NEWFOUNDLAND AND LABRADOR

HVDC PROJECT

HVDC LINK RELIABILITY STUDIES

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1.0 INTRODUCTION

This report summarizes reliability predictions prepared for the proposed Labrador-Newfoundland HVDC project.

Lightning performance has been calculated for the overhead lines in Labrador and on the Island of Newfoundland. Pole and bipole flashover rates are reported and their impact discussed. Bipole flashovers are expected to be of transient nature and, owing to the favorable control capability of HVDC links are expected to be recoverable with high probability.

Failure rate and repair time estimates have been prepared for overhead line sections, Strait crossing alternatives, and terminal equipment. Predictions of the reliability and availability of the HVDC link are presented in terms of the frequency, duration, and probability of various levels of transfer capability.

REVIEW OF LIGHTNING PERFORMANCE OF PROPOSED DC TRANSMISSION LINES LABRADOR-NEWFOUNDLAND HVDC PROJECT

1.0 Introduction

As part of the Labrador-Newfoundland Churchill Falls project, it is proposed to construct a ±400 kV dc transmission line. The lightning performance of this line may be a significant factor in the reliability of the project because

- o the line will be unshielded for most of its length
- o soil resistivity may be relatively high
- o the line is relatively long.

1.1 Source Documents

Information used in this study will be found in the reference list at the end of this section.

1.2 Line Characteristics

Figures 1 to 3 show the line route and the two principal structure types as shown in Reference 1.

The total line lengths are approximately 190 route km (120 mi) from Churchill Falls to Gull Island, 400 route km (250 miles) from Gull Island to Straits of Belle Isle, and approximately 690 km (430 mi) from the Straits of Belle Isle to Soldiers Pond. Typical maximum spans are 400 m.

Several combinations of insulator size, discs per string, and string configuration are proposed. For this evaluation a 19 x 170 mm I string of standard discs is assumed to be typical. The keraunic level is estimated as 5 thunderdays/year.

2.0 Performance Assessment

2.1 Number of Strokes to the Line

The number of strokes to the line is usually obtained from the keraunic level, as this is often the only information available. The keraunic level is actually a poor indicator of the number of strokes to a line, and where possible it is preferable to use ground flash density obtained from flash counters, the performance of nearby lines, or thunderstorm hours. As an example, Eriksson [4] shows that in South Africa, a keraunic level of 5 may correspond to ground flash densities from 0.26 to 1.3 km^2/year.

Recently, values for ground flash density and consequent strokes to the line have undergone considerable development and discussion. There is still considerable disagreement in this area. References 4 and 5 suggest a lower ground flash density for a given keraunic level than is usual, but postulate a stroke mechanism that increases the number of strokes that terminate on the line. In contrast, reference 6 suggests a higher ground flash density but a lower number of strokes to the line. Because the methods of reference 6 are known to be reasonably consistent, and to give approximately correct predicted performance for a range of transmission line designs, they have been used for this study.

For a keraunic level T of 5 thunderdays/year, the ground flash density N_G is [6]

$$N_G = 0.12\ T/km^2/yr$$
$$= 0.6/km^2/year \text{ or } 1.6/mi^2/year$$

However, a more accurate value can be obtained from the known lightning performance of nearby 230 kV lines [3]. These lines have 16 insulators, an average height of 45 feet, an average width of 46 feet and a known tripout rate of 3.4/100 mile/year. Assuming that approximately 15% of flashovers will self-extinguish, the flashover rate of the line is

$$\frac{3.4}{0.85} = 3.91/100 \text{ mile/year}$$

For 16 insulators, the CFO is approximately 1440 kV. The surge impedance of the conductors is

$$Z_c = 60 \ln \frac{2h}{r} \text{ and } r = 0.6 \text{ inches}$$

i.e.,

$$Z_c = 450 \text{ ohms}$$

Then

$$I = \frac{CFOx2}{2_c}$$
$$= 6.4 \text{ kA}$$

From [6]

$$P_I = 98.4\%$$

i.e., the number of strokes N_r to the line is

$$N_L = \frac{3.91}{.984} = 3.97/100 \text{ mile/year}$$

From [6] the ground flash density N_G can be obtained from

$$N_L = N_G\ (b + 4h^{1.09})$$

whence

$$N_G = 0.7/\text{mi}^2/\text{year}$$

This compares to the $1.6/\text{mi}^2/\text{year}$ calculated above, or the $2/\text{mi}^2/\text{year}$ in the Teshmont study [3].

The number of strokes to the dc line is then obtained from

$$N_L = N_G\,(b + 4h^{1.09})$$

where

b = 11 m (36 feet)

h = 31 m (102 feet) conservatively ignoring conductor sag

i.e.,

$$N_L = \frac{0.7}{10}\,(36 + 4 \times 102^{1.09})$$
$$= 2.53/100 \text{ mile/year or } 1.6/100 \text{ km/year}$$

2.2 Calculation of Flashover Rate

For 19 insulators, the CFO is approximately 1710 kV. The conductor surge impedance Z_c is

$$Z_c = 60 \ln \frac{2x102x12}{1.06}$$

$$= 465 \text{ ohms}$$

For the positive pole

$$I = \frac{(1770-400)x2}{465} = 5.9 \text{ kA}$$

$$P_I = 98.7\%$$

For the negative pole

$$I = \frac{(1770+400)x2}{465} = 9.3 \text{ kA}$$

$$P_I = 95.7\%$$

i.e., the probability of flashover of the positive and negative poles will be virtually the same. If this were a backflash event, it is probable that the positive pole would flash over first and in so doing would protect the negative pole, but since this line is unshielded, the flashovers are expected to be evenly distributed between the two poles.

The calculation assumes that all strokes will be to the conductors. This is slightly conservative, as in fact some strokes will terminate on the towers and will have a lower flashover probability, but tower strokes are ignored as resulting in a relatively small change to the final performance.

The final flashover rate is then approximately

$$2.53 \times \frac{(.987+.957)}{2} = 2.46/100 \text{ mile/year}$$

$$\text{or } 1.54/100 \text{ km/year}$$

2.3 Calculation of Line Performance

Ignoring variations of performance along the line, for the 680 mile (1088 km) line the flashover rate will be

$$F = 2.46 \times 680/100$$

$$= 16.7/\text{year} \quad \text{and} \quad 19.7/\text{year for the 800 mile line}$$

Note that the tripout rate is the same as the flashover rate on a dc line, i.e., there are no self-clearing flashovers as can occur on an ac line.

2.4 Double Pole Flashovers

The tripout rate for flashovers of the second pole was calculated at 0.56/year.

In practice this rate may be higher, due to strokes terminating simultaneously on both poles, and it would be prudent to assume up to 2 events per year with double pole flashovers.

2.5 Flashover Rate for Shielded Line

If the line is shielded by a single ground wire the flashover rate is considerably reduced to approximately 0.5 to 1.0 per year, depending on footing resistance.

3.0 Grounding

3.1 Footing Resistance

A sensitivity study was performed to determine the maximum allowable footing resistance for the towers. For an unshielded line, footing resistance is normally of little concern since it has virtually no effect on initial flashover, but for a dc line the concern is for flashovers of the second circuit.

With realistic assumptions of reduced resistance as a function of impulse current it is concluded that the maximum allowable footing resistance is 50 ohms (measured with low current). Footing resistance above this value cause a disproportionate increase in the double pole flashover rate.

It is noted that this value of 50 ohms is in agreement with the Teshmont report [3].

3.2 Grounding Procedures

The methods for attaining the desired footing resistance described by Teshmont [3] appear to be sound, with one exception where it is recommended that grounding be cross-connected between towers of adjacent lines.

Although this would reduce the probability of a double pole flashover, it would increase the probability of flashover of poles on both lines, and it is therefore recommended that the grounding of two adjacent lines be kept separate.

4.0 Shielded Line Sections to Substations

It is common practice when using unshielded lines to shield a short length of line adjacent to the line ends to help protect the substation equipment by limiting surge magnitudes and steepnesses on the phase conductors.

5.0 Comments and Conclusions

1. The flashover rate of the dc lines is estimated at 19.7 events per year.
2. The double pole flashover rate is estimated at 0.54 to 2.0 events per year.
3. A maximum allowable footing resistance of 50 ohms is recommended.
4. Cross connection of grounds of adjacent lines is not recommended.
5. If the lines were shielded with a single shield wire, the flashover rate would be approximately 1.0 events per year.
6. The flashover levels of the positive and negative poles are approximately the same despite the difference in pole voltage. This is because the line is unshielded, i.e., strokes can terminate in either phase. If the line were shielded, the positive pole would tend to flash over first, rather than the negative one. As the first pole to flash over would provide protection for the other, the negative pole of a shielded line would have considerably better performance than the positive pole.

References

[1]. Transmission of Electricity from Labrador to Newfoundland. Single Bipole 400 kV DC. Engineering Report March 1980, SNC-Lavalin Newfoundland, Ltd.

[2]. Meteorological Study of the Gull Island-Stephenville-Holyrood Transmission Line Routes, MRI, November, 1973.

[3]. Gull Island Transmission Facilities Engineering Report. Report on Lightning Performance of HVDC Lines. Teshmont Consultants, Ltd., March, 1977.

[4]. R. Anderson and A. Eriksson, "Lightning Parameters for Engineering Application," Electra No. 69, 1980.

[5]. A. Eriksson, "Lightning Striking Distances - An Analytical Study," South African Institute of Engineering Transactions, 1980.

[6]. Transmission Line Reference Book: 345 kV and Above, EPRI, 2nd Edition Draft, 1981.

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1.0 Summary

A review was made of the performance of existing DC and AC systems similar to the Labrador-Newfoundland DC link. Fault rates and restoration times for the link were prepared based on the above analysis and on estimated restoration times for conditions to be encountered the Labrador-Newfoundland system.

Two alternate configurations were investigated for the crossing of the Strait of Belle Isle - a submarine trench scheme and an underground tunnel scheme.

A reliability model of the HVDC system was developed and analyzed for both DC and AC links from Gull Island to Churchill Falls. For the AC alternative, three different stages were evaluated.

The following points highlight the major findings of the reliability study of the Labrador-Newfoundland HVDC link:

1. The dominant contributors to system unreliability are the bipole line sections and the submarine cable crossing.

2. DC terminal equipment was found to contribute very little to the overall unreliability of the system.

Results of the study were presented in capacity - probability tables indicating the probability of various transfer levels.

1.1 Reliability Premises for Preliminary Analysis

In order to perform a reliability analysis, it is necessary to set forth preliminary design objectives or design premises.

1. Single failure capability - momentary outages

   a) System capable of withstanding bipole momentary outages without incurring instability, cascading, or collapse. Temporary, automatic load shedding permissible to balance momentary deficit in generation.

   b) System capable of withstanding pole momentary outages without incurring instability, cascading, collapse, or load loss.

2. Single failure capability - sustained outages

   a) System capable of withstanding bipole sustained outage without cascading, collapse, or instability leading to uncontrolled separation. Load shedding, controlled separation, and equipment isolation may be undertaken to preserve portions of the bulk power system and to minimize time to restore lost load.

   b) System capable of withstanding sustained single circuit (pole) outage without incurring instability, cascading, or collapse. (Monopolar operation at rated bipole capability.)

c) System capable of withstanding pole loss without instability, cascading, or collapse. (Monopolar operation at rated pole capability. Load restoration with on island reserves.)

d) System capable of withstanding valve group sustained outage without incurring instability, cascading, collapse, or load loss. Overload capability of the remaining valve groups may be used to minimize production from island reserves.

3. Single failure capability

a) No single valve group equipment failure may result in sustained outage of a pole.

b) No single pole equipment failure may result in sustained outage of the bipole.

c) No single AC equipment failure may result in sustained outage of the bipole.

4. Spares Capability - Sufficient equipment (spares) will be placed at each terminal or maintenance depot to provide for component replacement capability or sufficient spare capacity will be available at each terminal to cover the loss of any single component.

