrial customers.
- It is not possible to upgrade a 69 kV line to 138 kV design at a later date cost effectively if at all.

1 5. The long term plan for any expansion to the Yukon's hydro grid is at the 138 kV
2 voltage level or higher due to the small incremental capital cost between 69 kV
3 and 138 kV.

4
5 6. Increase in reliability.
6

7 The selection of 138 kV vs 69 kV for this project was also addressed at some length during
8 the VGC PPA proceeding. It was noted that the VGC Group PPA default transmission
9 option defines a minimum priority development consistent with the SKTP planning to
10 provide 138 kV capability to facilitate potential future load and/or renewable resource
11 supply development in this region. Key features noted included the following:

- 12
- 13 • SKTP planning assessed transmission options, including 69 versus 138 kV
14 options, and concluded that the mono pole option with braced post insulators at 69
15 kV would not provide significant cost savings compared with the proposed H-
16 Frame structure and 138 kV when assessing costs for this new transmission.
17
 - 18 • Further, proceeding to install a 69 kV transmission option with adequate upgrade
19 limited only for VGC Group and Alexco would maintain existing service, but ignore
20 the opportunity to strengthen and enhance the existing grid system to better
21 support future development opportunities in the region.
22
 - 23 • The example of the existing relatively new 69 kV from Stewart Crossing to Mayo
24 highlights the significant added costs to come back in future (as per the full SKTP
25 proposal) to increase the capability of transmission to 138 kV after a new 69 kV
26 line has been installed.
27

28 It is expected that reliability will improve through replacing a 66 year old transmission line
29 (built in the 1950's) that is at end of life with a new transmission line that is installed using
30 today's line design standards.

31
32 Once the line is in service, reliability will be tracked.

1 (i)

2
3 Attachment 1 summarizes concerns raised by members of the public as part of the public
4 engagement process to support the development of the Project Proposal for the Stewart-
5 Keno Transmission Line Project and how these concerns were addressed.

6
7 During construction – the following stakeholder engagement occurred:

- 8
- 9 • Virtual meetings with FNNND Council, Village of Mayo and Selkirk Development
10 Corporation (designate for Selkirk First Nation) to discuss status of the project,
11 COVID-19 safety plans and to determine any concerns with proceeding with the
12 project during COVID-19 (no concerns were raised about proceeding with the
13 project during COVID-19 so long as YEC followed strict project and community
14 COVID-19 safety plans).
 - 15
 - 16 • Weekly Project Updates to contacts at the FNNND, Selkirk First Nation, Village of
17 Mayo, Selkirk Development Corporation and NND Development Corporation.
18 These started in June 2020 and have continued since.
 - 19
 - 20 • Monthly Project Updates prepared for Village of Mayo Council, FNNND Council
21 and Selkirk First Nation Council. Emailed to each government's designates
22 beginning in June 2020 and have continued since.
 - 23
 - 24 • One Newspaper ad that ran in the Yukon News in June 2020 to advise Yukoners
25 that the project was moving forward.
 - 26
 - 27 • Project Newsletters mailed to residents in Mayo, Keno and Pelly with updates
28 about the project. Newsletters were distributed in June 2020, August 2020 and
29 February 2021.
 - 30
 - 31 • A virtual public meeting hosted on June 11, 2020 to discuss the project. Less than
32 five people attended.
 - 33
 - 34 • Project information is provided on YEC's website and in occasional social media
35 posts.

1 YEC received a complaint about ruts that were left in a resident's driveway by one of
2 YEC's contractors during construction. The complaint was addressed and repairs were
3 made to the driveway.

4
5 The Department of Environment, Government of Yukon also engaged YEC to discuss a
6 public complaint of construction-related disturbances to the Minto Creek Bridge
7 Interpretive Trail area. Yukon Energy prepared a restoration plan for consideration by YG
8 in this regard and expects to implement the restoration activities in the spring and summer
9 of 2021 as it conducts other post-construction clean-up activities along the transmission
10 line typical of such projects.

11
12 **(j)**

13
14 Contractors were selected through a competitive RFP process. Each of the contacts were
15 evaluated based on technical ability, price and the ability to provide FN opportunities.
16 Once the evaluation process was completed and successful bidder selected based on
17 total score, contract negotiations began, were finalized and signed.

18
19 **(k)**

20
21 The L180 Transmission line will be completed and fully energized in March 2021. Upon
22 energization of the new line, the old 69kV line will be decommissioned / removed with an
23 anticipated end date of April 2021.

Chimax Inc.

TRANSMISSION LINE DESIGN CRITERIA

**STEWART TO KENO TRANSMISSION PROJECT
138 kV TRANSMISSION LINES**



Yukon Energy Corporation

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February 24, 2016 (Rev-1)

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Appendix A – Site Location Plan

Appendix B – Code & Regulation List

Appendix C – Cables and Insulators Catalogue Information

Appendix D – Climatic Data Reference Data

Appendix E – PLS-Cadd IEC 60826:03 Wind & Ice Adjustment Models

Appendix F – IEEE Std. 738 Ampacity Calculation Program Output

1.0 Project Overview

Yukon Energy Corporation (YEC) is proposing to construct a 138kV transmission line from Stewart Crossing South (SCS) substation to Keno City (KC) substation. The overall transmission line and associated substation construction or modification is grouped as SKTL project.

1.1 Project Descriptions

The proposed 138kV transmission line route originates and travels north from SCS substation (S251) generally parallel existing L175 138kV transmission line to a point north of Stewart Crossing North (SCN). At this point the route turns east and parallels the existing L176 69kV transmission line to Mayo substation (S249). The transmission line will turn northeast to parallel the existing L250 69kV transmission line to KC substation (S257). A new substation at McQuesten (S258) will be constructed north of Halfway Lakes to convert voltage from 138kV to 69kV. The transmission line from S258 to S257 will be constructed for 138kV and energized at 69kV.

The existing L176 and L250 69kV transmission right of way is 60m wide which should accommodate 2 (two) parallel transmission line circuits.

The preliminary design will assess deviations from the YEC primary proposed route due to land use conflicts, environmental restriction, construction and maintenance access, geological restriction, etc.

1.2 Design Codes and Regulations

The design of the 138kV transmission line will be based on both deterministic approach as per CSA C22.3 No.1 (C22.3 No.1) “Overhead System” and reliability approach as per CSA C22.3 No.60826 (C22.3 No.60826) “Design Criteria of Overhead Transmission Lines”.

The conditions outlined in CSA C22.3 No.1 are minimum design requirements for both transmission and distribution overhead lines.

CSA C22.3 No.60826 outlines additional extreme weather conditions and design requirements for transmission line voltage exceeding 70kV (phase – phase voltage) as recommended in CSA C22.3 No.1 Section 10.

YEC has specified the design of the SKTL transmission lines to comply with Alberta Electrical Utility Code (AEUC) in addition to CSA code requirements. Chimax will also review and incorporate the relevant information and guidelines outlined in the Alberta Electrical System Operator (AESO) ISO Rules Section 502.2 “Bulk Transmission Line Technical Requirements”.

In addition to the Canadian overhead line design code, additional design codes and regulations will be followed for each transmission line component design. A full list of design codes and regulations is provided in Appendix B.

2.0 Equipment and Material Descriptions

2.1 Cable Descriptions

The 138kV phase conductors, optical fiber cable and overhead grounding wire (OHGW).

2.1.1. 138kV Phase Conductor

The YEC standard phase conductor for the proposed 138 kV transmission lines is 266.8MCM 26/7 ACSR (Partridge). Alternatively, 397MCM 26/7 ACSR (Ibis) had also been used on few YEC transmission lines. Based on future load growth and cost estimate consideration, 397.5 MCM 26/7 ACSR (Ibis) was used as benchmark phase conductor. Comparison of structural requirement between the two conductors are also performed.

The general mechanical and electrical properties of 266.8 MCM 26/7 ACSR (Partridge) and 397.5 MCM 26/7 ACSR (Ibis) are listed in Table 2.1.1.

Table 2.1.1

Mechanical Properties								
Conductor	Conductor Size		Stranding No. x Dia. (in)		O.D. (in)	Nominal Mass (lb/1000 ft)	Rated Strength	
	MCM	mm ²	Al	Steel			(lbf)	(kN)
266.8 MCM ACSR (Partridge)	266.8	135.2	26x0.101 3	7x0.0788	0.642	366.0	11300	50.3
397.5 MCM ACSR (Ibis)	397.5	201.4	26x0.123 6	7x0.0961	0.783	545.0	16100	71.6
Electrical Properties								
Conductor	Cross Section Area (in ²)		Resistance (ohms/ 1000ft)			GMD (ft)	Inductive Reactance (ohms/10 00ft)	Capacitive Reactance (Mohms/100 0ft)
	Total	Al	DC @20°C	AC @25°C	AC @75°C			
266.8 MCM ACSR (Partridge)	0.2437	0.2095	0.0651	0.0665	0.0796	0.0217	0.0880	0.5673
397.5 MCM ACSR (Ibis)	0.3630	0.3123	0.0437	0.0447	0.0535	0.0265	0.0835	0.5361

2.1.2. Optical Fiber Cable

YEC will install optical fiber communication cable along proposed transmission line to improve existing protection and control communication. Standard installation of optical fiber cable on new transmission line will utilize optical grounding wire (OPGW). The current YEC 138kV transmission line standard does not utilize any lightning protection wire. Chimax has evaluated both optical cable communication underbuilt, all dielectric self-support (ADSS) and compared it to the OPGW configuration.

Table 2.1.2 – OPGW Properties

Electrical and Mechanical Properties							
OPGW Size	Fibers (max)	Fault Current (kA) ² s	Cross Section Area (in ²)	O.D. (in)	Nominal Mass (lb/ft)	Rated Strength	
						(lbf)	(kN)
SFPOC/SFSJ-J-10783	48	63	0.1474	0.496	0.356	18454	82.0

The final selection of OPGW will depend on the long-term forecast fault current levels and ground resistivity along the transmission line route.

Due to relative long span and restricted cable sag of ADSS cable required for the proposed transmission line, technical information is not available as standard information. Manufacturer had only confirmed the following parameters at this time.

Table 2.1.3 – ADSS Properties

Electrical and Mechanical Properties							
ADSS Size	Fibers (max)		Cross Section Area (in ²)	O.D. (in)	Nominal Mass (lb/ft)	Rated Strength	
						(lbf)	(kN)
OFS ADSS	48		0.2186	0.527	T.B.C.	T.B.C.	T.B.C.

Overhead Shield Wire (OHGW)

For H-Frame with two shieldwire configuration and lightning protection within 1 km of any station for other configuration, the overhead ground wire (OHGW) for the proposed transmission line will be based on existing shieldwire used in existing YEC transmission lines.

Table 2.3 – OHGW Properties

Mechanical Properties							
Cable Size	Stranding No. x Dia. (in)	O.D. (in)	Cross Section Area (in ²)	Resistance (ohms/1000ft) @20°C	Nominal Mass (lb/1000ft)	Rated Strength	
						(lbf)	(kN)
3/8" EHS Galv. Steel	7x0.1819	0.546	0.182	0.2264	524.9	27030	120.1

2.2 Insulator and Configuration

The preferred suspension insulators for standard 138kV H-Frame tangent and running angle structures shall be toughened glass suspension insulators. The Mono wood pole alternative shall employ a braced post insulator configuration for tangent structures.

The default deadend insulators shall be toughened glass strain insulators. Alternatively, polymeric strain insulator will be considered in the cost evaluation. (SaskPower standard H-Frame utilize glass insulators for suspension / running angle structures and polymer strain insulators for deadend application)

The electrical and mechanical properties of individual toughened glass insulators are given in Table 2.2.1.

Table 2.2.1 – Toughen Glass Suspension & Strain Insulator Properties

Mechanical & Electrical Properties							
Insulator Description	Diameter (in) [mm]	Leakage Distance (in) [mm]	Tensile Strength (lbf) [kN]	Low Frequency Flashover		Critical Impulse Flashover	
				Dry (kV)	Wet (kV)	Positive (kV)	Negative (kV)
Sediver N70/146	10 [255]	12 5/8 [320]	15000 [70]	80	50	125	130
Sediver N12/146	10 [255]	12 5/8 [320]	25000 [120]	80	50	125	130

The minimum insulation level for 138kV transmission line depends upon the critical impulse flashover and the pollution levels along the transmission line area. For 138kV transmission line, the maximum phase to phase voltage shall be 145kV and phase to ground voltage of 84kV. Table 2.2.2 summarized the insulation criteria and minimum insulator requirement for 138kV transmission line.

Table 2.2.2 – Minimum Insulator Requirement

	Pollution Level			
	Very Light	Light	Medium	Heavy
Critical Impulse Flashover (kV)	715			
No. of Insulators	6			
IEC 60815 Leakage Distance (mm/kV)	22.0	27.8	34.7	43.3
Minimum Leakage Distance (mm)	1848	2336	2915	3638
No. of Insulators	6	7.3	10	12
Recommended No. of Insulators	7	8	10	12

Typical recommended minimum leakage distance in manufacturer catalogue is based on 25mm/kV which will be 7 strings insulator and is consistent with existing YEC specification.

For the preliminary design of the SKTL, 8 strings insulator will be used for the majority of the 138kV H-Frame structures. For structures located on Galena Hill and Keno where pollution levels are expected to

be higher, 10 string insulators will be utilized. The preliminary designs and cost estimates will be based on 10 strings insulators to allow flexibility in final transmission line design.

The proposed polymer insulators electrical and mechanical properties are outlined in Table 2.2.3 and Table 2.2.4.

Table 2.2.3 – Polymer Suspension & Strain Insulator Properties

Mechanical & Electrical Properties							
Insulator Description	Section Length (in) [mm]	Leakage Distance (in) [mm]	Tensile Strength (lbf) [kN]	Low Frequency Flashover		Critical Impulse Flashover	
				Dry (kV)	Wet (kV)	Positive (kV)	Negative (kV)
NGK-Locke 251-SC410-YJ	60 [1525]	114.6 [2911]	25000 [111]	525	465	815	865
NGK-Locke 301-SC450-YJ	66.3 [1685]	125.8 [3195]	30000 [133]	570	505	890	940

Table 2.2.4 – Braced Post Insulator Properties

Mechanical Properties					
Insulator Description	Maximum Design Loads				Dimensions
	Vertical Load (lbf)	Long. Load (lbf)	Tension Load (lbf)	Comp. Load (lbf)	Length (in) [mm]
NGK-Locke HV-556	10000	1375	7500	7500	64.0 [1625]
Electrical Properties					
Insulator Description	Leakage Distance (in) [mm]	Low Frequency Flashover		Critical Impulse Flashover	
		Dry (kV)	Wet (kV)	Positive (kV)	Negative (kV)
NGK-Locke HV-556	148.8 [3780]	545	475	820	890

2.3 Structure Material and Configuration

The proposed 138kV transmission lines shall be YEC standard H-Frame structures along with alternative mono wood pole structures.

Currently, the baseline design will be based on wood poles H-Frame configuration utilizing toughened glass suspension insulator for tangent and light angle structures. Where right of way is restrictive, mono wood pole configuration will be used. The mono wood pole tangent and light angle shall be braced post triangular configuration with top and bottom phases on one side and middle phase on opposite side. Mono wood pole angle and dead end structures shall be vertically framed with guying.

As per previous Carmack to Stewart transmission line (CSTL), the minimum pole class shall be Class 3 to provide reliability and facilitation of pole climbing during maintenance.

2.4 Foundation Configuration

For H-Frame configuration, all wood poles shall be direct embedded with standard 10% pole length plus 0.610m (2ft) embedment. Additional foundation augmentation will be determined based on site requirement, such as side slope, swamps and weak soils.

For mono pole configuration, standard 10% pole length plus 0.610m will be used as baseline embedment and evaluated against site soil condition and ground line bending moment to ensure sufficient resistance will be achieved.

2.5 Conductor Hardware

All conductor hardware shall meet or exceed the specification outlined in CSA C83 “Communication and Power Line Hardware”. In addition, all current carrying connectors shall also meet the requirements outlined in CSA C57 “Electric Power Connectors for Use in Overhead Line Conductors”.

Baseline suspension clamp for proposed 138kV transmission lines shall be standard aluminum suspension clamp along with armor rod protection.

2.6 Vibration Protection

In addition to critical loading scenarios for phase conductor, the conductor tension is further limited to 15% UTS under -50°C extreme winter temperature to minimize vibration fatigue.

Stockbridge vibration damper will be installed on all phase conductors as well as for OHGW as required. Spiral vibration damper will be specified on all OPGW for vibration control to protect the fiber optic cable.

The preliminary vibration damper calculation will be performed using Preformed Line Product (PLP) Vortex Damper Design Application with design span and tension information.

3.0 Meteorological (Climate) Data

3.1 Site Descriptions

The closest meteorological locations outlined in both C22.3 No.1 and C22.3 No.60826 is Dawson City.

3.2 Deterministic Approach Weather Case

CSA C22.3 No.1 Section 7 outlines the minimum deterministic weather loads shall be applied to each line components. C22.3 No.1 Annex C Figure C.1 indicates that the Yukon falls under CSA Medium A Loading condition which does not represent local observed ice loading situations. The CSA Heavy Loading is used for the previous CSTL and proposed transmission lines. Parameters are given in C22.3 No.1 Table 30 and are listed as follows:

Table 3.1

Conditions	Temperature (°C)	Horizontal Wind Loading (N/m ²)	Radial Ice	
			Thickness (mm)	Ice Density (kg/m ³)
CSA Heavy	-20	400	12.5	900

3.3 Reliability Approach Weather Cases

CSA C22.3 No.60826 is the Canadian adaptation of IEC 60826 “Design criteria of overhead transmission lines”, with implementation of appropriate Canadian variations and weather parameters. C22.3 No.60826 Table CA.1 listed 50 years return period (1/50) weather conditions for Canadian Locations. The mean annual maximum snow accumulation depths are provided in CSA C22.3 No.1 Table D.1. The ice, wind and snow depth parameters for the closest meteorological locations to the transmission line are listed below:

Table 3.2

Locations	Reference Average Minimum Temperature (°C)	Reference (1/50) Wind Speed (km/h)	Reference (1/50) Radial Ice		Mean Annual Maximum Snow Depth (m)
			Thickness (mm)	Ice Density (kg/m ³)	
Whitehorse (reference)	-43	85	10	900	0.4
Dawson City	-51	80	10	900	0.6

The ambient temperature for radial ice formation due to freezing precipitation is assumed at -10°C.

The reference wind and ice loading values given above are based on 1 in 50 year (1/50 return period) event.

3.3.1. Reference Ice Loadings

The reference ice loading listed in CSA C22.3 No.60826 does not reflect the occasionally observed rime ice condition on existing transmission line in Yukon. Additional ice loading of 51mm (2") rime ice (density of 350kg/m³) has been included in the design of the proposed transmission line.

The cable diameter factor and structure height factor according to C22.3 No.60826 Section 6.3.4.1 will be adjusted accordingly in PLS-Cadd model for site specific design.

3.3.2. Reference Wind Loading

The 1 in 50 return period reference wind loading is recommended for the design of the transmission line for capital cost minimization.

3.3.3. Combined Wind and Low Temperature

As per requirement under CSA C22.3 No.60826 Section 6.2.4 for span typically less than 200m, combination of minimum temperature with wind shall be included for reliability design load scenario. The combination shall be verified for reference average minimum temperature with 60% of design wind speed. The design wind speed for combination with minimum temperature is recommended to be 1 in 50 return period.

3.3.4. Combined Ice and Wind Loadings

The requirement of combination of the ice with wind is defined in CSA C22.3 No.60826 Section 6.4. The section outlines two ice and wind combinations as follows:

- Reduced Ice with High Wind - 85% Reference Ice with 60% Reference Wind (normal combined ice and wind)
- High Ice with Average Wind - 130% Reference Ice with 40% Reference Wind (extreme combined ice and wind with spatial factor)

The recommended level of reliability for ice loading combined with wind loading shall be 1 in 50 return periods.

4.0 Electrical Design Criteria

4.1 Code Clearances

4.1.1. Vertical and Horizontal External Clearances

4.1.1.1. Vertical Clearances

The minimum vertical ground clearance required for lowest cable is listed in C22.3 No.1 Table 2 (ground clearances), Table 3 (waterways), Table 9 (building, signs, fence, etc.) and Table 10 (bridges).

Segments of the proposed transmission lines are located at altitude between 1000 m to 1300 m above sea-level. According to C22.3 No.1 clause 5.3.1.1 (b), the required clearance shall be increased by 1% for each 100 m above of 1000 m. The designed high altitude clearance will be based on 3% increase of basic minimum clearance.

The minimum code specified clearance and recommended design values are summarized below:

Table 4.1.1 - 138kV (Maximum Voltage 145kV) Vertical Ground Clearance

Clearance Descriptions	C22.3 No.1 Min. Clearance (m)	Mean Annual Snow Depth (m)	Survey Tolerance (m)	Const. Tolerance (m)	138kV Design Clearance (m)	138kV High Altitude Clearance (m)
Ground Clearance (CSA C22.3 No.1 Table 2)						
Vehicular Clearance (Vehicle Height <4.15m)	5.5	0.6	0.3	0.3	6.7	6.9
Non-Vehicular Clearance (Pedestrian / ATV)	4.0	0.6	0.3	0.3	5.2	5.4
Railroad Crossings	8.4		0.3	0.3	9.0	9.3
Waterway Crossings (CSA C22.3 No.1 Table 3)						
Class 1 (Vessel H ≤ 4.0 m)	6.7		0.6		7.3	7.5
Class 2 (Vessel H ≤ 6.0 m)	8.7		0.6		9.3	9.6
Class 3 (Vessel H ≤ 8.0 m)	10.7		0.6		11.3	11.7
Class 4 (Vessel H ≤ 10.0 m)	12.7		0.6		13.3	13.7
Class 5 (Vessel H ≤ 12.0 m)	14.7		0.6		15.3	15.8
Class 6 (Vessel H ≤ 14.0 m)	16.7		0.6		17.3	17.8
Features (CSA C22.3 No.1 Table 9 & Table 10)						
Buildings	4.2	0.6	0.3	0.3	5.4	5.6
Signs, Fences, etc.	4.2		0.3	0.3	4.8	5.0
Bridges	3.4	0.6	0.3	0.3	4.6	4.8
Ground Clearance (AEUC 2013 Table 5)						
High Load Clearance (Vehicle Height <5.3m)	6.7	0.6	0.3	0.3	7.9	8.1

Table 4.2 - Communication Vertical Ground Clearance

Clearance Descriptions	C22.3 No.1 Min. Clearance	Mean Annual Snow Depth	Survey Tolerance	Const. Tolerance	Comm. Design Clearance
	(m)	(m)	(m)	(m)	(m)
Ground Clearance (CSA C22.3 No.1 Table 2)					
Vehicular Clearance (Vehicle Height <4.15m)	4.5	0.6	0.3	0.3	5.7
Non-Vehicular Clearance (Pedestrian / ATV)	2.5	0.6	0.3	0.3	3.7
Railroad Crossings	7.3		0.3	0.3	7.9
Waterway Crossings (CSA C22.3 No.1 Table 3)					
Class 1 (Vessel H ≤ 4.0 m)	5.0		0.6		5.6
Class 2 (Vessel H ≤ 6.0 m)	7.0		0.6		7.6
Class 3 (Vessel H ≤ 8.0 m)	9.0		0.6		9.6
Class 4 (Vessel H ≤ 10.0 m)	11.0		0.6		11.6
Class 5 (Vessel H ≤ 12.0 m)	13.0		0.6		13.6
Class 6 (Vessel H ≤ 14.0 m)	15.0		0.6		15.6
Features (CSA C22.3 No.1 Table 9 & Table 10)					
Buildings	0.1	0.6	0.3	0.3	1.3
Signs, Fences, etc.	0.1		0.3	0.3	0.7
Bridges	2.5	0.6	0.3	0.3	3.7
Ground Clearance (AEUC 2013 Table 5)					
High Load Clearance (Vehicle Height <5.3m)	5.6	0.6	0.3	0.3	6.8

The C22.3 No.1 vertical clearances between cable crossings not supported by same structure are listed in C22.3 No.1 Table 13.

In addition to C22.3 No.1 wire crossing specification, Local Distribution Companies (YEC & AEY) should be consulted at each crossing for specific requirement during the final design.

Table 4.2 - Aerial Cable Crossing Vertical Clearance

Upper Cables	69kV (m)	138kV (m)
Lower Cables		
Communication	0.9	1.2
Secondary (<750V)	0.8	1.1
Distribution (>750V & ≤34.5kV)	0.9	1.2
Sub-Transmission (>44kV & ≤69kV)	1.1	1.4
138kV to 138kV		1.5
Typical LDC Clearance (Communication to 44kV Cables)		2.5

The wire crossing of the 138kV transmission lines will be designed based on the highest specified clearance requirement.

4.1.1.2. Horizontal Clearances

The horizontal cable clearance is defined for cable under conductor Blowout Wind condition as specified in C22.3 No.1 Section 5.2.7 & A5.2.7. The horizontal clearance requirements are specified in C22.3 No.1 Table 6 (Railroad), Table 9 (building, signs, fence, etc.), Table 10 (bridges) and Table 35 (flashover for tree pruning).

Table 4.3 – 138kV Horizontal Electrical Ground Clearance

Clearance Descriptions	C22.3 No.1 Min. Clearance	Survey Tolerance	138kV Design Clearance
	(m)	(m)	(m)
Railroads (CSA C22.3 No.1 Table 6)			
Main Tracks	3.5	0.3	3.8
Sidings	2.9	0.3	3.2
Features (C22.3 No.1 Table 9, Table 10 & Table 35)			
Buildings	2.6	0.3	2.9
Signs, Fences, etc.	2.6	0.3	2.9
Bridges	2.2	0.3	2.5
Tree Pruning	0.97	0.3	1.3

The specified horizontal conductor clearances are specified for locations where vertical clearances are not achieved.

In addition to conductor electrical clearance, minimum structure clearances in proximity to adjacent features are also governed by appropriate national, provincial and local bylaws.

Table 4.4 – Structural Clearance to Adjacent Facilities

Clearance Descriptions	Min. Clearance (m)
Railroads (C22.3 No.1 Table 7)	
Railroad Tracks	
Main Tracks	2.5
Sidings	1.9
Road Clear Zone Requirement	
Edge of Road	5.0 or 6.0 depended on Road Classification

4.1.2. Electrical Clearances to Structures

Electrical clearance from energized conductors and hardware depends on maximum system voltage and switching surge ratio of the transmission system.

The minimum electrical clearances between phase conductors to supporting structure for voltage greater than 50kV phase-ground (<69kV phase-phase) are outside of the voltage range specified in C22.3 No.1. American National Electrical Safety Code (NESC – IEEE C2) shall be used to determine the electrical clearances between energized live parts and support structure components. As per NESC clause 235E1 for 138kV transmission lines, Table 235-6 shall provide the minimum clearance requirements. In addition, CSA C22.3 No. 1 Table A.1 provides flashover to ground distance based on typical switching surge factor.

Table 4.5 – 138kV Electrical Clearances to Structures

Clearance Descriptions	Minimum Clearance (m)
NESC Table 235-6 (290 Pa [6 psf] wind @ 15°C)	
Surface of Structure (joint-use)	0.76
Anchor Guys	
Inline Parallel Guys	1.59
Bisect & Offset Guys	0.96
CSA C22.3 No. Table A.1	
Switching Surge Flashover	0.97
Additional Clearance Consideration (RUS 1724E-200 Table 7-1)	
At Rest - No Wind	1.22
Extreme Hourly Wind	0.31

4.1.3. Lightning Performance and Shielding

The average structure height (ground to OPGW and OHGW) of the proposed transmission lines shall be below 92ft, the shielding angle of 30 degree, as per RUS 1724E-200 Table 8-3, was used for the determination of shieldwire and phase conductor separation.

Shielding angle of lightning protection by OPGW and OHGW shall be verified based on latest edition of IEEE Standard 1243 “Guide for Improving the Lightning Performance of Transmission Lines”. The ground flash design should either be based on historical data (when available) or IEEE Std. 1243 equation (2) or equation (3).

4.1.4. Grounding

Pole and shieldwire grounding shall be installed at every structure location. Unattached grounding system resistivity shall be 25ohms or below. Grounding study shall be performed in final design phase to estimate number of ground rod(s) at each ground connection.

4.1.5. Galloping Conductors

Conductor and shield wire separations will be assessed for ice and wind galloping under the following conditions;

Table 4.6 – Galloping Conditions

Conditions	Temperature (°C)	Horizontal Wind Loading (Pa) [psf]	Radial Ice	
			Thickness (mm)	Ice Density (kg/m ³)
Galloping Swing	-5	95.7 [2]		
Galloping Ice	-5	95.7 [2]	12.7	900

An additional separation of 0.3m shall be provided between galloping ellipses for design buffer.

4.2 Clearance Buffers

The proposed design clearance buffers has been listed in each of the clearance categories

4.3 Structure Spotting Criteria

The preferred standard design span for proposed 138kV transmission lines to be 150m to 180m based on phase separation requirement under galloping conditions and maintaining reasonable structure height during extreme ice loading conditions. The actual design spotting will be based on above consideration with right of way constraint and adjacent utilities provided in topographical survey utilizing PLS-Cadd 3D TIN terrain model.

4.4 Ampacity Rating Criteria

The phase conductor ampacity calculations are performed based on IEEE Std. 738-2013. C22.3 No.1 Section 3 “Rated ampacity” which outlines the basic ambient and cable conditions to be used for the ampacity calculation.

The ampacity calculations based on parameters outlined in Table 4.4.1 for selected phase conductor cable 266.8MCM ACSR (Partridge) and 397.5MCM ACSR (Ibis) are performed using PLS-Cadd embedded IEEE 738-2013 module. The PLS-Cadd program generated ampacity calculation outputs are given in Appendix F. The calculated continuous and limited thermal ratings for a single conductor are summarized below:

Table 4.7 – IEEE Std. 738 Ampacity Calculations

Parameters	CSA C22.3 No.1	AESO 502.2
Ambient Temperature	40°C	40°C
Case 1 – Maximum Thermal Rating (Maximum Conductor Temperature)	100°C	100°C
Case 2 – Operating Temperature 40 MW (44.5 MVA) x 1.25 OL @138 kV	240 A	240 A
Case 3 –Design Thermal Rating (Design Conductor Temperature)	75°C	75°C
Wind Speed	0.61 m/s (2 ft/s)	0.61 m/s (2 ft/s)
Wind Angle to Conductor	90°	90°
Conductor Latitude	63.6°	63.6°
Conductor Elevation (above sea level)	800m	800m
Conductor Direction (maximum solar heat)	E-W	E-W
Emissivity	0.5	0.6
Solar Absorption Coefficient	0.5	0.8

Table 4.8 – Conductor Continuous and Limited Thermal Ratings

Cable Conditions	CSA C22.3 No.1	AESO 502.2
Case 1 – Maximum Thermal Rating		
266.6 MCM 27/6 ACSR (Partridge)	484 A	475 A
397.5 MCM 27/6 ACSR (Ibis)	624 A	612 A
Case 2 – Operating Temperature		
266.6 MCM 27/6 ACSR (Partridge)	59.0°C	62.7°C
397.5 MCM 27/6 ACSR (Ibis)	54.9°C	58.9°C
Case 3 – Design Thermal Rating		
266.6 MCM 27/6 ACSR (Partridge)	361 A (62 MW @138 kV) (31 MW @69 kV)	341 A (58 MW @138 kV) (29 MW @69 kV)
397.5 MCM 27/6 ACSR (Ibis)	463 A (79 MW @138 kV) (39 MW @69 kV)	434 A (74 MW @138 kV) (37 MW @69 kV)

Based on above ampacity and conductor temperature data for the proposed 138kV transmission lines, the design conductor sag shall be based on conductor temperature of 75°C.

5.0 Structural Design Criteria

5.1 Conductor and Conductor Support Hardware

The conductor and conductor supporting hardware shall be design and selected to withstand the required loadings as per requirement outlined in this section.

5.1.1. Conductor Tension Limits

CSA C22.3 No.1-2006 and CSA C22.3 No.60826 design codes are based on maximum allowable design tensions under various loading conditions. However, the latest edition of CSA C22.3 No.1-2010 has been revised to recommended maximum initial catenary for phase conductor.

5.1.1.1. Tension Limit (% Ultimate Tensile Strength)

C22.3 No.1-2006 Table 34 and Table 35 outlined the tension limit of phase conductor and galvanized steel wire as lightning protection wires (Table 35 has not been modified in the 2010 edition).

Table 5.1 – CSA C22.3 No.1-2006 Allowable Cable Tension Limits

Loading Conditions	AAC, ACSR and Aluminum Alloys Phase Conductors	Galvanized Steel Wires
Maximum tension under appropriate loading conditions	60%	60%
Maximum recommended initial unloaded (initial) tension at mean temperature (EDT)	35%	20%
Maximum recommended final unloaded (creep) tension at mean temperature (EDT)	25%	15%

Strength factor for reliability design are listed in C22.3 No.60826 Section 7. The standard values for strength coefficient of variation is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors and equivalent tension limits are given below:

Table 5.2 – CSA C22.3 No.60826 Allowable Cable Material Factors

Conductor & Shieldwire	Cable Material Factor		Support Design Strength Factor	Combined Allowable Material Factor
	COV	Factor		
Intact Load	3%	0.962	0.80	0.77
Failure Load	3%	0.962	0.90	0.87

5.1.1.2. Maximum Initial Cable Catenary

CSA C22.3 No.1-2010 edition section 8.7.3 “Wire tension limits” has been revised to provide additional safety for fatigue damage of conductors due to aeolian vibration. C22.3 No.1 2010 Table 33 provides the recommended catenary parameter for different span lengths.

As per CSTL design requirement, the catenary parameter requirement is consistent with maximum 15% cable UTS under -50°C. These requirements did impact the structure height requirement but provide reliability where large ranges of temperature variation can occur.

5.1.1.3. Recommended Cable Design Criteria

In consideration of various governing factors for cable design criteria, the follow conditions and criteria are used for the design of conductor and OPGW / OHGW;

Table 5.4 – Recommended Cable Design Criteria

Design Conditions	Cable Condition	Conductor	OPGW / OHGW
C22.3 No.1 CSA Heavy	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Extreme Ice	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Gust Wind	Loaded	50% UTS	50% UTS
C22.3 No. 60826 Wind & Low Temp.	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Ice & Wind (High Wind)	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Ice & Wind (Low Wind)	Loaded	70% UTS	60% UTS
EDT	Initial	35% UTS	20% UTS
EDT	Creep	25% UTS	15% UTS
Catenary @ Mean Annual Min. Temp.	Initial	1500 m	1500 m
Min. Temperature (-50°C)	Creep	15% UTS	15% UTS

5.1.2. Insulators, Support Hardware and Conductor Accessories

Reliability design utilizes actual environmental loadings based on desired project return period to compare with reduced allowable material resistances.

