TRANSMISSION OF ELECTRICITY
FROM WAVE POWER DEVICES

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This report assesses the problems likely to be encountered in transmitting bulk electrical energy from a source tens of kilometres offshore to the mainland of the United Kingdom.

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CONTENTS

APPENDICES

TABLES

FIGURES

1 GENERATION AND CONVERSION PLANT

1.1 D.C. Generator

The d.c generator consists of a salient pole stator field system and a rotational armature. The latter feeds d.c. through brushgear and a copper commutator. The voltage produced at the armature is directly proportional to the speed of the machine, neglecting losses, and also to the level of field excitation.

Unfortunately, the commutator requires frequent maintenance because of sparking during commutation at the brushends. This may also prove a problem in explosive environments. Flame-proofed machines are available but expensive due to the frame size being larger than that for a conventional machine of the same horse-power. Because of the commutator, the d.c. generator is limited in terminal voltage and speed. These are approximately 1000 V and 3000 rev/min respectively.

In the application considered it may be possible to install up to 10 equal-rated generators in each concrete structure. This would require each generator to be rated at say 4000 kW which is within the maximum obtainable d.c. generator rating. However, it is preferable to transmit at high voltages of say 100 kV. Therefore, because of the limitation of maximum generated voltage of d.c. machines and the maintenance problem associated with the commutator, d.c. generation plant will not be considered further.

1.2 A.C. Generator

The a.c. generator would certainly be a synchronous machine with a d.c. field excitation system on the rotor. The d.c. is fed to the field windings by slip rings and a brushgear assembly. However, as the current fed to the rotational windings is small in comparison with the d.c. machine and no commutator exists, maintenance problems are minimal.

As with the d.c. generator, the synchronous generator terminal voltage can be controlled by the level of field excitation. However, it is the ability of the a.c. generator to operate at unity or leading power factor which makes it a useful machine. It can therefore be used to improve the power factor of a system.

Several different synchronous generator rotor constructions can be obtained and their use depends on the application. Until the exact rating, speed and starting information have been decided, the particular rotor arrangement cannot be determined. The different classes of rotor and applications will therefore only be discussed briefly.

There are two general types of rotor construction; the salient-pole and the cylindrical or non-salient pole rotor. The salient-pole construction can be used to generate large powers but at reasonably low speeds due to the problem of the rotor centrifugal forces, whereas the cylindrical rotor type can be used up to very high speeds. The salient-pole machine tends to be shorter and larger in diameter than the cylindrical machine.

In the application considered, the starting of the generators does not impose a great problem as this can be carried out by wave power. It may therefore not be necessary for the generator to have special starting windings of the induction type. However, they may exist if damper windings are considered necessary.

Because of conductor size, slot widths, insulation thickness, etc., there is a minimum economical machine size for each terminal voltage. For example, a 250 h.p. generator would operate at 6.6 kV, whereas a 1000 h.p. generator may operate a 11 kV. This decision is however not restricted to the machine design as the capital cost of switchgear and transformers at each voltage must be considered. In the application the machine may generate at either 3.3 kV or 6.6 kV.

1.3 Conversion and Terminal Equipment

Where multi-machine systems are considered, the individual generators must be connected in parallel or series. In each concrete structure the individual machines would be synchronised and the output fed to a transformer on some floating switching station. This is shown in Fig. 1. The starting of the generators could be carried out, for example, by starting one machine by utilising wave power. This motor would be made to operate at, say, the national grid frequency of 50Hz. The other machines could be started by the same means and then synchronised with the first machine. The operating frequency of the complete system must be the same, and if transmission by a.c. is considered this frequency must be that of the national grid. Electrical

starting from one machine

to another is possible but the initial machine would still be started by hydraulic means. This is because it may not be realistic to permit two-way power flow from the mainland, especially if d.c. transmission is considered.

The output from each structure would be fed to a separate 3-ph step-up transformer. The step-up ratio and connection of each transformer would depend on the transmission method. If a.c. transmission is utilised each transformer output may be paralleled and the voltage stepped up to say 132kV or 275kV. At the mainland terminal a further transformer would connect the complete system to the national grid. This system is shown in Fig. 2. In this arrangement there is no need to group machines or structures as the complete system is effectively in parallel. This arrangement also permits the removal of any single unit for servicing or fault reasons.

It is not practical to connect a 3-ph a.c. system in series unless for the purposes of d.c. transmission. For d.c. transmission the a.c. must be rectified first using a high-voltage valve or diode bridge rectifier assembly. The high d.c. voltage level required for effective transmission can be accomplished by connecting several of these rectifier assemblies in series, as shown in Fig. 3. The number of units connected in series will obviously depend on the transmission voltage and the voltage level of each rectifier. It would be possible to connect one rectifier to the output transformer of each 'duck'. In this way maximum system reliability can be obtained and the loss of any one unit would have a small effect on the transmission voltage level. Any unit can be removed by closing the by-pass switch. When a.c. rectification occurs the d.c. is not smooth but has a ripple superimposed on the d.c. For a 6 pulse rectifier arrangement the ripple frequency is 300 Hz. A 12 pulse arrangement would give a smaller ripple amplitude and the frequency would be 600 Hz. This is preferable and can be obtained by arranging the transformer secondaries alternately in star and delta.

Flow of power cannot be reversed when a diode bridge is employed. However, this is not necessary in this application as the floating power station does not consume power to any great extent, and if it did then this could be provided by its own generators. Two-way power is possible using thyristor bridges but it would be more expensive.

At the mainland terminal it is necessary to convert the d.c. to a.c. for connection to the national grid. A thyristor or controlled valve line-commutated inverter would be employed to do this. Again, to improve reliability several inverters could be used as shown in the complete system in Fig. 4, the inverters being connected in series each feeding its own transformer.

Note that in high-voltage series converting equipment the units at the end of the string would be operating at very high potentials. There is obviously a safety problem.

2. COMPARISON OF A.C. AND D.C. FOR SUBMARINE TRANSFER

Since 1900 most electrical power systems have operated on a.c. because of its convenience for local distribution and of the relative ease of switching compared with d.c. It was therefore logical that the first submarine cable links should also use a.c. and the world's first d.c. link was not build until 1954. This link between Sweden and Gotland is 100 km long and operates at 100 kV. Table 1 gives details of more recent d.c. links, and those planned for the near future are detailed in Table 2.

Before discussing the relative merits of the different systems it is worth considering briefly the design of a submarine cable, since this will be a major component in any scheme.

In designing submarine cables, the following must be considered:

(a) the size and weight of the cable should be as low as possible to allow ease of handling during manufacture, transportation and laying.
(b) the number of joints should be as few as possible
(c) the cable should be strong enough to withstand the tensions of laying and recovery, flexing and abrasion.
(d) the construction must be such as to prevent corrosion
(e) the design should be simple to allow easy and quick joining at sea
(f) production costs should be as low as possible

The thickness of insulation is dictated by the cable working voltage and the current-carrying capacity by the maximum permissable temperature rise of the conductors, the thermal resistance of the various elements in the cable construction and the ambient temperature of the sea.

Electrical failure or breakdown of the cable insulation can occur by instantaneous puncture, by thermal instability or by long-term degradation due to ionic discharges in any voids in the insulation. Such voids are caused by trapped gas or air during manufacture, rough treatment or continuous load cycling.

To reduce the long-term breakdown, most high-voltage cables use a solid dielectric impregnated with low-viscosity mineral oil. If the oil is supplied via oil-filled ducts running inside the cable close to the conductors, the cable can be kept in service even if the sheath is punctured provided that the oil pressure is maintained.

Alternative methods of filling voids are pressurising with dry gas, usually oxygen-free nitrogen, which has attractive insulating properties, or by applying pressure through an elastic medium to the cable dielectric so that on cooling the sheath returns to its original state (e.g. compression cables). Fig. 5 shows the grouping of different forms of void control.

"Mollerhog" cables lie between the categories of compression and oil-filled cables. Here stranded conductors are screened with colloidal carbon paper tape and three insulated and screened cores are laid side by side in flat formation and enclosed in a lead sheath which has flat sides and semicircular ends.

The combination of lead sheath and corrugated tapes act as an elastic membrane which expands and contracts with increasing and decreasing conductor temperature and prevents void formation. Longitudinal channels for oil flow under load conditions lie between the centre and outer conductors and the sheaths. External oil feeding equipment is unnecessary in this type of cable.

Plastic or rubber insulation can be used for submarine cables and in this case metal sheaths are not required. However, with polythene insulation it has been found difficult to eliminate voids during manufacture so above 100 KV impregnated paper still seems to be the most reliable insulant.

With impregnated paper, lead sheaths are usually used and these have to be protected against corrosion. For armour, aluminium wires have been found to be the most resistant to corrosion and many have withstood long service.

Before detailing possible transmission schemes, some comments about the limiting factors should be made. To lay a submarine cable is expensive and difficult and requires a specially equipped vessel and relatively calm seas. The cable should be laid where the sea-bed is relatively flat and free from abrasive rocks and should be brought ashore on a gently sloping beach. At a point several hundred metres from the shore it is necessary to increase the cable conductor diameter to ensure adequate current-carrying capacity as the ambient temperature rises.

Jointing of cables is done at sea and techniques are available to ensure the joint is at least as good electrically and mechanically as the rest of the cable. Repairs are possible but they are time consuming and expensive. It may take four to five weeks to restart operation and cost tens of thousands of pounds.

3 ALTERNATING OR DIRECT CURRENT SCHEME

The maximum length of an a.c. submarine cable is generally governed by the quadrature current required to charge the cable capacitance. Unlike land installations, it is impossible to include power-factor correction equipment at intervals along a submarine cable-run. The decision as to the maximum tolerable quadrature current depends very much on the operational characteristics of the installation and often a value judgement has to be made between investing in d.c. equipment or installing an a.c. system with increased current-carrying capacity. Such an increase will result in the a.c. cable having a conductor of larger cross-section than the corresponding d.c. cable.

Appendix I gives details of the relative efficiencies of use of copper for each system.

In addition for a.c. the cable insulation is stressed to the peak operating voltage whereas the power transmitted is proportional to the root mean square voltage (rms = peak voltage divided by $\sqrt{2}$). In the d.c. case with rms and peak voltage the same, less insulation and hence lower weight and cost gives the same power-transfer capability.

An a.c. link operates successfully only if there is sufficiently close frequency control of each of the two systems linked, and the load capacity of the link is not too small compared with the plant capacity. Also a.c. transmission has the disadvantage that control of flow over parallel circuits is not possible without series and quadrature boosters which allow equal amounts of series and quadrature power to flow in each of the parallel circuits.

It is therefore possible that while the total inter-connection capacity may be sufficient for the desired transfer, one particular circuit, by carrying more than its share, may restrict the total transfer capacity.

On the other hand, d.c. transmission over a circuit with converters at each end permits satisfactory control over the transfer. There is no need for a.c. systems linked with d.c. to operate directly in step. They may be at different frequencies as in the Cross-Channel Link, where the transfer can be set to a predetermined value and the transfer will be maintained irrespective of variation in the frequency of the two systems. Any fault level will bring out the circuit-breakers protecting the converter equipment.

The limiting case of transfer between two such systems arises when the importing system has no generating plant at all, a 'dead' load, over a d.c. connection. This would be the case if eventually the whole country were supplied by wave power generators. In such circumstances it would be necessary to provide synchronous capacitors, possibly supplemented by static capacitors, to meet the whole demand for quadrature power. Synchronous capacitors require suitable control to maintain the frequency of a system without generating plant. This reactive KVA is in addition to the demand by the rectifier and inverter plant for reactive KVA which may well amount to some 60% of the link capacity.

