IMPROVING THE RELIABILITY OF HVDC SYSTEMS

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ABSTRACT

The design of modern day high voltage transmission schemes has become more challenging by the fact that both ac and dc modes of transmission are available. This thesis presents a method for evaluating the performance of a proposed or an existing HVDC scheme from a reliability point of view. A review of the recent developments in HVDC technology is presented and this is followed by a comparison of the advantages and disadvantages of ac versus dc transmission. A method is proposed that will enable system designers to determine the reliability of a dc scheme. Based on this information, it may be possible to improve the reliability and hence the performance of the HVDC system. This thesis concludes by mentioning some of the research work that is currently being undertaken to further improve the reliability of HVDC systems.

LIST OF SYMBOLS

Main Symbols:

VG	valve group element
PR	pole (rectifier) element
PI	pole (inverter) element
BPR	bipole (rectifier) element
MDT	mean down time
A	availability
$\overline{A}$	unavailability
LOTC	loss of transmission capacity
AOD	average outage duration
FOR	forced-outage-rate represents the unavailability or probaability of outage.
λ	frequency of outages per year based on manufacturers data

Subscripts:

VG-p	valve group element, power component subsystem
VG-v	valve group element, valve control subsystem
VG-d	valve group element, dc control subsystem
PR-p	pole (rectifier), power component subsystem
PR-v	pole (rectifier), valve control subsystem
PR-d	pole (rectifier), dc control subsystem
PI-p	pole (inverter), power component subsystem
PI-v	pole (inverter), valve control subsystem
PI-d	pole (inverter), dc control subsystem
BPR-p	bipole (rectifier), power component subsystem
BPI-p	bipole (inverter), power component subsystem
TLM	transmission line, monopolar
TLBP	transmission line, bipolar

1.0 INTRODUCTION

HVDC transmission systems are becoming increasingly more important in the growth and development of large power systems. This is due to the exploitation of natural resources located far away from the load centers and to the economic advantages offered by interconnecting large power systems.

In the past, the economics of ac versus dc transmission were mainly based on the "breakeven transmission distance" required to justify dc. The costs of dc conversion equipment was known to be greater than the cost of the equivalent ac terminals but the dc lines were less expensive per MW of transfer capacity.

As early project successes became apparent and as planners got a better appreciation of HVDC's role, more utilities began to consider HVDC as an important option. The operational characteristics of dc were found to be more important than the economics of distance. At present, 29 projects are in operation, scheduled or under consideration in North America alone. While some of these schemes have been justified by the economics of distance, many have been justified by more complex factors (as discussed in references [1-6]).

Due to the increasing dependence on electrical energy, more emphasis is also being placed on the application of reliability methods in the planning of transmission systems. In the case of ac transmission systems, it is difficult to evaluate the system response of an individual transmission line in terms of load flow and system stability since the transmission line forms part of a larger more complex transmission network. This task becomes unmanageable even in the case of small transmission networks. DC transmission systems on the other hand, do not present the same type of problems as in the case of ac transmission. There are no stability considerations as with ac and the power can be controlled more or less independently from the rest of the ac system. Thus, probability techniques can play an important role in the assessment of the overall dc system reliability.

The transmission capability of a dc scheme is dictated by the overall design and by the basic interrelationship between the components. With today's rising fuel costs, an outage on a dc system can have significant economic impact. A one percent increase in energy availability, when expressed on a capitalized basis, can be worth a significant percentage of the dc system purchase cost. When an outage occurs, energy must be supplied from an alternate source and usually at an increased price. On days when the load is near the annual peak, the cost of energy may be as high as \$100 per MWh [7]. On other days, the costs will be much less. A typical cost over the year may be about \$30 per MWh. For a 1000 MW system, this corresponds to \$30,000 per hour or \$720,000 per day assuming a 100 percent load factor. Thus, a one percent energy unavailability is worth about \$2.6 million per year. The capitalized value of a constant annual cost is obtained by dividing the annual cost by the annual carrying charges. Assuming a fixed charge rate of .20 which is typical for the American investor owned utilities, the capitalized cost of energy due to a one percent unavailability is:

$$\frac{\$2.6 \text{ million}}{.20} = \$13.1 \text{ million}$$

Consequently, a small increment in energy availability can have a large economic impact on the purchase cost of the HVDC system.

The design of modern day high voltage transmission systems has become more challenging by the fact that both ac and dc modes of transmission are available. In the power system planning process, the optimum power system design depends on a comparison of the advantages and disadvantages of ac versus dc transmission and on a careful examination of the reliability of the system. The purpose of this thesis is to examine the many aspects of HVDC transmission that are important for reliable system performance.

Chapter 2 deals with the development of HVDC technology from mercury arc valves to thyristor valves.

In Chapter 3, the advantages and disadvantages of ac versus dc transmission are presented in order to illustrate some of the complex factors that must be considered when planning an ac or dc transmission system.

A reliability model of a dc transmission system is developed in Chapter 4. The entire dc transmission system can be represented by a number of elements with specific power transmission capabilities and by the failure rates and repair times of these elements. From this information, it is possible to calculate a transmission capability probability table and hence, the availability of the entire dc transmission scheme can be determined.

In Chapter 5, the techniques developed in Chapter 4 are applied to the Nelson River BP2 system. This chapter demonstrates the effectiveness of the reliability model and its importance in the design of a HVDC system.

Chapter 6 deals with the current developments in HDVC technology. These developments are expected to have a significant impact on the design and reliability of new HVDC stations.

The conclusions of this thesis are presented in Chapter 7. The information presented in this thesis should enable the system designer to develop a reliability model for any dc transmission system. The reliability model can be used to make improvements to the reliability of the power system.

2.0 DEVELOPMENT OF HVDC TECHNOLOGY

Even though the economic advantages of dc power transmission were understood from the early days of electrical technology, its practical application could only be realized by the development of a suitably rated electronic valve. From the various switching principles that were developed in the early days of the power electronic industry, mercury arc rectification was favored for handling large currents.

Much of the development of the mercury arc valve for high voltage applications was carried out in Sweden by Dr. Uno Lamm. By 1939, a system of grading electrodes had been perfected along with a single phase valve construction. This provided the basis for larger peak inverse withstand voltages. The grading electrodes permitted a more uniform distribution of the reverse voltage near the anode and consequently, the number of arc-backs was greatly reduced.

The fast development of grading electrodes for mercury arc valves in the 1940's led to the first commercial application of HVDC technology in 1954 with the Sweden-Gotland link. This was immediately followed by other schemes of increased rating.

A detailed description of the construction and operation of mercury arc valves can be found in references [8] and [9]. Even though the mercury arc systems operated successfully, the high maintenance costs, voltage limitations and numberous arc backs encouraged the development of solid state technology.

The appearance of the thyristor (silicon controlled rectifier) in the late 1950's had a tremendous influence on HVDC technology. The thyristor valves offered the following advantages over the mercury arc valves:

1. Since the thyristors did not experience arc-back, the converter transformers became less expensive (due to less bracing), there was no service interruption and the control and protection schemes could be simplified.
2. By-pass valves were not required since the function of by-passing was done by the main working group.
3. The thyristors could be immersed in oil and in this case, the valve hall building would not be required.
4. No degassing facilities were required.
5. The use of thyristor valves eliminated the need for a "Clean Room" that was required for the assembly and maintenance of the mercury arc valves.
6. The thyristors demonstrated a very high level of reliability and they did not deteriorate in service.
7. No warm-up time was required for the thyristors prior to operation.
8. The thyristors could be arranged in a twelve pulse configuration, thereby eliminating the fifth and seventh harmonic ac filters and the sixth harmonic dc filter.
9. Reactive compensation was reduced for thyristor valve stations.
10. There was more freedom in the selection of ratings (i.e. current, voltage, power) of a thyristor valve station than of a mercury arc valve station.

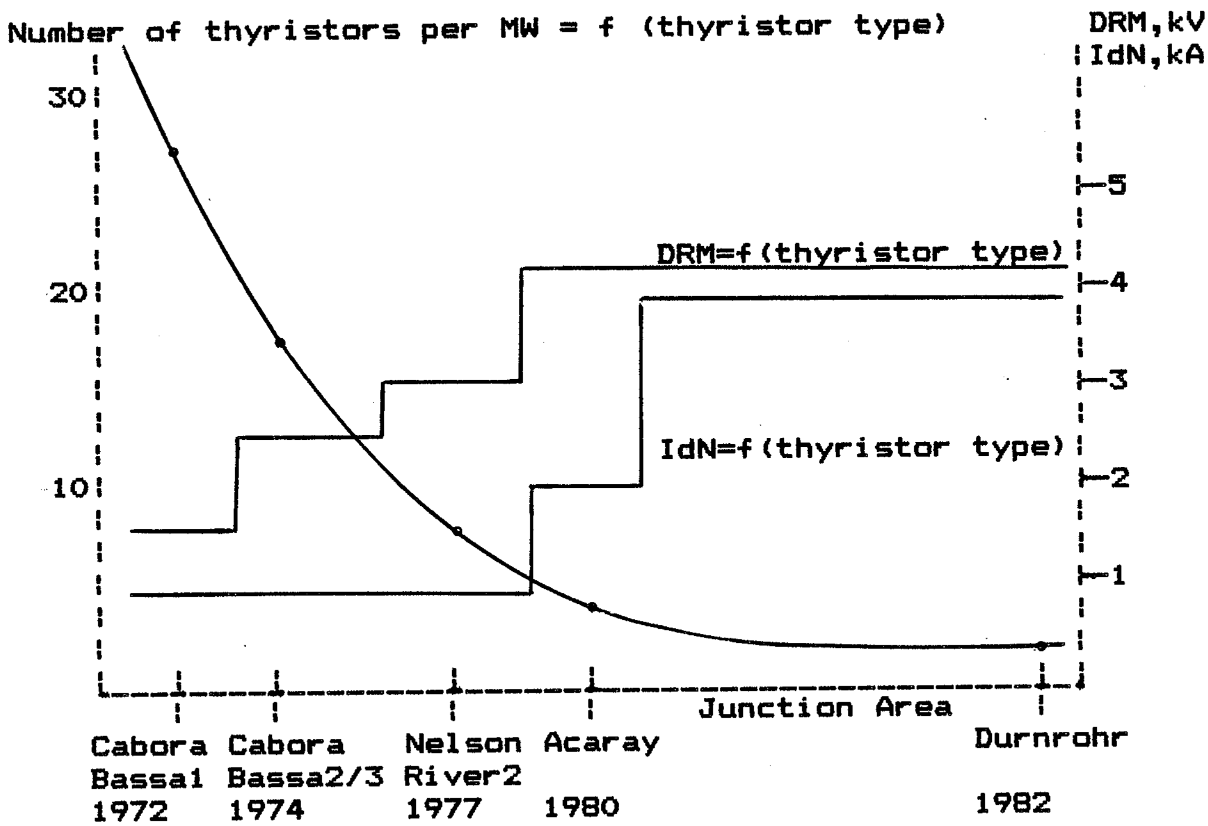
Even before the last two mercury arc schemes were commissioned, (Nelson River and Kingsnorth), the experience gained with thyristors was sufficient to discourage further development of mercury arc technology. A comparison of the reliability of mercury arc valve stations and thyristor valve stations is included in Appendix 1.

The early thyristors were limited by their low power rating. High voltage levels could only be achieved by stacking a large number of thyristors in series. These stacks were then arranged in a parallel configuration to obtain the desired current ratings. Consequently, a very complicated voltage grading system as well as a complicated firing circuit were required.

During the past few years, substantial progress has been made in improving the current rating and voltage withstand capability of the thyristor valves. At present, single thyristors are available with a current rating of 5000 A (corresponding to short circuit currents of 20-30 kA) together with voltage withstand capabilities of up to 5 kV. The improvement in the power handling capabilities of the thyristor valve has now made it possible to design schemes having a large current rating without using parallel connections of thyristors and with fewer thyristors connected in series. The progressive development of the power handling capability of thyristors is shown in Figure 1.

The improved power handling capability of the thyristor has had an effect on the design of the converter station. The individual thyristors are assembled in series to form a thyristor valve unit. In general, the number of thyristors per valve unit will depend on the desired voltage level. The valve units are usually arranged in a tower design in order to reduce cost and to permit a high degree of compactness. A twelve pulse configuration is normally used to reduce the number of filter circuits required.

FIGURE 1. Development of Thyristors for HVDC Applications (10).



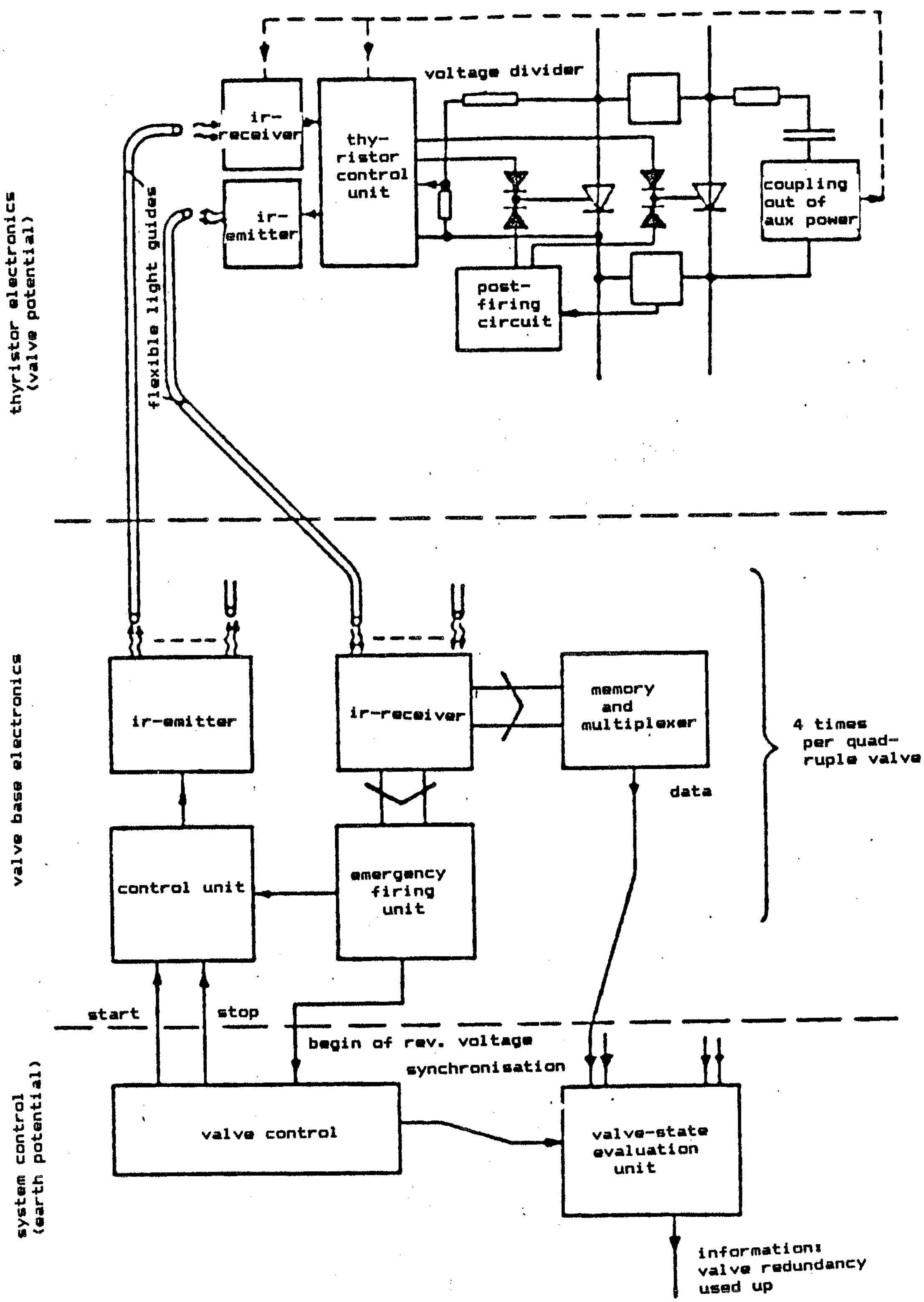
DRM direct repetitive maximum

The thyristors that are used in HVDC systems must be capable of handling the voltage and current stresses that occur in normal operation and as a result of fault conditions. The thyristor valves are protected against overvoltages by a lightning arrester across the dc terminals of the valve group and by a lightning arrester that is connected directly in parallel with the thyristor units. In addition, reactor and capacitor modules are included in the valve unit to keep thyristor stresses to a minimum during normal and abnormal operating conditions. Each thyristor also has a special back-up triggering circuit that provides firing pulses in the event that the forward voltage across the thyristor exceeds a certain value. Overcurrent protection is provided by the smoothing reactor and by causing the rectifier station to operate in the inverter mode. In some cases, overcurrent protection is provided by tripping the ac breaker that is connected to the converter transformer.