The allowable material strength is dependent on material consistency and structure reliability requirement. Material strength factor for reliability design are listed in C22.3 No.60826 Section 7. The standard values for strength coefficient of variation is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors are summarized below;

Table 5.5 - CSA C22.3 No.60826 Cable and Hardware Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Insulators	5%	0.936	0.84	0.94	0.75	0.84
Hardware	5%	0.936	0.84	0.94	0.75	0.84

Despite C22.3 No.60826 outlines the allowable strength factors for insulator and hardware, manufacturers of insulator and hardware recommended the allowable strength for these items shall be 50% of the design tensile strength. The selection of insulators and conductor attachment hardware shall be based on manufacturer design limits, with exception of the high ice with average wind (130% Ice & 40% Wind) combination, the maximum insulator and hardware usage shall be 0.75.

5.2 Guys and Hardware

CSA C22.3 No.60826 clause 7.3.1 outlines the damage limit of steel guys and Table 18 provide material strength factor for grouted guy anchor design. The design of guy anchors shall be according to IEEE Std. 691 “IEEE Guide for Transmission Structure Foundation Design and Testing”.

5.2.1. Guy Strand & Hardware

The maximum allowable guy cable and hardware tension shall be 0.75 (75%) ultimate tensile strength as per CSA C22.3 No.60826 Table 14.

5.2.2. Guy Anchors

The maximum design loadings for commercial available guy anchor shall be according to manufacturer recommended holding capacity. The material factor for grouted rock anchor shall be as follows;

Table 5.6 - CSA C22.3 No.60826 Allowable Rock Anchor Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Grouted Rock Anchor	10%	0.872	0.78	0.87	0.70	0.78

5.3 Structures

5.3.1. Load Factors

Deterministic approach is applied for designing transmission line components to withstand factored loads (vertical, transverse and longitudinal loads) under C22.3 No.1 conditions specific to the project area (see Table 3.1). The required overload factors are specified in C22.3 No.1 Section 7.4 to 7.9 and summarized in C22.3 No.1 Table 31.

Table 5.7 – CSA C22.3 No.1 Overload Factors for Limit State Design (Deterministic Approach)

Structure Type	Grade 2 Construction			Grade 1 Construction		
	Vertical	Trans.	Long.	Vertical	Trans.	Long.
Steel Components (crossarms, davit arms, braces, etc.)						
Tangent & Running Angle	1.15	1.10	1.00	1.30	1.20	1.10
Heavy Angle & Deadend	1.15	1.10	1.10	1.30	1.20	1.20
Wood Pole						
Tangent & Running Angle	1.50	1.30	1.00	2.00	1.90	1.20
Heavy Angle & Deadend	1.50	1.30	1.30	2.00	1.90	1.90

The allowable strengths for each transmission line structural component is calculated by PLS-Pole based on input material parameters, such as geometry, material yield strengths, mechanical properties of material type.

5.3.2. Strength Reduction Factors

The allowable material strength is dependent on material consistency and structure reliability requirement. Structural material strength coefficient of variation for steel component is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors are summarized below:

Table 5.8A - CSA C22.3 No.60826 Allowable Structural Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Steel Component	5%	0.936	0.84	0.94	0.75	0.84
Wood Component	15%	0.808	0.73	0.80	0.65	0.73

5.4 Design Loads

The design load cases for the proposed 138kV transmission lines shall be based on the climatic data outlined in Section 3.

5.4.1.1. *CSA Minimum Deterministic Load Case*

The minimum design loads for the proposed transmission lines shall be CSA Heavy Condition as per Table 3.1.

5.4.1.2. *Extreme Ice Load Cases*

The maximum extreme ice loadings shall be designed for 1 in 50 years return period reference data.

5.4.1.3. *Maximum Gust Wind Load Cases*

The maximum gust wind loadings shall be designed for 1 in 50 years return period reference.

5.4.1.4. *Combined Ice and Wind Load Cases*

Both combination of ice with wind loading conditions will be evaluated according to Section 3.3.4.

5.4.1.5. *Broken Wire and Unbalanced Ice Loads*

For tangent and running angle structures, since the application of braced post insulator had limited longitudinal load capability, the unbalanced longitudinal loading conditions are not considered.

5.4.1.6. *Containment Structures*

All dead end angle structures and double dead end containment structures shall be designed to withstand complete one sided cable loadings in addition to standard configuration loadings under all climatic conditions.

5.4.1.7. *Construction and Maintenance Loads*

Construction and maintenance load requirements are specified in C22.3 No.60826 Section 6.5.

The lifting components (such as lifting vent if required) during structure erection shall have minimum safety factor of 1.5 for planned control operation.

The safety factor for cable tension shall be 2.0 during cable stringing operation with 50% of the applied tension added as longitudinal load on all running angle structures.

5.5 Structure Design

The wood pole design shall be performed using PLS-Pole wood pole structural add-on application module. The PLS-Pole model shall include wood pole, steel crossarm, steel cross braces, insulators, guy cables, etc.

Attachment loadings will be generated by PLS-Cadd line design application using Method 4 “Structure Loads” calculations. Additional longitudinal loads for maintenance and construction scenario under every day temperature will be applied manually in PLS-Pole application.

5.6 Foundation Design

Transmission pole structures in this project are direct-embedded poles and shall be designed to resist the overturning moment, shear and axial loads generated from the design of pole structures using L-Pile caisson foundation application.

5.6.1. Moment Foundations

5.6.1.1. Design Philosophy

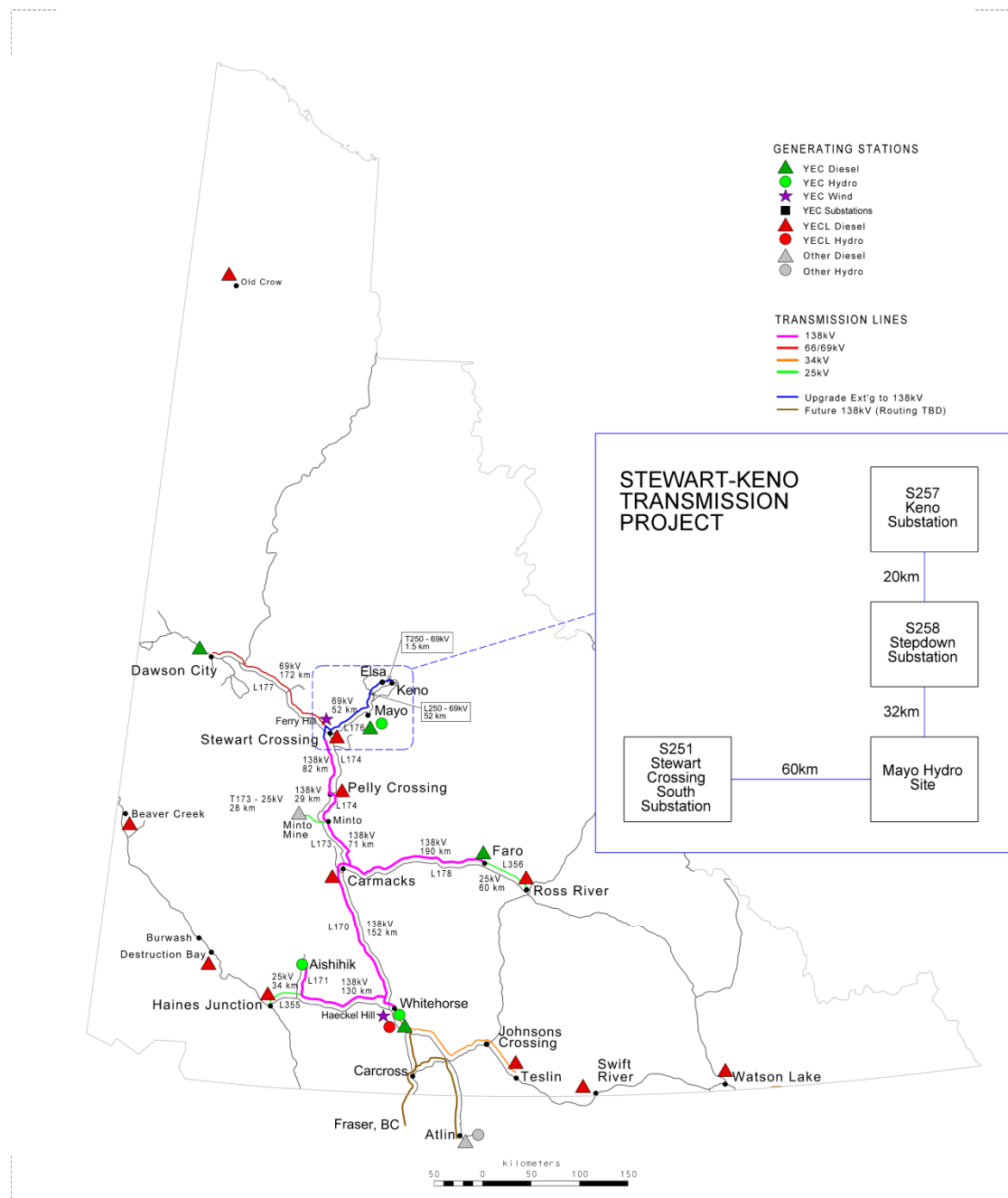
For direct-embedded method, the pole embedment length below the ground line shall be determined using an allowable lateral displacement approach. Horizontal subgrade reaction along the embedded length is determined based on borehole record information as per the geotechnical investigation report. Pole structure shall be designed to withstand the structural loading specified in other sections of this criteria document, and shall also be qualified to sustain the corresponding geotechnical loading to ensure structural integrity.

5.6.1.2. Deflection Limits

Pole recoverable deflection at ground line is limited to 25mm due to actual loading under normal weather condition, and 40mm due to actual loading under extreme weather condition. The soil input parameters for L-Pile application, such as friction angle for granular material and undrain strength for cohesive material, are deduced from site geotechnical report.

Appendix A – Site Location Plan

Appendix A - GEOGRAPHICAL MAP OF THE PROPOSED TRANSMISSION LINE



Appendix B – Code & Regulation List



Code & Regulations

Re: ***Transmission & Distribution Line Design – Code & Specifications***

This document listed the Design Code & Specifications for transmission and distribution overhead line design.

Design Specifications

- CAN/CSA C22.3 No. 1-10 “Overhead Systems”
- CAN/CSA C22.3 No. 1-06 “Overhead Systems”
- CAN/CSA C22.3 No. 60826-10 “Design Criteria for Overhead Transmission Lines”
- CAN/CSA C22.3 No. 61936-1:08 “Power Installations Exceeding 1 kV A.C.”
- IEEE Std. 738-2012 “IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors”
- National Electrical Safety Code (NESC C2-2012), 22st Edition 2012

Supplementary Specifications

- CAN/CSA C22.1-15 “Canadian Electrical Code, Part 1”
- Ontario Electrical Safety Code (OESC), 25th Edition 2012
- Alberta Electrical Utility Code (AEUC), 4th Edition 2013
- CAN/CSA M421-11 “Use of Electricity in Mines”
- CAN/CSA C22.3 No. 3-1998 “Electrical Coordination”
- CAN/CSA C22.3 No. 4-1974 “Control of Electrochemical Corrosion of Underground Metallic Structures”
- CAN/CSA C22.3 No. 5.1-93 “Recommended Practices for Electrical Protection – Electric Contact Between Overhead Supply and Communication Lines”
- CAN/CSA C22.3 No. 6-13 “Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines”
- CAN/CSA C22.3 No. 7-10 “Underground Systems”
- CAN/CSA C22.3 No. 9-08 “Interconnection of Distributed Resources and Electricity Supply Systems”
- ASCE/SEI 74-09 “Guidelines for Electrical Transmission Line Structural Loading”
- ASCE/SEI 48-11 “Design of Steel Transmission Pole Structures”
- ASCE/SEI 10-97 “Design of Latticed Steel Transmission Structures”
- IEEE Std. 524-2003 “IEEE Guide to the Installation of Overhead Transmission Line Conductors”
- IEEE Std. 691-2001 “IEEE Guide for Transmission Structure Foundation Design and Testing”
- IEEE Std. 951-1996 “IEEE Guide to the Assembly and Erection of Metal Transmission Structures”
- IEEE Std. 977-2010 “IEEE Guide to Installation of Foundations for Transmission Line Structures”
- IEEE Std. 1243-1997 “IEEE Guide for Improving the Lightning Performance of Transmission Lines”
- IEEE Std. 1441-2004 “IEEE Guide for Inspection of Overhead Transmission Line Construction”

Design Manual

- RUS Bulletin 1724E-200 “Design Manual for High Voltage Transmission Lines”
- RUS Bulletin 1724E-205 “Design Guide “Embedment Depths for Concrete and Steel Poles”
- RUS Bulletin 1724E-224 “Electric Transmission Guide Specifications and Drawings for Steel Pole Construction – 34.5 to 230 kV”
- RUS Bulletin 1724E-226 “Electric Transmission Guide Specifications and Drawings for Concrete Pole Construction – 34.5 to 230 kV”
- RUS Bulletin 1728F-810 “Electric Transmission Specifications and Drawings for 34.5 Through 69 kV”
- RUS Bulletin 1728F-811 “Electric Transmission Specifications and Drawings for 115 Through 230 kV”
- RUS Bulletin 1724E-104 “Reduced Size Neutral Conductors for Overhead Rural Distribution Lines”
- RUS Bulletin 1724E-150 “Unguyed Distribution Poles – Strength Requirements”
- RUS Bulletin 1724E-151 “Mechanical Loading on Distribution Crossarms”
- RUS Bulletin 1724E-152 “The Mechanics of Overhead Distribution Line Conductors”
- RUS Bulletin 1724E-153 “Electrical Distribution Line Guys and Anchors”
- RUS Bulletin 1724E-154 “Distribution Conductor Clearances and Span Limitations”
- RUS Bulletin 1728F-803 “Specifications and Drawings for 24.9/14.4 kV Line Construction”
- RUS Bulletin 1728F-804 “Specifications and Drawings for 12.47/7.2 kV Line Construction”
- Chance “Encyclopedia of Anchoring”
- Chance “Encyclopedia of Grounding”

Cable Specifications

- CAN/CSA G12-92 “Zinc-Coated Steel Wire Strand”
- ASTM A363-03 “Standard Specification for Zinc-Coated (Galvanized) Steel Overhead Wire Strand”
- ASTM A475-03 “Standard Specification for Zinc-Coated Steel Wire Strand”
- CAN/CSA C61089:03 “Round Wire Concentric Lay Overhead electrical Stranded Conductors”
- CAN/CSA C49.2-1975 “Compact Aluminum Conductors Steel Reinforced”
- CAN/CSA C68.3-97 “Shielded and Concentric Neutral Power Cables Rated 5 – 46 kV”

Insulator Specifications

- CAN/CSA C411.1-10 “AC Suspension Insulators”
- CAN/CSA C411.4-10 “Composite Suspension Insulators for Overhead Lines > 75 kV”
- CAN/CSA C411.5-10 “Dead-end/Suspension Composite Insulators for Overhead Lines $\leq$ 75 kV”
- CAN/CSA C411.6-11 “Line Post Composite Insulators for Overhead Distribution Lines $\leq$ 75 kV”
- CAN/CSA C411.7-11 “Composite Insulators for Guy Wires”
- IEC/TS 60815-2 “Selection and dimensioning of high-voltage insulators intended for use in polluted conditions – Part 2: Ceramic and glass insulators for a.c. systems”
- IEC/TS 60815-3 “Selection and dimensioning of high-voltage insulators intended for use in polluted conditions – Part 3: Polymer insulators for a.c. systems”
- ANSI C29.2-1992 “Wet-Process Porcelain and Toughened Glass – Suspension Type”
- ANSI C29.7-1996 “Wet-Process Porcelain Insulators – High Voltage Line-Post Type”
- ANSI C29.4-1989 “Wet-Process Porcelain Insulators – Strain Type”
- ANSI C29.9-1983 “Wet-Process Porcelain Insulators – Apparatus, Post-Type”
- ANSI C29.12-1997 “For Insulators – Composite – Suspension Type”
- ANSI C29.13-2000 “For Insulators – Composite – Distribution Deadend Type”
- ANSI C29.17-2002 “For Insulators – Composite – Line Post Type”
- ANSI C29.18-2003 “For Insulators – Composite – Distribution Line Post Type”
- RUS Bulletin 1724E-220 “Procurement and Application Guide for Non-Ceramic Composite Insulators, Voltage Class 34.5 kV and Above”

Material Specifications

- CAN/CSA O15-15 “Wood Utility Poles and Reinforcing Stubs”
- CAN/CSA O80 Series-08 “Wood Preservation”
- CAN/CSA A14-07 “Concrete Poles”
- CAN/CSA C57-98 “Electric Power Connectors for Use in Overhead Line Conductors”
- CAN/CSA C83-96 “Communication and Power Line Hardware”
- RUS Bulletin 1724E-204 “Guide Specification for Steel Single Pole and H-Frame Structures”
- RUS Bulletin 1724E-206 “Guide Specification for Spun, Prestressed Concrete Poles and Concrete Pole Structures”
- RUS Bulletin 1724E-214 “Guide Specification for Standard Class Steel Transmission Poles”
- RUS Bulletin 1724E-216 “Guide Specification for Standard Class Spun, Prestressed Concrete Transmission Poles”
- RUS Bulletin 1728F-700 “Specification for Wood Poles, Stubs and Anchor Logs”
- RUS Bulletin 1728H-701 “Specification for Wood Crossarms (Solid and Laminated), Transmission Timbers and Pole Keys”
- RUS Bulletin 1728H-702 “Specification for Quality Control and Inspection of Timber Products”
- ASTM A370-09a “Standard Test Methods and definitions for Mechanical Testing of Steel Products”
- ASTM A354-07a “Standard Specification for Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners”
- ASTM A490-09 “Standard Specification for Structural Bolts, Alloy Steel, Heat Treated, 150 ksi Minimum Tensile Strength”
- ASTM A320/A320M-08 “Standard Specification for Alloy-Steel and Stainless Steel Bolting Materials for Low Temperature Service”
- ASTM A572/A572M-07 “Standard Specification for High-Strength Low-Alloy Columbium-Vanadium Structural Steel”

Appendix C – Cables and Insulators Catalogue Information

TransPowr® ACSR Bare Overhead Conductor to CAN/CSA C61089

Aluminum Conductor Steel-Reinforced Concentric-Lay-Stranded

ACSR, ALUMINUM CONDUCTOR, STEEL-REINFORCED, CONCENTRIC-LAY-STRANDED (MECHANICAL PROPERTIES)																		
CODE WORD (1)	CONDUCTOR SIZE		STRANDING NO. X DIA. INCHES		CROSS-SECTION SQ. INCHES		O.D.		APPROX. WEIGHT LB/1000 FT (2)			PERCENT BY MASS		RATED STRENGTH		STANDARD PACKAGES (3)		
	AWG OR kcmil	mm ²	AL	STEEL	TOTAL	AL	INCHES	mm	TOTAL	AL	STEEL	AL	STEEL	LB	kN	REEL DESIG.	WT kg	LENGTH M
Turkey	6	13.3	6x0.0661	1x0.0661	0.0240	0.0206	0.198	5.04	36.1	24.5	11.6	67.90	32.10	1160	5.16	NR 30.22 COIL	268 88	4980 1646
Swan	4	21.1	6x0.0834	1x0.0834	0.0382	0.0328	0.250	6.36	57.4	38.9	18.4	67.89	32.11	1830	8.14	NR 36.22 COIL	401 100	4700 1169
Swanate	4	21.1	7x0.0772	1x0.1029	0.0411	0.0328	0.257	6.54	67.0	38.9	28.0	58.13	41.87	2300	10.2	RW 40.18 NR 30.22 COIL	544 272 109	5459 2729 1091
Sparrow	2	33.6	6x0.1052	1x0.1052	0.0608	0.0522	0.316	8.01	91.2	61.9	29.3	67.87	32.13	2800	12.5	RW 48.24 NR 36.22 NR 30.22 COIL	803 401 268 100	5910 2955 1970 735
Sparate	2	33.6	7x0.0974	1x0.1299	0.0654	0.0522	0.325	8.24	106.6	61.9	44.7	58.08	41.92	3510	15.6	RW 48.24 NR 30.22 COIL	544 272 109	3429 1714 686
Robin	1	42.4	6x0.1181	1x0.1181	0.0767	0.0657	0.354	9.00	115.0	78.1	36.9	67.88	32.12	3480	15.5	RW 48.24 NR 36.22 NR 30.22 COIL	801 401 268 100	4681 2341 1560 582
Raven	1/0	53.5	6x0.1327	1x0.1327	0.0968	0.0830	0.398	10.1	145.1	98.5	46.6	67.87	32.13	4250	18.9	RW 48.24 NR 36.22 NR 30.22 COIL	803 401 268 100	3715 1858 1237 462
Quail	2/0	67.4	6x0.1489	1x0.1489	0.1219	0.1045	0.447	11.3	182.9	124.2	58.7	67.89	32.11	5280	23.5	RW 48.24 NR 36.22 NR 30.22	803 401 268	2947 1474 981
Pigeon	3/0	85.0	6x0.1672	1x0.1672	0.1537	0.1317	0.502	12.7	230.6	156.5	74.0	67.89	32.11	6660	29.6	RW 48.24 NR 36.22 NR 30.22	801 401 268	2338 1169 780
Penguin	4/0	107.2	6x0.1878	1x0.1878	0.1939	0.1662	0.563	14.3	290.8	197.4	93.4	67.88	32.12	8400	37.4	RW 48.24 NR 36.22 NR 30.22	803 401 268	1853 927 617
Owl	266.8	135.2	6x0.2109	7x0.0703	0.2368	0.2096	0.633	16.1	341.0	249	92	73.01	26.99	9500	42.3	RM 68.38 RW 60.32 RW 48.24	2237 1118 559	4407 2204 1102
Waxwing	266.8	135.2	18x0.1217	1x0.1217	0.2210	0.2094	0.609	15.5	289.0	250	39	86.43	13.57	7000	31.1	RM 68.38 RW 66.36 RW 50.32	1882 1882 941	4377 4377 2188
Spoonbill	266.8	135.2	22x0.1101	7x0.0612	0.2300	0.2095	0.624	15.9	320.0	250	70	78.20	21.80	8800	39.1	RM 68.38 RW 60.32 RW 50.32	1275 1275 851	2668 2668 1778
Scaup	266.8	135.2	24x0.1054	7x0.0703	0.2366	0.2094	0.633	16.1	342.0	250	92	73.11	26.89	10100	44.9	RM 68.38 RW 66.36 RW 60.32	1481 1481 989	2902 2902 1935
Partridge	266.8	135.2	26x0.1013	7x0.0788	0.2437	0.2095	0.642	16.3	366.0	250	116	68.42	31.58	11300	50.3	RW 60.32	1719	3148

(1) Code words shown denote ACSR with regular-strength Class A galvanized steel core (S1A). See the Options section to find the appropriate code word modifier designation for alternative design options.

(2) Due to rounding, total values may be slightly greater or slightly less than the sum of the component values.

(3) Weights shown are for conductor only and do not include the reel. Normal length and shipping tolerances apply.

Dimensions and weights not designated minimum or maximum are nominal values and subject to manufacturing tolerances. In this context, weight means mass.

TransPowr® ACSR Bare Overhead Conductor to CAN/CSA C61089

Aluminum Conductor Steel-Reinforced Concentric-Lay-Stranded

ACSR, ALUMINUM CONDUCTOR, STEEL-REINFORCED, CONCENTRIC-LAY-STRANDED (ELECTRICAL PROPERTIES)

CODE WORD (4)	CONDUCTOR SIZE		STRANDING NO. X DIA. INCHES		CROSS-SECTION SQ. INCHES		O.D.		RESISTANCE (5) OHMS/1000 FT			AMPA CITY 75°C (6)	GEOMETRIC MEAN RADIUS FT	INDUCTIVE REACTANCE OHM/1000 FT (7)	CAPACITIVE REACTANCE MEGAOHM 1000 FT (7)
	AWG OR kcmil	mm ²	AL	STEEL	TOTAL	AL	INCHES	mm	DC @ 20°C	AC @ 25°C	AC @ 75°C				
Turkey	6	13.3	6x0.0661	1x0.0661	0.0240	0.0206	0.198	5.04	0.658	0.671	0.804	95	0.0064	0.1163	0.7512
Swan	4	21.1	6x0.0834	1x0.0834	0.0382	0.0328	0.250	6.36	0.414	0.422	0.505	125	0.0080	0.1109	0.7148
Swanate	4	21.1	7x0.0772	1x0.1029	0.0411	0.0328	0.257	6.54	0.414	0.422	0.505	125	0.0085	0.1096	0.7104
Sparrow	2	33.6	6x0.1052	1x0.1052	0.0608	0.0522	0.316	8.01	0.260	0.265	0.318	165	0.0101	0.1056	0.6785
Sparate	2	33.6	7x0.0974	1x0.1299	0.0654	0.0522	0.325	8.24	0.260	0.265	0.318	165	0.0107	0.1043	0.6741
Robin	1	42.4	6x0.1181	1x0.1181	0.0767	0.0657	0.354	9.00	0.206	0.210	0.252	190	0.0113	0.1029	0.6603
Raven	1/0	53.5	6x0.1327	1x0.1327	0.0968	0.0830	0.398	10.1	0.163	0.167	0.200	220	0.0127	0.1003	0.6421
Quail	2/0	67.4	6x0.1489	1x0.1489	0.1219	0.1045	0.447	11.3	0.130	0.132	0.158	250	0.0143	0.0976	0.6240
Pigeon	3/0	85.0	6x0.1672	1x0.1672	0.1537	0.1317	0.502	12.7	0.103	0.105	0.126	285	0.0161	0.0950	0.6059
Penguin	4/0	107.2	6x0.1878	1x0.1878	0.1939	0.1662	0.563	14.3	0.0816	0.0833	0.100	325	0.0180	0.0923	0.5877
Owl	266.8	135.1876	6x0.2109	7x0.0703	0.2368	0.2096	0.633	16.1	0.0647	0.0661	0.0791	385	0.0202	0.0896	0.5695
Waxwing	266.8	135.2	18x0.1217	1x0.1217	0.2210	0.2094	0.609	15.5	0.0649	0.0664	0.0794	410	0.0197	0.0903	0.5756
Spoonbill	266.8	135.2	22x0.1101	7x0.0612	0.2300	0.2095	0.624	15.9	0.0650	0.0664	0.0795	410	0.0207	0.0891	0.5717
Scaup	266.8	135.2	24x0.1054	7x0.0703	0.2366	0.2094	0.633	16.1	0.0650	0.0664	0.0795	415	0.0212	0.0886	0.5695
Partridge	266.8	135.2	26x0.1013	7x0.0788	0.2437	0.2095	0.642	16.3	0.0651	0.0665	0.0796	415	0.0217	0.0880	0.5673

(4) Code words shown denote ACSR with regular-strength Class A galvanized steel core (S1A). See the Options section to find the appropriate code word modifier designation for alternative design options.

(5) Based on a conductivity of 61.0% IACS at 20°C for aluminum and ignores the effects of the steel core. To convert to ohms/mile, multiply by 5.28. To convert to ohms/km, multiply by 3.281.

(6) Based on a conductor temperature of 75°C at 60 Hz and the following conditions: 32°C ambient temperature, 1.98 ft/sec (0.6 m/s) crosswind (90° to conductor), 0.5 coefficient of emissivity, 0.5 coefficient of absorptivity, 42° northern latitude, sea level elevation, 90° azimuth of line (East-West), clear atmosphere, and a date and time of noon on July 1 (resulting in 95.0 W/ft² of solar and sky radiated heat). Actual ampacity will differ based on local conditions. For specific ampacities, please contact your General Cable sales representative.

(7) Values for inductive reactance and capacitive reactance are expressed in terms of a 1 ft radius (30.48 cm). To convert the Geometric Mean Radius (GMR) to cm, divide the value by 0.03821. To convert inductive reactance to ohm/km, multiply the value by 3.281. To convert capacitive reactance to ohm/km, divide the value by 3.281.

TransPowr® ACSR Bare Overhead Conductor to CAN/CSA C61089

Aluminum Conductor Steel-Reinforced Concentric-Lay-Stranded

ACSR, ALUMINUM CONDUCTOR, STEEL-REINFORCED, CONCENTRIC-LAY-STRANDED (MECHANICAL PROPERTIES)																		
CODE WORD (1)	CONDUCTOR SIZE		STRANDING NO. X DIA. INCHES		CROSS-SECTION SQ. INCHES		O.D.		APPROX. WEIGHT LB/1000 FT (2)			PERCENT BY MASS		RATED STRENGTH		STANDARD PACKAGES (3)		
	AWG OR kcmil	mm ²	AL	STEEL	TOTAL	AL	INCHES	mm	TOTAL	AL	STEEL	AL	STEEL	LB	kN	REEL DESIG.	WT kg	LENGTH M
Junco	266.8	135.2	30x0.0943	7x0.0943	0.2584	0.2095	0.660	16.8	416.0	250	166	60.20	39.80	13700	60.9	RM 68.38 RW 66.36	2254 2254	3624 3624
Phoebe	300.0	152.0	18x0.1291	1x0.1291	0.2487	0.2356	0.646	16.4	325.0	281	44	86.41	13.59	7900	35.1	RM 66.36 RW 60.32	1887 943	3901 1951
Piper	300.0	152.0	30x0.1000	7x0.1000	0.2906	0.2356	0.700	17.8	468.0	282	186	60.20	39.80	15200	67.6	RMT 84.36 RW 60.32	3392 1696	4870 2435
Ostrich	300.0	152.0	26x0.1074	7x0.0835	0.2739	0.2355	0.680	17.3	411.0	282	130	68.45	31.55	12700	56.5	RW 60.32	1717	2801
Merlin	336.4	170.5	18x0.1367	1x0.1367	0.2789	0.2642	0.684	17.4	364.0	315	49	86.42	13.58	8900	39.6	RM 68.38 RW 66.36 RW 50.32	1885 1885 943	3472 3472 1736
Woodcock	336.4	170.5	22x0.1237	7x0.0687	0.2903	0.2644	0.701	17.8	403.0	315	88	78.21	21.79	10900	48.5	RMT 84.36 RW 60.32	2549 1275	4230 2115
Widgeon	336.4	170.5	24x0.1184	7x0.0789	0.2985	0.2642	0.710	18.0	431.0	315	116	73.13	26.87	12300	54.7	RMT 84.36 RW 60.32	2971 1486	4611 2306
Linnet	336.4	170.5	26x0.1137	7x0.0884	0.3072	0.2643	0.720	18.3	461.0	316	145	68.46	31.54	14000	62.3	RMT 84.36 RW 60.32	3438 1717	4995 2498
Oriole	336.4	170.5	30x0.1059	7x0.1059	0.3259	0.2642	0.741	18.8	525.0	316	209	60.20	39.80	17100	76.1	RMT 84.36 RM 60.32	3383 1692	4319 2159
Chickadee	397.5	201.4	18x0.1486	1x0.1486	0.3295	0.3122	0.743	18.9	431.0	372	58	86.42	13.58	10200	45.4	RM 68.38 RW 66.36 RW 50.32	1882 1882 941	2935 2935 1468
Stork	397.5	201.4	22x0.1344	7x0.0747	0.3428	0.3121	0.762	19.3	477.0	373	104	78.20	21.80	12900	57.4	RMT 84.36 RW 60.32	2542 1272	3575 1788
Brant	397.5	201.4	24x0.1287	7x0.0858	0.3527	0.3122	0.772	19.6	510.0	373	137	73.11	26.89	14600	64.9	RMT 84.36 RW 60.32	2964 1483	3898 1949
Ibis	397.5	201.4	26x0.1236	7x0.0961	0.3630	0.3123	0.783	19.9	545.0	373	172	68.46	31.54	16100	71.6	RMT 84.36 RW 60.32	3436 1717	4227 2114
Lark	397.5	201.4	30x0.1151	7x0.1151	0.3850	0.3121	0.806	20.5	620.0	373	247	60.21	39.79	20000	89.0	RM 68.38 RW 66.36	2252 2252	2432 2432
Pelican	477.0	241.7	18x0.1628	1x0.1628	0.3955	0.3747	0.814	20.7	517.0	447	70	86.42	13.58	12300	54.7	RM 68.38 RW 66.36 RW 50.32	1882 1882 941	2447 2447 1224
Toucan	477.0	241.7	22x0.1472	7x0.0818	0.4112	0.3744	0.834	21.2	572.0	447	125	78.21	21.79	15500	68.9	RMT 84.36 RW 60.32	2549 1275	2984 1492
Flicker	477.0	241.7	24x0.1410	7x0.0940	0.4233	0.3747	0.846	21.5	612.0	447	165	73.11	26.89	17300	77.0	RMT 84.36 RW 60.32	2964 1481	3249 1625
Hawk	477.0	241.7	26x0.1354	7x0.1053	0.4357	0.3747	0.858	21.8	654.0	448	206	68.45	31.55	19300	85.8	RMT 84.36 RW 60.32	3429 1715	3523 1762
Hen	477.0	241.7	30x0.1261	7x0.1261	0.4621	0.3747	0.883	22.4	744.0	448	296	60.20	39.80	23200	103	RM 68.38 RW 66.36	2250 2250	2027 2027
Heron	500.0	253.4	30x0.1291	7x0.1291	0.4843	0.3927	0.904	23.0	780.0	469	310	60.20	39.80	24300	108.1	RM 68.38	2250	1934
Osprey	556.5	282.0	18x0.1758	1x0.1758	0.4612	0.4369	0.879	22.3	603.0	521	82	86.43	13.57	14300	63.6	RM 68.38 RW 66.36 RW 50.32	1885 1885 941	2100 2100 1050

(1) Code words shown denote ACSR with regular-strength Class A galvanized steel core (S1A). See the Options section to find the appropriate code word modifier designation for alternative design options.

(2) Due to rounding, total values may be slightly greater or slightly less than the sum of the component values.

(3) Weights shown are for conductor only and do not include the reel. Normal length and shipping tolerances apply.