Taking the pessimistic case of a dead load system rated, say, at 400 MW over a d.c. circuit, the local reactive demand necessary would amount to some 240 MVAR to meet the requirements of the rectifiers and say another 240 MVAR to meet the requirements of the system. In other words, a demand of 480 MVAR must be provided to meet a load of 400 MW. The supply of a dead load for the d.c. link is therefore somewhat less attractive than the use of a link between two relatively large systems each with its own generating plant.

Fig. 6 shows a histogram of submarine cable installations from the mid-1930's to the present. Fig. 7 shows the number of installations operating at a given voltage level. The use of d.c. has clearly been for larger distances and higher voltages and hence power transfer. Transmission voltages of 200-250 kV are now being employed over distances of 100 km and more.

4 THE EARTH CONDUCTOR OF THE D.C. SYSTEM

The ground or the sea is an excellent return conductor for a d.c. line. No inductive effect forces the current to follow the line route near the surface as is the case with a.c. By contrast, the d.c. current, following the path of least resistance, penetrates into the good conducting interior of the earth or sea, leaving noticeable effects only in the vicinity of the earth electrodes.

The fundamental d.c. link has only one insulated conductor with plus or minus polarity, while the other pole of each terminal is connected to an earth electrode. Several high voltage d.c. submarine-cable installations have been constructed in this way. Two insulated conductors can also be used, each unearthed at either end. If opposite polarities are chosen for the line conductors, the earth or sea will carry zero current as long as the currents in the two poles are equal.

It should be noted however that each of the two poles can generally be regarded as an independent transmission line in which the earth is arranged to take care of the current difference. To safeguard optimum reliability, the terminal equipment, including to a large extent the auxiliaries, controls and protection, are made separately and individually for each pole and generally for each converter unit.

A typical anode installation would be of graphite bars immersed in the sea. Each cylindrical bar is made of graphite impregnated with linseed oil and is normally about 2 m in length and 10 cm in diameter. Barriers must be constructed around the electrodes at a distance which corresponds to a local electric field strength of about 1.5 Vm^{-1}. This should be low enough to avoid involuntary attraction (electrotaxis) of fish to the anode.

Decomposition rates of anode bars are about 20 g per 1000 Ah and it is normal to replace a bar when 75% of its weight is consumed.

Consideration must be given to magnetic anomalies which can have a detrimental effect on ships using magnetic compasses on the surface. For example, the Admiralty insist that the Cross-Channel Link should at no time produce a compass deflection exceeding two degrees.

5 COST COMPARISON

An economic appraisal of a.c. and d.c. systems is complicated because of the number of factors to be considered.

5.1 Capital Costs

In a d.c. system one of the major items of expenditure is the terminal equipment which would cost about £30 per kW at sending and receiving ends for bidirectional power flow. However, d.c. cable is much cheaper than the equivalent a.c. cable. On purely economic grounds a balance is reached at a certain line length depending on whether overhead, underground or submarine links are being considered.

Terminal equipment varies depending on the type of scheme to be used. In the d.c. case transformers and conversion equipment are required at both ends, while it is possible to have a busbar at one or both ends of the line for a.c. This would avoid the necessity for terminal transformation and reduce capital costs.

The relative costs are best compared using an example. However, it must be borne in mind that each installation should be assessed on its own merits and the example is merely illustrative.

Fig. 8 has been drawn to an arbitrary scale. It shows the cost of providing a firm connection of 400 MW over distances up to 60 km. The breakeven distance for d.c. appears to be about 50 km. Fig. 9 shows the effect of a 10% change in d.c. costs and a 5% change in a.c. costs since d.c. costs are more uncertain than a.c. The only real conclusion is that over short distances a.c. is cheaper and over very long distances d.c is cheaper. These figures refer exclusively to capital costs (see Appendix III).

5.2 Load Factor

The load on a power system will vary from time to time during any given period; the relationship between the actual load during the period and the load assuming the maximum value to be maintained throughout the period is given by the load factor. For the present purposes, the load factor is defined as the actual energy delivered from the scheme divided by the energy delivered if the scheme were operating continuously at maximum output.

Since the unit cost will be dependent upon the load factor of the system, methods of increasing the load factor must be studied.

5.3 Civil Costs

For the scheme considered, an installed generating capacity equivalent to 50 kWm^{-1} incident wave power density and a duck diameter of 10m were assumed. Fig. 10 shows that for such a scheme the mean annual return is 28kW/m, i.e. the load factor would be 56%.

If a larger diameter duck were considered, the load factor would increase (see Fig. 10) but the capital cost of the civil works involved would also increase.

Alternatively, if a higher electro-hydraulic rating were used, then the output per unit length would increase but the load factor would decrease.

A balance between the duck diameter and the associated power density must be drawn in order to optimise any design. Appendix II gives details of a method of assessing the unit cost in terms of the parametric variables and typical calculations, the results of which have been plotted in Figs. 11 and 12.

5.4 Electrical Costs

Fig. 13 shows the variation of total unit cost with load factor for the system considered for interest rates of 10% and 15%. Since the a.c. and d.c. costs are sensibly the same (Appendix III), this figure may be considered as representing the costs of each scheme. It appears that such schemes can deliver electrical energy to the shore at unit costs of a few pence, depending on load factor and required annual return.
Such unit costs are almost certainly somewhat higher than those of other electrical generating systems (e.g. coal or oil) but probably not sufficiently higher to rule our wave generation completely as uneconomic. It should also be noted that no attempt has been made to minimise costs for the present so some reduction of unit costs should be possible.

6 ROUTE FOR TRANSMISSION

Several possibilities exist for the route of the transmission of the generated power. The initial tens of kilometres must obviously be submarine cable but alternatives are available after this point.

6.1 All Submarine to England

This would involve a submarine cable run of a minimum of about 800 km from west of the Hebrides to somewhere near Liverpool, at which point a connection into the national grid system could be made. The advantage of this would be that power could be fed into the grid reasonably near the Midlands of England, one of the main load centres. Transmission to the conurbations in the South-East would be via the existing network. The disadvantages primarily involve cost and reliability. The probability of loss of supply on a run of this length would be relatively high (see Section 7) and the cost extremely high, if not prohibitive.

6.2 Submarine Cable to the Mainland of Scotland

If the cable were brought ashore say on the West coast of Argyll direct connection to the Scottish grid would be possible, although considerable reinforcement would be necessary to allow transmission to the main load centres to the south. The cable run in this scheme would be about 300 km and the above comments on reliability and cost apply here too. The cost of reinforcement of the existing grid would also be considerable.

6.3 Submarine Cable to the Hebrides

If the submarine cable were brought ashore at the nearest land, the Hebrides, the transmission could run overland across the island, submarine to Skye and then overland to the mainland. The scheme could be d.c. up to the point of connection to the main grid system. Considerable savings would be made by transmitting overland on towers and the reliability of the system would be improved by having the minimum length of submarine cable. However, a large overhead transmission line would have to be erected across the Highlands and considerable environmental opposition can be expected. If this can be overcome and the transmission line sited so as to cause minimum disturbance to the countryside, this scheme appears at first sight to be the most attractive both on cost and reliability.

7 RELIABILITY

If a large proportion of the electricity supply of the U.K. is to be met from wave power, a major consideration is the reliability of such a scheme. One convenient method of expressing reliability is a percentage availability of plant. Since supply from a given system is unavailable if any part of a series chain is lost, each of the items of electrical plant must be examined separately. Two types of loss of availability must be considered; scheduled outages for maintenance and special testing and unplanned outages due to faults.

7.1 Alternators

Servicing on the alternators used would be minimal if conventional design machines were chosen. On average three days per year would be needed for scheduled outages, and unplanned outages should be negligibly small in number.

7.2 Transformers

Operational experience with transformers manufactured to standard design has shown that they are extremely reliable with unplanned outages in the region of one every few tens of years on average. Routine maintenance would require removing each transformer from service about three days each year, but this could be done at the same time as the alternator servicing.

7.3 Submarine Cable Link and Terminal Equipment

An analysis of the more complex d.c. link will give a worse case figure for availability, the a.c. being at first sight inherently more reliable.

The availability figures for existing d.c. submarine schemes in Table 3 take account of power transfer limitations arising from all causes, including scheduled outages for maintenance and special testing in accordance with the accepted definitions. In 1970 the average annual equivalent availability for all systems for 82%, in 1971 this figure had risen to 86% and by 1972 it was 91%.

Since the availability is calculated on a 100% capacity basis for a two-terminal transmission and does not take into account the duplicity of plant normally appropriate to the a.c. transmission system, and bearing in mind that in some cases the availability would have been higher if the plant had in fact been required, the figures are in reality encouraging.

In many cases the justification for using HVDC has been that long submarine cables, or long overhead lines through regions where access is difficult during at least part of the year, are required. While the fault rate on these might be no higher than on shorter routes, the repair time for failures invariably is, and this has a direct bearing on availability.

8 UTILISATION

In Table 4 the actual operating times, energy transferred and direction of flow has been tabulated. It is at once clear when these figures are compared with Table 3 that the utilisation has no direct relationship to availability. This is as might be expected. The utilisation is usually dictated by the economic factors governing the overall power system. Only to a relatively small extent has the utilisation been reduced by lack of availability due to faults.

In a wave power scheme, utilisation would certainly be affected by lack of availability since the operational philosophy would probably be to run the system continuously. Here availability is critical and high reliability must be built into the scheme. This could be done either by duplication of major items, which would be extremely expensive, or by designing the system so that loss of one supply route did not seriously affect the overall transmission capability. One method of doing this would be to use parallel paths both at the sending and receiving ends, and for the submarine cables. The increased cost could probably be justified in terms of increased security of supply.

9 MAIN REASONS FOR OUTAGES

By taking the average of the loss of equivalent availability of all systems and stations in various categories (as shown in Fig. 14) the items to which outages must be attributed is made clear.

Scheduled outages for maintenance and testing account for a sizeable proportion of the outage time each year. This is made clear in Fig. 14. To a certain extent the time required for maintenance and, to a lesser degree, fault durations, result from an overall operating philosophy rather than direct technical questions. In particular, the outage time does not always represent the absolute minimum because in planning maintenance, all the factors influencing the overall cost of system operation must be considered. The HVDC system may be out of service for much longer than would appear strictly necessary when considered alone.

Undoubtedly, HVDC systems are more complex, or at least rely on a greater number of components than the a.c. equivalent. At first it would appear that the availability must inherently be poorer but full account must be taken of the flexibility of operation offered by HVDC. For example, one bridge or pole can be taken out of service without the necessity of a shut-down. Nonetheless, it is obvious that equipment designed to reduce the maintenance down time would have a significant impact on availability.

The d.c plant outages are by comparison very small, and the valve outages even smaller. This is a point to be remembered since much discussion of performance has in recent years centred on valve performance to the extent that the problems have not always been presented in the correct perspective.

As the transmission component of the unplanned outage (shown in Fig.14) is generally the highest, some attention must be paid to the submarine cable installation. The North of Scotland Hydro Electric Board report that on average a submarine cable will be damaged once per ten years per twenty kilometres of cable run. Since repairs are difficult and expensive some method of minimising the liklihood of damage and the repair time would be worthwhile. Heavy armour appears to be the obvious solution. However, if the armour is too heavy, difficulties arise in coiling and during laying. The repair of such cables could also need a larger ship and may restrict the choice of ships to perhaps two. The "jet method" or a plough to sink the cable below the surface of the sea bed seems more promising and should reduce the risk of damage.

