APPENDIX A

Power Flow Analysis for
Juneau – Greens Creek – Hoonah Intertie

Prepared by
Commonwealth Associates, Inc.

TRANSMISSION SYSTEM REVIEW
SOUTHEAST ALASKA INTERTIE

Prepared for

D. Hittle and Associates, Inc.

Prepared by

Commonwealth Associates, Inc.

engineers • consultants • construction managers

TRANSMISSION SYSTEM REVIEW

SOUTHEAST ALASKA INTERTIE

Prepared for

D. Hittle and Associates, Inc.

Prepared by
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INTRODUCTION

The construction of a new 69 kV transmission system between West Juneau, Greens Creek Mine, and Hoonah, in southeast Alaska, is being considered. This transmission system project is referred to as the "Southeast Intertie Segment 1." The total length of the line is 44 miles, of which approximately 34 miles will be submarine cable and 9 miles will be overhead line. In addition, a 9-mile overhead line will be required to connect to the Greens Creek Mine to a tap at Hawk Inlet. Power for Hoonah is presently generated with diesel generators and at Greens Creek Mine with an oil-fired combustion turbine and diesel generators. This new transmission line will be used to deliver hydroelectric power from Alaska Power and Light's existing transmission system to Greens Creek Mine and Hoonah. Commonwealth Associates, Inc. (CAI) was contracted to conduct a power flow analysis to determine if the high line charging associated with the submarine cables can cause high voltages at the end of the transmission system at Hoonah and determine how to mitigate the over-voltage condition.

ANALYSIS

The impedance values for the overhead transmission lines were calculated by using the tabular data listed in the *Transmission Line Reference Book* by the Electric Power Research Institute, and the spatial relationship of the conductors. The physical configuration of the phase separation on the transmission line poles is shown in Exhibit 1. The impedance values for the submarine cables were calculated using the cable data supplied by D. Hittle (see Table II). The study was conducted using CAI's TRANSMISSION 2000® Power Flow program.

Three groups of nine models were constructed: three models simulate no loading, three simulate peak loading, and three simulate an outage of the 25-mile submarine cable serving the load at Hoonah. The outage of the 25-mile submarine cable simulates conditions with and without the load at Greens Creek Mine. Each of the three groups of models represents the transmission system with and without 5 MVAr reactors. All cases assumed an infinite bus (swing) at West Juneau and a voltage of one per unit.

- Cases 101, 211, 301, and 311 have no reactors in service.
- Cases 105, 215, and 315 include one 5-MVAr reactor at the Hawk Inlet submarine cable termination yard.
- Cases 106 and 216 include three 5-MVAr reactors; two at Hawk Inlet and one at Hoonah. One reactor would be located on each side of the circuit breaker at Hawk Inlet.

The results of all the study cases are summarized in Table I below. This table lists the loads, losses, reactors, and bus voltages present at West Juneau, Hoonah, and Greens Creek Mine. An acceptable voltage range is customarily between 0.95 – 1.05 per unit. Bus reports, generated by the power flow program, are in the Appendix.

No Load or Initial Energization

Cases 101, 105, and 106 simulate an initial energization or no load condition on the transmission line, with zero, one, or three 5-MVAr reactors in service. Table I shows the voltages at Hoonah and Greens Creek Mine are at 1.00 per unit when all three reactors are in service and are probably too high when either zero or one 5-MVAr reactor is in service.

Peak Load

Cases 211, 215, and 216 simulate a peak load condition, where the load at Greens Creek Mine is 7.5 MW at 0.90 power factor and the load at Hoonah is 2.0 MW at 0.95 power factor, with zero, one, or three 5-MVAr reactors in service. Table I shows the voltage levels at Hoonah and Greens Creek Mine, for these cases, to be in an acceptable range.

Outage of 25-Mile Submarine Cable

Cases 301, 311, and 316 simulate an outage of the 25-mile submarine cable that serves the load at Hoonah. The voltage level at Greens Creek Mine is in an acceptable range.

TABLE I

Case	Load		Losses		Line Charging	Reactor	Voltages (pu)		
Number	MW	MVAr	MW	MVAr	MVAr	MVAr	W. Juneau	Hoonah	Greens Creek
101	0.0	0.0	0.533	0.855	-19.012	0.000	1.0000	1.057	1.048
105	0.0	0.0	0.284	0.423	-18.503	5.320	1.0000	1.041	1.032
106	0.0	0.0	0.030	0.042	-17.453	15.01	1.0000	1.000	1.001
211	9.5	4.287	0.490	0.809	-17.960	0.000	1.0000	1.020	1.007
215	9.5	4.287	0.340	0.548	-17.471	5.002	1.0000	1.004	0.991
216	9.5	4.287	0.283	0.493	-16.468	14.043	1.0000	0.963	0.961
301	0.0	0.0	0.028	0.055	-5.811	0.000	1.0000	N/A	1.011
311	7.5	3.362	0.149	0.280	-5.638	0.000	1.0000	N/A	0.978
315	7.5	3.362	0.198	0.361	-5.533	4.720	1.0000	N/A	0.963

Note: N/A - Not Applicable due to outage of 25-mile submarine cable

CONCLUSIONS

Installing two 5-MVAr reactors at Hawk Inlet and one at Hoonah will help regulate voltage for the loads at Hoonah and Greens Creek under normal operating conditions. Under a single contingency condition, (i.e., an outage of the 25-mile submarine cable) the second reactor at Hawk Inlet, located on the Greens Creek side of the circuit breaker, will provide voltage regulation for the connected loads at Greens Creek Mine.

TABLE II

Transmission Line Impedances for Power Flow Model
Southeast Alaska Intertie - West Juneau to Hoonah (69 kV)

Submarine Cables

Cross Section (mm^2)	Location	Distance (mi)	Total Line Impedance (pu) R	X	B
240 (single-armored)	Outer Point - Youngs Bay	9	0.064495	0.054760	0.049394
120 (single-armored)	Hawk Inlet - Spasski Bay	12.5	0.094225	0.076056	0.057771
120 (double-armored)	Hawk Inlet - Spasski Bay	12.5	0.089577	0.076056	0.057771

		R	X	B
		(ohms/mi)		(mho/mi)
240 (single-armored)	Z =	0.341181	0.289682	0.000115
	Z (pu) =	0.007166	0.006084	0.005488
120 (single-armored)	Z =	0.358884	0.289682	0.000097
	Z (pu) =	0.007538	0.006084	0.004622
120 (double-armored)	Z =	0.341181	0.289682	0.000097
	Z (pu) =	0.007166	0.006084	0.004622

Customer Supplied Data

	R	**X**	**C**
	(ohms/km)		(µf/km)
240 (single-armored)	0.125	0.16	0.19
120 (single-armored)	0.223	0.18	0.16
120 (double-armored)	0.212	0.18	0.16

Note: Per unit impedance on 100 MVA, 69 kV Base

TABLE II (cont.)

Transmission Line Impedances for Power Flow Model
Southeast Alaska Intertie - West Juneau to Hoonah (69 kV)

Overhead Lines

GMD (ft) = 7.4

Cross Section		Distance	Total Line Impedance (pu)		
(kcmils)	Location	(mi)	R	X	B
336 Oriole	West Juneau - Outer Point	11	0.07107	0.15894	0.00323
336 Oriole	Youngs Bay - Hawk Inlet	6	0.03876	0.08669	0.00176
336 Oriole	Spasski Bay - Hoonan	3.5	0.02261	0.05057	0.00103
336 Oriole	Hawk Inlet - Greens Creek Mine	9	0.05815	0.13004	0.00264

Line Impedance at 50° C — From: *Transmission Line Reference Book* - EPRI Red Book

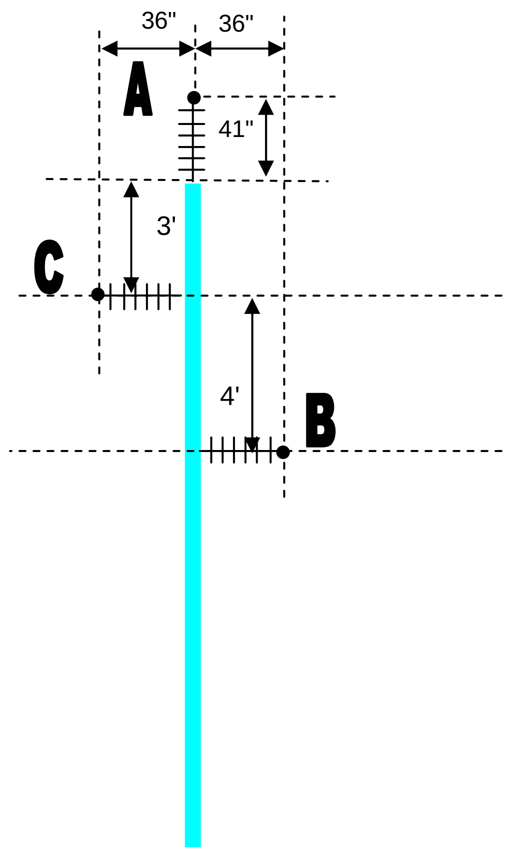
Cross Section		R	X	B
(kcmils)		(ohms/mi)		(mho/mi)
336 Oriole	Z =	0.307600	0.687900	0.000006
	Z (pu) =	0.006461	0.014449	0.000293

Note: Per Unit Impedances are on 100 MVA, 69 kV base

EXHIBIT I

Configuration of Overhead Lines

Conductors: 336 kcmil ACSR "Oriole" (1) conductor per phase



APPENDIX

POWER FLOW RESULTS

West Juneau to Hoonah
Case 101 - No Load, No Reactors

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---------------------------------------------------------------------------------------------
     1 JUNEAU        Area  1          Zone   1              69.00 kV  Reference
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000       0.0      0.0   0.53294  -18.157

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1    0.533   -18.157 L  152.0 18.1648  0.2304  0.1832 7.1069 15.894 0.3227

---------------------------------------------------------------------------------------------
     2 OUTER PT      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0283  70.954 kV  -0.760       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU         1   -0.303    18.340 L  149.3 18.3426  0.2304  0.1832 7.1069 15.894 0.3227
     3 YOUNGS BAY     1    0.303   -18.340 L  149.3 18.3426  0.1509 -5.1369 6.4495 5.4760 4.9394

---------------------------------------------------------------------------------------------
     3 YOUNGS BAY    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0365  71.522 kV  -1.314       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1   -0.152    13.203 L  106.6 13.2041  0.1509 -5.1369 6.4495 5.4760 4.9394
     4 HAWK INLET     1    0.152   -13.203 L  106.6 13.2041  0.0620 -0.0524 3.8765 8.6692 0.1760

---------------------------------------------------------------------------------------------
     4 HAWK INLET    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0475  72.275 kV  -1.589       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY     1   -0.090    13.151 L  105.1 13.1511  0.0620 -0.0524 3.8765 8.6692 0.1760
     7 GR CREEK       1    0.000    -0.290 L    2.3  0.2897  0.0000 -0.2897 5.8148 13.004 0.2640
    45 HI - SB        1    0.090   -12.861 L  102.7 12.8614  0.0807 -6.3159 9.4225 7.6056 5.7771

---------------------------------------------------------------------------------------------
     5 SPASSKI BAY   Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0569  72.923 kV  -2.220       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH         1    0.000    -0.115 L    0.9  0.1147  0.0000 -0.1147 2.2613 5.0570 0.1027
    45 HI - SB        1   -0.000     0.115 L    0.9  0.1147  0.0090 -6.4305 8.9577 7.6056 5.7771

---------------------------------------------------------------------------------------------
     6 HOONAH        Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0569  72.925 kV  -2.221       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY    1   -0.000    -0.000 L    0.0  0.0000  0.0000 -0.1147 2.2613 5.0570 0.1027

---------------------------------------------------------------------------------------------
     7 GR CREEK      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0476  72.288 kV  -1.594       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1    0.000     0.000 L    0.0  0.0000  0.0000 -0.2897 5.8148 13.004 0.2640

---------------------------------------------------------------------------------------------
    45 HI - SB       Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0545  72.758 kV  -2.066       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -0.009     6.545 L   51.9  6.5452  0.0807 -6.3159 9.4225 7.6056 5.7771
     5 SPASSKI BAY    1    0.009    -6.545 L   51.9  6.5452  0.0090 -6.4305 8.9577 7.6056 5.7771
```

West Juneau to Hoonah
Case 105 - No Load, 5 MVAr Reactor

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-----------------------------------------------------------------------------------------------
     1 JUNEAU         Area  1          Zone   1              69.00 kV  Reference
    Voltage          Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000        0.0      0.0   0.28389  -12.760

Line flows to         C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1    0.284   -12.760 L  106.8 12.7635  0.1129 -0.0768 7.1069 15.894 0.3227

-----------------------------------------------------------------------------------------------
     2 OUTER PT       Area  1          Zone   1              69.00 kV  Load
    Voltage          Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0199  70.371 kV  -0.528        0.0      0.0

Line flows to         C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU         1   -0.171    12.684 L  104.1 12.6848  0.1129 -0.0768 7.1069 15.894 0.3227
     3 YOUNGS BAY     1    0.171   -12.684 L  104.1 12.6848  0.0635 -5.1107 6.4495 5.4760 4.9394

-----------------------------------------------------------------------------------------------
     3 YOUNGS BAY     Area  1          Zone   1              69.00 kV  Load
    Voltage          Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0252  70.739 kV  -0.891        0.0      0.0

Line flows to         C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1   -0.108     7.573 L   61.8  7.5737  0.0635 -5.1107 6.4495 5.4760 4.9394
     4 HAWK INLET     1    0.108    -7.573 L   61.8  7.5737  0.0206 -0.1400 3.8765 8.6692 0.1760

-----------------------------------------------------------------------------------------------
     4 HAWK INLET     Area  1          Zone   1              69.00 kV  Load
    Voltage          Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0315  71.173 kV  -1.053        0.0      0.0                             -5.3199

Line flows to         C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY     1   -0.087     7.433 L   60.3  7.4335  0.0206 -0.1400 3.8765 8.6692 0.1760
     7 GR CREEK       1    0.000    -0.281 L    2.3  0.2809  0.0000 -0.2809 5.8148 13.004 0.2640
    45 HI - SB        1    0.087   -12.472 L  101.2 12.4723  0.0782 -6.1248 9.4225 7.6056 5.7771

-----------------------------------------------------------------------------------------------
     5 SPASSKI BAY    Area  1          Zone   1              69.00 kV  Load
    Voltage          Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0407  71.812 kV  -1.684        0.0      0.0

Line flows to         C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH         1    0.000    -0.111 L    0.9  0.1112  0.0000 -0.1112 2.2613 5.0570 0.1027
    45 HI - SB        1    0.000     0.111 L    0.9  0.1112  0.0087 -6.2359 8.9577 7.6056 5.7771

-----------------------------------------------------------------------------------------------
     6 HOONAH         Area  1          Zone   1              69.00 kV  Load
    Voltage          Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0408  71.814 kV  -1.685        0.0      0.0

Line flows to         C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY    1   -0.000    -0.000 L    0.0  0.0000  0.0000 -0.1112 2.2613 5.0570 0.1027

-----------------------------------------------------------------------------------------------
     7 GR CREEK       Area  1          Zone   1              69.00 kV  Load
    Voltage          Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0317  71.186 kV  -1.058        0.0      0.0

Line flows to         C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -0.000     0.000 L    0.0  0.0000  0.0000 -0.2809 5.8148 13.004 0.2640

-----------------------------------------------------------------------------------------------
    45 HI - SB        Area  1          Zone   1              69.00 kV  Load
    Voltage          Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0384  71.649 kV  -1.530        0.0      0.0

Line flows to         C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -0.009     6.347 L   51.1  6.3472  0.0782 -6.1248 9.4225 7.6056 5.7771
     5 SPASSKI BAY    1    0.009    -6.347 L   51.1  6.3472  0.0087 -6.2359 8.9577 7.6056 5.7771
```

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West Juneau to Hoonah
Case 106 - No Load, 15 MVAr Reactor
------------------------------------------------------------------------------------------
     1 JUNEAU        Area  1          Zone   1              69.00 kV  Reference
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000       0.0      0.0   0.02933  -2.4015

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT      1    0.029    -2.401 L   20.1  2.4017  0.0036 -0.3159 7.1069 15.894 0.3227

------------------------------------------------------------------------------------------
     2 OUTER PT      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0035  69.244 kV  -0.094       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU        1   -0.026     2.086 L   17.4  2.0858  0.0036 -0.3159 7.1069 15.894 0.3227
     3 YOUNGS BAY    1    0.026    -2.086 L   17.4  2.0861  0.0001 -4.9732 6.4495 5.4760 4.9394

------------------------------------------------------------------------------------------
     3 YOUNGS BAY    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0033  69.228 kV  -0.080       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT      1   -0.026    -2.887 L   24.1  2.8874  0.0001 -4.9732 6.4495 5.4760 4.9394
     4 HAWK INLET    1    0.026     2.887 L   24.1  2.8876  0.0034 -0.1691 3.8765 8.6692 0.1760

------------------------------------------------------------------------------------------
     4 HAWK INLET    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0007  69.050 kV  -0.015       0.0      0.0                              -10.014

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY    1   -0.023    -3.057 L   25.6  3.0566  0.0034 -0.1691 3.8765 8.6692 0.1760
     7 GR CREEK      1    0.000    -0.264 L    2.2  0.2644  0.0000 -0.2644 5.8148 13.004 0.2640
    45 HI - SB       1    0.023    -6.694 L   56.0  6.6936  0.0136 -5.7911 9.4225 7.6056 5.7771

------------------------------------------------------------------------------------------
     5 SPASSKI BAY   Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0021  69.143 kV  -0.118       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH        1    0.006     4.905 L   41.0  4.9047  0.0055 -0.0905 2.2613 5.0570 0.1027
    45 HI - SB       1   -0.006    -4.904 L   41.0  4.9044  0.0036 -5.8069 8.9577 7.6056 5.7771

------------------------------------------------------------------------------------------
     6 HOONAH        Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9996  68.970 kV  -0.054       0.0      0.0                              -4.9957

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY   1   -0.000    -4.995 L   41.8  4.9952  0.0055 -0.0905 2.2613 5.0570 0.1027

------------------------------------------------------------------------------------------
     7 GR CREEK      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0009  69.062 kV  -0.019       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET    1   -0.000     0.000 L    0.0  0.0000  0.0000 -0.2644 5.8148 13.004 0.2640

------------------------------------------------------------------------------------------
    45 HI - SB       Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0036  69.248 kV  -0.220       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET    1   -0.009     0.902 L    7.5  0.9025  0.0136 -5.7911 9.4225 7.6056 5.7771
     5 SPASSKI BAY   1    0.009    -0.902 L    7.5  0.9025  0.0036 -5.8069 8.9577 7.6056 5.7771
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West Juneau to Hoonah
Case 211 - 9.5 MW Load, No Reactor

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------------------------------------------------------------------------------------------------------
     1 JUNEAU        Area  1          Zone   1              69.00 kV  Reference
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000       0.0      0.0   9.99012  -12.864

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1    9.990   -12.864 L  136.3 16.2879  0.1856  0.0880 7.1069 15.894 0.3227