1.2 Terminal Reliability Model

The major elements of the terminal reliability model are shown in Figure 1.1. These are:

Major Element	Failure Effect (Outage)
AC Equipment	Pole
Converter Transformer & Valve Group	Valve Group
Pole Equipment	Pole
Bipole Equipment	Bipole
Pole Paralleling Equipment	Bipole

Note the dominant causes of pole and bipole outage will be associated with outages of the overhead line or outages of the cables crossing the Straits of Belle Isle. Terminal equipment causes of bipole outage are expected to be very infrequent and to be of short duration.

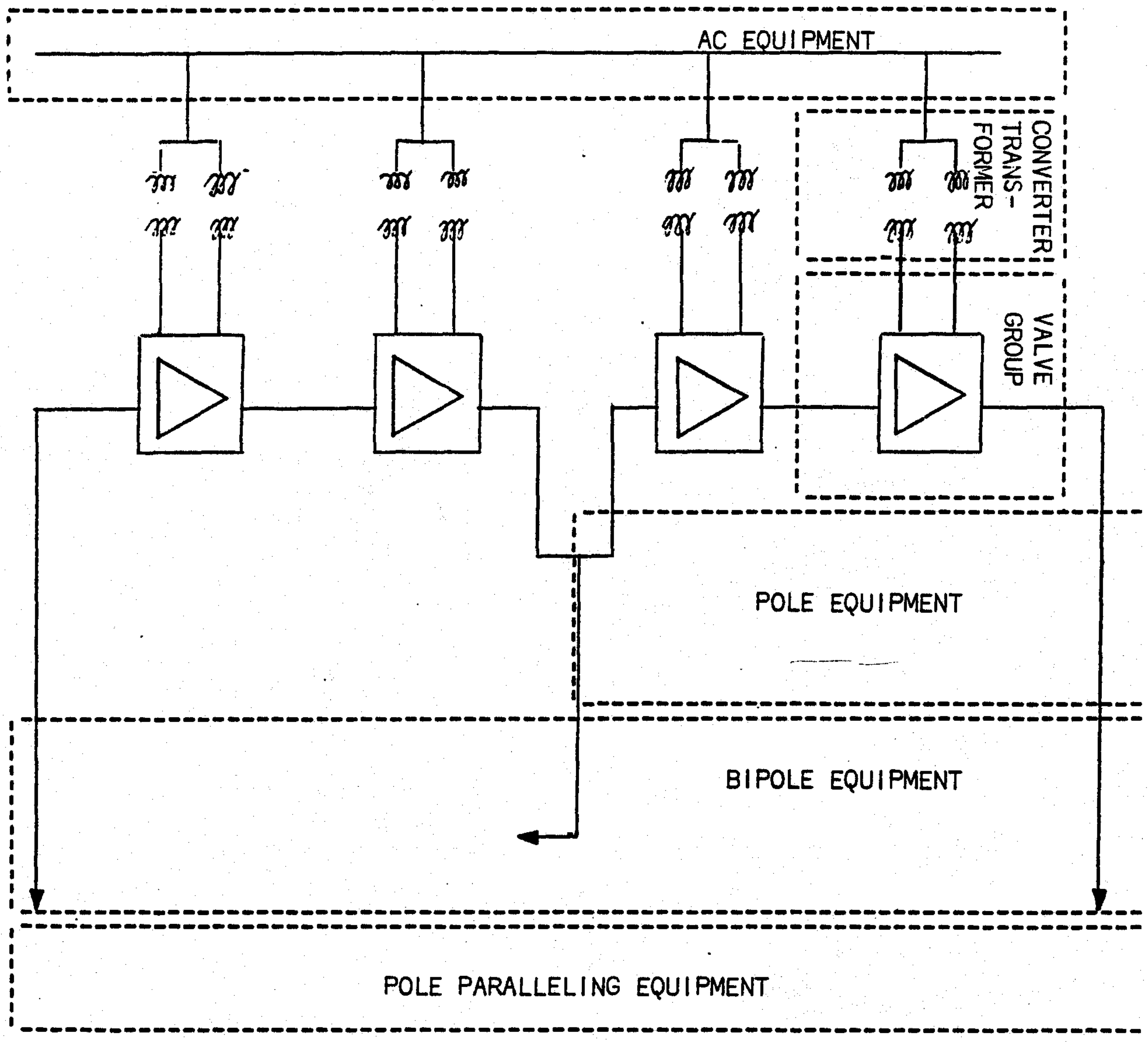


Figure 1.1 - Elements of the HVDC Terminal Reliability Model

1.3 Repair Procedures for Cable Systems

1. Submarine cables laid in pairs in trenches

In developing a model of the time to carry out cable repairs:

a) Repairs may be carried out during the period from May 15 - Dec. 15 corresponding to the open period of the Strait.

b) Following onset of a cable failure, waiting time must be allowed to secure and provision a cable repair ship.

c) Cable retrieval for repairs will require removal of both cables from the trench.

d) The availability of one repair ship will be assumed, repair operations may be done on one trench at a time.

2. Cables laid in tunnel-

Cables will be placed (imbedded) in separated trenches to minimize risk of common loss due to fault and fire damage. Repair on a faulted cable or joint may proceed with the remainder of cables in operation. Repair operation will be limited to one cable at a time.

2.0 Review of HVDC Component Outage Data

This section presents a review of available outage data for HVDC and AC systems as applied to the proposed Labrador-Newfoundland HVDC link. Sections 2.1 to 2.4 address the following system components:

1. Overhead lines (bipole and monopole tower sections)
2. Submarine cable across the Strait of Belle Isle
3. Thyristor valve groups
4. Pole equipment

Section 2.7 summarizes the effects of lightning on monopole and bipole circuit tripout rates.

The outage data base was developed primarily from published technical references (References 1-5), supplemented in certain instances by unpublished system data. In developing outage rates and durations for specific components, only those systems closely resembling the Labrador-Newfoundland link were used. The results presented reflect a conservative approach in selecting events to be included in the overall component outage rates.

2.1 Outage Statistics for DC Lines

The DC line under consideration extends from Churchill Falls across the Labrador plateau to the Strait of Belle Isle, crossing the Strait into Newfoundland and terminating at Soldiers Pond on the east coast of the island. Except for a 45 km stretch across the Long Range Mountains in western Newfoundland, both poles of the line are supported by a bipole guyed tower configuration, for a total distance of 1277 km. The Long Range Mountain crossing uses two, separated, single-pole towers rather than the bipole tower configuration.

In analyzing the overall impact of forced outages on the DC and connected AC systems, the overwhelming contribution to line unavailability comes from permanent outages (i.e., outages requiring repair or on-site inspection before energization and lasting from a few hours to a few days). Transient faults due to lightning, as reported in Section 2.7, will be cleared automatically by the appropriate protective equipment and have no contribution to the permanent fault rate. Insulator sparkover due to contamination can be mitigated by operating the DC system at a reduced voltage level.

For the Labrador-Newfoundland DC line, the principal fault mechanisms resulting in permanent outages are ice load, snow load, and wind. Each of these fault mechanisms may result in loss of either a single pole or both poles of the DC link. Separate outage rates and durations were calculated for single pole and bipole outages to provide an accurate representation of failure modes.

2.1.1 Single Circuit Outage

For the single circuit outage data the following transmission systems were used:

System	Type	Reference
Square Butte	±250 kV DC	1-3
Vancouver Pole 1	260 kV DC	1-3
Nelson River Bipole 1	±450 kV DC	1-3
Konte-Skan	250 kV DC	1-3
New Zealand	±250 kV DC	1-3
Volgograd-Donbass	±400 kV DC	1-3
New England	345 kV AC	Unpublished
Canadian Electrical Association Combined Data	230-735 kV AC	4
Bonneville Power Administration	500 kV AC	Unpublished
North America Combined Data	345-360 kV AC	5

In many of the above sources no distinction was made between temporary and permanent outages. In addition, very little information as to the cause of the line fault is given for the DC systems studied. It was recognized that the resulting outage rate figures obtained from the above source would probably over-estimate the real fault rate experienced in the Labrador-Newfoundland line by a fair margin.

Tables 2.1 and 2.2 summarize the individual system contributions to the overall failure statistics for the DC and AC systems respectively.

Table 2.1

DC System Outage Statistics

Temporary + Permanent

System	Circuit km-yrs	# of Faults	Fault Rate/ 100 km-yr	Total Fault Dur. (HRS)
Square Butte	2487	11	0.44	1361.3*
Vancouver Pole 1	328	4	1.22	14.99
Nelson River Bipole 1	8950	25	0.28	26.14
Konti-Skan	570	17	2.98	12.33
New Zealand	7980	35	0.44	191.39
Volgograd-Donbass	5640	23	0.41	52.55
Total DC Systems	25955	115	0.44	1658.7

Avg. = 14.42hrs

$= \frac{1658.7}{115}$

* Tornado Damage to Line

$.44 = \frac{115 \times 100}{25955}$

Table 2.2

AC System Outage Statistics

System	Circuit km-yr	#Of Faults Temp	#Of Faults Perm	Fault Rate/ 100 km-yr Temp	Fault Rate/ 100 km-yr Perm	Total Fault Dur (Hrs)
New England	16001	84	26	0.53	0.16	478.0
CEA	5818	12	13	0.21	0.22	493.5
BPA	14186.6	95	50	0.67	0.35	481.0
North America*	23721	97	22	0.41	0.09	NA
Total AC Systems	68366	288	111 -22	0.42	0.16	1452.5 = 16.32
	.6		89		.2472	89

Avg. Dur = 16.32 hr — ?

*Lightning outages adjusted to a keraunic level of 5

NA = no data available

The BPA and North America data were subdivided according to fault cause, and only those events relating to storm, snow or ice damage and line material failures were included in the outage statistics.

From the above analysis, a permanent fault rate of .15 pole outages/100 pole km-yr was chosen for the reliability studies. Recognizing the relative inaccessability of large portions of the Labrador-Newfoundland line, an average repair duration of 72 hours was used.

x2 length of li

2.1.2 Bipole Outage

In analyzing the risk of bipole outages, a conservative approach was taken. The estimates of outage rates were based on the 50-year return criteria used in the design of the bipole towers.

Each of the three major climatological sections of line considered a design return period of 50 years. Since each of these sections may experience extreme conditions independent of the other sections, the overall return period for extreme conditions on any portion of the line would be 50/3 = 16.67 years. If the pessimistic (conservative) premise is adopted that any extreme condition exceeding design criteria will result in bipole loss, then the corresponding forced outage rate would be .06/yr for the entire line. 1/16.67

A value of 0.06 faults/yr. was chosen for the reliability study, with an average restoration time of 168 hours.

2.2 Outage Statistics for the Strait of Belle Isle Submarine Cable

The 18 km DC submarine cable across the Strait of Belle Isle represents an essential link in the overall DC system reliability. Two crossing schemes were analyzed for this study.

1. Submarine trench scheme.

2. Underground tunnel scheme.

The submarine trench schemes involve two or three separate cable trenches, with each trench carrying two cables. Due to thermal limitations, the maximum power transfer per trench has been limited to 1200 MW with both cables operating, and 800 MW with a single cable operating.

The tunnel scheme involves sinking shafts at either end of the Strait at depths of 480 and 570 meters, and connecting the shafts by a tunnel 18 km long containing three HVDC cables, each capable of carrying 800 MW.

To get an estimate of failure rates for the cable trench scheme, several existing submarine cable systems were studied. In as many cases as possible, faults due to anchor damage were eliminated from the outage data base. Table 2.3 lists the systems considered along with their respective outage data.