The thyristor valve units are normally insulated by the surrounding air and they can be cooled by air or by water. Water has been chosen in many cases because of its excellent cooling properties namely high thermal conductivity, high specific heat, and because it has a lower viscosity and density than air. The use of water cooling had led to a more compact design, lower losses, better utilization of thyristors and the elimination of noise and dust problems.

In several existing schemes, the firing and monitoring of the thyristor pairs is accomplished by an indirect optical triggering system. A basic block diagram of the firing system is shown in Figure 2. All the electrical control signals that come from valve control or from other protective circuits (at ground potential) are converted in the valve base

FIGURE 2. Basic Block Diagram of the Firing and Monitoring System for the Thyristor Pairs. (Courtesy of Manitoba Hydro)



electronics to light pulses and are transmitted via the light signal transmission system to the thyristor electronics associated with each thyristor pair. The thyristor electronics (at valve potential) converts the light pulses back into electrical signals that are used for firing the thyristors. An RC network is provided across each thyristor pair to supply auxilliary power for the conversion of the light pulses to electrical signals and for the amplification of these electrical signals. The thyristor electronics also contains circuits that are used to protect the thyristor against voltage stresses that occur during recovery time or voltage breakdown following excessive overcurrents. Back-up circuits are also included for forced firing of the thyristors.

The status of the individual thyristor pairs is monitored by the thyristor electronics. The electrical signals are converted to light pulses and are sent back via the light signal transmission system to the valve base electronics. The light pulses are converted back into electrical signals and this information is sent to the thyristor fault monitoring (TFM) unit. The function of the TFM is to indicate the status of every thyristor and its associated circuitry.

The design of the thyristor firing and monitoring system is expected to change in the next few years due to the development of light triggered thyristors (LTTs). The development of these thyristors is covered in references [11] and [12]. The LTT offers several advantages over the conventional electrically triggered thyristors. Triggering of the LTTs is accomplished directly by a light emitting diode and consequently, the number of electronic components could be reduced to provide a more simple, compact and reliable valve module. The gate firing circuit would be immune to electrical signals and there would be less chance of a malfunction due to electrical noise. Also, the firing capability of the LTTs would not be affected by reduced power system voltages as in the case of the electrically triggered thyristors. Based on these advantages, it is expected that the LTTs will be eventually used in the design of new converter stations.

Experience with thyristor stations has shown that thyristors have a very low failure rate. Usually, there is some redundancy provided in the number of thyristors and hence, the reliability of a HVDC station is not determined by the thyristors. Electronic faults generally result in the protective firing of the thyristor until the next maintenance interval without imparing the transmission capacity and security.

The advanced stage of development attained by the thyristor stations is reflected in their high level of reliability and availability. As a result of this progess, dc transmission schemes are being considered more often as an alternative to ac transmission schemes.

3.0 AC VERSUS DC TRANSMISSION

In general, high voltage transmissions are used for bulk energy transfer and for system interconnections. Both HVAC and HVDC modes of transmission are available and each offers certain advantages and disadvantages in a given application.

As far as bulk energy transfer is concerned, it is essential to conduct an economic assessment in each case. Whenever the transmission distance is quite large, the case of HVDC transmission is well established in spite of the relatively high cost of the converter stations. A schematic diagram of a typical HVDC transmission system is shown in Figure 3.

The accounting procedures used in the economic comparison must include the cost of the lines, terminals, series and shunt compensation (which is required in the case of ac transmission), short circuit limitation, etc. A schematic diagram of a typical ac transmission system is shown in Figure 4. The cost of a transmission system can only be determined once the energy and capacity losses as well as the costs of alternate generation (to meet the load requirements) are capitalized.

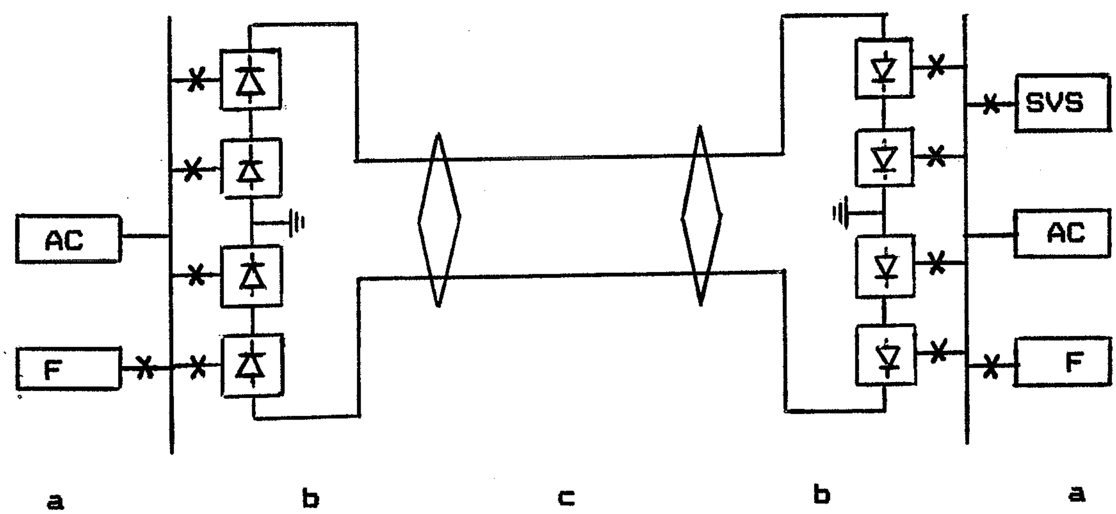
However, the cost alone should not be the decisive factor and special consideration must be given to intangibles such as:

a) operational performance, flexibility and reliability during disturbances;

b) the consequence of forced and scheduled outages;

c) the continuous and short time overload as well as the maximum loading capability; and

FIGURE 3. Schematic Diagram of a Typical HVDC Transmission System.



a: ac system

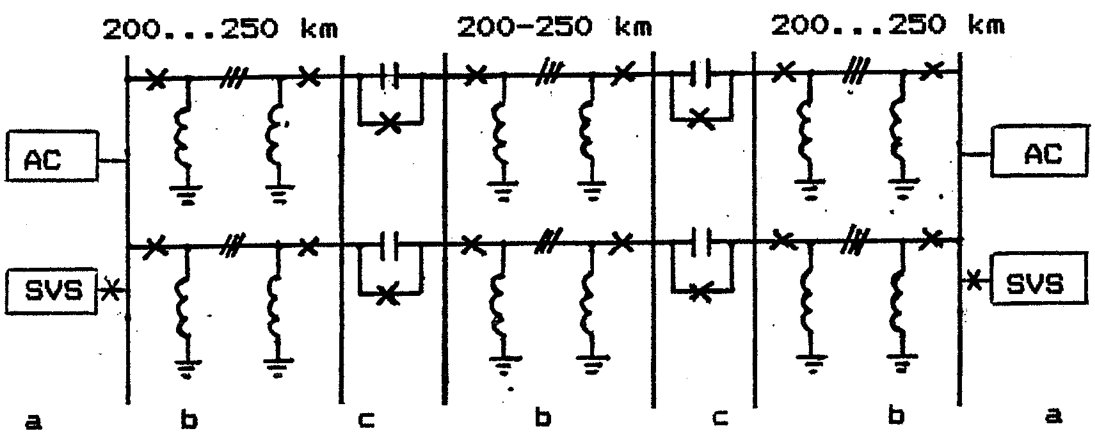
b: converter station

c: dc line

f: filter

SVS: static var system

FIGURE 4. Schematic Diagram of a Typical HVAC Transmission System.



a: ac system

b: ac transmission line

c: substation

svs: static var source

sc: series capacitors

d) the possibility of a staged installation program with respect to overall system planning.

It is very difficult to develop a general analysis to suit each and every transmission design problem. Some of the factors that are responsible for the complexity of a generalized theory include:

a) the wide range of situations and conditions among different countries or parts of a country; (e.g. overhead lines can vary from country to country by a factor as high as 2.5 while the cost of converter stations varies very little);

b) the lack of technical comparability between ac and ac-dc systems;

c) the need to consider the long-term effects on overall system planning when choosing from among different design alternatives; and

d) the rapid developments being made in both ac and dc technology.

Thus, when analyzing ac and dc alternatives, a precise economic assessment can only be made on a specific situation. Consideration must be given to the long range development of the system, its future load growth, availability of generation resources and the many other factors [13] that affect power system planning.

With reference to system interconnections, there is a great need to operate the entire system in perfect synchronism. A small disturbance in any one ac system may cause extremely large power surges on the ac tie lines. These surges could cause follow-up surges of a cascading nature in the other interconnected systems. In such a case, there is no practical alternative than the use of HVDC transmission.

The following two sections describe some of the advantages and disadvantages of ac and dc systems with respect to bulk energy transfer and power system interconnections.

3.1 Bulk Energy Transfer

When comparing ac and dc alternatives for bulk energy transfer, the fact that transmission by dc requires less expensive lines for the same power rating and no series or shunt compensation must be weighed against the costly ac to dc and dc to ac converter stations. In general, the use of standardized break-even distances for different power ratings is not the best criterion to be used when conducting economic comparisons. Nevertheless, distance is a primary factor in bulk energy transfer and its influence on the economic comparison of ac and dc alternatives is discussed in the following sections.

3.1.1 A Comparison of AC and DC Transmission Characteristics

The stability of an ac line is dependent on the power magnitude per circuit and on the length of the line. The steady state stability limit between two ac systems (Vs and Vr) is approximately determined by the expression:

$$P(\text{transfer}) = \frac{(Vs)\ (Vr)}{(Xsr)}\ (\text{Sin}\,\delta sr) \tag{1}$$

where δsr is the load angle between the voltage vectors Vs and Vr and Xsr is the series reactance between the same voltage vectors. Under normal operating conditions, the load angle is kept at about 30 degrees for stability reasons. The distance to which the natural load can be transmitted stably can be increased by providing series compensation and synchronous condensors or static compensators at the terminal ends. The ac transmission line must also be able to transmit charging current (capacitive reactive power) under light load conditions. Such conditions produce over-voltages and as a result, shunt compensation is also required.

Under steady state conditions, capacitance and inductance have no effect on the dc line and there is no need for intermediate switching stations.

However, the operation of a converter station requires a supply of reactive power. Under steady conditions, approximately one half of the real power rating of reactive power is required while under transient conditions, the factor may be as high as three-quarters. Reactive power is usually supplied to the converter stations by the capacitance of ac filters and by either synchronous condensors or by static compensators.

With dc, no stability problems occur and power is controlled freely and rapidly by converter controls. However, due to the small thermal capability of the thyristors, overloading is more limited in a dc system. If a long overload period is desired, the thyristors must be over rated and the converter plant must be designed for operation at higher temperatures.

High voltage transmission by underground cables is rarely used due to their high costs and long repair times. The length of ac cable transmission is limited due to the high charging reactive powers that are required. The length may be extended by using shunt reactors but such intermediate compensation is not practical in the case of an underwater link. In this situation, the use of a dc transmission scheme is more advantageous than the use of an ac scheme.

3.1.2 Earth Return Capability

The earth return is an attractive advantage in the case of dc transmission. It can be used either permanently as in the case of monopolar or homopolar schemes, or intermittently as in the case with a bipolar scheme. The use of earth return could provide a substantial saving in capital cost since only one conductor would be necessary to transmit the power. Transmission losses would also be lower since the resistance of the earth (which is about two ohms) is much less than the resistance of any metallic conductor. The feasibility of this concept is illustrated by the Gotland scheme where one submarine cable is used for power transmission and the sea is used for the return path.

The earth return must be properly designed in order to eliminate any communication/relaying influences or corrosion problems. In most cases, these difficulties can be overcome with little additional expense.

Earth return cannot be used with ac systems due to the associated inductive effects. Failure of one conductor in an ac circuit would result in a complete shutdown of the transmission line.

3.1.3 Favourable Right-of-Way

HVDC lines have a higher power transmission capacity than do HVAC lines for the same right-of-way width. This becomes important in areas where land costs are high or where environmental factors have to be considered. The transmission capacity of HVDC and HVAC as a function of the right-of-way width is shown in Figure 5.

Since the cost of a dc line is approximately fifty to sixty percent of the cost of an ac line, and since there are no stability limitations with dc (i.e. no technical limitations regarding the length of the line), the designer has more freedom in considering alternate routes of transmission. This feature is particularly important from the point of view of security from faults.

3.1.4 Supplying Power into Intensely Populated Centers

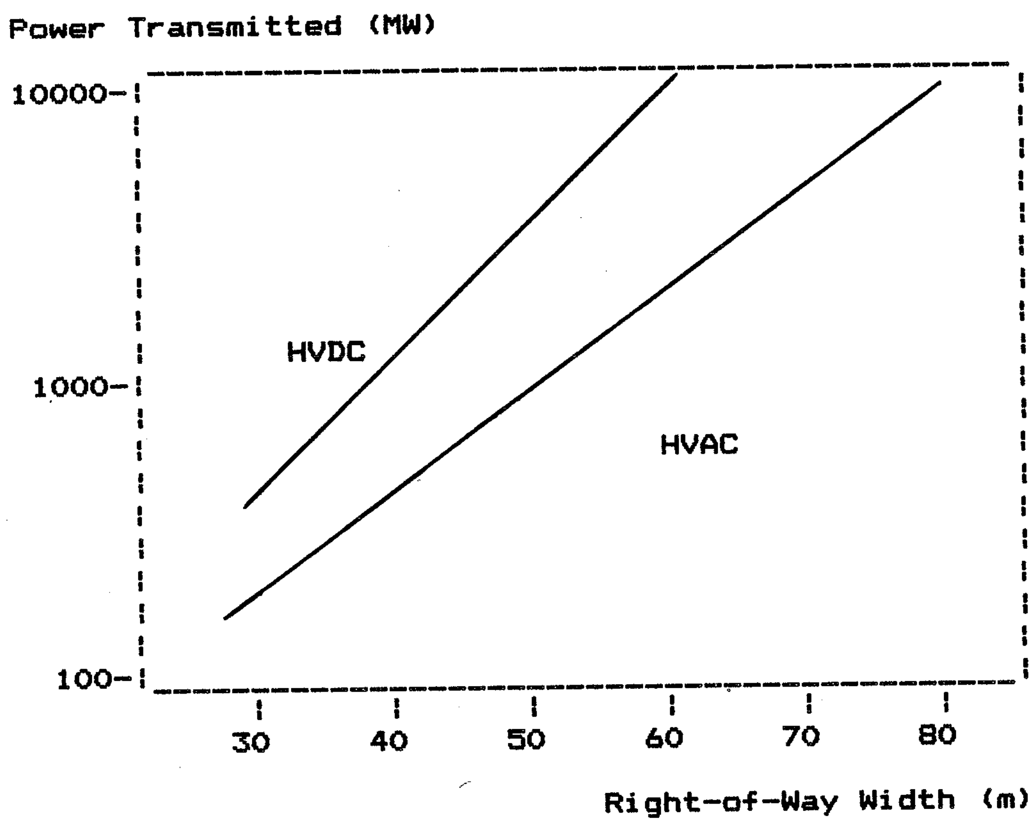
At present, many metropolitan areas are experiencing high load growths. City centers have become so congested that it is no longer possible to obtain a right-of-way for an overhead transmission line. In this case, more power can only be supplied by underground dc cables [15] or by converting the existing ac lines to dc lines. Such a conversion would increase the power transfer capability and possibly, the reliability as well.

In cases where the short circuit capacity of the transmission network has become too large, it is possible to sectionalize the network by means of an HVDC line as discussed in references [16] and [17]. An HVDC link makes only a negligible contribution to the short circuit capacity of the ac network as long as no rotating synchronous condensor is included.