Dimensions and weights not designated minimum or maximum are nominal values and subject to manufacturing tolerances. In this context, weight means mass.

TransPowr® ACSR Bare Overhead Conductor to CAN/CSA C61089

Aluminum Conductor Steel-Reinforced Concentric-Lay-Stranded

ACSR, ALUMINUM CONDUCTOR, STEEL-REINFORCED, CONCENTRIC-LAY-STRANDED (ELECTRICAL PROPERTIES)

CODE WORD (4)	CONDUCTOR SIZE		STRANDING NO. X DIA. INCHES		CROSS-SECTION SQ. INCHES		O.D.		RESISTANCE (5) OHMS/1000 FT			AMPA CITY 75°C (6)	GEOMETRIC MEAN RADIUS FT	INDUCTIVE REACTANCE OHM/1000 FT (7)	CAPACITIVE REACTANCE MEGAOHM 1000 FT (7)
	AWG OR kcmil	mm ²	AL	STEEL	TOTAL	AL	INCHES	mm	DC @ 20°C	AC @ 25°C	AC @ 75°C				
Junco	266.8	135.2	30x0.0943	7x0.0943	0.2584	0.2095	0.660	16.8	0.0651	0.0665	0.0796	415	0.0227	0.0870	0.5629
Phoebe	300.0	152.0	18x0.1291	1x0.1291	0.2487	0.2356	0.646	16.4	0.0577	0.0591	0.0707	440	0.0209	0.0889	0.5664
Piper	300.0	152.0	30x0.1000	7x0.1000	0.2906	0.2356	0.700	17.8	0.0579	0.0591	0.0708	450	0.0241	0.0856	0.5537
Ostrich	300.0	152.0	26x0.1074	7x0.0835	0.2739	0.2355	0.680	17.3	0.0579	0.0592	0.0708	445	0.0230	0.0867	0.5582
Merlin	336.4	170.5	18x0.1367	1x0.1367	0.2789	0.2642	0.684	17.4	0.0515	0.0527	0.0631	475	0.0221	0.0876	0.5574
Woodcock	336.4	170.5	22x0.1237	7x0.0687	0.2903	0.2644	0.701	17.8	0.0516	0.0527	0.0631	475	0.0232	0.0865	0.5535
Widgeon	336.4	170.5	24x0.1184	7x0.0789	0.2985	0.2642	0.710	18.0	0.0516	0.0527	0.0631	475	0.0238	0.0859	0.5514
Linnet	336.4	170.5	26x0.1137	7x0.0884	0.3072	0.2643	0.720	18.3	0.0516	0.0528	0.0632	480	0.0244	0.0854	0.5492
Oriole	336.4	170.5	30x0.1059	7x0.1059	0.3259	0.2642	0.741	18.8	0.0516	0.0528	0.0632	480	0.0255	0.0843	0.5447
Chickadee	397.5	201.4	18x0.1486	1x0.1486	0.3295	0.3122	0.743	18.9	0.0436	0.0447	0.0534	525	0.0240	0.0857	0.5443
Stork	397.5	201.4	22x0.1344	7x0.0747	0.3428	0.3121	0.762	19.3	0.0436	0.0447	0.0535	530	0.0252	0.0846	0.5404
Brant	397.5	201.4	24x0.1287	7x0.0858	0.3527	0.3122	0.772	19.6	0.0436	0.0447	0.0534	530	0.0259	0.0840	0.5383
Ibis	397.5	201.4	26x0.1236	7x0.0961	0.3630	0.3123	0.783	19.9	0.0437	0.0447	0.0535	530	0.0265	0.0835	0.5361
Lark	397.5	201.4	30x0.1151	7x0.1151	0.3850	0.3121	0.806	20.5	0.0437	0.0447	0.0535	535	0.0277	0.0824	0.5316
Pelican	477.0	241.7	18x0.1628	1x0.1628	0.3955	0.3747	0.814	20.7	0.0363	0.0373	0.0446	590	0.0263	0.0836	0.5301
Toucan	477.0	241.7	22x0.1472	7x0.0818	0.4112	0.3744	0.834	21.2	0.0364	0.0373	0.0446	590	0.0276	0.0825	0.5262
Flicker	477.0	241.7	24x0.1410	7x0.0940	0.4233	0.3747	0.846	21.5	0.0364	0.0373	0.0446	595	0.0283	0.0819	0.5240
Hawk	477.0	241.7	26x0.1354	7x0.1053	0.4357	0.3747	0.858	21.8	0.0364	0.0373	0.0446	595	0.0290	0.0814	0.5218
Hen	477.0	241.7	30x0.1261	7x0.1261	0.4621	0.3747	0.883	22.4	0.0364	0.0373	0.0446	600	0.0304	0.0803	0.5174
Heron	500.0	253.4	30x0.1291	7x0.1291	0.4843	0.3927	0.904	23.0	0.0347	0.0356	0.0425	620	0.0311	0.0797	0.5137
Osprey	556.5	282.0	18x0.1758	1x0.1758	0.4612	0.4369	0.879	22.3	0.0311	0.0320	0.0383	645	0.0284	0.0818	0.5180

(4) Code words shown denote ACSR with regular-strength Class A galvanized steel core (S1A). See the Options section to find the appropriate code word modifier designation for alternative design options.

(5) Based on a conductivity of 61.0% IACS at 20°C for aluminum and ignores the effects of the steel core. To convert to ohms/mile, multiply by 5.28. To convert to ohms/km, multiply by 3.281.

(6) Based on a conductor temperature of 75°C at 60 Hz and the following conditions: 32°C ambient temperature, 1.98 ft/sec (0.6 m/s) crosswind (90° to conductor), 0.5 coefficient of emissivity, 0.5 coefficient of absorptivity, 42° northern latitude, sea level elevation, 90° azimuth of line (East-West), clear atmosphere, and a date and time of noon on July 1 (resulting in 95.0 W/ft² of solar and sky radiated heat). Actual ampacity will differ based on local conditions. For specific ampacities, please contact your General Cable sales representative.

(7) Values for inductive reactance and capacitive reactance are expressed in terms of a 1 ft radius (30.48 cm). To convert the Geometric Mean Radius (GMR) to cm, divide the value by 0.03821. To convert inductive reactance to ohm/km, multiply the value by 3.281. To convert capacitive reactance to ohm/km, divide the value by 3.281.

OPGW Design

Ref: SFPOC/SFSJ-J-10783

Cable: 36/48 SMF OPGW

Key Design Data – Complete Cable:

Nominal Cross Sectional area	mm ²	91
Center-Stainless Steel Tube –No./Dia.	mm	1/3.4
Center-Aluminum tube–No./Dia.	mm	1/6.2
L1- Aluminum Clad Steel Wires –No./Dia.(20%)	mm	3/3.2
L1- Aluminum Clad Steel Wires –No./Dia.(27%)	mm	6/3.2
Lay Direction-Outer Layer		LEFT HAND

General Design Data (For Information Only)

Overall Diameter	mm	12.60±1%
Ultimate Conductor Tensile Strength	kgf	8371
Max. Working Tension	%	60
Approximate Total Mass	kg/km	517
Electrical Resistance at 20°C	Ω/km	0.5935
Modulus of Elasticity	N/mm ²	130,154
Coefficient of Linear Expansion	×10 ⁻⁶ /°C	14.2
Short Circuit Current Capacity(Ambient=40°C)	kA ² S	63.0
Minimum bending diameter	mm	1000
Operating temperature range	°C	-40~+85

Optical Data

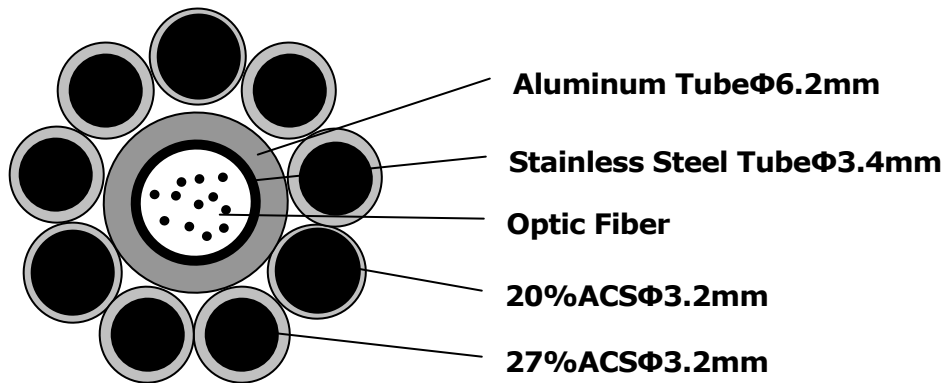
Optical Fibre Type	-	Single Mode G.652D
Fiber Manufacturer	-	OFS
Mode Field Diameter-1310nm	μm	9.2±0.4
Mode Field Diameter-1550nm	μm	10.4±0.5
Cladding Diameter	μm	125.0±0.7
Core-Clad Concentricity	μm	≤ 0.5
Cladding Non-Circularity	%	≤ 1.0
Coating Diameter	μm	235-245
Coating-Cladding Concentricity	μm	<12
Attenuation Coefficient-1310nm	dB/km	≤0.35
Attenuation Coefficient-1550nm	dB/km	≤0.22
Cable Cut-Off Wavelength	nm	≤1260
Zero Dispersion Wavelength	nm	1302-1322

OPGW Design

Ref: SFPOC/SFSJ-J-10783

Cable: 36/48 SMF OPGW

OPGW Cross section Drawing



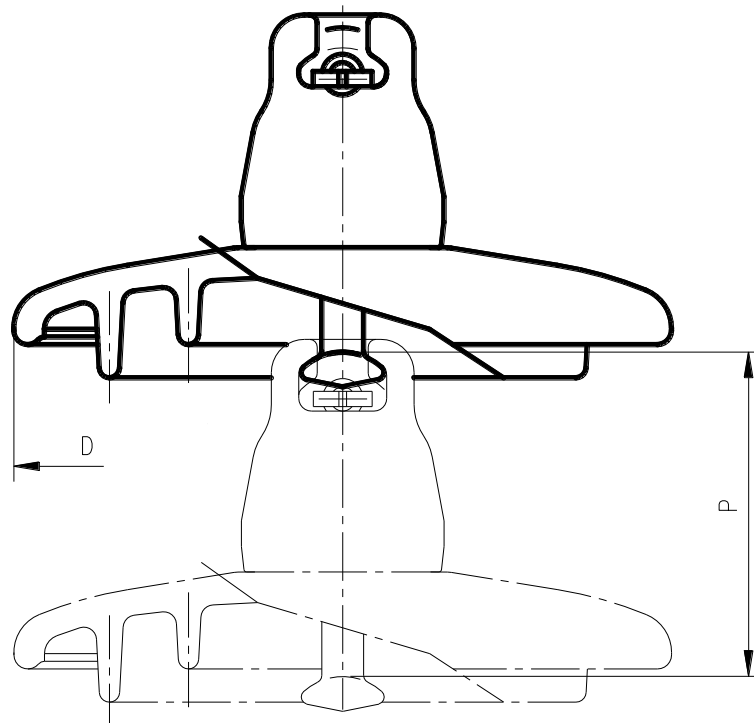
Color Coding:

Fiber 1 to Fiber 12: Blue, Orange Green, Brown, Slate, White, Red, Natural, Yellow, Violet, Rose, Aqua.

Fiber 13 to Fiber 24: same base color but with one black ring mark at regular intervals.

Fiber 25 to Fiber 36: same base color but with two black ring marks at regular intervals.

Fiber 37 to Fiber 48: same base color but with three black ring marks at regular intervals.



DIMENSIONS

Diameter of shell (D)
Spacing (P)
Creepage distance
Coupling according to CSA-C411.1 & ANSI C29-2
Approximate net weight

10 in 255 mm
5 3/4 in 146 mm
12 5/8 in 320 mm
Type:CS-3 & Class: 52.3 Type:B
8.8 lbs 4 kg

Tested as per CSA-C411.1 & ANSI C29.2

ELECTRICAL PERFORMANCES

Low frequency
Dry flashover voltage 80 kV
Wet flashover voltage 50 kV
Critical impulse flashover voltage
Positive 125 kV
Negative 130 kV
Low frequency puncture voltage 130 kV
Radio interference test voltage rms 10 kV
Maxi radio interference - 1 MHz 50 μV

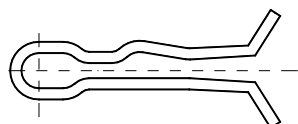
MECHANICAL PERFORMANCES

Combined mechanical and electrical strength 15000 lbs 70 kN
Tension proof 7500 lbs 35 kN
Mechanical impact strength 400 in.lbs 45 N.m

According to CSA-C411.1 & ANSI C29.2

COMPONENT PARTS

Dielectric shell : TOUGHENED GLASS
Cap : HOT DIP GALVANIZED CAST IRON
Pin : HOT DIP GALVANIZED FORGED STEEL
Cotter key : STAINLESS STEEL
Cement : ALUMINOUS, hot cured



SEDIVER®

Registered trade mark

INSULATOR TYPE

N 70/146

Date

2012-11-20

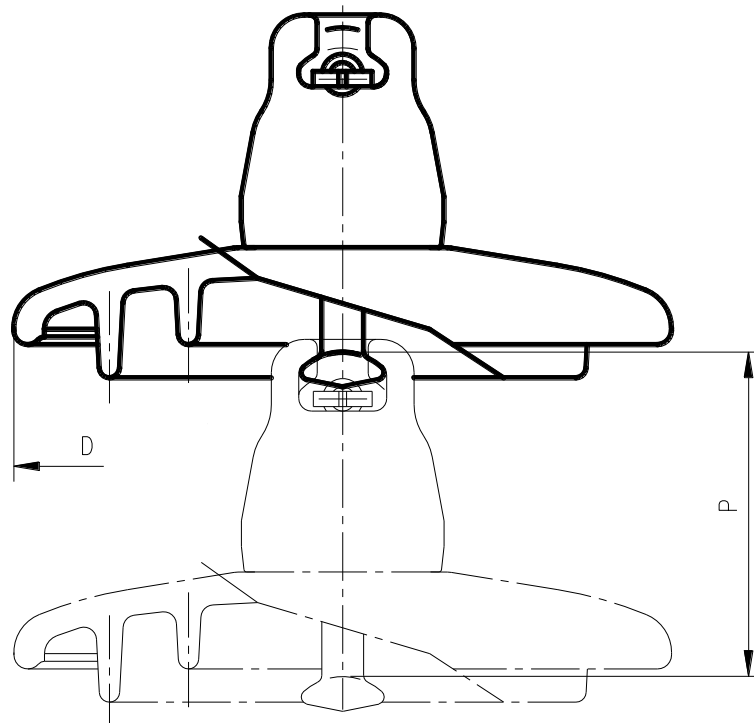
Approved

SEVES Spa

Via R. Giuliani 360 50141 Firenze Italy

Drawing no ENG 4975A1D9

issue : -



DIMENSIONS

Diameter of shell (D)
Spacing (P)
Creepage distance
Coupling according to CSA-C411.1 & ANSI C29-2
Approximate net weight

10 in 255 mm
5 3/4 in 146 mm
12 5/8 in 320 mm
Type:CS-5 & Class:52.5 Type:J
8.8 lbs 4 kg

Tested as per CSA-C411.1 & ANSI C29.2

ELECTRICAL PERFORMANCES

Low frequency
Dry flashover voltage 80 kV
Wet flashover voltage 50 kV
Critical impulse flashover voltage
Positive 125 kV
Negative 130 kV
Low frequency puncture voltage 130 kV
Radio interference test voltage rms 10 kV
Maxi radio interference - 1 MHz 50 µV

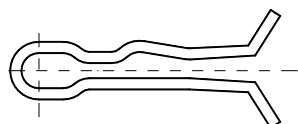
MECHANICAL PERFORMANCES

Combined mechanical and electrical strength 25000 lbs 120 kN
Tension proof 12500 lbs 60 kN
Mechanical impact strength 400 in.lbs 45 N.m

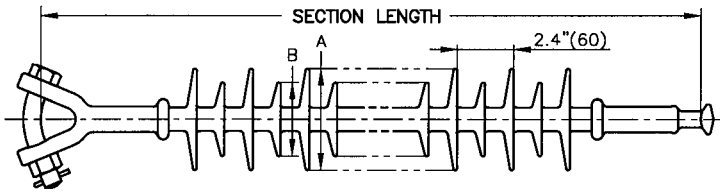
According to CSA-C411.1 & ANSI C29.2

COMPONENT PARTS

Dielectric shell : TOUGHENED GLASS
Cap : HOT DIP GALVANIZED CAST IRON
Pin : HOT DIP GALVANIZED FORGED STEEL
Cotter key : STAINLESS STEEL
Cement : ALUMINOUS, hot cured



INSULATOR TYPE		Date	
		2012-11-20	
SEVES Spa Via R. Giuliani 360 50141 Firenze Italy		Approved	
		Drawing no ENG 4975A241 issue : -	



Shed Type	Shed Diameter	
	A	B
"SC" Normal	ø3.0" (ø76mm)	ø3.0" (ø76mm)
"SS" Alternating	ø4.2" (ø106mm)	ø3.0" (ø76mm)
"SL" Alternating	ø5.2" (ø132mm)	ø4.0" (ø102mm)

Typical System Voltage (kV)	Catalog No.	No. of Sheds	Section Length			Leakage Distance (inch (mm))	Arcing Distance (inch (mm))	Low Frequency Flashover		Critical Impulse Flashover		Approx. Weight (lbs. (kg))
			YJ (inch (mm))	SJ (inch (mm))	EJ (inch (mm))			Dry kV	Wet kV	Positive kV	Negative kV	
69	251-SC210-YJ	21	36.0 (915)	35.4 (900)	36.4 (925)	58.7 (1491)	26.5 (674)	305	270	450	480	7.1 (3.2)
	251-SS210-YJ					71.5 (1816)	27.1 (688)	310	275	460	490	8.1 (3.7)
	251-SL210-YJ					92.8 (2356)	27.9 (708)	320	280	470	505	10.1 (4.6)
69	251-SC250-YJ	25	40.7 (1035)	40.2 (1020)	41.1 (1045)	69.9 (1775)	31.2 (794)	350	310	525	560	7.6 (3.5)
	251-SS250-YJ					85.0 (2159)	31.8 (808)	355	310	535	565	8.9 (4.0)
	251-SL250-YJ					110.3 (2802)	32.6 (828)	360	320	545	580	11.3 (5.1)
69/115	251-SC280-YJ	28	44.3 (1125)	43.7 (1110)	44.7 (1135)	78.3 (1988)	34.8 (884)	380	340	580	615	8.1 (3.7)
	251-SS280-YJ					94.5 (2401)	35.1 (892)	385	340	585	620	9.4 (4.3)
	251-SL280-YJ					122.9 (3122)	35.8 (909)	390	345	595	630	12.1 (5.5)
69/115	251-SC310-YJ	31	47.8 (1215)	47.2 (1200)	48.1 (1225)	86.7 (2201)	38.3 (974)	415	365	635	675	8.5 (3.9)
	251-SS310-YJ					105.2 (2673)	38.9 (988)	420	370	645	680	10.1 (4.6)
	251-SL310-YJ					136.7 (3471)	39.7 (1008)	430	380	655	695	13.0 (5.9)
115/138	251-SC350-YJ	35	52.6 (1335)	52.0 (1320)	53.0 (1345)	97.8 (2485)	43.1 (1094)	460	405	705	750	9.1 (4.1)
	251-SS350-YJ					118.7 (3016)	43.6 (1108)	465	410	715	760	10.8 (4.9)
	251-SL350-YJ					154.2 (3917)	44.4 (1128)	470	420	730	770	14.2 (6.4)
138	251-SC390-YJ	39	57.3 (1455)	56.7 (1440)	57.7 (1465)	109.0 (2769)	47.8 (1214)	505	445	780	825	9.6 (4.4)
	251-SS390-YJ					132.2 (3359)	48.4 (1228)	510	450	790	835	11.6 (5.3)
	251-SL390-YJ					171.8 (4363)	49.1 (1248)	515	460	800	850	15.3 (6.9)
138	251-SC410-YJ	41	59.6 (1515)	59.1 (1500)	60.0 (1525)	114.6 (2911)	50.2 (1274)	525	465	815	865	9.9 (4.5)
	251-SS410-YJ					139.0 (3531)	50.7 (1288)	530	470	825	875	11.9 (5.4)
	251-SL410-YJ					180.6 (4586)	51.5 (1308)	540	480	840	885	15.9 (7.2)
138/161	251-SC450-YJ	45	64.4 (1635)	63.8 (1620)	64.8 (1645)	125.8 (3195)	54.9 (1394)	570	505	890	940	10.5 (4.8)
	251-SS450-YJ					152.5 (3874)	55.4 (1408)	575	510	900	950	12.7 (5.8)
	251-SL450-YJ					198.1 (5032)	56.2 (1428)	580	520	910	965	17.0 (7.7)
161	251-SC500-YJ	50	70.3 (1785)	69.7 (1770)	70.7 (1795)	139.8 (3550)	60.8 (1544)	625	555	980	1040	11.2 (5.1)
	251-SS500-YJ					168.8 (4288)	61.1 (1552)	625	560	985	1045	13.6 (6.2)
	251-SL500-YJ					219.5 (5575)	61.8 (1569)	635	565	995	1055	18.4 (8.3)
161	251-SC550-YJ	55	76.2 (1935)	75.6 (1920)	76.8 (1950)	153.7 (3905)	66.7 (1695)	680	605	1075	1135	11.9 (5.4)
	251-SS550-YJ					186.3 (4731)	67.3 (1709)	685	610	1080	1145	14.6 (6.6)
	251-SL550-YJ					242.0 (6147)	68.1 (1729)	690	615	1095	1155	19.9 (9.0)

25kip Other End Fitting Combination Section Length Adjustment Table, Base Coupling: Eye-Ball (EJ), Inch						Yukon Energy Corporation
Eye/Eye (EE)	+1.4	Clevis/Eye (CE)	+0.4	Clevis/Clevis (CC)	0	
Clevis/Ball (CJ)	-1.0	Y-Clevis/Y-Clevis (YY)	+0.5	Y-Clevis/Ball (YB)	0	
Y-Clevis/Eye (YE)	+0.9	Y-Clevis/Socket (YS)	-0.1	Clevis/Tongue (CT)	0	

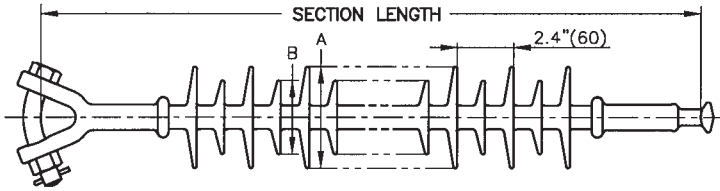
Typical System Voltage (kV)	Catalog No.	No. of Sheds	Section Length			Leakage Distance inch (mm)	Arcing Distance inch (mm)	Low Frequency Flashover		Critical Impulse Flashover		Approx. Weight lbs. (kg)
			YJ inch (mm)	SJ inch (mm)	EJ inch (mm)			Dry kV	Wet kV	Positive kV	Negative kV	
161/230	251-SC590-YJ	59	80.9 (2055)	80.3 (2040)	81.5 (2070)	164.9 (4189)	71.4 (1815)	725	645	1145	1210	12.5 (5.7)
	251-SS590-YJ					199.8 (5074)	72.0 (1829)	730	650	1155	1220	15.4 (7.0)
	251-SL590-YJ					259.6 (6593)	72.8 (1849)	735	655	1170	1235	21.0 (9.5)
230	251-SC640-YJ	64	86.8 (2205)	86.2 (2190)	87.4 (2220)	178.9 (4544)	77.4 (1965)	780	695	1240	1310	13.2 (6.0)
	251-SS640-YJ					216.1 (5488)	77.7 (1973)	780	700	1245	1315	16.3 (7.4)
	251-SL640-YJ					280.9 (7136)	78.3 (1990)	785	705	1255	1325	22.4 (10.2)
230	251-SC690-YJ	69	92.7 (2355)	92.1 (2340)	93.3 (2370)	192.9 (4899)	83.3 (2115)	835	745	1330	1405	13.9 (6.3)
	251-SS690-YJ					233.5 (5932)	83.8 (2129)	840	750	1340	1415	17.3 (7.9)
	251-SL690-YJ					303.5 (7708)	84.6 (2149)	845	755	1350	1425	23.9 (10.8)
230/345	251-SC740-YJ	74	98.6 (2505)	98.0 (2490)	99.2 (2520)	206.9 (5254)	89.2 (2265)	890	795	1420	1500	14.6 (6.6)
	251-SS740-YJ					249.8 (6346)	89.5 (2273)	890	795	1425	1505	18.2 (8.3)
	251-SL740-YJ					324.8 (8251)	90.2 (2290)	895	805	1435	1515	25.3 (11.5)
230/345	251-SC780-YJ	78	103.3 (2625)	102.8 (2610)	103.9 (2640)	218.0 (5538)	93.9 (2385)	930	835	1495	1575	15.2 (6.9)
	251-SS780-YJ					263.3 (6689)	94.2 (2393)	935	835	1500	1580	19.0 (8.6)
	251-SL780-YJ					342.4 (8697)	94.9 (2410)	940	845	1510	1595	26.4 (12.0)
345	251-SC810-YJ	81	106.9 (2715)	106.3 (2700)	107.5 (2730)	226.4 (5751)	97.5 (2475)	965	865	1550	1635	15.6 (7.1)
	251-SS810-YJ					274.0 (6961)	98.0 (2489)	970	870	1560	1645	19.6 (8.9)
	251-SL810-YJ					356.1 (9046)	98.8 (2509)	975	875	1570	1655	27.3 (12.4)
345	251-SC860-YJ	86	112.8 (2865)	112.2 (2850)	113.4 (2880)	240.4 (6106)	103.4 (2626)	1010	905	1640	1730	16.4 (7.4)
	251-SS860-YJ					290.3 (7375)	103.7 (2634)	1010	905	1645	1735	20.5 (9.3)
	251-SL860-YJ					377.5 (9589)	104.4 (2651)	1015	910	1655	1745	28.7 (13.0)
345	251-SC910-YJ	91	118.7 (3015)	118.3 (3005)	119.3 (3030)	254.4 (6461)	109.3 (2776)	1050	940	1735	1825	17.1 (7.7)
	251-SS910-YJ					307.8 (7818)	109.8 (2790)	1050	940	1740	1835	21.5 (9.8)
	251-SL910-YJ					400.0 (10161)	110.6 (2810)	1055	945	1755	1850	30.2 (13.7)
345	251-SC1000-YJ	100	129.3 (3285)	128.9 (3275)	129.9 (3300)	279.5 (7100)	119.9 (3046)	1115	1000	1900	2000	18.4 (8.3)
	251-SS1000-YJ					337.6 (8575)	120.2 (3054)	1115	1000	1905	2005	23.2 (10.5)
	251-SL1000-YJ					439.0 (11150)	120.9 (3071)	1120	1005	1915	2015	32.7 (14.8)
345/500	251-SC1090-YJ	109	140.0 (3555)	139.6 (3545)	140.6 (3570)	304.7 (7739)	130.6 (3316)	1180	1055	2065	2170	19.6 (8.9)
	251-SS1090-YJ					368.6 (9362)	131.1 (3330)	1185	1060	2070	2180	24.9 (11.3)
	251-SL1090-YJ					479.1 (12168)	131.9 (3350)	1185	1065	2085	2195	35.3 (16.0)

Approx. Weight is for Y-clevis & Ball unless otherwise specified.

Test methods and criteria are in accordance with ANSI C29.11 and ANSI C29.12.

All tables show the typical products. Please contact NLPI for other dimensions and end fitting combinations.

Electrical values exceeding the capacity (AC FOV>1200kV, L.I. FOV>3000kV) are presumed by the extrapolation of values obtained from short string unit.



Shed Type	Shed Diameter	
	A	B
"SC" Normal	ø3.0 (ø76mm)	ø3.0 (ø76mm)
"SS" Alternating	ø4.2 (ø106mm)	ø3.0 (ø76mm)
"SL" Alternating	ø5.2" (ø132mm)	ø4.0 (ø102mm)

Typical System Voltage (kV)	Catalog No.	No. of Sheds	Section Length			Leakage Distance (inch (mm))	Arcing Distance (inch (mm))	Low Frequency Flashover		Critical Impulse Flashover		Approx. Weight (lbs. (kg))
			YJ (inch (mm))	SJ (inch (mm))	EJ (inch (mm))			Dry kV	Wet kV	Positive kV	Negative kV	
69	301-SC210-YJ	21				58.7 (1491)	26.5 (674)	305	270	450	480	7.7 (3.5)
	301-SS210-YJ		37.8 (960)	36.8 (935)	38.0 (965)	71.5 (1816)	27.1 (688)	310	275	460	490	8.8 (4.0)
	301-SL210-YJ					92.8 (2356)	27.9 (708)	320	280	470	505	10.8 (4.9)
69	301-SC250-YJ	25				69.9 (1775)	31.2 (794)	350	310	525	560	8.3 (3.8)
	301-SS250-YJ		42.5 (1080)	41.5 (1055)	42.7 (1085)	85.0 (2159)	31.8 (808)	355	310	535	565	9.7 (4.4)
	301-SL250-YJ					110.3 (2802)	32.6 (828)	360	320	545	580	11.9 (5.4)
69/115	301-SC280-YJ	28				78.3 (1988)	34.8 (884)	380	340	580	615	8.8 (4.0)
	301-SS280-YJ		46.1 (1170)	45.1 (1145)	46.3 (1175)	94.5 (2401)	35.1 (892)	385	340	585	620	10.1 (4.6)
	301-SL280-YJ					122.9 (3122)	35.8 (909)	390	345	595	630	12.8 (5.8)
69/115	301-SC310-YJ	31				86.7 (2201)	38.3 (974)	415	365	635	675	9.3 (4.2)
	301-SS310-YJ		49.6 (1260)	48.6 (1235)	49.8 (1265)	105.2 (2673)	38.9 (988)	420	370	645	680	10.8 (4.9)
	301-SL310-YJ					136.7 (3471)	39.7 (1008)	430	380	655	695	13.7 (6.2)
115/138	301-SC350-YJ	35				97.8 (2485)	43.1 (1094)	460	405	705	750	9.7 (4.4)
	301-SS350-YJ		54.3 (1380)	53.3 (1355)	54.5 (1385)	118.7 (3016)	43.6 (1108)	465	410	715	760	11.5 (5.2)
	301-SL350-YJ					154.2 (3917)	44.4 (1128)	470	420	730	770	14.8 (6.7)
138	301-SC390-YJ	39				109.0 (2769)	47.8 (1214)	505	445	780	825	10.4 (4.7)
	301-SS390-YJ		59.1 (1500)	58.1 (1475)	59.3 (1505)	132.2 (3359)	48.4 (1228)	510	450	790	835	12.3 (5.6)
	301-SL390-YJ					171.8 (4363)	49.1 (1248)	515	460	800	850	16.1 (7.3)
138/161	301-SC450-YJ	45				125.8 (3195)	54.9 (1394)	570	505	890	940	11.2 (5.1)
	301-SS450-YJ		66.1 (1680)	65.2 (1655)	66.3 (1685)	152.5 (3874)	55.4 (1408)	575	510	900	950	13.5 (6.1)
	301-SL450-YJ					198.1 (5032)	56.2 (1428)	580	520	910	965	17.6 (8.0)
161	301-SC500-YJ	50				139.8 (3550)	60.8 (1544)	625	555	980	1040	11.9 (5.4)
	301-SS500-YJ		72.0 (1830)	71.1 (1805)	72.2 (1835)	168.8 (4288)	61.1 (1552)	625	560	985	1045	14.3 (6.5)
	301-SL500-YJ					219.5 (5575)	61.8 (1569)	635	565	995	1055	19.2 (8.7)
161	301-SC550-YJ	55				153.7 (3905)	66.7 (1695)	680	605	1075	1135	12.6 (5.7)
	301-SS550-YJ		78.0 (1980)	77.0 (1955)	78.1 (1985)	186.3 (4731)	67.3 (1709)	685	610	1080	1145	15.4 (7.0)
	301-SL550-YJ					242.0 (6147)	68.1 (1729)	690	615	1095	1155	20.5 (9.3)
161/230	301-SC590-YJ	59				164.9 (4189)	71.4 (1815)	725	645	1145	1210	13.2 (6.0)
	301-SS590-YJ		82.7 (2100)	81.7 (2075)	82.9 (2105)	199.8 (5074)	72.0 (1829)	730	650	1155	1220	16.1 (7.3)
	301-SL590-YJ					259.6 (6593)	72.8 (1849)	735	655	1170	1235	21.8 (9.9)

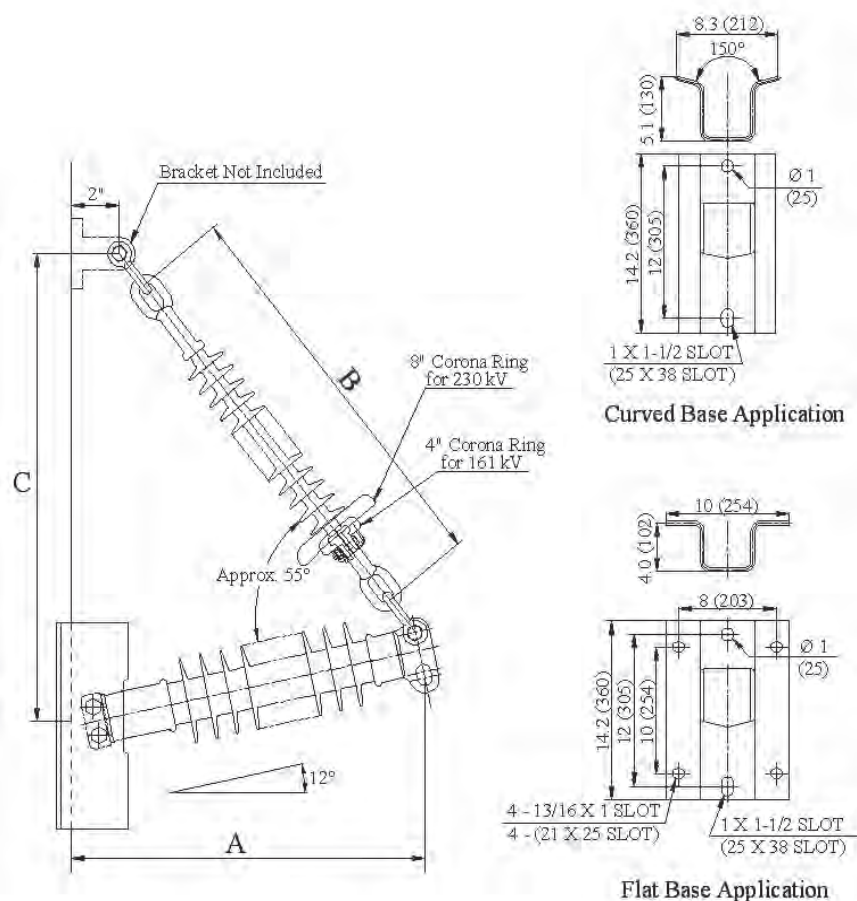
30kip Other End Fitting Combination Section Length Adjustment Table, Base Coupling: Eye-Ball (EJ), Inch				Yukon Energy Corporation
Eye/Eye (EE)	+1.5	Y-Clevis/Y-Clevis (YY)	+1.1	2021 General Rate Application
Y-Clevis/Eye (YE)	+1.3	Y-Clevis/Socket (YS)	YUC-EC-1-51(a)	REVISED – Attachment 1

Please contact NLPI for additional end fittings and combinations, including Clevis and Tongue hardware.