------------------------------------------------------------------------------------------------------
     2 OUTER PT      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0134  69.924 kV  -1.408       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU         1   -9.805    12.953 L  134.1 16.2449  0.1856  0.0880 7.1069 15.894 0.3227
     3 YOUNGS BAY     1    9.804   -12.952 L  134.1 16.2448  0.1285 -4.9608 6.4495 5.4760 4.9394

------------------------------------------------------------------------------------------------------
     3 YOUNGS BAY    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0129  69.887 kV  -2.083       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1   -9.676     7.992 L  103.7 12.5495  0.1285 -4.9608 6.4495 5.4760 4.9394
     4 HAWK INLET     1    9.676    -7.991 L  103.7 12.5492  0.0590 -0.0492 3.8765 8.6692 0.1760

------------------------------------------------------------------------------------------------------
     4 HAWK INLET    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0160  70.102 kV  -2.721       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY     1   -9.617     7.942 L  102.7 12.4724  0.0590 -0.0492 3.8765 8.6692 0.1760
     7 GR CREEK       1    7.539     3.448 L   68.3  8.2896  0.0393 -0.1824 5.8148 13.004 0.2640
    45 HI - SB        1    2.078   -11.390 L   95.4 11.5777  0.0685 -5.9338 9.4225 7.6056 5.7771

------------------------------------------------------------------------------------------------------
     5 SPASSKI BAY   Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0205  70.411 kV  -3.451       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH         1    2.001     0.552 L   17.0  2.0756  0.0009 -0.1047 2.2613 5.0570 0.1027
    45 HI - SB        1   -2.001    -0.552 L   17.0  2.0757  0.0086 -6.0081 8.9577 7.6056 5.7771

------------------------------------------------------------------------------------------------------
     6 HOONAH        Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0197  70.360 kV  -3.499   2.00000  0.65700

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY    1   -2.000    -0.657 L   17.3  2.1050  0.0009 -0.1047 2.2613 5.0570 0.1027

------------------------------------------------------------------------------------------------------
     7 GR CREEK      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0071  69.490 kV  -3.153   7.50000  3.63000

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -7.499    -3.630 L   69.2  8.3318  0.0393 -0.1824 5.8148 13.004 0.2640

------------------------------------------------------------------------------------------------------
    45 HI - SB       Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0204  70.407 kV  -3.246       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -2.010     5.456 L   47.7  5.8142  0.0685 -5.9338 9.4225 7.6056 5.7771
     5 SPASSKI BAY    1    2.010    -5.456 L   47.7  5.8142  0.0086 -6.0081 8.9577 7.6056 5.7771
```

West Juneau to Hoonah
Case 215 - 9.5 MW Load, 5 MVAr Reactor

```
-----------------------------------------------------------------------------------------------
     1 JUNEAU        Area  1          Zone   1              69.00 kV  Reference
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000       0.0      0.0   9.84011  -7.6347

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT      1    9.840    -7.635 L  104.2 12.4546  0.1085 -0.0817 7.1069 15.894 0.3227

-----------------------------------------------------------------------------------------------
     2 OUTER PT      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0051  69.352 kV  -1.194       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU        1   -9.732     7.553 L  102.6 12.3188  0.1085 -0.0817 7.1069 15.894 0.3227
     3 YOUNGS BAY    1    9.732    -7.553 L  102.6 12.3188  0.0768 -4.9076 6.4495 5.4760 4.9394

-----------------------------------------------------------------------------------------------
     3 YOUNGS BAY    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0017  69.114 kV  -1.683       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT      1   -9.655     2.645 L   83.6 10.0107  0.0768 -4.9076 6.4495 5.4760 4.9394
     4 HAWK INLET    1    9.655    -2.645 L   83.6 10.0107  0.0385 -0.0901 3.8765 8.6692 0.1760

-----------------------------------------------------------------------------------------------
     4 HAWK INLET    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0002  69.012 kV  -2.219       0.0      0.0                              -5.0017

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY    1   -9.616     2.555 L   83.2  9.9500  0.0385 -0.0901 3.8765 8.6692 0.1760
     7 GR CREEK      1    7.541     3.459 L   69.4  8.2960  0.0405 -0.1710 5.8148 13.004 0.2640
    45 HI - SB       1    2.076   -11.016 L   93.8 11.2097  0.0663 -5.7503 9.4225 7.6056 5.7771

-----------------------------------------------------------------------------------------------
     5 SPASSKI BAY   Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0044  69.306 kV  -2.952       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH        1    2.001     0.556 L   17.3  2.0767  0.0010 -0.1013 2.2613 5.0570 0.1027
    45 HI - SB       1   -2.001    -0.556 L   17.3  2.0767  0.0085 -5.8212 8.9577 7.6056 5.7771

-----------------------------------------------------------------------------------------------
     6 HOONAH        Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0037  69.254 kV  -3.002   2.00000  0.65700

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY   1   -2.000    -0.657 L   17.6  2.1051  0.0010 -0.1013 2.2613 5.0570 0.1027

-----------------------------------------------------------------------------------------------
     7 GR CREEK      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9911  68.389 kV  -2.665   7.50000  3.63000

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET    1   -7.500    -3.630 L   70.3  8.3323  0.0405 -0.1710 5.8148 13.004 0.2640

-----------------------------------------------------------------------------------------------
    45 HI - SB       Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0044  69.306 kV  -2.745       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET    1   -2.009     5.266 L   47.0  5.6360  0.0663 -5.7503 9.4225 7.6056 5.7771
     5 SPASSKI BAY   1    2.009    -5.266 L   47.0  5.6360  0.0085 -5.8212 8.9577 7.6056 5.7771
```

```
                                                                 Southeast Alaska Intertie
West Juneau to Hoonah
Case 216 - 9.5 MW Load, 15 MVAr Reactor
-------------------------------------------------------------------------------------------------------
     1 JUNEAU        Area  1          Zone   1              69.00 kV  Reference
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000       0.0      0.0   9.78316  2.35525

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1    9.783     2.355 L   84.2 10.0627  0.0725 -0.1570 7.1069 15.894 0.3227

-------------------------------------------------------------------------------------------------------
     2 OUTER PT      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9891  68.251 kV  -0.797       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU         1   -9.711    -2.512 L   84.8 10.0304  0.0725 -0.1570 7.1069 15.894 0.3227
     3 YOUNGS BAY     1    9.711     2.512 L   84.8 10.0304  0.0782 -4.7223 6.4495 5.4760 4.9394

-------------------------------------------------------------------------------------------------------
     3 YOUNGS BAY    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9801  67.626 kV  -0.923       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1   -9.632    -7.235 L  102.8 12.0467  0.0782 -4.7223 6.4495 5.4760 4.9394
     4 HAWK INLET     1    9.632     7.235 L  102.8 12.0467  0.0591 -0.0352 3.8765 8.6692 0.1760

-------------------------------------------------------------------------------------------------------
     4 HAWK INLET    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9698  66.917 kV  -1.256       0.0      0.0                            -9.4055

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY     1   -9.573    -7.270 L  103.7 12.0208  0.0591 -0.0352 3.8765 8.6692 0.1760
     7 GR CREEK       1    7.543     3.481 L   71.7  8.3075  0.0432 -0.1493 5.8148 13.004 0.2640
    45 HI - SB        1    2.030    -5.616 L   51.5  5.9720  0.0126 -5.4252 9.4225 7.6056 5.7771

-------------------------------------------------------------------------------------------------------
     5 SPASSKI BAY   Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9663  66.674 kV  -1.472       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH         1    2.008     5.216 L   48.4  5.5891  0.0077 -0.0784 2.2613 5.0570 0.1027
    45 HI - SB        1   -2.008    -5.216 L   48.4  5.5891  0.0100 -5.4072 8.9577 7.6056 5.7771

-------------------------------------------------------------------------------------------------------
     6 HOONAH        Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9631  66.451 kV  -1.461   2.00000  0.65700                            -4.6374

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY    1   -2.000    -5.294 L   49.2  5.6596  0.0077 -0.0784 2.2613 5.0570 0.1027

-------------------------------------------------------------------------------------------------------
     7 GR CREEK      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9605  66.274 kV  -1.730   7.50000  3.63000

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -7.500    -3.630 L   72.6  8.3323  0.0432 -0.1493 5.8148 13.004 0.2640

-------------------------------------------------------------------------------------------------------
    45 HI - SB       Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9701  66.939 kV  -1.516       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -2.018     0.191 L   17.5  2.0267  0.0126 -5.4252 9.4225 7.6056 5.7771
     5 SPASSKI BAY    1    2.018    -0.191 L   17.5  2.0267  0.0100 -5.4072 8.9577 7.6056 5.7771
```

West Juneau to Hoonah
Case 301 - No Load, No Reactor, Outage of 25-mile submarine cable

```
---------------------------------------------------------------------------------------------
     1 JUNEAU        Area  1          Zone   1              69.00 kV  Reference
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000       0.0      0.0   0.02788  -5.7560

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT      1    0.028    -5.756 L   48.2  5.7561  0.0222 -0.2758 7.1069 15.894 0.3227

---------------------------------------------------------------------------------------------
     2 OUTER PT      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0089  69.613 kV  -0.228       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU        1   -0.006     5.480 L   45.5  5.4802  0.0222 -0.2758 7.1069 15.894 0.3227
     3 YOUNGS BAY    1    0.006    -5.480 L   45.5  5.4802  0.0056 -5.0308 6.4495 5.4760 4.9394

---------------------------------------------------------------------------------------------
     3 YOUNGS BAY    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0105  69.724 kV  -0.336       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT      1   -0.000     0.449 L    3.7  0.4494  0.0056 -5.0308 6.4495 5.4760 4.9394
     4 HAWK INLET    1    0.000    -0.449 L    3.7  0.4494  0.0000 -0.1797 3.8765 8.6692 0.1760

---------------------------------------------------------------------------------------------
     4 HAWK INLET    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0108  69.745 kV  -0.344       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY    1   -0.000     0.270 L    2.2  0.2698  0.0000 -0.1797 3.8765 8.6692 0.1760
     7 GR CREEK      1    0.000    -0.270 L    2.2  0.2698  0.0000 -0.2698 5.8148 13.004 0.2640
    45 HI - SB       1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 9.4225 7.6056 5.7771

---------------------------------------------------------------------------------------------
     5 SPASSKI BAY   Area  1          Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0569  72.926 kV  -2.220       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH        1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 2.2613 5.0570 0.1027
    45 HI - SB       1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 8.9577 7.6056 5.7771

---------------------------------------------------------------------------------------------
     6 HOONAH        Area  1          Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0569  72.926 kV  -2.221       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY   1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 2.2613 5.0570 0.1027

---------------------------------------------------------------------------------------------
     7 GR CREEK      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0110  69.757 kV  -0.348       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET    1    0.000     0.000 L    0.0  0.0000  0.0000 -0.2698 5.8148 13.004 0.2640

---------------------------------------------------------------------------------------------
    45 HI - SB       Area  1          Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0545  72.760 kV  -2.066       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET    1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 9.4225 7.6056 5.7771
     5 SPASSKI BAY   1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 8.9577 7.6056 5.7771
```

West Juneau to Hoonah
Case 311 - 7.5 MW Load, No Reactor, Outage of 25-mile submarine cable

```
------------------------------------------------------------------------------------------------
     1 JUNEAU        Area  1         Zone   1              69.00 kV  Reference
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000       0.0      0.0   7.64852  -1.9964

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1    7.649    -1.996 L   66.1  7.9048  0.0440 -0.2236 7.1069 15.894 0.3227

------------------------------------------------------------------------------------------------
     2 OUTER PT      Area  1         Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9976  68.832 kV  -0.773       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU         1   -7.605     1.773 L   65.5  7.8085  0.0440 -0.2236 7.1069 15.894 0.3227
     3 YOUNGS BAY     1    7.605    -1.773 L   65.5  7.8085  0.0378 -4.8574 6.4495 5.4760 4.9394

------------------------------------------------------------------------------------------------
     3 YOUNGS BAY    Area  1         Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9923  68.468 kV  -0.989       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1   -7.567    -3.085 L   68.9  8.1713  0.0378 -4.8574 6.4495 5.4760 4.9394
     4 HAWK INLET     1    7.566     3.085 L   68.9  8.1711  0.0265 -0.1130 3.8765 8.6692 0.1760

------------------------------------------------------------------------------------------------
     4 HAWK INLET    Area  1         Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9866  68.074 kV  -1.301       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY     1   -7.540    -3.198 L   69.5  8.1901  0.0265 -0.1130 3.8765 8.6692 0.1760
     7 GR CREEK       1    7.540     3.198 L   69.5  8.1899  0.0406 -0.1639 5.8148 13.004 0.2640
    45 HI - SB        1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 9.4225 7.6056 5.7771

------------------------------------------------------------------------------------------------
     5 SPASSKI BAY   Area  1         Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0569  72.926 kV  -2.220       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH         1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 2.2613 5.0570 0.1027
    45 HI - SB        1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 8.9577 7.6056 5.7771

------------------------------------------------------------------------------------------------
     6 HOONAH        Area  1         Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0569  72.926 kV  -2.221       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY    1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 2.2613 5.0570 0.1027

------------------------------------------------------------------------------------------------
     7 GR CREEK      Area  1         Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9778  67.467 kV  -1.768   7.50000  3.36200

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -7.499    -3.362 L   70.3  8.2183  0.0406 -0.1639 5.8148 13.004 0.2640

------------------------------------------------------------------------------------------------
    45 HI - SB       Area  1         Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0545  72.760 kV  -2.066       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 9.4225 7.6056 5.7771
     5 SPASSKI BAY    1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 8.9577 7.6056 5.7771
```

West Juneau to Hoonah
Case 315 - 7.5 MW Load, 5 MVAr Reactor, Outage of 25-mile submarine cable

```
-----------------------------------------------------------------------------------------------
     1 JUNEAU        Area  1          Zone   1              69.00 kV  Reference
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0000  69.000 kV   0.000       0.0      0.0   7.69805  2.91061

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1    7.698     2.911 L   68.9  8.2299  0.0488 -0.2102 7.1069 15.894 0.3227

-----------------------------------------------------------------------------------------------
     2 OUTER PT      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9897  68.289 kV  -0.582       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     1 JUNEAU         1   -7.649    -3.121 L   69.8  8.2614  0.0488 -0.2102 7.1069 15.894 0.3227
     3 YOUNGS BAY     1    7.649     3.121 L   69.8  8.2614  0.0587 -4.7491 6.4495 5.4760 4.9394

-----------------------------------------------------------------------------------------------
     3 YOUNGS BAY    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9816  67.734 kV  -0.618       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     2 OUTER PT       1   -7.591    -7.870 L   93.2 10.9339  0.0587 -4.7491 6.4495 5.4760 4.9394
     4 HAWK INLET     1    7.591     7.870 L   93.2 10.9340  0.0486 -0.0591 3.8765 8.6692 0.1760

-----------------------------------------------------------------------------------------------
     4 HAWK INLET    Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9716  67.043 kV  -0.828       0.0      0.0                           -4.7203

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     3 YOUNGS BAY     1   -7.542    -7.929 L   94.2 10.9430  0.0486 -0.0591 3.8765 8.6692 0.1760
     7 GR CREEK       1    7.542     3.209 L   70.6  8.1961  0.0419 -0.1533 5.8148 13.004 0.2640
    45 HI - SB        1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 9.4225 7.6056 5.7771

-----------------------------------------------------------------------------------------------
     5 SPASSKI BAY   Area  1          Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0569  72.926 kV  -2.220       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     6 HOONAH         1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 2.2613 5.0570 0.1027
    45 HI - SB        1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 8.9577 7.6056 5.7771

-----------------------------------------------------------------------------------------------
     6 HOONAH        Area  1          Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0569  72.926 kV  -2.221       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     5 SPASSKI BAY    1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 2.2613 5.0570 0.1027

-----------------------------------------------------------------------------------------------
     7 GR CREEK      Area  1          Zone   1              69.00 kV  Load
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
0.9627  66.426 kV  -1.310   7.50000  3.36200

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1   -7.500    -3.362 L   71.4  8.2191  0.0419 -0.1533 5.8148 13.004 0.2640

-----------------------------------------------------------------------------------------------
    45 HI - SB       Area  1          Zone   1              69.00 kV  Outaged
    Voltage         Angle  [------LOAD------][---GENERATION---][----SHUNTS----]
1.0545  72.760 kV  -2.066       0.0      0.0