10 CONCLUSIONS

This report constitutes a superficial preliminary overview of such electrical problems as might be associated with generation from wave power devices. The following conclusions have been drawn from the results of the study:

1 electrical generation would be a.c. on board the duck string
2 some electrical interconnection of ducks would be required to to pool generated power for transmission ashore
3 transmission ashore can be done either by a.c. or d.c.
4 submarine cables would be necessary for part of the route to the nearest point on the national grid, but the submarine section should be as short as possible
5 considerable reinforcement of the existing grid may be necessary but no detailed study of this has been made in the report
6 on the basis of the estimates and calculations made, it is not obvious on a capital cost ground that an a.c. scheme would be cheaper than d.c.
7 the present day unit cost of electrical energy delivered ashore depends on the load factor of the system. For the scheme considered, assuming a practical value of about 40%, the unit cost is in the region of a few pence, depending upon which interest rates and which uncertainty limits are assumed. This cost appears sufficiently low for such a scheme not to be immediately dismissed on economic grounds.

11 RECOMMENDATIONS

The bulk of the report has been based on the performance of a single scheme. The design parameters, e.g. duck diameter, station rating, cable voltage, etc., were selected as reasonable operating values with no attempt at optimisation. The economic survey likewise used extrapolations and interpolations of available data, since accurate figures are not easily obtainable and sometimes impossible to obtain. The uncertainty limits applied to the results may be over-optimistically small, but were judiciously chosen in the light of available information. Consequently, the following areas of further work are recommended:

1. detailed design of the duck by minimising cost against output energy per annum
2. a more detailed consideration of the electrical plant both at sea and on shore, including scheduled maintenance periods during times of low average available wave power
3. a closer study of the problems likely to be encountered with the submarine cable link, for example the effects of possible cable flexing and sea-bed abrasion
4. an economic optimisation of the system with respect to capital costs against annually generated energy
5. a study of the factors affecting the reliability of the system in an attempt to develop methods of improving generation availability

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APPENDIX I

COMPARISON OF COPPER EFFICIENCIES

In order to compare the two systems, it has been assumed that the efficiency of transmission is the same in both cases (i.e. the same power produces the same line losses), that the maximum voltages applied to the conductors and the cost of insulation required is the same in each case.

D.C. SCHEME

$$\text{system voltage} = V$$

$$\text{Current, } I_{dc} = \frac{\text{Power}}{2V} = \frac{P}{2V} ,$$

since each line will carry half the power, The load is assumed to be balacced so there are no losses in the earth conductor.

$$\text{Line loss} = 2\, I_{dc}{}^2 R_{dc} = 2\, \frac{P^2}{4V^2} \,.\, R_1 = \frac{P^2 R_{dc}}{2V^2}$$

3 PHASE A.C.

The voltage V is the maximum voltage between conductors (the line voltage). Since the insulation is designed for to withstand V, the r.m.s. value is $\frac{V}{\sqrt{2}}$.

$$\text{Power transmitted} = \sqrt{3}\, V_\ell I_{ac} \,.\, \cos\phi$$

$$= \sqrt{3}\, \frac{V}{\sqrt{2}} \,.\, I_{ac} \cos\phi$$

where cos ϕ is the power factor.

$$I_{ac} = \frac{P}{\sqrt{3}\, \frac{V}{\sqrt{2}} \cos\phi}$$

$$\text{line loss} = 3\, I_{ac}{}^2 R_{ac}$$

$$= 3\, \frac{P^2\, R_{ac}}{\frac{3}{2} . V^2 \cos^2\phi}$$

$$= \frac{2P^2 \, R_{ac}}{V^2 \, \cos^2\phi}$$

for the line losses to be equal

$$\frac{P^2 R_{dc}}{2V^2} = \frac{2P^2 \, R_{ac}}{V^2 \, \cos^2\phi}$$

i.e. $$\frac{R_{dc}}{R_{ac}} = \frac{\text{area of a.c. conductor}}{\text{area of d.c. conductor}}$$

$$= \frac{A_{ac}}{A_{dc}} = \frac{4}{\cos^2\phi}$$

Volume of copper in the d.c. case $= 2.A_{dc}.\ell$ where ℓ is the cable length

Volume of copper in a.c. case $= 3.A_{ac}.\ell$

$\mathrm{Vol}_{dc} = 2\, A_{dc}\, \ell$, $\mathrm{vol}_{ac} = 3\, A_{ac}\, \ell$

$$\frac{A_{ac}}{A_{dc}} = \frac{\mathrm{vol}_{ac}}{3\ell} \; \frac{2\ell}{\mathrm{vol}_{dc}}$$

$$= \frac{\mathrm{vol}_{ac}}{\mathrm{vol}_{dc}} \; \frac{2}{3}$$

$$\frac{\mathrm{vol}_{ac}}{\mathrm{vol}_{dc}} = \frac{12}{2\,\cos^2\phi} = \frac{6}{\cos^2\phi}$$

It can be seen that the d.c. system is much superior to the a.c. system from the point of view of conductor economy.

In other words, the same power can be transferred by a d.c scheme using considerably less copper, and hence the cable will be less expensive.

APPENDIX II

COST OF DUCK

The civil cost of a duck has been estimated at:

£3000 m^{-1} length for 6-m diameter device
£5000 m^{-1} length for 10-m diameter device
£7500 m^{-1} length for 15-m diameter device.

Whole Year Output

The whole year output figures from which the estimates of available mechanical input to the electrical plant on board have been taken from the results of Hoffman and are plotted in Fig. 12.

Unit costs are calculated by dividing the total recurrent cost for one year by the total energy in one year. Basically, the recurrent civil cost is the required annual return on invested capital.

Thus

Capital cost of a duck per metre length = £AD m^{-1}
where A is the cost of a duck per metre diameter
and D is the duck diameter.

(Note the assumption that has been made that civil costs vary directly with duck diameter.)

If the scheme is rated at P watt and has a design power density of Q, Wm^{-1}

$$\text{then length of station} = \frac{P}{Q}\ \text{m.}$$

$$\text{Total cost of station} = £\,\frac{P}{Q}\,AD$$

$$\text{Annual return at say 10\%} = £0.1\ \frac{PAD}{Q}$$

$$= \text{recurrent civil cost.}$$

$$\text{Load factor} = \frac{\text{total energy delivered per annum}}{\text{maximum possible energy per annum}}$$

$$= \frac{\text{average power output per metre x 8760}}{\text{design power output per metre x 8760}}$$

$$= \frac{R}{Q}$$

where R is obtained from Fig. 12.

Numbers of units of energy per annum

$$= \text{Rating} \times \text{load factor} \times \text{hours in a year}$$

$$= P \times \frac{R}{Q} \times 8760$$

$$\text{Unit cost} = \frac{\text{Recurrent cost}}{\text{numbers of units}}$$

$$= £0.1 \ \frac{PAD}{Q} \cdot \frac{Q}{PR.8760}$$

$$= \frac{£0.1AD}{8760R} = \frac{10AD}{8760R} \text{ pence}$$

On basis of present system i.e. 400 MW, 10m diameter duck, design wave-power density 50 kW m^{-1},

Unit cost of wave energy to the station

$$= \frac{10 \times 500 \times 10}{8760 \times 28}$$

$$= 0.21 \text{ p/kWh}$$

APPENDIX III

GENERAL DETAILS OF THE SCHEME

Capacity	400MVA
Duck diameter	10 m
Incident wave power density	50 kW m^{-1}
Length of installation	8000 m
Cost of duck construction	£5k.m^{-1}
Total duck cost	£40 x 10^6

A.C. SCHEME 400 MVA 275 kV 3 phase

Generators	£4,000,000
Motors	6,000,000
Transformers	4,000,000
Generator switches	6,000,000
Circuit breakers	2,000,000
Cable	400,000 km^{-1}
Laying costs	6,000 km^{-1}
Communications	30,000

D.C. SCHEME 400 MW ± 250kV earth return

Generators	£4,000,000
Motors	6,000,000
Transformers	4,000,000
Generator switches	6,000,000
Circuit breakers	2,000,000
Rectifier	1,500,000
Convertor	8,000,000
Sea electrodes	500,000
Cable	200,000 km^{-1}
Laying costs	6,000 km^{-1}

A.C. CABLE SPECIFICATION

Line voltage	275 kV
Current carrying capacity per conductor	800 A
Conductor cross-sectional area	500 mm^2
Resistance per conductor	0.043 ohm km^{-1}
Charging current	1.9 Akm^{-1}

For 60 km cable run, assuming a single cable

Charging current per conductor = 114 A

Losses at full load

Assuming generation efficiency of 0.96
and transformation efficiency of 0.98

MVA available for transmission $= 400 \times 0.98 \times 0.96$

$= 376$ MVA

Current per conductor $= \dfrac{376 \times 10^6}{275 \times 10^3 \times \sqrt{3}}$

$= 790$ A

In phase current $= (790^2 - 114^2)^{\frac{1}{2}}$

$= 778$ A.

Power in cable at full load $= \sqrt{3} \times 275 \times 10^3 \times 778$

$= 370.5$ MW.

Loss per conductor $= I^2R = 790^2 \times 0.043 \times 60$

$= 1.61$ MW.

Total cable loss $= 3 \times 1.61 = 4.8$ MW

Transmitted power $= 370.5 - 4.8$

$= 366$ MW

Assuming transformation efficiency of 0.98 at receiving end

Full-load power $= 358$ MW

$\therefore$ Losses $= 42$ MW

Cost of a.c. losses

	£ per kW
Generating equipment	20
Transformers	10
Terminal equipment	12
Cable (for 60 km run)	60

Cost of losses $= 102 \times 42 \times 10^3$

$= £4.3\,M$

Total system cost

Generation plant	£10,000,000
Transformers	4,000,000
Switches	6,000,000
Circuit breakers	2,000,000
Cable	24,000,000
Laying	360,000
Communications	30,000
Losses	4,300,000
Total	£50.7M
Annual cost at 10%	£ 5.07M

The unit cost of electrical energy delivered ashore will depend on the load factor of the electrical transmission system. Initially this has been taken at 100% since it is probable that wave power would be used for base load demand.

For the electrical equipment

Number of units suppled per annum

= 8760 x load factor of duck x load factor of electrical system x maximum transmission capability

$$= 8760 \times 0.56 \times 1.0 \times 358 \times 10^3$$

$= 1.75 \times 10^9$ kWh per annum.

$$\text{Unit electrical cost} = \frac{5.07 \times 10^6 \times 10^2}{1.75 \times 10^9}$$

$$= 0.29 \text{ p/kWh}$$

Operation and maintenance costs have been taken at 0.15 p/kWh

$\therefore$ Unit cost = electrical cost + civil cost + operating cost

$$= 0.29 + 0.21 + 0.15$$

$$= 0.65 \text{ p/kWh}$$

Electrical load factor

Account must be taken of the electrical load factor of the system.

Total civil costs per annum (from Appendix II).

$$= 0.1 \times \frac{400 \times 10^6 \times 10 \times 500}{50 \times 10^3}$$

$$= £4 \times 10^6$$

Total annual cost $= £(4 + 5.07) \times 10^6$

$= £9.07$ M

at l.f $= 50\%$

Units $= 8.75 \times 10^8$ kWh

$$\text{Unit cost} = \frac{9.07 \times 10^8}{8.75 \times 10^8} = 1.04$$

Total Unit cost $= 1.04 + 0.15$

$= 1.19$ p/kWh

Fig. 13 shows the effect of load factor on unit cost for interest rates of 10% & 15%.