Typical System Voltage (kV)	Catalog No.	No. of Sheds	Section Length			Leakage Distance (inch (mm))	Arcing Distance (inch (mm))	Low Frequency Flashover		Critical Impulse Flashover		Approx. Weight lbs. (kg)
			YJ (inch (mm))	SJ (inch (mm))	EJ (inch (mm))			Dry kV	Wet kV	Positive kV	Negative kV	
230	301-SC640-YJ	64	88.6 (2250)	87.6 (2225)	88.8 (2255)	178.9 (4544)	77.4 (1965)	780	695	1240	1310	13.9 (6.3)
	301-SS640-YJ					216.1 (5488)	77.7 (1973)	780	700	1245	1315	17.0 (7.7)
	301-SL640-YJ					280.9 (7136)	78.3 (1990)	785	705	1255	1325	23.2 (10.5)
230	301-SC690-YJ	69	94.5 (2400)	93.5 (2375)	94.7 (2405)	192.9 (4899)	83.3 (2115)	835	745	1330	1405	14.6 (6.6)
	301-SS690-YJ					233.5 (5932)	83.8 (2129)	840	750	1340	1415	18.1 (8.2)
	301-SL690-YJ					303.5 (7708)	84.6 (2149)	845	755	1350	1425	24.7 (11.2)
230/345	301-SC730-YJ	73	99.2 (2520)	98.2 (2495)	99.4 (2525)	204.1 (5183)	88.0 (2235)	875	785	1405	1480	15.2 (6.9)
	301-SS730-YJ					247.0 (6275)	88.5 (2249)	880	790	1410	1490	18.7 (8.5)
	301-SL730-YJ					321.0 (8154)	89.3 (2269)	890	795	1425	1500	25.8 (11.7)
345	301-SC810-YJ	81	108.7 (2760)	107.7 (2735)	108.9 (2765)	226.4 (5751)	97.5 (2475)	965	865	1550	1635	16.3 (7.4)
	301-SS810-YJ					274.0 (6961)	98.0 (2489)	970	870	1560	1645	20.3 (9.2)
	301-SL810-YJ					356.1 (9046)	98.8 (2509)	975	875	1570	1655	28.0 (12.7)
345	301-SC910-YJ	91	120.5 (3060)	119.5 (3035)	120.7 (3065)	254.4 (6461)	109.3 (2776)	1050	940	1735	1825	17.9 (8.1)
	301-SS910-YJ					307.8 (7818)	109.8 (2790)	1050	940	1740	1835	22.3 (10.1)
	301-SL910-YJ					400.0 (10161)	110.6 (2810)	1055	945	1755	1850	30.9 (14.0)
345	301-SC1000-YJ	100	131.1 (3330)	130.1 (3305)	131.3 (3335)	279.5 (7100)	119.9 (3046)	1115	1000	1900	2000	19.2 (8.7)
	301-SS1000-YJ					337.6 (8575)	120.2 (3054)	1115	1000	1905	2005	23.8 (10.8)
	301-SL1000-YJ					439.0 (11150)	120.9 (3071)	1120	1005	1915	2015	33.5 (15.2)
345/500	301-SC1090-YJ	109	141.7 (3600)	140.7 (3575)	141.9 (3605)	304.7 (7739)	130.6 (3316)	1180	1055	2065	2170	20.3 (9.2)
	301-SS1090-YJ					368.6 (9362)	131.1 (3330)	1185	1060	2070	2180	25.6 (11.6)
	301-SL1090-YJ					479.1 (12168)	131.9 (3350)	1185	1065	2085	2195	36.2 (16.4)
500	301-SC1170-YJ	117	151.2 (3840)	150.2 (3815)	151.4 (3845)	327.0 (8307)	140.0 (3556)	1235	1105	2210	2325	21.6 (9.8)
	301-SS1170-YJ					395.6 (10048)	140.6 (3570)	1235	1110	2220	2335	27.1 (12.3)
	301-SL1170-YJ					514.2 (13060)	141.4 (3590)	1240	1110	2230	2350	38.4 (17.4)
500	301-SC1310-YJ	131	167.7 (4260)	166.7 (4235)	168.1 (4270)	366.2 (9301)	156.6 (3977)	1325	1185	2465	2595	23.6 (10.7)
	301-SS1310-YJ					442.8 (11248)	157.1 (3991)	1325	1190	2475	2605	29.8 (13.5)
	301-SL1310-YJ					575.6 (14621)	157.9 (4011)	1330	1190	2485	2615	42.3 (19.2)
500/765	301-SC1410-YJ	141	179.7 (4565)	178.5 (4535)	179.9 (4570)	394.1 (10011)	168.4 (4277)	1385	1240	2650	2785	24.9 (11.3)
	301-SS1410-YJ					476.6 (12106)	168.9 (4291)	1390	1245	2660	2795	31.8 (14.4)
	301-SL1410-YJ					619.5 (15736)	169.7 (4311)	1390	1245	2670	2810	45.2 (20.5)
765	301-SC1530-YJ	153	193.9 (4925)	192.7 (4895)	194.1 (4930)	427.7 (10863)	182.6 (4638)	1455	1305	2870	3020	26.7 (12.1)
	301-SS1530-YJ					517.1 (13135)	183.1 (4652)	1455	1305	2875	3025	34.2 (15.5)
	301-SL1530-YJ					672.2 (17074)	183.9 (4672)	1460	1310	2890	3040	48.7 (22.1)



2.5" (63mm) CORE BRACED LINE POST (BLP) ASSEMBLY



System Voltage, kV	Catalog No.	Component Catalog No. ¹⁾		Arcing Distance, in. (mm)	Leakage Distance, in. (mm) ²⁾	Dimension			Low Frequency Flashover		Critical Impulse Flashover		Design Loads, lbs. ^{3),4)}			
						A in. (mm)	B in. (mm)	C in. (mm)	Dry kV	Wet kV	Pos. kV	Neg. kV	Vertical	Tension	Compression	Longitudinal
115	HV-554	Strut	L2-SN321-13	46.5 (1181)	132.3 (3360)	58.2 (1478)	69.8 (1772)	64.1 (1628)	495	435	730	800	10000	7500	7500	1530
		Stay	251-SC480-EE													
138	HV-556	Strut	L2-SN361-13	52.4 (1331)	148.8 (3780)	64.0 (1625)	78.0 (1982)	71.3 (1810)	545	475	820	890	10000	7500	7500	1375
		Stay	251-SC550-EE													
161	HV-558	Strut	L2-SN431-13	62.0 (1575)	177.8 (4515)	74.1 (1881)	92.2 (2343)	83.4 (2118)	620	545	960	1040	10000	7500	7500	1165
		Stay	251-SC670-EE-04													
230	HV-560	Strut	L2-SN581-13	81.8 (2078)	239.8 (6090)	95.7 (2432)	121.8 (3093)	108.1 (2745)	765	670	1255	1350	8450	7500	7500	880
		Stay	251-SC920-EE-08													

- 1) Refer to individual product catalogs for details of the components.
- 2) The leakage distance is the lesser value of the strut and stay.
- 3) Design loads are for single loads in the specified direction.
- 4) Design load values do not consider the supporting structure strength.

The catalog numbers listed above use a bendable curved base. A flat base option is also available upon request.

Application of corona ring(s) depends on requirements.

For more detailed information please contact our local sales representative.

Appendix D – Climatic Data Reference Data

CAN/CSA-C22.3 No. 60826-10

Design criteria of overhead transmission lines

Location	Elevation (m)	Latitude	Longitude	Minimum temperature (°C)*	Reference wind speed† (km/h)	Reference ice thickness‡ (mm)	Wet snow thickness§ (mm)
Prince Edward Island							
Charlottetown	5	46.23	-63.13	-22	112	30	—
Souris	5	46.35	-62.25	-21	114	30	—
Summerside	10	46.40	-63.78	-22	114	30	—
Tignish	10	46.95	-64.03	-22	122	30	—
Newfoundland and Labrador							
Argentia	15	47.30	-53.98	-14	130	35	—
Bonavista	15	48.65	-53.12	-16	140	40	—
Buchans	255	48.82	-56.87	-27	115	24	—
Cape Harrison	5	54.78	-57.95	-31	130	35	—
Cape Race	5	46.65	-53.07	-13	154	45	—
Channel-Port aux Basques	5	47.57	-59.15	-15	133	32	—
Corner Brook	35	48.95	-57.95	-18	111	24	—
Gander	125	48.98	-54.59	-20	117	30	—
Grand Bank	5	47.10	-55.77	-15	130	35	—
Grand Falls	60	48.93	-55.67	-29	100	28	—
Happy Valley-Goose Bay	15	53.32	-60.37	-32	98	20	—
Labrador City	550	52.95	-66.92	-38	95	15	—
St. Anthony	10	51.37	-55.58	-27	138	30	—
St. John's	65	47.57	-52.72	-16	138	42	—
Stephenville	25	48.55	-58.58	-18	114	24	—
Twin Falls	425	53.50	-64.53	-37	95	17	—
Wabana	75	47.63	-52.95	-17	130	40	—
Wabush	550	52.92	-66.87	-38	95	15	—
Yukon							
Aishihik	920	61.60	-137.52	-46	85	10	—
Dawson	330	64.07	-139.42	-51	80	10	—
Destruction Bay	815	61.25	-138.80	-45	117	10	—
Faro	670	62.23	-133.36	-47	80	10	—
Haines Junction	600	60.78	-137.54	-47	87	10	—
Snag	595	62.40	-140.37	-53	80	10	—
Teslin	690	60.17	-132.72	-44	80	10	—
Watson Lake	685	60.13	-128.71	-48	80	10	—
Whitehorse	655	60.72	-135.05	-43	85	10	—
Northwest Territories							
Aklavik	5	68.23	-135.01	-44	100	10	—
Echo Bay / Port Radium	195	66.05	-117.88	-44	99	10	—
Fort Good Hope	100	66.29	-128.63	-45	89	10	—
Fort McPherson	25	67.43	-134.88	-46	90	10	—
Fort Providence	150	61.35	-117.65	-43	80	10	—
Fort Resolution	160	61.19	-113.67	-42	93	10	—
Fort Simpson	120	61.93	-121.35	-44	80	10	—
Fort Smith	205	60.00	-111.88	-43	80	10	—
Hay River	45	60.85	-115.73	-41	89	10	—
Inuvik	45	68.35	-133.72	-45	100	10	—
Mould Bay	5	76.23	-119.33	-46	114	10	—
Norman Wells	65	65.28	-126.85	-45	89	10	—

Appendix E – PLS-Cadd IEC 60826:03 Wind & Ice Adjustment Models

IEC 60826:2003 Design Code – Input Parameter Definitions

IEC 60826:2003 Terrain Category

The information below applies only when the 'IEC 60826:2003' is selected in Criteria/Weather Cases or Criteria/Structure Loads.

Terrain Category

☐ A: Large stretch of water upwind, flat coastal areas
☒ B: Open country with very few obstacles, for example airports or cultivated fields with few trees or buildings
☐ C: Terrain with numerous small obstacles of low height (hedges, trees and buildings)
☐ D: Suburban areas or terrain with many tall trees

Static

Drag coefficient for iced wires (applies in presence of any ice thickness or load per unit length)

Summary of IEC Related Adjustments

Wire wind height adjust model set to IEC 60826:2003 does following:

- Wire and insulator wind speed adjusted by roughness factor K_r (terrain category).
- Wire wind speed adjusted for combined wind factor G_c (terrain category, attachment height)
- Insulator wind speed adjusted for combined wind factor G_t (terrain category, attachment height)
- Ice thickness adjusted by wire diameter factor K_d and by height factor K_h (sec. 6.3.4.1)

Wire gust response factor set to IEC 60826:2003 does following:

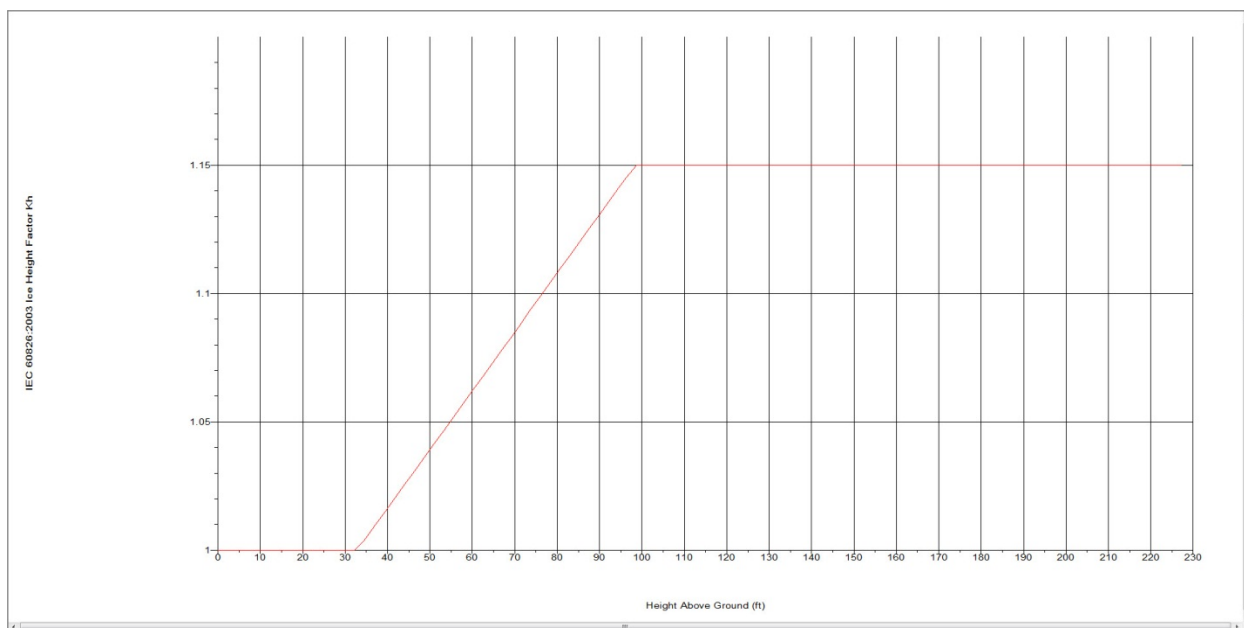
- Wire gust response factor adjusted for span factor G_l (span length)
- Wire gust response factor multiplied by drag coefficient for iced wires in presence of ice thickness or load per unit length.

Structure wind load model set to IEC 60826:2003 does following:

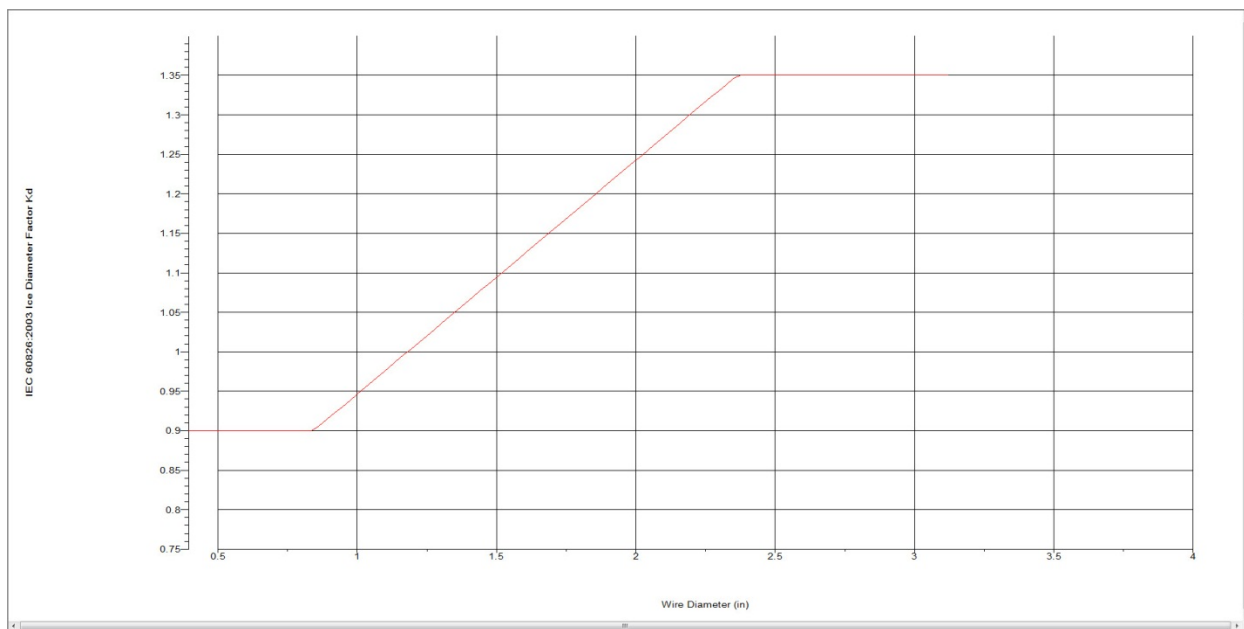
- Structure wind speed adjusted by roughness factor K_r (terrain category)
- Structure wind adjusted for height. (done in PLS-POLE/TOWER)
- Structure wind adjusted for structure gust response factor. (done in PLS-POLE/TOWER)
- Drag coefficients adjusted as per IEC. (done in PLS-POLE/TOWER)
- Ice on structure increases vertical load but not wind load. (done in PLS-POLE/TOWER)

Notes on inputs to Criteria/Weather Cases:

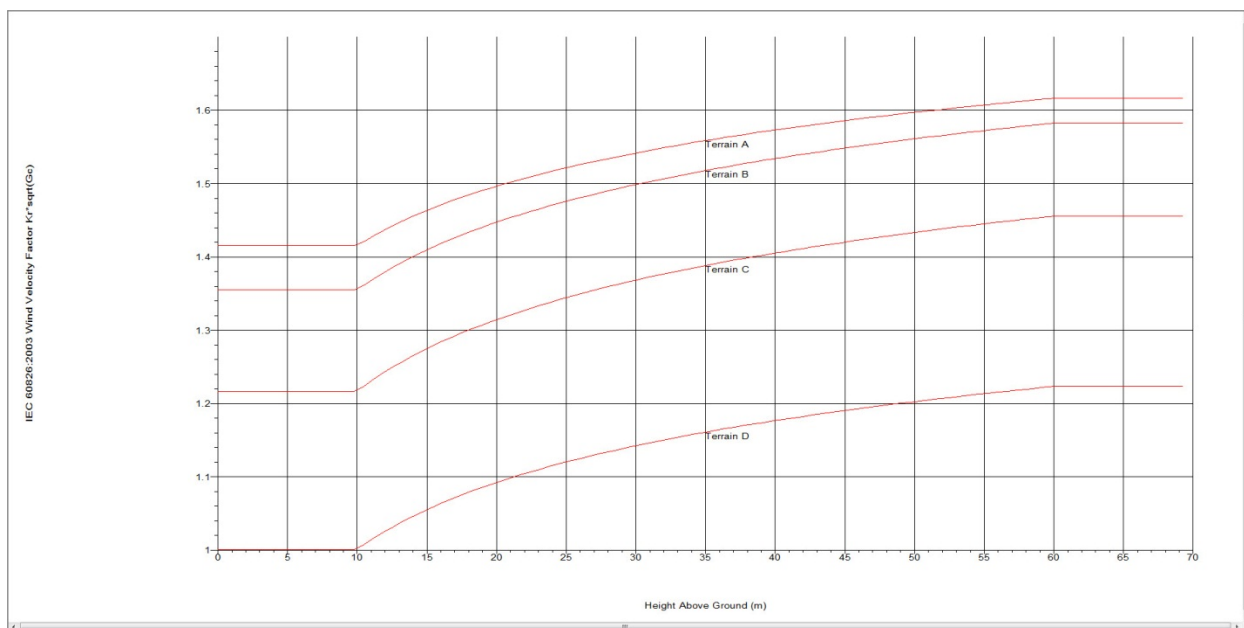
- Wind pressure should be 10 minute average V_{rb} .
- Air density factor should include any correction factor for altitude.
- Ice should be ice load on a 30mm diameter conductor at 10m reference height.



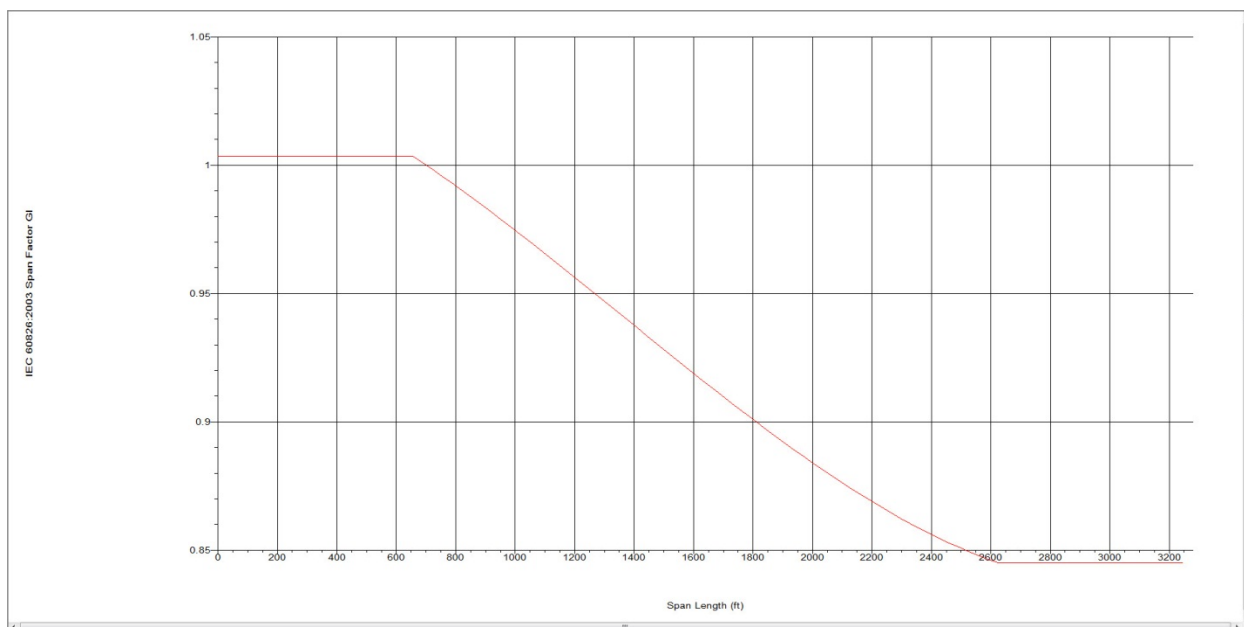
IEC Ice Height Factor (K_h) vs. Attachment Height



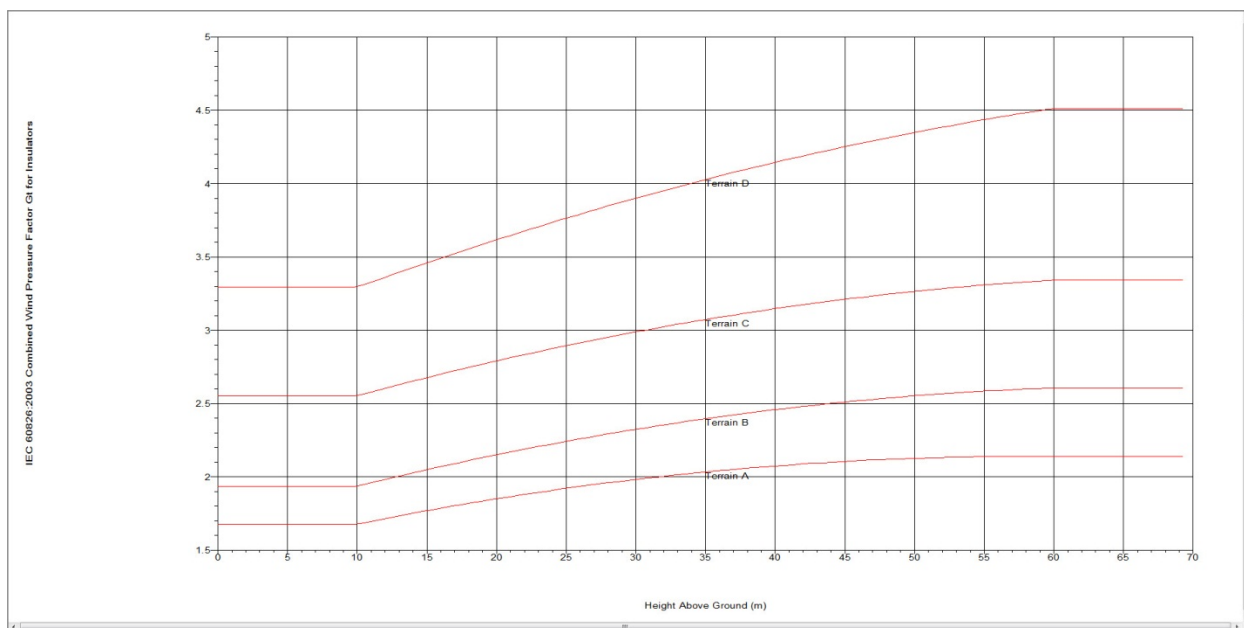
IEC Ice Diameter Factor (K_d) vs. Wire Diameter



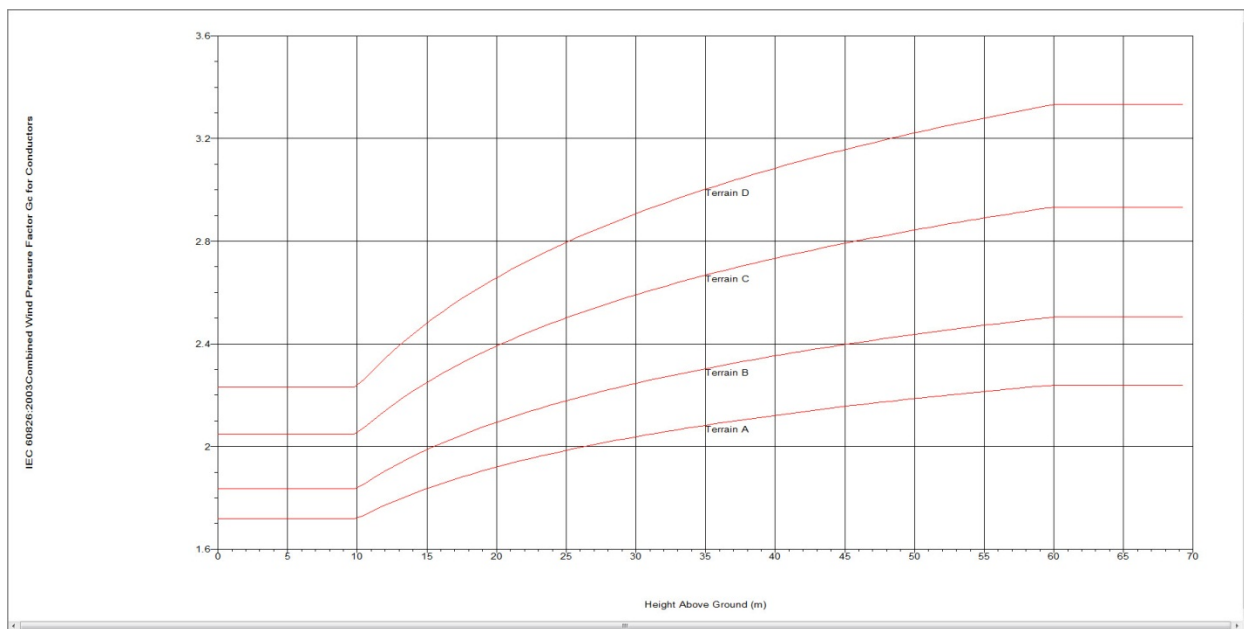
IEC Wind Velocity Factor ($K_r \cdot \sqrt{G_c}$) vs. Attachment Height



IEC Span Factor (G_I) vs. Span



IEC Combined Wind Pressure Factor (G_t) for Insulators vs. Attachment Height



IEC Combined Wind Pressure Factor (G_c) for Conductors vs. Attachment Height

Appendix F – IEEE Std. 738 Ampacity Calculation Program Output

PLS-CADD Version 13.20x64 3:50:27 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

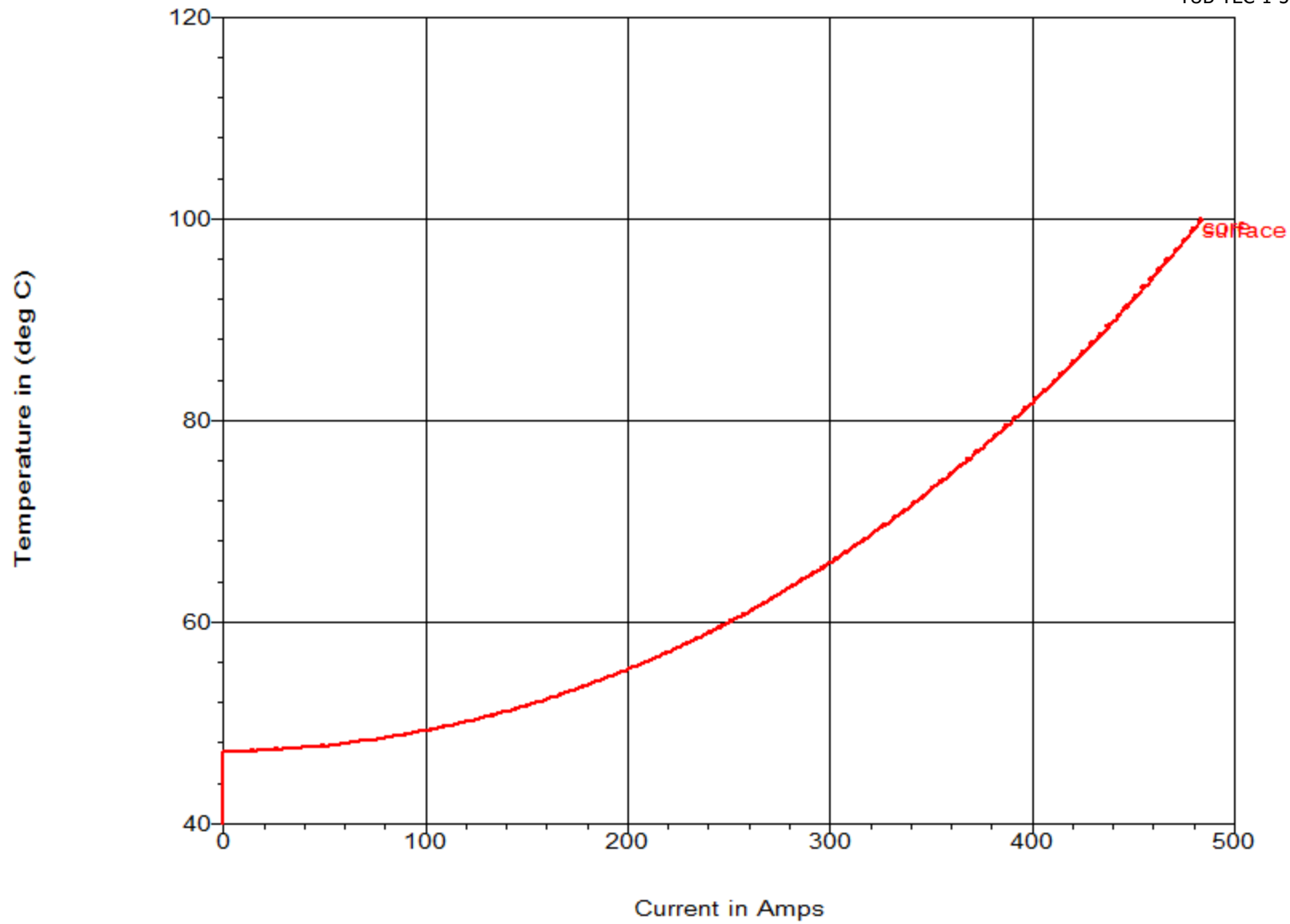
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
and 0.2556 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 8.539 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 14.183 (Watt/m)
Convective cooling is 59.286 (Watt/m)

Given a maximum conductor temperature of 100.0 (deg C),
The steady-state thermal rating is 484.4 amperes



PLS-CADD Version 13.20x64 3:51:07 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