Line flows to        C     MW         MVAr T  Amps    MVA    MW/MVar Loss    %R     %X     %B
     4 HAWK INLET     1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 9.4225 7.6056 5.7771
     5 SPASSKI BAY    1    0.000     0.000 *    0.0  0.0000  0.0000  0.0000 8.9577 7.6056 5.7771
```

APPENDIX B

Selected Photographs

Photo B-1 – Young Bay boat dock to north (right) of proposed cable landing site on Admiralty Island.

Photo B-2 – Aerial view of road to Kennecott Mining Company - Greens Creek mine.

Photo B-3 – Hawk Inlet, looking northeast from near the inlet entrance to the KMC-GC ore terminal facility. Note the large tide flat to the right.

Photo B-4 – Hawk Inlet terminal facility on Admiralty Island.

Photo B-5 – Kennecott Mining Company - Greens Creek mine on Admiralty Island.

Photo B-6 – Hawk Inlet at mouth of Greens Creek looking northwest. Entrance to Hawk Inlet is just to left of photo.

Photo B-7 – Spasski Bay on Chicagof Island, looking west toward Hoonah in the distance.

Photo B-8 – THREA powerhouse in Hoonah.

Photo B-9 – Gartina Highway in Hoonah looking east.

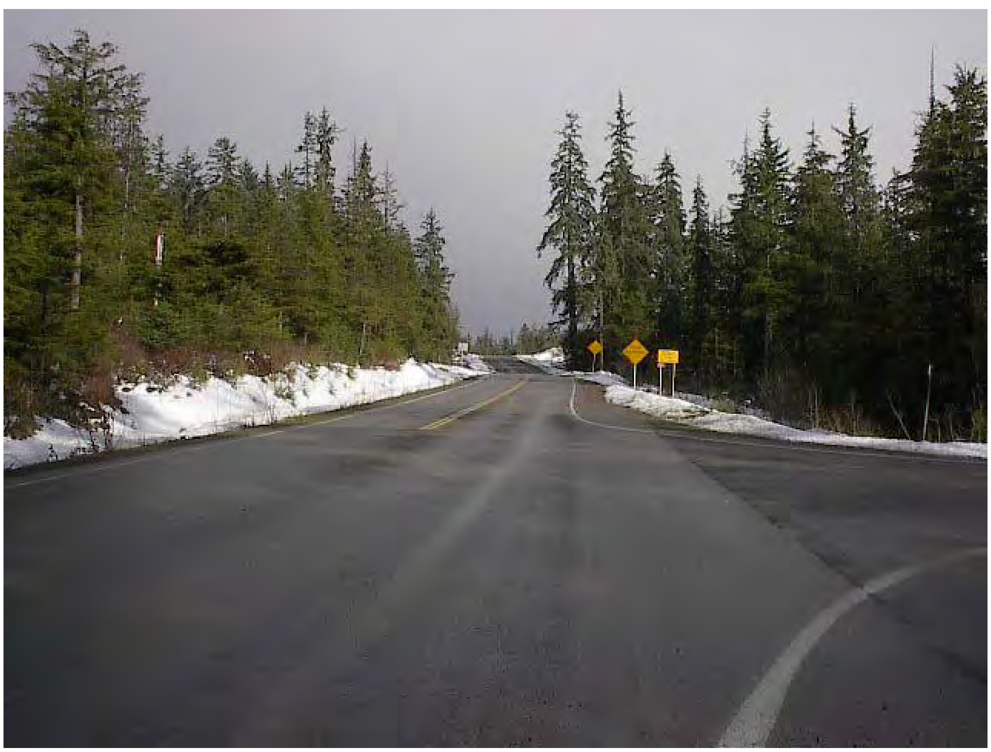

Photo B-10 – Gartina Highway in Hoonah looking east at end of pavement and interconnection with USFS Road No. 8502. Access to Hoonah airport is to the right..

Photo B-11 – Wrangell Narrows from Experimental Fur Farm looking west toward Tonka log handling facility.

Photo B-12 – Wrangell Narrows beach looking east toward Experimental Fur Farm site.

Photo B-13 – Access road to Experimental Fur Farm area looking west from Mitkof Highway toward Wrangell Narrows.

Photo B-14 – Mitkof Highway south of Petersburg with 138-kV Tyee transmission line to the left.

APPENDIX C

Plan Profile Diagrams for Kake – Petersburg Intertie
Prepared by Commonwealth Associates, Inc.

(23 pages)

APPENDIX D

Report on Submarine Cable Considerations
Prepared by Poseidon Engineering, Ltd.

Some Design and Cost Considerations for Submarine Cable Systems to be utilized for Power Delivery from Juneau to Hoonah, Alaska and from Petersburg to Kake, Alaska

Project 2003-102

16 March 2003

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ORGANIZATION THAT PREPARED THIS REPORT

POSEIDON ENGINEERING, LTD.

EXECUTIVE SUMMARY

The Southeast Conference has contracted with D. Hittle & Associates, Inc. to evaluate the technical and economic considerations for electrical connections between Juneau and Hoonah and between Petersburg and Kake. Both projects require the use of submarine cables.

This report addresses the design considerations and some of the problems that might affect the costs associated with the submarine cable systems required for these projects.

CONTENTS

1

INTRODUCTION

Two separate projects are covered by this report.

Juneau, AK – Hoonah, AK with a tap for the Greens Creek Mine

Petersburg – Kake

Juneau to Hoonah

This project consists of the following sections:

11 miles of overhead line between West Juneau Substation to the future Outer Point Submarine Cable Termination Yard

9 miles of submarine cable between the future Outer Point Submarine Cable Termination Yard and the future Young's Bay Submarine Cable Termination Yard

6 miles of overhead line between the future Young's Bay Submarine Cable Termination Yard and the future Hawk Inlet Submarine Cable Termination Yard

25 miles of submarine cable between the future Hawk Inlet Submarine Cable Termination Yard and the future Spasski Bay Submarine Cable Termination Yard

3.5 miles of overhead line between the future Spasski Bay Submarine Cable Termination Yard and Hoonah Substation

Petersburg to Kake

Southern Route

A short segment of overhead line between either the existing Wrangell-Petersburg line or the Petersburg Substation to a future cable termination yard in the vicinity of the Alaska Experimental Fur Farm

1 mile of submarine cable between the Alaska Experimental Fur Farm across the Wrangell Narrows to a future cable termination yard near the abandoned Tonka Log transfer Facility

10 to 12.5 miles of overhead line between the West side of Wrangell Narrows to a future Submarine Cable Termination Yard on the East side of Duncan Canal near Mitchell Slough

1.1 to 4 miles of submarine cable between the East side of Duncan Canal to a future Submarine Cable Termination Yard on the West side of Duncan Canal

1. South Route – Immediately south of Mitchell Slough, Cable length – 1.1 miles
2. North Route – Immediately South of Ohmer Slough, Cable Length – 4 miles

31 to 34 miles of overhead line from the West side of Duncan Canal to Kake

Northern Route

Short overhead Line from Petersburg Substation to the East side of Wrangell Narrows

Submarine cable across Wrangell Narrows

50+ miles of overhead line from the West side of Wrangell Narrows to Kake Substation

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2

CABLE DESIGN

General

While there are numerous types of cable that have been developed and used since the late 1800's, only a few are deemed appropriate for this application. These include:

Ethylene Propylene Rubber Cables - for AC applications

Cross-Linked Polyethylene Cables - for AC applications

Impregnated, Paper Insulated (non-draining) Cables - for DC applications

Polyethylene (HMWPE and XLPE) Insulated Cables - AC Circuits

Polyethylene insulation has been used for cable insulation since the early 1960's. Excessive failure rates occurred on cables manufactured, with either High Molecular Weight Polyethylene (HMWPE) or Cross Linked Polyethylene (XLPE), through the late 1980's. Research in the 1990's indicated that these failures were associated with the presence of moisture in the insulation that formed "water trees". The occurrence of an electrical transient (i.e. lightning impulse or switching surge) frequently would change the "water trees" to "electrical trees" which eventually led to a breakdown in the insulation.

Virtually all of the HMWPE and XLPE cables manufactured today are of a dry design, utilizing a metallic moisture barrier over the insulation to prevent the ingress of water. These cables are believed to exhibit very good reliability characteristics and are typically the cables of choice for AC systems up to 230 kV.

Ethylene Propylene Rubber (EPR) Insulated Cables - AC Circuits

Ethylene Propylene Rubber (EPR) insulation has also been around for many years and has some very desirable properties, especially for submarine cable application. One of these properties is flexibility that is almost a necessity if the cable is expected to see movement. Another desirable property is the stability of the insulation in a moist or wet environment. Unfortunately, this desirable trait is only exhibited after the moisture has migrated into the insulation and come to equilibrium. Prior to reaching equilibrium, this insulation also exhibits a somewhat high failure rate until equilibrium is achieved. Therefore, an initial “soaking” period prior to energization or a semi-dry design utilizing full non-metallic jacket over the three conductors or a metallic moisture barrier over each individual conductor is considered desirable. Due to its typically higher cost, EPR is not utilized as extensively as polyethylene. Also, this material exhibits higher losses that become significant at voltage levels above 69 kV.

Impregnated Paper Insulated (non-draining) Cable - DC Circuits

At the present time, extruded insulation is not deemed satisfactory for DC applications. Therefore, a non-draining Impregnated Paper Insulated cable is recommended for any DC alternative. The paper insulation and the impregnating fluid utilized in this type of cable have virtually infinite life at room temperature. The only known aging mechanism in this type of cable is that which occurs at elevated temperatures. Therefore, the cable industry recommends that operating temperatures of the cable not exceed 85°C (185°F) under normal operation.

Splices and Terminations

It is anticipated that only “factory splices” will be utilized in the submarine cable sections. Shore-end splices, if used to maximize the cable ampacity of the submarine cable sections, will utilize normally accepted splicing techniques and materials and will be located in permanently wet soil in the cable landing beaches.

Terminations will be those normally provided by the cable supplier. No special designs are anticipated.

Cable Armor

All submarine cables must be capable of supporting their own weight during installation and during retrieval for repair. Submarine cables must also have sufficient weight and rigidity to resist movement along the sea bottom. Therefore, it is assumed that any submarine cable used for this application will be armored. For large power cables a single layer of armor is generally adequate for cables installed in waters having a depth of 1200 feet (200 fathoms) or less. At greater depths, a second layer of armor is sometimes used on larger cables to withstand the greater tensions that occur due to the longer catenary between the laying vessel and the bottom.

It is assumed that all submarine cables installed on this project will utilize armor wires that are bedded in a polypropylene serving and that a bitumen compound will be utilized to minimize any corrosion. This design normally provides a long life for the cable armor.

An impressed current cathodic protection system may be utilized to protect the near shore sections of cable.

Another design that is finding increasing use on 3-conductor AC cables and DC cables, utilizes a jacket of high density polyethylene over each armor wire. A cathodic protection system is utilized to protect any “holidays” in the coating. Not only does this design provide virtually infinite life for the armor, but the monitoring of the amount of impressed current required for protection provides evidence of any physical damage that has occurred to the armor.

Submarine Cable for Alternating Current (AC) Applications

It is assumed that all AC cables utilized for these projects will be a 3-conductor design. This is due to the very high cost for installing submarine cables, which could triple for a three single conductor design. A second consideration is the elevated hysterisis and eddy current losses that occur in the armor of a single conductor cable. Also, the use of a single conductor design precludes the use of insulated armor wire and, therefore the ability to provide cathodic protection to the armor wire. A static cable is desired to eliminate the need for pressurization facilities at the ends of the cables and to minimize the problems in the event that a repair is necessary. Therefore, Self-contained, fluid-filled cables and high-pressure, pipe-type cables are not considered for application in this instance.

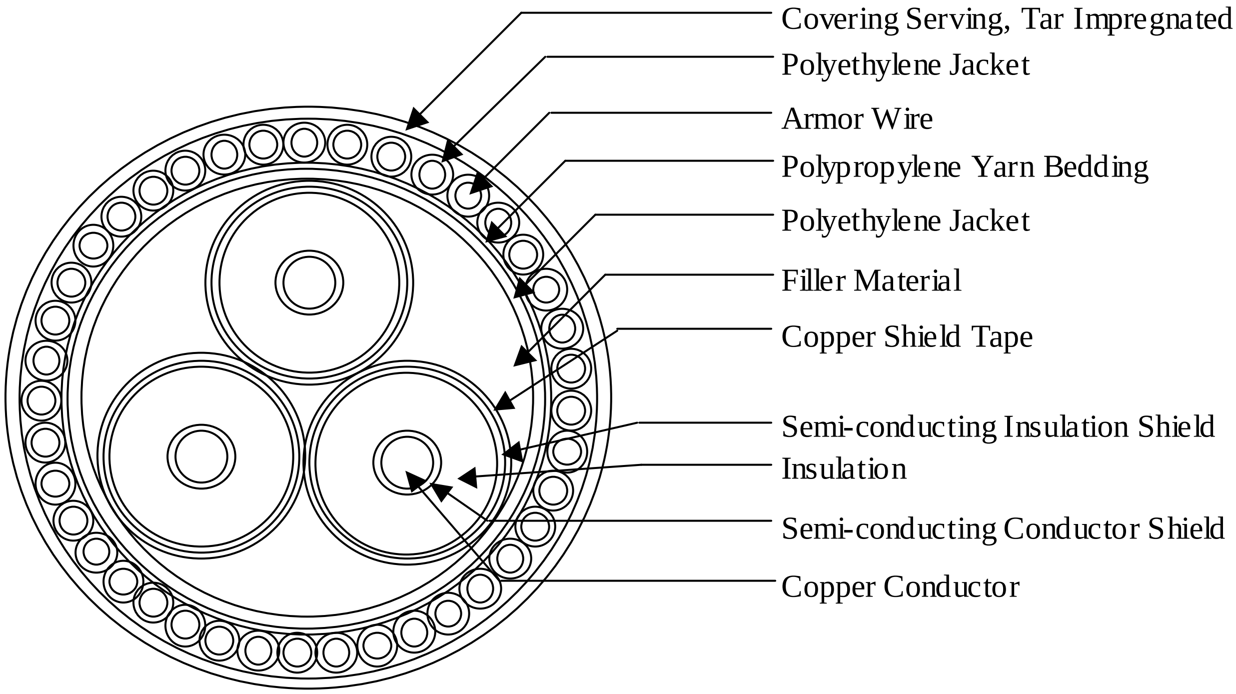

Figure 2-1 Ethylene Propylene Rubber Submarine Cable for 13.8 kV and 34.5 kV Applications

13.8 kV, 34.5 kV AC Circuits

Because of the harsh marine environment in which the cables are to be installed, the maximum in cable flexibility is desired. For this reason EPR is frequently the insulating material of choice. However, this material is only readily available on submarine cables up to 34.5 kV AC; is more costly; exhibits losses that become significant at 69 kV and higher; and for "wet" designs, has a failure rate similar to polyethylene cables until moisture comes to equilibrium in the insulation. Therefore, it is assumed that EPR will only be considered for 13.8 and 34.5kV AC circuits.

69 & 138 kV AC Circuits

3 Conductor 69 & 138 kV XLPE Submarine Cable

At voltages of 69 kV and above, Cross-Linked Polyethylene (XLPE) generally becomes the insulation of choice. The most common design for a 3 Conductor, 69 or 138 kV polyethylene submarine cable is shown in Figure 2-2. The principal advantages to using a three-conductor design are: 1) Reduced installation costs; 2) Reduced manufacturing costs; 3) Reduced armor losses; and, 4) Coated armor wire may be used which enables the use of cathodic protection for extending the life of the armor wire.

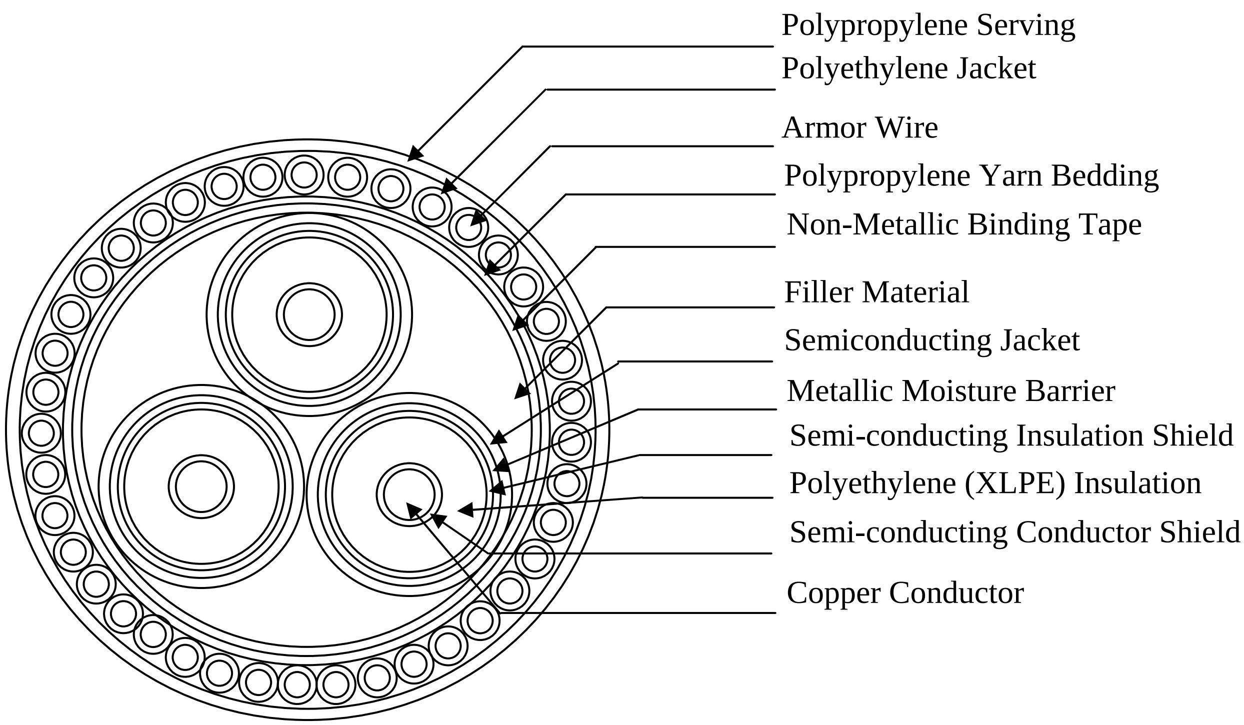

Figure 2-2 Three Conductor, 138 kV Cross-Linked Polyethylene Submarine Cable

Single Conductor 138 kV Submarine Cable

Unfortunately, 3 conductor XLPE submarine cables are limited in size by the cable manufacturing and submarine installation equipment. Maximum overall diameter is approximately 7 inches. This equates to a three-conductor XLPE cable having a maximum conductor size of approximately 1000 kcm for 69 kV cables and 800 kcm for 138 kV armored cables.

Larger capacity circuits at 138 kV must utilize three single conductor cables. As mentioned before, this generally eliminates the safe application of polyethylene jacketing over each armor wire. However, it should be noted that special armor designs have been used on very rare occasions to minimize this problem. A single conductor

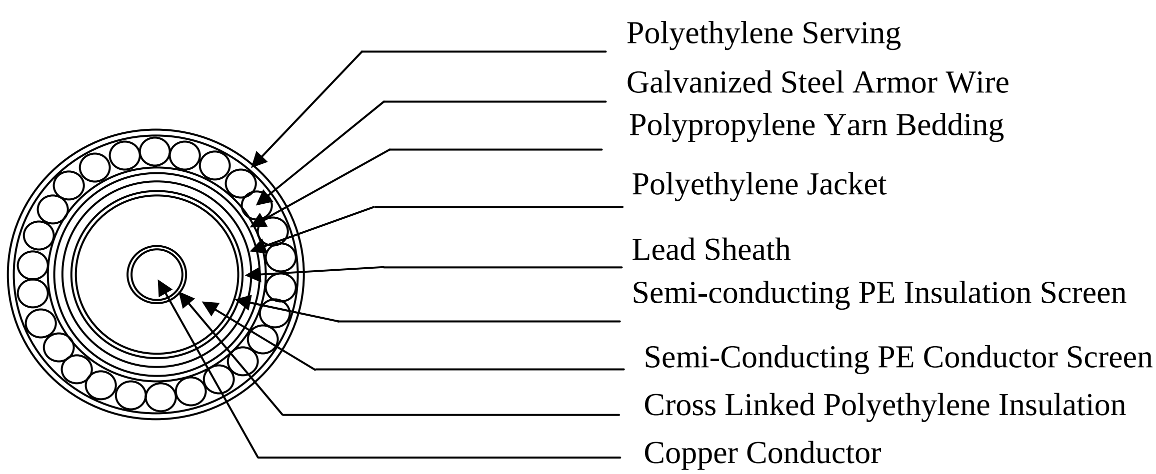

Figure 2-3 Single Conductor 138 kV XLPE Cable

138 kV cable design is shown in figure 2-3.

Submarine Cable Type for Direct Current (DC) Applications

The DC cables will be of a single conductor design, also having a protective covering over the armor. Figure 2-4 shows a cable having a high-density polyethylene jacketing on each armor wire. Due to environmental constraints, monopolar DC operation using the seawater as a return conductor is no longer feasible. Therefore, a DC circuit will consist of two single conductor cables. While an AC cable circuit consists of a single three-conductor cable, a DC Cable circuit will consist of two separate cables, one for the positive pole and one for the negative pole.

Impregnated Paper Insulated DC Cable

Impregnated paper insulated, non-draining, power cable has been in existence since the beginning of the 19th Century and is presently in use a voltages up to ±400 kV DC. It's reliability has been demonstrated in actual operation through all these years. Because of the extremely high cost to repair a submarine cable, it is assumed that this type of cable will be utilized for all DC submarine sections of these projects. This cable is shown in Figure 2-4.

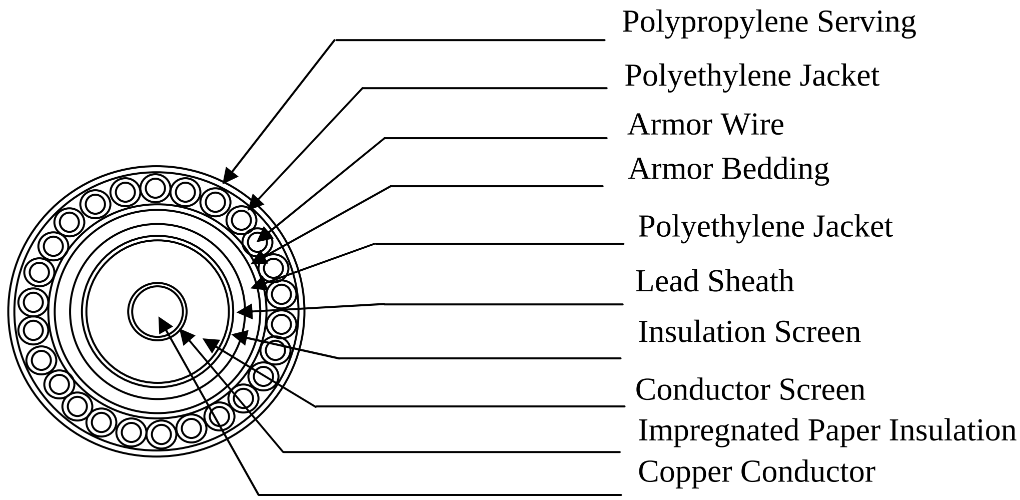

Figure 2-4 Impregnated Paper Insulated Cable for DC Application

Polyethylene DC Cable

ABB offers an XLPE cable for their HVDC Light™ system. Although ABB has an excellent reputation throughout the utility industry, it is a relative newcomer to the design and manufacturing of extruded DC submarine power cables. Previous R&D into the use of extruded dielectrics such as High molecular weight polyethylene (HMWPE) and Cross-linked Polyethylene (XLPE) concluded that these materials were not suitable for DC application. One of the reasons was due to the stress enhancement that occurred during polarity reversal that was inherent with the change in direction of power flow in Thyristor type DC Converters. HVDC Light™ eliminates this problem. However, the electrical stress enhancement that occurs in the insulation, especially around voids and contaminants , both during testing and normal operation has not been completely eliminated. Fillers and additives are normally used to reduce the amount of space charge buildup. However, the long term effects of these materials on the aging of the insulation is not well known. Most utilities now prefer a low frequency AC test as an alternative to a DC test for AC installations, to avoid the possible generation of electrical “trees” that could result in the premature failure of an extruded cable. There is very limited operational experience with not only the ABB cable, but with any extruded cable for DC application. Virtually all of the present HVDC Light™ installations utilize direct buried land cables which are readily available for repair and which are not subjected to the harsh submarine environment.

Therefore, until more operational experience is obtained, it is recommended that only mass impregnated, non-draining, paper insulated cable be considered for a submarine DC system. This is due primarily to the very high costs involved in a submarine cable repair (see Section 3). The cable should have a lead sheath over the insulation as a moisture barrier, a polyethylene jacket over the lead sheath, at least one layer of #6 BWG galvanized steel armor (additional armor may be required due to the depth), a serving of tar impregnated jute over the armor and a serving of polypropylene as the outermost layer.

Power Losses

Power losses in an HVDC Light™ system equal approximately 1.8% of the power being converted. This is considerably higher than losses with HVDC conversion using thyristor technology, which is around 0.8%. The cost of loses should be factored into the economic comparison between the AC and DC alternatives. The comparison should use the economic life of the cable. The normally accepted value for economic life is 30 to 35 years.

Ampacity Requirements

	34.5 kV AC	69 kV AC	138 kV AC	±10 kV DC	±50 kV DC	±150 kV DC
1 MW	17 amps	8 amps	4 amps	50 amps	10 amps	3 amps
10 MW	167 amps	84 amps	42 amps	500 amps	100 amps	33 amps
20 MW	335 amps	168 amps	84 amps	1000 amps	100 amps	33 amps
50 MW	837 amps	418 amps	209 amps	2500 amps	500 amps	167 amps
100 MW	1670 amps	837 amps	418 amps	5000 amps	1000 amps	333 amps
200 MW	3340 amps	1672 amps	836 amps	10 kA	2000 amps	667 amps
500 MW	6680 kA	4180 amps	2090 amps	25 kA	4000 amps	1670 amps

Table 2-1 Conductor current ratings for specified system voltages

Cable Characteristics

Load Factor - 100%

Ambient Earth/Water Temperature - 25°C

Earth/Water Thermal Resistivity - 60 °C-cm/watt

Maximum Cable/Environment Interface Temperature - 65 °C continuous