3.1.5 Modular Construction

Another advantage of a dc transmission system is that it can be built in stages depending on the load growth. The dc line voltage can be

FIGURE 5. Power Transmission Capacity as a Function of Right-of-Way Width [14].



increased in stages by simply adding on more valve groups. This feature influences the amount of capital that is required throughout the project term and allows for greater flexibility of construction staging.

3.1.6 Environmental Effects

The environmental effects of high voltage transmission lines have caused a greater concern in recent years. The principal causes of concern are:

a) audible noise;

b) radio and television interference;

c) electric field; and

d) ion production.

a) Audible noise occurs mostly during wet weather and it influences the design and cost of ac transmission lines. Audible noise is not a problem in the case of dc transmission because the static field ion production alleviates any surface discontinuities which may appear.

b) In the case of ac transmission, corona losses and radio interference losses increase greatly at high voltages and special precautions have to be taken such as the bundling of conductors. No special precautions have to be taken in the case of dc transmission.

c) The electric field problem is less severe in the case of dc than ac due to the lack of steady state displacement current.

d) Ion production is not a problem for ac transmission since corona occurs near the conductor (i.e. within one foot). In the case of dc transmission, investigations are still being carried out in an attempt to minimize the earth ion current. [18]

3.1.7 Effects of Losses and Discount Rates

The economic comparison of alternate transmission schemes is usually based on a present worth of revenue analysis. Included in the economic comparison is the revenue requirements on capital and on the differential transmission system losses. The cost impact of transmission reliability on the installed generating capacity of the system must also be considered including the energy and capacity losses due to transmission outages.

Before any final economic assessment can be made, it is important to ensure that the reliability of the ac alternative is equivalent to the dc alternative. In many cases, the reliability of a two-pole dc line is compared to that of two three-phase ac lines. This assumption is valid when considering insulator faults (i.e. faults which would cause a fifty percent loss in transmission capacity). However, when a tower fault is considered, this comparison is no longer valid. A more accurate comparison could be obtained by including the probability of occurence of both types of faults and their associated power transmission loss.

As an example, BC Hydro recently completed a study to assess the transfer of 4760 MW over a distance of approximately 1000 km [19]. Several alternatives were selected on the basis that a first contingency loss of a single transmission system element would not require a reduction of generating capacity. The following alternatives were studied:

a) two 765 kV lines with sixty-five percent series compensation;

b) three 765 kV lines with forty percent series compensation;

c) two 900 kV lines with sixty percent series compensation;

d) two 1150 kV lines with thirty-five percent series compensation;

e) 2 $\pm$ 500 kV dc bipolar schemes; and

f) 2 $\pm$ 600 kV dc bipolar schemes.

In order to compare alternatives of equal reliability, a two circuit 765 kV series compensated ac line was compared to a 2 $\pm$ 600 kV dc bipolar scheme.

The reliability evaluation was performed in two stages. First, Monte Carlo simulation was conducted on the various radial transmission alternatives. This provided an indication of the availability of different power transfer levels as well as the frequency of departure from these levels. Secondly, a loss of load probability evaluation was conducted for the entire BC Hydro system based on the information collected in the first part. The results obtained are shown in Table 1.

The basic dc station (no major spares) had a relatively low availability of 94.82% as compared to the 765 kV ac scheme which had an availability of 98.65%. The addition of a spare converter transformer and a spare smoothing reactor increased the availability of the dc alternative to 99.17%. However, the frequency of departure from 100 percent capacity in this case was still more than twice that of the ac alternative. The frequency of departure below 100 percent capacity could be reduced to approximately the same level as in the ac alternative by providing the dc alternative with pole paralleling capability.

The capital costs for the two alternatives are shown in Table 2.

TABLE 1. BC Hydro Reliability Study Results [19]

Alternative	Availability of 100% Capacity (%)	Frequency of Departures from 100% Capacity no./a	System LOLP d/a
765 kV ac	98.65	8.29	.116
$\pm$ 600 kV dc (with spare converter trans & smoothing reactor	99.17	19.64	.111
$\pm$ 600 kV dc (with spares and with paralleling)	99.34	10.00	-

TABLE 2. BC Hydro Station and Transmission Capital Costs Based on 1981 Dollars [19]

Component	2 X 765 kV ac ($ Millions)	2 X ± 600 kV dc $ (Millions)
Transmission Line (with shunt compensation)	895	533
Stations	117	529
Series Compensation	129	-
TOTAL	1141	1064

These costs are in 1981 dollars and are based on the information collected from the manufacturers of ac and dc equipment. Both the alternatives were evaluated using a cash flow and present worth analysis. The present worth of the estimated losses was also included. Allowance was made in the economic analysis for the difference between the cost of money and inflation being equal to a discount rate of three percent. The effect of varying the discount rate is shown in Figure 6.

A significant outcome of the BC Hydro study is illustrated in Figure 7. For a low value of losses, the dc alternative produced the lowest capital cost. However, the double circuit 765 kV ac line becomes less expensive when losses were evaluated at about \$6.4 mills per kWh. It should be pointed out that during the study, BC Hydro losses were evaluated at about \$20 mills per kWh. This situation occurs as a result of the lower dc voltage level used (i.e. $\pm$ 600 kV). If a $\pm$765 kV scheme was considered, then it is expected that the cost of the dc alternative would decrease as the value of losses is increased.

The BC Hydro study requires a few principal comments. It appears that the cost of the ac scheme is apparently lower than it should be while the cost of the dc scheme is slightly inflated. Nevertheless, the study illustrates the importance of incorporating the effects of discount rates and losses into the economic assessment of transmission alternatives.

3.2 System Interconnection

The interconnection of power systems offers several technical and economic advantages such as:

FIGURE 6. Cost Comparison with Varying Discount Rate [19].

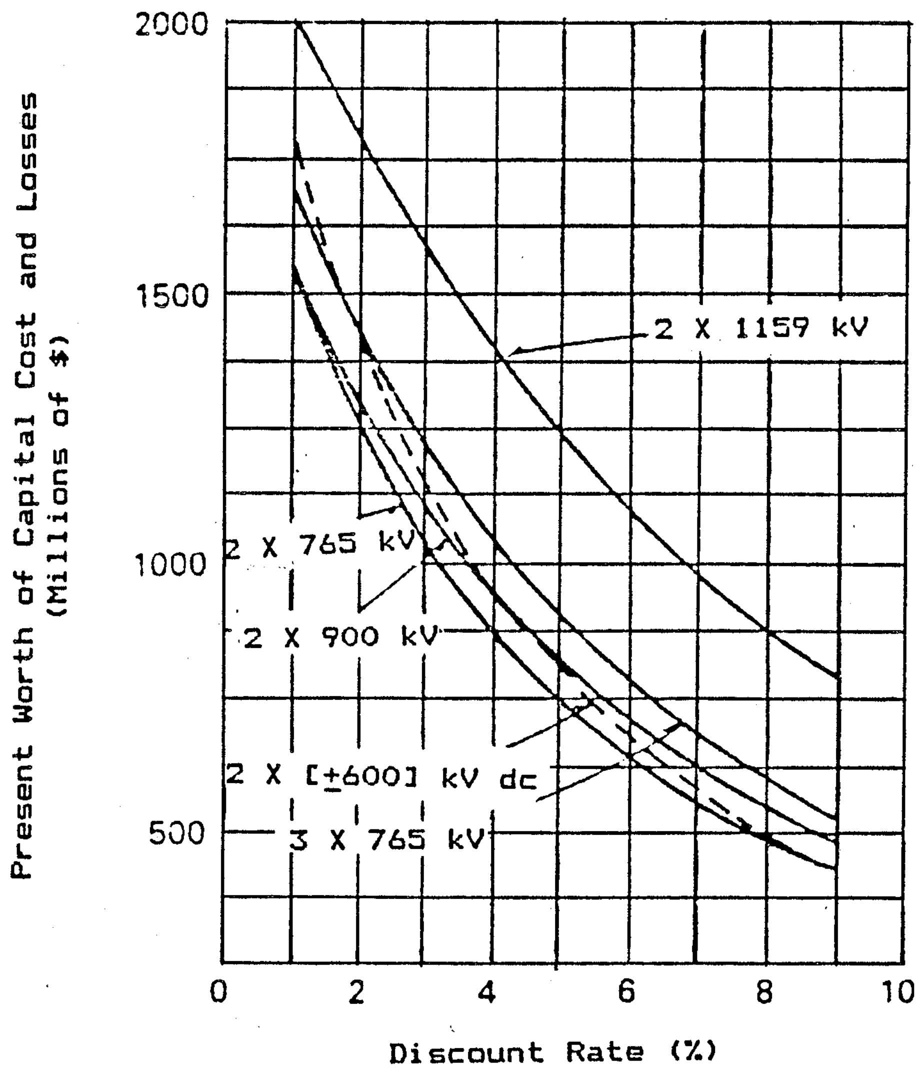
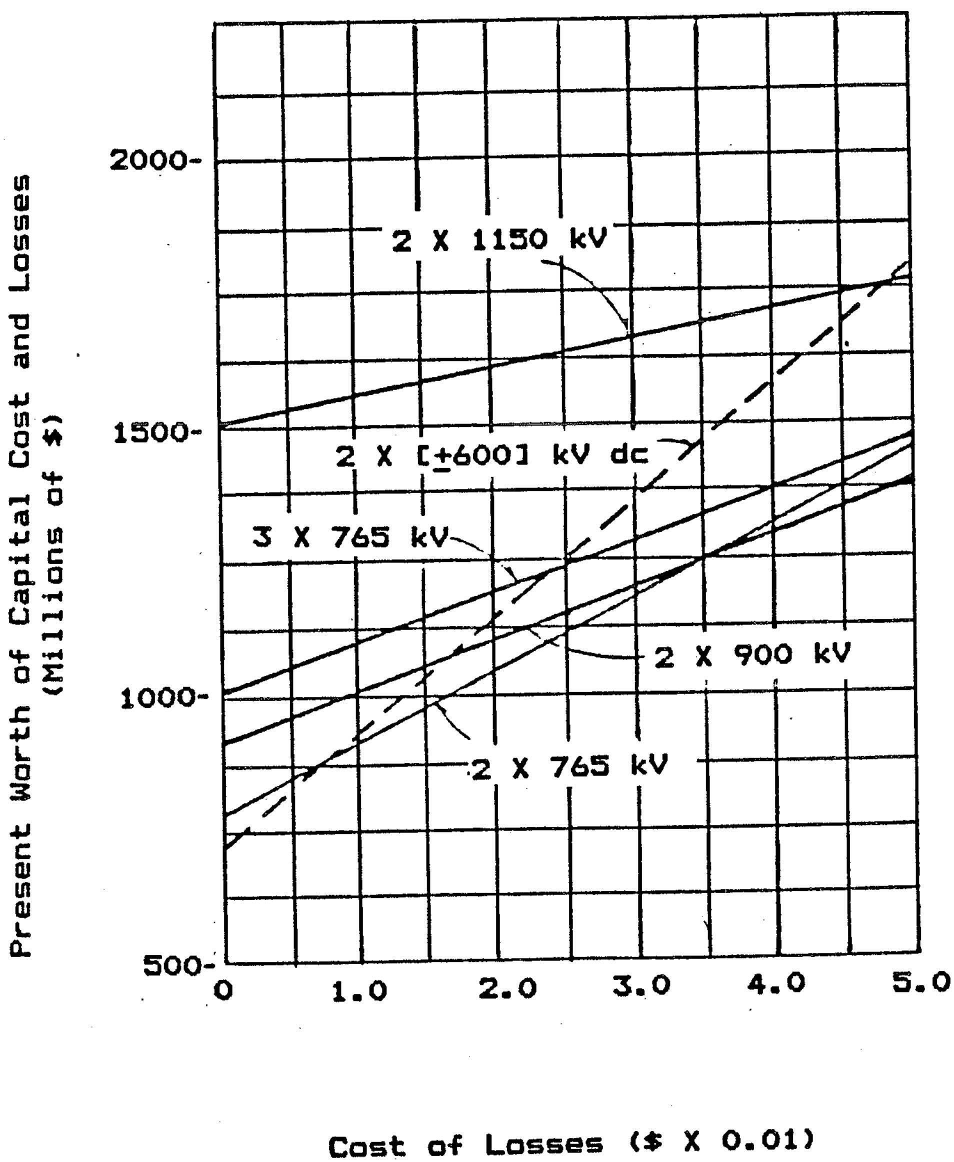


FIGURE 7. Cost Comparison with Varying Losses [19].



a) optimal scheduling of hydro power and thermal power in order to compensate for seasonal fluctuation of the water supply;

b) reliability of the interconnected system is improved if the reserve capacity is unchanged;

c) a reduction of installed generating capacity since a lower level of overall reserve power is needed;

d) generation scheduling may be accomplished by the larger and therefore more economical units (important for smaller networks); and

e) a reduction in the peak load of an interconnected network due to differences in daily, monthly or yearly load cycles of the parts of the system.

In general, the interconnection of power systems is accomplished by ac tie-lines. In some cases, ac connections cannot be made and a dc link is the only alternative.

a) Since the economic power rating of system interconnections are small in comparison to the installed capacity of the interconnecting systems, an ac tie-line may offer power flow and stability control problems. A dc tie-line provides a fast and flexible power flow control as well as stability improvement for the interconnected systems.

b) An ac tie-line reduces the overall system impedance and consequently increases the short circuit levels. These high levels may cause electrical and mechanical stresses on some equipment and may exceed the capability of the existing circuit breakers. A dc tie will not increase the short circuit level.

c) If systems of different frequencies are to be interconnected, an ac tie-line is not possible and a dc tie-line must be used. Examples of HVDC back-to-back links are the Sakuma, Shin Shinano, and Acaray schemes.

d) An ac interconnection is often uneconomical in the case of network systems that are controlled according to different principles (i.e. current control, voltage control or power control). In this case, the use of a HVDC back-to-back link is preferred. An example of such an interconnection is the Durnrohr scheme in Austria.

In a study carried out by Harders and Povh [20], reliability calculations showed that the savings that occurred as a result of a HVDC interconnection amounted to a significant percentage of the capital investment required. Savings can be realized in the investment cost of power stations since interconnections permit the sharing of reserve capacity and this allows a smaller overall reserve capacity to be installed.

Thus, HVDC transmission offers advantages not only for bulk energy transfer, but for system interconnections as well.

4.0 RELIABILITY ANALYSIS OF HVDC TRANSMISSION

Reliability analysis is an important step in the development of a dc transmission system. An accurate prediction of the reliability would allow accurate forecasts to be made of maintenance costs, support costs, spare requirements, etc. However, a reliability prediction can rarely be made with a high degree of accuracy or confidence. Nevertheless, it can provide the system designer with an adequate basis for comparing various options and for emphasizing the critical reliability features of the design.

Reliability analysis is used in the design of an HVDC transmission system to accomplish the following objectives:

a) assess the long-term operating behaviour of the system;

b) optimize system performance and overall station reliability;

c) compare alternative system designs;

d) identify weak spots and unbalances in the design;

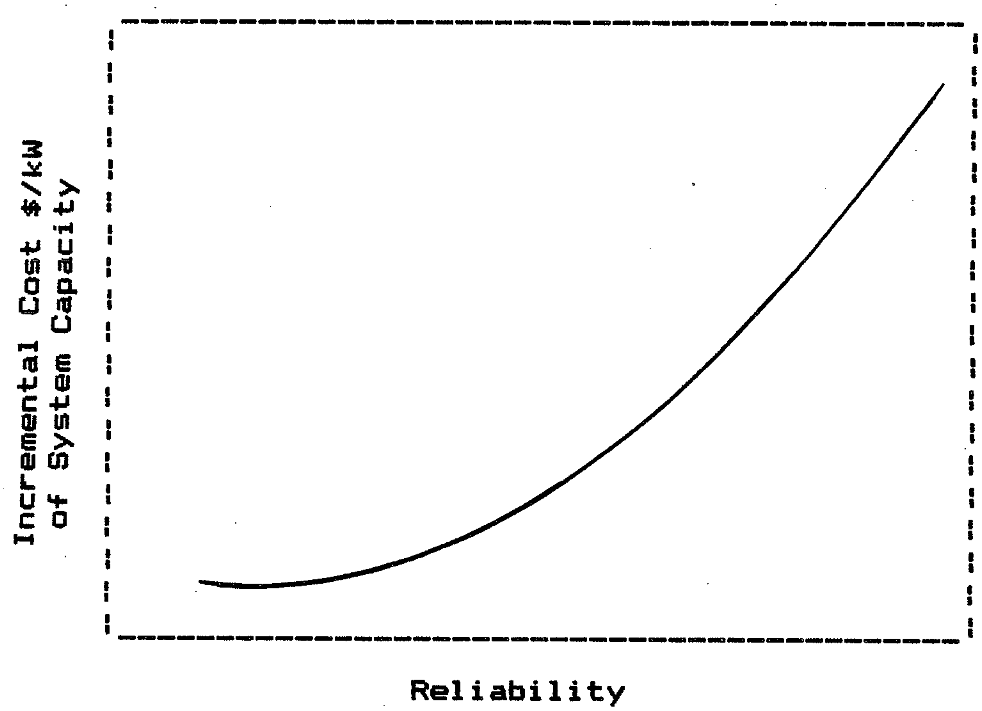
e) assess the relative importance of the various failure modes;

f) establish the maintenance, repair and spare parts policy based on the computed reliability figures; and

g) assess the cost of improving the system reliability.

