THESIS FOR THE DEGREE OF MASTER OF ENGINEERING.

UNIVERSITY OF TASMANIA.

PROBLEMS ASSOCIATED WITH THE INTERCONNECTION OF ELECTRICAL POWER SYSTEMS.

SUBMITTED BY

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SUPPLEMENTARY MATERIAL

Appendices I, II, III, and IV.

Appendix III contains
reports on:-

"Rotor winding deformation on turbo-alternators"

and

"Behaviour of overhead conductors under short circuit conditions"

PROBLEMS ASSOCIATED WITH THE INTERCONNECTION OF ELECTRICAL POWER SYSTEMS.

Introduction.

Due to its continuing rapid growth and the already large capital expenditure involved, the Electricity Supply Industry is a major factor, of increasing importance in National Economy.

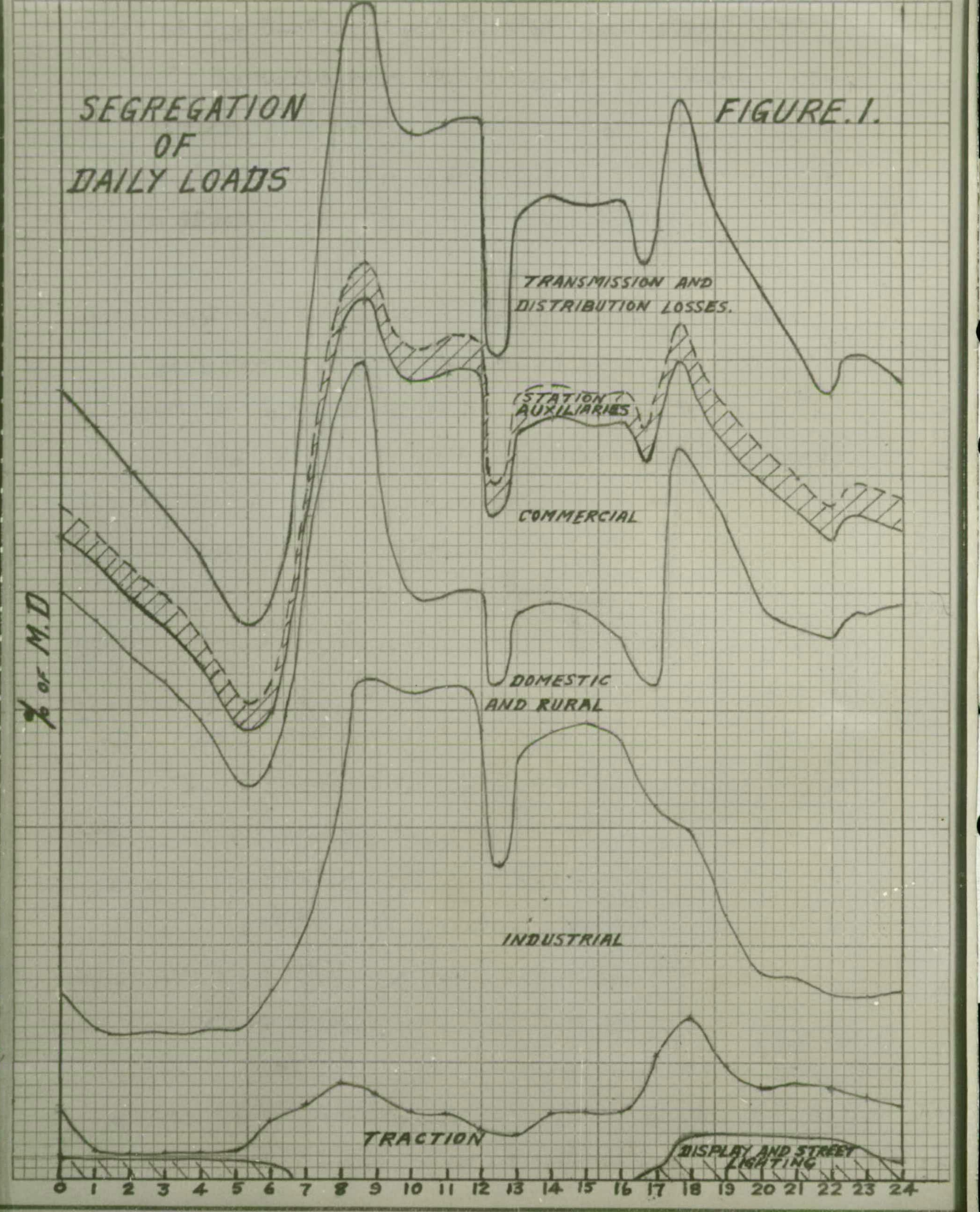
Complex technical problems have been solved successfully in relation to long distance transmission, higher efficiency of generating plant, protection, switching, indication, communication and control.