D.C. CABLE DETAILS

Cable voltage	± 250 kV
No. of conductors	2
Current-carrying capacity per conductor	800A
Cross-sectional area of conductor	500 mm^2
Resistance per conductor	0.043 ohm km^{-1}

D.C. losses at full load

Generation = .96

Transformation = .98

Conversion = 0.95

Power into cable $= 400 \times .96 \times .98 \times .95$

$= 357.5$ MW

Current in cable $= \dfrac{357.5 \times 10^6}{250 \times 10^3} \cdot \tfrac{1}{2}$

$= 715$ A

Loss in cable $= 715^2 \times 0.043 \times 2 \times 60$

$= 2.64$ MW

Power at receiving end $= (357.5 - 2.64) \times 0.98$

$= 347.8$ MW

Total losses $= 400 - 347.8 = 52.2$ MW

Cost of D.C. losses

	£ per kW
Generating equipment	20
Transformers	10
Terminal equipment	35
Cable (for 60 km run)	15
	80

Cost of losses $= 52.2 \times 10^3 \times 80$

$=$ £4.2 M

Total system cost

Generation plant	£10,000,000
Transformers	4,000,000
Switches	6,000,000
Circuit breakers	2,000,000
Conversion equipment	9,500,000
Earth electrodes	500,000
Cable	12,000,000
Laying	360,000
Communications	50,000
Losses	4,200,000
Total	£48 M

Civil cost as in a.c. scheme	£40 M
Total capital cost	88 M
Annual cost at 10%	8.8 M

At 100% l.f.

$$\text{Units} = 8760 \times 347.8 \times 10^3 \times .56$$

$$= 1.7 \times 10^9 \text{ kWh/annum}$$

$$\text{Cost/kWh} = \frac{8.8 \times 10^8 \text{ p/kWh}}{1.7 \times 10^9}$$

$$= 0.51 \text{ p/kWh}$$

Assume operation and maintenance cost at 0.2 p/kWh;
(Higher than a.c. cost because of increased complexity of terminal equipment.)

$$\text{Total Cost} = 0.71 \text{ p/kWh}$$

At 50% l.f.

$$\text{Generated unit cost} = \frac{8.8 \times 10^8}{1.7 \times 10^9 \times 0.5}$$

$$= 1.02 \text{ p/kWh}$$

$$\text{TOTAL UNIT COST} = 1.22 \text{ p/kWh}$$

Since the d.c. costs lie within a few percent of those for the a.c. scheme. the results on Fig. 13 can be taken as representing variation of a.c. & d.c. unit costs with load factor - at least within the uncertainty limits of the cost estimates.

TABLE 1

RECENT D.C. LINKS

Location and Date	Voltage between poles (KV)	Power (MW)	Cable Length (Km)	Cable Type
Gotland (Sweden) 1954	100	20	100	Solid (One conductor)
Cross-Channel (England-France) 1961	200	160	65	Solid (One conductor)
Cook Strait (New Zealand) 1965	500	600	45	Pre-impregnated gas pressure (One conductor)
Konti-Skan (Sweden-Denmark) 1965	250	250	58	Solid (One conductor)
Sardinia-Italy via Corsica 1966	200	200	118	Solid (One conductor)
Canada (Mainland)-Vancouver Island 1968	260	312	73	Solid (One conductor)

T A B L E 2

D.C. INSTALLATIONS PLANNED OR UNDER CONSTRUCTION

Scheme and Date	Operating voltage (kV)	Power (MW)	Length (km)
Norway-Denmark (1976)	± 250	500	130
Zaire (1976)	± 500	560	1700
Nelson River (1976)	150	270	-
North Dakota-Minneapolis (1978)	± 400	800	675
Cabora Bassa (1975)	± 533	1920	1400
Future cross channel	2000 MW link between England and France being planned.		

TABLE 3

SYSTEMS IN OPERATION AND EQUIVALENT AVAILABILITY FOR 1968, 1970, 1971 AND 1972

System and Commissioning Year	Capacity MW	Direct Voltage kV	Percentage Annual Equivalent Availability			
			1968	1970	1917	1972
Gotland (1954) (1970)	30	150	98.1	95.9	95.4	93
Cross Channel (1961)	160	± 100				
England			79	70.5	84.9	96.3
France			94.5	94.8	77	83.6
Volograd-Donbass (1962)	750	± 400	89	76	88	93.4
Konti-skan (1965)	270	250	76.8	88.9	65.3	86.9
Denmark			95.2	95.92	96.3	96.8
Sweden			77.9	89.6	66.8	88.0
Sakuma 1 (1965)	300	± 125	94.7	95.1	92.7	92.2
New Zealand (1965)	600	± 250	-	92.1	94.3	92.2
Sardinia (1966)	200	200	37.1	53.5	77.6	81.5
Vancouver (1968)	312	260	80.4	69.5	87.6	92.2
Pacific Intertie (1970)	1440	± 400				
Celilo				86.22	93.9	89.6
Sylmar				79.7	-	-
Eel River (1972)	320	80				99.69
Average equivalent availability %			82	83	86	91

TABLE 4

UTILISATION DURING 1968, 1970, 1971 AND 1972

System	Power flow to-	1968		1970		1971		1972	
		Actual Operating time h	Energy GWh	Actual Operating time h	Energy GWh	Actual Operating time h	Energy GWh	Actual Operating time h	Energy GWh
Gotland	Gotland Mainland	6039 2512	103.7 29.8	2995 4771	44.3 76	7506 1014	140 10	730 7373	2.3 176.1
Cross Channel	France England	25 5501	2.6 735.4	133 4248	5.9 557	11 1104	0.8 118	101 4381	4.7 427
Volgograd Donbass	Donbass Volgograd	5060 (total)	332 755	2792 2758	599 383	1984 1487	354 245	2380 1961	523 218
Konti-Skan	Denmark Sweden	6527 1514	1097.8 193.3	796 6522	122.9 1479.2	2412 2435	446.7 454.9	2908 1587	524.5 235.7
Sakuma 1	50 Hz 60 Hz	3554 1051	247.1 75.7	1138 830	80.8 59.3	806	18.4 32.6	141 169	11.8 12.5
New Zealand	North Island	-	2032	8280	2988	8683	2713	8645	3628
Sardinia	Mainland Sardinia	1974 4138	87.5 85.9	1051 6530	66.9 300.3	5019 1600	248.9 108.3	2216 5734	137.3 272.3
Vancouver	Vancouver Island	3611	258	8064	1186.7	7935	1362	8475	1767
Pacific Intertie	Celilo Sylmar			829 3468	380 2168		2.1 536	856 1816	223.2 949.9
Eel River	New Brunswick							2108	558.6