In the reliability analysis process, the optimum design of the dc transmission system will undoubtedly concern designers for many years to come. Ideally, the reliability of the system should be improved up to a point where the incremental cost equals the incremental worth. The relationship between the incremental change in reliability and the incremental cost ($/kW) is shown in Figure 8. In reality, there is no way of

FIGURE 8. Incremental Change in Reliability.



determining the worth of reliability. Attempts have been made to estimate by how much the reliability will be affected by a given expenditure but there is much scope for variation and uncertainty. Consequently, the worth of reliability must be based on both qualitative and quantitative estimates.

The qualitative analysis is very important because it forms the basis of the reliability analysis. To accomplish this, it is first necessary to establish the reliability goals and the criteria that will be used for making planning decisions. Once this is done, a failure mode and effect analysis (FMEA) can be conducted on the system. The FMEA is important because it provides valuable information for optimizing the system performance and for trade-off studies. The FMEA consists of the following steps:

a) description of the system in terms of block and circuit diagrams;
b) definition of subsystems and description of interfaces;
c) description of components and their respective failure rates;
d) identification of various subsystem dependencies;
e) assessment of the effect and consequences of various component/ subsystem failure modes;
f) description of the effect of external disturbances on different components/subsystems;
g) assessment of the importance of failures on the different system operating states; and
h) development of a maintenance, repair and spare parts policy for the system.

In any qualitative analysis, it is important to realize that all equipment is subject to failure and the problem is to balance the system reliability requirements against the system cost.

The qualitative analysis is carried out in conjunction with the quantitative analysis. The quantitative analysis consists of developing mathematical models and numerical methods in order to determine the reliability of the system.

Thus, reliability analysis provides important information that is needed by the system designer to develop a reliable and safe dc transmission system. The next few sections demonstrate the application of reliability analysis to the design of a HVDC transmission system.

4.1 Qualitative Analysis

A dc transmission system consists of many elements that are quite complex. Failure of some of these elements may result in a partial loss of transmission capacity. Thus, the first step in a reliability analysis is to formulate a model that represents the system accurately and is easy to understand.

The qualitative analysis is demonstrated for the case of two series connected valve groups per pole. Since there are four valve groups per station, the transmission capacity can only be reduced by multiples of twenty-five percent.

The qualitative analysis can be simplified by dividing the dc transmission system into two parts namely the converter stations and the transmission line.

All items which produce a twenty-five percent loss of transmission capacity upon failure are lumped into a single VG (valve group) element. The main items in this element include the valves, valve group controls, valve group switching, converter transformers, valve cooling, and so on. The outage rate of a VG element is determined by the outage rates of the individual items that comprise the VG element.

Similarly, all elements that cause a fifty percent loss of transmission capacity upon failure can be lumped into a single P (pole) element. This element includes equipment such as the smoothing reactors, dc filters, potential devices, etc.

Elements such as the ground electrode and main controls are grouped in the BP (bipole) element since their failure will produce an entire shutdown of the transmission system.

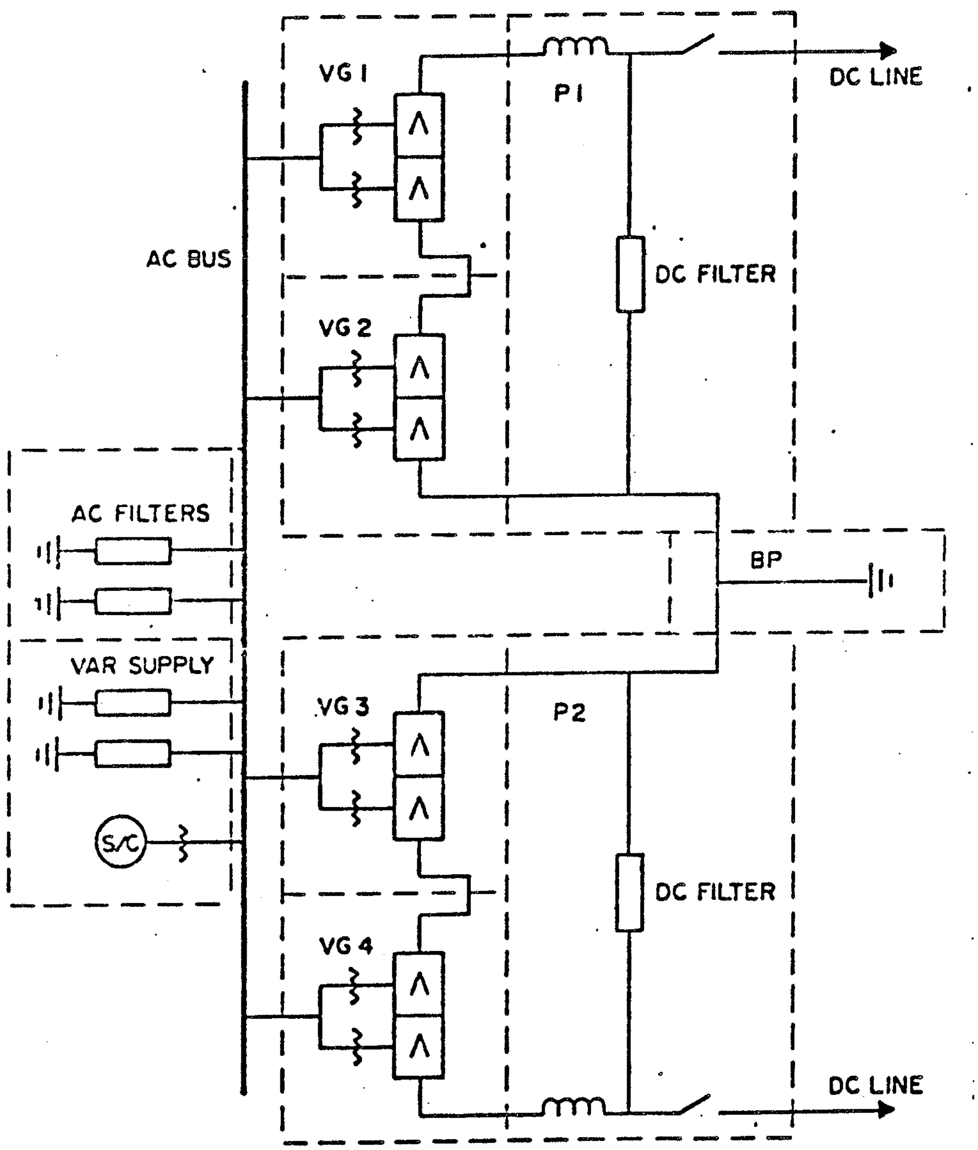
Some equipment such as synchronous condensors, measuring and detection devices and ac filters can be included with either the VG, P or BP elements depending on the effect of their failure on the transmission capability.

Thus, both converter stations will have four VG elements, two P elements and one BP element as shown in Figure 9.

The qualitative analysis must also take into account the insulator and tower faults which affect the performance of the dc transmission line. The dc line can be modelled in this case as two elements of fifty percent capacity (representing the two poles or conductors of the system) in series with an element representing the bipolar outage rate of the dc line.

In some cases, it may be desirable to subidivde the VG and P element into subsystems. Both the VG and P elements will contain many components

FIGURE 9. The Basic Elements of a HVDC Converter Station [21].



and it may be difficult to analyze the results of a reliability study without getting lost in the complexity of the model. The number of subsystems will be determined by the designer and will depend on the level of accuracy that is desired.

As an example, it is possible to subdivide the VG and P elements into three subsystems such as power components (p), valve control (v) and dc control (d). Such a procedure will emphasize the critical areas of a design more accurately and allow modifications to be made more readily.

The power components of the converter station (Nelson River BP2) are separated into VG, P and BP elements. The power components consist of ac filters, converter transformers, valve hall equipment, dc filters and the dc switchyard. Also included in this subsystem are the various dc current transducers, dc voltage dividers, current and voltage transformers, etc. that are necessary for proper operation.

The valve control (v) subsystem consists of all the equipment that is necessary for the accurate timing and setting of the firing pulses. This includes circuits for current and extinction angle control, firing angle and voltage control via the transformer tap changer control, current reference processing and current and voltage limitation. The following protection circuits are normally incorporated in the valve control equipment as well:

a) valve overcurrent protection;

b) bridge differential protection;

c) pole differential protection; and

d) dc line protection.

Other circuits like extinction angle supervision and pulse firing monitoring have protection features as well.

The dc control subsystem contains the control equipment that is required for the starting and shutdown of the valve groups. This subsystem also includes the interlocking system which permits operation only when all the conditions have been met (i.e. switches in the right position, keys in the right place, etc.). The tapchanger controls are also included in the dc control subsystem.

Based on this information, it is possible to create a reliability model of the entire dc transmission system as shown in Figure 10 [21]. The reliability model can then be used in the quantitative analysis to determine the availability of transmission capacity.

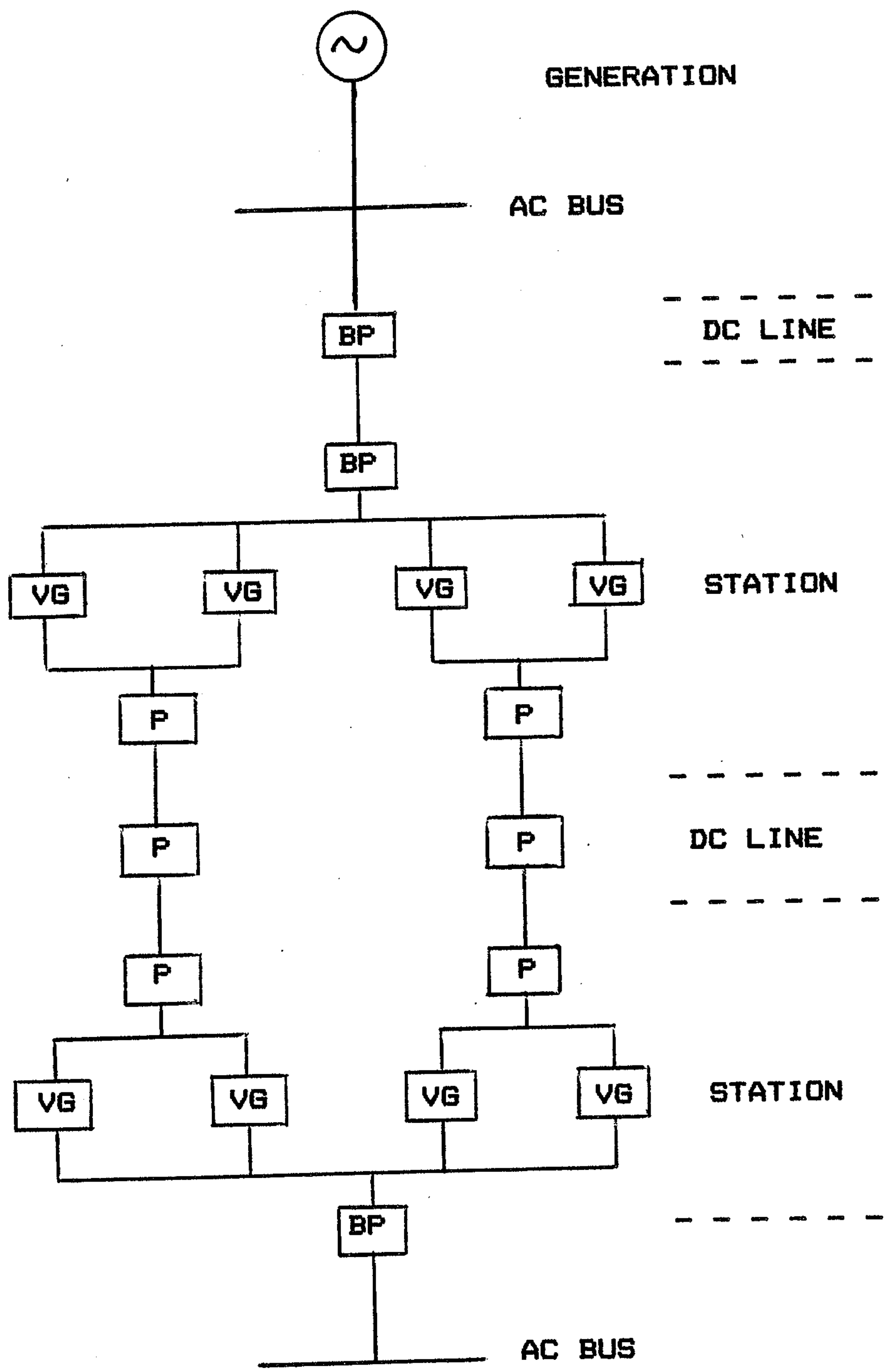
4.2 Data Collection

Once the operation of the dc system has been defined and the reliability model has been completed, it is necessary to collect data on the performance of various components. Without reasonably accurate data, it is not practical to attempt a "parts count" prediction. The degree to which a reliability analysis is made depends upon the confidence in the data. Data on the failure rate of components can be obtained from the manufacturers of the particular components or it can be estimated from international data sources. Sample data has been collected for the components used on the Nelson River BP2 scheme and is included in Appendix 2.

4.3 Quantitative Analysis

The purpose of the quantitative analysis is to develop a method of

FIGURE 10. A Reliability Model of the Nelson River BP2 Scheme.



calculating the failure rate of the subsystems (and consequently, of the elements) based on the design of the dc transmission system and on the parameters and components chosen. A description of quantitative reliability methods can be found in references [22] and [23].

The forced outage rate of a subsystem can be defined by the following equation:

$$FOR(sub) = \sum_{i} (Ni)\ (\lambda i) \quad [outages/year] \tag{2}$$

where Ni is the number of type i components and λi is the failure rate of component i [outages/year]. The outage rate for an element is simply the summation of the outage rates of all the subsystems. This is expressed by the equation:

$$FOR(element) = \sum_{i} FOR(subj) \quad [outages/year] \tag{3}$$

where FOR(subj) is the forced outage rate for the jth subsystem.

In a quantitative analysis, it is important to know the mean down time (MDT) of an element in order to determine the availability of the element. The MDT per year of a subsystem can be expressed as:

$$MDT/year(sub) = \sum_{i} (Ni)\ (\lambda i)\ (MDTi) \quad [h/year] \tag{4}$$

where Ni and λi are the same as before and MDTi is the mean down time of component i. The mean down time of an element composed of j subsystems is:

$$MDT/year(element) = \frac{\sum_{j} (FOR(subj))\ (MDTj)}{\sum_{j} FOR(subj)} \quad [h/year] \tag{5}$$

The MDT of a component can be difficult to determine particularly at the design stage. In some cases, it can be obtained from the performance of other HVDC systems. Otherwise, it will be necessary for the designer to make some assumptions regarding the maintenance schedule and the spare parts availability in order to obtain a reasonable approximation for the MDT of a component.

Once the failure rate and MDT of an element are known, it is possible to calculate the unavailability and hence, the availability of an element. The unavailability of an element ($\bar{A}$(element)) is given by the equation:

$$\bar{A}(\text{element}) = (\text{FOR}(\text{element}))\,(\text{MDT}(\text{element}))\quad[\text{h/year}] \qquad (6)$$

Thus, the availability of an element (A(element)) is:

$$A(\text{element})\% = \left(1 - \frac{\bar{A}(\text{element})}{8760}\right) \times 100\% \qquad (7)$$

where 8760 is the number of hours in a year.