While the limits of technical development have not yet been reached, and the day to day application of existing techniques is necessary; the standardisation of specifications and designs for many individual items of plant and even for extensible generating, terminal, and distribution stations is practicable. The financial and operational benefits of standardisation of this kind are becoming more generally recognised and adopted.

As the solutions of purely technical problems are achieved and the extent of standardisation increases, the need for improvement in power system economics becomes more prominent.

The causes of varying rates of load growth and of daily and seasonal load variation together with methods of controlling them; the most economical load and plant capacity factors at which systems should operate; the best combinations of different classes of generating plant; the minimisation of system losses; the optimum margin for reserve plant; and the relation of plant availability to demand are all subjects which require much more study than they have yet received.

Such study offers opportunity for financial savings of a very high order, and the thesis describes investigations which have been carried out by the writer in connection with these problems.


SEGREGATION
OF
DAILY LOADS
FIGURE. I.
TRANSMISSION AND
DISTRIBUTION LOSSES.
(STATION)
AUXILIARIES
COMMERCIAL
DOMESTIC
AND RURAL
INDUSTRIAL
TRACTION
DISPLAY AND STREET
LIGHTING
% OF M.D
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

Items which affect Peak Load Characteristics and Annual Load Factor.

The load curves of electricity supply systems all exhibit the variable daily characteristic, and seasonal variations in the magnitude of the peak load and in the shape of the daily load curve are also evident.

The reasons for these variations on a particular system and for the different characteristics of individual systems, together with their implications, are dealt with below.

A graphical analysis of a combined system load curve illustrating the daily variations in demand and the diversity of component demands is given in Figure 1.

As an electricity supply system is developed and new types of load are connected to it the shape of the daily load curve can alter appreciably with regard to :-

(i) The number of peaks which occur during a 24-hour period.

(ii) The magnitude of the peaks expressed as a percentage of the steady or base load portion of the daily load curve.

(iii) The duration of each of the individual peaks.

(iv) The time of day at which the maximum load occurs.

(v) The rate of rise and fall of load.

Appreciable changes can take place within a few years and major changes can occur within 20 years or less. Figures 2 and 3 indicate the nature of such variations in daily load curves on a power system supplying industrial, rural, domestic, commercial, traction and street-lighting loads. Some of the causes of these changes are :-

(i) Alteration of normal working hours of the consumers.

(ii) Change in the habits of the consumers.

(iii) Development or abandonment of alternative methods of space heating and/or water heating.

(iv) Development of "off peak" water and space heating.