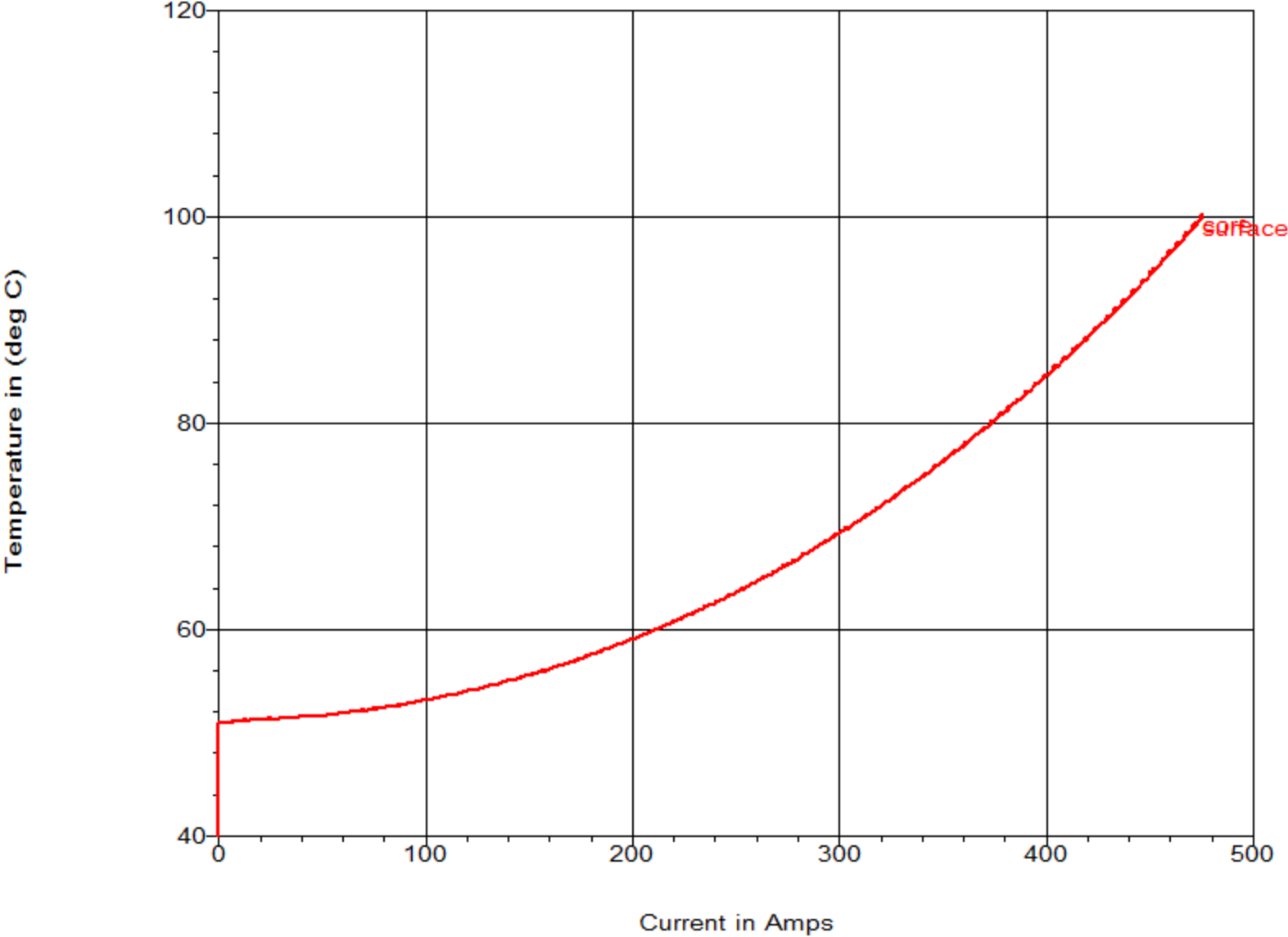
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
and 0.2556 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.662 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 17.020 (Watt/m)
Convective cooling is 59.286 (Watt/m)

Given a maximum conductor temperature of 100.0 (deg C),
The steady-state thermal rating is 475.8 amperes



PLS-CADD Version 13.20x64 3:48:23 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

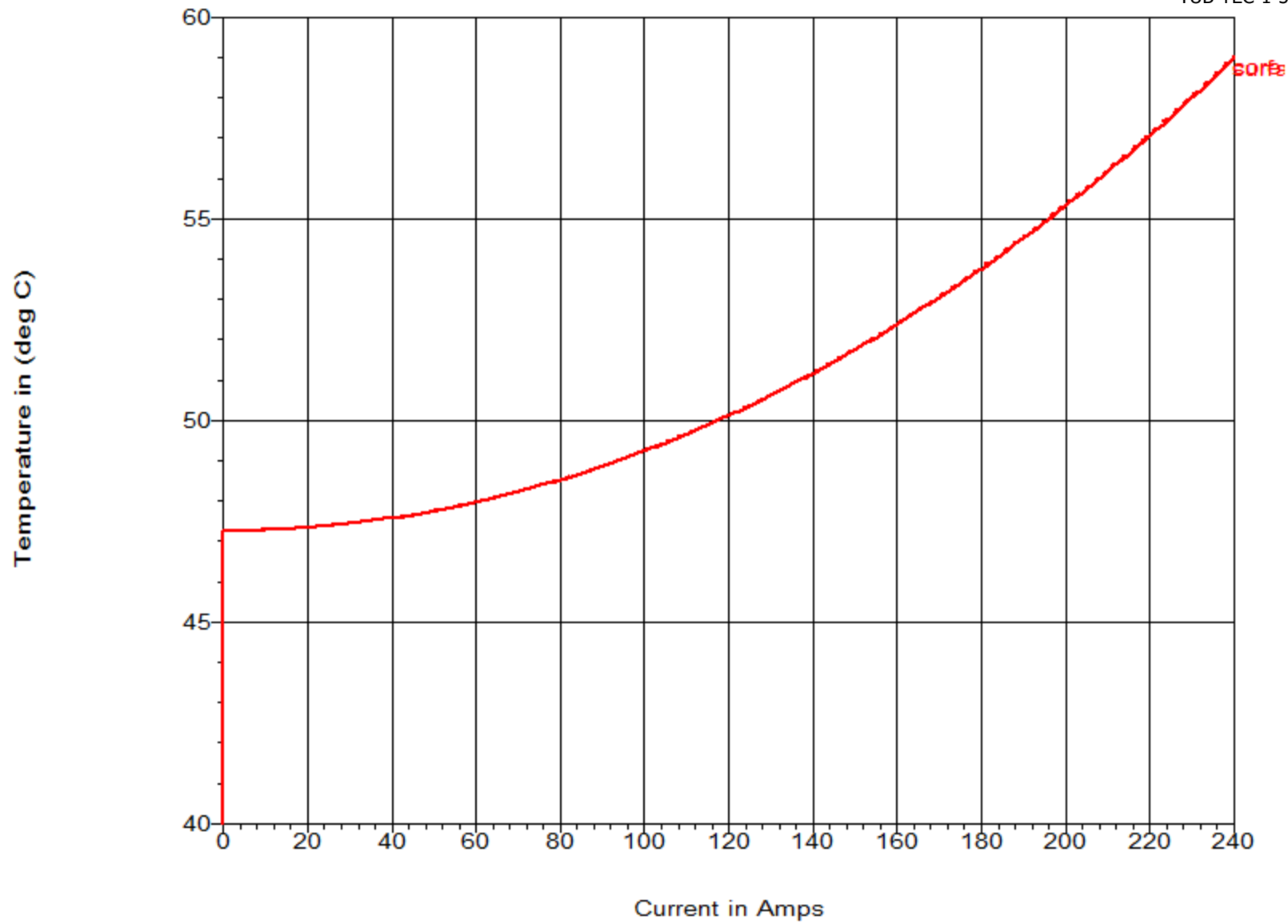
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
and 0.2556 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 8.539 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 3.704 (Watt/m)
Convective cooling is 18.779 (Watt/m)

Given a constant ac current of 240.0 amperes,
The conductor surface temperature is 59.0 (deg C)
The conductor core temperature is 59.0 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 13.20x64 3:55:40 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

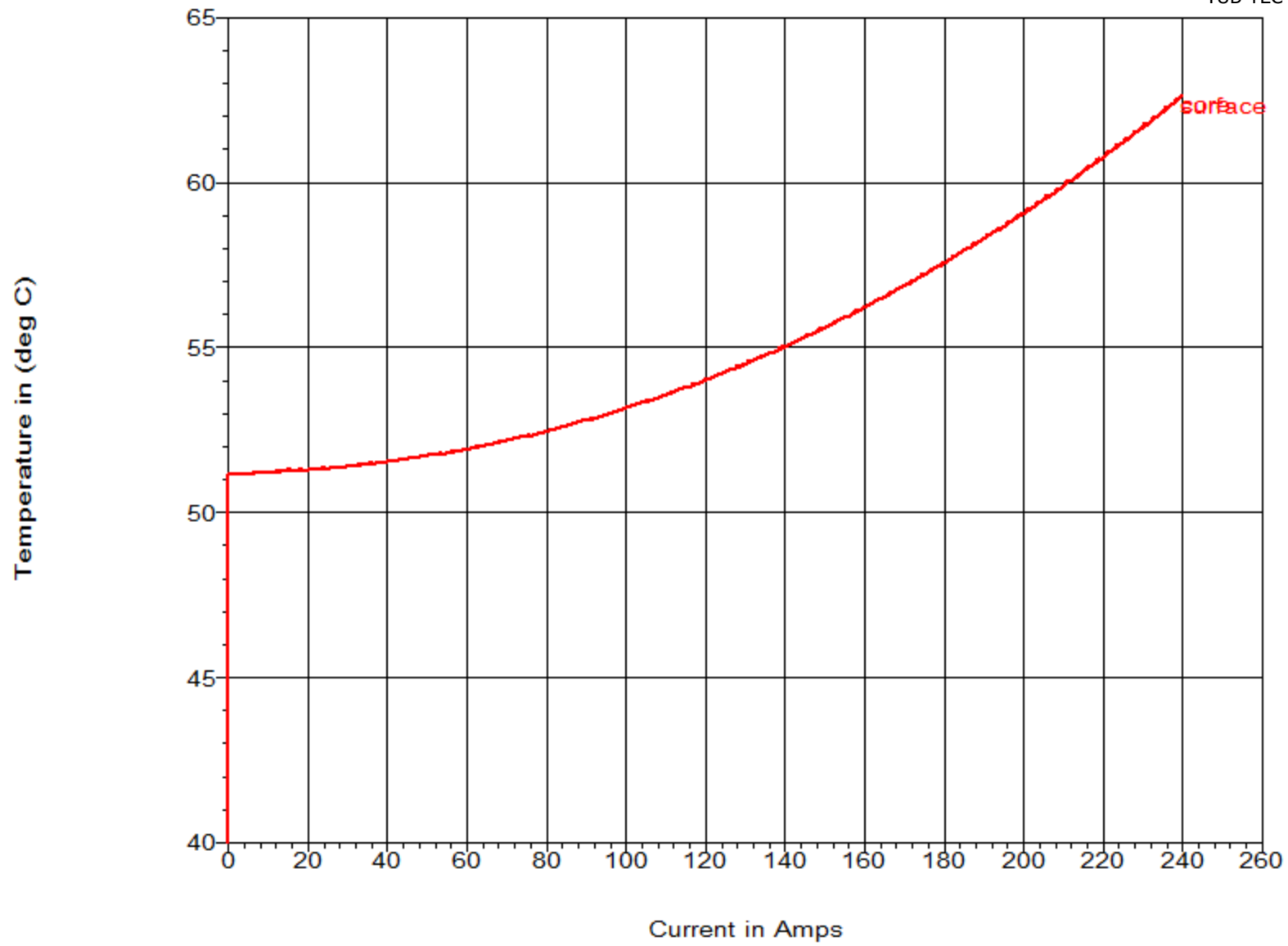
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
and 0.2556 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.662 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 5.393 (Watt/m)
Convective cooling is 22.393 (Watt/m)

Given a constant ac current of 240.0 amperes,
The conductor surface temperature is 62.6 (deg C)
The conductor core temperature is 62.7 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 13.20x64 3:44:35 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

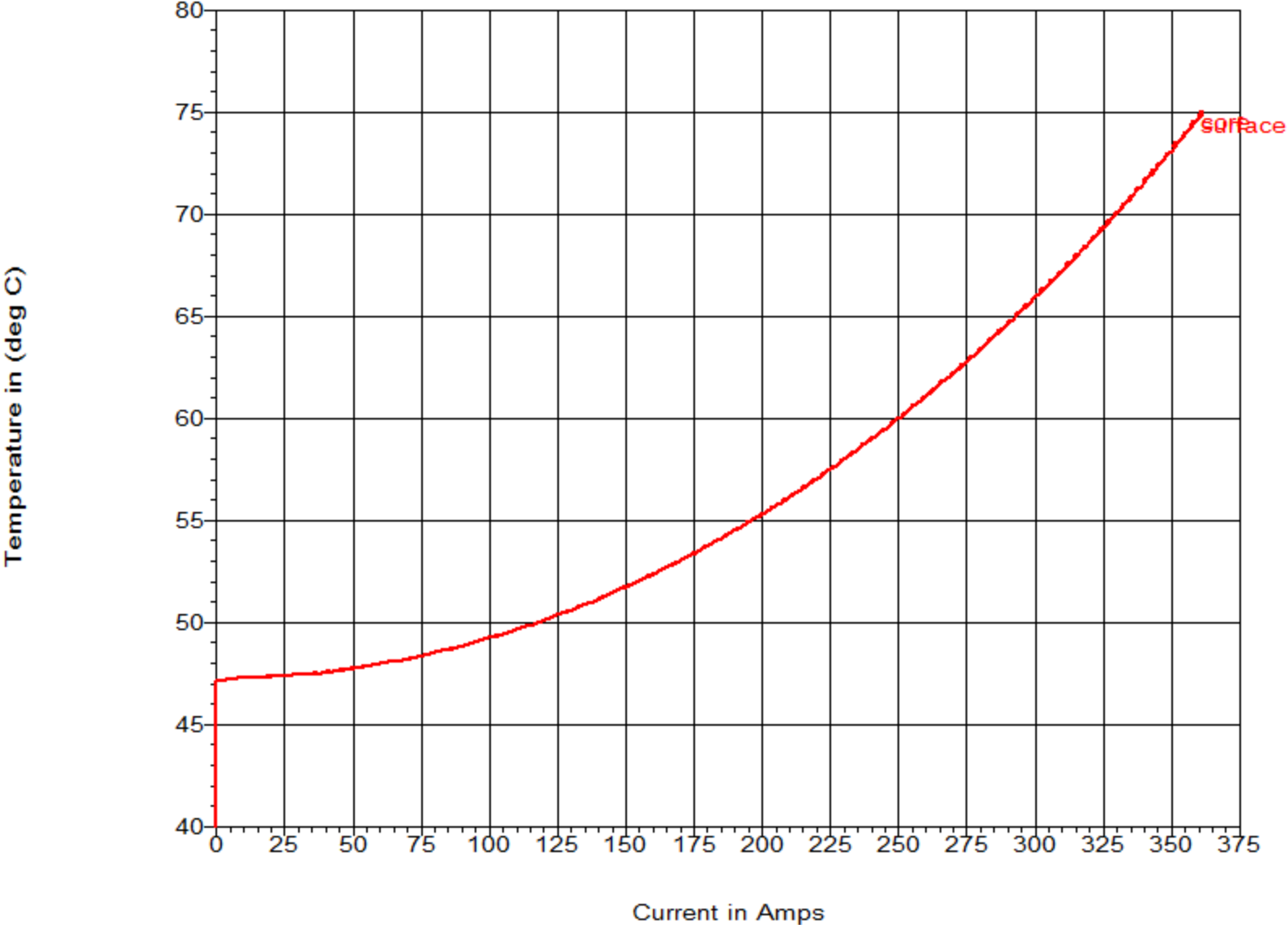
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
and 0.2556 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 8.539 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 7.366 (Watt/m)
Convective cooling is 34.610 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 361.7 amperes



PLS-CADD Version 13.20x64 3:47:38 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

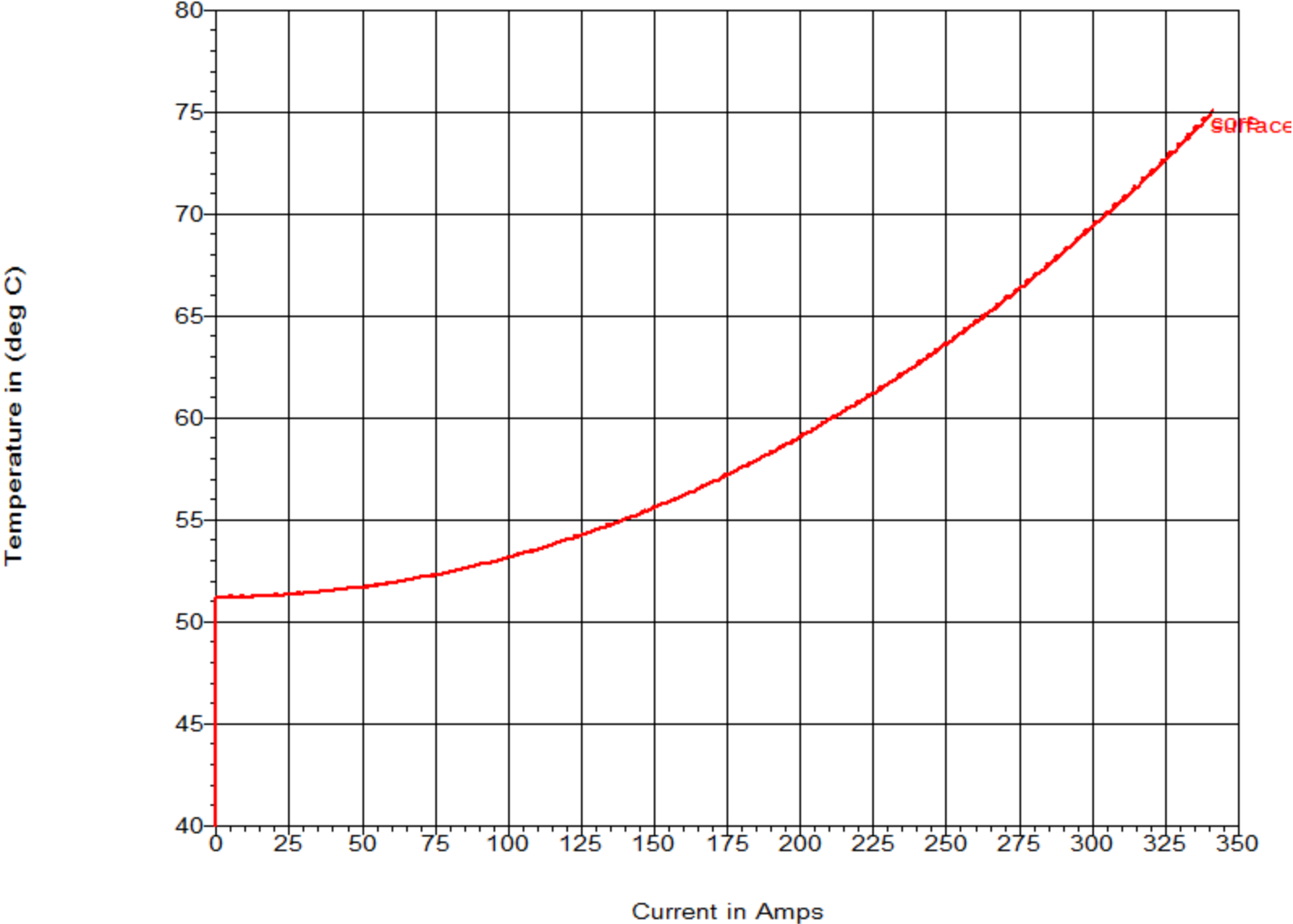
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
and 0.2556 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.662 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 8.839 (Watt/m)
Convective cooling is 34.610 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 341.4 amperes



PLS-CADD Version 13.20x64 3:52:40 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

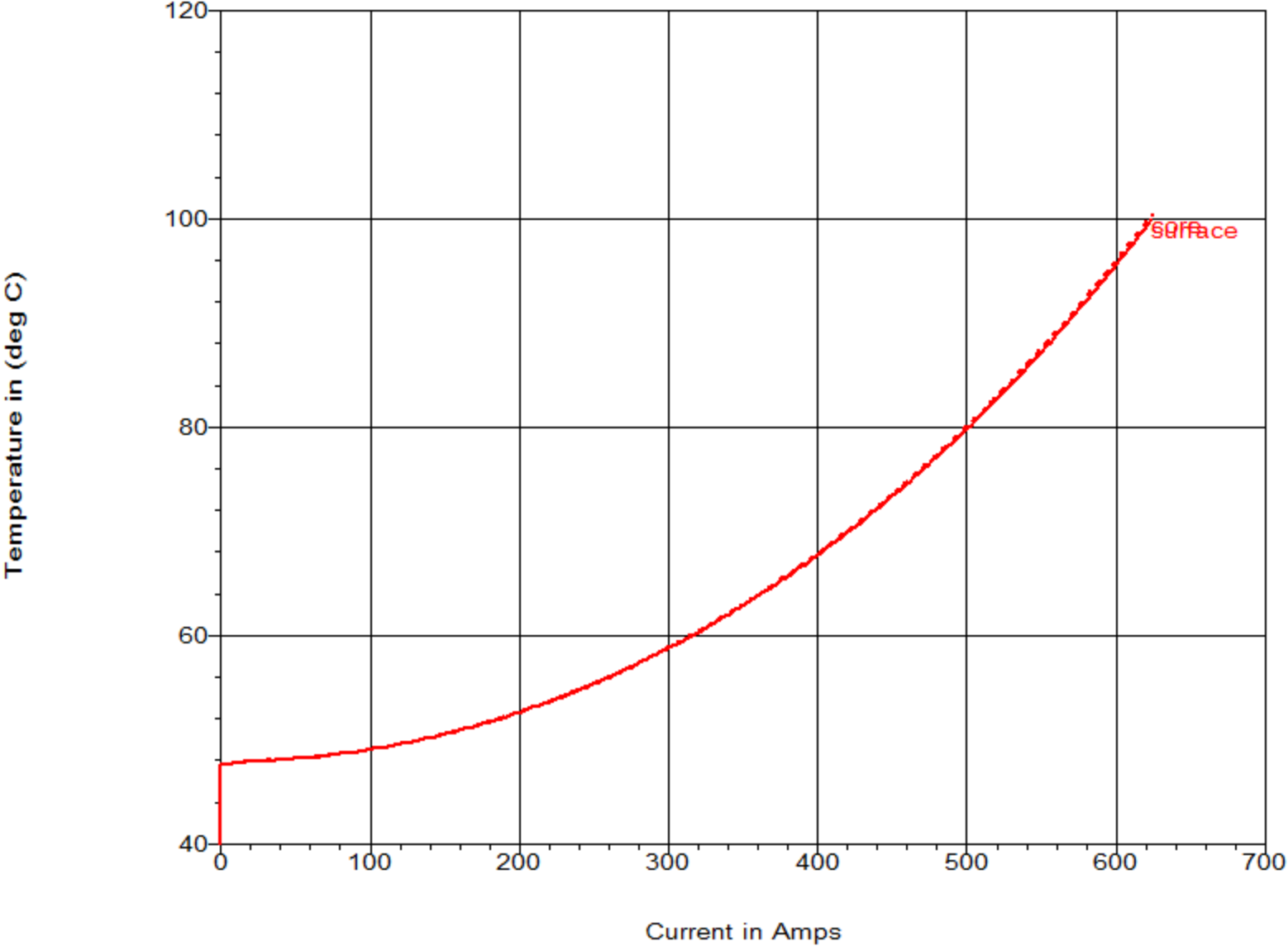
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.1436 (Ohm/km) at 25.0 (deg C)
and 0.1717 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 10.414 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 17.298 (Watt/m)
Convective cooling is 65.540 (Watt/m)

Given a maximum conductor temperature of 100.0 (deg C),
The steady-state thermal rating is 624.1 amperes



PLS-CADD Version 13.20x64 4:06:41 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

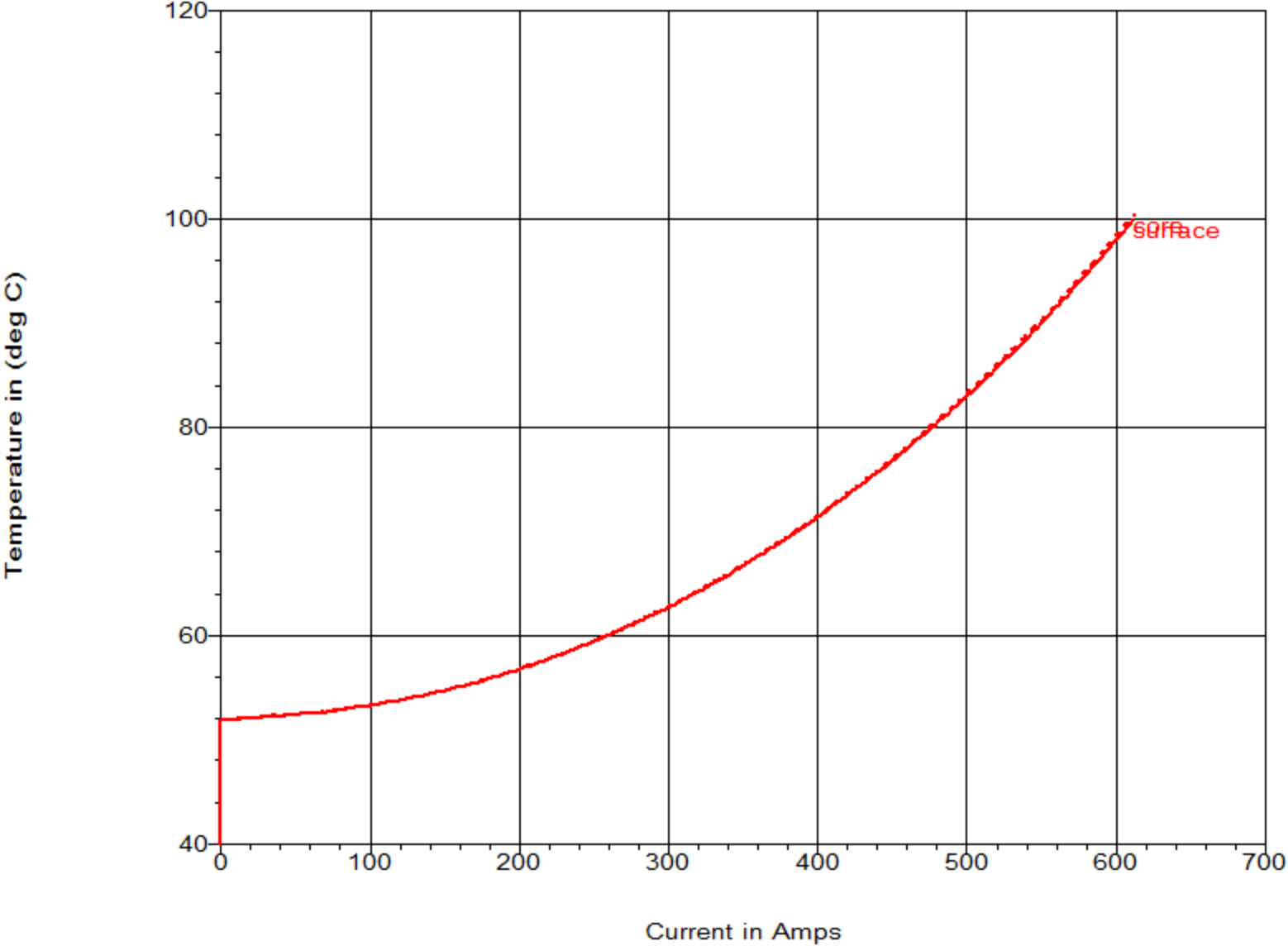
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.1436 (Ohm/km) at 25.0 (deg C)
and 0.1717 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 16.663 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 20.758 (Watt/m)
Convective cooling is 65.540 (Watt/m)

Given a maximum conductor temperature of 100.0 (deg C),
The steady-state thermal rating is 612.0 amperes



PLS-CADD Version 13.20x64 4:07:12 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

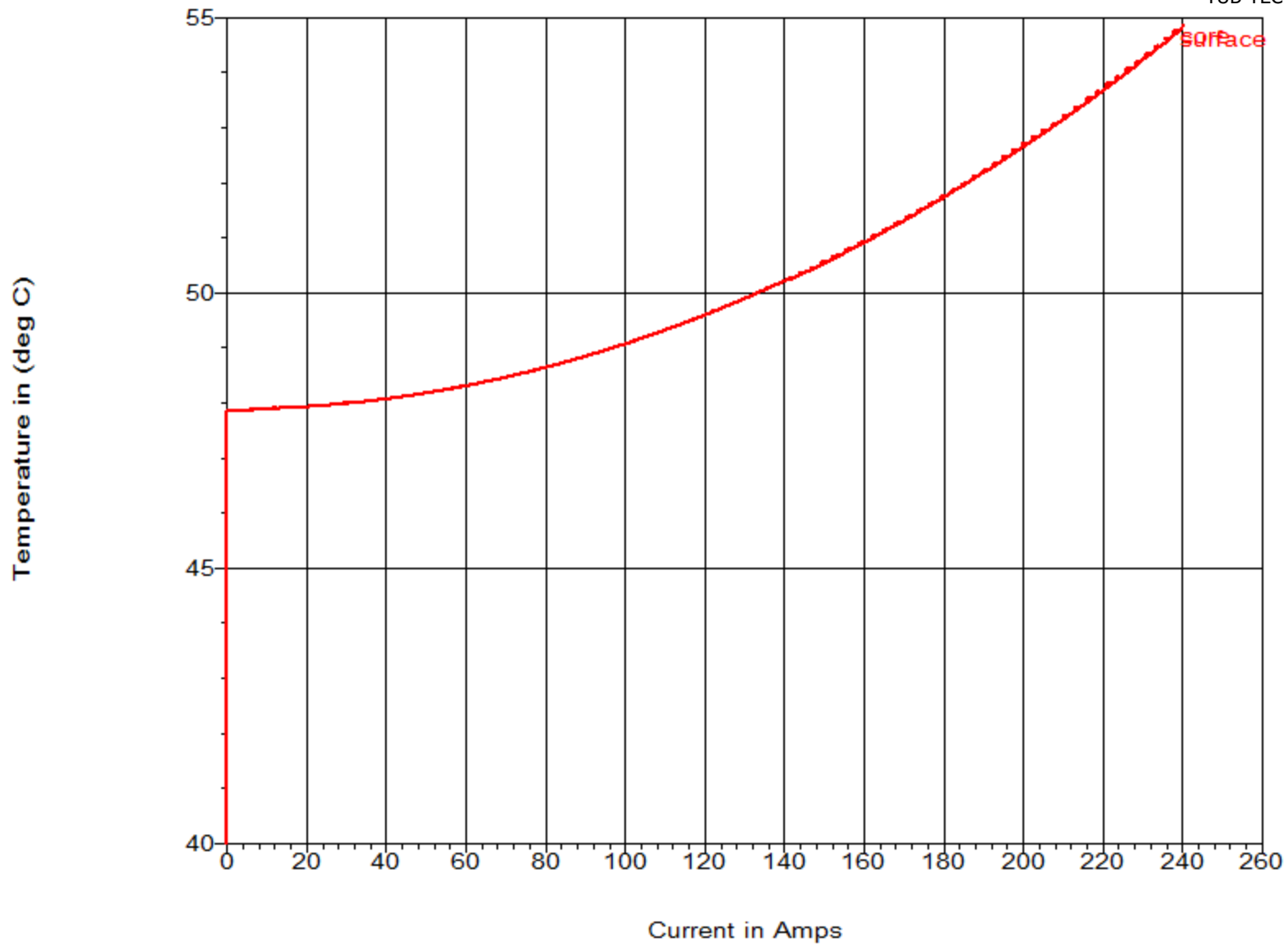
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.1436 (Ohm/km) at 25.0 (deg C)
and 0.1717 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 10.414 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 3.455 (Watt/m)
Convective cooling is 16.203 (Watt/m)

Given a constant ac current of 240.0 amperes,
The conductor surface temperature is 54.8 (deg C)
The conductor core temperature is 54.9 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 13.20x64 4:07:52 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

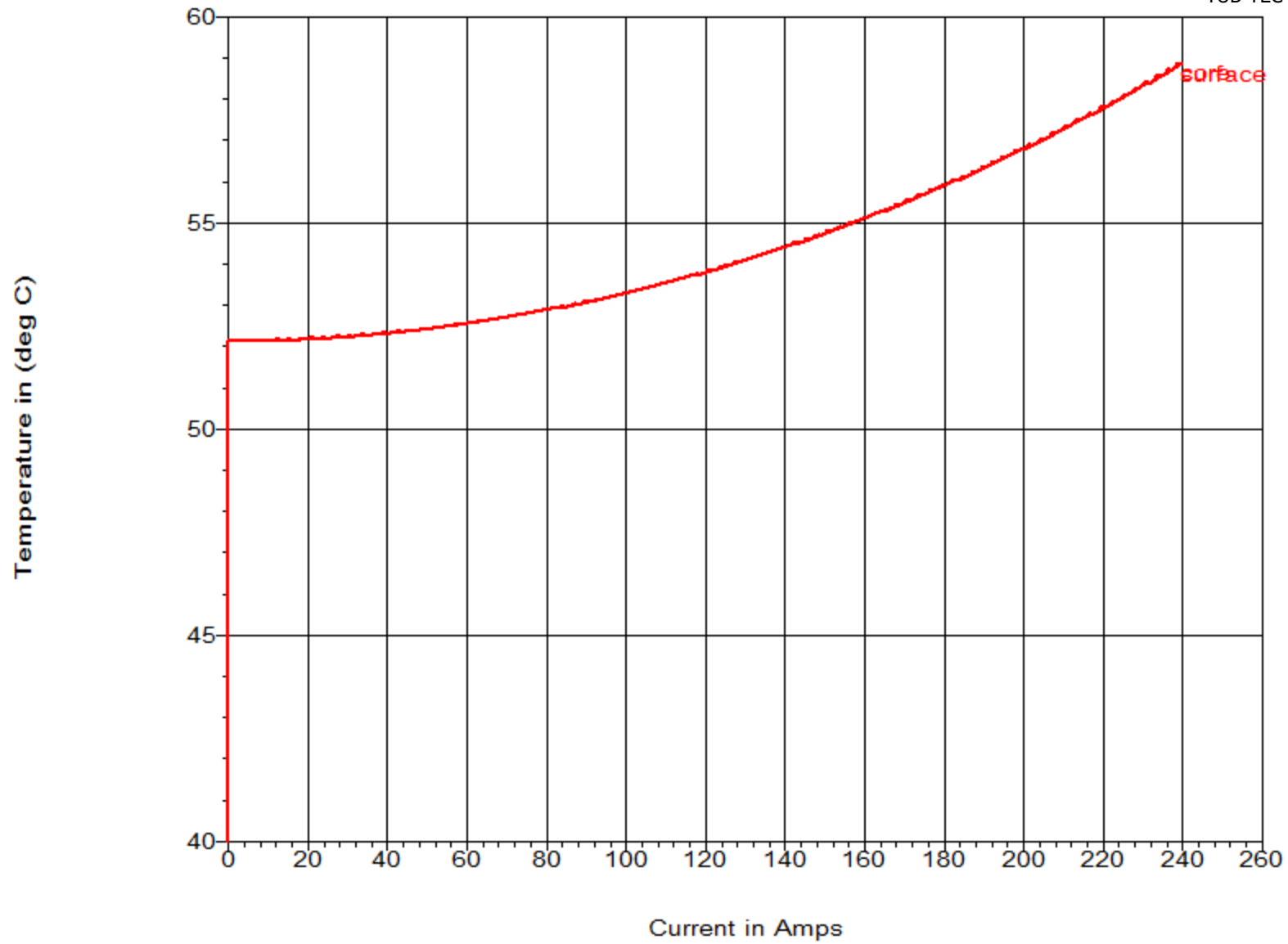
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.1436 (Ohm/km) at 25.0 (deg C)
and 0.1717 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 16.663 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 5.387 (Watt/m)
Convective cooling is 20.648 (Watt/m)