Using the previous equations, it is possible to calculate the outage rate and MDT of each element in the dc transmission system. This information is summarized in Tables 3 through 7.

This analysis can also be performed for each subsystem as well. The forced outage due to power components can be calculated as:

$$\text{FOR}(p) = (\text{FOR}(\text{VG-p}))\,8 + (\text{FOR}(\text{PR-p}))\,2 + (\text{FOR}(\text{PI-p}))\,2 + (\text{FOR}(\text{BPR-p})) + (\text{FOR}(\text{BPI-p}))\quad[\text{outages/year}] \qquad (8)$$

The forced outage rate due to valve control and dc control can be calculated in a similar fashion as shown in equations (9) and (10):

$$\text{FOR}(v) = (\text{FOR}(\text{VG-v}))\,8 + (\text{FOR}(\text{PR-v}))\,2 + (\text{FOR}(\text{PI-v}))2\quad[\text{outages/year}] \qquad (9)$$

$$\text{FOR}(d) = (\text{FOR}(\text{VG-d}))\,8 + (\text{FOR}(\text{PR-d}))\,2 + (\text{FOR}(\text{PI-d}))2\quad[\text{outages/year}] \qquad (10)$$

The information obtained from these calculations will indicate the critical reliability features of the design. As a result, modifications

TABLE 3. Outage Rates and MDT for BP Element (Rectifier)

Subsystem	FOR (#/year)	MDT (h/year)
power components (p)	FOR(BPR-p)	MDT(BRP-p)
valve control (v)	-	-
dc control (d)	-	-
FOR(element) / MDT(element)	FOR(BPR)	MDT(BPR)
Availability %	A(BPR)	

TABLE 4. Outage Rates and MDT for BP Element (Inverter)

Subsystem	FOR (#/year)	MDT (h/year)
power components (p)	FOR(BPI-p)	MDT(BRI-p)
valve control (v)	-	-
dc control (d)	-	-
FOR(element) / MDT(element)	FOR(BPI)	MDT(BPI)
Availability %	A(BPI)	

TABLE 5. Outage Rates and MDT for P Element (Rectifier)

Subsystem	FOR (#/year)	MDT (h/year)
power components (p)	FOR(PR-p)	MDT(PR-p)
valve control (v)	FOR(PR-v)	MDT(PR-v)
dc control (d)	FOR(PR-d)	MDT(PR-d)
FOR(element) / MDT(element)	FOR(PR)	MDT(PR)
Availability %	A(PR)	

TABLE 6. Outage Rates and MDT for P Element (Inverter)

Subsystem	FOR (#/year)	MDT (h/year)
power components (p)	FOR(PI-p)	MDT(PI-p)
valve control (v)	FOR(PI-v)	MDT(PI-v)
dc control (d)	FOR(PI-d)	MDT(PI-d)
FOR(element) / MDT(element)	FOR(PI)	MDT(PI)
Availability %	A(PI)	

TABLE 7. Outage Rates and MDT for VG Element

Subsystem	FOR (#/year)	MDT (h/year)
power components (p)	FOR(VG-p)	MDT(VG-p)
valve control (v)	FOR(VG-v)	MDT(VG-v)
dc control (d)	FOR(VG-d)	MDT(VG-d)
FOR(element) / MDT(element)	FOR(VG)	MDT(VG)
Availability %	A(VG)	

can be made to the design at an early stage rather than at a later stage where the cost of a design change is much more expensive.

In order to determine the availability of the entire dc transmission system, it is necessary to take into account the reliability of the dc transmission line. Data for the transmission line can be obtained from the performance of other dc transmission lines that are operating under approximately similar conditions. In the reliability analysis, it is necessary to determine the failure rate and MDT of the monopolar transmission line (FOR(TLM), MDT(TLM)) and of the bipolar line (FOR(TLBP), MDT(TLBP)). The reliability model can then be used to calculate the number of outages of different amounts of transmission capacity and the energy unavailability for the transmission system.

A loss of twenty-five percent transmission (LOTC(25%)) capacity is given by the equation:

$$\text{LOTC}(25\%) = (\text{FOR(VG)})8 \quad [\text{outages/year}] \tag{11}$$

The average outage duration (AOD(25%)) for this case would be equal to the MDT(VG).

A loss of fifty percent transmission (LOTC(50%)) capacity can be expressed as:

$$\text{LOTC}(50\%) = (\text{FOR(PR)})2 + (\text{FOR(PI)})2 + (\text{FOR(TLM)})2 \quad [\text{outages/year}] \tag{12}$$

The average outage duration for this case (AOD(50%)) can be estimated based on the contributions of MDT(PR), MDT(PI) and MDT(TLM).

Similarly, a loss of one hundred percent transmission capacity (LOTC(100%)) is given by the equation:

$$\text{LOTC}(100\%) = \text{FOR(BPR)} + \text{FOR(BPI)} + \text{FOR(TLBP)} \quad [\text{outages/year}] \tag{13}$$

The average outage duration (ADD(100%)) must again be estimated based on the contributions of MDT(BPR), MDT(BPI) and MDP(TLBP).

The availability of transmission capacity can be calculated from equations 11, 12 and 13. The energy availability is the theoretical amount of energy that could be transmitted by the dc transmission system at full capacity and at continuous operation.

The length of time that the dc transmission system must operate in a derated state can be calculated by equation (14):

$$\overline{A}(100\%) = \mathrm{LOTC}(100\%)\mathrm{AOD}(100\%) + \mathrm{LOTC}(50\%)\mathrm{ADD}(50\%) + \mathrm{LOTC}(25\%)\mathrm{AOD}(25\%) \quad \text{[hours/year]} \qquad (14)$$

where $\overline{A}(100\%)$ represents the unavailability of one hundred percent transmission capacity. Therefore, the availability of transmission capacity for this case is:

$$A(100\%) = [1 - \frac{(\overline{A}(100\%))}{8760}]100\% \quad \text{[percent]} \qquad (15)$$

The energy availability of seventy-five percent transmission capacity can be calculated by taking into account the loss of fifty percent and one hundred percent transmission capacities. The unavailability of seventy-five percent transmission capacity is expressed by equation (16):

$$\overline{A}(75\%) = \mathrm{LOTC}(100\%)\mathrm{AOD}(100\%) + \mathrm{LOTC}(50\%)\mathrm{AOD}(50\%) \quad \text{[hours/year]} \qquad (16)$$

Thus, the availability of at least seventy-five percent transmission capacity is simply:

$$A(75\%) = [1 - \frac{(\overline{A}(75\%))}{8760}]100\% \quad \text{[percent]} \qquad (17)$$

The unavailability of fifty percent transmission capacity may be calculated by equation (18):

$$\overline{A}(50\%) = \mathrm{LOTC}(50\%)\mathrm{AOD}(50\%) \quad \text{[hours/year]} \qquad (18)$$

and consequently, the availability of at least fifty percent transmission capacity is:

$$A(50\%) = [1 - \frac{(\bar{A}(50\%))}{8760}]100\% \quad [\text{percent}] \tag{19}$$

Similarly, the unavailability of twenty-five percent transmission capacity may be calculated as shown in equation (20):

$$\bar{A}(25\%) = LOTC(100\%)AOD(100\%) \quad [\text{hours/year}] \tag{20}$$

Thus, the availability of at least twenty-five percent transmission capacity is:

$$A(25\%) = [1 - \frac{(\bar{A}(25\%))}{8760}]100\% \quad [\text{percent}] \tag{21}$$

The average energy availability can be calculated by the following equation:

$$\text{Energy (AVG)} = \frac{A(100\%) + A(75\%) + A(50\%) + A(25\%)}{4} \tag{22}$$

The energy unavailability is one hundred minus the Energy (AVG) and this quantity is considered to be the most indicative of overall reliability performance [21].

The previous analysis can be used in the design of new HVDC transmission systems and in the modification of existing schemes. If the unavailability is too high, then changes may be made to the design of the system. In this way, repetitive design changes and reliability analysis can lead to an optimum system design.

4.4 Maintenance Outages

The reliability model can be expanded to take into account the time required for the scheduled maintenance of the dc transmission system. The maintenance time can be obtained from the data of other stations and must take into account the power company's operating schedule, facilities, number and skill of maintenance personnel, and the spare parts provision. The maintenance policy should also take into account the equipment locations, weather conditions and the power demand.

5.0 CALCULATING THE RELIABILITY OF THE NELSON RIVER BP2 HVDC TRANSMISSION SYSTEM

The reliability techniques that were developed in Chapter 4 can be used to determine the performance of a dc transmission system. The Nelson River BP2 scheme was used as an example due to the availability of data. A single line diagram of this scheme is shown in Figure 11.

The entire dc transmission system was broken down into VG, P, BP and transmission line elements, according to the method presented in Section 4.1.

Since both the VG and P elements are quite large, they were further subdivided into three subsystems namely power components (p), valve control (v) and dc control (d). The BP element consists of only the p subsystem and it does not contain any v or d subsystems.

The power components considered in the reliability calculation are shown in Figure 12. Data on the power components is included in Appendix 3 (A3-1) and the results are summarized in Table 8.

The valve control subsystem was broken down into smaller blocks in order to simplify the reliability analysis. The functional blocks are included in Appendix 3 (A3-2) and the results are summarized in Table 9.

Similarly, the dc control subsystem was broken down into smaller functional blocks in order to simplify the analysis procedure. The functional blocks for the dc control subsystem are included in Appendix 3 (A3-3) and the results are summarized in Table 10.

From the results of Tables 8, 9, and 10, it is possible to calculate the failure rate (equation 3), MDT (equation 5), unavailability (equation

FIGURE 11. A Single Line Diagram of the Nelson River BP2 Scheme.

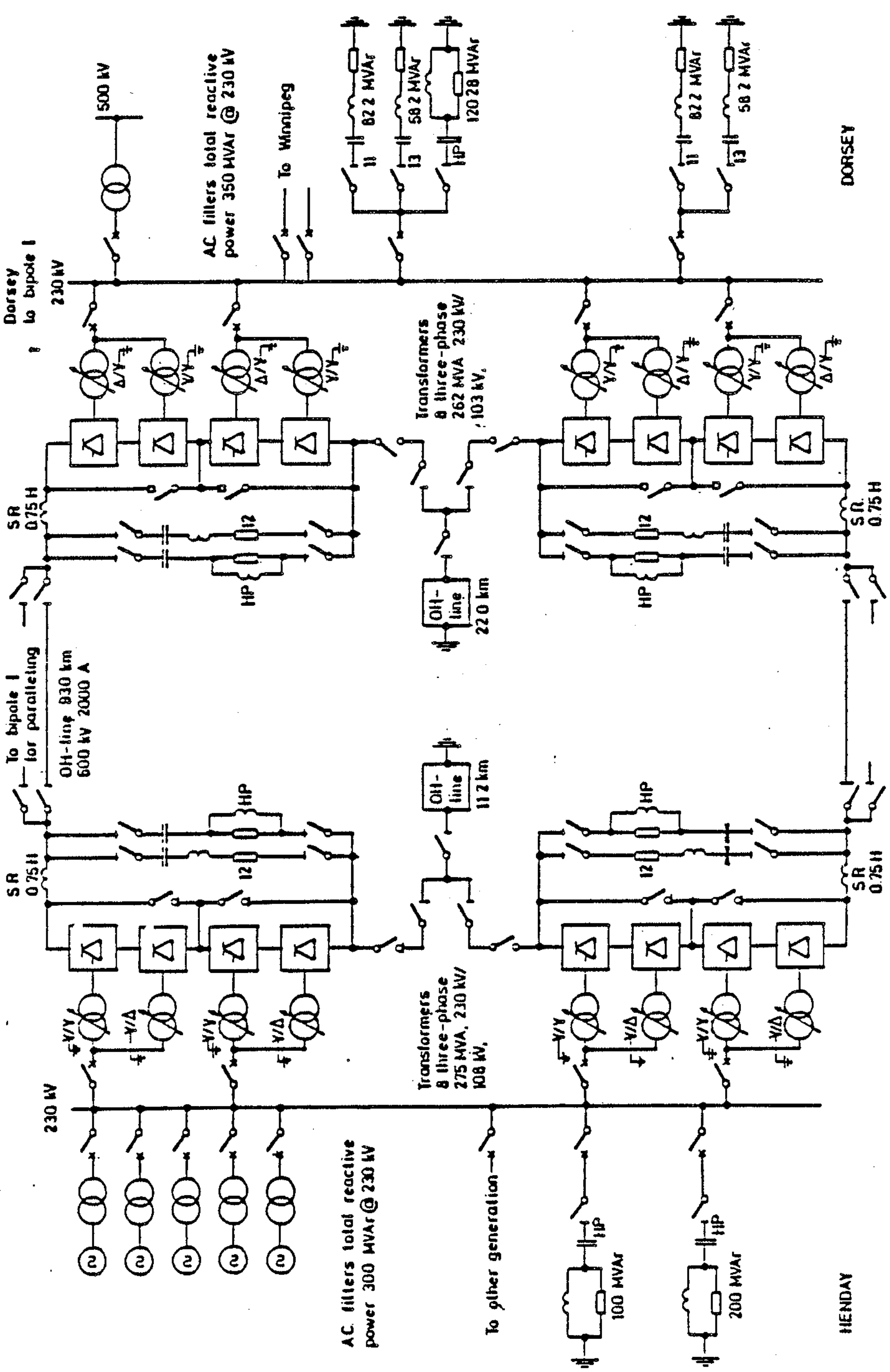


FIGURE 12. The Power Components of a Converter Station (Nelson River BP2 - Courtesy of Manitoba Hydro).

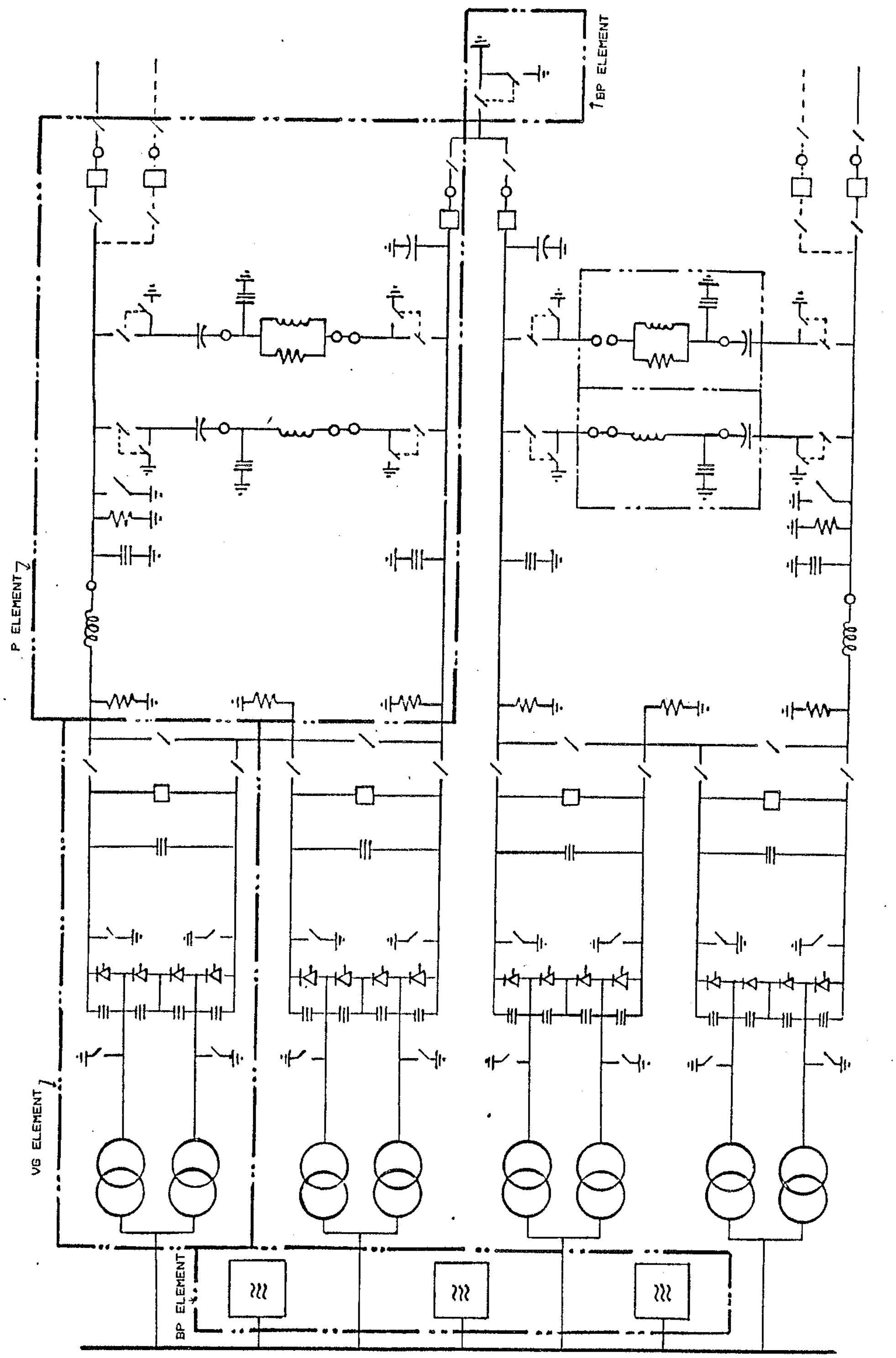


TABLE 8. Outage Rates and Mean Down Time for the Power Component Subsystem

Power Component Subsystem		
Element	FOR [1/year]	MDT [h]
BPR	FOR(BPR-p) = .066	MDT(BPR-p) = 24.0
BPI	FOR(BPI-p) = .066	MDT(BPI-p) = 24.0
PR	FOR(PR-p) = .514	MDT(PR-p) = 29.6
PI	FOR(PI-p) = .514	MDT(PI-p) = 29.6
VG	FOR(VG-p) = .464	MDT(VG-p) = 55.0

TABLE 9. Outage Rate and Mean Down Time for the Valve Control Subsystem

Value Control (v) Subsystem		
Element	FOR [1/year]	MDT [h]
PR	FOR(PR-v) = .309	MDT(PR-v) = 4
PI	FOR(PI-v) = .412	MDT(PI-v) = 4
VG	FOR(VG-v) = 1.098	MDT(VG-v) = 4

TABLE 10. Forced Outage Rate and Mean Down Time for DC Control Subsystem

DC Control (d) Subsystem		
Element	FOR [1/year]	MDT [h]
PR	FOR(PR-d) = .337	MDT(PR-d) = 4
PI	FOR(PI-d) = .337	MDT(PI-d) = 4
VG	FOR(VG-d) = .135	MDT(VG-d) = 4

6) and the availability (equation 7) of each element. The calculations are included in Appendix 4 and the results are summarized in Table 11.