Conductor Material - Annealed Uncoated Copper

Stranding - Class B or C

Because of the relatively high thermal resistivity observed in the glacial deposits found in the soils of SE Alaska, it is possible that larger conductor shore-end cables will be used where the cables are buried between the permanently wet soil in the beach and the cable termination yard. The cost of these short cables is considered to be negligible, relative to the project cost. However, the cost of splicing the submarine cable to the larger shore-end cable is significant and should be included. For any buried section of submarine cables, a thermal profile of the cable route should be obtained to optimize the cable design and to avoid the possibility of "Thermal Runaway".

Cable Requirements

	34.5 kV AC	69 kV AC	138 kV AC	±10 kV DC	±50 kV DC	±150 kV DC
1 MW	1 Circuit #1 AWG	1 Circuit	NA	1 Circuit 300 kcmil	1 Circuit 300 kcmil	NA
10 MW	1 Circuit #1 AWG	1 Circuit	NA	1 Circuit 300 kcmil	1 Circuit 300 kcmil	NA
20 MW	1 Circuit 350 kcmil	1 Circuit 250 kcmil	NA	2 Circuits 300 kcmil	1 Circuit 300 kcmil	1 Circuit 300 kcmil
50 MW	2 Circuits 350 kcmil	1 Circuits 350 kcmil	1 Circuit	4 Circuits 300 kcmil	1 Circuit 300 kcmil	1 Circuit 300 kcmil
100 MW	3 Circuits 750 kcmil	1 Circuits 750 kcmil	1 Circuits	NA	2 Circuits 300 kcmil	1 Circuit 300 kcmil

Table 2-2 Number of cable circuits required for various system configurations

Design Considerations (Juneau to Hoonah)

Outer Point to Young Bay (Approximately 9.2 miles)

From NOAA charts the water depth appears to increase uniformly from 0 feet at the shoreline to 300 feet near the center of Stephens Passage. A “Limited Topographic Survey” by R&M Engineering along one proposed route shows a gradual increase in depth over the first 3000 feet to a depth between 200 and 250 feet. The depth remains between 200 and 250 feet (note: the profile from 155+00 to 215+00 is missing) until station 335+00 at which point the bottom begins a gradual decrease in depth until the shoreline is reached at station 487+00. The nautical charts show a bottom that consists of mud and shells with occasional large rocks near Outer Point. The remainder of the route appears to consist of mud, sand and pebbles all the way to Young Bay

No evidence of steep terrain or large rocks, that might cause suspensions in the submarine cables, has been detected. However, a thorough submarine topographical survey and subsurface profile needs to be accomplished to determine the best route for the submarine cable. This will identify areas to be avoided such as shipwrecks, large rocks, rock outcroppings, etc., that could cause suspensions and damage to the cable. This survey may be conducted utilizing a multi-beam sonar system such as the Reson Seabat 8101. If deleterious conditions are suspected, additional information should be obtained with a side-scan sonar system.

Based on the information presently available, no obvious problems are anticipated with this cable installation. The cable should be buried approximately 1 meter in depth at both shores, out to a depth of 10 feet below Mean Lower Low Water. Either direct burial utilizing sand for both bedding and backfill or placement in a duct with a thermal backfill may be utilized.

The cable proposed by AEL&P should be entirely adequate for this portion of the project.

Foreign Cables

No evidence of foreign cables was noted on any of the material furnished.

Ecological Survey

Recent experience with other submarine cable installations has indicated that the State of Alaska may want a pre-installation and post-installation survey of the flora and/or fauna population in the shallow areas (25' or less water depth below MLLW). A good cable installation plan through these environmentally sensitive areas that minimizes the disturbance to the flora and fauna is also desirable.

Hawk Inlet to Spasski Bay (Approximately 25 miles)

The Hawk Inlet Submarine Cable Terminal is anticipated to be located immediately South of the docks. This puts the cable entry point midway between two communications cables. The power cable should be installed in a position to avoid crossing either of these existing cables.

The owners/operators of all existing cables must be contacted to: determine accurate cable locations; minimize cable crossings, and to reach agreement on the procedure to be used to protect the existing cable(s) at any crossing. Unfortunately, the charts provided do not indicate whether all cable crossings may be avoided.

Due to the ship traffic in Hawk Inlet, it is recommended that consideration be given to burying the cable one meter deep all the way down the Inlet to a point 600 - 800 feet Southwest of Hawk Point. Based on the Nautical Chart provided, a machine such as the Nexan's CapJet should be adequate.

From Hawk Inlet the cable route proceeds in a westerly direction North of Whitestone Harbor and Pullizzi Point, then into Spasski Bay.

Based on the information presently available, no obvious problems are anticipated with the cable installation. The cable should be buried approximately 1 meter in depth at both shores, out to a depth of 10 feet below Mean Lower Low Water. Either direct burial utilizing sand for both bedding and backfill or placement in a duct with a thermal backfill may be utilized.

Water depths approach 2,100 feet (350 fathoms) in this crossing and double armored cable should be considered for the deeper portions of the crossing. However, this decision normally rests with the cable manufacturer and installer, since knowledge regarding the tensioning equipment and the cable design itself (especially its weight in seawater) are required. For double armored cables, the lay (direction of pitch and the pitch itself) of each armor layer is important. Opposite lays with long pitch are generally used for the deepest cables. However, this reduces cable flexibility and generally necessitates the use of a rotating turntable for cable storage. It also can affect the minimum bending radius for circular tensioning machines as well as the compression withstand parameters for linear tensioning machines.

The cable specified by AEL&P should be entirely adequate for this portion of the project.

Installation Inspection and Suspension Removal

A visual inspection of the cable is required either during the installation or immediately afterward, and all suspensions greater than 10 feet in length should be removed, either by moving the cable or by shoring the cable with bags of concrete.

Tidal Currents

Tidal currents are assumed to be 4 knots or less on the bottom. Therefore, cable movement of any cable laid directly on the bottom is not expected.

Burial Considerations

Protection of the cable from physical damage is of paramount importance. Therefore, the cable should be buried from the shore to a depth of at least 10' below Mean Lower Low Water (MLLW) and through all known anchorages and fishing grounds regardless of depth. See Chapter 4 for a detailed discussion on Cable Burial.

Spare Cable for DC Applications

HVDC Light™ operates only in a bipolar mode. It cannot operate in a monopolar mode using the earth as a return conductor. Therefore, a minimum of two cables is required, one for the positive pole and one for the negative pole. Because there are long periods of time during which submarine cable repairs would be difficult if not impossible to achieve, a complete spare cable may be deemed advisable, along with the necessary switching equipment to place the spare cable into either the positive or negative position

Spare Cable for AC Applications

At higher voltages using single phase conductors, submarine crossings may include a spare single conductor cable to provide additional security for the AC circuits in the event one of the cables fails. The submarine crossing of Taku Inlet on the Snettisham transmission line uses four separate single-phase cables. Disconnect switches allow the spare cable to be inserted into any of the other AC cable positions as needed. It would not generally be considered practical to provide a spare three-phase bundled cable simply for backup purposes. A length of spare cable should be acquired as part of the initial purchase to provide for more timely repairs in the future.

Design Considerations (Petersburg - Kake)

Southern Route - Wrangell Narrows Crossing (Approximately 1 mile)

From NOAA charts the water depth appears to increase uniformly from 0 feet at the shoreline to 30 feet near the center of Wrangell Narrows. The nautical charts show a bottom that consists of mud and rocks.

No evidence of steep terrain or large rocks, that might cause suspensions in the submarine cables, has been detected. However, a thorough submarine topographical survey and subsurface profile needs to be accomplished to determine the best route for the submarine cable. This will identify areas to be avoided such as shipwrecks, large rocks, rock outcroppings, etc., that could cause suspensions and damage to the cable. This survey may be conducted utilizing a multi-beam sonar system such as the Reson Seabat 8101. If deleterious conditions are suspected, additional information should be obtained with a side-scan sonar system.

Based on the information presently available, no obvious problems are anticipated with the cable installation. The cable should be buried approximately 1 meter in depth at both shores, out to a depth of 10 feet below Mean Lower Low Water. Either direct burial utilizing sand for both bedding and backfill or placement in a duct with a thermal backfill may be utilized. Due to the large amount of boat traffic through Wrangell Narrows, burial for the entire length is recommended.

Foreign Cables

No evidence of foreign cables was noted on any of the material furnished.

Ecological Survey

Recent experience with other submarine cable installations has indicated that the State of Alaska may want a pre-installation and post-installation survey of the flora and/or fauna population in the shallow areas (25’ or less water depth below MLLW). A good cable installation plan through these environmentally sensitive areas that minimizes the disturbance to the flora and fauna is also desirable.

Duncan Canal Crossing (Approximately 1.3 miles)

Installation Inspection and Suspension Removal

A visual inspection of the cable is required either during the installation or immediately afterward, and all suspensions greater than 10 feet in length should be removed, either by moving the cable or by shoring the cable with bags of concrete.

Tidal Currents

Tidal currents are assumed to be 6 knots or less on the bottom. Therefore, cable movement of any cable laid directly on the bottom is not anticipated. However, additional data is required to determine the actual tidal velocity and any changes in bottom contour that might occur due to tidal erosion and/or siltation.

Burial Considerations

Protection of the cable from physical damage is of paramount importance. Therefore, the cable should be buried from the shore to a depth of at least 10 feet below Mean Lower Low Water (MLLW) and through all known anchorages and fishing grounds. Boat traffic in Duncan Canal does not appear to be large and there appears to be no sign of any large ships frequenting the waters. For additional information, see Chapter 4 for a detailed discussion on Cable Burial.

Spare Cable for DC Applications

HVDC Light™ operates only in a bipolar mode. It cannot operate in a monopolar mode using the earth as a return conductor. Therefore, a minimum of two cables is required, one for the positive pole and one for the negative pole. Because there are long periods of time during which submarine cable repairs would be difficult if not impossible to achieve, a complete spare cable may be deemed advisable, along with the necessary switching equipment to place the spare cable into either the positive or negative position

Spare Cable for AC Applications

One spare three conductor cable may be included for the AC circuits. Suitable disconnect switches should be included to allow the spare cable to be inserted into any of the other AC cable positions.

Depth

The water depth is assumed to increase uniformly from 0 feet at the shoreline to 90 feet at the deepest point.

Bottom Conditions and Pre-Installation Bottom Surveys

From cursory observations, the bottom appears to consist mainly of sand, shells, mud and sediment with an occasional outcropping of rock. No evidence of steep terrain or large rocks, that might cause suspensions in the submarine cables, has been detected. However, a thorough submarine topographical survey and subsurface profile needs to be accomplished to determine the best route for the submarine cable. This will identify areas to be avoided such as shipwrecks, large rocks, coral outcroppings, etc., that could cause suspensions and damage to the cable. This survey may be conducted utilizing a multi-beam sonar system such as the Reson Seabat 8101. If deleterious conditions are suspected, additional information should be obtained with a side-scan sonar system.

Ecological Survey

Recent experience with other submarine cable installations has indicated that the State may want a survey of the flora and/or fauna population in the shallow areas (25’ or less water depth below MLLW). A good cable installation plan through these environmentally sensitive areas that minimizes the disturbance to the flora and fauna is also desirable.

Post Installation Inspection and Suspension Removal

A visual inspection of the cable is required either during the installation or immediately afterward, and all suspensions greater than 10 feet in length should be removed, either by moving the cable or by shoring the cable with bags of concrete.

3

CABLE FAILURE AND REPAIR

Failure due to Aging

The paper insulation and the oil in the impregnated paper insulated cables have virtually infinite life at room temperature. The only known aging mechanism in this type of cable is that which occurs at elevated temperatures. Therefore, the cable industry recommends that operating temperatures of the cable not exceed 85°C (185°F) under normal operation.

Although many polyethylene cables manufactured between the early 1960's and the late 1980's exhibited very poor reliability, today's cables are expected to rival the impregnated paper insulated cables for longevity. This is due to the use of a metallic moisture barrier (normally lead) that is applied over the insulation, which keeps water from penetrating the insulation and forming "water trees" which can eventually lead to failure in this type of cable. As with the impregnated paper insulated cable, operation at elevated temperatures may result in premature failure. The recommended operating temperature is limited to a maximum of 90 °C for Cross-Linked Polyethylene.

Ethylene Propylene Rubber (EPR) insulation has a very good performance record in wet environments (after moisture has come to equilibrium in the insulation) and a life of 30 to 50 years is expected. As with the above cables the operating temperature for EPR cable should be limited to 90°C.

Due to numerous unknowns regarding the thermal circuit along the cable route, the actual operating temperature for any of the above cables should be limited to a maximum of 65 °C at the cable's interface with the external environment. This prudent design criteria will assure that the cable will not go into thermal runaway.

Failure due to Manufacturing Defects

Today’s cables are manufactured in “clean room’ environments. While it is possible that some contamination could occur during the extrusion process or the application of the paper tapes (e.g. wrapping a fly in the insulation, etc.), it is highly unlikely and such defects would probably be found during the ionization test at the factory. Therefore, <u>the likelihood of failure due to a manufacturing defect is considered highly unlikely</u>.

Suspensions and Failure due to Vibration or "Strumming"

A submarine cable that is suspended above the sea floor and exposed to any tidal current will exhibit some motion. This motion or vibration is called “Strumming” and is comparable to the vibrations that produce the sound in musical instruments such as guitars, violins, pianos, etc. The amplitude and frequency of this motion is dependent on the length of the suspension, the velocity of the seawater across the cable and the tension on the cable through the length of the suspension. The amplitude will increase as the velocity of the water increases, as the length of the suspension increases and as the tension on the cable decreases. The frequency increases as the tension increases and as the length of the suspension decreases. Frequency is not related to water velocity except for very long suspensions and/or very low cable tensions.

As the cable strums or vibrates on either side of the suspension point, the lead sheath exhibits some bending. This bending will, over a period of time, cause a fatigue failure of the lead sheath and abrasion of the polyethylene jacket. Once the lead sheath and polyethylene jackets are breached, ingress of water will occur. Water in an oil-impregnated cable will result in a rapid failure, if the cable is energized. Water in an extruded cable may penetrate the insulation by osmosis and may cause a reduction in dielectric strength in the insulation.

During the design of the cable system, the cable engineer should use a design that minimizes "strumming".

“Common Mode” Failures

“Common mode” failures occur when a single event damages more than one cable. These failures include those caused by anchors, fishing gear and seismic events.