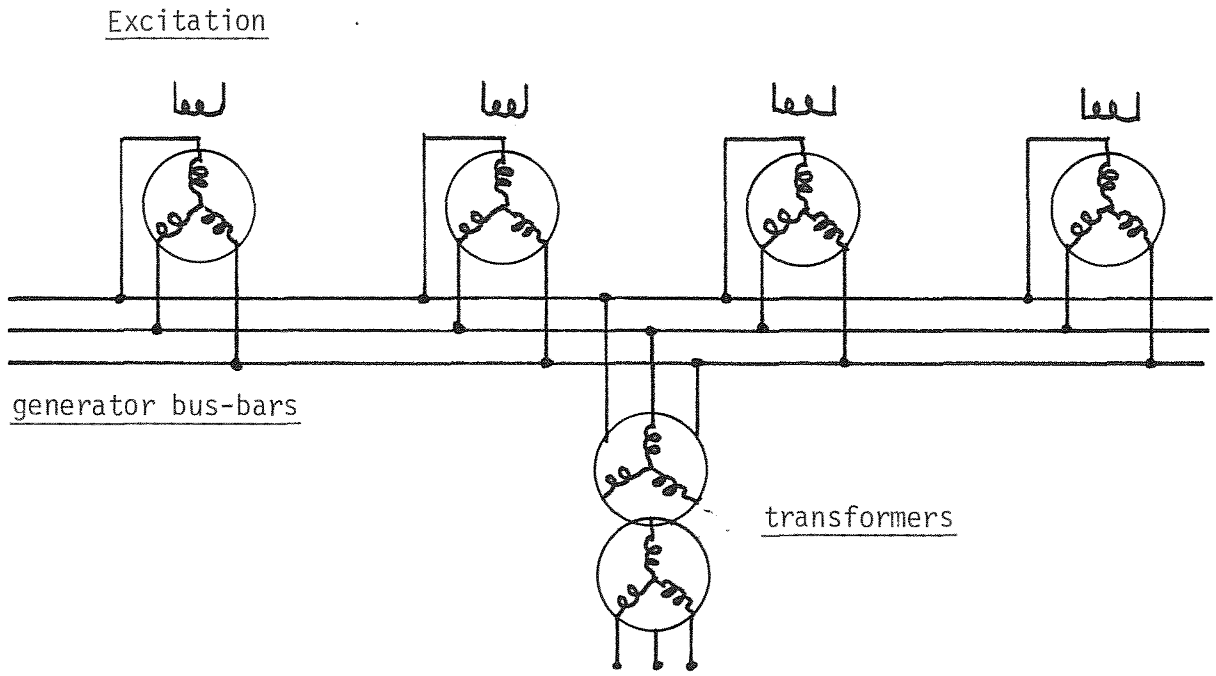


FIG.1. GENERATORS/TRANSFORMER CONNECTIONS

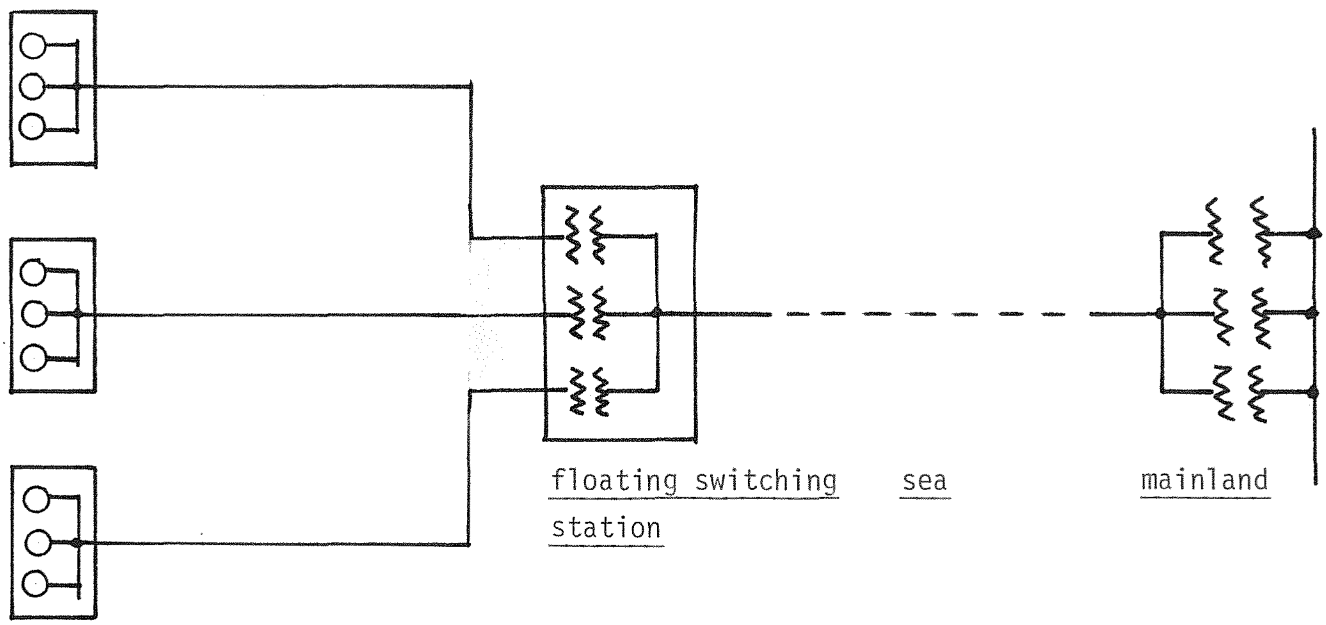


FIG.2. A.C. GENERATION/TRANSMISSION SYSTEM

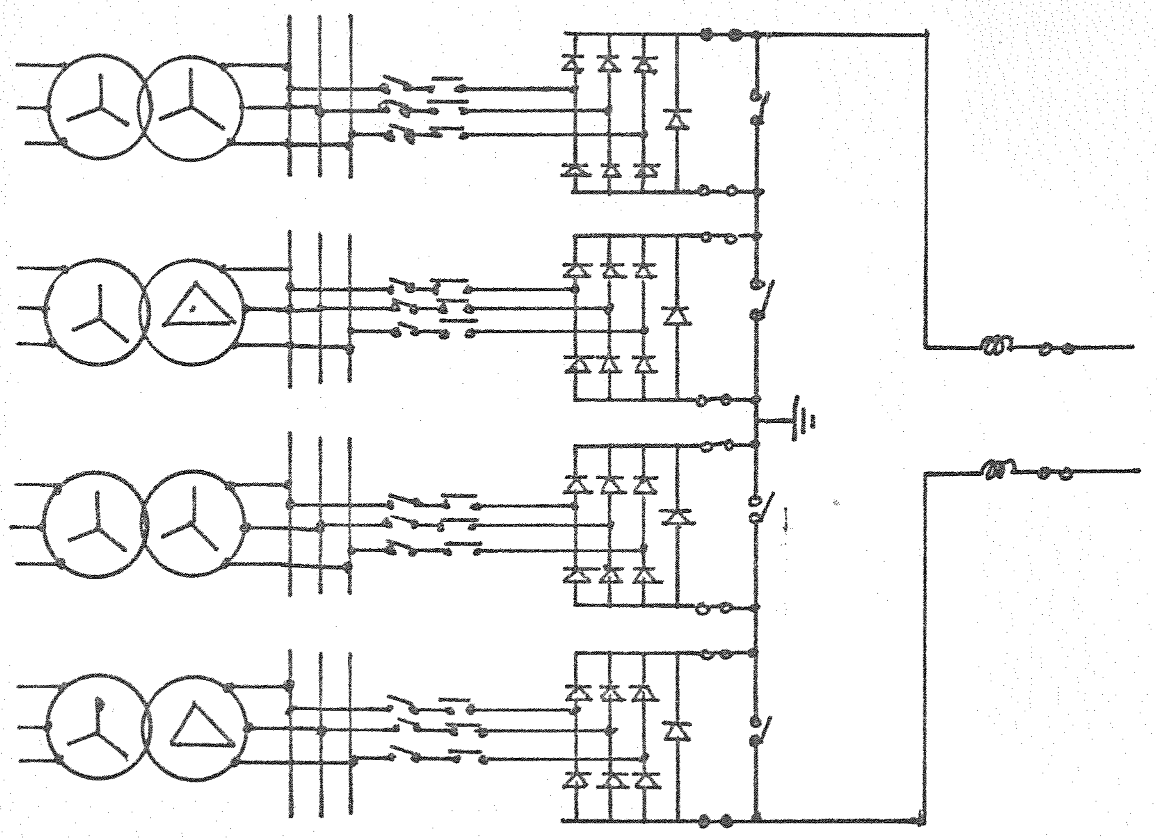


FIG.3. HIGH VOLTAGE SERIES RECTIFIER ARRANGEMENT

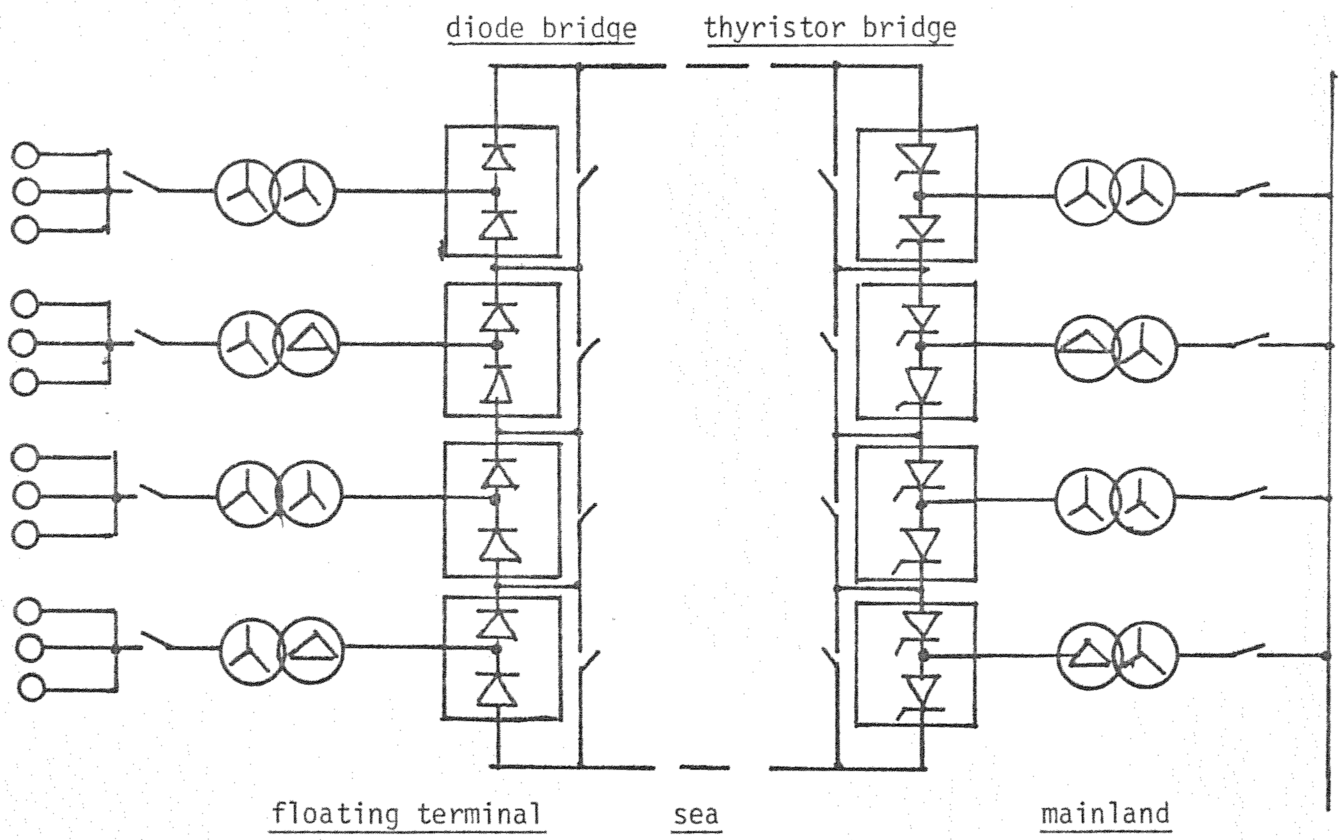


FIG.4. COMPLETE GENERATION/DC TRANSMISSION SYSTEM

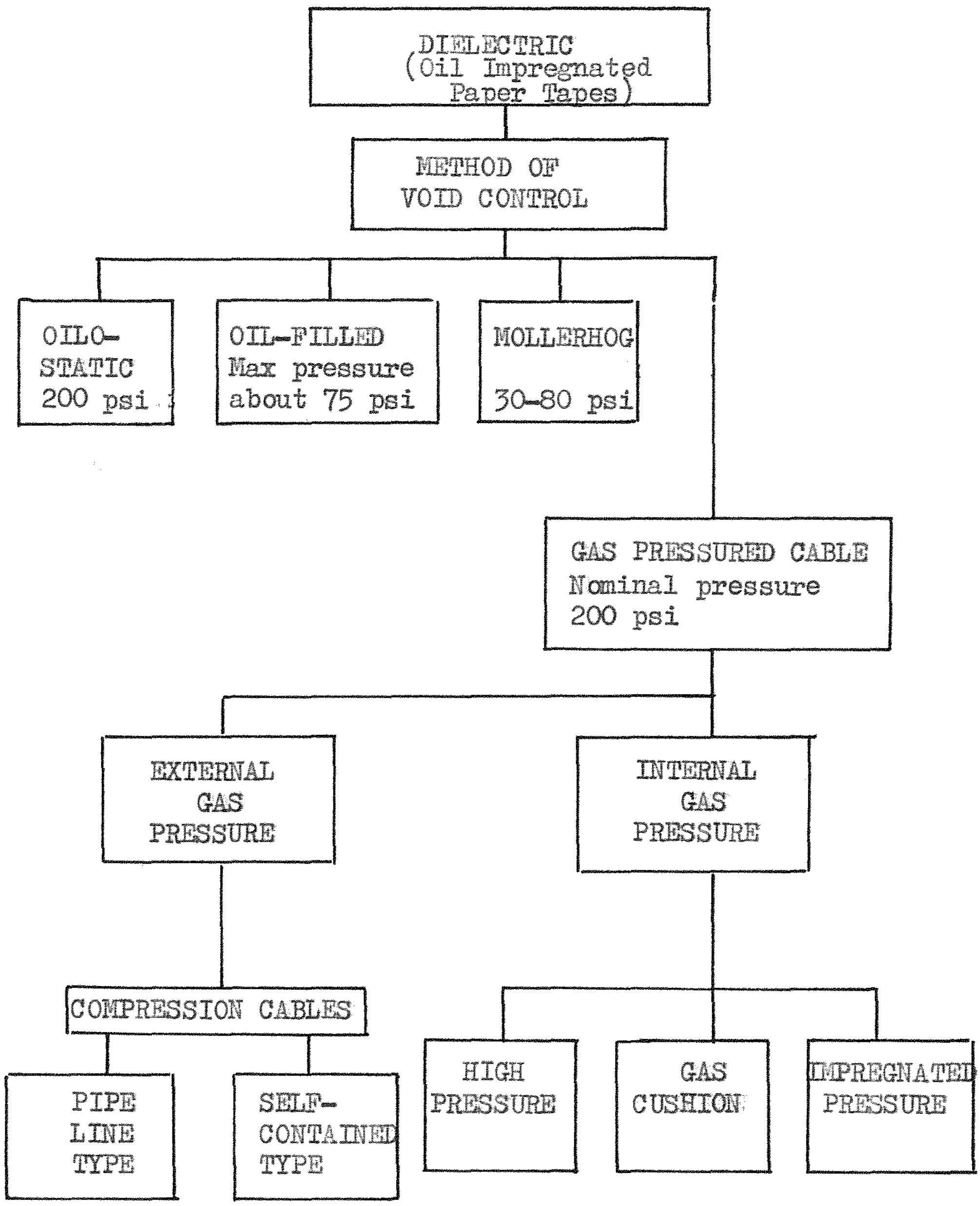