The forced outage rate of each subsystem can also be calculated by using equations 8, 9 and 10. The forced outage rate of the p subsystem is:

$$\text{FOR}(p) = (.464)\ (8) + (.514)\ (2) + (.514)\ (2) + (.066) + (.066) = 5.90 \quad [\text{outages/year}]$$

The forced outage rate of the v subsystem is:

$$\text{FOR}(v) = (1.098)\ (8) + (.309)\ (2) + (.412)\ (2) = 10.23 \quad [\text{outages/year}]$$

Similarly, the forced outage rate of the d subsystem is:

$$\text{FOR}(d) = (.135)\ (8) + (.337)\ (2) + (.337)\ (2) = 2.43 \quad [\text{outages/year}]$$

Thus, the total bipole outage rate is simply:

$$\text{Bipole outage rate} = 5.90 + 10.24 + 2.43 = 18.57 \ [\text{outages/year}]$$

It is evident from these calculations that at least fifty percent of the outages that occur at the converter stations will be related to valve control. An improvement in the overall reliability of the system may be achieved by improving the reliability of the valve control subsystem.

Since the Nelson River BP2 scheme is bipolar, the transmission line is modelled as two elements representing the two poles of the system (TLM) in series with an element representing the bipolar outage rate of the system (TLBP). Data on the performance of a 1000 km dc transmission line was obtained from [21] and is listed below.

$$\text{FOR(TLM)} = 5.0 \ [\text{outages/year}]$$

$$\text{MDT(TLM)} = 1.0 \ [\text{hours}]$$

$$\text{FOR(TLBP)} = 0.54 \ [\text{outage/year}]$$

$$\text{MDT(TLBP)} = 6.3 \ [\text{hours}]$$

TABLE 11. FOR, MDT, Unavailability ($\overline{A}$), and Availability (A) of Each Element

Element	FOR [1/year]	MDT [H]	$\overline{A}$ [h]	A [%]
BPR	FOR(BPR) = .066	MDT(BPR) = 24.0	1.58	99.9820
BPI	FOR(BPI) = .066	MDT(BPI) = 24.0	1.58	99.9820
PR	FOR(PR) = 1.160	MDT(PR) = 15.3	17.75	99.7974
PI	FOR(PI) = 1.263	MDT(PI) = 14.4	18.19	99.7924
VG	FOR(VG) = 1.697	MDT(VG) = 17.9	30.45	99.6524

Thus, it is possible to calculate the number of outages of different amounts of transmission capacity (equations 11 to 13) and consequently, it is possible to calculate the energy availability for the transmission system (equations 14 to 21). The calculations are included in Appendix 5 and the results are summarized in Table 12.

The average energy availability of the Nelson River BP2 scheme was calculated to be 99.1415%. The forced energy unavailability was found to 0.8586%. These calculations do not include any scheduled maintenance outages but nevertheless, they give a good indication of the performance of the entire dc transmission system. As a comparison, the forced energy unavailability of the Nelson River BP2 scheme was 0.9% in 1983 (based on two valve groups in operation). The reliability analysis developed in this thesis can be used to give a good indication of the performance of the entire dc transmission system. The accuracy of the reliability analysis can only be verified after data has been collected on the actual system performance for several years.

The reliability analysis does not take into account the possibility of several events occurring at the same time such as the simultaneous loss of two or more VG elements, the loss of two or more P elements, the loss of one VG and one P element, etc. Although the frequency of such events is rare, the probability of occurrence does exist. The reliability analysis may be improved by taking into account the probability of occurrence of these simultaneous events.

TABLE 12. Energy Availability for the Nelson River BP2 Scheme

Transmission Capacity (%)	Availability (%)
100	97.0012
75	99.7823
50	99.8305
25	99.9518
0	100.0
Energy (AVG)	99.1415%
Energy Unavailability	0.8586%

6.0 RESEARCH AND DEVELOPMENT

There is a considerable amount of research and development work under way to improve the reliability of HVDC schemes and to justify the use of dc in case of ac versus dc comparisons.

Basically all the research and development work currently in progress can be subdivided into two areas. The first area deals with improving the reliability model and the techniques that are presently being used to compute the reliability of the dc transmission system. The second area deals with the recent advances in HVDC technology that may improve both the reliability and the cost of converter stations. The various proposals which may influence the rate of expansion of dc transmission systems are:

a) single generator converter units (unit connection);

b) compact converter stations; and

c) microcomputers and direct digital control.

This chapter gives a brief introduction into both areas.

6.1 Improving the Reliability Calculations

The quantitative procedure can be improved by using state-space analysis and simulation techniques in the calculation of the reliability of the dc transmission system.

The best known state-space analysis method is the Markov analysis [24]. If a component is defined to be either in the operating state or in the failed state and if the probabilities associated with both states can be determined, then it is possible to calculate the probability of being in one state or the other at some future time. The Markov analysis is applied under the following constraints:

1. The probability of going from one state to another is constant.
2. Future states of the system are independent of all past states except the immediately preceding one.

Nevertheless, Markov analysis can be very useful in reliability analysis. Even for simple systems, the matrix algebra that is required is quite complex and many computer programs have been written to simplify the procedure.

An attractive alternative to the Markov analysis is the Monte Carlo simulation because it involves no complex mathematical analysis. The Monte Carlo simulation can be easily applied to model complex systems but it requires extensive use of computer time. Since the simulation techniques generate variable results, several program runs are necessary in order to obtain an estimate of the means and variances of the parameters of interest.

The use of Markov analysis and Monte Carlo simulation techniques in the quantitative analysis of a dc transmission system will depend on the cost of implementing and using these methods versus the expected improvements in system reliability.

6.2 Generator-Rectifier Units (Unit Connection)

At present, the generators and converter transformers are connected in a parallel arrangement. An alternative arrangement has been suggested in which each generator is connected directly to a converter transformer and operates independently from the other generators [25]. The advantages of such an arrangement are:

a) There are no synchronization or stability problems since each generator unit operates independently from the others.

b) Balancing of reactive power flow between generators is not required.

c) AC filters may not be required and consequently there would no longer be any problems of self-excitation of the generators following load rejection. Also, any harmonic resonances that would normally occur between the generators or the converter transformers and the filters would be eliminated.

d) The fault level of the ac system would be reduced as a result of the generators segregation. This leads to considerable savings in the cost of the generators, converter transformers and switching systems. Due to the asynchronous nature of the interconnection, generation would be possible at more economical frequencies.

The control of the single generator-converter units could be accomplished by the rectifier bridge, resulting in a much simpler generator control or by the generator. The latter control method could lead to the possibility of a diode-rectifier converter [26].

The diode rectifier would be a much simpler unit than the thyristor rectifier with no firing requirements, no communication or control equipment, simpler grading circuits and lower energy dissipation. The elimination of the ac bus, transformers, filters and circuit breakers and the reduced fault currents should provide an overall reliability and availability that is higher than a conventional thyristor system. Simulator studies have been conducted to demonstrate the feasibility of this proposal.

6.3 Compacting Converter Stations

The failure rate of a dc transmission system could be further reduced by enclosing the entire converter station in SF6 gas in order to protect the system from the environment. Such a design would also provide for a more compact converter station.

A light triggered thyristor has already been developed for a SF6 insulated - SF6 cooled converter station [27]. Valve units rated at 250 kV and 3000 A can be housed in a metal tank (dead front design) and can be transported on a trailer fully constructed.

Prototype valves rated at 125 kV and 600 A have been built to demonstrate the feasibility of such a scheme. A 9.6 MW back-to-back plant rated at 16 kV and 600 A has been put into service in order to gain more experience [28]. Results obtained from the prototype installation indicate that the use of compressed SF6 gas for insulation and cooling is expected to improve the reliability and cost of HVDC transmission systems.

6.4 Microprocessor Based Digital Control

The availability of relatively cheap microprocessors and the development of complex bus architectures has led to the design of simple but highly effective HVDC control systems [29, 30]. The use of microprocessors will offer substantial improvements in areas such as optimization of control parameters, reliability, maintainability and excellent possibilities for future upgrading. Parallel processing can also be used to further speed up the control calculations.

The use of microprocessors for the control of dc transmission systems can offer certain advantages that are beyond the scope of present analogue-based systems such as:

a) the control mode and the control characteristics can be altered by software;

b) different types of control modes can be implemented with the same hardware;

c) the control system design is more compact; and

d) system performance (response) can be stored digitally for diagnostic purposes.

The calculations that were done in Chapter 5 for the Nelson River BP2 scheme indicated that the failure rate of the valve control subsystem had a greater impact on the bipolar outage rate than did the other subsystems. The use of microprocessors for digital control may offer substantial improvements in this area and may considerably improve the reliability of the entire dc transmission system.

7.0 CONCLUSIONS

Based on the above work, the following conclusions can be made:

1. Reliability analysis plays an important role in the design of HVDC transmission system. Since a small increment in energy unavailability can have a significant impact on the purchase cost of the HVDC system, it is important to optimize the design of the system.
2. The design of modern day high voltage transmission schemes must take into account the fact that both ac and dc modes of transmission are available. The use of dc transmission in certain cases can offer several advantages over the use of ac transmission and therefore, cost alone should not be the decisive factor in determining what type of transmission system is to be built.
3. The selection of either ac or dc transmission alternatives should be based on a comparison of the whole integrated power system including an evaluation of the advantages and disadvantages of ac versus dc alternatives. By considering the technical, economic and reliability aspects, it is possible to achieve an optimum power system design.
4. The reliability analysis used in this thesis can be applied to any HVDC system configuration. The entire dc transmission system can be represented by a simplified reliability model. The model can then be used to determine the availability of transmission capacity.
5. Based on this information, it is possible to make changes to the design of the system in order to improve the overall reliability. The method proposed in this thesis can be used in the design of new

stations and in the modification of existing stations.

6. The results obtained from the reliability analysis of the Nelson River BP2 scheme provide a good indication of the expected performance of the dc transmission system.
7. The accuracy of this method is limited by:
   a) the accuracy of the failure rate of each component; and
   b) the estimation of the mean down time of each component.
8. The accuracy of the reliability analysis presented in this thesis can be improved by:
   a) obtaining more accurate data on the failure rate of each component;
   b) determining the mean down time of components based on the operating company's maintenance and repair policies and on data obtained from the performance of other dc transmission systems; and
   c) using either Markov analysis and/or Monte Carlo simulation techniques in the quantitative analysis.
9. The reliability analysis method presented in this thesis can also be used to study the impact of new developments in HVDC technology (eg. light-triggered thyristors, generator-rectifier units, compact converter stations and microprocessor control) on the overall system reliability.

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APPENDIX 1

HVDC SYSTEM RELIABILITY PERFORMANCE

A1.1 HVDC System Reliability Performance

Data on the reliability performance of HVDC systems throughout the world has been collected by the Cigre Working Group 04 of Study Committee 14 since 1968. The definition of terms and the methods used to calculate various reliability statistics are given in the "Cigre Protocol for Reporting the Operation and Performance of HVDC Transmission Systems".

A1.2 Energy Availability

One statistic that is used to indicate HVDC system performance is energy availability. Energy availability is a measure of the energy that could have been transmitted except for limitations arising from forced and scheduled outages. It is calculated as a percentage of the total energy that could have been transmitted at the maximum continuous rating of the system. Figure A1-1 shows the energy availability of mercury arc stations and Figure A1-2 shows the energy availability of thyristor valve stations. The higher energy availability of the thyristor valve stations indicates that they are much more reliable than the mercury arc valve stations.

A1.3 Energy Unavailability

Energy unavailability is a measure of the energy which could not be transmitted by the HVDC system due to forced and scheduled outages. It is equal to one hundred minus the energy availability. The energy unavailability is shown for mercury arc valve stations in Figure A1-3 and for thyristor valve stations in Figure A1-4. It is quite evident that the mercury arc valve stations have higher maintenance and operation

FIGURE A1-1. Energy Availability of Mercury-Arc Valve Stations [31].

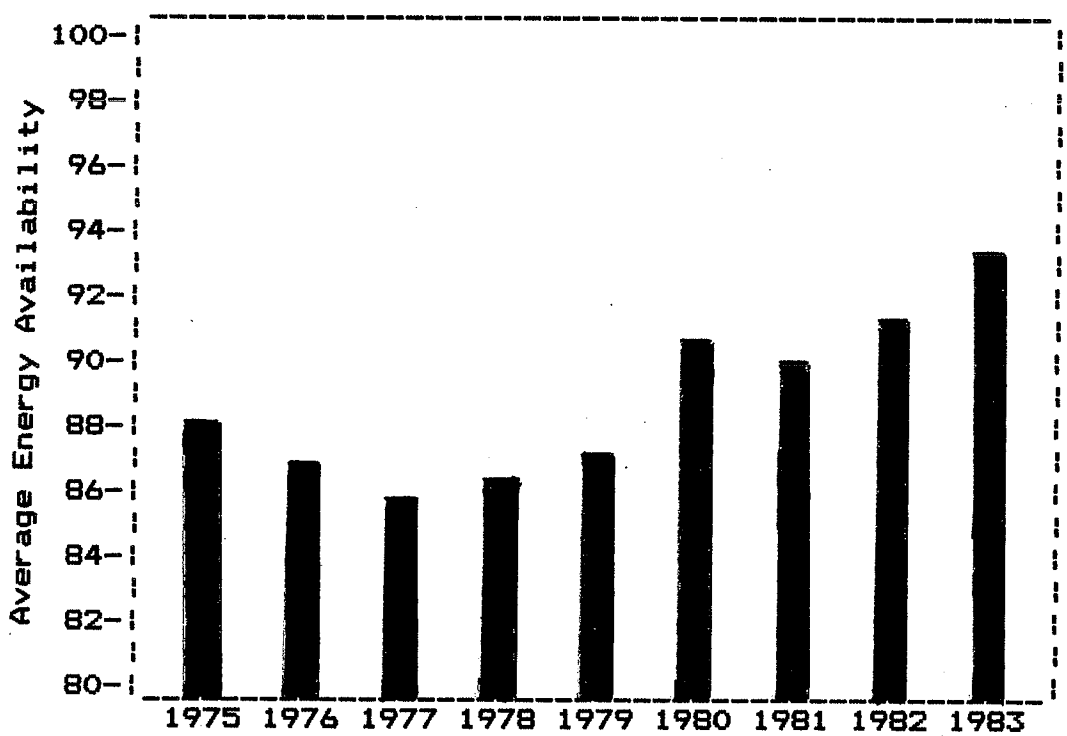


FIGURE A1-2. Energy Availability of Thyristor Valve Stations [31].