Given a constant ac current of 240.0 amperes,
The conductor surface temperature is 58.9 (deg C)
The conductor core temperature is 58.9 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))



PLS-CADD Version 13.20x64 3:51:58 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

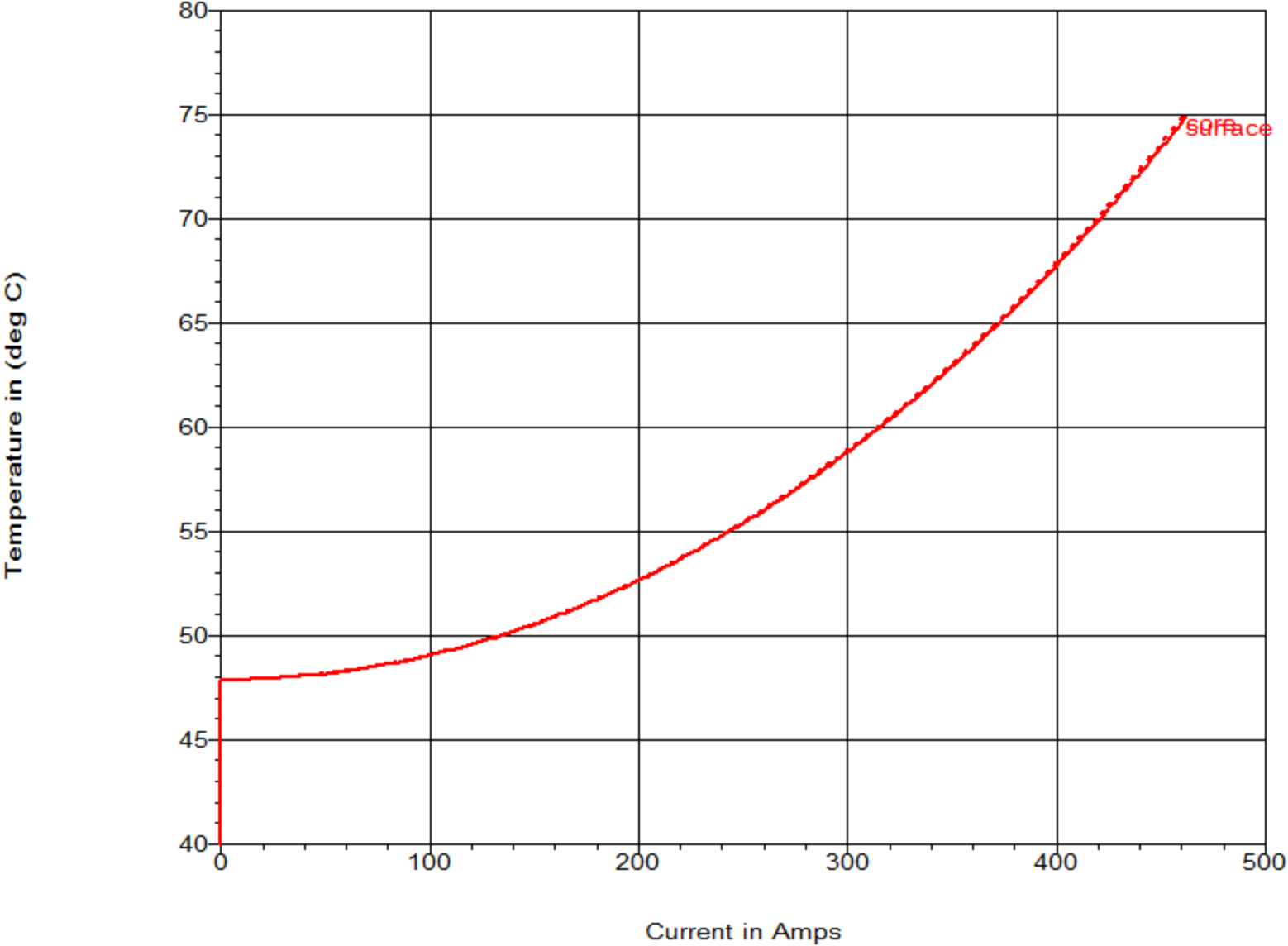
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.1436 (Ohm/km) at 25.0 (deg C)
and 0.1717 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 10.414 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 8.984 (Watt/m)
Convective cooling is 38.264 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 463.0 amperes



PLS-CADD Version 13.20x64 4:05:57 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

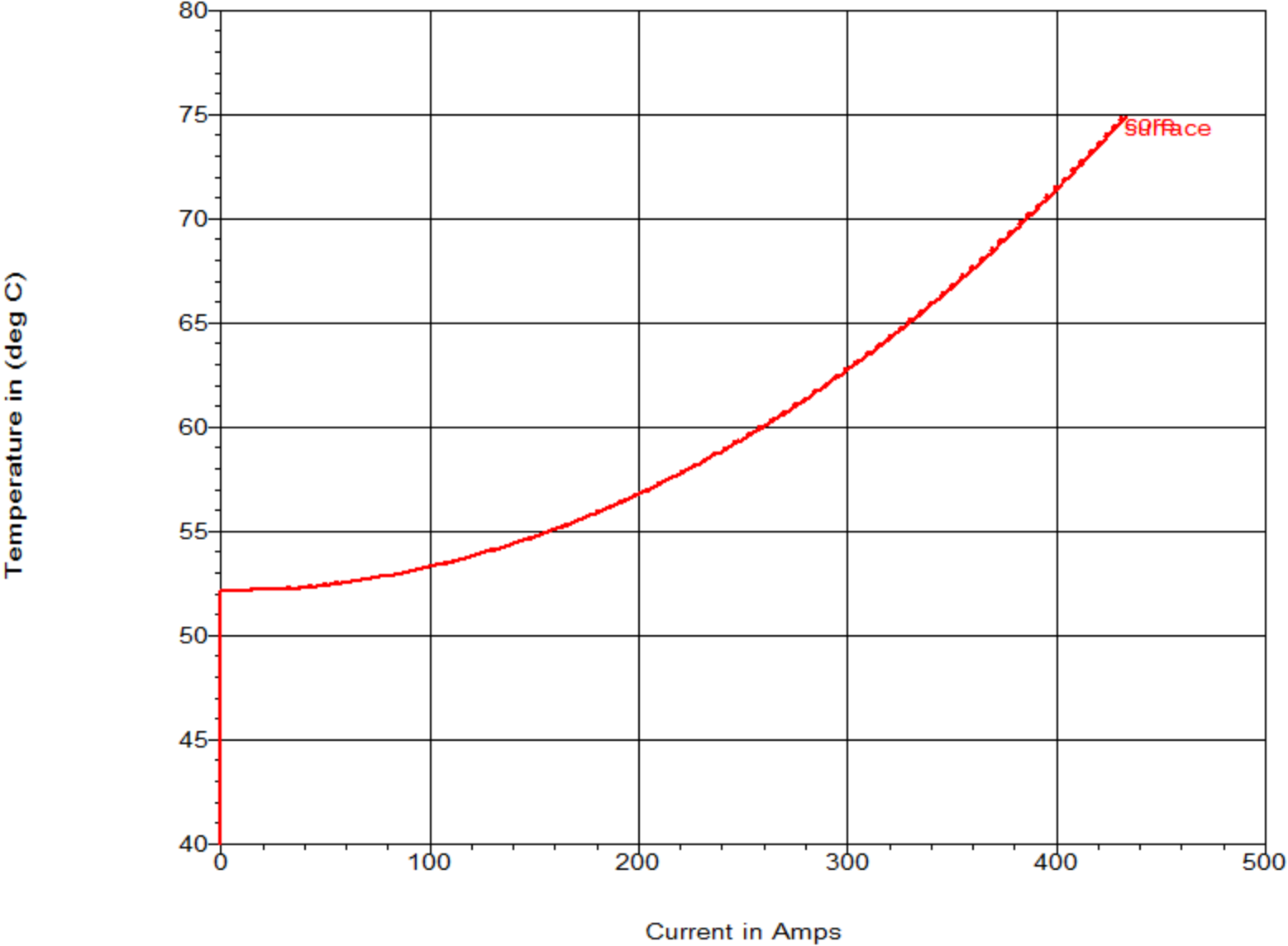
Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:

Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is 0.1436 (Ohm/km) at 25.0 (deg C)
and 0.1717 (Ohm/km) at 75.0 (deg C)
Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 16.663 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m²) - which was calculated)
Radiation cooling is 10.780 (Watt/m)
Convective cooling is 38.264 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 434.1 amperes



1 **REFERENCE:** Application, Tab 5.3.1.2, page 5-24, line 18

2
3 **ISSUE:** Pilot DSM Program

4
5 **QUOTE:** "YEC faces a capacity shortage under the single contingency (N-1)
6 planning criterion. With this capacity planning context, and mindful of
7 the policy context outlined in the Yukon Government's Climate change
8 strategy, YEC has pursued a pilot program testing internet connected,
9 wifi enabled demand response technology designed to control
10 residential baseboard and hot water heating during winter peak periods
11 to help reduce system peak and reduce reliance on thermal generation
12 such as diesel or natural gas.

13
14 The objective of the program is to: evaluate the technical feasibility of
15 the demand response technology; model and test the peak shifting
16 effect of the pilot; test the reliability of the peak shifting effects of the
17 pilot; and evaluate customer acceptance of the demand response
18 events.

19
20 The project is managed by YEC with funding support from Atco Electric
21 Yukon (AEY), Yukon Development Corporation (YDC) and Natural
22 Resources Canada (NRCan). Project expenditures of \$0.809 million
23 (\$0.434 million in 2019 and \$0.375 million in 2020) are to be included
24 in rate base, offset by contributions of \$0.365 million in 2019, are
25 amortized over 10 years."

26
27 **QUESTION:**

28
29 a) Please provide a detailed description of the components of this pilot project. For
30 example, in which areas of Yukon is the project being conducted, and how many
31 customers are included in the pilot? Please provide the forecasted and actual costs
32 to date allocated to each component.

33
34 b) Please provide details of the funding amounts provided by AEY, YDC and NRCan,
35 including a description of how YEC and AEY determined the relative amounts to
36 be contributed by each party.

1 c) Please provide the information and assumptions on which this pilot project is
2 based, including but not limited to:

- 3
- 4 i. quantity of and electrical demand of the installed water heaters;
- 5
- 6 ii. percentage of water heaters that could be taking part in the final project;
- 7
- 8 iii. estimated demand of the water heaters during peak demand periods;
- 9
- 10 iv. average lifespan of water heaters being used in the pilot program
- 11 compared to the typical household water heater;
- 12
- 13 v. the cost of the equipment, including installation cost, included in the pilot;
- 14
- 15 vi. description of any incentives offered to the participating ratepayers;
- 16
- 17 vii. potential security concerns for participants' wireless internet systems
- 18 and measures being implemented to address those concerns; and
- 19
- 20 viii. estimated frequency and duration of disconnections or service calls
- 21 resulting from the new equipment and YEC's proposed measures to
- 22 manage such events.
- 23

24 d) Please provide any analysis carried out by YEC or its program partners comparing
25 the proposed program to direct incentives paid to customers who take their own
26 steps to reduce demand or shift peak demand. If no such analysis has been done,
27 please explain why.

28

29 e) Please provide the results of analysis performed by YEC or its program partners
30 examining the costs and benefits of the project relative to any alternatives
31 considered.

32

33 **ANSWER:**

34

35 **(a)**

36

1 The Residential Demand Response Pilot will install internet-connected, wifi-enabled
2 electric baseboard thermostats and hot water tank controllers in the homes of residential
3 electrical customers anywhere on the Yukon Integrated System. The thermostats and hot
4 water tank controllers will be used to temporarily lower the temperature set-point of the
5 homes heat and hot water during a period of peak demand to lower the demand on the
6 grid.

7
8 1000 thermostats and 400 hot water tank controllers will be installed as part of the pilot
9 across 400 Yukon residences.

10 The actual costs to the end of 2020 are \$269K in equipment, \$149K in labour, \$512k in
11 professional services and \$8K in expenses. The forecast remaining costs to complete the
12 pilot are \$68K labour and \$414k professional services, including ongoing licensing and
13 support.

14
15 **(b)**

16
17 AEY is providing \$300,000, YDC is providing \$250,000 and NRCan is providing \$650,000.
18 The funding amounts with AEY and YDC were reached through discussion with these
19 organizations. NRCan offers up to 50% of eligible costs in for the demonstration stream
20 of their Smart Grid funding stream.

21
22 **REVISED RESPONSE**

23
24 Board Order 2021-10 Appendix C notes:

25
26 This IR was not fully answered by YEC because they did not provide a description
27 of how YEC and AEY determined the relative amounts to be contributed by each
28 party. The Board directs YEC to provide a complete response to this IR.

29
30 The AEY contribution was determined based on the estimated cost of the physical asset
31 projected to be installed in the AEY service area. The YEC contribution was the remainder
32 of the project cost after contributions.

33
34 **(c)**

35
36 **(i)**

1 Controllers are being installed on 400 hot water tanks as part of this pilot. The electrical
2 demand of a standard residential hot water tank is estimated to be an average of
3 4.5kW/unit.

4
5 **(ii)**
6

7 No projection has been made as to how many total hot water tanks could take part if this
8 pilot is transitioned into a full program.

9
10 **(iii)**
11

12 As the heating elements of the 400 hot water tanks participating in the pilot are at various
13 stages of heating, it is assumed that these tanks would contribute 400kW to the peak
14 demand (1kW/unit).

15
16 **(iv)**
17

18 Controllers are being installed on customers' existing typical hot water tanks. Accordingly,
19 the average lifespan of the hot water tanks in the program are the same as a typical hot
20 water tank. YEC does not have detailed data on this expected lifespan at this time.

21
22 **(v)**
23

24 The total cost of equipment for this pilot is \$269,000 and installation costs are \$134,000.

25
26 **(vi)**
27

28 There are no financial incentives being paid to participants of the pilot.

29
30 **(vii)**
31

32 There was a potential security concern that records of a participant's hot water use and
33 heating could be accessed and constitute a personal privacy breach. For this reason, the
34 supplier of the controllers used in the pilot program were evaluated on the cyber security
35 of their systems and care has been taken to protect any personal information of
36 participants in the program design.

1 (viii)

2
3 It is expected that service calls or disconnections of a customer's heating or hot water are
4 extremely infrequent. In the case that a participant experiences a heating or hot water
5 emergency, a local electrical contractor is kept on retainer to respond. Participants are
6 provided with the contractor's contact information as part of the program.

7
8 (d)

9
10 This particular pilot was pursued by YEC due to the funding opportunities from NRCAN,
11 AEY and YDC largely offsetting the program costs, enabling learnings from the pilot to be
12 applied to future DSM programs at far less than the full project cost. The analysis and
13 design of other DSM programs, such as direct incentives to customers, will now be
14 advanced given OIC 2021/16 directions enabling YEC to recover through rates the costs
15 reasonably incurred to provide or participate in a demand side management program.

16
17 **REVISED RESPONSE**

18
19 Board Order 2021-10 Appendix C notes:

20
21 It appears that no analysis of the type identified in the IR was done. However, YEC
22 did not explain why. The Board directs YEC to provide a complete response [sic] to
23 this IR including an explanation for why such analysis was not done by YEC.

24
25 Direct incentives and other options relate to program delivery and are not required at this
26 stage of program development. The objective of the pilot is to assess the likelihood of a
27 successful demand response program in Yukon. This assessment is achieved through the
28 execution of the following steps:

- 29
30 • evaluate the technical feasibility of the demand response technology;
31
32 • model and test the peak shifting effect of the pilot;
33
34 • test the reliability of the peak shifting effects of the pilot; and
35
36 • evaluate customer acceptance of the demand response events.

1 This pilot was undertaken as a data-gathering exercise on a potential DSM technology
2 that could be considered in program design and made possible by the funding
3 opportunities available to YEC at the time. If the pilot shows positive results and the
4 technology is acceptable for a DSM program, analysis will be completed to look at other
5 options for shifting peak, such as direct incentives paid to customer who take their own
6 steps to reduce peak, at that time.

7
8 **(e)**

9
10 YEC has not performed any analysis of this project relative to alternatives. As discussed
11 in (d) this pilot was pursued as funding was available to do so.

1 **REFERENCE:** Application, Tab 5.3.1.2, page 5-25, line 9

2
3 **ISSUE:** LED Streetlight Retrofit Program

4
5 **QUOTE:** "In addition to the program's specifically developed in response to the
6 Yukon Governments Climate Change initiative, the Board also noted in
7 Order 2018-10 (Para 481) that it "considers that retrofitting streetlights
8 at end of life with LED lights were prudent expenditures. Any LED
9 installations that are not end-of-life conversions must not be included in
10 YEC's rate base." The 2017/18 GRA outlined the basis for the LED
11 Streetlight Replacement program noting that YEC decided to move
12 forward with the retrofit of streetlight assets with LEDs. Streetlights in
13 downtown Dawson and Mayo were retrofit in 2016 with plans to retrofit
14 the remaining streetlights in Faro, Mendenhall and Champagne in
15 2018. As illustrated in Table 5.3, \$0.273 million was added to rate base
16 in 2018." (footnote removed)

17
18 **QUESTION:**

- 19
20 a) Please confirm that all costs added to rate base in 2018 for LED streetlight retrofits
21 were for retrofitting streetlights that were at end of life. If not confirmed, please
22 explain.
23
24 b) If part (a) is not confirmed, please separate the \$0.273 million into amounts for
25 end-of-life retrofitting and retrofitting of streetlights that were not at end of life.
26
27 c) Please confirm that YEC has not added any amounts to rate base for streetlight
28 retrofitting in 2019 and 2020 and does not propose to do so in 2021. If not
29 confirmed, please explain.
30
31 d) Are there any remaining streetlights that have not been retrofitted to LEDs? If so,
32 please estimate the percentage of streetlights that have not been retrofitted, the
33 cost of retrofitting the remaining streetlights, and outline YEC's planned timeline
34 for doing so.

1 **ANSWER:**

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

4
5 For clarity, the transfer to rate base in 2018 for \$0.273 million was not all related to the
6 streetlight replacement program. The costs breakdown further as follows:

8	inCharge Program Delivery	\$0.180
9	Streetlight Change Outs	<u>\$0.093</u>
10		<u>\$0.273</u>

11
12 inCharge program delivery is the cost to deliver the programs approved by the YUB in
13 Order 2014-06. As a historical DSM cost, this amount will be written off the accounts of
14 YEC and ratepayers will bear no burden.

15
16 Not all of the streetlights retrofit were end-end-of-life. As described in response to YUB-
17 YEC-1-81 in the 2017/18 GRA, YEC believes these assets are at or near end of life. This
18 is assumed as the majority of the asset value is historical cost transferred by community
19 i.e. YEC has no visibility on the value of the lamp head separate from the rest of the
20 structure – pole, wiring, civil improvements, etc. Based on past experience with installation
21 costs, YEC estimates \$0.006 million in undepreciated capital costs from streetlights
22 replaced. YEC proposes to write off this amount from the streetlight PP&E accounts.

23
24 **(c)**

25
26 Costs were added in 2020 for the environmental disposal of the old HPS streetlight heads
27 (\$0.008 million).

28
29 **REVISED RESPONSE**

30
31 Board Order 2021-10 Appendix C notes:

32
33 YEC did not confirm whether there are streetlight retrofitting costs being added to
34 rate base in 2019 and 2021. The Board directs YEC to confirm whether any
35 streetlight retrofitting costs were added to rate base in 2019 and 2021.

1 YEC confirms that there are no streetlight retrofitting costs being added to rate base for
2 2019 and 2021.

3

4 **(d)**

5

6 There are some high-powered highway lights that have not been retrofit. These lights were
7 not retrofit as the business case of the energy savings did not justify the LEDs required
8 for this application.

1 **REFERENCE:** Application, Appendix 5.1, page 5.1-3

2
3 **ISSUE:** Replacement of Mayo A Surge Chamber Project

4
5 **QUOTE:** "The Mayo A surge chamber is at end life and must be replaced before
6 there is a catastrophic failure. An engineering study is being undertaken
7 in 2021 to determine solutions and further work is forecast in 2022."
8

9 **QUESTION:**

10
11 a) Please indicate the year in which the Mayo A surge chamber was installed and the
12 expected service life at the time of installation.

13
14 b) Please explain how often YEC carried out tests on this chamber in the past to
15 assess its reliability and how often maintenance work was required. If possible,
16 please provide the number of times maintenance was conducted on this chamber
17 in the last 10 years, on a per annum basis, and the cost of this maintenance work.

18
19 c) Please describe the nature of the catastrophic failure that could occur in the Mayo
20 A surge chamber.

21
22 d) Please provide details on the engineering study that will be conducted on the
23 chamber.
24

25 **ANSWER:**

26
27 **(a)**

28
29 The surge chamber was Installed in 1952. Expected service life unknown.
30

31 **(b)**

32
33 A reliability test was performed in 2018; annual maintenance consists of visual inspection
34 and confirmation of heating functionality prior to winter.

1 Maintenance was performed twice (2019/2020)

- 2
- 3 • The 2019 cost was \$142; and
- 4
- 5 • The 2020 cost was \$21,212.
- 6

7 **(c)**

8

9 The nature of the catastrophic failure that could occur is unknown.

10

11 **REVISED RESPONSE**

12

13 Board Order 2021-10 Appendix C notes:

14

15 In its application, YEC indicated that the Mayo A surge chamber must be replaced

16 before a catastrophic failure occurs. The Board considers the IR response is

17 insufficient. The Board directs YEC to provide a more detailed and responsive

18 answer. For example, what are the potential consequences of not replacing the

19 Mayo A surge chamber?

20

21 A surge tank is a water storage device used as a pressure neutralizer in hydropower water

22 conveyance systems in order to dampen excess pressure variance. The main functions

23 of the surge tank are:

- 24
- 25 • When the hydro output decreases, the water moves backwards and gets stored in
- 26 the tank.
- 27
- 28 • When the hydro output increases, additional demand for water will be provided by
- 29 surge tank.
- 30

31 In short, the surge tank mitigates pressure variations due to rapid changes in velocity of

32 water. Based on the configuration of this plant, the Mayo A and B hydro plants cannot be

33 safely operated without the surge tank.

34

35 The Mayo surge tank in normal operating conditions is approximately 25% full above

36 ground level depending on the elevation of the forebay (Wareham Lake). If the tank was

37 to have a catastrophic failure the volume of discharged water from the tank would flow

1 downhill to the Mayo A hydro plant eroding the steep bank causing extensive damage to
2 the cider block building and potentially the hydro assets inside. The only way to reduce
3 and stop the water flow would require the closure of the main headgate at Wareham. This
4 action would take both Mayo A and B hydro plants out of service until the tank was repaired
5 or replaced as both plants share a single intake. This could take weeks to months
6 depending on the extent of the damage. The loss of generation would be made up with
7 other generation assets (hydro or thermal), depending on load and reservoir levels; water
8 normally used by the hydro plant in Mayo would be spilled. This scenario would be worse
9 in the winter months due to freezing of the water, increasing the extent of the damage and
10 the ability to make repairs.

11
12 **(d)**

13
14 An engineering study will be completed to determine options and a recommendation for
15 the replacement of the surge chamber.

16
17 **REVISED RESPONSE**

18
19 Board Order 2021-10 Appendix C notes:

20
21 YEC's response to this IR was not fully answered because they provided no further
22 details on the engineering study. For example, there was no mention of the tests
23 YEC will undertake. The Board directs YEC to provide further details on the
24 engineering study and what has currently been done with respect to this study.
25 This should be feasible given YEC mentioned the engineering study was being
26 undertaken in 2021.

27
28 This asset is end-of-life. This position is supported by asset assessment work completed
29 in 2018. The assessment included visual inspection, ultrasonic thickness measurement
30 and acoustic hammering.

31
32 The assessment concluded that the surge tank shell had numerous areas with corrosion
33 and/or pitting in excess of 60% and in places >85%. Based on these results, the surge
34 tank is recommended for replacement.

35
36 Due to competing priorities, the engineering study planned for 2021 has not been
37 completed. The scope of the study will be to provide design options for a replacement

- 1 surge tank. YEC will review and select an optimal solution and construct in a future year
- 2 (currently estimated in 2023).

1 **REFERENCE:** Application, Appendix 5.1, page 5.1-4

2
3 **ISSUE:** Stop Log Crane WH Main Spill Way Project

4
5 **QUOTE:** "The stop log crane at the Whitehorse hydro main spill way is critical
6 infrastructure that is required for installing stop logs, including in
7 emergency situations. Furthermore, cranes are subject to annual
8 inspection by regulation. The stop log crane is aging and is
9 experiencing a number of issues. Several structural fasteners are
10 showing signs of rusting and possible fatigue ... Due to the age and
11 design of this unit, any parts required to facilitate this repair will have to
12 be independently sourced and/or manufactured."
13

14 **QUESTION:**

- 15
16 a) Please indicate the year in which the stop log crane was installed and the expected
17 service life at the time of installation.
18
19 b) Please clearly describe what work will be done, as part of this project in 2021, that
20 is covered by the \$200,000 cost. Are further costs, beyond the \$200,000 in 2021,
21 anticipated in the near future for the stop log crane?
22

23 **ANSWER:**

24
25 **(a)**

26
27 The estimated installation date is 1958 as part of the original infrastructure. The expected
28 service life of an exterior crane is 20 years.
29

30 **(b)**

31
32 Assessment and engineering work will be completed in 2021 and has yet to begin. This
33 information will be used for project planning and estimating. The crane replacement
34 project will commence in 2022.

1 **REVISED RESPONSE**

2
3 Board Order 2021-10 Appendix C notes:

4
5 YEC's response to this IR was not fully answered because they provided no further
6 details on the engineering study. For example, there was no mention of the tests
7 YEC will undertake. The Board directs YEC to provide further details on the
8 engineering study and what has currently been done with respect to this study.
9 This should be feasible given YEC mentioned the engineering study was being
10 undertaken in 2021.

11
12 An onsite engineering assessment has been completed by the Owner's Engineer for this
13 project. They took measurements of structural components to verify sizing and performed
14 visual inspection to assess the conditions of the mechanical and electrical components.
15 Remaining work for 2021 includes assessing additional crane features for safety and/or
16 reliability benefits, as well as what components need replacing. It is expected that all
17 mechanical and electrical systems need replacing due to age and obsolescence. Most of
18 the structural components are expected to be reusable, though this decision is waiting on
19 the assessment report from the Owner's Engineer. Specifications will be written for the
20 required refurbishment work in 2021. YEC will release an RFP for the refurbishment work
21 in early 2022. Future costs for the refurbishment work aren't certain, but are expected to
22 be in the range of \$1,000,000 to \$2,000,000. Due to the expected value of the work, YEC
23 Board of Directors approval will be required in advance of execution.

REFERENCE: Application, Appendix 5.1, page 5.1-7

ISSUE: Southern Lakes Transmission Line and Whitehorse Interconnection Projects

QUESTION:

- a) Does YEC have an estimate of the total costs for these two projects, if completed? If so, please provide cost breakdowns for the projects. More specifically, provide the activities YEC forecasts to conduct and the cost amount allocated to those activities. If not, please explain why not.

ANSWER:

(a)

As stated in the 10-Year Renewable Electricity Plan, the full cost of the Southern Lakes Transmission Line project is estimated at \$166,000,000. The methodology for creating this cost estimate for the transmission project is presented in Section 3 of the Transmissions Options Evaluation Study, completed for the 2016 Resource Plan.¹ Specifically, Options 4 and 10, presented in Table 4 of this study. The full cost of the Whitehorse Interconnection Project is estimated to be \$7.7 million, for the components as shown in the table below.

Element	Cost Estimate
Whitehorse S150 & P126 Upgrades	\$3 million
L151 Reroute	\$0.5 million
Riverside Substation S171 Upgrades	\$3.5 million
Subtotal:	\$7 million
Contingency (10%)	\$0.7 million
Total Interconnection Upgrades Cost:	\$7.7 million

¹ For further details see the following:

[https://yukonenergy.ca/media/site_documents/Appendix_5.21_Transmission_Options_Evaluation_\(Midgard_2016\).pdf](https://yukonenergy.ca/media/site_documents/Appendix_5.21_Transmission_Options_Evaluation_(Midgard_2016).pdf)

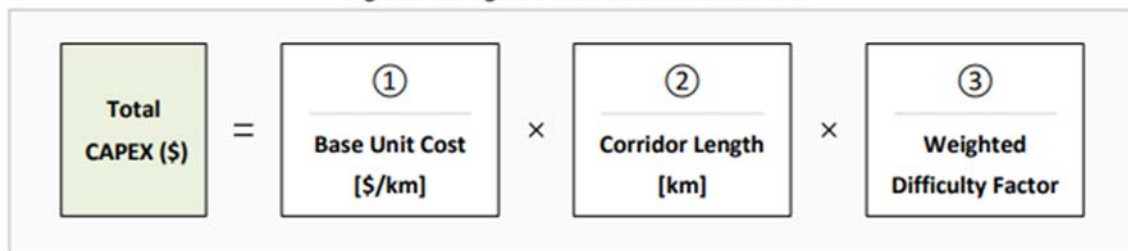
REVISED RESPONSE

Board Order 2021-10 Appendix C notes:

While YEC provided the total cost for the Southern Lakes Transmission Line project, it did not provide a cost breakdown. Thus, the Board directs YEC to provide a cost breakdown of this project.

As discussed in Section 3 of the report referenced in the original response, a cost breakdown was not used to create the \$166 million cost estimate. Rather, a factor-based Capex model was used to develop the Class 5 cost estimate for the project based on the corridor length and anticipated route difficulty. Figure 3 from the report is provided as reference below.

Figure 3: Midgard Parametric CAPEX Model



The table below provides a high-level estimate of the how this overall capital cost may break down based on typical transmission projects; however, this is subject to change following project initiation and planning.

Element	% Capital Cost
Project Management, Communications & Engagement	3%
Permitting	5%
Engineering	10%
Construction Management, Materials & Equipment	22%
Clearing & Access	25%
Installation	30%
Right-of-Way	5%

1 **REFERENCE:** Application, Appendix 5.3, page 5.3-3

2
3 **ISSUE:** Whitehorse Generating Station Water Use Licence Renewal
4 Project
5

6 **QUOTE:** "The existing water use licence for the Whitehorse Rapids Generating
7 Station (WRGS) expires at end of 2025 and must be renewed in order
8 to ensure ongoing, lawful operation of the WRGS hydro facilities. This
9 is a multi-year project to renew the existing long-term project
10 authorizations for the WRGS Hydro Plants and associated
11 infrastructure. Project activities include conducting required baseline
12 studies (e.g. environmental, socio-economic, engineering), and
13 undertaking environmental and socio-economic effects assessment,
14 First Nation engagement and consultation, other stakeholder
15 engagement as required to submit a YESAA project proposal to the
16 Whitehorse Designated Office. Project activities will also include
17 completing the YESAA review process, the water use renewal process
18 with the Yukon Water Board, and Fisheries Act Authorization (DFO)
19 regulatory process."
20

21 **QUESTION:**
22

- 23 a) Is the \$260,000 cost for 2021 the full expected cost of this project? If not, please
24 provide the full expected cost of this project along with a breakdown of that cost
25 into individual cost components. Please also include a description of why each cost
26 component is a necessary part of the project.
27
28 b) What measures is YEC undertaking to ensure that the cost of this project does not
29 increase by a similar magnitude as the costs for the Aishihik licence renewal?
30
31 c) What efforts have been made to streamline planning work for the Southern Lakes
32 Enhanced Storage to avoid duplication with this water licence renewal project?

1 **ANSWER:**

2
3 **(a)**

4
5 No. The estimated cost of the full project is approximately \$5,000,000. A detailed workplan
6 and budget will be developed as part of the project initiation work in 2021.
7

8 **REVISED RESPONSE**

9
10 Board Order 2021-10 Appendix C notes:

11
12 What is the status of the detailed work plan and budget? The Board directs YEC
13 to provide a complete response showing individual components as identified in its
14 project work plan and provide a description of why each cost component is a
15 necessary part of the project.
16

17 The information requested is not available at this time. The detailed work plan and budget
18 is currently in development with a planned completion in Q4 2021, and useful cost
19 estimates will only be available when this planning work is completed. As demonstrated
20 in Table 5.6, this project remains in work in progress at the end of the test year; therefore,
21 there is no rate impact from this expenditure in this GRA.
22

23 **(b)**

24
25 YEC plans to conduct a "lessons learned" exercise regarding the Aishihik licence renewal
26 to identify areas for improvement and lessons to apply to the Whitehorse generating
27 station renewal.
28

29 **(c)**

30
31 The scope of the assessment and permitting for the Southern Lakes Enhanced Storage
32 Project (SLESP) includes an examination primarily of the storage component of the
33 Whitehorse Rapids Generating Station operations. The subsequent water use licence
34 renewal for the whole facility and operations, including an extension to the term of the
35 project authorizations, will have a broader scope. It is expected that most of the issues
36 that will be examined during the assessment and permitting for the Enhanced Storage
37 Project will be able to stand as evidence for the assessment and permitting for the long-

1 term licence renewal and will effectively limit the scope of the water use licence renewal
2 project to primarily those things that were not otherwise assessed during the Enhanced
3 Storage Project just a few years earlier. Accordingly, it is anticipated that redundancy will
4 be minimized and the scope of the water relicensing project will be reduced via the work
5 done on the Enhanced Storage Project.