Table 2.3

Existing DC Submarine Cable Experience (Refs 1-3)

System	Pole km-yrs	#Faults	#Faults/100 pole km-yr
Skagerrak	284.5	1	0.35
Sardinia	484	4	0.83
New Zealand	468	3	0.64
Cross Channel 1	390	4	1.03
Totals	1626.5	12	0.74

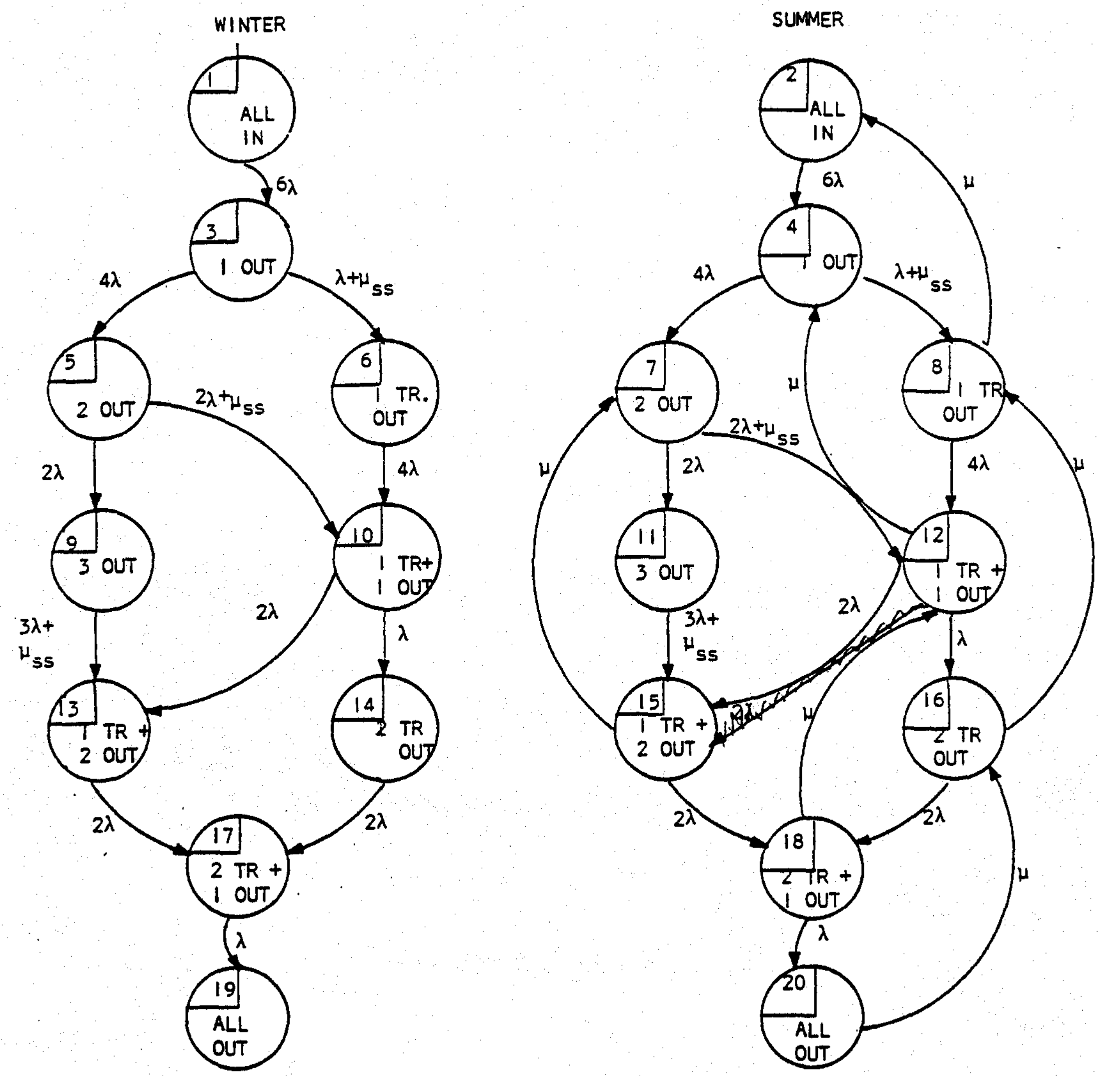
Past experience in the several submarine DC installations indicated no significant difference in failure rates.

2.2.1 Trench Scheme

The submarine trench configurations use two cables in each trench. Switching provisions are assumed at the Labrador and Newfoundland terminations of the cable crossing such that flexibility in cable assignment may be achieved and switching and and paralleling operations may be carried out rapidly.

Considering the operating experience on submarine cables, a single cable failure rate of .5 faults/100 km-yr was used for all cable configurations. Each 18 km cable, therefore, was assigned a fault rate of .5 x.18 = .09 faults/yr. Due to the severe climatic conditions experienced in the region around the Strait, most likely time for repairs on faulted cables will be from May 15 to December 15, six months time estimated to complete repairs. In addition, an estimated waiting time of three months is required to outfit and place a supply ship in position to repair the faulted cable.

Figure 2.1 presents the Markov state model for the three-trench cable scheme. The probability of being in each state is included on the diagram.



NOTE: Each state transfer to its' corresponding state in the opposite season with transition rate λ_s (Summer to Winter) and λ_w (Winter to Summer)

λ_s = λ_w = 2.0

λ = Single cable failure rate = .09

μ_{ss} = Rate of arrival of supply ship = 8760/2190 = 4.0

μ = Restoration rate of cable = 8760/4380 = 2.0

Figure 2.1

3-Trench Scheme - Reduced Cable Ratings

The model shown in Figure 2.1 has distributed distributions for the "open Strait" or "repair period" and the "closed Strait" or "no repair period". This model was chosen in preference to the strict calendar open period model to reflect the seasonal weather, not calendar, dependence of the repair period.

Table 2.4

3-Trench State Probabilities

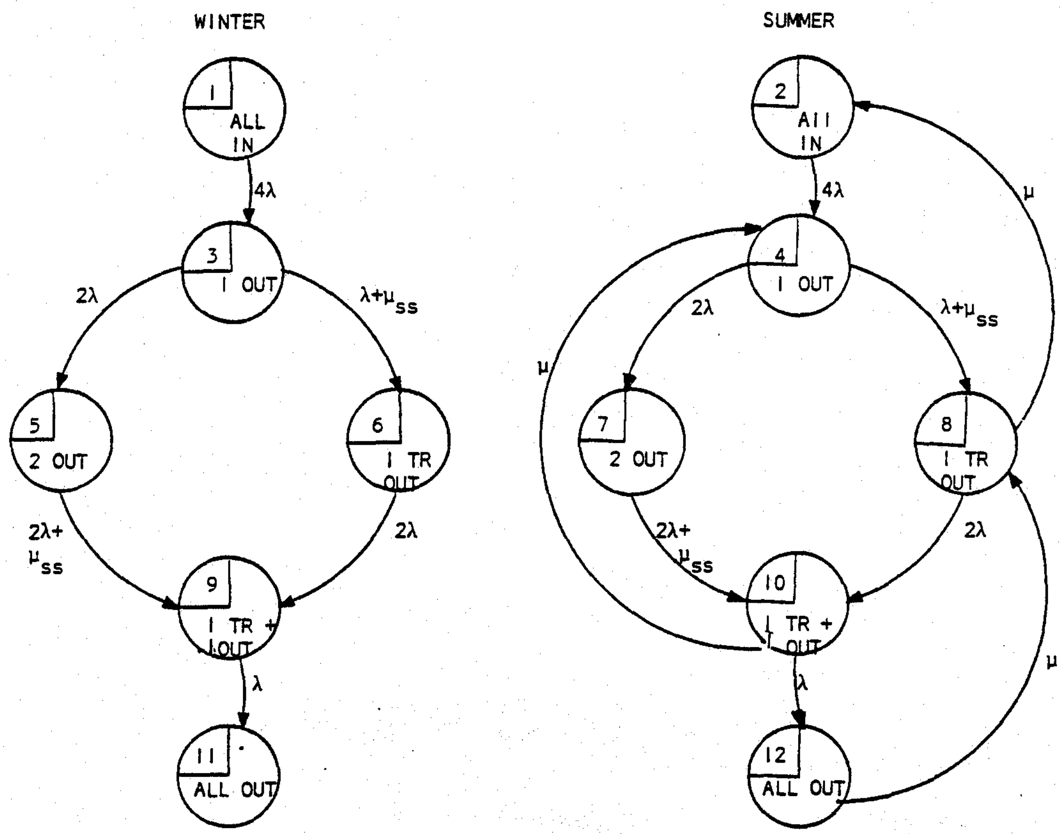
No. of Trenches with:			Probability	
2 Cables In	1 Cable In	0 Cables In	Winter	Summer
3	0	0	.1940	.2463
2	1	0	.3122E-1	.4831E-1
1	2	0	.4144E-2	.7558E-2
2	0	1	.1549	.1189
0	3	0	.2095E-3	.2838E-3
1	1	1	.8336E-1	.5808E-1
0	2	1	.1756E-1	.1119E-1
1	0	2	.8495E-2	.5509E-2
0	1	2	.5540E-2	.3444E-2
0	0	3	.6536E-3	.4043E-3

The individual state probabilities for both winter, "closed" and summer, "open" periods are shown in Table 2.4.

For this model of cable states, waiting and repairs were represented by a series of states with mean residence times corresponding to the times cited above. Such a model leads to time varying risks of overlapping cable outage, rising to higher values during the latter portions of the "closed Strait" period than during the "open Strait", "repair period". The time of occurrence of the winter peak load is at the end of the "repair period" and in the early portion of the "no repair period". (This corresponds to the time span of lower risk of cables on outage.) Furthermore, the difference in risks between the high risk and low risk periods was found to be quite small, that is, the effect of the difference was found not large enough to warrant separation of the submarine cable risks into repair and no repair periods for generating capacity assessment. Annual average figures were used for capacity analyses.

Failure rates and repair times were selected conservatively to assure reasonable risk values were used for capacity assessments.

A 2-trench cable scheme was also used in the alternative expansions. The Markov state diagram for this configuration is shown in Figure 2.2, with associated state probabilities as shown in Table 2.5. The state transition model has distributed distributions for the "open Strait" and "closed Strait" periods.



NOTE: Each state transfers to its' corresponding state in the opposite season with transition rate λ_s (Summer to Winter) and λ_w (Winter to Summer)

$\lambda_s = \lambda_w = 2.0$

$\lambda = .09$

$\mu_{ss} = 4.0$

$\mu = 2.0$

Figure 2.2

2-Trench Scheme (Used in DC Analysis)

Table 2.5

2-Trench State Probabilities

No. of Trenches with:			Probability	
2 Cables in	1 Cable in	0 Cable in	Winter	Summer
2	0	0	.2760	.3257
1	1	0	.2722E-1	.3566E-1
0	2	0	.1261E-2	.1447E-2
1	0	1	.1504	.1083
0	1	1	.4032E-1	.2596E-1
0	0	2	.4797E-2	.2983E-2

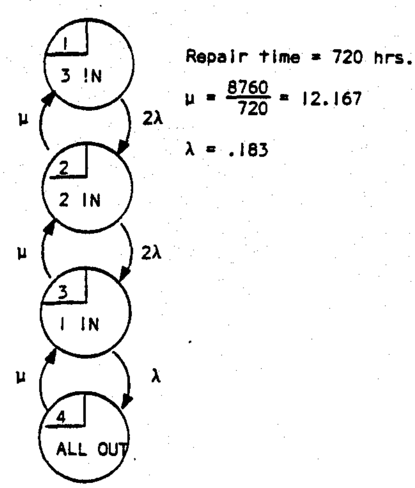
2.2.2 Tunnel Scheme

The configuration studied for this scheme involved the placement of three oil-filled cables in a tunnel underneath the Strait of Belle Isle. The principal reliability question surrounding the cable tunnel scheme is the effect of the cable stop joints on the overall cable reliability. Operating experience with HVDC stop joints has been gained from the Kingsnorth-Beddington underground link in the U.K. In the four years of operation considered in Reference 3, 3 stop joint failures were identified. Given 43 stop joints and four years experience in the Kingsnorth system (9) the estimated stop joint fault rate would be .017/joint-yr. A figure of .031/joint-yr. (80 percent confidence) was used in the study. The tunnel configuration studied assumed three stop joints per cable, resulting in a combined fault rate for each cable given by the following:

$$\underbrace{.5\ \frac{\text{faults}}{100\ \text{kmyr}} \times .18}_{\text{CABLE}} + \underbrace{3 \times .031\ \frac{\text{faults}}{\text{yr}}}_{\text{STOP JOINTS}} = .183\ \frac{\text{faults}}{\text{yr}}$$

A 30-day cable repair time was used for the cable tunnel scheme, with repairs allowed at any time during the year.