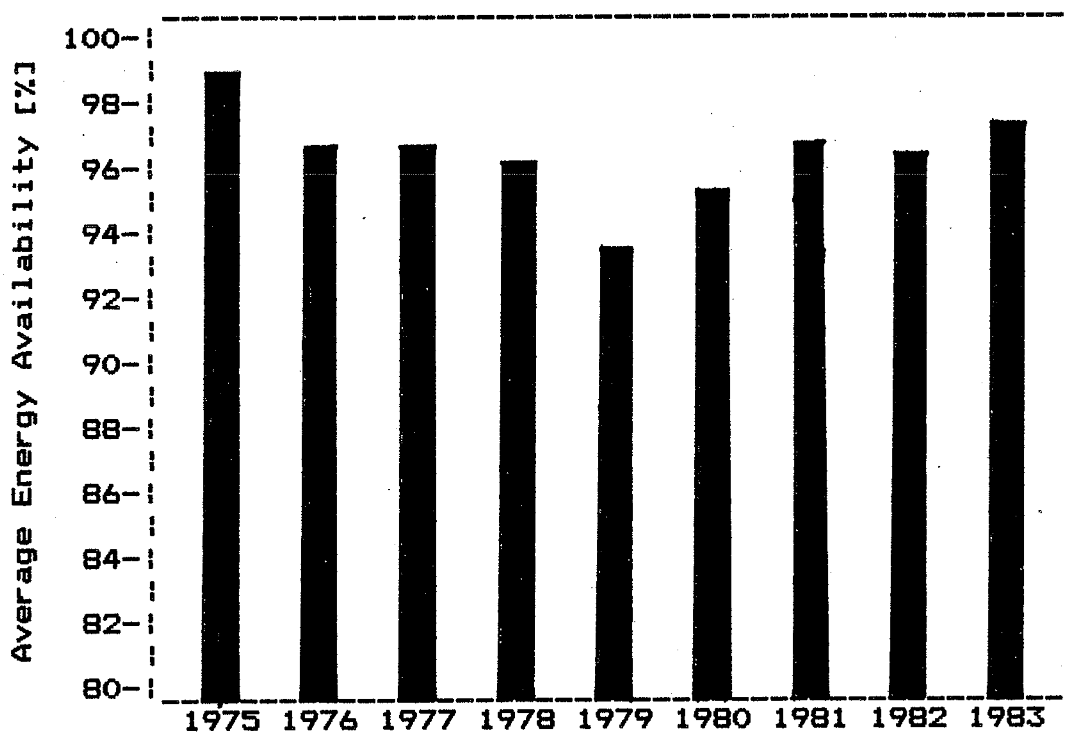


FIGURE A1-3. Average Energy Unavailability of Mercury-Arc Valve Stations [31].

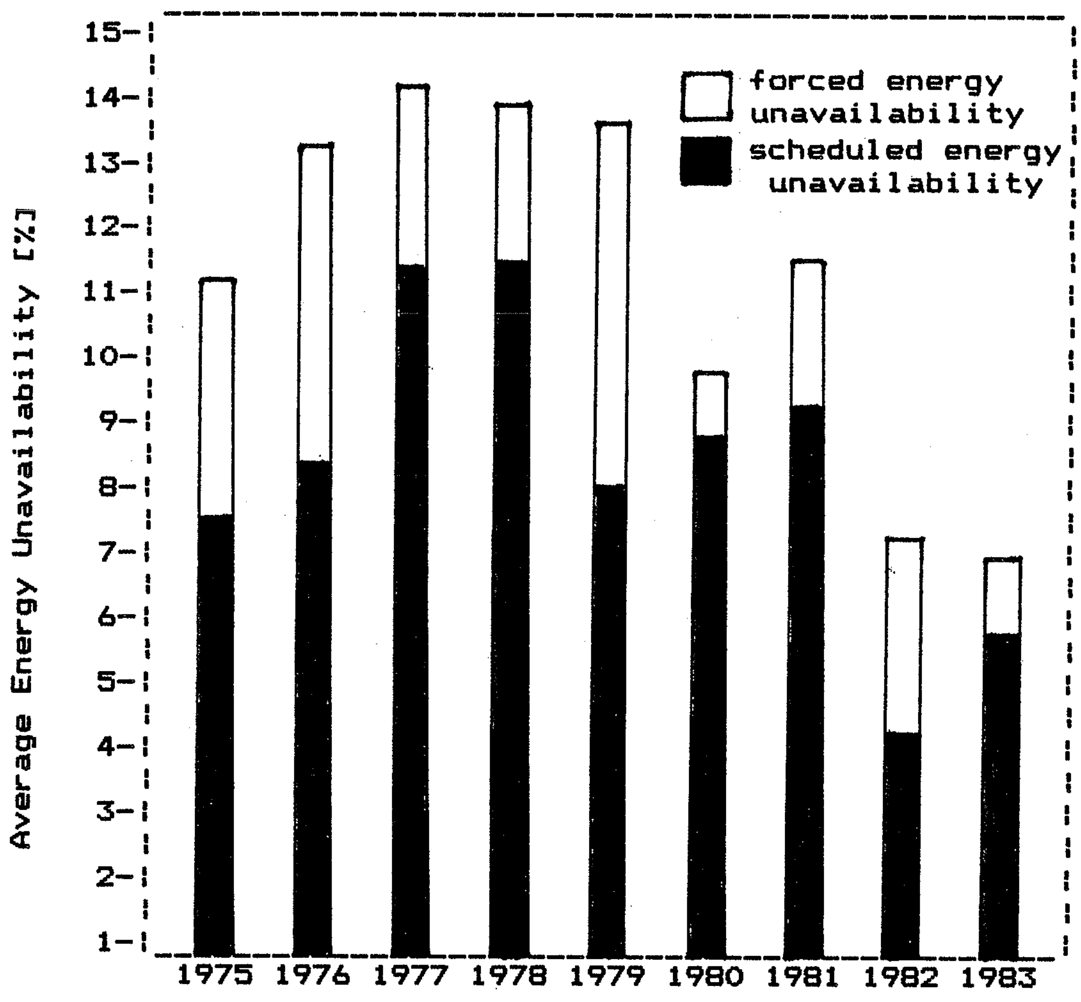
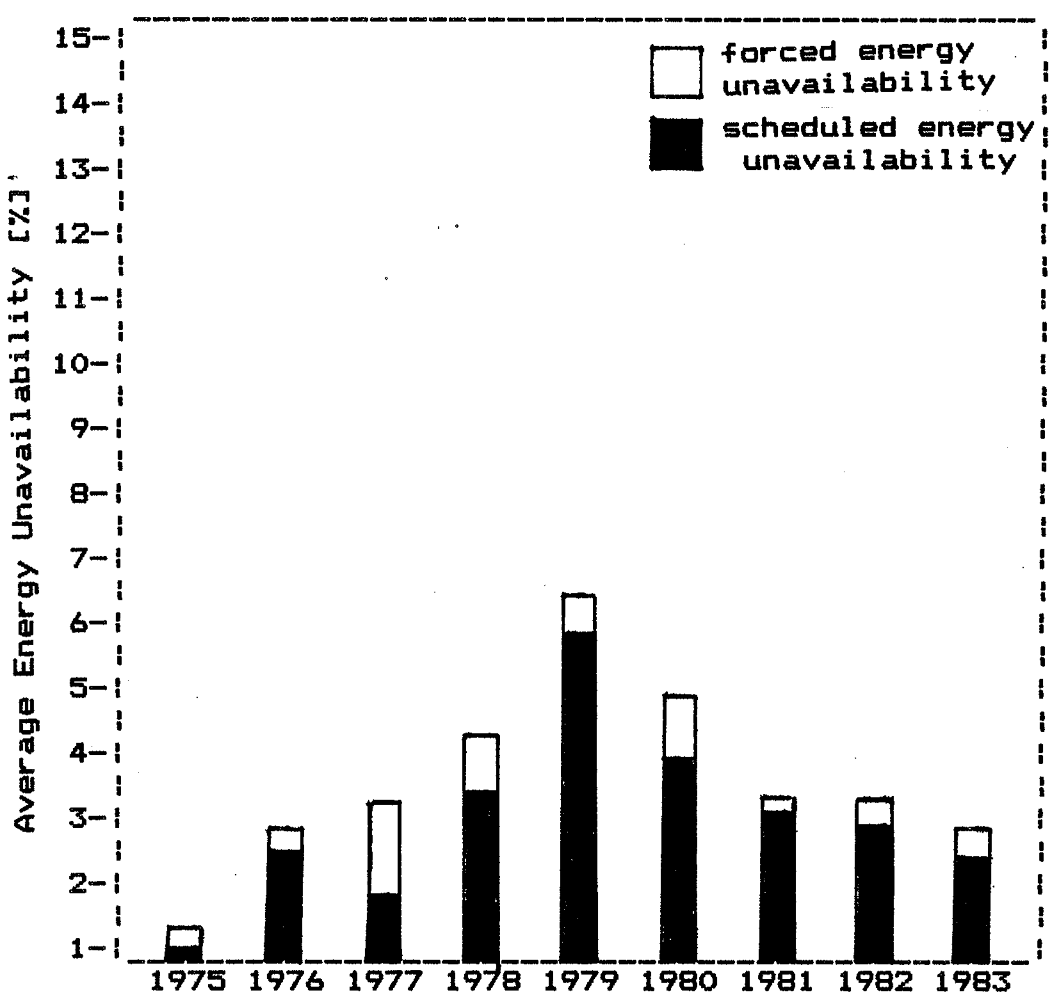


FIGURE A1-4. Average Energy Unavailability of Thyristor Valve Stations [31].



costs (due to these higher outage rates) than do thyristor valve stations.

Even though forced outages contribute only a small fraction of the energy unavailability, these outages have the greatest impact on the utility. The forced outages can be further classified by the category of equipment involved.

The thyristor valves experience a lower frequency of outages than do the mercury arc valves. However, one problem that still exists with the thyristor valve stations is the relatively high incidence of outages due to control and protection problems. This indicates that much more research work must be done in this area in order to improve the overall reliability of the thyristor valve HVDC stations.

The experience gained with thyristor schemes so far justifies the present conviction that thyristor valve stations are much more reliable than mercury arc valve stations. Excluding transmission line outages, the forced unavailability of thyristor valve systems is only about a third of that of mercury arc valve stations. Typical thyristor failure rates of less than 1 percent per year are currently achieved but they do not affect thyristor valve operation due to built in thyristor valve redundancy.

APPENDIX 2

COMPONENT DATA FOR NELSON RIVER BP2
HVDC TRANSMISSION SYSTEM

A2.1 Failure Rates

The failure rates of the components used on the Nelson River BP2 scheme were obtained from various technical notes and from the design manuals of the BP2 system. Additional information on reliability prediction was obtained from the US MIL-HBK-217: Reliability Prediction For Electronic System.

The failure rates of the various components are included in Tables A2-1 through to A2-4.

TABLE A2-1. Power Component Outage Rates
(Courtesy of Manitoba Hydro)

Component	λ [% / year]
converter transformer	5.
DC-smoothing reactor	2.
reactor (filter)	1.
resistor (filter)	1.
surge diverter (arrester)	1.
DC-voltage divider	1.
current transformer	1.
DC-current transducer	1.
el. line surge capacitor	1.
voltage discharge transformer	1.
high speed switch	0.7
capacitor unit (AC-filter)	0.23
disconnect switch	0.2
grounding switch	0.2
current transformer (convert transf)	0.2
DC-current transducer (smooth react)	0.2
capacitor unit (DC-filter)	0.1
valve hall bushing	0.1
valve surge diverter	0.1

TABLE A2-2. Electronic Component Outage Rates (Valve Control)
(Courtesy of Manitoba Hydro)

Component	$\lambda[10^{-6}$ /h]
IC-CMOS 15V	0.011 - 0.042
IC-CMOS 10V	0.011 - 0.0042
IC MHTL	0.028 - 0.086
IC operational amplifier	0.108 - 0.303
IC multiplier	1.364
IC divider	2.030
DA - converter	3.5
Ref. - amplifier	0.2
transistor bipolar Si	0.0036 - 0.108
transistor FET	0.126
diode Si	0.0046 - 0.102
diode zener	0.098
thyristor	0.055
resistor	0.002 - 0.41
capacitor	0.0001 - 0.035
relay	0.014
pulse transformer	0.005
transformer, choke	0.068
current transformer	0.068
special purpose amplifier	2.0
motor pot. meter	2.0
feeler	0.11
fuse	0.02
print with contacts	0.071
solder point	0.00044

TABLE A2-3. Electronic Component Outage Rates (DC-Control)
(Courtesy of Manitoba Hydro)

Component	$\lambda [10^{-6} /h]$
IC	0.0174 - 0.0478
diode Si	0.0053 - 0.0173
diode zener	0.0975
resistor	0.0015 - 0.0085
resistor variable	0.50 - 2.4
capacitor, paper/plastic	0.004
capacitor, ceramic	0.042
capacitor, electrolytic	0.11 - 0.468
choke	0.039
relay 100 cycles/year	0.0042 - 0.0045
relay 1 cycle/hour	0.148 - 0.178
printed circuit board	0.0006 - 0.003
socket	0.023 - 0.087
solder point	0.00044
wirewrap	0.000037
crimp	0.00025
other connection	0.0044
fuse	0.1

TABLE A2-4. Component Failure Rate For Thyristor Valves (Courtesy of Manitoba Hydro)

Component	$\lambda [10^{-6} /h]$
thyristor (power)	0.11
thyristor (small)	0.02
transistor (power)	0.025 - 0.036
transistor (signal)	0.0077 - 0.0115
Darlington	0.026 - 0.06
diode (power)	0.01 - 0.2
diode (signal)	0.003 - 0.01
BOD	0.02 - 0.045
LED	0.02
photo diode	0.0015
zener diode	0.028 - 0.05
IC (linear)	0.17 - 0.3
C - MOS	0.003 - 0.44
light guide	0.1
capacitor	0.001 - 0.036
resistor	0.0002 - 0.063
pulse transformer	0.01
differential current transformer	0.05
reactor	0.0015 - 0.021
fuse	0.02
solder connection (wave)	0.0005

APPENDIX 3

POWER COMPONENTS, VALVE CONTROL AND DC CONTROL, NELSON RIVER BP2 HVDC TRANSMISSION SYSTEM

A3.1 Power Components

The failure rate of the VG element due to the power component subsystem was determined by adding together the number of failures of each power component. The various power components belonging to the VG element are listed in Table A3-1. The total number of power components was determined by a "parts count" procedure. Similarily, the MDT/year of the VG element due to the power component subsystem was determined by adding together the MDT of each power component.

The VG element was calculated to have 3.715 failures per year and a MDT/year of 204.360 hours. Since there are eight VG elements in the bipole, the number of failures of one VG element is

$$\text{FOR (VG-p)} = \frac{3.715}{8} = .464 \text{ [failures/year]}$$

The mean down time of a VG element (due to power components) is

$$\text{MDT (VG-p)} = \frac{204.360}{3.715} = 55.0 \text{ [hours]}$$

The power components belonging to the P element are listed in Table A3-2 (dc switchyard) and in Table A3-3 (dc filters).

The number of failures of the P element per year due to the power component subsystem was calculated to be:

$$0.672 + 1.384 = 2.056 \text{ [failures/year]}$$

and the MDT/year of the P element was found to be:

$$27.648 + 33.216 = 60.864 \text{ [hours/year]}$$

Since there are four P elements per bipole, the forced outage rate of one P element is:

$$\text{FOR(PR-p)} = \text{FOR(PI-p)} = \frac{2.056}{4} = .514 \text{ [failures/year]}$$

The mean down time of the P element (due to power components) is:

$$MDT(PR\text{-}p) = MDT(PI\text{-}p) = \frac{60.864}{2.056} = 29.6 \text{ [hours]}$$

The power components belonging to the BP element are listed in Table A3-4.