FIGURE 5

HIGH VOLTAGE CABLE TREE

INDICATING THE GROUPING UNDER FORMS OF VOID CONTROL

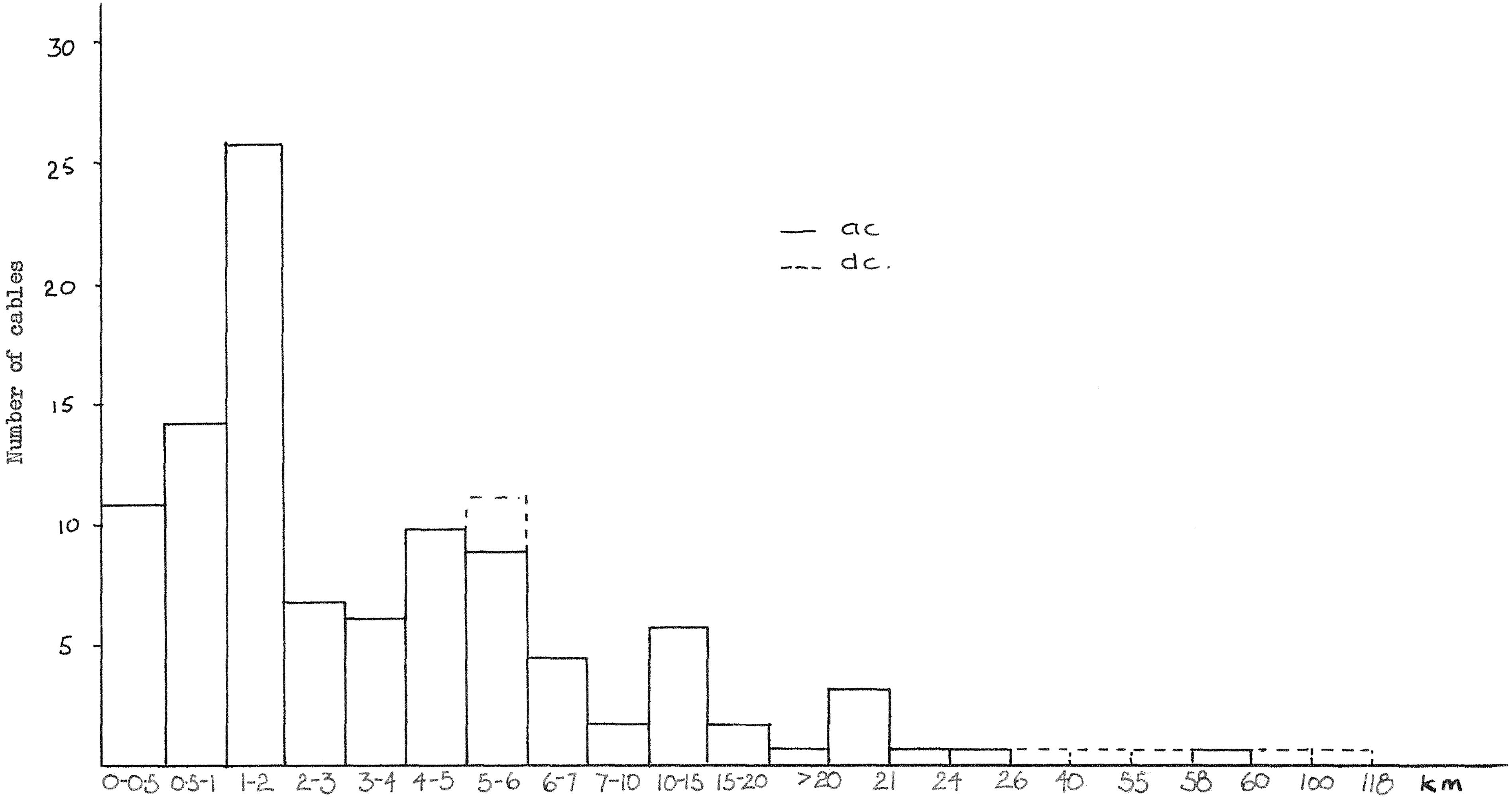


FIGURE 6 NUMBER OF SUBMARINE CABLES AGAINST CABLE RUN

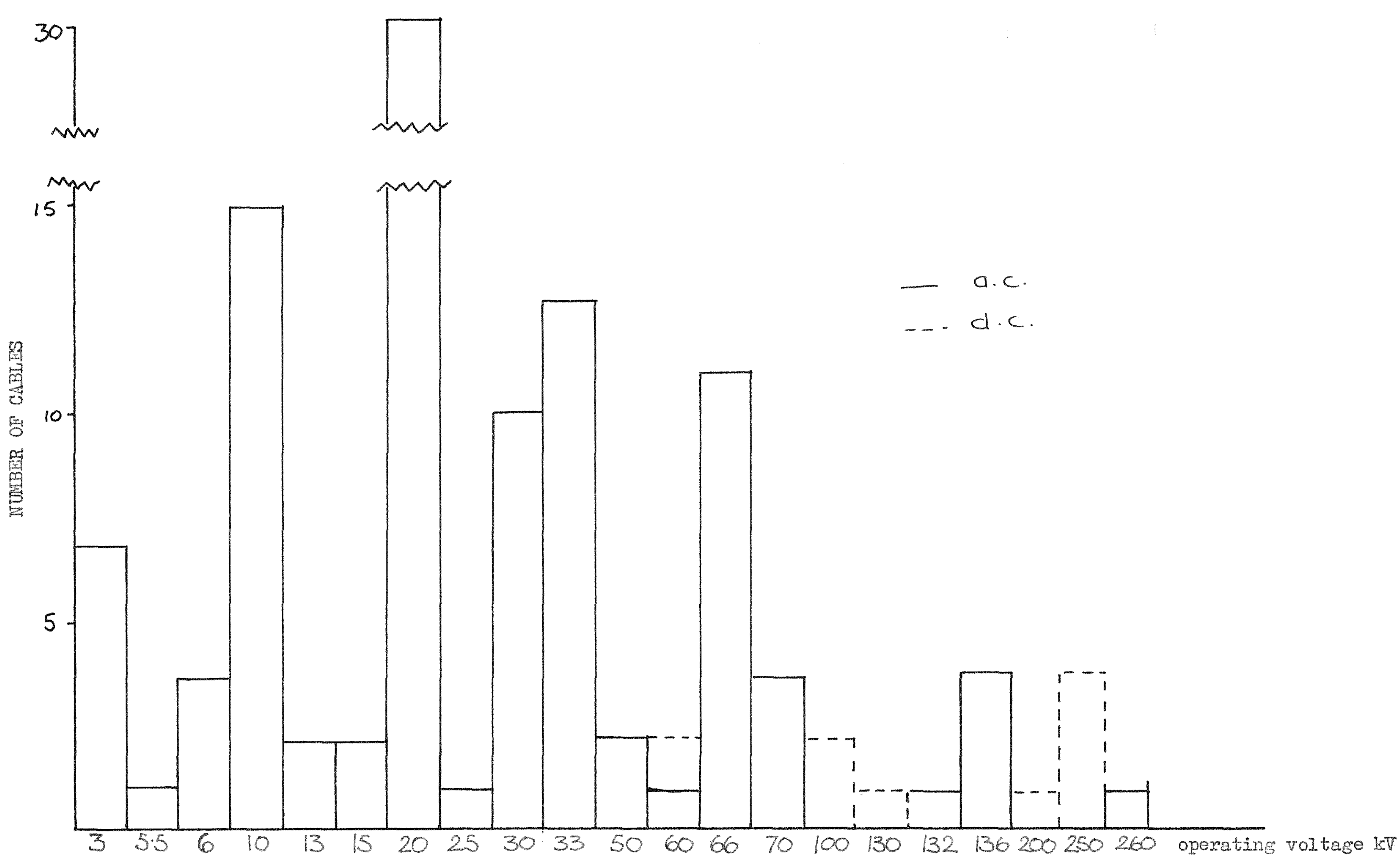


FIGURE 7 NUMBER OF SUBMARINE CABLES AGAINST OPERATING VOLTAGE

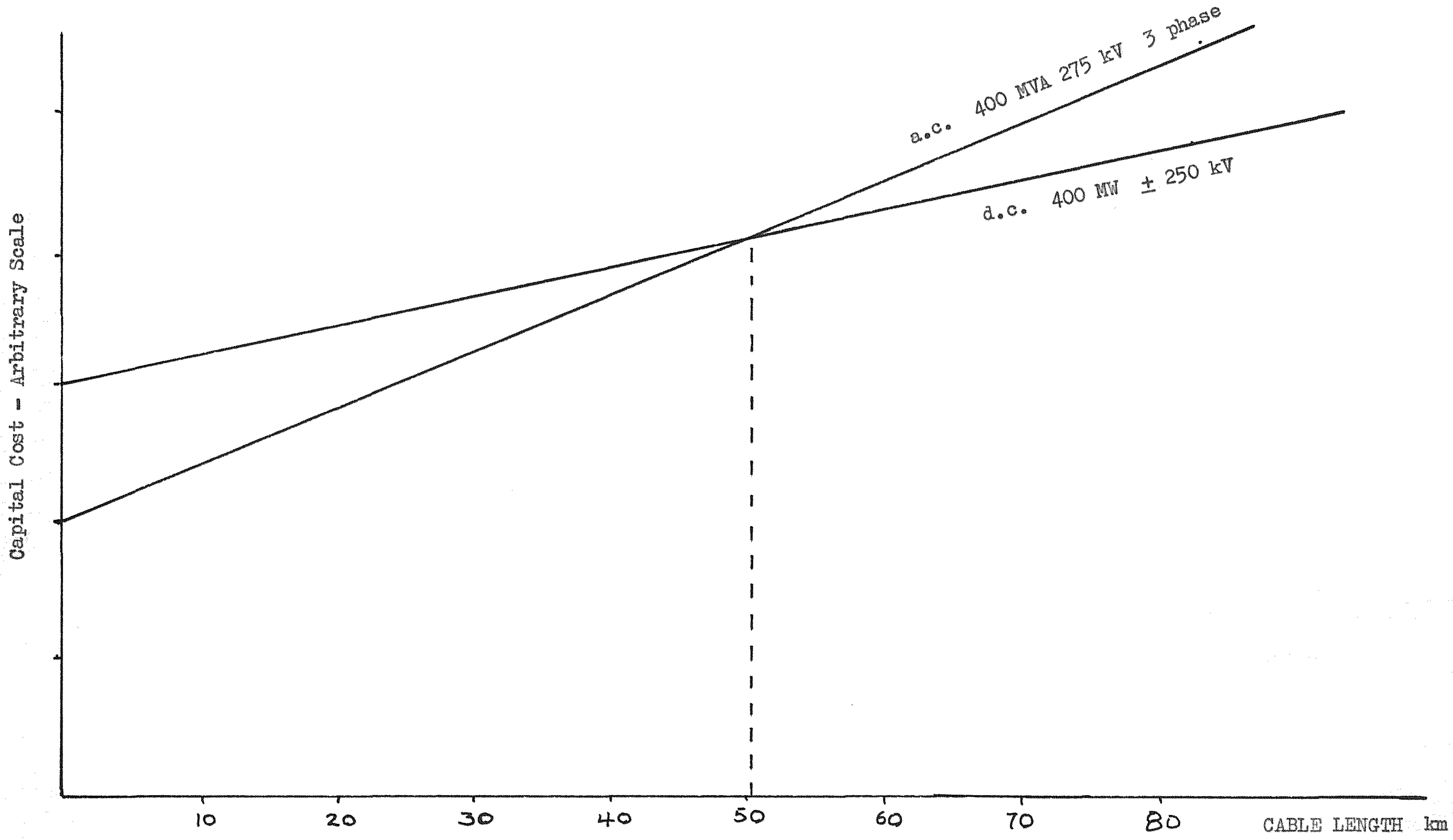


FIGURE 8 CAPITAL COST COMPARISON OF A.C. AND D.C. SCHEMES