Figures 2.3 through 2.5 present the Markov state diagram for 3-, 4-, and 5-cable tunnel schemes. The repair model selected provided for repair on one cable at a time. The 3-cable scheme was used in the DC alternative analysis and in the first-stage of the AC alternative analysis (see sections 3.1 and 3.3). The 4-cable scheme was used in the second-stage AC analysis, while the 5-cable scheme was used in the third-stage AC analysis.



← only 2 cables operating

Figure 2.3 - Markov Diagram 3-cable Tunnel Scheme

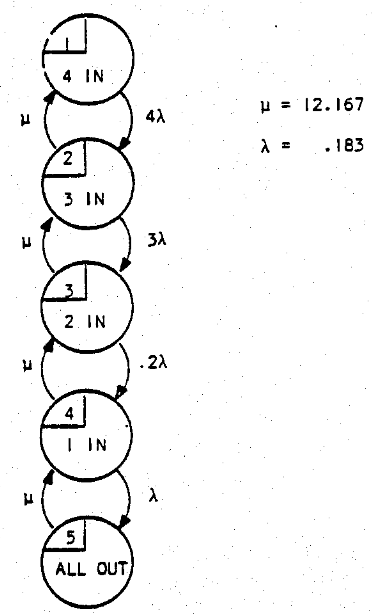


Figure 2.4 - Markov Diagram 4-cable Tunnel Scheme

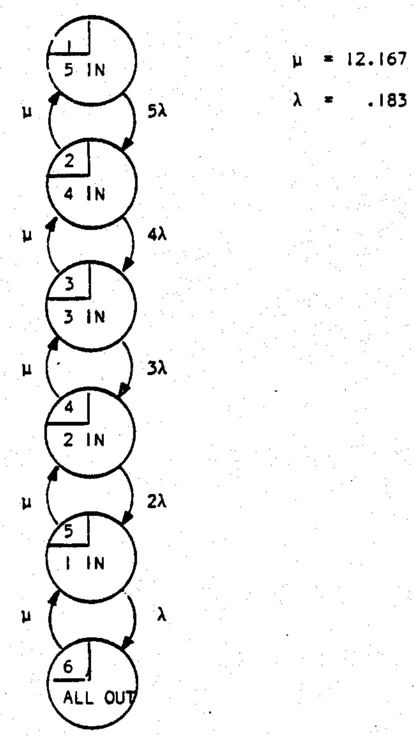


Figure 2.5 - Markov Diagram 5-cable Tunnel Scheme

Tables 2.6 through 2.8 list the state probabilities for each of the cable tunnel schemes.

Table 2.6

3-Cable Tunnel Scheme

# of Cable in Service	Probability
3	.9699
2	.2920E-1
1	.8791E-3
0	.1323E-4

Table 2.7

4-Cable Tunnel Scheme

# of Cable in Service	Probability
4	.9407
3	.5666E-1
2	.2559E-2
1	.7707E-4
0	.1160E-5

Table 2.8

5-Cable Tunnel Scheme

# of Cable in Service	Probability
5	.9259
4	.6971E-1
3	.4198E-2
2	.1896E-3
1	.5711E-5
0	.8599E-7

2.3 Outage Statistics for Thyristor Valve Groups

The thyristor valve groups along with the DC pole equipment comprise the major equipment to be considered when determining the reliability of DC terminal equipment. From operating experience it would be expected that the DC terminal equipment would contribute very little to the overall unreliability of the system.

To determine the failure risk for the thyristor valve groups, existing DC 12 pulse schemes were considered. As a measure of the exposure of each system, the total number of converter unit years was used, which includes both the rectifier and inverter groups in operation for the length of time in service. Table 2.9 presents the systems used and the calculated failure rates and durations.

Table 2.9

Existing Thyristor Valve Group Experience (Refs 1-3)

System	Converter Unit-yrs	#Faults	#Faults/ Converter Unit-Yrs	Avg. Duration
Square Butte	13.28	65	4.895	3.00
Nelson River Bipole 2	2	18	9.000	5.45
Skagerrak	12	15	1.250	1.75
Eel River	48	71	1.479	2.58
David A. Hamil	8	18	2.250	2.73
Totals	83.28	187	2.245	2.95

The faults listed in Table 2.9 include events involving failure of thyristor control and protection equipment and AC protection equipment as well as actual thyristor valve element failures which resulted in unscheduled outage of the valve group.

Valve Group AC Equipment

Includes converter transformer(s) and associated power (AC) and protection equipment switched with the valve group (quadrivalve)

	Rate 1/yr.	Duration hrs.
Forced Outage	.08	168
Scheduled Outage	1	12

Scheduled maintenance will be done with the rest of the valve group equipment. The outage duration for major component failure (return to service shop or to factory for rebuild) can be reduced significantly by the provision for spare equipment and means for rapid removal, reinstallation and reconnection of the spare. Average outage duration can be reduced to 30 hours or less with provision for on-site and switchable spares.

2.4 Outage Statistics for DC Pole Equipment

This category includes bypass switches, DC arrestors, bushings, measuring equipment, smoothing reactors, and filter components. The number of pole-years in service (number of poles X number of years in service) was chosen as the measure of exposure. Table 2.10 lists the DC systems considered and the calculated fault rates and durations.

Table 2.10

Existing DC Pole Equipment Experience (Refs 1-3)

System	Pole-Years	#Faults	#Faults/ Pole-Year	Avg. Duration (Hrs)
Vancouver Pole 2	2	5	2.50	9.28
Square Butte	3.33	26	7.808	1.55
Eel River	12	6	0.5	15.16
David A. Hamil	2	4	2.0	0.66
Totals	19.33	38	1.97	4.74

2.5 Statistics for Terminal-Caused Bipole Outages

Very few thyristor valve systems have experienced sustained bipole outages. Borrowing experience from mercury arc valve systems, the terminal caused bipole outage time was 2.4 hours per period year. This figure included down time due to operating errors but excluded the catastrophic (earthquake) loss of the Sylmar terminal of the ± 400 kV Pacific High Voltage Intertie.

Overhead line and terminal causes of bipole outages will be combined for the study as they do not vary among the alternates. The common cause (bipole outage) events were assigned a rate of .081 events per year with an average outage time of 168 hours per event.

For pole paralleling equipment, a fault rate of .003/yr. was used with an average repair time of 24 hours.

2.6 Synchronous Condenser Performance

Reliability analyses for the synchronous condensers at Soldiers Pond have presumed a spare condenser. It was concluded that with a spare in place the risk of HVDC transformer curtailment due to forced or overlapping loss of two or more condensers would contribute negligibly compared to the risks predicted for the lines and cables crossing.

SYNCHRONOUS CONDENSERS
SWEDISH STATE POWER BOARD DATA

"Redogörelse för 1977 års driftstörningar vid Statens Vattenfallsverk", also for 1975.

Synchronous Condensers (8) up to 100 MVAR

$\sum$	hrs	6480	accumulated outage time
$\sum$	cases	59	unscheduled outages

r/event = 109.8 hrs. per outage

Events/100 years including control 90.4/100 yrs.

$\lambda = .904/\text{yr.}$

$r = 109.8 \qquad \lambda r = 99.2592 \text{ hrs/yr.}$

$$p = \frac{\lambda r}{1+\lambda r} = .011204$$

Distribution of Outage Duration

	N	%
> 1 month	3	5
1 wk - 1 mon	4	7
1 day - 1 week	3	5
1 hr - 1 day	21	35
< 1 hour	28	48
	59 outages	100 %

INVERTER TERMINAL SYNCHRONOUS CONDENSER CAPABILITIES

USING SWEDISH STATE POWER BOARD DATA

SYNCHRONOUS CONDENSER		GENERATOR UNITS
150	150	135 42.5
MVAR	Cumulative Probability	Cumulative Probability
477.5	1	.95593
435	.04406	.96676
342.5	.03323	.97759
327.5	.02240	.99926
300	.737E-3	
285	.614E-3	
192.5	.369E-3	
173.5	.123E-3	
150	.572E-6	
135	.294E-6	
42.5	.155E-6	
0	.158E-7	

2.7 Effect of Lightning on Circuit Tripout Rates

An investigation was made to determine the effects of lightning strokes on the reliability of the single circuit and bipole line configurations. This section provides a brief summary of the findings of that study. A companion report addresses the details of the lightning study.

From the study, the flashover rate is estimated to be 20/year, with the predicted double pole tripout rate estimated at approximately 0.6/year. Most lightning activity occurs during the summer months, that is, during the period of time of lower load and not during the time of exposure to ice and snow loads.

Circuit (pole) tripouts due to lightning will not contribute to the overall unavailability of the DC system. Operating experience has shown that most lightning related outages are transient in nature and are cleared by the appropriate protective equipment. Studies of the dynamic response of the on island system have indicated that momentary blocking of a pole can be sustained without need for load shedding and without risk of separation or instability.

The estimated bipole fault rate due to lightning is .6/year. Bipole faults will have momentary impact on the system. Bipole blocking and restart is necessary to clear the fault.

Studies have been made on momentary blocking of the bipole. The studies indicate that the bulk power system can be designed to withstand bipole block and restart to clear lightning caused flashover. Some load shedding would result during the disturbance. Restoration of shed load may proceed immediately following bipole recover.

During the outage of one pole of the HVDC link, lightning flashover of the operating pole will also have momentary impact equivalent to the momentary blocking of the bipole just cited.

The bipole failure rate used in the availability analysis considers only permanent faults, and does not include the lightning (momentary) tripout rate.

3.0 Receiving End System Reliability Analysis

This section describes the methods used to develop reliability models for the HVDC transmission system. Three transmission schemes were analyzed:

1. Full DC system from Churchill Falls to Soldiers Pond, 800 MW supplied by Churchill Falls.
2. 735 kV AC link from Churchill Falls to Gull Island, 400 MW AC transfer with (200 firm plus 200 emergency recall) six 283 MW generating units at Gull Island.
3. 345 kV AC link from Churchill Falls to Gull Island, 400 MW AC transfer (200 firm plus 200 emergency recall), with three 206 MW generating units at Muskrat Falls, connected to Gull Island by two 345 kV AC ties.

The full DC scheme was studied using both the trench and tunnel cable configuration. For the AC schemes, the three trench scheme (with full cable switching and paralleling provisions) was studied. Two levels of generating unit unavailability were considered at Churchill Falls (3% and 7%) for the final, two bipole stages.

3.1 DC Link to Churchill Falls

For the DC link analysis, a two-trench model (as shown in Figure 2.2) was used to represent the cable system.

In addition to the two-trench model, the DC configuration was also analyzed with the 3-cable tunnel scheme.

3.1.1 Basic Reliability Model

Since only one path exists to transmit power from Churchill Falls to the Island of Newfoundland, the loss of certain critical elements in the transmission scheme can reduce and even eliminate power transfer. Consequently, a model of the DC transmission scheme is necessary to determine the overall system reliability. The model chosen is shown in Figure 3.1. The 800 MW recall from Churchill Falls is considered firm (i.e., enough generation reserve at Churchill Falls to cover forced outage of machines and still supply 800 MW across the link). The analysis assumes the recall is assigned a priority higher than any other contract.