Anchors

Failures caused by anchors generally occur in shallower waters close to shore. Because of the need to put out a scope of anchor line equal to between 5 and 15 times the water depth, most vessels anchor in waters having a depth of 40 feet (MLLW) or less. Normally the worse the weather the longer the scope of anchor line required to prevent the dragging of the anchor along the bottom. Smaller vessels (50 feet or less) would tend to stop once a cable is snagged. Submarine cables are very robust and the surrounding armor wires provide a very high tensile or breaking strength. In most cases an anchor windless on a smaller vessel is unable to retrieve the anchor due to the weight of the cable and the anchor is abandoned.

Larger vessels represent the greatest hazard to submarine cables. Fortunately, the persons in charge of these vessels tend to be better educated in seamanship and therefore, when anchoring, tend to be more respectful of the cable areas shown on their nautical charts. They also tend to use anchoring techniques that minimize any dragging of the anchor.

All cable crossings should be marked on the appropriate nautical charts that are issued by NOAA. The use of Cable Warning Signs, while not mandatory, certainly help in court when suing to obtain compensation for cable damage from the damaging vessel. Cable warning signs should be installed at all terminal sites and should continue to be maintained as required.

Fishing, Claming and Crabbing Gear

The sleds that precede the nets on Bottom Trawlers and Draggers normally cause the majority of damage to submarine cables. Long lines having multiple hooks have been found snagged on submarine cables. However, damage to the cable that necessitates repair is not expected. Long lines usually involve one cable and, therefore are not considered a “common mode” type of event.

Seismic Events

Seismic events such as earthquakes and major underwater earth slides are unpredictable and are considered to be beyond the scope of this analysis. Previous experience has demonstrated that unburied submarine cables are generally quite flexible and while they move when the sea floor shifts during an earthquake, either horizontally or vertically, they normally do not sustain any damage. However, an earth slide that covers the cables quite likely will damage the cables and all involved cables may require replacement.

The majority of seismic damage incurred by submarine cable systems comes from the tidal surge or tsunami that results from the earth movement. This damage normally extends from a depth of approximately 20 feet below MLLW to a height of 20 to as much as 100 feet above sea level. Total cable replacement will likely be required in this instance.

Standard Fault Location Procedure

The following represents the procedure that should be followed in the event of a failure to a submarine cable:

- Review of Cable Design, Installation and Fault Data
- Megohmmeter (Megger) Testing to determine the resistance of each conductor to ground.
- Longitudinal Resistance Testing using a 12 volt car battery and an ammeter to determine both the phasing and the longitudinal integrity of the conductors. When

the cable length is unknown, this test, with the addition of a precision voltmeter and the use of a precision ammeter, can be used to determine the actual cable length to approximately 0.5%. This testing may be used to determine the longitudinal resistance of not only the power conductors, but also the copper shields and the ground conductors.

- DC Resistance Measurement of the Fault to Ground for the faulted conductor to determine the amount of reflection that might be expected during Time Domain Reflectometry testing.
- Time Domain Reflectometry (TDR) Measurements to determine the distance to all discontinuities in the cable (i.e. splices & faults).
- Bridge and Resistance Division Measurements when the faulted conductor is longitudinally intact or continuous.
- Arc Reflection Measurements if TDR measurements are unsuccessful.
- Special Testing (e.g. Current Tracing, Electric Field Tracing, Tone Tracing, etc.) if all else fails.

Review of Cable Design, Installation and Fault Data

Installation drawings should be reviewed. These normally provide the cable length and design information. Plan and profile drawings are sometimes helpful to identify possible trouble spots such as ridges, rocks, steep slopes, and narrow channels. Today a multi-beam sonar scan of the cable can provide considerable information that may be helpful in identifying the location of the failure. Evidence such as suspensions, anchors, etc. may show up on these scans, especially in the shallower depths.

Details regarding the voltage, current and power immediately prior to and during the fault may be especially helpful.

Megohmmeter (Megger) Testing

This test is used to determine which phase(s) are faulted and provides an approximate resistance of the fault to ground.

Longitudinal Resistance Testing

The DC resistance for stranded copper conductors (annealed and uncoated) may be found in several locations including The Handbook for Electrical Engineers, The Simplex Manual, and numerous publications available from the Institute of Electrical and Electronic Engineers and the Edison Electric Institute. This value for the subject conductor is provided in ohms per 1000 feet at 25 °C. This resistance "R" should be corrected for the average temperature found along the cable route. Because the conductor in a three-conductor cable is twisted in a helical shape along its length, the actual conductor length is approximately 2% greater than its route length. This should be taken into consideration when determining cable length.

For this test all three phases of the cable should be "shorted" together at one end.

At the opposite end of the cable, connecting a car battery between two of the "shorted" conductors should provide a current of approximately 12.5/"R" amps (assuming a battery voltage of 12.5 volts). If the phasing of the conductors is known at one end of the cable, this test may be used to determine the phasing at the opposite end of the cable as well as determining the integrity of the conductors. This information has significant importance in determining what to expect during the Time Domain Reflectometry test.

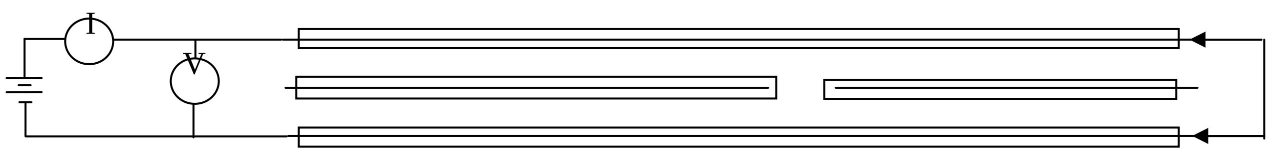

Figure 3-1 Test Setup for Determining Cable Length. Both multimeters should be of the 4-½-digit type having a high degree of accuracy (e.g. Fluke 187 or 189)

In this case the length would be determined by dividing the Voltage “V” by the Current “I”. The resistance, determined from the tables and corrected for water temperature and the conductor rotation factor, would then be divided into this value. Because the total conductor length is twice the cable length, the length calculated above must be divided.

<u>Note</u>: To obtain the greatest accuracy, several measurements should be made, each time reversing the battery polarity. This eliminates any error caused by telluric (earth) and galvanic (corrosion) currents and potentials.

DC Resistance Measurement of the Fault to Ground

This measurement is normally made only on the faulted phase. A 12-volt car battery is connected between the faulted conductor and the metallic shield for all three conductors, which are connected together. Two multimeters are used, one to measure the current, and the other to measure the voltage. The test setup is shown in Figure 3-2.

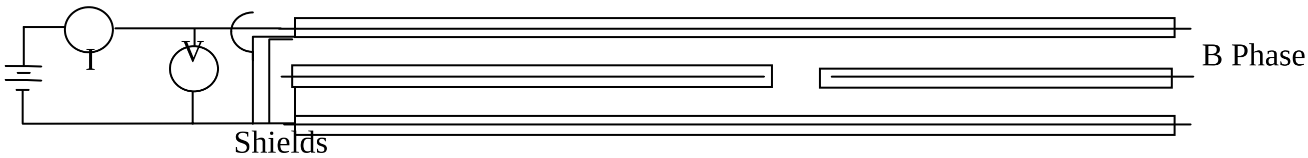

Figure 3-2 Test Setup for Determining Fault Resistance

This test is conducted both with the positive terminal of the battery connected to the faulted conductor and then with the negative terminal connected to the faulted conductor. Reversing the polarity will assist in removing the telluric and galvanic induced potentials from the measurement. The Resistance is equal to the Voltage "V" divided by the Current "I". Averaging these results together provides the actual Fault Resistance.

Time Domain Reflectometry (TDR) Measurements

In simple terms, Time Domain Reflectometry (TDR) consists of sending very short pulses down the conductor. These pulses are typically 50 to 5000 nanoseconds in duration and approximately 30 to 50 volts in amplitude. When the pulses encounter a change in impedance, such as that caused by a splice or a fault, a reflection is sent back toward the sending end. A positive (upward) going reflection indicates an increase in impedance; a negative (downward) reflection indicates a decrease in impedance. In the above case, where there was both an “open” in the conductor and a low impedance “short” to ground, it was found that the open represented the most significant change and resulted in a very noticeable positive reflection.

The pulses travel down the conductor at a speed between one-fifth and one-third the speed of light. This speed is directly dependent upon the type and condition of the insulation. The theoretical speed of travel in Ethylene Propylene Rubber (EPR) may be determined by dividing the dielectric constant for this type of insulation into the speed of light in a vacuum (3×10^8 meters per second or 300 meters per μsec). Assuming a dielectric constant of 2.1 yields a propagation velocity of 142.9 meters per μsec. TDR manufacturers typically use twice the propagation velocity and call it the “Propagation Factor”. This is due to the pulse traveling down to the discontinuity and back to the TDR, or exactly twice the distance to the discontinuity. Therefore, the theoretical propagation factor for EPR insulation is approximately 286 meters per μsec. This value represents the upper limit. In practical situations this factor is found to be considerably lower, especially if moisture has migrated into the insulation. Since the far end of the cable (for an intact or continuous conductor) is readily visible on the TDR display and the length was either measured or obtained from the plan and profile drawings, the actual propagation factor may be found.

Bridge and Resistance Division Measurements

There are numerous forms of these measurements from the "old days" when high impedance digital instrumentation was not available. Under normal circumstances, this type of measurement would not be utilized.

Arc Reflection Measurements

To obtain a distance to the fault using the Arc Reflection Method, an arc must be established at the fault between the conductor and ground. The pulse from the arc travels in both directions from the fault: One pulse returning directly to the fault locating equipment; the other pulse traveling to the far end of the cable where it is reflected back toward the equipment. The difference in arrival times for the two pulses may be used to obtain the distance to the fault. Unfortunately, due to the low impedance of the salt water that migrates into the fault in a submarine cable installed in salt water, fault-locating personnel frequently find that an arc cannot be established. Furthermore, this method does not work when there is an “open” in the conductor because the pulse traveling to the far end is attenuated too much when it attempts to return through the “open” in the conductor. Also, this type of test may cause additional damage to the cable due to the application of high voltage impulses, which may over-stress the “good” insulation.

Special Testing

These tests require the use of underwater detection devices that are handled by divers or, in deep water, are towed behind a small vessel. This type of fault location is virtually always performed by special fault locating personnel and is beyond the scope of this report.

Cable Repair

There are two basic types of repair for submarine cables. Both scenarios generally require that the repair vessel be anchored during the splicing procedure.

Cable Retrieval Method

The first method involves retrieving an end of the cable at the end nearest the failure location and coiling it aboard the retrieving vessel until the point of failure is on board. Once the failure is aboard, the point of failure and any adjacent cable that has been compromised, either by physical damage or water ingress, is removed. The two ends of good cable are then spliced together and the cable is re-layed to the location where it had initially been retrieved. Additional cable is spliced in as required to complete the circuit. This type of repair generally requires the least amount of additional cable. It also allows for the visual inspection of the general cable condition as the cable is being retrieved. This method also has the advantage of allowing additional types of fault locating to be conducted as the point of failure is approached. Especially helpful is the ability to physically look for evidence of the fault as the cable is retrieved (see figure 3-1).

Figure 3-1 Physical Damage to a 15 kV EPR Submarine Cable caused by a 1550-Ampere Fault (as it appeared coming aboard the Repair Barge)

The negative aspects to this type of repair are threefold: 1) A large amount of cable is physically manipulated which may cause additional problems; 2) Three splices (or two splices and a re-termination) are required; and, 3) Previous repairs normally cannot be handled by the retrieval equipment and must be dealt with either by cutting them out during the retrieval process or by utilizing additional equipment to pass them around the Capstan or Linear Machine which is being used for the retrieval.

The Cut and Splice Method

Once fault locating has "pin-pointed" the failure the cable is cut at that point and one end of the cable is picked up and brought aboard. As the cable is brought aboard, the repair vessel moves back along the cable to accommodate the water depth (see figure 3-2). The damaged and/or wet cable is removed and a new section of cable is spliced in. The repair vessel now re-lays the cable as it is moved to a position over the end of the cable that remained on the bottom. This end is now retrieved and the damaged cable is removed. A second splice joins the two ends of the cable. The laying vessel is slowly moved perpendicular to the cable direction while the final repair splice is lowered to the bottom, thus completing the repair.

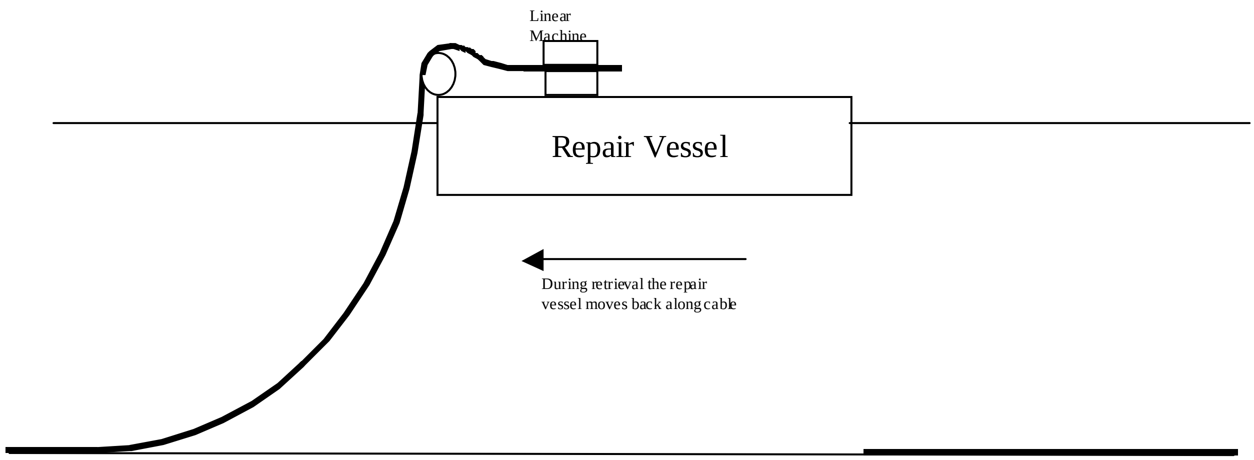

Figure 3-2 Movement of the Repair Vessel during Cable Retrieval

Due to problems associated with accurately locating the fault prior to cutting the cable, this method is generally used on long cables, where the distance from shore to the fault is long, and on shallow cables where divers may assist in pinpointing the fault and cutting the cable. This method is virtually always used on self-contained, fluid-filled cables. However this is beyond the scope of this report.

Marine Repair Equipment

The primary piece of equipment that is required for a submarine cable repair is the Repair Vessel. Today the vessel of choice for either repair is the Dynamic Positioning ship or barge. These vessels typically have a Differential Geographical Positioning System (DGPS) controlled propulsion system which allows them to retrieve and re-lay cable quite easily and accurately. They can also hold their position for long periods of time. However, due to uncertainties in weather, these vessels are normally anchored during the spicing operation. A tugboat, preferably a "Tractor" type with rotating propulsion systems (e.g. the Ulstein "Z" Drive), is used to assist in anchoring the repair vessel and to help hold position in adverse weather. A utility boat is used to provision the repair vessels, transport crews and run for parts and supplies needed during the repair.

The repair vessel is generally equipped with a cable retrieval system, a cable crib to store cable in, a splicing shed, anchoring equipment, a propulsion system, workshops, a command and navigation center, plus crew facilities.

In addition to the above, the Cable Retrieval Method normally requires a backhoe if the cable is to be cut at the shoreline for the retrieval process.

Fault Location and Repair Costs

It must be noted that the amount of time required for a repair to a submarine cable is extremely dependent upon the water depth and the weather. The following analysis assumes average conditions where 1/4 of the time will be lost due to weather. Deeper water requires a significantly greater amount of time, larger anchors and stronger cables. Therefore, this analysis looks at two depths: 0 to 500 feet; and, 500 to 1000 feet of depth. At depths greater than 1000 feet, repair costs generally are billed on a cost plus basis with no guarantee of repair.

Additional contingencies may be incurred such as the need for man-lifts, safety watchers around energized equipment, etc. An average cost has been included for this.

Fault Location Costs

Fault location typically requires two fault locating persons plus two helpers. Three days should be allowed for transportation of men and equipment to the site. It will often take a couple of days to obtain an accurate fix on the location of the fault. This work precedes the organization of the marine equipment because the type and location of the fault will determine the type of repair.

Table 3-1
Fault Location Costs

Water Depth	0 to 500 feet	500 to 1000 feet
Transportation (2 trips)	$4,800	$4,800
Lodging and Per Diem	$6,800	$7,800
Salary	$36,000	$42,000
Contingencies	$5,000	$7,500
Total Costs	$52,600	$62,100

The fault locating team will also be required from the time that the marine equipment is on site until the fault is aboard the repair vessel.

Cable Repair Costs