1 **REFERENCE:** Application, Appendix 5.5, page 5.5-1

2
3 **ISSUE:** Deferred Studies, EV Infrastructure Project, Electric Vehicle
4 Charging Stations

5
6 **QUOTE:** "The Yukon government 'Our Clean Future: A Yukon Strategy for
7 Climate Change, Energy and a Green Economy' includes a number of
8 actions to encourage the adoption of electric vehicles in Yukon, and the
9 construction of public electric vehicle charging stations. The Yukon
10 Government is forecasting 5,000 electric vehicles in the Yukon by 2030.
11 YEC must be proactive in undertaking infrastructure upgrades and
12 improvements to accommodate the anticipated increased demand on
13 the electrical grid due to this planned growth. Strategy development will
14 assess the potential impact of electric vehicles on the Yukon electrical
15 system and identify a path forward for YEC to meet these challenges.
16 Not addressing this could result in unforeseen costs and reactionary
17 programs."

18
19 **QUESTION:**

- 20
21 a) Please provide a breakdown of the forecasted \$200,000 for this project. More
22 specifically, provide the activities YEC is planning to engage in and provide the
23 cost allocated to each activity. Does YEC foresee any customer contributions
24 related to costs for this project?
25
26 b) Please provide your preliminary view on whether the Capital Works projects
27 discussed in this application will defer or eliminate infrastructure upgrades related
28 to electric vehicle charging station growth.
29
30 c) How many electric vehicle charging stations have been installed by the Yukon
31 Government and YEC?
32
33 d) What rate schedule(s) apply to these charging stations and how are these
34 revenues accounted for in YEC's Application?
35
36 e) Please include details of the quantities of energy supplied through and any
37 revenues for YEC resulting from the charging stations.

1 f) In YEC's view, why is it reasonable for system demand to be increased and the
2 charges recovered through rates when the benefits of the charging stations would
3 only accrue to those who own electric vehicles?
4

5 **ANSWER:**
6

7 **(a) to (f)**
8

9 Subsequent to the submission of the Application, YEC has chosen to defer this project to
10 a future year, as it is expected to take several years for the rollout of electric vehicles to
11 take place at a larger scale in Yukon. The Compliance Filing will be adjusted to reflect this
12 decision. This change has no impact on the forecast revenue requirement for the 2021
13 test year, i.e., Appendix 5.5 includes only projects forecast to remain in WIP.
14

15 **REVISED RESPONSE**
16

17 Board Order 2021-10 Appendix C notes:
18

19 YEC did not provide responses to IRs (b) to (f). While this project may be delayed,
20 YEC should still be able to provide more details on the information requested in
21 these IRs. Thus, The Board directs YEC to provide complete responses to IRs (b)
22 to (f).
23

24 **(b)**
25

26 The primary impact from EV charging stations is at the distribution level on the grid. As
27 YEC only serves about 10% of retail customers in Yukon, the utility has comparatively few
28 distribution assets. Therefore, the impact to YEC directly is expected to be quite modest.
29

30 **(c)**
31

32 YEC has not installed any EV charging stations to date. According to publicly available
33 information, Yukon had 16 EV charging stations installed as of October 2020. These
34 stations were all operated by Yukon government.

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

2
3 As YEC does not own any charging stations, there is no direct revenue from this source.
4 There would be some indirect wholesales revenue from ATCO but YEC has no visibility
5 on the volume of sales by ATCO. There is no rate schedule in Yukon for charging stations.
6

7 **(f)**

8
9 The reasonableness question goes to cost of service and rate design issues, assuming
10 recognition of the basic utility principle of obligation to serve. The utility is granted
11 monopoly rights over its franchise area in exchange for an obligation to serve customers
12 who connect to their system – and therefore it would not be reasonable for a utility to
13 refuse the service described in the question. Issues as to rates approved, however, go to
14 separate cost of service and rate design issues that are beyond the scope of YEC's capital
15 planning.
16

17 In this instance, the distribution customer level service is likely to be provided by AEY -
18 and Yukon Energy is providing the generation as required to its wholesale customer.
19 Should YEC either develop or assume operations of highway fast charging EV stations at
20 some point in in the future, a new rate specifically applying to EV fast charging would need
21 to be developed and approved by the regulator based on established cost of service
22 principles.
23

24 As reviewed in Yukon Energy's recent resource plans, YIS peak capacity load
25 requirements have been increased by a range of specific customer loads, including new
26 electric vehicle charging station loads forecast for the future.¹ To date, resulting added
27 capacity resource development costs for all of these added peak capacity load
28 requirements are being recovered through general rates.
29

30 Future DSM planning will assess options to manage peak demand growth, including
31 opportunities to shift residential electric charging loads to off peak periods when existing
32 capacity can be utilized.

¹ The 10 Year Renewable Electricity Plan included forecast load from ~5,000 EV's by 2030, as indicated by Yukon Government in Our Clean Future strategy.

1 **REFERENCE:** Application, Appendix 5.5, page 5.5-1

2
3 **ISSUE:** P125 Trashrack Study

4
5 **QUOTE:** "The P125 intake is becoming blocked with debris and frazil ice. These
6 blockages are currently being removed manually by divers and plant
7 operators. This results in multiple outages each year to address
8 blockages. Not addressing this issue will mean continued outages and
9 requirement for divers to address the issue manually. A track [sic] rack
10 must be installed that can permanently address the variety of debris
11 encountered at the intake. The study will confirm the deck structural
12 capacity and other details such as power supply and trash rack
13 geometry."
14

15 **QUESTION:**

16
17 a) Please provide the number and duration of outages caused by the debris and frazil
18 ice blockage in the last 10 years, on a per annum basis, and the costs incurred for
19 these outages.
20

21 b) Please provide a breakdown of the forecast \$200,000 for this project. More
22 specifically, provide the activities YEC is planning to engage in and provide the
23 cost allocated to each activity.
24

25 **ANSWER:**

26
27 **(a)**
28

29 Yukon Energy is in the process to complete the Trashrack Study. The initial observations
30 for the 2018 and 2019 year was Yukon Energy had an average of 6 days of plant outages
31 for cleaning out the trashrack. Based on this estimate, crane cost in addition to potential
32 energy gains from the having the trashrack partly blocked in between cleanings, initial
33 estimates show that the trashrack cleaner is potentially economic and should be studied.
34 Also, having a trashrack cleaner would help to lower the risk of frazil ice blockages on
35 WH1,2,3,4, in the early winter, which leads to system instability. During the full study, all
36 potential benefits will be reviewed and the last 10 years of history will be included.

1 **REVISED RESPONSE**

2
3 Board Order 2021-10 Appendix C notes:

4
5 While YEC provided the average number of plant outages, it did not include the
6 costs incurred for these outages. The Board directs YEC to complete this response
7 and provide the costs incurred for these outages.

8
9 Costs incurred relating to outages caused by frazil ice blockage in the last 10 years are
10 as follows:

11
12 2012 \$53,214
13 2014 \$195,990
14 2017 \$257,896
15 2018 \$148,897

16
17 **(b)**

18
19 Costs for the project include \$100,000 for detailed design, \$30,000 for project
20 management, and \$70,000 for procurement and selection of vendor(s).

1 **REFERENCE:** **Application, Tab 9, Depreciation Study, pages 9-6 and 9-16**

2
3 **ISSUE:** **Depreciation Expense**

4
5 **QUOTE:** **"Basis of Depreciation Estimates**

6 The straight-line, broad (average) life group, remaining-life depreciation
7 system was employed to calculate annual and accrued depreciation in
8 this study. In this system, the annual depreciation expense for each
9 group is computed by dividing the original cost of the asset less
10 allocated depreciation reserve less estimated net salvage by its
11 respective average life group remaining life. The resulting annual
12 accrual amounts of all depreciable property within a function were
13 accumulated, and the total was divided by the original cost of all
14 functional depreciable property to determine the depreciation rate. The
15 calculated remaining lives and annual depreciation accrual rates were
16 based on attained ages of plant in service and the estimated service
17 life and salvage characteristics of each depreciable group. The
18 computations of the annual functional depreciation rates are shown in
19 Appendix A."

20
21 **"Depreciation True Up Calculation**

22 Annual depreciation expense amounts for the depreciable accounts of
23 Yukon Energy were calculated by the straight-line method, average life
24 group procedure, and remaining-life technique. With this approach,
25 remaining lives were calculated according to standard ALG expectancy
26 techniques, using the Iowa Survivor Curves noted in the calculation.
27 For each plant account, the difference between the book depreciation
28 reserve and theoretical depreciation reserve, was divided by the
29 average remaining life to yield the annual depreciation true up. These
30 calculations are shown in Appendix A.

31
32 **Depreciation Rate Calculation Process**

33 Annual depreciation expense amounts for accounts all accounts were
34 calculated by the straight-line, average life group procedure, whole-life
35 technique.

1 These calculations are shown in Appendix A. The calculations of the
2 theoretical depreciation reserve values and the corresponding
3 remaining life calculations are shown in workpapers. Book depreciation
4 reserves were based on Company individual accounts and the
5 theoretical reserve computation was used to compute a composite
6 remaining life for each account.”
7

8 **PREAMBLE:** The above quotes refer to the use of a remaining-life depreciation
9 system; remaining-life technique and whole-life technique.
10

11 **QUESTION:**
12

- 13 a) Please fully explain the difference between each of the remaining-life depreciation
14 system, remaining-life technique and whole-life technique references. Please also
15 include an explanation of how each are incorporated and used within YEC’s
16 depreciation expense calculations.
17
- 18 b) Please provide a copy of the interview notes (as between YEC and Alliance
19 Consulting Group) prepared during the course of YEC’s depreciation study.
20
- 21 c) Please clarify that all data relied on during the preparation of YEC’s depreciation
22 study was actuarial-based and did not contain any simulated data.
23
- 24 d) YEC indicates in many instances “there was insufficient transactional data for an
25 actuarial life analysis” notwithstanding that this statement was accompanied by
26 other operational observations which implied the existence of actuarial data.
27 Please provide a retirement rate analysis (observed life table) for each
28 depreciation study account including the plotted actual data points and proposed
29 survivor curve.
30
- 31 e) Please provide a calculated annual accrual and accrued depreciation for each
32 depreciation study account.
33
- 34 f) Please clarify if YEC uses amortization accounting for all depreciation study
35 accounts that have been assigned the use of a square curve (SQ). If not confirmed,
36 please explain fully how YEC accounts for asset retirements for depreciation study
37 accounts using an SQ.

1 g) Please explain the basis for YEC's asset classes and groupings. If YEC has relied
2 on information respecting asset classes and groupings from other jurisdictions,
3 please provide a copy of that information including a description of the assets that
4 should be recorded into each separate asset class and grouping.
5

6 **ANSWER:**

7
8 **(a)**
9

10 The calculation of depreciation rates for YEC used the whole-life technique. The difference
11 between the actual and calculated accumulated provision for depreciation for each group
12 was allocated to future periods using the average remaining life for each group. Effectively,
13 this translates into the remaining life technique. Please see the attached excerpt from
14 Depreciation Systems for an explanation of the differences between the whole-life and
15 remaining life techniques.
16

17 **(b)**
18

19 Please see Attachment 1 to this response (interview notes).
20

21 **(c)**
22

23 All data relied upon was actuarial.
24

25 **(d)**
26

27 Please see Attachment 2 to this response.
28

29 **(e)**
30

31 Please see response to YUB-YEC-1-109 for the requested information.
32

33 **(f)**
34

35 Alliance Consulting Group is interpreting the question in being vintage group amortization
36 as set for the USA FERC accounting release 15.

1 [https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/vintage-year-](https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/vintage-year-accounting-general-plant-accounts)
2 [accounting-general-plant-accounts](https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/vintage-year-accounting-general-plant-accounts)

3
4 YEC does not use amortization accounting. Asset retirements are made by YEC based
5 on when assets are taken out of service. The SQ curve assigned in a few accounts in the
6 depreciation study are assigned due to the lack of sufficient historical transactional data
7 in which to determine a specific retirement dispersion. Therefore, those accounts were
8 assigned a SQ dispersion.

9
10 **(g)**

11
12 YEC has developed a fixed asset catalog which details its system of accounts and the
13 components within each account. Please see attachment 1 to this response.

14
15 **REVISED RESPONSE**

16
17 Order 2021-10, Appendix C notes:

18
19 YEC provided an "Attachment 1" in response to YUB-YEC-111(b) which are
20 "interview notes" and which the Board finds is not the equivalent as "the basis for
21 YEC's asset classes and groupings" requested in YUB-YEC-111(g). The Board
22 directs YEC to provide the information requested.

23
24 There is no one source for YEC's fixed assets accounts. The basic structure has been in
25 use for as many years as YEC has corporate records (i.e. >25). At times, YEC has
26 consulted other available public sources of industry information (e.g., Ontario Energy
27 Board Uniform System of Accounts) but as stated above, this was used for reference not
28 to replicate.

29
30 The OEB reference can be found at:

31 [https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-](https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Accounting-Procedures-Handbook-Elec-Distributors-20120101.pdf)
32 [01/Accounting-Procedures-Handbook-Elec-Distributors-20120101.pdf](https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Accounting-Procedures-Handbook-Elec-Distributors-20120101.pdf).

33
34 Attachment 1 contains the current YEC user manual for PP&E.

Yukon Energy Corporation
GP Users Manual for Property Plant and Equipment
Draft Copy

Fixed Assets

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Yukon Energy Corporation

GP Users Manual for Property Plant and Equipment

Draft Copy

Fixed Assets Coding Structure

Account Definition

GP uses a subledger system which assigns a class ID to each asset. The assets then roll up from the class ID to the GL.

The following is the GL code which precedes the Class ID's that are assigned to the GL Code. For each Class ID there is a bit of description on what types of asset would be included.

PROPERTY, PLANT & EQUIPMENT

GL Code

0000-000-1610 LAND

Class ID

1610-003	Land Hydro Production Land associated with hydro production plant.
1610-004	Land Diesel Production Land associated with diesel production plant.
1610-006	Land Main Transmission Facilities Land associated with main transmission facilities.
1610-008	Land Distribution System Land associated with distribution system.
1610-009	Land General Plant Land associated with general plant.
1610-106	Land Rights Land rights associated with general plant.
1610-110	Land – LNG Production Land associated with LNG production.

GL Code

0000-000-1615 HYDRO PLANT

Yukon Energy Corporation

GP Users Manual for Property Plant and Equipment

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Class ID

1615-200 Structures and Improvements (OL = 72 years)

Structures and improvements associated with hydro production plant. This would include control structure upgrades, elevator upgrades, bridge work, gate house improvements. These improvements have a longer life expectancy than those coded to 1645-200 (Buildings and Other equipment – Structures and improvements).

1615-205 Reservoirs Dams and Waterways (OL = 99 years)

This account shall include the cost of facilities used for impounding, collecting, storage, diversion, regulation and delivery of water used primarily for generating electricity. Components of cost:

1. Bridges and culverts (when not a part of structure and improvements).
2. Clearing and preparing land.
3. Dams, including waterways, spillways, flash boards, spillway gates with operating and control mechanism, tunnels, gate houses and fish ladders.
4. Dikes and embankments.
5. Electric system including conductors, control system, transformers, lighting fixtures, etc.
6. Excavation, including shoring, bracing, bridging, refill and disposal of excess excavated material.
7. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided. Intakes, including trash racks, rack cleaners, control gates and valves with operating mechanisms and intake house where not a part of station structure.
8. Platforms, railings, steps, gratings, etc. appurtenant to structures listed herein.
9. Retaining walls.
10. Water conductors and accessories, including canals, tunnels, flumes, penstocks, pipe conductors, fore bays, tailraces, navigation locks and operating mechanisms, water hammer and surge tanks and supporting trestles and structures.
11. Water storage reservoir, including dams, flash boards, spillway gates and operating mechanisms, inlet and outlet tunnels, regulating valves and valve towers, silt and mud sluicing tunnels with valve or gate towers and all other structures wholly identified with the foregoing items.

1615-206 Reservoirs Dams and Waterways Twin Assets (OL = 0 years)

This account is used to twin assets from 1615-205 Reservoirs Dams and Waterways. The assets in this account are not depreciated. Assets in Reservoirs, Dams and Waterways 1615-205 have a life of 103 years, however GP only allows a maximum life of 99 years. Therefore assets in this class are twinned with a suffix of 2 to account for the extra 4 years.

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1615-504 Hydro Assets Overhaul (OL = 10 years)

1615-506 Waterwheels, Turbines and Generators (OL = 85 years)

This account shall include the installation costs of water wheels and hydraulic turbines (from connection with penstock or flume to tailrace) and generators driven thereby devoted to the production of electricity by water power or for production of power for industrial or other purposes, if the equipment used for such purposes is a part of the hydraulic power plant works. Components of costs:

1. Exciter water wheels and turbines, including runners (gates, governors, pressure regulators, oil pumps, operating mechanisms) scroll cases, draft tubes and draft tube supports.
2. Foundation and settings, specially constructed for and not expected to outlast the apparatus for which provided.
3. Generator cooling systems, including air cooling and washing apparatus, air fans and accessories, air ducts, etc.
4. Generators, main A.C. or D.C., including field rheostats and connections for self-excited units and excitation system when identified with the generating unit.
5. Lubricating systems, including gauges, filters, tanks, pumps, piping, etc.
6. Main penstock valves and appurtenances including main valves, control equipment, by-pass valves, fittings and other accessories.
7. Main turbines and waterwheels, including runners, gates, governors, pressure regulators, oil pumps, operating mechanisms, scroll cases, draft tubes and draft tube supports.
8. Mechanical meters and recording instruments.
9. Miscellaneous water wheel equipment including gauges thermometers, meters and other instruments.
10. Platforms, railings, steps, gratings, etc. appurtenant to apparatus listed herein.
11. Scroll case filling and drain system, including gates, pipes valves, fittings, etc.
12. Water actuated pressure regulator systems, including tanks and housings, pipes, valves, fittings and insulations, piers and anchorage, excavation and backfill.

1615-600 Accessory Electric Equipment (OL = 45 years)

This account shall include the installation costs of auxiliary generating apparatus, conversion equipment and equipment used primarily in connection with the control and switching of electric energy produced by hydraulic power and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts, such motors being included in the account in which the equipment with which they are associated is included.

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Note A: do not include in this account transformers and other equipment used for changing the voltage or frequency of electricity for the purpose of transmission or distribution.

Note B: when any item of equipment listed herein is used wholly to furnish power to equipment, it shall be included in such equipment accounts.

Components of cost:

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arrestors, instrument shunts, conductors and conduit, special supports for conduit generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, special housings, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks current transformers, potential transformers conductors and conduit special support for generator main leads, grounding switch, special housings, protective screens, etc. station buses, including main auxiliary, transfer, synchronizing and fault ground buses, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories voltage regulators and accessories, compensators, resistors, starting transformers, current transformers potential transformers, protective relays, storage batteries and charging equipment; isolated panels and equipment, conductors and conduit, special supports, special fire extinguishing equipment and test equipment.
4. Station control system including station switchboards with panel wiring panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, truck-type switchboards complete, cubicles, station supervisory control devices, frequency control equipment, master clocks, watt-hour meter, station totalizing watt meter, storage batteries panels and charging sets, instrument and transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, etc

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1615-601 Accessory Digital Equipment (OL = 20 years)

This account shall include the installation costs of digital generating apparatus, conversion equipment and equipment used primarily in connection with the control and switching of electric energy produced by hydraulic power and the protection of electric circuits and equipment.

1615-700 Miscellaneous Power Plant Equip (OL = 30 years)

This account shall include the installation costs of miscellaneous equipment in and about the hydroelectric generating plant, which is devoted to general station use and is not properly includable in other hydraulic production accounts. Components of cost:

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails monorails, hoists, etc., with electric and mechanical connections.
3. Fire extinguishing equipment for general station use.
4. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
5. Miscellaneous belts, pulleys, countershafts, etc.
6. Miscellaneous equipment, including atmospheric and weather indicating devices, intra site communication equipment, laboratory equipment, insect control equipment signal systems, calla phones, emergency whistles and sirens, fire alarms and other similar equipment refrigerating system, including compressors, pumps, cooling coils, etc.
7. Station maintenance equipment including lathes, shapers, planers, drill presses, grinders, etc., with motors, shafting, hangers, pulleys, etc.
8. Ventilating equipment, including items wholly identified with apparatus listed herein.

1615-730 Hydro Fences (OL = 40 years)

This account shall include the costs associated with fencing around Hydro plants.

GL Code

0000-000-1620 DIESEL PRODUCTION

Class ID

1620-200 Structures and Improvements (OL = 72 years)

This account shall include the costs associated with diesel production structures. These improvements have a longer life expectancy than those

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coded to 1645-200 (Buildings and Other equipment – structures and improvements).

1620-201 Building & Improvements (OL = 55 years)

This account shall include the costs associated with diesel production buildings. These improvements include maintenance, upgrades and renovations.

1620-403 Fuel Holders, Products and Accessories (OL = 25 years)

This account shall include the installation costs of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe through which fuel is directly drawn to the engine and the cost of gas producers and accessories devoted to the production of gas for use in prime movers driving main electric generators.

Components of cost:

1. Coils.
2. Heating piping and valves.
3. Pumps.
4. Fuel scrubbing equipment.
5. Tanks and fuel oil storage.

1620-500 Generating Equipment and Prime (OL = 40 years)

This account shall include the installation costs of diesel or other power driven main generators and the prime movers devoted to the generation of electric energy, together with their auxiliaries. Components of cost:

1. Air filtering system.
2. Belting, shafting, pulleys, reduction gearing, etc.
3. Cooling system, including items wholly identified with apparatus listed herein.
4. Cranes, hoists, etc., including items wholly identified with apparatus listed herein.
5. Engines, diesel, gasoline, gas or other internal combustion.
6. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
7. Generator cooling system, including air cooling and washing apparatus, air fans and accessories, air ducts, etc.
8. Generators, main A.C. or D.C., including field rheostats and connections for self-excited units and excitation system when identified with the generating unit.
9. Governors.
10. Ignition system
11. Inlet valve.
12. Lubricating systems, including filters, tanks, pumps, and piping, coolers.
13. Mechanical meters, including gauges, recording instruments, sampling and testing equipment.

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14. Mufflers.
15. Piping.
16. Platforms, railings, steps, grating, etc., appurtenant to apparatus listed herein.
17. Starting systems, compressed air, or other, including compressors and drives, tanks, piping, motors, boards and connections, storage tanks, etc.
18. Steelwork specially constructed for apparatus listed herein.
19. Waste heat broilers, anti-fluctuations, etc. lubricating oil (first charge) etc.

1620-504 Diesel Assets Overhaul (OL = 5 years)

1620-508 Minto Generating Equipment (OL = 12 years)

This account includes the installation costs of diesel generating equipment at Minto Mine.

1620-600 Accessory Electric Equipment (OL = 45 years)

This account shall include the installation costs of auxiliary generating apparatus, conversion equipment and equipment used primarily in connection with control and switching of electric energy produced in other power generating stations and the protection of electric circuits and equipment except electric motors used to drive equipment included in other accounts. Such motors shall be included in the account in which it is associated.

Note A: Do not include in this account transformers and other equipment used for changing voltage or frequency of electric energy for the purpose of transmission or distribution.

Note B: When any item or equipment listed herein is used wholly to furnish power to equipment included in another account, its cost shall be included in such other account.

Components of cost:

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arrestors, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, special housings, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and protective relays, isolated panels and equipment,

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- conductors and conduit, special support for generator main leads, grounding switch, special housings, protective screens, etc.
4. Station control system, including station switchboards with panel wiring. Panels with instruments and control equipment only, panels with switching equipment, mounted or mechanically connected, trunk type boards complete, cubicles, station supervisory control boards, generator and exciter signal stands, temperature recording devices, frequency control equipment, master clocks, watt-hour meters, station totalizing wattmeter, storage batteries, panels and charging sets, instrument transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, etc.
 5. Station buses, including main, auxiliary, transfers, synchronizing and fault ground bases, including oil circuit breakers and accessories, disconnection switches and accessories, circuit breakers and accessories, disconnection switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors, starting transformers, current transformers, potential transformers, protective relays, storage batteries and charging equipment, isolated panels and equipments, conductors and conduit, special supports, special housings, concrete pads, general station ground system, special fire extinguishing system and test equipment.

1620-700 Miscellaneous Power Plant Equip (OL = 30 years)

This account shall include the installation costs of miscellaneous equipment in and about the other power generating plant devoted to general station use and not properly includable in any of the other foregoing power production accounts. Components of cost:

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails, monorails, hoists, etc. with electrical and mechanical connections.
3. Fire extinguishing equipment for general station use.
4. Foundations and settings; specially constructed for and not expected to outlast the apparatus for which provided. Miscellaneous equipment, including devices, intra site communication equipment, laboratory equipment, signal systems, calla phones, emergency whistles and sirens, fire alarms, belts, pulley, countershafts, etc.
5. Refrigerating system including compressors, pumps, cooling coils, etc.
6. Station maintenance equipment, including lathes shapers, planers, drill presses, hydraulic presses, grinders, etc. with motors, shafting, hangers, pulleys, etc.
7. Ventilating equipment including items wholly identified with apparatus listed herein.

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GL Code

0000-000-1625 DISTRIBUTION SYSTEM

Class ID

1625-300 Poles and Fixtures (OL = 35 years)

This account shall include the installation costs of poles and fixtures used for supporting overhead distribution conductors and service wire.

Note: materials used for substations, including transformers, will be charged to account 1625-710 Substation Equipment.

Components of cost:

1. Anchors, head arm and other guys, including any guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Cross arms and braces.
4. Extension arms.
5. Foundations.
6. Ground rods and clamps.
7. Guards.
8. Insulator pins and suspension bolts.
9. Pole steps.
10. Poles, wood, steel, concrete or other material.
11. Racks complete with insulators.
12. Reinforcing and stubbing.
13. Settings.
14. Shaving.
15. Painting.
16. Roofing.
17. Stencilling.
18. Tagging.
19. Transformers racks and platforms.
20. Other fixtures.

1625-304 Brushing (OL = 50 years)

This account shall include the costs associated with brushing of the distribution system.

1625-305 Survey Costs (OL = 35 years)

This account shall include the costs associated with land surveys, assessments, management and easements.

1625-401 Overhead Conductors (OL = 35 years)

This account shall include the installation costs of overhead conductors and accessories used for distribution purposes. Components of cost:

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1. Armour rods, connectors, hot line clamps and compressor fittings.
2. Brackets.
3. Circuit breakers (Pole mounted).
4. Conductors, including insulated and bare wires and cables.
5. Connectors.
6. Ground wires.
7. Splices.
8. Switches.
9. Tie wire and clamps.
10. Other line accessories.
11. Insulators.

1625-410 Overhead Services (OL = 40 years)

This account shall include the installation and maintenance costs of overhead services such as transmission line installation and upgrades.

1625-501 Underground Conduit (OL = 40 years)

This account shall include the installation costs of underground conduit devices and tunnels used for distribution purposes.

Note: The cost of ditching is to be included in this account when associated with the cable which is directly buried.

Components of cost:

1. Conduit, concrete, brick and tile, including iron pipe, Murray duct and standpipe on poles.
2. Excavation, including shoring, bracing, backfill, trenching and disposal of excess excavated material.
3. Foundations and setting specially constructed for and not expected to outlast the apparatus for which constructed, including pad mount equipment.
4. Ground rods and ground wire.
5. Insulators.
6. Lateral conduits.
7. Lighting systems.
8. Manholes, concrete or brick, including iron or steel frames and covers, pathways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
9. Pavement disturbed, including cutting and replacing pavement, pavement base and sidewalks.
10. Planking.
11. Protection of street openings.
12. Removal and relocation of subsurface obstructions.
13. Sewer connections, including drains, traps, tide valves, check valves, etc.
14. Sumps, including pumps.
15. Vaults for transformers and equipment.

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16. Ventilating equipment.

1625-510 Underground Services (OL = 40 years)

This account shall include the installation costs of underground conductors and services. Components of Cost:

1. Cables, wire, armoured conductors buried or submarine, including insulating materials, splices in terminal chamber, potheads, termination, etc.
2. Circuit breakers.
3. Fireproofing in connection with any item installed herein.
4. Hollow core, oil filled cable, including straight or stop joints, pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, etc.
5. Lead and fabric covered conductors, compound filled, oil filled or vacuum splices, potheads.
6. Racking of cables.
7. Service pedestals.
8. Switches.
9. Other line devices.

1625-610 Meters (OL = 30 years)

This account shall include the cost of meters purchased and used in measuring electricity delivered to its users whether actually in service or held in reserve. Components of cost:

1. Alternating current watt-hour meters.
2. Demand meters.
3. Graphic demand meters.
4. Maximum demand meters.
5. Digital pulse recorders.

Note: This account shall not include meters for recording output of a generating station, substation, etc. It includes only meters used to record energy delivered to customers.

1625-620 Meter Equipment (OL = 30 years)

This account shall include the installation costs of metering devices and appurtenances thereto used to transform electricity so that it can be measured by meter when delivered to its users. Components of cost:

1. Installation, labour of (first installation only)
2. Instrument transformers.
3. Meters boards, boxes, tanks, fittings and connectors.
4. Meter switches, cut-outs and test switches.
5. Potential transformer fuses.
6. Protective devices.
7. Service entrance cable and caps.
8. Multi breakers.
9. Grounding materials.

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1625-710 Substation Equipment (OL = 40 years)

This account shall include the installation costs of substation equipment including transformers, etc. which are used for the purpose of changing the characteristics of electricity in connection with distribution.

Components of cost:

1. Bus compartments, concrete, brick and sectional steel, including items permanently attached thereto.
2. Conduit, including concrete and iron duct runs not part of building.
3. Control equipment, including batteries, battery charging equipment, transformers, remote relay boards and connections.
4. Conversion equipment, indoor and outdoor, frequency changers, motor generator sets, rectifiers, synchronous converters, motors, cooling equipment and associated connections.
5. Fixed and synchronous condensers, including transformers, switching equipment, blowers, motors and connections.
6. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
7. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment, etc.,
8. Ground rods and ground wires for grounding network.
9. Platforms, railings, steps, gratings and appurtenances, apparatus tested herein.
10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lighting arrestors, cable and wire runs from and to outdoor connections or to manholes and the associated regulators, reactors, resistors, surge arrestors and associated equipment.
11. Switchboards, including meters, relays, control wiring, etc.
12. Switching equipment indoor and outdoor, including all of the circuit breakers and operating mechanisms, truck switches and disconnect switches.
13. Tools and appliances.
14. Towers, steel structures, poles and appurtenant fixtures used for supporting substation equipment and buses.
15. Transformers.

1625-720 Substation Buildings (OL = 55 years)

This account shall include the costs associated with buildings located at the distribution substation site.

1625-730 Substation Fences (OL = 20 years)

This account shall include the fences surrounding the distribution substation site.

1625-815 Street Lights (OL = 40 years)

This account shall include the installation costs of equipment used wholly

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for public street and highway lighting or traffic, fire alarm, police and other signal systems. Components of cost:

1. Armoured conductors, buried or submarine, including insulators, insulating materials, splices, trenching, etc.
2. Automatic control equipment.
3. Ballasts, conductors, overhead or underground, including lead or fabric covered parkway cables, splices, insulators, etc.
4. Lamps, arc, incandescent, mercury vapour or other types, including glassware, suspension fixtures, brackets, etc. municipal inspection, ornamental lamp standards.
5. Pavements disturbed, including cutting and replacing pavement, pavement base and sidewalks.
6. Permits
7. Poles, wood, concrete or steel, used exclusively for street lighting.
8. Protection of street openings.
9. Relays, electric eyes and time clocks.
10. Switches.
11. Transformers, pole mounted or underground, used exclusively for street lighting.

1625-905 Line Transformers (OL = 40 years)

This account shall include the installation costs of overhead and underground distribution line transformers and pole type and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve. Components of cost:

1. Installation, labour of (first installation only).
2. Switches forming part of a transformer unit.
3. Transformer cut out boxes (fuse cut outs)
4. Lightning arrestors.
5. Transformers, line and network.
6. Capacitors.
7. Network protectors.

1625-921 Capacitor Installations (OL = NA)

This account shall include the costs associated with capacitor installations on distribution lines.

1625-961 Sentinel Lights (OL = 30 years)

This account shall include the installation costs of sentinel and flood lighting (other than street lighting for municipalities and highways), for which customers are charged a flat rate. Components of cost:

1. Brackets, complete with fixture and ballast.
2. Poles, wood, steel or concrete.
3. Electric eye and relays.
4. Conductors, overhead and underground.

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GL Code

0000-000-1630 WIND TURBINE

Class ID

1630-400 Wind Turbine (OL = 30 years)

This account shall include the costs associated with the wind turbines and wind monitoring equipment, including blade upgrades and heaters

GL Code

0000-000-1635 MAIN TRANSMISSION FACILITIES

Class ID

1635-300 Poles and Fixtures (OL = 65 years)

This account shall include the installation costs of poles and fixtures used for transmission purposes. Components of cost:

1. Anchors, head arm and other including guy guards, guy clamps, strain plates and strain insulators.
2. Brackets
3. Cross arms and braces.
4. Excavations, backfill, etc.
5. Extension arms.
6. Foundation.
7. Gaining, roofing, stencilling and tagging.
8. Ground rods and clamps.
9. Guards.
10. Insulator pins and guys, suspension bolts.
11. Paving.
12. Pole steps.
13. Poles – wood, steel, concrete, or other material.
14. Racks, c/w insulators.
15. Railings, etc.
16. Reinforcing and stubbing.
17. Setting.
18. Shaving and painting.
19. Timbers.
20. Vibration dampers.

1635-304 Brushing (OL = 50 years)

This account shall include the costs of brushing associated with the main transmission lines and facilities.

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- 1635-305 Survey Costs (OL = 50 years)**
This account shall include the land survey costs associated with the main transmission facilities.
- 1635-340 Brushing Poles (OL = NA)**
- 1635-402 Overhead Conductors/Poles (OL = 50 years)**
This account shall include the installation costs of overhead conductors used for transmission purposes. Components of cost:
1. Circuit breakers not in substations.
 2. Conductors, including insulators and bare wires.
 3. Lightning arrestors.
 4. Switches.
 5. Other line devices and cables.
 6. Conductor clamps, insulators, including pin suspension and other types.
- 1635-404 Overhead Conductors/Towers (OL = 50 years)**
This account shall include the installation costs of overhead conductors used for transmission purposes. Components of cost:
1. Circuit breakers not in substations.
 2. Conductors including insulators and bare wires
 3. Lightning arrestors.
 4. Switches.
 5. Other Line devices and cables.
 6. Conductor clamps, insulators, including pin suspension and other types.
- 1635-509 Towers and Fixtures (OL = NA)**
This account shall include the installation costs of towers and fixtures used for transmission purposes. Components of cost:
1. Anchors, head arm and other including guy guards, guy clamps, strain plates and strain insulators.
 2. Brackets.
 3. Cross arms and braces.
 4. Excavations, backfill, etc.
 5. Extension arms.
 6. Foundation.
 7. Gaining, roofing, stencilling and tagging.
 8. Ground rods and clamps.
 9. Guards.
 10. Insulator pins and guys, suspension bolts.
 11. Paving.