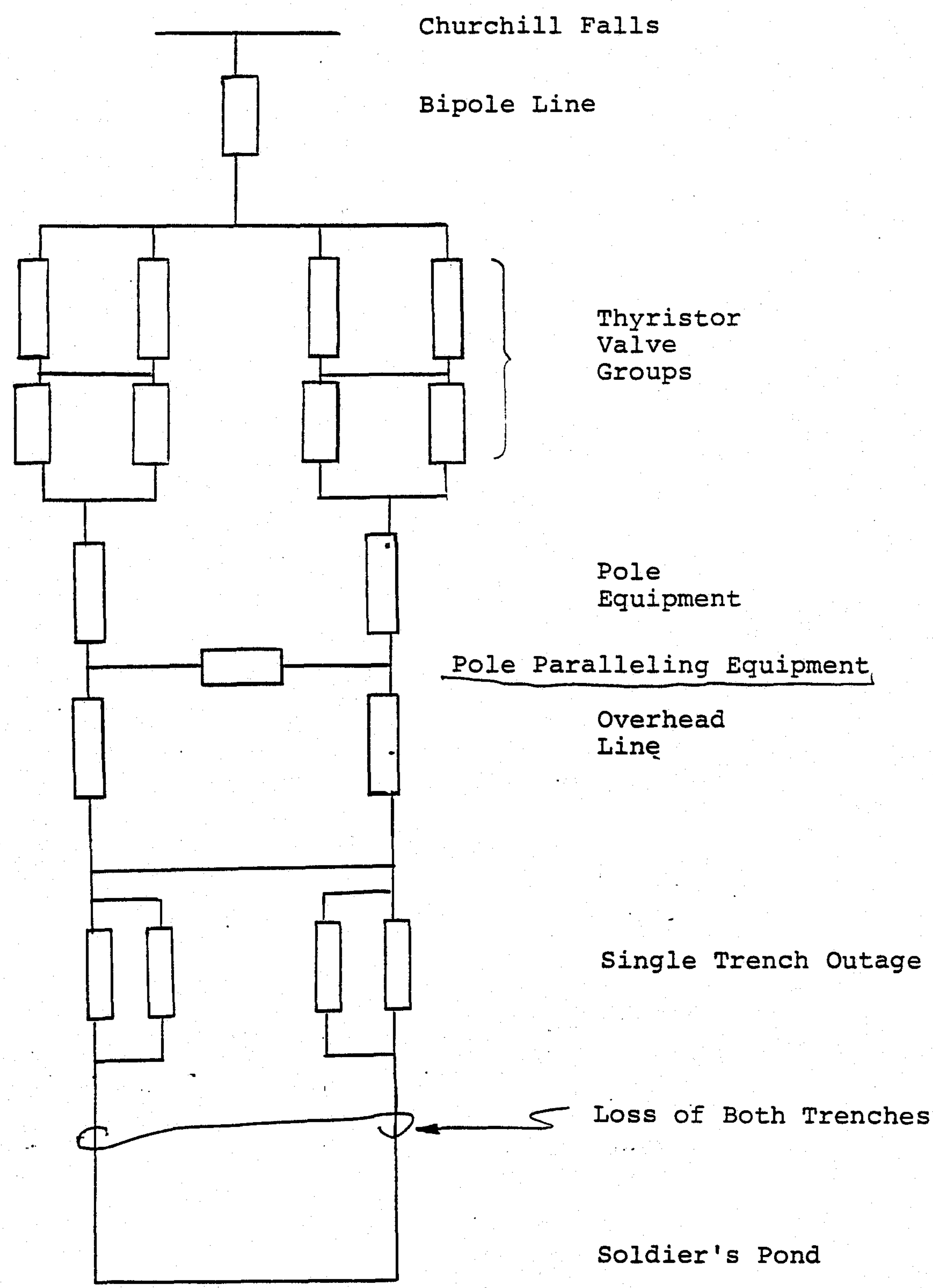


Figure 3-1

LABRADOR-NEWFOUNDLAND RELIABILITY MODEL

Analysis of the reliability model shown in Figure 3.1 is accomplished through the Substation Reliability Program SSRP. The program accepts a generalized reliability model with fault rates and repair times for each system element, operates breakers to isolated faulted components, and provides a topological analysis following fault interruption and following switching operations. The analysis is divided into post-fault (immediately after circuit breaker operation occurs) and post-switching (after remedial switching operations have minimized the extent of interruption). For the purposes of this study only post-switching events are considered. Following the complete evaluation of the system, a tabulation of all failure events is made based on the maximum transfer capability of the post-switching network. SSRP uses a directed graph network model, and determines maximum transfer capability and limiting elements.

3.1.2 Reliability Case Description

Three cases were run with the Substation Reliability Program, covering both cable schemes with and without valve maintenance. The cases tested were:

1. DC system with two-trench cable scheme, no maintenance.
2. DC system with two-trench cable scheme, 1 valve group on maintenance.
3. DC system with cable tunnel scheme, no maintenance.

In modelling valve maintenance, one of the valve groups indicated in Figure 3.1 was removed from the network, reducing the maximum transfer capability from 728 MW to 546 MW.

The results of the three cases are shown in Tables 3.1 through 3.3. In each table, the maximum transfer capability, exact frequency and probability of each transfer level are shown.

Table 3.1

Case 1 Results

MW Transfer	Frequency (1/yr)	Probability
728	---	.9798
546	18.8	.8436 E-2
364	4.1	.2186 E-2
182	0.03	.871 E-5
0	0.15	.9554 E-2

The two-state equivalent machine model for Case 1 is represented by one unit, 726 MW, .956% FOR.

Table 3.2

Case 2 - Results

MW Transfer	Frequency(1/yr)	Probability
546	---	.9830E-0
364	13.8	.6374 E-2
182	2.1	.1100 E-2
0	0.15	.9555 E-2

The two-state equivalent machine model for Case 2 is represented by one unit, 545 MW, .956% FOR.

Table 3.3

Case 3 - Results

MW Transfer	Frequency(1/yr)	Probability
728	---	.9875 E-0
546	18.9	.8478 E-2
364	4.1	.2197 E-2
182	0.03	.8750 E-5
0	0.14	.1795 E-2

The two-state equivalent machine model for Case 3 is represented by one unit, 726 MW, .180% FOR.

The outages resulting in loss of the bipole (0 MW transfer in Tables 3.1 through 3.3) can be divided into two categories - loss due to a single contingency and loss due to multiple contingencies. The main interest in this division has to do with the dynamic response of the receiving end system when confronted with a sustained bipole loss. Failure from the fully operational state under full transfer is the most severe event. When the link is in a contingency condition there is opportunity to take defensive operating actions to provide for additional on-island operating reserves.

These categories may be of interest in preparing operating strategies. It is common practice to operate the system in a manner that will permit withstand of more probable contingencies. Such contingencies would include those which would result in monopolar operation. High speed pole paralleling capability will permit the system to recover with minimum amounts of load shed and will tend to minimize the duration of load interruption.

Under first contingency condition, monopolar operation rated (800 MW) power transfer, the system can recover from momentary pole blocking due to transient faults. Load shedding would be required under less probable, permanent faults.

Table 3.4

Full Bipole Loss - Single and Multiple Contingencies

Case	Single Contingency Bipole Loss p	f	Multiple Contingency Bipole Loss p	f
1	.931 E-2	.086	.244 E-3	.063
2	.931 E-2	.086	.245 E-3	.068
3	.155 E-2	.080	.245 E-3	.063

Another important figure is the amount of time per year spent operating the system in a monopolar mode with ground return due to a component failure. This becomes important when determining the sizing of the earth return electrodes. For the DC link, the only component outages that require monopolar ground return operation involve loss of either the single circuit overhead lines or the submarine cables. Table 3.5 indicates the component outage frequencies and durations resulting in monopolar ground return operation, along with the expected number of hours in this type of operating mode on an annual basis.

Table 3.5

Monopolar Ground Return Outage Summary

Event	Frequency (1/yr)	Fault Duration (Hrs)	# Hrs/ Year
Loss of Single Circuit Overhead Line	3.83	72	275.8
Loss of Three Out of Four Cables (Trench Scheme)	.0579	10030	580.7
Loss of Two Out of Three Cables (Tunnel Scheme)	.0109	709	7.7

Total for overhead line + trench scheme = 856.5 hours
Total for overhead line + tunnel scheme = 283.5 hours

3.2 Emergency Capacity - Loss Sharing Model for Churchill Falls Generation

The model of the Churchill Falls generating units used in the reliability analysis is based on the following priorities:

1. Twin Falls 225 MW and NLH 300 MW recall firm - first priority.

2. Hydro Quebec demand (4382.6 MW + 1.6% losses or 4453 MW) less 300 MW recall

3. NLH 200 MW emergency recall

Balancing demand with capacity available, Churchill Falls capacity is 11 units 500 MVA .95 PF or 475 MW per unit totaling 5225 MW.

HQ contract less 300 MW recall:	4153 MW
Twin Falls commitment	225
NLH firm recall 300	300
Base Demand	4678

Consider emergency conditions with 4678 MW base demand. The critical point for full curtailment of NLH 200 MW emergency supply would be with plant capacity available less than or equal to 4678 MW. This would correspond to 9.85 times unit rating of 500 MVA, .95 PF, or 475 MW. Note that the full or non-curtailed base demand plus NLH 200 MW emergency recall would require 10.27 or eleven units available. Hence, the risk of curtailment of emergency supply would be the risk of having ten or fewer units available. Capacity-probability tables for the Churchill Falls plant have been prepared under two premises:

A. 1977, 1979 operating experience for hydro units 400 - 499 MW range = 7.02 percent (43.8 unit years) from the CEA. These data are strongly influenced by the 1977 experience at Churchill Falls.

P {ten units or less} = .550

STATE CAPACITY	CUMULATIVE PROBABILITY
11	0.100000E 01
10	0.549896E 00
9	0.177230E 00
8	0.369792E-01
7	0.530975E-02
6	0.542301E-03
5	0.399247E-04
4	0.211143E-05
3	0.784583E-07
2	0.194869E-08
1	0.290949E-10

B. Hydro Operating experience on a broader MW base = 3%.

P {ten units or less} = .285

STATE CAPACITY	CUMULATIVE PROBABILITY
11	0.100000E 01
10	0.284698E 00
9	0.413486E-01
8	0.371719E-02
7	0.225620E-03
6	0.964713E-05
5	0.295708E-06
4	0.648906E-08
3	0.992287E-10

Thus, the availability of 200 MW emergency recall should be modeled as 0.45 for the case of 7% forced outage risk for Churchill Falls units and 0.715 for the case of 3% forced outage risk for the units.

3.3 AC Link to Churchill Falls

The AC link analysis considers two 735 kV lines connecting Churchill Falls to Gull Island. Churchill Falls can supply up to 400 MW across the tie. This 400 MW recall can be divided into 200 MW firm recall as first priority and 200 MW emergency recall as third priority after Hydro Quebec demand. In addition, six 283 MW generating units are located at Gull Island. Allowing for 7 percent losses these units are modeled as 283 MW net units. Three stages of system development were considered:

1. Stage #1 - bipole to Soldiers Pond (total 848 MW load, winter rating).
2. Stage #2 - bipole to Soldiers Pond, monopole to Three Brooks (total 1276 MW load).
3. Stage #3 - bipole to Soldiers Pond, bipole to Three Brooks (total 1705 MW load).

3.3.1 Basic Reliability Model

Figures 3.2 through 3.4 show the one-line diagrams modeled for the three system stages defined above. In all cases, the three-trench cable model was used in the analysis. A contingency analysis program (PCAP) was used to investigate the systems described in Figures 3.2 through 3.4. The program allows up to five circuit or capacity outage events at one time. The final program summary includes the total probability and frequency of load curtailment and system separation events.