This analysis assumes a fifteen-day period for mobilization and transit for the barge and Tug. Actual costs will vary depending upon the availability and locality of the marine repair equipment.

Table 3-2
Cable Repair Costs

Water Depth	0 to 500 feet	500 to 1000 feet
Transportation, persons	$9,000	$9,000
Transportation, equipment	$450,000	$450,000
Per Diem and Lodging	$32,000	$42,000
Cable Recovery and Re-lay	$450,000	$600,000
Cable Splicing (15 kV/138 kV)	$32,000/$69,000	$32,000/$69,000
Materials	$20,000	$25,000
Contingencies	$50,000	$100,000
Total Costs (15 kV/138 kV)	$1,043,000/1,080,000	$1,258,000/$1,295,000

4

CABLE BURIAL

Reasons for Burial:

Protection from Anchors

Protection from High Velocity tidal currents

Protection from Objects moving in the tidal flow

Protection from Fishing, Crabbing and Shrimp Catching Gear

Protection from "Johnny Balls" on tow lines

Removal of suspensions

Depth of Burial

Protection from Anchors

Large Ships (VLCC, Cargo, etc.)

1. Soft Bottom (Mud, Sand, broken shell, etc.) – 8 to 14 feet
2. Moderate Bottom (Cobbles, mixed sand or mud and rock less than 1 foot diameter) – 4 to 10 feet
3. Hard Bottom (Solid clay, large rock in sand or mud, caliche, etc) – 3 to 5 feet

Small commercial vessels and large yachts

1. Soft Bottom (Mud, Sand, broken shell, etc.) – 4 to 8 feet
2. Moderate Bottom (Cobbles, mixed sand or mud and rock less than 1 foot diameter) – 3 to 5 feet
3. Hard Bottom (Solid clay, large rock in sand or mud, caliche, etc) – 2 to 4 feet

Protection from Tidal Currents

(These burial depths are for single armored cable weighing 15# per foot or more in sea water and having a diameter of 6 ½ inches or less). Note: Cable movement is a calculable factor and is dependent upon: the ratio of cable diameter to weight, cable torsion and cable bending moment. It is recommended that this calculation be accomplished for any cable, based on the prevailing conditions.

High Velocity Tidal Current (10 to 15 knots – e.g. Cook Inlet, Alaska) where terrain shifting is found

1. Soft Bottom (Mud, Sand, broken shell, etc.) – 10 to 20 feet
2. Moderate Bottom (Cobbles, mixed sand or mud and rock less than 1 foot diameter) – 3 to 5 feet
3. Hard Bottom (Solid clay, large rock in sand or mud, caliche, etc) – 2 to 4 feet

Medium Velocity Tidal Currents (3 to 6 knots)

1. Soft Bottom (Mud, Sand, broken shell, etc.) – 0 to 6 feet
2. Moderate Bottom (Cobbles, mixed sand or mud and rock less than 1 foot diameter) – 0 to 4 feet
3. 3. Hard Bottom (Solid clay, large rock in sand or mud, caliche, etc) – 0 to 2 feet

Low Velocity Tidal Currents (0 to 3 Knots)

1. Soft Bottom (Mud, Sand, broken shell, etc.) –0 to 2 feet
2. Moderate Bottom (Cobbles, mixed sand or mud and rock less than 1 foot diameter) – 0 to 1 foot
3. Hard Bottom (Solid clay, large rock in sand or mud, caliche, etc) – 0 to 1 foot

Protection from Objects moving in the tidal flow

1. Soft Bottom (Mud, Sand, broken shell, etc.) – 3 to 5 feet
2. Moderate Bottom (Cobbles, mixed sand or mud and rock less than 1 foot diameter) – 2 to 4 feet
3. Hard Bottom (Solid clay, large rock in sand or mud, caliche, etc) – 1 to 3 feet

Protection from Fishing and Crabbing Gear

3. Soft Bottom (Mud, Sand, broken shell, etc.) – 3 to 5 feet
4. Moderate Bottom (Cobbles, mixed sand or mud and rock less than 1 foot diameter) – 2 to 4 feet
5. Hard Bottom (Solid clay, large rock in sand or mud, caliche, etc) – 1 to 3 feet

Protection from "Johnny Balls" on tow lines

One of the significant causes of damage to the cables may come from "Johnny Balls" (the fairly large steel or lead weights located near the center of a tow line, used to absorb the shock to the tow line and vessels during rough weather). Long Island Lighting Co. experienced several outages on their 138 kV submarine cable system due to being struck by these weights. Johnny Balls are primarily used on open ocean tows, where rough weather or large waves are likely. The danger arises when the tug slows or turns in the cable area, both of which cause slack in the towline and allow the ball to sink. As water depth increases the probability of damage from a "Johnny Ball" decreases. Tugs tend to use much shorter towlines and no Johnny Balls in inland waters. This provides them with better control of their tows.

1. Soft Bottom (Mud, Sand, broken shell, etc.) – 2 to 4 feet
2. Moderate Bottom (Cobbles, mixed sand or mud and rock less than 1 foot diameter) – 1 to 3 feet
3. Hard Bottom (Solid clay, large rock in sand or mud, caliche, etc) – 1 to 2 feet

Removal of suspensions

The depth of burial varies from a minimum of 1 foot to a depth equal to the height of the suspension plus 1-foot

Arguments against burial:

Fatigue factor

All of the materials used in a power cable are susceptible to fatigue failure. The additional manipulation required to bury a cable increases the probability of fatigue failure. The most susceptible components are the lead sheath, insulation and the conductor.

Increased probability of cable damage during burial

This factor is directly dependent upon the equipment used for burial. It may include: abrasion of the outer servings and cable armor by the cable guide or “tooth”; abrasion by the material that the cable is being buried in; basketing of the conductor and/or armor due to the relatively sharp radii usually incurred during burial; and, most significantly, damage associated with the manipulation of the cable and installation equipment when an immovable object is encountered. Cable plows normally aren't designed to back up. When you run into an obstacle, you risk the safety of the cable in moving the "tooth" up to go over the obstacle. Sometimes you can't raise the tooth, which necessitates partial dismantling of the plow on the bottom and/or cutting and splicing the cable.

Virtually all of the recent cable burials have used subsurface profiling and/or “real time” obstacle detection during installation. Even with this equipment many obstacles, such as large rocks and solid reefs, have gone undetected thus requiring backing the installing equipment up (which is really not recommended), removal of the cable from the cable guide or “tooth”, or sharp turns either sideways or vertically to get around the object. <u>Note: This presents a virtually impossible situation when the cable is laid then buried in a separate operation, because there is normally insufficient slack in the cable to make these detours</u>.

Jetting under the cable and letting the cable settle into the jetted trench alleviates most of these problems. However, due to the rigidity of armored cables, this method normally will not achieve the burial depths required for protection from anchors and, in general, costs considerably more.

Reduced access to the cable in the event of a cable failure

Proper retrieval of the cable for repair is very time consuming and costly and involves jetting around the cable while lifting the cable out of the trench. Improper retrieval, or pulling the cable out of its trench without removal of the overlying material, usually results in exceeding the minimum allowable bending radius and quite likely will result in additional cable problems.

Reduced Current Carrying Capacity

The ampacity of the cable is inversely proportional to the depth of burial (the deeper it is buried the less the current it may carry). Burial of the shore ends has previously included a foot or more of free draining sand around the cable, thus assuring a good thermal environment. We have no thermal data for the deeper areas in either area that has been proposed for the "off-shore generation". Assuming that the installation procedure does not provide select thermal backfill around the cable, we must assume that the trench will fill with adjacent native material or, possibly worse yet, the finest materials in the water column (i.e. plankton and silt). It must be assumed that the uncontrolled backfill materials may promote thermal runaway. Therefore, unless thermal resistivity profiling is accomplished or free draining sand is used, it would be prudent to assume a thermal resistivity of 90 °C-cm/watt and limit the cable to soil interface temperature to 65 °C for these buried sections.

Cost

There is generally a considerable cost associated with the burial of the cable. This cost varies with the size of the cable, the depth of burial, the depth of water and the type of material in which the cable is to be buried.

Based on recent (October 2001) figures from the installation of three conductor submarine cables across Rosario Strait and Lopez Sound in the State of Washington the cost of cable burial is estimated as follows:

1. Burial Depth - 1 Meter in fairly soft material using a towed 300 horsepower waterjet unit (e.g. Nexans T-5 Embedment Machine) - approximately $125,000 per mile in depths of 100 feet or less.

2. Burial Depth - 1 Meter in moderately hard material using a towed 1000 horsepower waterjet unit (e.g. Nexans "Capjet" Embedment Machine) - approximately $175,000 per mile in depths of 100 feet or less.

3. Burial Depth - 1 Meter in hard material or 3 Meters in fairly soft material using a self-propelled waterjet unit (Harmstorf's Hydrojet unit) - approximately $1,000,000 to $3,000,000 per mile. In water depths of 100 feet or less.

Burial versus non-burial

Considering the increased costs and problems associated with cable entrenchment, is burial justified? This is a judgment that must be based on the probability of incurring damage from the previously discussed causes, the costs of installing a larger cable due to the thermal constraints and the lack of access in the event of a fault.

Recommendations

All cables should be buried to a depth of 25 to 100 centimeters in water depths of 10 feet or less at Mean Lower Low Water (MLLW). Burial depth may vary depending upon the hardness of the material being excavated. A burial depth of 25 centimeters is recommended in hard bottom and 100 centimeters in soft bottom. A soft bottom is expected in most locations. However, hard material may be incurred in a few locations. Therefore, a machine such as the Nexans "Capjet" should be the equipment of choice. Based on this analysis, the cost of burial for these cables is expected to be $175,000 per mile of cable that is to be buried.

5

RISK ASSESSMENT

Background

All Properly designed and installed submarine cables have a normal operating life that exceeds fifty years. However, damage to the cables from external events may cause premature failure, necessitating a cable repair or possibly the replacement of the entire cable system. External damage can come from many sources such as boats, anchors, “Johnny Balls”, fishing and crabbing gear, shoreline excavation, earthquakes and tsunamis. The prediction of these extremely random events is difficult, if not impossible. Unfortunately, some utilities have such rotten “luck” that they have incurred outages from external sources several times in one year. If a person were able to predict these occurrences, they would, most certainly, be in Las Vegas making millions. However, utilizing the experience of other utilities having similar submarine systems, one may make some generalizations. Tempering this experience with the environment found in Southeast, one might be able to analyze the situation.

The following analysis assumes that each cable is buried approximately 1 meter deep out to a water depth of 10 feet below Mean Lower Low Water (MLW).

Boats

Damage from boats generally occurs when a vessel runs aground directly on top of a submarine cable. This normally occurs in the shallow area near the terminals. These are relatively rare events, especially today with modern aids to navigation such as GPS, etc., and better nautical charts. Damage from an event such as this might occur once in 500 years per terminal, or once in approximately 125 years for the two cables. This type of damage will occur whether the cable is buried or not.

Anchors

Damage from anchors is a more common event. Occurrences such as these are directly proportional to the vessel traffic in the area and the suitability of the area for anchor holding and protection from the prevailing weather. For these cables it is expected that such an event will occur once every 10 years per cable. However, only one out of five anchor incidents is expected to result in damage that requires a repair. Therefore, the risk to the cable system is approximately one occurrence, requiring repair, every 50 years, assuming burial out to a water depth of 100 feet. The probability rises to approximately one event every 10 years when the cable is not buried.

All cable crossings should be marked on the appropriate nautical charts that are issued by NOAA. The use of Cable Warning Signs, while not mandatory, certainly help in court when suing to obtain compensation for cable damage from the damaging vessel. Warning signs should be installed at all terminal sites, both ashore and afloat.

"Johnny Balls"

"Johnny Balls" are the weights that are put on towlines to absorb the shock caused by differential movement of the tug and its tow. Most of this movement is caused by waves. In good weather, with small waves present, tugboat operators prefer to shorten their towline to gain better control of the tow, thereby reducing the chance of a Johnny Ball going deep enough in the water to damage the cables. Damage from this source is proportional to the number of tows crossing the submarine cables and the frequency of large waves in the vicinity of the cables. For this cable system, damage from Johnny Balls might be expected once every 200 years for each cable circuit that is exposed to tug traffic. For an unburied cable, the probability of damage from a Johnny Ball rises to once every 50 years.

Fishing, Claming, and Crabbing Gear

Fishing and crabbing appear to represent the greatest risk in SE Alaska. The risks to submarine cables that are associated with fishing and crabbing gear consist of damage from the sled that precedes the net in dragging and trawling operations, damage from crab pots and hooks from Long Liners that snag the cable.

Dredging for clams has caused considerable cable damage in those areas where submarine cables and dredging operations co-exist. However, there does not appear to be any commercially viable clam beds in the vicinity of any of these cables.

It should also be noted that only one out of six contacts is expected to cause damage that requires a repair. Therefore, the risk associated with the fishing, claming and crabbing industries is expected to occur once every 10 years per cable. Because only one in six events is expected to cause damage that requires repair, the assigned risk is one event, requiring repair every 30 years for the two submarine cables.
If the cable remains unburied through these areas, one may expect contact approximately once every two years and damage requiring repair approximately once every 12 years.

Shoreline Excavation

Shoreline excavation is not expected to represent any significant risk to the cables in the near future. However, during the next hundred years the population near the terminal areas may grow, thereby increasing this risk. In the proposed terminal locations it is expected that any excavation would be noticed and the excavator would be notified about the presence of the cables. Therefore, the risk for each circuit is expected to be one incident requiring repair every 150 years. All cables should be buried in the vicinity of the shoreline. Therefore, the probability remains the same.

Implementation of a monthly inspection tour of each cable terminal area should decrease this probability considerably.

Earthquakes and Tsunamis

Earthquakes, or seismic events, while relatively infrequent can result in very significant damage to a submarine cable system. The direct danger to the submarine portion of the cables results from major submarine landslides that bring rocks and other debris down on top of the cables. A pre-lay bottom survey should be used to locate these sites.

The armored submarine cables are quite flexible and, because they presumably will only be buried at the shore-ends, will move with the earth. Therefore, damage directly due to the earthquake is not expected.

Danger to that part of the cable system from the near shore area up to and including the terminals themselves, comes from both the earthquake and the resultant tsunami that maybe associated with major underwater earthquakes which result in exposed submarine land displacement. At least one of these major events is expected to occur during the next 300 years. Here the danger may come from the earthquake directly, causing the cable termination’s to topple as well as the large tidal surge known as a tsunami. Unfortunately an event such as this may necessitate the replacement of the entire cable system.

This risk remains approximately the same, due to the magnitude of the event, whether the cable is buried or not.

Risk Assessment

The actual risk to the entire cable system is obtained by adding all of these probabilities together. Therefore, the overall risk to the buried cable system from the external causes described above is one event, requiring repair every 20 years on average, over the next one hundred years. For a cable that is unburied through the critical areas defined previously, the risk rises to approximately one event every 4.2 years. <u>Please note that this assessment does not address the probability of damage from “strumming” or vibration due to tidal movement over a suspension</u>. That issue will need to be assessed after installation.