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12. Racks, c/w insulators.
13. Railings, etc.
14. Reinforcing and stubbing.
15. Setting
16. Shaving and painting.
17. Timbers.
18. Towers.
19. Vibration dampers.

1635-710 Substation Equipment (OL = 54 years)

This account shall include the installation costs of transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with transmission or controlling transmission circuits. Components of cost:

1. Bus compartments, concrete brick and sectional steel including items permanently attached thereto.
2. Conduit, including concrete and duct runs not a part of a building.
3. Control equipment, including batteries, battery charging equipment, transformers, remote relay boards and connections.
4. Conversion equipment, including transformers, indoors and outdoors, frequency changes, motor generator sets, rectifiers, synchronous converters, motors, cooling and equipment and associated connections.
5. Fixed and synchronous condensers, including transformers switching equipment, blowers, motors and connections.
6. Foundations and settings; specially constructed for and not expected to outlast the apparatus for which provided.
7. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment.
8. Ground rods and ground wire for ground network.
9. Platforms, railings, steps, gratings and appurtenances to apparatus listed herein.
10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lightning arrestors, cable and wire runs from and to outdoor connections or to man holes and the associated regulators, reactors, resistors, surge arrestors and accessory equipment.
11. Switchboards, including meters, relays, control wiring, etc.

1635-720 Substation Buildings (OL = 55 years)

This account shall include the costs associated with substation buildings.

1635-730 Substation Fences (OL = 20 years)

This account shall include the costs associated with substation fences.

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GL Code

0000-000-1640 SUB TRANSMISSION LINES

Class ID

1640-300 Poles and Fixtures (OL = 45 years)

This account shall include the installation costs of poles and fixtures used for supporting overhead distribution conductors and service wire.

Note: materials used for substations, including transformers, will be charged to account 1640-710 Substation Equipment.

Components of cost:

1. Anchors, head arm and other guys, including any guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Cross arms and braces.
4. Extension arms.
5. Foundations.
6. Ground rods and clamps.
7. Guards.
8. Insulator pins and suspension bolts.
9. Pole steps.
10. Poles, wood, steel, concrete or other material.
11. Racks complete with insulators.
12. Reinforcing and stubbing.
13. Settings.
14. Shaving.
15. Painting.
16. Roofing.
17. Stencilling.
18. Tagging.
19. Transformers racks and platforms.
20. Other fixtures.

1640-301 Poles & Fixtures Minto Mines (OL = 12 years)

This account shall include the installation costs of poles and fixtures at Minto Mine.

1640-304 Brushing (OL = 50)

This account shall include the costs of brushing associated with sub transmission lines.

1640-305 Survey Costs (OL = NA)

This account shall include the land survey costs associated with the sub transmission lines.

1640-306 Brushing Minto Mine (OL = 12 years)

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This account shall include the costs of brushing associated with sub transmission lines at Minto Mine.

1640-307 Survey Costs Minto Mine (OL = 12 years)

This account shall include the land survey costs associated with the sub transmission lines at Minto Mine.

1640-401 Overhead Conductors (OL = 45 years)

This account shall include the installation costs of overhead conductors and accessories used for distribution purposes. Components of cost:

1. Armour rods, connectors, hot line clamps and compressor fittings.
2. Brackets.
3. Circuit breakers (Pole mounted).
4. Conductors, including insulated and bare wires and cables.
5. Connectors.
6. Ground wires.
7. Splices.
8. Switches.
9. Tie wire and clamps.
10. Other line accessories.
11. Insulators.

1640-405 Underground Conductors/Conduit (OL = 45 years)

This account shall include the installation costs of underground conduit devices and tunnels used for distribution purposes. Note: The cost of ditching is to be included in this account when associated with the cable which is directly buried. Components of cost:

1. Conduit, concrete, brick and tile, including iron pipe, murray duct and standpipe on poles.
2. Excavation, including shoring, bracing, backfill, trenching and disposal of excess excavated material.
3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed, including pad mount equipment.
4. Ground rods and ground wire.
5. Insulators.
6. Lateral conduits.
7. Lighting systems.
8. Manholes, concrete or brick, including iron or steel frames and covers, pathways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
9. Pavement disturbed, including cutting and replacing pavement, pavement base and sidewalks.
10. Planking.
11. Protection of street openings.
12. Removal and relocation of subsurface obstructions.
13. Sewer connections, including drains, traps, tide valves, check valves,

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- etc.
14. Sumps, including pumps.
15. Vaults for transformers and equipment.
16. Ventilating equipment

- 1640-407 Overhead Conductors Minto Mine (OL = 12 years)**
This account shall include the installation cost of overhead conductors at Minto Mine.
- 1640-710 Substation Equipment (OL = 40 years)**
This account shall include costs associated with substation equipment.
- 1640-711 Substation Equipment Minto Mine (OL = 12 years)**
This account shall include costs associated with substation equipment and upgrades at Minto Mine.
- 1640-921 Capacitor Installations (OL = NA)**
This account shall include the costs of capacitor installations on sub transmission lines.

GL Code

0000-000-1645 BUILDING AND OTHER EQUIPMENT

Class ID

- 1645-106 Land Rights (OL = NA)**
This account shall include costs associated with land rights of the general plant.
- 1645-110 Survey Costs Land (OL = 50 years)**
This account shall include costs associated with land survey of the general plant.
- 1645-200 Structures and improvement hydro (OL = 40 years)**
This account shall include costs of improvements associated with a hydro facility that is not attached to the hydro plant itself. These improvements are much more general and have a shorter expected life than those allocated to the code 1615-200 (Hydro – Structures and improvements). This would include renovations and improvements to berms, signage, roads, boilers, and fall arrest.
- 1645-201 Building and Improvements (OL = 55 years)**
This account shall include costs associated with buildings and improvements. This would include staff housing, warehouses, offices, fencing, building envelopes, fish hatchery, yard work, guard rails.

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- 1645-202 Office Furniture & Equip (OL = 20 years)**
This account shall include the cost of office furniture and equipment owned by the utility and devoted to utility service and not permanently attached to buildings, except the cost of such furniture and equipment which the utility elects to assign to other plant accounts on a functional basis. Components of cost:
1. Bookcases and shelves.
 2. Desks, chairs and desk equipment.
 3. Drafting room equipment.
 4. Filing, storage and other cabinets.
 5. Floor coverings.
 6. Library and library equipment.
 7. Mechanical office equipment, such as accounting machines and typewriters, adding machines, calculators.
 8. Safes
 9. Tables.
- 1645-210 Communication Site Towers (OL = 30 years)**
This account shall include costs of communication site towers associated with general plant.
- 1645-220 Communication Site Fences (OL = 20 years)**
This account shall include costs of communication site fences associated with general plant.
- 1645-310 Main Frame Computer (APL Share) (OL = NA)**
This account shall include the 1/3 cost of mainframe computer equipment and installation cost which is jointly owned by APL, NUL and CWNG. Components of cost:
1. Mainframe equipments (AMDAHL)
- 1645-320 Computer Hardware (OL = 6 years)**
This account shall include the full cost of computer equipment (other than mainframe), which is owned by APL. Components of cost:
1. Personal computers and associated equipment.
 2. Printers (Mainframe and PC)
 3. Terminals.
 4. Word processors and associated equipment.
 5. Keyboards
 6. DASD (Direct Access Storage Device)
- 1645-330 Computer Software (OL = 5 years)**
This account shall include the cost of computer software purchases, including upgrades, enhancements and maintenance.
***Note: Now goes to intangibles – account 2120**

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1645-340 CUL Hardware (OL = NA)

1645-505 Tools and Instruments (OL = 20 years)

This account shall include the cost of tools, implements and equipment used on construction, repair work, general shops and garages and the installation costs of laboratory equipment used for general laboratory purposes and not specifically provided for or includable in other accounts.

Components of cost:

1. Air compressors
2. Automobile repair shop equipment.
3. Cable pulling equipment
4. Electric equipment.
5. Gasoline pumps, oil pumps and storage tanks.
6. Greasing tools and equipment, hoists.
7. Ladders.
8. Lathes.
9. Machine tools
10. Motor drive tools.
11. Pipe threading and cutting tools.
12. Pneumatic tools
13. Pumps
14. Work Benches.
15. Ammeters.
16. Frequency changers.
17. Galvanometers.
18. Induct meters.
19. Laboratory standard mille-volt meters.
20. Laboratory standard voltmeters.
21. Meter testing equipment.
22. Motor generator sets
23. Panels
24. Phantom loads.
25. Portable graphic ammeters, voltmeters and wattmeters.
26. Potentiometers.
27. Rotating standards.
28. Standard call, reactance resistor and shunt.
29. Switchboards.
30. Synchronous timers.
31. Testing panels.
32. Transformers.
33. Voltmeters.

1645-507 Wind Monitoring Equipment (OL = 20 years)

This account shall include costs associated with wind monitoring equipment. This includes tall towers and ultrasonic anemometers.

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- 1645-605 Communication Equipment (OL = 20 years)**
This account shall include the installation costs of telephone, fibre optic and wireless equipment for general use in connection with utility operations. Components of cost:
1. Antennae
 2. Booths
 3. Cables
 4. Distribution boards
 5. Handsets, manual and dial
 6. Insulators
 7. Intercommunicating sets
 8. Loading coil
 9. Poles and fixtures used wholly for telephone or fibre optics.
 10. Radio transmitting and receiving sets.
 11. Remote control equipment and lines
 12. Sending Keys
 13. Storage batteries.
 14. Switchboards
 15. Testing instruments
 16. Underground conduit and cable used wholly for telephone or fibre optics.
 17. Touch tone encoders.
- 1645-701 Training Development Costs (OL = 10)**
This account shall include the costs associated with training development.
- 1645-810 Company Owned Houses/Land (OL = 35 years)**
This account shall include the costs of upgrades and maintenance associated with the land of houses owned by the company.
- 1645-820 Company Owned Houses/Buildings (OL = 35 years)**
This account shall include the costs of upgrades and maintenance associated with the buildings of houses owned by the company.
- 1645-850 AMP Project (OL = 10 years)**
This account shall include the costs associated with the AMP financial system implementation and upgrades.

GL Code

0000-000-1650 TRANSPORTATION

Class ID

- 1650-406 Transportation Depreciation**
This account is for accumulated depreciation prior to implementation of FIS in June 1993.

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- 1650-411 Utility Vehicles (OL = 9 years)**
This account shall include the costs of utility vehicle purchases. These include utility trailers, cargo trailers, atvs, snowmobiles, and boats.
- 1650-412 Sedans and Station wagons (OL = 7 years)**
This account shall include the costs of vans, cars and smaller vehicles that don't fit the category 1650-440 - Trucks under $\frac{3}{4}$ tons.
- 1650-420 Trucks and Pole Trailers (OL = 31 years)**
This account shall include the costs of large trucks that pull pole trailers and small pole trailers < 10,000 lbs.
- 1650-430 Pole Trailers > 10,000 lbs. (OL = 31 years)**
This account shall include the costs of pole trailers larger than 10,000 lbs.
- 1650-440 Trucks $\frac{3}{4}$ to 2 ton (OL = 13 years)**
This account shall include the costs of trucks $\frac{3}{4}$ ton to 2 tonnes used by the employees to carry out day to day duties.
- 1650-450 Trucks >2 ton and < 3 ton (OL = NA)**
This account shall include the costs of trucks more than 2 tonnes but less than 3 tonnes used by the employees to carry out day to day duties.
- 1650-460 Pole Cats (OL = NA)**
- 1650-470 Trucks > 3 ton (OL = 25 years)**
This account shall include the costs of trucks more than 3 tonnes including diggers, crane trucks, forklifts and bucket trucks.
- 1650-480 Tractor (OL = NA)**
- 1650-490 Foremost (OL = 25 years)**
This account shall include the costs of large specialty vehicles which are usually tracked (rather than wheeled).

GL Code

0000-000-1655 Critical Spares

Class ID

- 1655-750 Critical Spares (OL = 00 years)**
This account shall include repair/replacement parts for units that are critical to keep in working order. These parts may have a long lead time or be difficult to source. This class is not depreciated as these parts are not yet in use.

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GL Code

0000-000-1665 Gas Production

Class ID

1665-200 Structures and improvements (OL = 72 years)

The accounts for structures and improvements shall include the cost of all buildings and facilities to house, support, or safeguard property or persons, including all fixtures permanently attached to and made a part of buildings and which cannot be removed therefrom without cutting into the walls, ceilings, floors, or without in some way impairing the buildings, and improvements of a permanent character on or to land. Also include those costs incurred in connection with the first clearing and grading of land and rights-of-way and the damage costs associated with construction and installation of plant.

The cost of specially provided foundations not intended to outlast the machinery or apparatus for which provided, and the cost of angle irons, castings, etc., installed at the base of an item of equipment, shall be charged to the same account as the cost of the machinery, apparatus, or equipment.

The items of cost to be included in the accounts for structures and improvements are as follows:

1. Architects' plans and specifications including supervision.
2. Boilers, furnaces, piping, wiring, fixtures, and machinery for heating, lighting, signalling, ventilating, and air-conditioning systems, plumbing, vacuum cleaning systems, incinerator and smoke pipe, flues, etc.
3. Fire protection systems when forming a part of a structure.
4. Foundations and piers for machinery, constructed as a permanent part of a building or other item listed herein.
5. Grading and clearing when directly occasioned by the building of a structure.
6. Landscaping, lawns, shrubbery, etc.
7. Permanent paving, concrete, brick, flagstone, asphalt, etc., within the property lines.
8. Sump pumps and pits
9. Yard drainage system
10. Yard lighting system
11. Yard surfacing, gravel, concrete, or oil. (First cost only.)

1665-403 Fuel holders, producers and accessories (OL = 32 years)

This account shall include the cost installed of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe through which fuel is directly drawn to the engine, also the cost of gas producers and accessories devoted to the production of gas for use in prime movers driving main electric generators. Items of cost

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include:

1. Blower and fans.
2. Boilers and pumps.
3. Economizers.
4. Exhauster outfits.
5. Flues and piping.
6. Pipe system.
7. Producers.
8. Regenerators.
9. Scrubbers.
10. Steam injectors.
11. Tanks for storage of oil, gasoline, etc.
12. Vaporizers.

1665-500 Generating Equipment and Prime movers (OL = 40 years)

This account shall include the cost installed of other prime movers devoted to the generation of electric energy, together with their auxiliaries. Items of cost include:

1. Air-filtering system.
2. Belting, shafting, pulleys, reduction gearing, etc.
3. Cooling system, including towers, pumps, tanks, and piping.
4. Cranes, hoists, etc., including items wholly identified with apparatus listed herein.
5. Engines, gasoline, gas, or other internal combustion.
6. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
7. Governors.
8. Ignition system.
9. Inlet valve.
10. Lighting systems.
11. Lubricating systems, including filters, tanks, pumps, and piping.
12. Mechanical meters, including gauges, recording instruments, sampling, and testing equipment.
13. Mufflers.
14. Piping.
15. Starting systems, compressed air, or other, including compressors and drives, tanks, piping, motors, boards and connections, storage tanks, etc.
16. Steelwork, specially constructed for apparatus listed herein.
17. Waste heat boilers, antifluators, etc.

1665-508 Generators (OL = NA)

This account shall include the cost installed of power driven main generators. Items of cost include:

1. Cranes, hoists, etc., including items wholly identified with such apparatus.
2. Fire-extinguishing equipment.
3. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.

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4. Generator cooling system, including air cooling and washing apparatus, air fans and accessories, air ducts, etc.
5. Generators—main, a.c. or d.c., including field rheostats and connections for self-excited units and excitation system when identified with the generating unit.
6. Lighting systems.
7. Lubricating system, including tanks, filters, strainers, pumps, piping, coolers, etc.
8. Mechanical meters, and recording instruments.
9. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.

NOTE: If prime movers and generators are so integrated that it is not practical to classify them separately, the entire unit may be included in account 1665-508, Generators.

1665-600 Accessory electric equipment (OL = 45 years)

This account shall include the cost installed of auxiliary generating apparatus, conversion equipment, and equipment used primarily in connection with the control and switching of electric energy produced in other power generating stations, and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts. Such motors shall be included in the account in which the equipment with which it is associated is included. Items of cost include:

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment, and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arresters, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, etc., special housings, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, current transformers, potential transformers, protective relays, isolated panels and equipment, conductors and conduit, special supports for generator main leads, grounding switch, etc., special housing, protective screens, etc.
4. Station control system, including station switchboards with panel wiring, panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, trunk type boards complete, cubicles, station supervisory control boards, generator and exciter signal stands, temperature-recording devices, frequency control equipment, master clocks, watt-hour meter, station totalizing wattmeter, storage batteries, panels and charging sets, instrument transformers for supervisory metering, conductors and conduit, special

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supports for conduit, switchboards, batteries, special housing for batteries, protective screens, doors, etc.

5. Station buses, including main, auxiliary transfer, synchronizing and fault ground buses, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors, starting transformers, current transformers, potential transformers, protective relays, storage batteries and charging equipment, isolated panels and equipment, conductors and conduit, special supports, special housings, concrete pads, general station ground system, special fire-extinguishing system, and test equipment.

NOTE A: Do not include in this account transformers and other equipment used for changing the voltage or frequency of electric energy for the purpose of transmission or distribution.

NOTE B: When any item of equipment listed herein is used wholly to furnish power to equipment included in another account, its cost shall be included in such other account.

1665-700 Miscellaneous power plant equipment (OL = 30 years)

This account shall include the cost installed of miscellaneous equipment in and about the other power generating plant, devoted to general station use, and not properly includible in any of the foregoing other power production accounts. Items of cost include:

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails, monorails, hoists, etc., with electric and mechanical connections.
3. Fire-extinguishing equipment for general station use.
4. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
5. Miscellaneous equipment, including atmospheric and weather indicating devices, intrasite communication equipment, laboratory equipment, signal systems, callophones, emergency whistles and sirens, fire alarms, and other similar equipment.
6. Miscellaneous belts, pulleys, countershafts, etc.
7. Refrigerating system including compressors, pumps, cooling coils, etc.
8. Station maintenance equipment, including lathes, shapers, planers, drill presses, hydraulic presses, grinders, etc., with motors, shafting, hangers, pulleys, etc.
9. Ventilating equipment, including items wholly identified with apparatus listed herein.

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NOTE: When any item of equipment, listed herein is used wholly in connection with equipment included in another account, its cost shall be included in such other account.

1665-730 Fencing (OL = 30 years)

This account includes the cost of fences surrounding the site. This fencing is not chain link fence but rather a corrugated metal fence. This is a solid fence built to prevent vapour dispersion.

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Net Differences

Net Difference depreciation amounts are not kept in the fixed asset subledger. The amounts in these accounts are kept in a spreadsheet and the entries to the accounts are made once a month.

0000-000-1611	LAND DIFFERENCES
0000-000-1711	Land Differences Accum Depr
0000-000-1616	HYDRO PLANT DIFFERENCES
0000-000-1716	Hydro Plant Differences Accum Depr
0000-000-1621	DIESEL PLANT DIFFERENCES
0000-000-1721	Diesel Plant Differences Accum Depr
0000-000-1626	DISTRIBUTION SYSTEMS DIFFERENCES
0000-000-1726	Distribution Differences Accum Depr
0000-000-1631	WIND TURBINE DIFFERENCES
0000-000-1731	Wind Turbine Differences Accum Depr
0000-000-1636	MAIN TRANSMISSION DIFFERENCES
0000-000-1736	Main Transmission Differences Accum Depr
0000-000-1641	SUB TRANSMISSION DIFFERENCES
0000-000-1741	Sub Transmission Differences Accum Depr
0000-000-1646	BUILDINGS & EQUIPMENT DIFFERENCES
0000-000-1746	Bldngs & Equip Differences Accum Depr
0000-000-1651	TRANSPORTATION DIFFERENCES
0000-000-1751	Transportation Differences Accum Depr

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Accumulated Depreciation

Depreciation is calculated in the subledger by asset within the Class ID. The deprecation amount is then pushed forward to the GL through the GL code. There are several class ID's that point to each accumulated depreciation account in the GL code.

GL Code

0000-000-1710 LAND ACCUM DEPR

Class ID

1610-003	Land Hydro Production
1610-004	Land Diesel Production
1610-006	Land Main Trx Facilities
1610-008	Land Distribution System
1610-009	Land General Plant
1610-106	Land Rights
1610-110	Land – LNG Production

GL Code

0000-000-1715 HYDRO PLANT ACCUM DEPR

Class ID

1615-200	Hydro-Strctrs & Imprvmts
1615-205	Hydro-Rsrvoirs Dams & Wtrways
1615-206	Hydro, Dams wtwys Twin Assets
1615-504	Hydro Assets Overhaul
1615-506	Hydro-Wtrwhls, Trbines & Gen's
1615-600	Hydro-Accessory Electric Equip
1615-700	Hydro-Misc Power Plant Equipm
1615-730	Hydro-Fences

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GL Code

0000-000-1720 DIESEL PLANT ACCUM DEPR

Class ID

1620-200 Diesel – Strctrs and Imprvmts
1620-201 Diesel - Building & Imprvmnt
1620-403 Diesel - Fuel Hldrs, Prdcts & Accss
1620-500 Diesel – Gnrtnng Equip & Prime
1620-508 Diesel – Minto Gnrtnng Equip
1620-600 Diesel – Acc Electric Equip
1620-700 Diesel – Misc Power Plant Equip

GL Code

0000-000-1725 DISTRIBUTION SYSTEMS ACCUM DEPR

Class ID

1625-300 Dist System – Poles & Fxtrs
1625-304 Dist System - Brushing
1625-305 Dist System - Survey Costs
1625-401 Dist System – O/H Cndctrs
1625-410 Dist System – O/H Services
1625-501 Underground Conduit
1625-510 Dist System - Undrgrnd Services
1625-550 Dist System – Altrntv Enrgy Eq
1625-610 Dist System - Meters
1625-620 Dist System - Meter Equip
1625-710 Dist System – Sbstdn EEquip
1625-720 Dist System - Sbstdn Buildings

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1625-730 Dist System - Substation Fences

1625-815 Dist System - Street Lights

1625-905 Dist System - Line Transformers

1625-921 Capacitor Installations

1625-961 Dist System - Sentinel Lights

GL Code

0000-000-1730 WIND TURBINE ACCUM DEPR

Class ID

1630-400 Wind Turbine

GL Code

0000-000-1735 MAIN TRANSMISSION ACCUM DEPR

Class ID

1635-300 Main Trx - Poles & Fxtrs

1635-304 Main Trx - Brushing

1635-305 Main Trx - Survey Costs

1635-340 Brushing Poles

1635-402 Main Trx – O/H Cndctrs/Poles

1635-404 Main Trx – O/H Cndctrs/Towers

1635-509 Towers and Fixtures

1635-710 Main Trx – Sbstn Equip

1635-720 Main Trx – Sbstn Buildings

1635-730 Main Trx – Sbstn Fences

GL Code

0000-000-1740 SUB TRANSMISSION ACCUM DEPR

Class ID

1640-300 Sub Trx - Poles and Fxtrs

1640-301 Sub Trx - Poles & Fxtrs Mnt Mn

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1640-304	Sub Trx - Brushing
1640-305	Sub Trx - Survey Costs
1640-306	Sub Trx - Brushing Mnt Mn
1640-307	Sub Trx - Survey Costs Mnt Mn
1640-401	Sub Trx – O/H Cndctrs
1640-405	Sub Trx – Undrgrnd Cndctrs/Cnd
1640-407	Sub Trx – O/H Cndcts Mnt Mn
1640-710	Sub Trx – Sbstn EEquip
1640-711	Sub Trx – Sbstn Equips Mnt Mn
1640-921	Compactor Installations

GL Code

0000-000-1745 BUILDINGS & EQUIPMENT ACCUM DEPR

Class ID

1645-106	Building & Other - Land Rights
1645-110	Bldg&Otr - Survey Costs Land
1645-200	Bldg&Otr – Strctrs/Imprvmnt Hyd
1645-201	Bldg&Otr – Building & Imprvmnt
1645-202	Bldg&Otr – Office Frntr & Equip
1645-210	Bldg&Otr - Comm Site Towers
1645-220	Bldg&Otr – Comm Site Fences
1645-310	Bldg&Otr – Mn Frm Cmptr (APL)
1645-320	Bldg&Otr - Computer Hardware
1645-330	Bldg&Otr - Computer Software
1645-340	Bldg&Other - CUL Hardware

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1645-505 Bldg&Otr - Tools & Instruments

1645-507 Bldg&Otr - Wind Mntrng Equip

1645-605 Bldg&Otr - Comm Equipment

1645-701 Training Development Costs

1645-810 Bldg&Otr - Houses/Land

1645-820 Bldg&Otr - Houses/Buildings

1645-850 Bldg&Otr - AMP Project

GL Code

0000-000-1750 TRANSPORTATION ACCUM DEPR

Class ID

1650-406 Trxptn – Depreciation

1650-411 Trxptn - Utility Vehicles

1650-412 Trxptn - Sedans and Stn Wagons

1650-420 Trxptn - Trucks and Pole Trailers

1650-430 Trxptn - Pole Trailers > 10,000 lbs.

1650-440 Trxptn - Trucks 3/4 to 2 ton

1650-450 Trxptn - Trucks >2 ton and < 3 ton

1650-460 Trxptn - Pole Cats

1650-470 Trxptn - Trucks > 3 ton

1650-480 Trxptn - Tractor

1650-490 Trxptn - Foremost

GL Code

0000-000-1765 GAS PRODUCTION ACCUM DEPR

Class ID

1665-200 Structures and Improvements

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1665-403	Fuel Holders
1665-500	LNG Generator
1665-508	Generators
1665-600	Accessory Electric Equipment
1665-700	Miscellaneous power plant equipment
1665 730	LNG Fence

Fixed Asset Unit Numbers

When a fixed asset is set up it must be assigned a unit number. Having assigned unit numbers will ensure that we know the true cost or how much we have spent on each unit that we own. We cannot set up an asset when it relates to more than one unit number. The cost must be allocated to the unit numbers. There has to be a one to one relationship.

There is a location within GP to put this number. When you go to the Asset General Information screen there is a little book in the right hand corner. When you click on this a drop down box shows up with an option for Asset User Data. The third box in this field is for the Unit #. The units to be added are shown below.

In Fixed Assets a unique **Unit Number** is assigned to each asset we need to record costs on. Each unit number is unique and can only be used once.

Assigning Unit Numbers

The assignment of unit numbers is not always clear. The project manager will be required to assist Finance with the assignment of numbers.

Naming convention used

For the most part we have tried to split the numbering of assets into three digit designations. For the most part the split is Location (A= Aishihik, W= Whitehorse, D=Dawson), type of asset (D=Diesel, H=Hydro, W=Wind) and Number (1, 2, 3, etc.). Of course there are exceptions to this rule. All line assets start with L and then the remaining digits are the line that it refers to. All houses start with H and the last digit is the location of the house. All substations start with S and then the remaining digits are the substation that it refers to. All distribution lines start with T and the last digits are the distribution that it refers to. Vehicles are named as their unit number only.

We have taken the following approach for certain unit numbers:

AH0 – this includes those assets that relate to the Aishihik building structure. This would include items like elevator, roof, heating, warehouse storage, etc. Items from this

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category cannot be allocated to any particular hydro unit.

WHQ – this includes all the trailers, all computer hardware and software, SCADA, printers and faxes, chairs, desks, file cabinets, shelving, fridges, appliances, facilities signage, land easement, fall protection

Vehicles – these have been assigned the actual vehicle number.

L355 – these are assets that are either sub transmission assets from Aishihik to Haines Junction or assets that are called Aishihik Distribution System within the fixed asset system.

GME – this is general moveable equipment that cannot be assigned to any particular location. This would include items like chains, jacks, pump, washers, tools, mobile radio equipment

FD0 - this includes those assets that relate to the Faro Diesel building. This would include items like the building, roof, heating, hoists, fuel storage.

DDO – this includes those assets that relate to the Dawson Diesel building. This would include items like the building, roof, heating, hoists, fuel storage

MDO - this includes those assets that relate to the Mayo Diesel building. This would include items like the building, roof, heating, hoists, fuel storage

MHO - this includes those assets that relate to the Mayo Hydro A building. This would include items like the building, roof, heating, hoists, fuel storage

MBH - this includes those assets that relate to the Mayo Hydro B building. This would include items like the building, roof, heating, hoists, fuel storage

WDO - this includes those assets that relate to the Whitehorse diesel building. This would include items like the building, roof, heating, hoists, fuel storage

Unit Number	Description
AH0	Aishihik Hydro General
AH1	Aishihik Hydro#1
AH2	Aishihik Hydro#2
AH3	Aishihik Hydro #3
AHP	Aishihik Hydro Plant
ALCS	Aishihik Lake Control Structure
CLCS	Canyon Lake Control Structure
DD0	Dawson Diesel Units General
DD1	Dawson Diesel Unit #1
DD2	Dawson Diesel Unit #1
DD3	Dawson Diesel Unit #3
DD4	Dawson Diesel Unit #4 - removed
DD5	Dawson Diesel Unit #5
DDP	Dawson Diesel Plant
DDS	Dawson Distribution including Feeder 1, Feeder 2 & Express Feeder
DM1	Diesel Mobile Unit #1
DHQ	Dawson Office

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Unit Number	Description
FD0	Faro Diesel Units General
FD1	Faro Diesel Unit #1
FD2	Faro Diesel Unit #2
FD3	Faro Diesel Unit #3
FD4	Faro Diesel Unit #4
FD5	Faro Diesel Unit #5
FD7	Faro Diesel Unit #7
FFB	Faro Diesel Plant
FDS	Faro Distribution including Feeder 1 and Feeder 2
FHW1	Ferry Hill Wind Monitoring
GME	General Moveable Equipment
H1A	House Aishihik
H4F	House 4 Faro
H5M	House 5 Mayo Block 8
H6D	House 6 Dawson – this looks like 2 houses are on the same title when purchased from Yukon Housing
H7D	House 7 Dawson – this is the house on 5 th that is used for travelling staff
H8M	House 8 Mayo Lot 1088
H9M	House 9 Mayo Lot 1095
H10M	House 10 Mayo Industrial subdivision
H11M	Bunkhouse Trailer Mayo Lot 1117
KUL	Kulan Warehouse and Yard
LCS	Lewes Control Structure
LNG	LNG Facilities - Whitehorse
MLCS	Marsh Lake Control Structure
MD0	Mayo Diesel Units General
MD1	Mayo Diesel Unit #1
MD2	Mayo Diesel Unit #2
MD3	Mayo Diesel Unit #3
MDP	Mayo Diesel Plant
MDS	Mayo Distribution
MH1	Mayo Hydro A Unit #1
MH2	Mayo Hydro A Unit #2
MHB1	Mayo Hydro B – Unit#1
MHB2	Mayo Hydro B – Unit#2
MHB	Mayo Hydro B Plant
MBR	Mayo Hydro B Penstock
MHO	Mayo Hydro A Plant
MOW	Mayo Office Warehouse
WDS	Wareham Dam Structure

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Unit Number	Description
MSS	Mayo Spillway Structure
MMD	Minto Mine Diesels
SW2	Sumanik Wind Monitoring#2
WD0	Whse Diesel Units General
WD1	Whse Diesel Unit#1
WD2	Whse Diesel Unit#2
WD3	Whse Diesel Unit#3
WD4	Whse Diesel Unit#4
WD5	Whse Diesel Unit#5
WD6	Whse Diesel Unit#6
WD7	Whse Diesel Unit#7
WDP	Whse Diesel Plant
WHDS	Whse Dam Structure
WFH	Whse Fish Hatchery
WFL	Whse Fish Ladder
WH1	Whse Hydro Unit#1
WH2	Whse Hydro Unit#2
WH3	Whse Hydro Unit#3
WH4	Whse Hydro Unit #4
WHP	Whse Hydro Plant
WHQ	Whse Office Bldg
WW1	Whse Wind Gen#1
WW2	Whse Wind Gen#2
YM3	Whse Mobile unit 3
BCW1	Bear Creek Wind Monitoring#1
DBW1	D Bay Wind Monitor#1
L127	WH4 to Riverside Sub
L150	S150 to Riverside Sub
L151	LNG Plant to S150
L169	Riverside to McIntyre
L170	Takhini to Carmacks
L171	Aishihik to Takhini
L172	TL Riverside to Takhini
L173	TL Carmacks to Minto
L174	Minto to Stewart
L175	Stewart X south to Stewart X north
L176	TL Stewart to Mayo
L177	TL Stewart to Dawson
L178	TL Carmacks to Faro
L248	TL Mayo B Hydro Plant
L250	TL Mayo to Keno City
L254	Minto Spur line
L355	Aishihik Transmission
L356	Ross River Transmission

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Unit Number	Description
L453	Mayo Transmission
OCW1	Old Crow Wind Monitor#1
S146	Faro Trx Substation Reactor Sub
S150	Whitehorse Rapids Substation
S151	Whitehorse LNG
S162	Faro Mine Trx Substation
S163	Carmacks substation for 25kv
S164	Takhini Substation
S167	Aishihik Transmission Substnt
S170	McIntyre Creek Substation
S171	Riverdale Substation
S248	Mayo B substation
S249	Mayo Substation
S250	Callison Substation
S251	StewartX south
S252	Pelly Crossing
S253	Minto Substation
S254	Minto Mine Substation
S255	Carmacks Substation – new substation as of 2010
S256	Stewart X North
S257	Keno Substation
S870	Faro Trx Substation - Main Sub
S6846	Deep Creek Switch
S7316	Johnson Crossing Distribution
S7572	Ross River Switch
S9550	Haekel Hill switch
ST147	To McGundy Creek distribution
T153	Little Fox distribution
T170B	Braeburn Distribution
T170C	Campbell Highway Distribution
T170L	Little Salmon distribution
T170D	Drury Creek distribution
T171C	Champagne Distribution
T171M	Mendenhall Distribution
T177M	Moose Creek Distribution
T177P	Patridge Creek Distribution
T170SF	South Fox Lake Distribution
T250	Alexco Keno 69kv spur line (7 other taps off L250 all designated as T250)