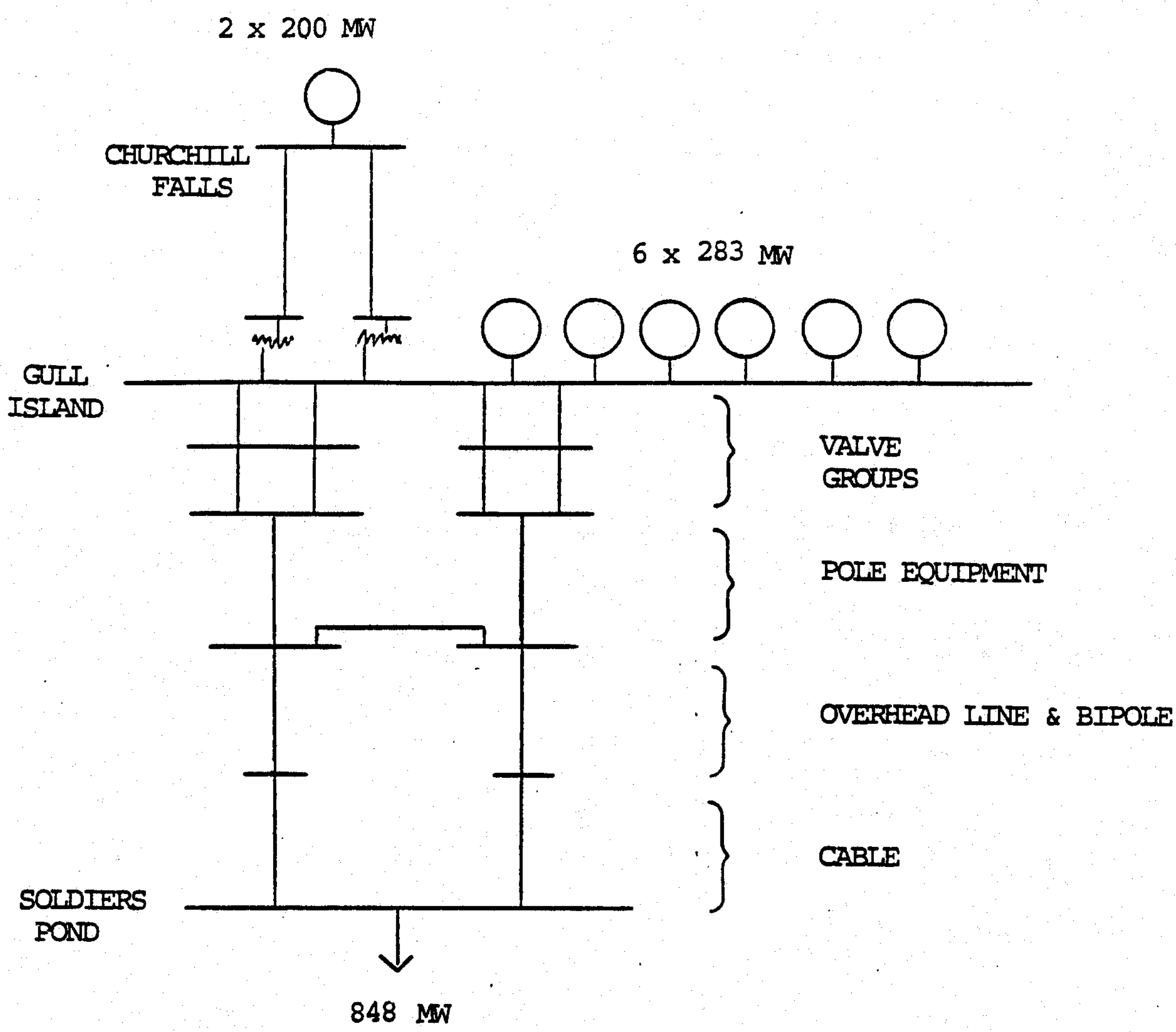


FIGURE 3.2

<u>Churchill Falls AC Line - Stage #1</u>

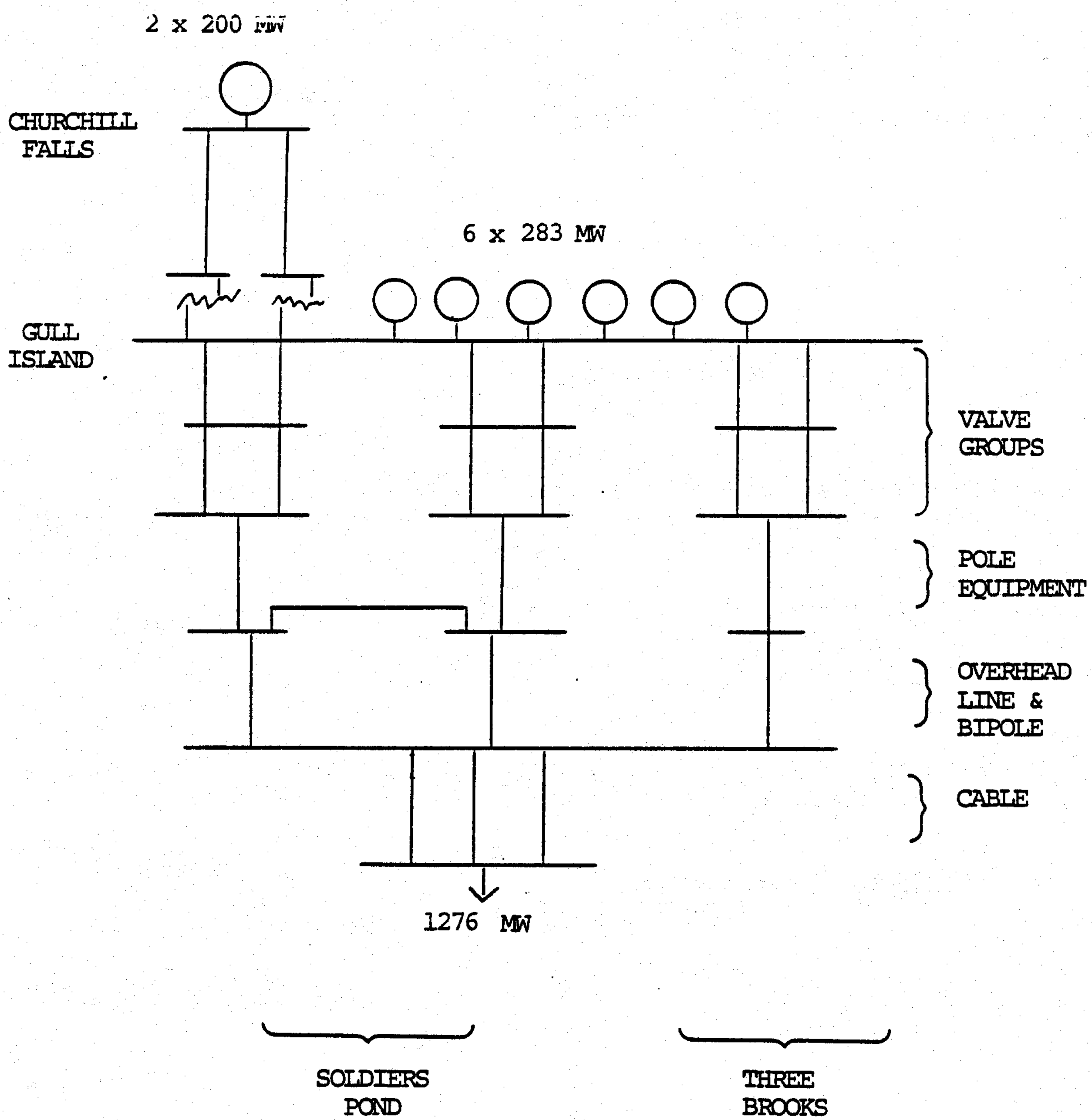


FIGURE 3.3

Churchill Falls AC Line - Stage #2

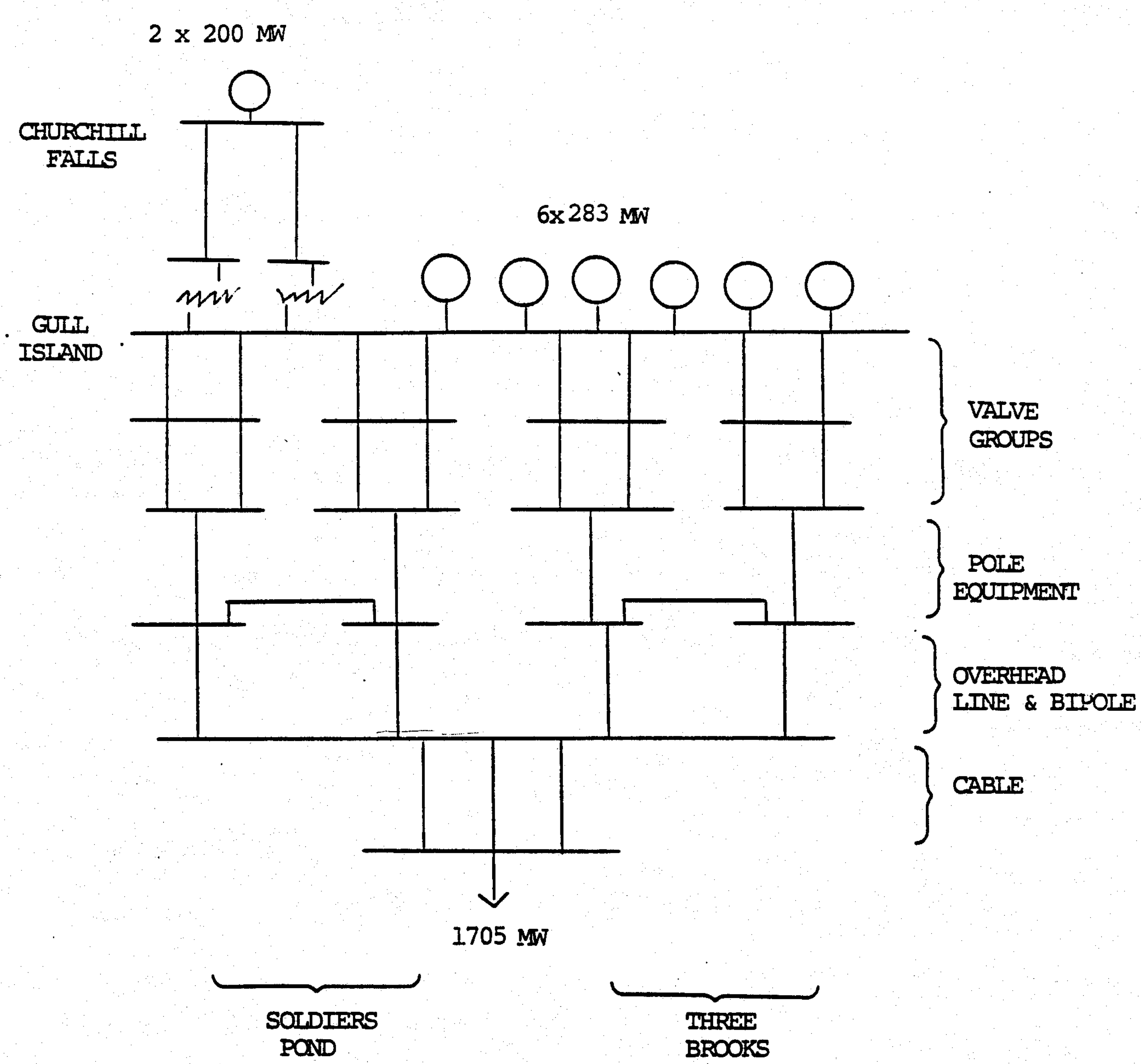


FIGURE 3.4

Churchill Falls AC Line - Stage #3

3.3.2 Reliability Case Description

Eight cases were run using PCAP to analyze the AC link reliability model:

1. Stage #1, no valve group maintenance, cable trench scheme.
2. Stage #2, no valve group on maintenance, cable trench scheme.
3. Stage #3, no valve group maintenance, cable trench scheme, 3 percent forced outage rate on Churchill Falls units.
4. Stage #3, no value group maintenance, cable trench scheme, 7 percent forced outage rate on Churchill Falls units.
5. Stage #1, no valve group maintenance, cable tunnel scheme.
6. Stage #2, no valve group maintenance, cable tunnel scheme.
7. Stage #3, no valve group maintenance, cable tunnel scheme, 3 percent forced outage rate on Churchill Falls units.
8. Stage #3, no value group maintenance, cable tunnel scheme, 7 percent forced outage rate on Churchill Falls units.