APPENDIX E

Report on Direct Current (DC) Technologies
Prepared by Northstar Power Engineering and Dr. George Karady

Draft Report

SOUTHEAST ALASKA INTERTIE STUDY

George G. Karady and F. Mike Carson

April 2003

SOUTHEAST ALASKA INTERTIE STUDY

George G. Karady and F. Mike Carson
2003

NOMENCLATURE

- <u>HVDC</u> — High Voltage DC energy transportation system
- <u>Light HVDC</u> — DC energy transportation system using voltage source converters
- <u>IGBT</u> — Insulated Gate Bipolar Junction Transistor, suitable for high frequency switching.
- <u>Thyristor</u> — High power switching device, which can turn on a circuit, but turns off when the current reverses.
- <u>Monopolar DC</u> — A DC system which has only one current carrying conductor and the current returns through the earth
- <u>Bipolar DC</u> — A DC system, which has two current carrying conductors and no ground current
- <u>Hybrid system</u> — An energy transportation system that has AC lines and DC submarine cables
- <u>Multi-terminal DC</u> — A DC system that contains more than one converter connected in parallel to the system.
- <u>Converter</u> — Electronic circuit that can work as a rectifier or as an inverter

INTRODUCTION

The Southeast Intertie is designed to interconnect major towns and communities in southeastern Alaska and provide reliable electric supply to the communities at a reasonable price. The intertie will reduce the use of environmentally undesirable energy generation from expensive diesel fuel and permit the use of more efficient larger hydroelectric power plants with renewable resources. The intertie would also provide back-up power during faults in local generation.
The Southeast Intertie is divided into six major segments:

1) Juneau-Greens Creek- Hoonah
2) Kake – Petersburg
3) Ketchikan - Prince of Wales Island
4) Ketchikan – Metlakatla
5) Kake - Sitka - Angoon - Hoonah;
6) Juneau – Haines

The present study concentrates on the first two segments, but the development of an optimized system requires the basic data from the other segments. The major technical data of the first two segments are summarized in Tables 1 and 2.

Table 1 Technical data of Segment 1

Start	End	Distance miles	Type	Load/ Rating	Taps
Segment 1	**Juneau-Greens Creek- Hoonah**				
AELP Sub-station	Outer Point	11.4	Line		
Outer Point	Young Bay	9.5	Cable		
Young Bay	Hawk Inlet	6	Line		
Hawk Inlet	Greens Creek Mine Tap	8.8	Line		10MW
Hawk Inlet	Spasski Bay	25	Cable		
Spasski Bay	Hoonah	3.5	Line		2.5MW

Table 2 Technical data of Segment 2

Start	End	Distance miles	Type	Rating	Taps
Segment 2	**Kake – Petersburg**				
Wrangell Narrows		1.1	Cable		
Wrangell Narrows	Duncan Canal	11	Line		
Duncan Canal		1.3	Cable		
Duncan Canal	Kake Substation	32.7	Line		2MW
Kake Substation	Kake Powerhouse	1.9	Line		
Kake Substation	Hamilton Island	1.7	Cable		

The objective of the present study is the identification of the most advantageous transmission system for the intertie. The technical problem is that the interconnection is between islands and requires submarine cables. In an AC system, the capacitive current limits the length of a submarine cable to about 40-50 miles. This problem can be eliminated by using DC energy transmission. A DC system eliminates the capacitive charging current of the cable and permits long submarine cable routes. Another advantage is that the DC system capacity is significantly larger than an AC system when cables are used. However, a DC system requires converters at both ends, which increases the initial investment. Another problem is that most operating HVDC systems are designed for point-to-point transmission. Recent development of new high power transistors (IGBTs) and the advancement of voltage source converter technology have produced the HVDC with VSC transmission system. This has opened new areas for the use of DC transmission. These developments suggest that DC transmission or the combination of AC and DC transmission should be considered for the Southeast Alaska Intertie.

The available energy transmission methods are:

1) AC transmission using 69 kV transmission line
2) Combination of AC and traditional DC transmission
3) DC transmission with VSCs
4) Combination of AC and DC transmission with VSCs

COMPARISON OF AC, HVDC AND HVDC/VSC TECHNOLOGIES

The first two segments of the intertie the system contain 74.3 miles of transmission lines and 52.2 miles of cables, assuming that the crossing of waterways requires submarine cables. Total length is 126.5 miles. The estimated load on the lines is small and in the range of 1.1-10 MW. The complete Southeast Alaska Intertie will form a network, which permits the transmission of energy from one end to the other. However the first two segments will operate independently. The total length of Segment 1 is 64.5 miles with 29.7 miles of transmission line and 34.5 miles of submarine cable. The estimated maximum load is 11.1 MW. The total length of Segment 2 is 48.7 miles with 44.6 miles of transmission line and 4.1 miles of submarine cable. The estimated maximum load is 1.5 MW.

Feasibility and Limitations of AC transmission

The less than 20 MW loading suggests the use of a 69 kV system, such as used by Alaska Electric Light & Power. Figure 1 shows the typical wood pole line used in Alaska.

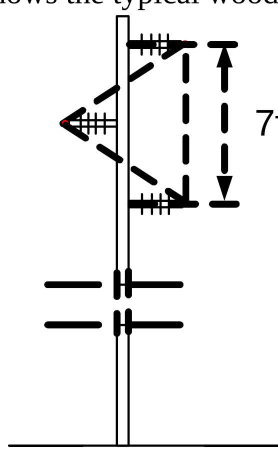

Figure 1. 69 kV AC Transmission Structure.

The traditional 69 kV transmission line impedance is 0.28 + i0.681 ohm/mi and the capacitance is 16.484 nF/mi. The calculation assumed an average distance GMD = 7ft between the conductors and an average height of 25ft. A span of 500ft and a ACSR ORIOLE 336 kcmil conductor was used. The ampacity of this conductor is 530A.

We obtained technical data for 240 sq. mm and 120 sq. mm, three phase, extruded, solid dielectric 69 kV submarine cables from AEL&P.

220 sq. mm Cable	120 sq. mm Cable
R = 0.125 ohm/km	R = 0.223 ohm/km
X = 0.160 ohm/km	X = 0.180 ohm/km
C = 190 nF/km	C = 160 nF/km
I_c = 2.9 A/km	I_c = 2.4 A/km

Figure 2 shows a typical extruded cable construction.

Figure 2. Typical extruded crosslink polyethylene cable

Each segment contains line and cable sections. Each section can be represented by a circuit. The equivalent circuit of a system which contains lines and cables is shown in Figure 3.

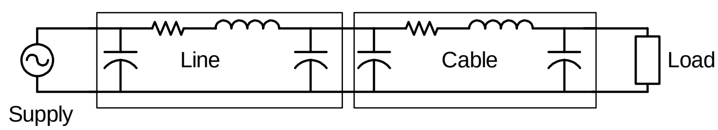

Figure 3. Equivalent circuit of Segment 1.

This circuit is simplified by combining the transmission lines in the segment into one . and the cables into another . For the analysis, it is assumed that the cable supplies variable loads connected to end of the cable and no intermediate load is on the line. The voltage at the load is the rated voltage of 69kV.

The required supply voltage, voltage regulation and currents are calculated as the function of the load to evaluate the feasibility of the AC system. It is assumed that the length of the section is 50 or 100 miles, the load power factor is 0.8 lagging and cable length divided by line length ratio is 0.5, 1 and 1.5. The details of the calculation are presented in the Appendix.

The line regulation versus load function for a 50 mile AC system is shown in Figure 4. Typically a utility works with +/- 5% regulation; however, a 69 kV transmission line without intermediate loads and with a voltage regulator at the load side can operate with a +/- 10% regulation.

The figure clearly shows that if the k = cable length / line length ratio is k = 0.5 (cable length is 16.67 mi), the system operates properly if the load is less than 27 MW.

For k = 1 (cable length is 25 mi), the system operates properly if the load is less than 25 MW

For k = 1.5 (cable length is 30mi), the system operates properly if the load is less than 21 MW

$P_{load} := 0 \cdot M \cdot W, 1M \cdot W .. 50M \cdot W$ $\qquad L_{total} = 50\,mi$ $\qquad k = \dfrac{L_{cable}}{L_{line}}$

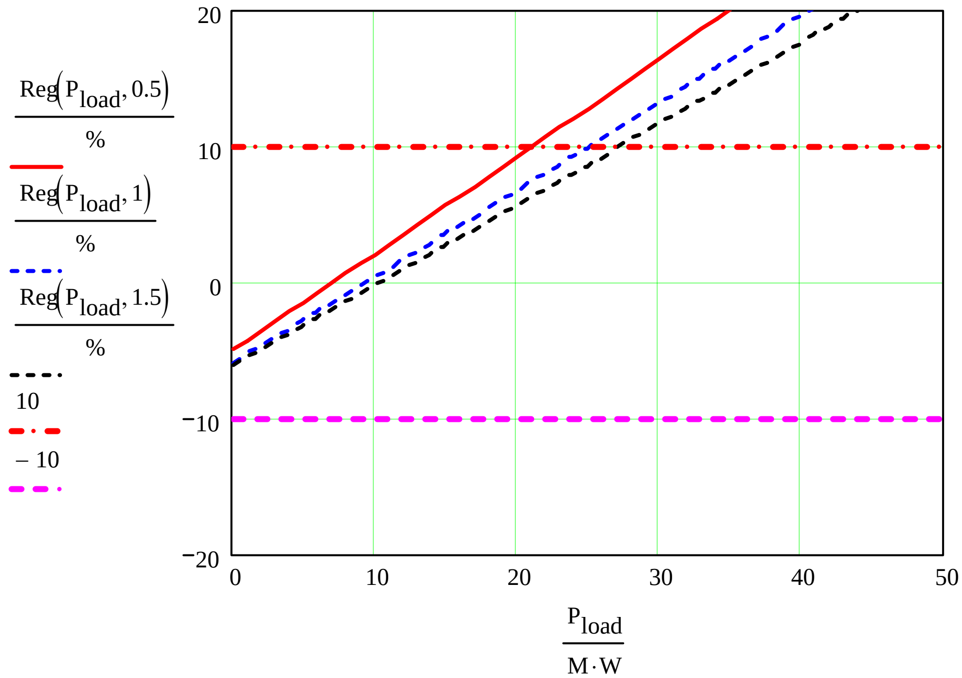

Figure 4. Segment 1. Regulation vs. load

The second constraint is that the cable and line current have to be less than the rated current. In this system, the cable is rated 500A and the line rated current is 530A.

Figure 5 shows the cable current at different cable lengths in a system with total length of 50 mi.

The figure indicates that the cable current has a load dependent minimum value. The figure shows that the minimum current is between 60A and 115A.

The figure shows that at k = 1.5 (cable length of 30 mi) the line current is above line rating of 500A if the load is more than 52 MW. At k = 1, (cable length of 25 mi) the line current is above rated value of 500A if the load is more than 54 MW. If k = 0.5, (cable length of 16.6 mi), the line current is more than 500A if the load is above 52 MW. This indicates the cable current does not limit the operation in this segment.

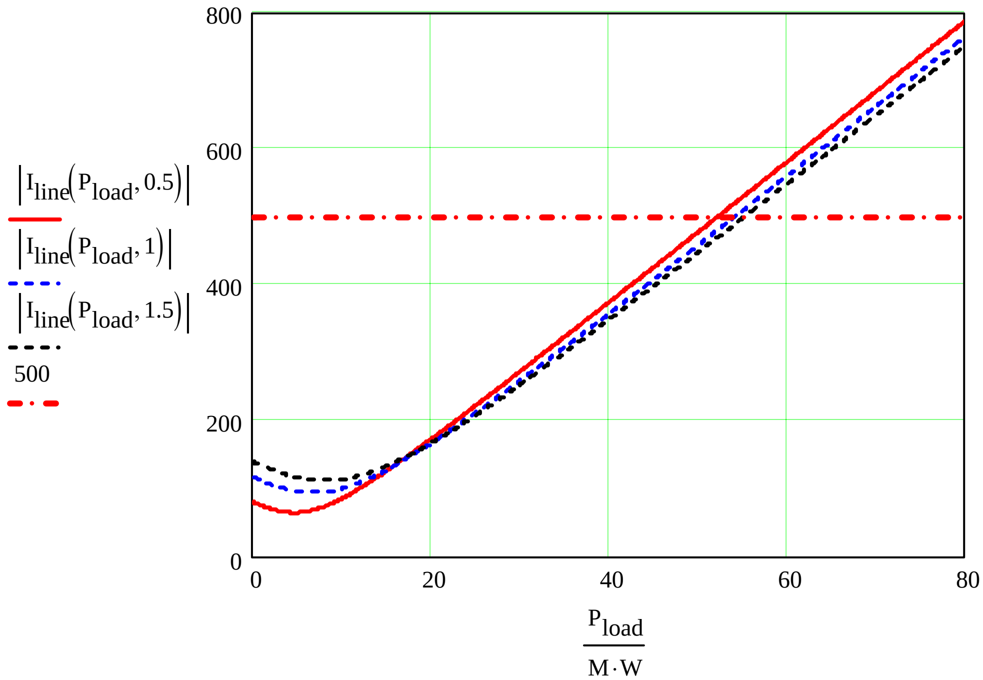

Figure 5. Cable current vs. load

Similar study on a 100 mile system shows that the system with k = 0.3 (33 mi cable) operates properly between 6MW and 20 MW. At a no-load condition, the overvoltage at the cable end is 20% and the system losses are unacceptably high. At k =1 (50 mi cable) and at k = 1.5 (60 mi cable), the no-load overvoltage will be more than 30%. These are unacceptable operating conditions. The system may be able to operate if switched or thyristor controlled shunt reactors are used.

This example demonstrates that the 69 kV AC system operating conditions are dependent on the length of the system. A 30 mile cable operates well in a 50 mile system, but generates unacceptable overvoltages in a 100mi system. This suggests that a study of the total intertie system is needed before the feasibility of a 69 kV system is determined.

<u>Conclusion</u>

1. The cursory analysis shows that the 69 kV system operating conditions are dependent on the length of the system.

    a. The use of a 69kV AC system is **feasible** if the cable length in the segment is less than 30 miles in a <u>50 mile system</u>

    b. The use of a 69kV AC system is **<u>not feasible</u>** if the cable length in the segment is more than 30 mile in a <u>100 mile system</u>.

2. The operating range of the system can be extended by using switched or thyristor controlled inductance to compensate for the cable current.

3. The segment by segment investigation may lead to misleading conclusions. The total system has to be studied for the proper design.

Feasibility HVDC transmission

The HVDC transmission systems are point-to-point configurations where a large amount of energy is transported between two regions. A typical example is the Pacific Intertie that transports the energy generated by hydroelectric plants in Oregon to the Los Angeles area in summer and feeds the surplus energy from Los Angeles to Oregon in winter.

The traditional HVDC system is built with line commutated current source converters with thyristor valves. The operation of this converter requires a voltage source like synchronous generators or synchronous condensers in the AC network at both ends. The current commutated converters can not supply power to an AC system which has no local generation. The control of this system requires fast communication channels between the two stations.

Figure 6 shows the concept of a HVDC system with thyristor valves. The major components of the system are:

- Two converter transformers, connected in parallel at the supply side
- Two converters, connected in series, with thyristor valves,
- AC and DC filters,
- Smoothing reactor at the DC side.

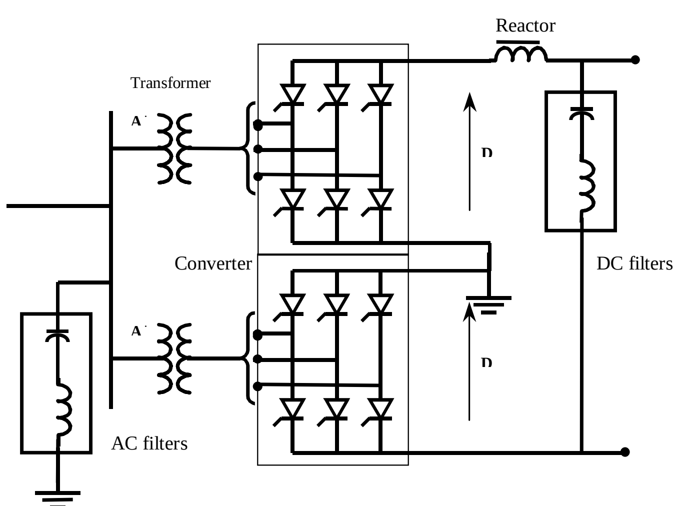

Figure 6. The concept of a HVDC converter with thyristor valves

A HVDC station requires considerable land because the transformers, filters and phase correction capacitors are placed outdoors. The valves and control equipment are placed in a closed air-conditioned/heated building. The completely enclosed system requires a large building and is prohibitively expensive.

The system can be ‘monopolar’ or ‘bipolar’. The monopolar system uses one high voltage conductor and ground return. This is advantageous from an economic point of view, but is prohibited in the continental USA because the ground current causes corrosion of pipe lines and other buried metal objects. In Europe, monopolar systems are in operation. Most of them are used for submarine crossings. The National Electric Code prohibits the use of a monopolar system; however, Alaska could apply for permission on the base of remote sites and low population density. It can be foreseen that this would delay a project significantly and would be disadvantageous in the future.

The bipolar system uses two conductors, one with plus and one with minus polarity. The mid point is grounded. In normal operation, the current circulates through the two high voltage conductors without ground current. However, in case of conductor failure, the system can transport half of the power in monopolar mode. This operation can be maintained for a limited time only.

Based on the above explanation, the bipolar HVDC system is recommended.

Multi-terminal operation, where converters are connected in parallel, is difficult and requires expensive control. The need for reactive power and the complications related to multi-terminal operation eliminates the use of traditional HVDC as a network.

However, the combined AC and HVDC system is feasible. In this system, point-to-point HVDC is used for a long (more than 40 mile) submarine crossing. Segment 1 and Segment 2 have no long submarine crossings.

The other problem with the traditional system is the need for reactive power support, which requires continuous operation of local generators or the use of static VAR compensators. This would eliminate one of the major advantages of the intertie, which is the use of low cost and environmentally friendly remote hydroelectric generation instead of the expensive local diesel generation.

The cost of the traditional HVDC system is high because of the need for filters, capacitors and other auxiliary equipment. The traditional HVDC system is designed for the transport of large amounts of energy measured in hundred of megawatts. This system is not economical less for than 20 MW loads.

HVDC system with voltage source converters (Light HVDC system)

Recently, ABB and Siemens started to build HVDC systems using semiconductor switches (IGBT or MOSFET) and pulse width modulation (PWM). The capacity of a HVDC system with VSCs is around 30-50 MW. Operating experience is limited but many new systems are being built worldwide. The relatively low power rating makes this system ideal for Alaska, where the loads are less than 20 MW.

The PWM inverters and rectifiers with IGBT or MOSFET switches are frequently used for motor drives. These drives operate close to unity power factor and do not generate significant current harmonics in the AC supply. Also the PWM drive can be controlled very accurately. These technical parameters indicate that the voltage converter based PWM system is a nearly ideal transmission component.

The voltage source converter concept is shown on Figure 7. The major components are:

- AC reactance
- Six IGBT or MOSFET switches with shunting diodes
- DC capacitor

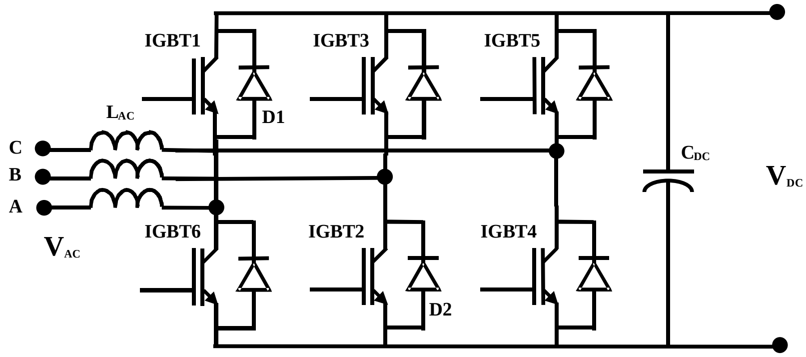

Figure 7. Circuit diagram of a PWM converter

The six switches form a six-pulse bridge. The switches are turned on in sequence, e.g. 12, 34, 56, etc. The turn-on of switch 1 connects the positive DC terminals to phase A and the turn-on of switch 2 connects the negative DC terminals to phase B. The switches are turned on for a short period of time, which generates a pulse train at the AC terminals.

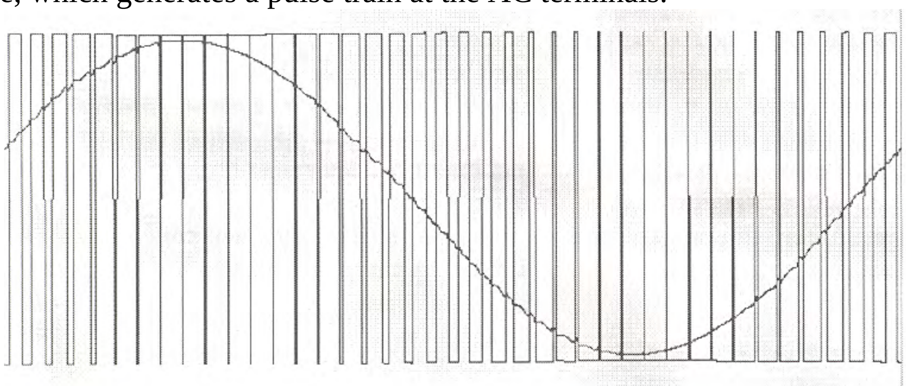

Figure 8. PWM voltage waveform

Figure 8 shows the generated pulse train. It can be seen that the width of the pulses is modulated and hence the name PWM. The filtering of the output voltage produces a sinusoidal waveform.

The DC capacitor reduces the harmonics on the DC side. The DC capacitor also controls the turn-off overvoltages, by providing a low impedance path. The turn-off of the switches generates these overvoltages. The output voltage can be controlled by the pulse pattern (on and off time ratio) and by the DC voltage.

This system can operate in both inverter and rectifier mode and can supply a passive AC system. As an example, it can start up an AC system after a fault. The converter can independently regulate the real and reactive power transfer. The converter voltage phase angle mostly controls the active power and the reactive power is dependent on the voltage magnitude. The converter can act as a motor or generator without mass and can provide either capacitive or inductive reactive power. The converter controls the AC current and consequently does not contribute to the AC short circuit current.

The PWM converter is an ideal device for energy transmission, because it can supply passive networks and several converters can be connected in parallel, which permit tapping of energy at towns or other loads.

The IGBTs are cooled with de-ionized water. The auxiliary power for the gate drives of the IGBTs is obtained by rectifying the voltage across the IGBTs. Snubber circuits control the voltage distribution within a valve, when several IGBT is connected in series. The PWM system can be installed in a building, because only small filters and capacitors are needed for the system operation.

A HVDC system with VSCs contains two converters. It can transfer energy in both directions. One of the converters operates as a PWM rectifier the other as an inverter. The rectifier can be controlled to operate close to unity power factor. The inverter can produce AC power with the required power factor. Typical losses claimed by ABB for two converters is 5%. Figure 9 shows the concept of a point-to-point energy transmission system.