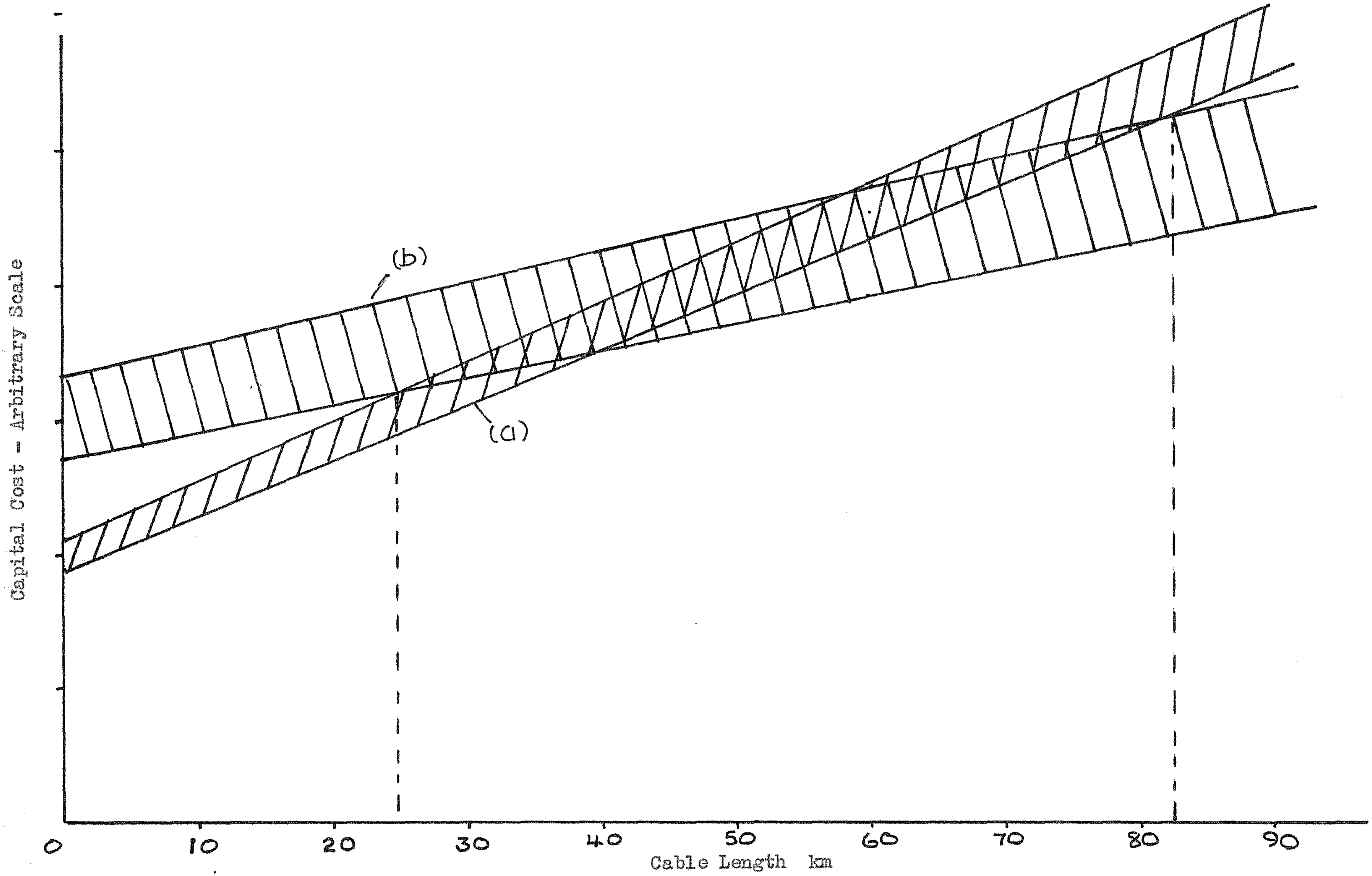


FIGURE 9

CAPITAL COST COMPARISON OF A.C. AND D.C. SCHEMES

(a) a.c. 400 MVA 275 kV 3 phase

(b) d.c. 400 MW ± 250 kV

Limits a.c. ± 5%
d.c. ± 10%

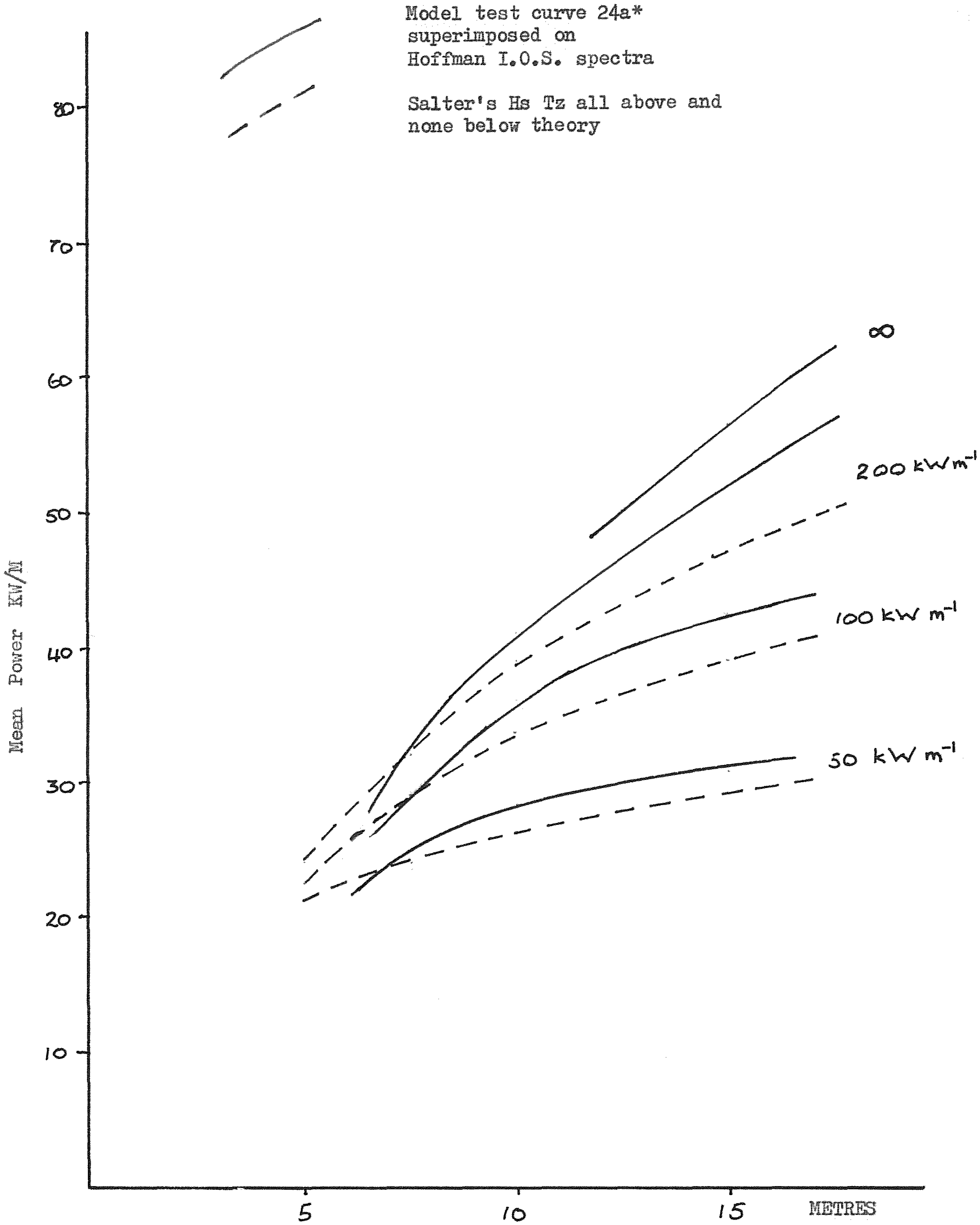


FIGURE 10 WHOLE YEAR OUTPUT FOR DUCK DIAMETER AND POWER LIMIT
Wave to duck transfer assuming constant operation above power limit.