From experience, removing one valve group for maintenance does not impact the equivalent machine forced outage rates, but does derate one machine by the capacity of one valve group. As a result, valve group maintenance cases were not run for Stage 2 and Stage 3 configurations. The non-zero outage rates considered for the Churchill Falls units will only affect the overall reliability for the third stage configuration. Therefore, only the stage 3 cases were run with non-zero forced outage rates on the Churchill Falls units.

Tables 3.6 through 3.13 report the capacity probability tables for the eight cases studied.

The partial outage states in each table result from a combination of different component outages representing more than one partial outage state. For example, the 588 MW capacity state in case #1 includes not only partial outages due to valve group single contingencies but also pole equipment outages, resulting in a partial outage state greater than 212 MW.

Although the ac link studies were performed with two 735 kV lines from Churchill Falls to Gull Island, plans are to build only one 735 kV line. The effect of reducing the number of transmission lines between Churchill Falls and Gull Island is to increase slightly the probability and frequency of occurrence for the partial outage states. The increase in probability is somewhat offset by the decrease in the partial megawatts curtailed. The overall effect is to increase the total megawatt hours of partial load curtailment (MW curtailed x probability x 8760) by a slight amount ranging from a 1.78% increase (40.1 MW hrs/yr) for stage 1 trench configuration to a 7.51% increase (14283 MW hrs/yr) for the stage 3 trench configuration.

Table 3.6

Case #1 Results

MW	Probability	Frequency (1/Yr)
848	.9812	---
588	.9904E-2	16.66
0	.8912E-2	0.13

Table 3.7

Case #2 Results

MW	Probability	Frequency (1/Yr)
1276	.9523	---
1204	.8597 E-3	0.36E-4
848	.4427 E-1	33.2
428	.1481 E-2	0.46
212	.3724 E-5	.11E-1
0	.1103 E-2	.11E-1

Table 3.8

Case #3 Results

MW	Probability	Frequency (1/Yr)
1705	.8947	---
1621	.6890 E-1	6.6
1255	.3531 E-1	35.7
589	.1975 E-4	.54E-1
0	.1113 E-2	.13E-1

Table 3.9

Case #4 Results

MW	Probability	Frequency (1/Yr)
1705	.8471	---
1571	.1165	11.1
1255	.3531	35.7
589	.1975 E-4	.054
0	.1113 E-2	0.13

Table 3.10

Case #5 Results

MW	Probability	Frequency (1/Yr)
848	.9886	---
587	.9983 E-2	21.1
0	.1439 E-2	0.11

Table 3.11

Case #6 Results

MW	Probability	Frequency (1/Yr)
1276	.9738	---
1204	.8597 E-3	0.36E-3
848	.2378 E-1	32.7
428	.1505 E-2	0.47
212	.3814 E-5	0.12E-1
0	.1378 E-3	0.11E-1

Table 3.12

Case #7 Results

MW	Probability	Frequency (1/Yr)
1705	.9127	---
1621	.6890 E-1	6.6
1383	.1820 E-1	35.5
589	.2022 E-4	.55E-1
0	.1466 E-3	.11E-1

Table 3.13

Case #8 Results

MW	Probability	Frequency (1/Yr)
1705	.8651	---
1571	.1165	11.1
1383	.1820 E-1	35.5
589	.2022 E-4	.055
0	.1466 E-3	.011

For cases 1, 3 through 5, 7 and 8 the capacity probability tables can be reduced to a single equivalent machine by using the equivalent forced outage rate concept described in section 4.0. For cases 2 and 6, certain low probability states (the 1204 and 212 MW states in Case #2) were combined into the equivalent "all-in" MW capacity state according to the method described in Section 4.

Table 3.14 presents the equivalent unit forced outage rate models for the eight AC link cases analyzed.

Table 3.14

Equivalent Forced Outage Rate Models - AC Link

	Case	Unit Size (MW)	Forced Outage Rate (Percent)	
GULL stage 1	1	845	.891	Trench
2	2	848 428	2.4 4.5	
3	3	1683	.11	
	4	1673	.11	(7% FOR @ C.F)
1	5	845	.144	Tunnel
2	6	848 428	.58 2.39	
3	7	1693	.015	
	8	1684	.015	7% FOR @ C.F.

3.4 Muskrat Falls Generation Alternative

In this alternative, three 206 MW generating units are located at Muskrat Falls, and connected to Gull Island via two 345 kV AC lines. The link from Churchill Falls to Gull Island consists of a single 345 kV AC line. The recall capability at Churchill Falls is the same as that described in Section 3.2. Only the first stage of development (single bipole to Soldiers' Pond) is considered in the analysis, with a total of 848 MW.

3.4.1 Basic Reliability Model

Figure 3.5 presents the one-line diagram representing the Muskrat Falls generation alternative. The approach described in Section 3.3.1 was used to investigate the reliability of this configuration.

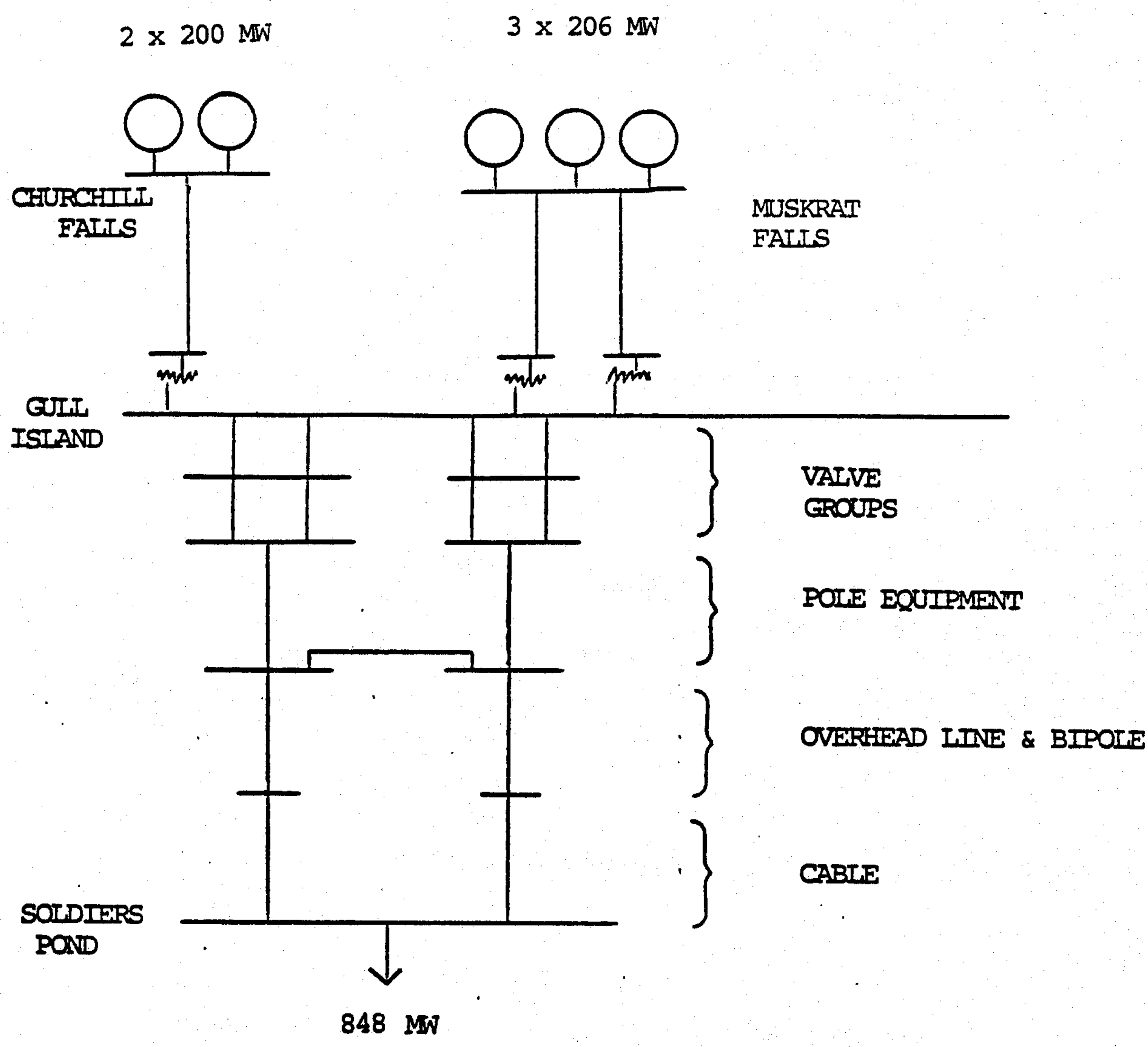


FIGURE 3.5

Muskrat Falls AC Lines

3.4.2 Reliability Case Description

Four cases were run using PCAP to analyze the Muskrat Falls reliability model.

1. Trench scheme (3% FOR for Churchill Falls units)
2. Trench scheme (7% FOR for Churchill Falls units)
3. Tunnel scheme (3% FOR for Churchill Falls units)
4. Tunnel scheme (7% FOR for Churchill Falls units)

Tables 3.15 through 3.18 report the capacity probability tables for the four cases studied.

Table 3.15

Case #1 Results

MW	Probability	Frequency (1/Yr)
848	.6284	---
736	.3495	16.8
587	.9075 E-2	19.6
577	.4045 E-2	0.48
0	.8925 E-2	0.12

Table 3.16

Case #2 Results

MW	Probability	Frequency (1/Yr)
848	.3874	---
735	.5906	28.1
587	.9075 E-2	19.6
576	.4045 E-2	0.48
0	.8925 E-2	0.12

Table 3.17

Case #3 Results

MW	Probability	Frequency (1/Yr)
848	.6358	---
736	.3495	16.8
587	.9147 E-2	19.8
577	.4075 E-2	0.49
0	.1442 E-2	0.11

Table 3.18

Case #4 Results

MW	Probability	Frequency (1/Yr)
848	.3947	---
735	.5906	28.1
587	.9147 E-2	19.8
576	.4075 E-2	0.49
0	.1442 E-2	0.11

For all four cases, the capacity-probability tables were reduced to single equivalent machines by using the equivalent forced outage rate concept described in Section 4.0. Table 3.19 presents the equivalent unit forced outage rate models for the four Muskrat Falls cases analyzed.

Table 3.19

Equivalent Forced Outage Rate Models - AC Link

Case	Unit Size (MW)	Forced Outage Rate (Percent)	
1	805	.893	Muskrat: Tunnel
2	778	.893	
3	805	.144	Muskrat: Tunnel
4	778	.144	

3.5 Summary of the Equivalent Unit Forced Outage Rate Models

This section summarizes the equivalent unit models obtained for the DC link, AC Gull Island, and AC Muskrat Falls configurations, as presented in sections 3.1.2, 3.3.2 and 3.4.2. The capacity probability tables from which the models were derived are indicated in parenthesis for each case.