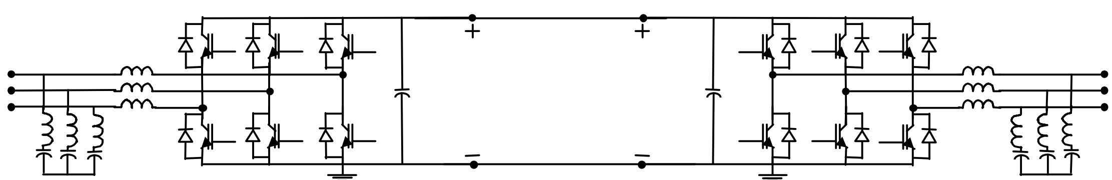

Figure 9. DC system with voltage source converters

The system is very simple and requires only a few components. The major components are the AC filters, DC capacitance, AC reactors, converters and the DC line or cable. The converter can be controlled remotely via a dial up telephone line. The system at the AC side is protected by standard circuit breakers. The converters can be energized separately.

For start up, the ac breaker is closed at one side. The diodes in the converter produce a DC voltage and energize the DC line. This charges the power supplies of the gate drive units and permits a start of the converter operation. The first converter that starts will control the DC voltage. The second converter that starts controls the power transfer. The reactive power is controlled independently at each station. The active power flowing in the DC network has to be equal to the active power transmitted from the first network to the second network plus the losses. In this system, one converter station maintains the DC voltage constant. The other station controls the active power flow within the limits of the system. This is achieved by controlling the phase angle between the network voltage and the sinusoidal reference control voltage.

If an AC fault occurs on the side that receives the power, the power-controlling converter is blocked. This interrupts the out going power, but not the incoming power. This results in a fast rise of DC voltage. The DC voltage-controlling converter will reduce or even reverse the incoming power to maintain the DC voltage constant.

If the fault occurs on the AC side of the converter that controls the DC voltage, the converter is blocked and a sudden drop in the DC voltage occurs. In this case, the remaining converter will control the DC voltage and simultaneously control the reactive power flow. The operation mode of this converter will be similar to the operation of a dynamic voltage restorer.

In case of a ground fault in the AC system, the converter control will reduce the DC voltage to limit the current flow to the pre-fault value. The voltage source converter will not increase the short circuit current in the AC system.

Limitations with overhead lines

HVDC systems with VSCs have several design limitations when used with overhead DC lines. The limitations include possible excessive stresses to the converter IGBT valves caused by remote faults, instability of the DC circuit and electromagnetic interference. For this reason, HVDC systems with VCSs are usually interconnected with cables.

There are two types of remote faults which stress the IGBT valves: single line to ground and line to line faults. High impedance grounding of the neutral bus at the converter station is used to reduce the exposure of the IGBT valves to ground faults. In the case of line to line faults, the freewheeling diodes will be stressed and must be designed for the peak fault current and energy. Also, a high speed circuit breaker is required to clear the fault within 3 cycles.

The system resonant frequency of an overhead line DC circuit is very close to the frequency of the AC grid. This could result in oscillations and dynamic instability. A large DC storage capacitor will increase the frequency and reduce the oscillations but could cause high fault discharge currents.

VSC converters produce harmonic currents which must be prevented from flowing into an overhead DC line and causing EMI on adjacent communications systems. Harmonic filters will reduce the objectionable currents but add to the converter cost.

ABB and Siemens are currently developing and marketing HVDC systems with VSCs world wide. A list of current projects can be obtained from their websites. Siemens Nexans is investigating the feasibility of a 150 km 150 kV DC link from Stewart BC to the Forest Kerr hydroelectric project in a remote area of British Columbia. Table 2 shows recent applications of HVDC systems with VSCs. The material was copied from the ABB and Siemens websites.

Table 2. Light HVDC systems by ABB

Project	Rating	Dist.	Application	Commissioning
Murraylink	200 MW	180 km	Interconnection Underground cable	2002
Hagfors	± 22 MVAr	N/A	Flicker mitigation	March 1999
Gotland	50 MW	70 km	Wind power, Underground cable	June 1999
Tjære-borg	7 MW	4 km	Wind power, Underground cable	March 2000
RWE	0-38 MVAr	N/A	Flicker mitigation	June 2000
Directlink	180 MVA (3x60 MW)	65 km	Interconnection, Underground cable	Dec 1999
CSW	36 MVAR/MW	N/A	BtB Asynchronous Tie	May 2000
Cross Sound	330 MW	40 km	Network Connection, Submarine cable	2002

All DC transmission with voltage source converters

Voltage source converters, applied to HVDC, permit multi-terminal operation. Several converters can be connected in parallel to a DC transmission system. For example, a four terminal circuit suitable for an intertie project is shown in Figure 10.

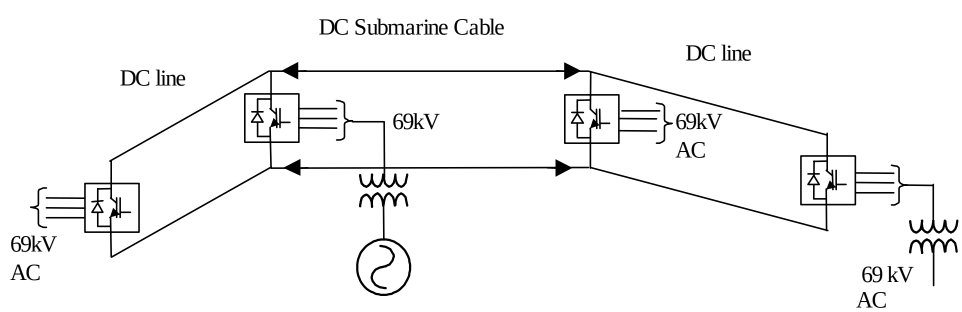

Figure 10. DC system with VSCs

The proposed system contains four converters connected in parallel by transmission lines and submarine cables. We propose a bipolar system with two high voltage converters connected in series and the middle point is grounded. This system has a positive high voltage conductor and a negative high voltage conductor. In an emergency when one of the conductors fails, the system can operate in the monopolar mode with ground return for a limited period of time. Typically, the system maximum voltage is +/- 80-100kV and the rated current is around 300A-750A.

Each converter supplies the local 69kV transmission line or a low voltage (15kV) distribution line. This implies that a long DC transmission system should be built with converters at the load points. Standard wood pole line construction can be used for DC with only two conductors. Typical 69 kV insulation permits operation up to about 50 - 60kV; however, the addition of three more insulators will upgrade the system to 100kV. The 336 ACSR Oriole conductor is adequate for currents up to 530A. The system requires two 100 kV rated DC cables at the submarine crossing. The cable current rating should match the transmission line current rating (500A). The DC system eliminates the inductive voltage drop, which allows power transmission for a longer distance. The power transfer capability of the system is presented below:

$P_{load} := 0, 1M\cdot W .. 30M\cdot W$ $\quad L_{cable}(0.5) = 16.667mi$ $\quad L_{cable}(1) = 25mi$ $\quad L_{cable}(1.5) = 30mi$

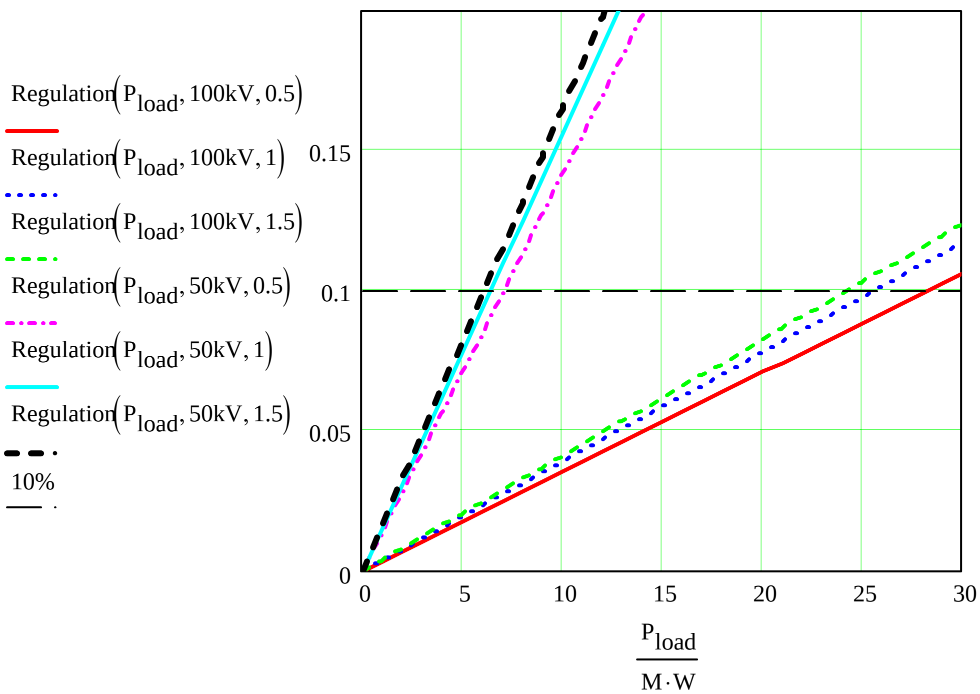

Figure 11. Voltage drop on a DC line vs. Load at different voltages

The figure clearly shows that the ratio of line length to cable length has little effect on the power transfer capability of the line. A maximum voltage regulation of 10% was assumed. In this case, the DC system can carry:

- 5-6 MW if the DC voltage between the conductors is 50kV
- 24-29 MW if the DC voltage between the conductors is 100kV

One possible operating mode of the all DC system is that the most powerful station with a

20MW or more capacity power plant maintains the DC voltage constant. This is achieved by modulation of the PWM pattern. The DC voltage is measured and compared to the reference DC voltage. The difference signal changes the amplitude or phase angle of the reference sine wave. With this control method, this station maintains the power balance by keeping the DC voltage constant.

The other stations either consume or inject power into the system, depending on the load. The control variable for these stations is the DC current. Each station can control the reactive power independently from the active power.

Conclusion: An economical solution is to build a 50 kV bipolar system with 69kV transmission line construction designed for two conductors and with two DC cables rated for 50kV. This system with one 50 kV, 300A converter will be able to supply energy up to 5 MW. The system can be upgraded to 20 MW at a later time by connecting a 50kV, 300A converter in series with the existing one when the load demands it.

The obvious disadvantage of this system is the high cost of the converters at each tap.

Combined AC and DC transmission with voltage source converters

The combined AC and DC system is built with standard 69kV transmission lines and point-to-point DC transmission at a long submarine (30 miles or more) crossing. The concept of this system is shown in Figure 12.

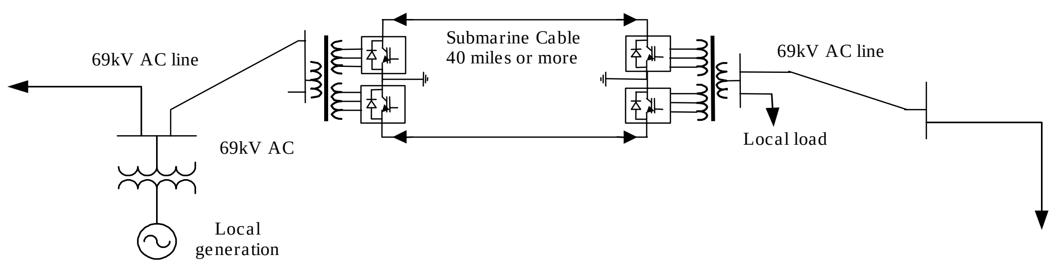

Figure 12. Concept of combined AC and DC system with voltage source converters

The all DC system with voltage source converters is advantageous when the power that has to be transmitted for a long distance is around 30MW- 50MW. The 4-10MW loads in the present system can be served easily by a 69 kV traditional AC system. As an alternative, the 69 kV system can be easily upgraded to 138 kV in the future, by adding insulators to the line and using phase spacers between the phase conductors. The spacers restrict conductor movement and reduce galloping when snow falls from the lines in the spring. The proposed future upgrade from 69kV to 138 kV would produce a compact AC line. Because of the low number of thunderstorm hours and the rarity of lightning stokes, the expected system reliability is high.

At the long submarine crossing, the voltage source converters can operate safely in spite of the weak local system with low short circuit ratio. The low short circuit ratio produced operational problems in traditional HVDC systems. The rectifier side converter can operate with close to unity power factor, reducing the reactive power requirement and eliminating the need for large capacitor banks or expensive static VAR compensators. The inverter at the other side of the submarine crossing produces sinusoidal voltages with a low level of harmonics. This inverter can supply the load and regulate reactive power.

The preliminary cost estimates show that minimization of the number of converters will reduce the cost of the system.

Conclusion: Because of the low level of load, the most advantageous system is the combined AC and DC system. Utilities have extensive operating experience with the existing 69 kV AC system, which suggests the use of a DC system with VSCs only at the long submarine crossing as a point-to-point transmission system.

Underground cable

The reliability of a DC transmission system can be improved by replacing the transmission lines with overland DC cables. ABB developed a new single conductor DC cable and claims that the cost of this cable is comparable with the cost of an overhead line with the same capacity. The cables can be directly buried as shown in Figure 13.

Figure 13 Installation of DC cable by direct burial

The technical data of the cable with aluminum conductor and extruded insulation are:

- Conductor: 95mm^2 aluminum
- Insulation: 5.5mm triple extruded PE/XLPE
- Screen: Copper wires

- Sheath: HDPE
- Weight: 1.05 kg/m
- Voltage: 100kV
- Current: less than 300A
- Power: less than 30MW

The handling is easy because of the lightweight cables. The author predicts that this DC cable will be cost effective even for a medium length (50-60 km) energy transmission. The advantages are:

- Smaller right of way and environmental effect and reduced public resentment and political opposition.
- Reduced and static dc magnetic field generation.
- Fewer problems with converter design and stability.
- Ease of construction especially where primitive roads are available.
- Easier to obtain building permits for a cable than for an overhead line.

For Alaska intertie system, overland cable that is direct buried should be considered if the all DC system is selected. However, overland DC cables are not needed if the combined AC and DC system is selected.

BUDGETARY COST ESTIMATE FOR HVDC SYSTEM

The cost estimates use the data already published in the George G. Karady, F. Mike Carson: SITKA-KAKE-PETERSBURG HVDC INTERTIE STUDY,1999. We obtained budgetary cost estimates from ABB for the HVDC system converters and cables. These costs are approximate and can be used only to compare different systems. The design of a DC system selected for funding requires more detail and a more accurate cost estimate. The cost figures used for the estimate are:

HVDC system 50 MW, 100kV, Thyristor converter

Approximate per unit value is: 660 $/kW

Light HVDC 50 MW, +/-84kV, IGBT converter pair (Source: verbal communication with ABB)

Approximate per unit value is: 180-220 $/kW

Transformer 50MVA, 69kV/138kV

Approximate per unit value is: 10 $/kVA

It should be pointed out that the relationship between the cost and capacity (MW) is not linear, because the cost of the control system, communication system, auxiliary electrical supply are more or less independent of the size of the converter. Similarly the size of the site and building also has a lower limit. The authors estimate that cost figures presented can be reasonably used above 10MW.

Cable cost	75 kV DC	150 mm^2	\$18/ft or \$95,050/mile
	100kV DC	240 mm^2	\$25/ft or \$132,000/mile
	Installation 1 cable		\$4.5/ft or \$23,760/mile
	Installation 2 cables		\$6.0/ft or \$31,680/mile

The above cable costs are from the Harza estimate. Pirelli Cables estimated the installed cable price to be between \$200/m to \$500/m, which corresponds to \$321k/mile to \$804k/mile. Harza added a \$7,000,000 mobilization cost to the installation cost. This cost is independent of the type or number of cables and, consequently, was not considered in this study. ABB recently provided the following estimated costs for DC submarine cables:

- 300A HVDC light cable for less than 300m depth 0.06 MUS\$/km
- 300A HVDC light cable for more than 300m depth 0.08 MUS\$/km

- 500A Mass Impregnated cable for less than 150m depth 0.10 MUS$/km
- 500A Mass Impregnated cable for more than 150m depth 0.12 MUS$/km

Transmission line cost

Basic cost	138 kV AC Wood	$148,000/mile
	69 kV AC Wood	$123,000/mile
	100 kV DC monopolar	$74,000/mile
	100 kV DC bipolar	$113000/mile
Rock and Muskeg	138 kV AC Wood	$192,000/mile
	69 kV AC Wood	$155,000/mile
	100 kV DC monopolar	$100,000/mile
	100 kV DC bipolar	$145,000/mile

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DESIGN OF SEGMENT 1 AND 2

The connection diagram of Segment 1 is shown in Figure 14. Segment 1 is supplied by the AEL&P system at Juneau. The load on the system is very light. The major loads are the Greens Creek Mine, about 10 MW, with an assumed power factor of 0.8 lagging and Hoonah, about 1.1 MW. A very small load, less than 100kW, is connected to the line at Hawk Point for the harbor.

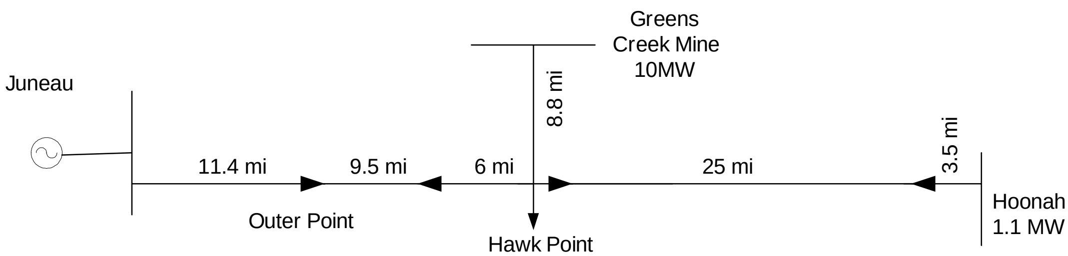

Figure 14. Segment 1 connection diagram

Each section of the system can be represented by an equivalent . circuit. The system equivalent circuit is shown on Figure 15. The system operation was analyzed assuming a 69 kV AC network and by converting the system to a 100kV, 2 x 50 kV three terminal DC system. The analysis is presented in Appendix.

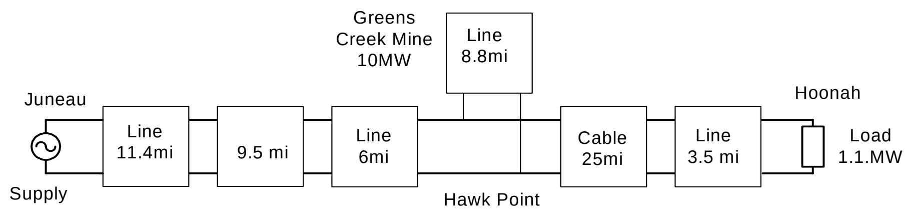

Figure 15. Equivalent AC system.

AC system

The results of the AC circuit analysis show that the present 1.1 MW load at Hoonah and the 10 MW load at Greens Creek Mine cause a regulation of 1.159% at Greens Creek Mine and a negative regulation of -0.301% at Hoonah. The current is below the rated current of 500A and the system losses are 352kW or 3.17%.

Accordingly, the 69 kV AC system is suitable for this section. A cursory calculation shows that the system can be loaded at Hoonah up to 15 MW. A similar analysis shows that the 69 kV AC system also feasible for Segment 2.

DC system

The total DC system with voltage source converters is a viable option. This system requires 3 converters as shown in Figure 16.

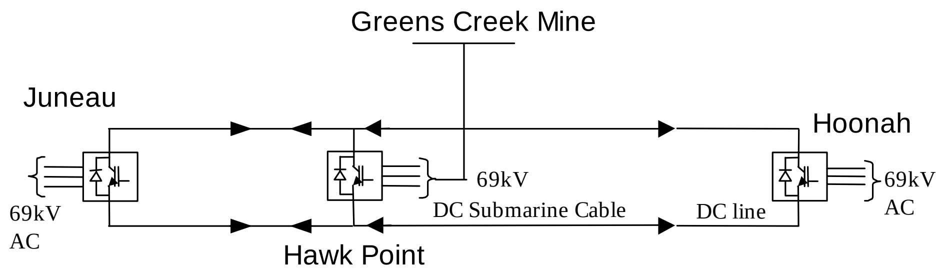

Figure 16. DC system for Segment 1

The DC system analysis shows that the voltage drop will be less than 3% at the present load condition if the DC voltage is 100kV. In case of 2 x 50 kV DC voltage, the system can transmit energy from Juneau to Hoonah up to 17 MW and with one 50 kV converter up to 8.5 MW. The latter should be sufficient for more than a decade.

The obvious disadvantage of the system is that the three (3) converter stations cost around 3/2 x 200$/kW x 15 MW = $4.5M in addition to the transmission line and cable costs.

Combined DC and AC system

The combined AC and DC system uses 69 kV AC transmission and a dedicated DC link between Hawk Point and Hoonah. The present load at Hoonah is around 1.1 MW. This load is expected to increase to less than 5 MW in the next decade. This requires a DC system rated 60kV and 300A. The estimated converter station cost is: 15MW x 200 $/kW = $3.0M. This is an addition to the transmission line and DC cable costs.

According the above analysis, the combined system is a feasible but expensive solution.

Conclusion

The segment by segment investigation may lead to misleading conclusions. The total intertie system should be analyzed to develop the proper design.

Segment 1. The most economical solution is the 69 kV AC system. The combined AC and DC system, with 50 kV, 300A upgradeable converters gives great flexibility for future connections to other towns.

Segment 2. The most economical solution is a 69kV AC system, because of the low load level and short cable crossings. However, a DC system consisting entirely of cables buried along existing USFS roads has environmental and maintenance advantages.