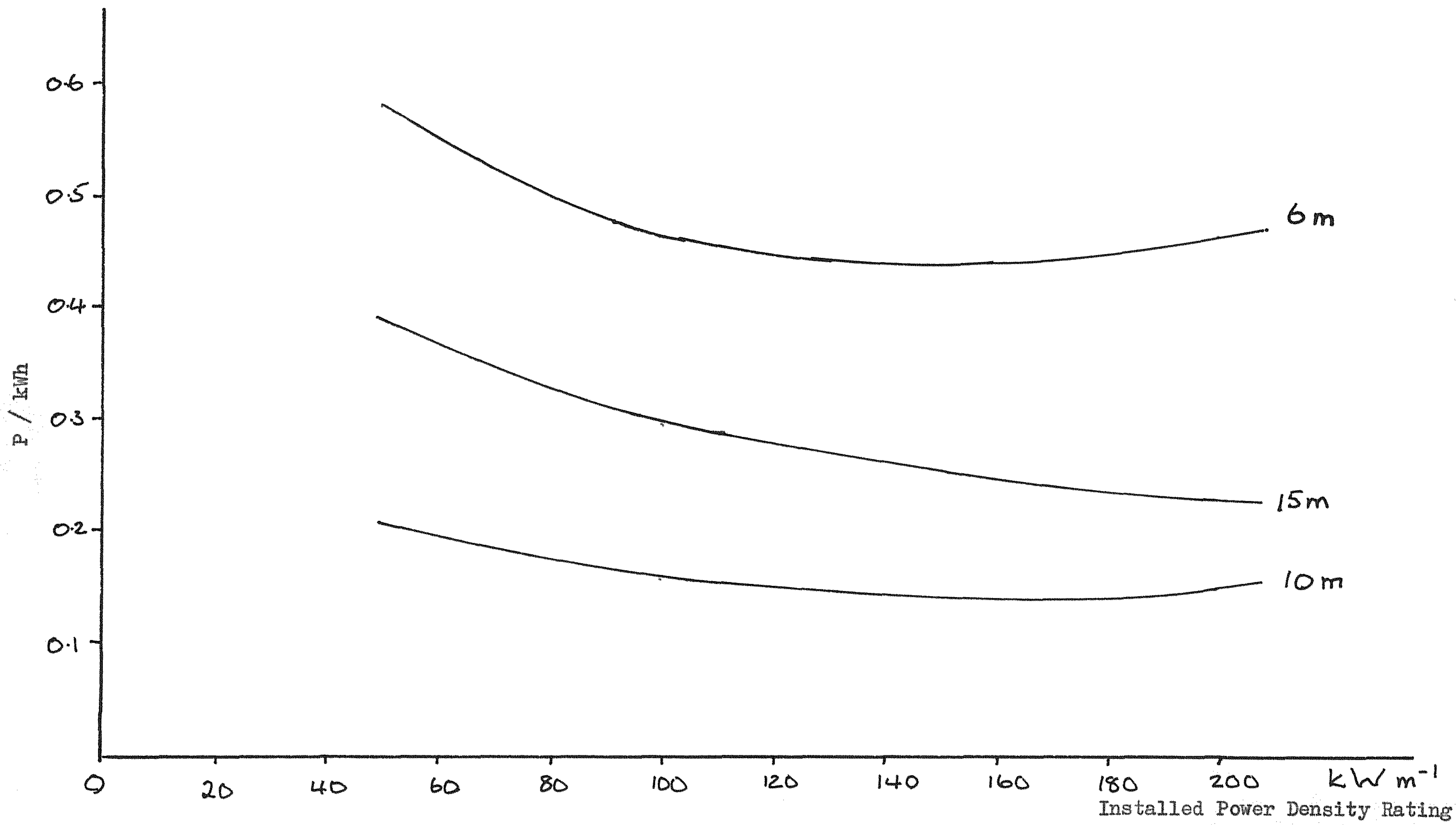


FIGURE 11 CIVIL UNIT COST AGAINST POWER DENSITY RATING

Unit cost based on civil cost alone

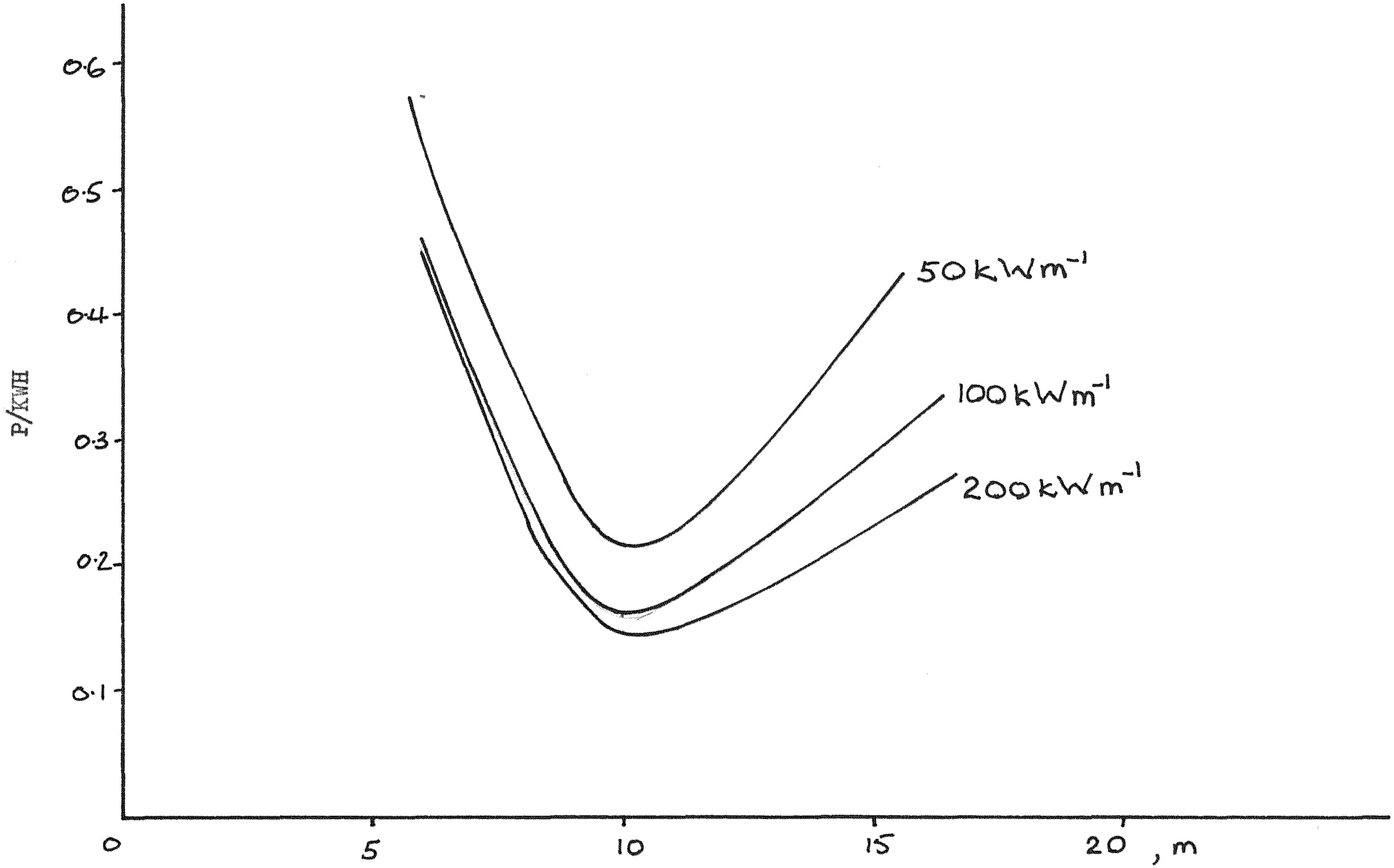


FIGURE 12 CIVIL UNIT COST AGAINST DUCK DIAMETER

FIGURE 13

UNIT COST OF ELECTRICITY

(Delivered through 60 km submarine link.)

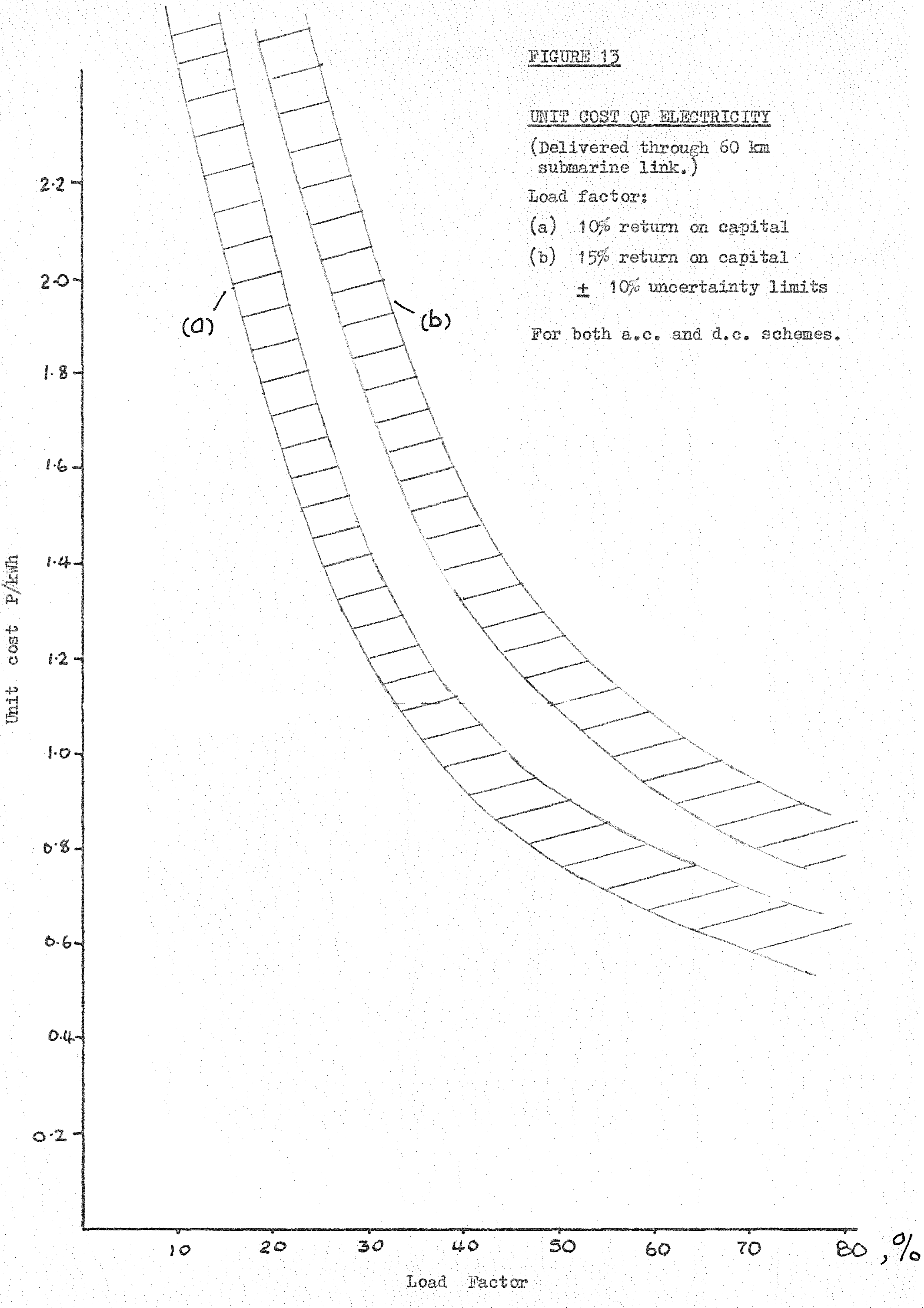
Load factor:

(a) 10% return on capital

(b) 15% return on capital

± 10% uncertainty limits

For both a.c. and d.c. schemes.



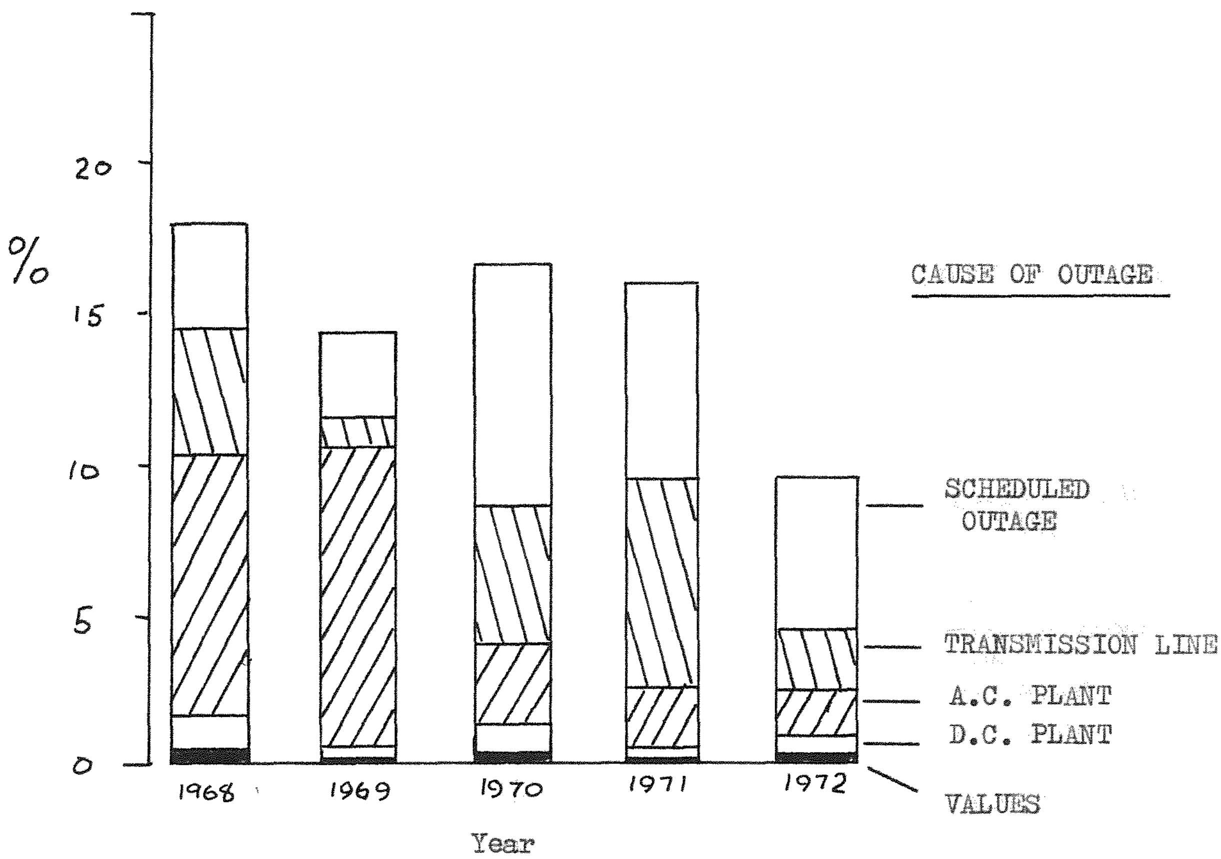


FIGURE 14 AVERAGE LOSS OF EQUIVALENT AVAILABILITY OF HVDC SYSTEMS