Table 3.20

Unit Forced Outage Models

Case Description	Unit Size MW	Forced Outage Rate (Percent)
DC link, Case #1 (Table 3.1)	726	.956
DC link, Case #2 (Table 3.2)	545	.956
DC link, Case #3 (Table 3.3)	726	.180
AC Gull Island, Case #1 (Table 3.6)	845	.891
AC Gull Island, Case #2 (Table 3.7)	848 428	2.4 4.5
AC Gull Island, Case #3 (Table 3.8)	1683	.11
AC Gull Island, Case #4 (Table 3.9)	1673	.11
AC Gull Island, Case #5 (Table 3.10)	845	.144
AC Gull Island, Case #6 (Table 3.11)	848 428	.58 2.39
AC Gull Island, Case #7 (Table 3.12)	1693	.015
AC Gull Island, Case #8 (Table 3.13)	1684	.015
AC Muskrat Falls, Case #1 (Table 3.15)	805	.893

AC Muskrat Falls, Case #2 (Table 3.16)	778	.893
AC Muskrat Falls, Case #3 (Table 3.17)	805	.144
AC Muskrat Falls, Case #4 (Table 3.18)	778	.144

4.0 MODELING THE HVDC INFEED FOR STATIC CAPACITY RISK ASSESSMENT

Given the significance of the HVDC infeed to the Newfoundland system, a decision was made to assess the capacity available via the HVDC link at the point of infeed to the NLH bulk power supply at Soldiers Pond. The HVDC link together with the source generation is represented by a number of capacity states which reflect the effects of various component outages. Each state is characterized by a maximum capacity available to the NLH bulk power system, a probability of existence of the state, and a frequency of occurrence of the state. For static capacity adequacy assessment, the state probabilities are required.

At the request of Shawmont Newfoundland Ltd., the state probability models developed for the link and source generation were placed in the form of equivalent generating units. Each equivalent unit was to be restricted to two capacity states: full capability and forced outage. In order to model the multistate HVDC link results by two state models, an analytical model was prepared to reflect the multistate effects in an approximate, conservative manner.

Ideally, one would like to "factor" the multistate model into a set of two state models whose combinations of capacity states exactly correspond in probability and capacity to the original multistate model to handle such situations. This was done in so far as possible. However, situations arise where such factoring is not complete. The technique which follows is directed to the development of a two state equivalent of a multistate model.

Let it be supposed that table of capacity states $\{C_{NF}; P_{NF}(OUT = C_{MAX}-C_{NF})\}$ has been prepared for the Newfoundland generation. $P_{NF}(OUT)$ is the cumulative probability of a generating capacity outage of "OUT" or greater magnitude.

Further, let it be supposed that the capacity states for the HVDC link are, for sake of illustration $\{C_H, P_H; C_{P1}, P_{P1}; C_{P2}, P_{P2}; 0, P_O\}$

Adding the effect of the link to the "on island" generating capacity may be done as follows. For the combined system "C"

$$\begin{aligned} P_C(OUT) &= P_H{*}P_{NF}(OUT)+P_{P1}{*}P_{NF}(OUT-(C_H-C_{P1})) \\ &\quad + P_{P2}{*}P_{NF}(OUT-(C_H-C_{P2})) \\ &\quad + P_O{*}P_{NF}(OUT-C_H) \\ &= \sum_{K=1}^{N} P_K\, P_{NF}(OUT-(C_H-C_K)) \end{aligned}$$

The capacity of the combined system is the sum of the installed (firm) "on island" capacity plus the capacity of the HVDC link, C_H.

A new table of capacity states is then developed for ranges of "OUT" of interest in establishing daily risk of static capacity shortfall and the annual risk index.

In the range of interest, it is possible to develop an equivalent model involving "two-state" unit equivalents" to give a conservative approximation to the capacity state probability table.

To illustrate, suppose a two state model C_E with forced outage probability P_E is to represent the four state model of the HVDC link. Recognizing that the equivalent has reduced capacity, C_E, and modified probability, P_E, the outage with the equivalent that corresponds to the outage, "OUT", with the multistate model of the link is $OUT-(C_H-C_E)$. For the same cumulative probability of outage, for the same capacity available: $C_A = C_{NF}+C_H-OUT = C_{NF}+C_E-OUT'$

$$P_C(OUT) = (1-P_E)\ P_{NF}(OUT-(C_H-C_E)) + P_E*P_{NF}(OUT-C_H)$$

$$= \sum_{K-1}^{N} P_K\ P_{NF}(OUT-(C_H-C_K))$$

$$PE = \frac{\left[\sum_{K=1}^{N} P_K\ P_{NF}(OUT-(C_H-C_K)) - P_{NF}(OUT-(C_H-C_E))\right]}{P_{NF}(OUT-C_H) - P_{NF}(OUT-(C_H-C_E))}$$

It is possible to pick P_E and C_E to fit a specific range of capacity states.

For example, let the value of C_E be fixed, then the value of P_E may be determined from the fit to a desired value of probability at a specified capacity state. The fitting is facilitated by the use of an exponential fit of the "on-island" capacity-probability table

$$P_{NF}(OUT) = A \exp^{-OUT/S}$$

where A and S are used to fit a range of the table. Then P_E is determined from

$$(1-P_E) \exp^{(C_H-C_E)/S} + P_E \exp^{C_H/S} = \sum_{K=1}^{N} P_K \exp^{(C_H-C_K)/S}$$

$$P_E = \frac{\left(\sum_{K=1}^{N} P_K \exp^{-C_K/S} - \exp^{-C_E/S}\right)}{1 - \exp^{-C_E/S}}$$

A convenient value for C_E to reflect the impact of MW-hrs curtailed due to partial capacity states that are equivalenced is:

$$C_E = C_H - \sum_{K=1}^{N} P_K(C_H-C_K)$$

4.1 Relationship to the "Equivalent Forced Outage"

By way of comparison, if the capacity C_H were very small compared to S then the expression for P_E reduces to a familiar form:

$$P_E = \left(\sum_{K=1}^{N} P_K(1-C_K/S) - (1-C_E/S)\right)/C_E/S$$

recognizing that $\sum P_K = 1$

$$P_E = 1 - \sum_{K=1}^{N} P_K\, C_K/C_E = \sum_{K=1}^{N} P_K(1-C_K/C_E)$$

and if C_E were to be set equal to C_H then in this instance P_E would be simply

$$P_E = \sum_{K=1}^{N} P_K(1-C_K/C_H)$$

the familiar form for the "equivalent forced outage". However, in the case at hand C_H is not very small compared to S and, hence, the rule of thumb for the equivalent forced outage does not apply.

Example

For the Newfoundland generation as reported in SMR-3-80 Tables 4 and 5 the capacity - probability model may be prepared and used to form the estimates P_E and C_E. Figure 4.1 shows a plot of the cumulative probability function of capacity on forced outage for the Newfoundland generation including Hinds Lake and Upper Salmon. The experimental coefficient for this curve varies from S=50 in the range 200-300 MW out to S=25 in the range 500-700 MW out.

Consider the following capacity states for the infeed:

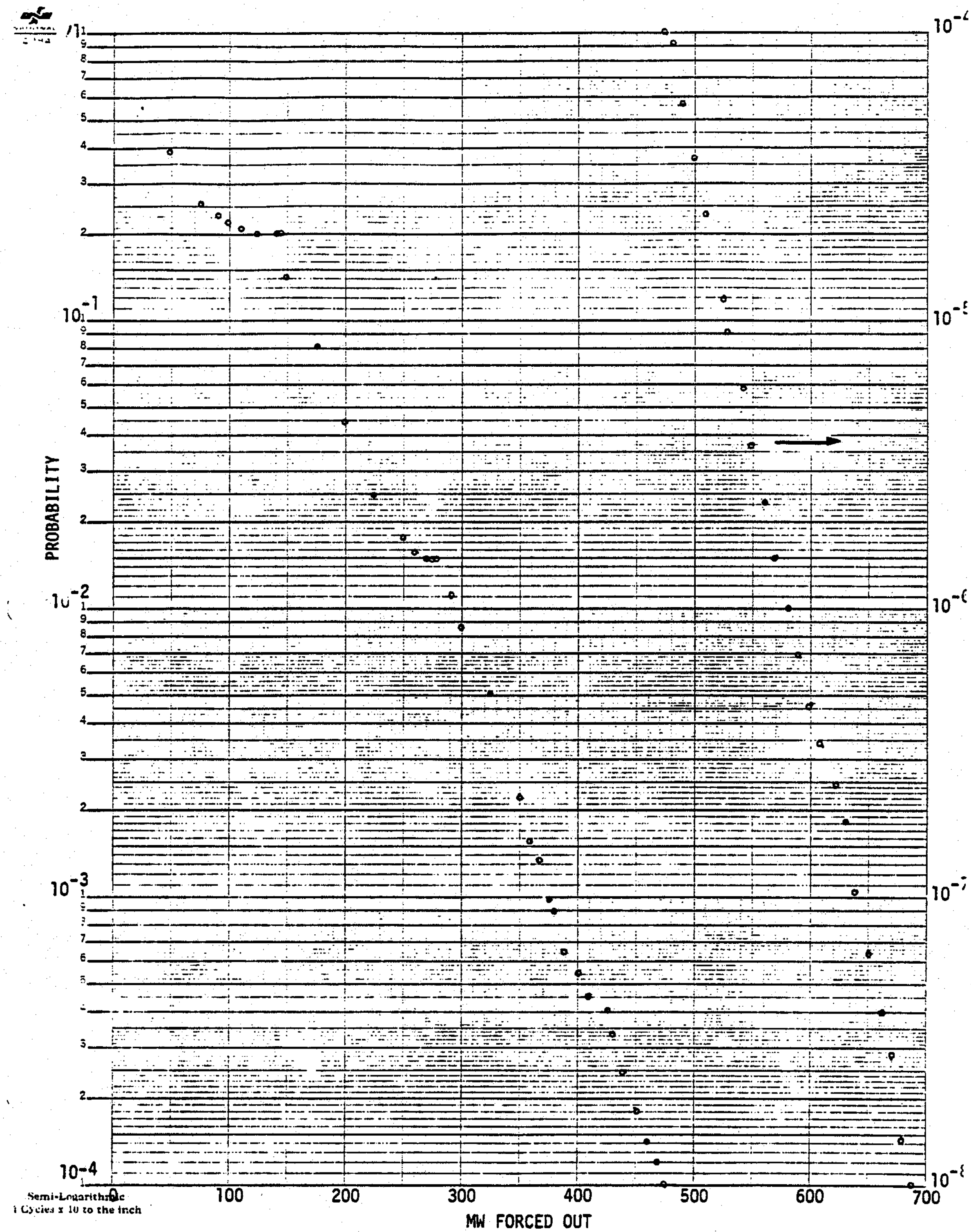
Capacity	728	546	364	182	0
Probability	.9794	.846E-2	.2174E-2	-	.997E-2

1985 Conditions

NFL System Peak = 1516

NFL Installed Capacity = 1606

NFL Installed Reserve = 90


PROBABILITY
MW FORCED OUT
0
100
200
300
400
500
600
700
10^{-1}
10^{-2}
10^{-3}
10^{-4}
10^{-5}
10^{-6}
10^{-7}
10^{-8}
Semi-Logarithmic
3 Cycles x 10 to the inch

Set $C_E = 728 - 2.3 = 726$

Solving for P_E: at nominal system peak condition:

OUT = 90 + 728 = 818 MW

$$P_E = \frac{\sum_{1}^{5} P_K\, P_{NF}\,(818-(C_H-C_K)) - P_{NF}\,(816)}{P_{NF}(90) - P_{NF}(816)}$$

A subset of the capacity outage Table:

C_{OUT}	P_{NF}	C_K	P_K
90	.2324	0	.997 E-2
272	.1535E-1	182	-
454	.1777E-3	364	.2174E-2
636	.1285E-6	546	.846 E-2
816	.3144E-11		
818	.2641E-11	726	.9794

$\sum P_K\, P_{NF} = .22709E-3$

$\therefore P_E = .997E-3$

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