The failure rate of the BP element due to power components was calculated to be 0.132 failures/year and the MDT/year of a BP element was found to be 3.168 hours/year.

Since there are two BP elements in the bipole, (one at the rectifier end and one at the inverter end), the forced outage of one BP element is:

$$FOR(BPR\text{-}p) = FOR(PBI\text{-}p) = \frac{0.0132}{2} = .066 \text{ [failures/year]}$$

The mean down time of a BP element is:

$$MDT(BPR\text{-}p) = MDT\ (BPI\text{-}p) = \frac{3.168}{.132} = 24.0 \text{ [hours]}$$

The reliability calculations were based on the following assumptions:

1. Failure of the dc filters is assumed to cause a forced outage.
2. Failure of the thyristor fault monitoring is designed not to cause a forced outage upon failure.
3. The ac filters are considered as a highly redundant system and repair is allowed during operation.
4. The MDT of the converter transformer and smoothing reactor was assumed to be 168 hours (one week). The MDT of the other power components was assumed to be 24 hours.

TABLE A3-1. VG Element Power Components
(Rectifier and Inverter Stations)

Power Component	Total	FOR [%/year]	FOR [#/year]	MDT [h]	MDT/year [h/year]
valve hall bushing	64	0.1	.064	24	1.536
grounding switch	64	0.2	.128	24	3.072
valve surge diverters	96	0.1	.096	24	2.304
valve bridge arms	96	0.47	.451	24	10.824
VBE	24	5.6	1.344	24	32.256
converter transf.	16	5.0	.800	168	134.400
current transf.	416	0.2	.832	24	19.968
Total			3.715		204.360

TABLE A3-2. P Element Power Components (DC Switchyard)
(Rectifier and Inverter Stations)

Power Component	Total	FOR [%/year]	FOR [#/year]	MDT [h]	MDT/year [h/year]
dc smoothing reactors	4	2.0	.080	168	23.440
dc current transducer	16	0.2	.032	24	0.768
dc voltage dividers	16	1.0	.160	24	3.840
surge diverters	16	1.0	.160	24	3.840
grounding switches	16	0.2	.032	24	0.768
high speed switches	16	0.7	.112	24	2.688
disconnect switches	48	0.2	.096	24	2.304
Total			.672		27.648

TABLE A3-3. P Element Power Components (DC Filters)
(Rectifier and Inverter Stations)

Power Component	Total	FOR [%/year]	FOR [#/year]	MDT [h]	MDT/year [h/year]
capacitor unit	800	0.1	.800	24	19.200
reactor	8	1.0	.080	24	1.920
resistor	4	1.0	.040	24	0.960
surge diverter	8	1.0	.080	24	1.920
current transformer	32	1.0	.320	24	7.680
disconnect switches	16	0.2	.032	24	0.768
grounding switches	16	0.2	.032	24	0.768
Total			1.384		33.216

TABLE A3-4. BP Element Power Components (Rectifier and Inverter Stations)

Power Component	Total	FOR [%/year]	FOR [#/year]	MDT [h]	MDT/year [h/year]
electrode line capacitor	4	1.0	.040	24	0.960
high speed switch	4	0.7	.028	24	0.672
dc current transducer	4	1.0	.040	24	0.960
disconnects	10	0.2	.020	24	0.480
grounding switches	2	0.2	.004	24	0.096
Total			.132		3.168

5. The same number of power components are available at the rectifier and inverter stations. The calculations were based on data collected from the rectifier station.

A3.2 Valve Control

The valve control subsystem that forms part of the VG element was subdivided into bridge controls, valve group controls and valve group monitoring. The groups were further subdivided into various functional blocks as shown in Tables A3-5 through to A3-7. The failure rate of every functional block was calculated based on a "counts type" analysis and on the failure rates of the individual components.

The number of failures of the VG element due to valve controls was calculated to be:

$$5.360 + 1.467 + 1.960 = 8.787 \text{ [failures/year]}$$

Since there are eight VG elements per bipole, the failure rate of one VG element is:

$$FOR(VG\text{-}v) = \frac{8.787}{8} = 1.098 \text{ [failures/year]}$$

The mean down time of a VG element due to the valve control subsystem was assumed to be four hours, i.e.:

$$MDT(VG\text{-}v) = 4 \text{ [hours]}$$

The valve control subsystem that forms part of the P element can also be subdivided into functional blocks as shown in Tables A3-8 through to A3-12.

The number of failures of the P element at the rectifier stations due to valve control problems was calculated to be:

TABLE A3-5. VG Element, Valve Control Subsystem
(Bridge Controls for Rectifier and Inverter Stations)

Functional Blocks	FOR [1 / year]
current signals	.656
extinction angle measurement	.384
commutation failure detection	.608
pulse logic	.384
valve firing monitoring	.992
differential and o.c. protection	.432
current transformer monitoring	.384
power supply	1.520
Total	5.360

TABLE A3-6. VG Element, Valve Control Subsystem
(Group Control for Rectifier and Inverter Stations)

Functional Blocks	FOR [1 / year]
short circuit current control	.128
reference input preset	.168
control loop switch over	.115
group voltage control	.104
extinction angle control	.328
formation of controlled variable	.048
disturbance compensation	.032
gate pulse controller	.536
dc voltage control limitation	.008
Total	1.467

TABLE A3-7. VG Element, Valve Control Subsystem
(Group Monitoring For Rectifier and Inverter Stations)

Component	FOR [1 / year]
by-pass switch	.048
group voltage	.168
commutation voltage	.056
undervoltage switching program	.080
pulse blocking	.112
overcurrent switching program	.080
differential protection	.112
valve excess voltage	.168
ac breaker tripping	.136
control angle	.200
power supply	.448
cubicle temperature	.008
release of current controller	.160
switch off programs	.104
60 hz clock	.080
Total	1.960

TABLE A3-8. P Element, Valve Control Subsystem
(Line Protection For Rectifier and Inverter Stations)

Functional Blocks	FOR [1 / year]
wave front detection I	.009
line differential protection	.005
open line detection	.002
wave front detection II	.010
line protection automatic	.003
paralleling start initiation	.002
fault section determination	.012
parallel synchronization	.002
Total	.045

TABLE A3-9A. P Element, Valve Control Subsystem
(Transformer Tapchanger Controls, Rectifier Station)

Functional Blocks	FOR [1 / year]
automatic control of transformer setting	.180
function groups of the transformer setting	.095
Total	.275

TABLE A3-9B. P Element, Valve Control Subsystem (Transformer Tapchanger Controls, Inverter Station)

Functional Blocks	FOR [1 / year]
voltage regulation	.147
commutation margin regulation	.145
Total	.292

TABLE A3-10. P Element, Valve Control Subsystem (Current Reference Input and Id Automatic Control, Rectifier Station)

Functional Blocks	FOR [1 / year]
current reference input from other station	.047
selection of manual Id reference inputs	.021
Id reference inputs reduction	.037
Id reference inputs selection	.040
adoption of the Id - reference inputs	.017
current regulator	.058
voltage control	.022
pole differential protection	.010
Id - detection	.019
power supply	.050
Total	.321

TABLE A3-11. P Element, Valve Control Subsystem
(Id Regulation and Compensation Regulation,
Inverter Station)

Functional Blocks	FOR [1 / year]
forming current reference	.050
current and voltage regulation	.073
current reference during paralleling	.027
current balance control	.081
over current protection	.062
pole differential protection	.011
power supply	.050
Total	.354

TABLE A3-12. P Element, Valve Control Subsystem (Power Advance and Current Value, Inverter Station)

Functional Blocks	FOR [1 / year]
power order setting from LDO	.022
power order from inverter desk	.017
Pmax from inverter desk	.018
Pmax (fixed)	.033
Pref from "Excess Po Transfer Circuitry"	.015
current value from power control	.005
manual set values of the current	.004
current reference	.026
reducing current reference	.003
ground current compensation control	.009
supplementary set value of the current	.004
Total	.156

$$\frac{.045}{2} + .275 + .321 = .619 \text{ [failures/year]}$$

Since there are two P elements at the rectifier, the failure rate of one P element is:

$$FOR(PR\text{-}v) = \frac{.619}{2} = .309 \text{ [failures/year]}$$

The number of failures of the P element at the inverter station due to valve control was calculated to be:

$$\frac{.045}{2} + .292 + .354 + .156 = .825 \text{ [failures/year]}$$

Since there are two P elements at the inverter station, the failure rate of one P element is:

$$FOR(PI\text{-}v) = \frac{.825}{2} = .412 \text{ [failures/year]}$$

The mean down time of the P element at both the rectifier and inverter stations was assumed to be four hours, i.e.:

$$MDT(PR\text{-}v) = MDT(PI\text{-}v) = \text{[4 hours]}$$

A3.3 DC Control

The dc control subsystem was broken down into several functional blocks as shown in Table A3-13 and Table A3-14.

The failure rate of the VG element due to the dc control subsystem was calculated to be 1.080 failures/year. Since there are eight VG elements in the entire bipole, the failure rate of one VG element is:

$$FOR(VG\text{-}d) = \frac{1.080}{8} = .135 \text{ [failure/year]}$$

The failure rate of the P element due to the dc control subsystem was calculated to be 1.347 failures/year. Since there are four P elements altogether, the failure rate of one P element is:

$$\text{FOR(PR-d)} = \text{FOR(PI-d)} = \frac{1.347}{4} = .337 \text{ [failures/year]}$$

The mean down time of both the VG and P elements was assumed to be four hours, i.e.:

$$\text{MDT (VG-d)} = \text{MDT (PR-d)} = \text{MDT (PI-d)} = 4 \text{ [hours]}$$

The reliability calculations were also based on the assumption that the dc control subsystem at the inverter station is identical to the dc control subsystem at the rectifier station.

TABLE A3-13. VG Element, DC Control Subsystem
(Rectifier and Inverter Stations)

Functional Blocks	FOR [1 / year]
group switching control	.371
tapchanger controls	.460
group preliminary selection	.107
LVHS switch control	.142
Total	1.080

TABLE A3-14. P Element, DC Control Subsystem
(Rectifier and Inverter Stations)

Functional Blocks	FOR [1 / year]
dc filter switching control	.367
start/stop synchronization	.289
various switch controls	.472
key interlocking	.219
Total	1.347

APPENDIX 4

CALCULATION OF THE FAILURE RATE RATE, MDT, UNAVAILABILITY AND AVAILABILITY OF EACH ELEMENT

CALCULATIONS:

1. BPR Element

$$FOR(BPR) = FOR(BPR\text{-}p) = .066 \ [1/year]$$

$$MDT(BPR) = MDT(BPR\text{-}p) = 24.0 \ [hours]$$

$$\overline{A}(BPR) = (FOR(BPR) \cdot MDT(BPR)) = (.066)\ (24) = 1.58 \ [hours]$$

$$A(BPR) = (1 - \frac{1.58}{8760})\ 100\% = 99.9820\%$$

2. BPR Element

$$FOR(BPI) = FOR(BPI\text{-}p) = .066 \ [1/year]$$

$$MDT(BPI) = MDT(BPI\text{-}p) = 24.0 \ [hours]$$

$$\overline{A}(BPI) = (FOR(BPI) \cdot MDT(BPI)) = (.066)\ (24) = 1.58 \ [hours]$$

$$A(BPI) = (1 - \frac{1.58}{8760})\ 100\% = 99.9820\%$$

CALCULATIONS:

3. PR Element

$$\mathrm{FOR(PR)} = \mathrm{FOR(PR\text{-}p)} + \mathrm{FOR(PR\text{-}v)} + \mathrm{FOR(PR\text{-}d)}$$
$$= 514 + .309 + .337$$
$$= 1.160 \text{ [1/year]}$$

$$\mathrm{MDT(PR)} = \frac{\mathrm{FOR(PR\text{-}p)MDT(PR\text{-}p)+FOR(PR\text{-}v)MDT(PR\text{-}v)+ FOR(PR\text{-}d)MDT(PR\text{-}d)}}{\mathrm{FOR(PR)}}$$
$$= \frac{(.514)(29.6) + (.309)(4) + (.337)(4)}{1.160}$$
$$= 15.3 \text{ [hours]}$$

$$\overline{A}\mathrm{(PR)} = \mathrm{(FOR(PR))\ (MDT(PR))}$$
$$= (1.160)\ (15.3)$$
$$= 17.75 \text{ [hours]}$$

$$A\mathrm{(PR)} = (1 - \frac{17.75}{8760})\ 100\% = 99.7974\%$$

4. PI Element

$$\mathrm{FOR(PI)} = \mathrm{FOR(PI\text{-}p)} + \mathrm{FOR(PI\text{-}v)} + \mathrm{FOR(PI\text{-}d)}$$
$$= 514 + .412 + .337$$
$$= 1.263 \text{ [1/year]}$$

$$\mathrm{MDT(PI)} = \frac{\mathrm{FOR(PI\text{-}p)MDT(PI\text{-}p)+FOR(PI\text{-}v)MDT(PI\text{-}v)+ FOR(PI\text{-}d)MDT(PI\text{-}d)}}{\mathrm{FOR(PI)}}$$
$$= \frac{(.514)(29.6) + (.412)(4) + (.337)(4)}{1.263}$$
$$= 14.4 \text{ [hours]}$$

$$\overline{A}\mathrm{(PI)} = \mathrm{(FOR(PR))\ (MDT(PR))}$$
$$= (1.263).(14.4)$$
$$= 18.19 \text{ [hours]}$$

$$A\mathrm{(PI)} = (1 - \frac{18.19}{8760})\ 100\% = 99.7974\%$$

5. VG Element

$$FOR(VG) = FOR(VG\text{-}p) + FOR(VG\text{-}v) + FOR(VG\text{-}d)$$

$$= 464 + 1.098 + .135$$

$$= 1.697 \text{ [1/year]}$$

$$MDT(VG) = \frac{FOR(VG\text{-}p)MDT(VG\text{-}p)+FOR(VG\text{-}v)MDT(VG\text{-}v)+ FOR(VG\text{-}d)MDT(VG\text{-}d)}{FOR(VG)}$$

$$= \frac{(.464)(55.0) + (1.098)(4) + (.135)(4)}{1.697}$$

$$= 17.94 \text{ [hours]}$$

$$\overline{A}(VG) = FOR(VG)\ MDT(VG)$$

$$= (1.697)\ (17.94)$$

$$= 30.45 \text{ [hours]}$$

$$A(VG) = (1 - \frac{30.45}{8760})\ 100\%$$

$$= 99.6524\%$$

APPENDIX 5

ENERGY AVAILABILITY CALCULATIONS

CALCULATIONS:

1. LOTC(25%) = (1.697)(8) = 13.58 [outages]

AOD(25%) = 17.94 [hours]

In this case AOD(25%) = MDT(VG)

2. LOTC(50%) = (1.160)(2) + (1.263)(2) + (5.0)(2)

= 14.85 [outages]

AOD(50%) = 1.0 h

Since the transmission line outages have the greatest impact in this category, the average outage duration is approximately equal to MDT(TLM). For a general reliability analysis, such an approximation is satisfactory.

3. LOTC(100%) = 0.066 + 0.066 + .54 = 0.67 [outages]

AOD(100%) = 6.3 [hours]

The bipolar transmission line outage rate contributes the most to this category, i.e.:

AOD(100%) = MDT(TLBP)

4. $$A(100\%) = \left[1-\left(\frac{(.67)(6.3)+(14.85)(1.0)+(13.58)(17.94)}{8760}\right)\right]100\%$$

$$= 97.0012$$

5. $$A(75\%) = \left[1-\left(\frac{(.67)(6.3)+(14.85)(1.0)}{8760}\right)\right]100\%$$

$$= 99.7823\%$$

6. $A(50\%) = [1-(\frac{(14.85)(1.0)}{8760})]100\%$

$= 99.8305\%$

7. $A(25\%) = [1-(\frac{(.67)(6.3)}{8760})]100\%$

$= 99.9518\%$

8. $A(0\%) = 100\%$

9. $\text{Energy (AVG)} = \frac{97.0012 + 99.7823 + 99.8305 + 99.9518}{4}$

$= 99.1415\%$

10. Energy Unavailability $= 100 - 99.1415\%$

$= 0.8586\%$