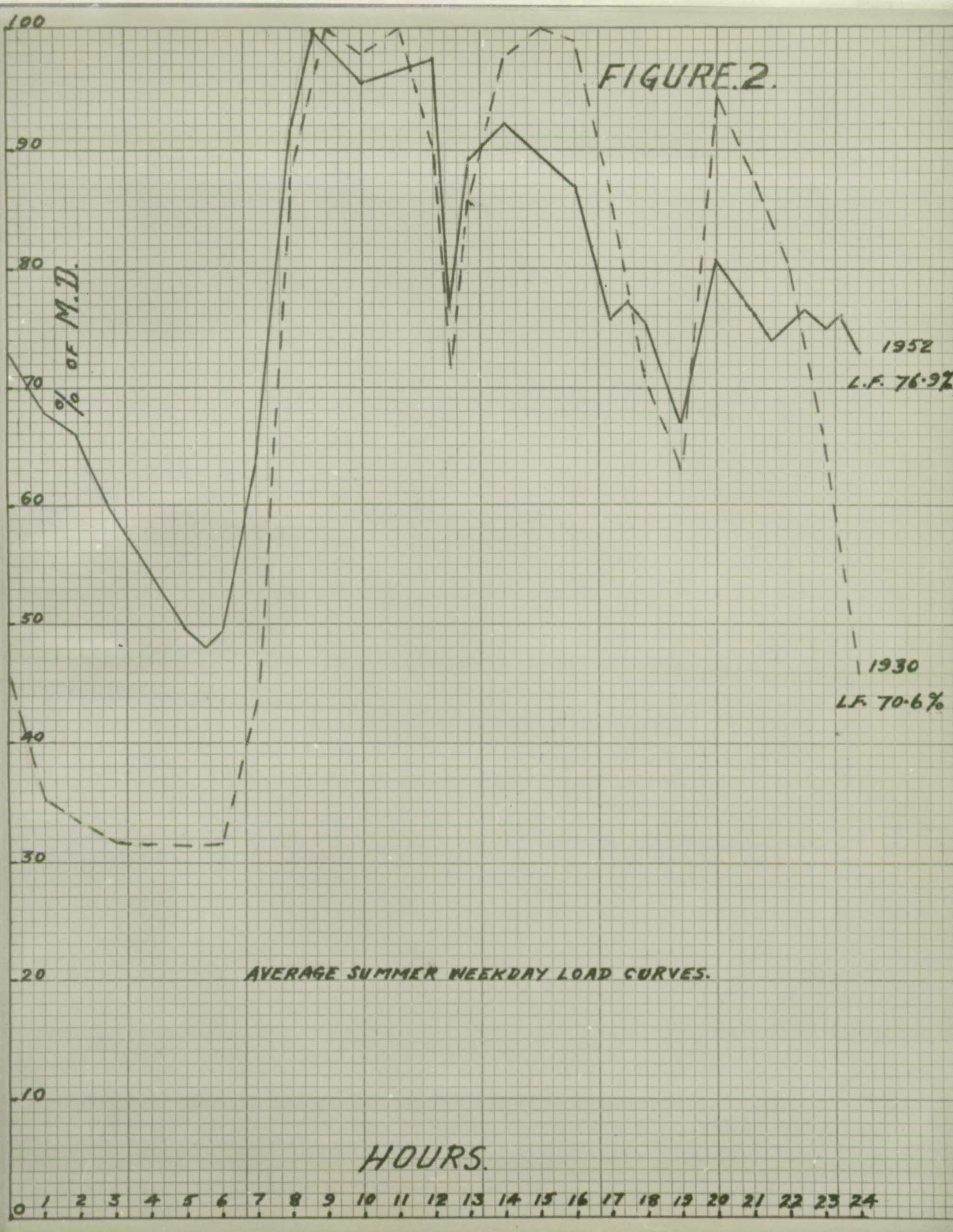


FIGURE.2.
% of M.D.
100
90
80
70
60
50
40
30
20
10
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOURS.
AVERAGE SUMMER WEEKDAY LOAD CURVES.
1952
L.F. 76·9%
1930
L.F. 70·6%

(v) Development of new industrial processes.

(vi) Development of new types of domestic load.

(vii) Development of various rural loads.

(viii) Development of commercial and domestic refrigeration plant.

(ix) Introduction of "Daylight Saving" ("Summer" or "Double Summer" Time) as an emergency or regular measure.

(x) Amount of street and display lighting and times of connection and disconnection.

(xi) Changes in weather conditions.

While some of these changes are fortuitous, others are controllable and can be altered by financial incentive, consumer education, agreement, regulation or statute. An active policy of load moulding has been adopted by some supply authorities with a view to filling in the troughs in the daily load curves and reducing seasonal variations in order to achieve a reduction in the overall cost per kilowatt hour generated. The advantage gained by a policy of this kind is particularly evident on thermal systems because the additional load can be generated at a lower cost than the existing load of the system. This cost amounts to little more than the added fuel cost and scope exists for this mutually advantageous development on thermal systems with annual load factors below 70%.

Figures 2 and 3 also indicate typical differences in the shape of the daily load curve for working weekdays in summer and winter. Accentuation of the main morning or evening winter peaks may occur due to overlapping by near peaks of component loads which at other times of the year have diversity. The extent to which this occurs is dependent on geographical latitude which influences the amount of overlap of the following near peaks :-

(i) Industrial power.

(ii) Inductrial lighting and heating.

(iii) Traction.

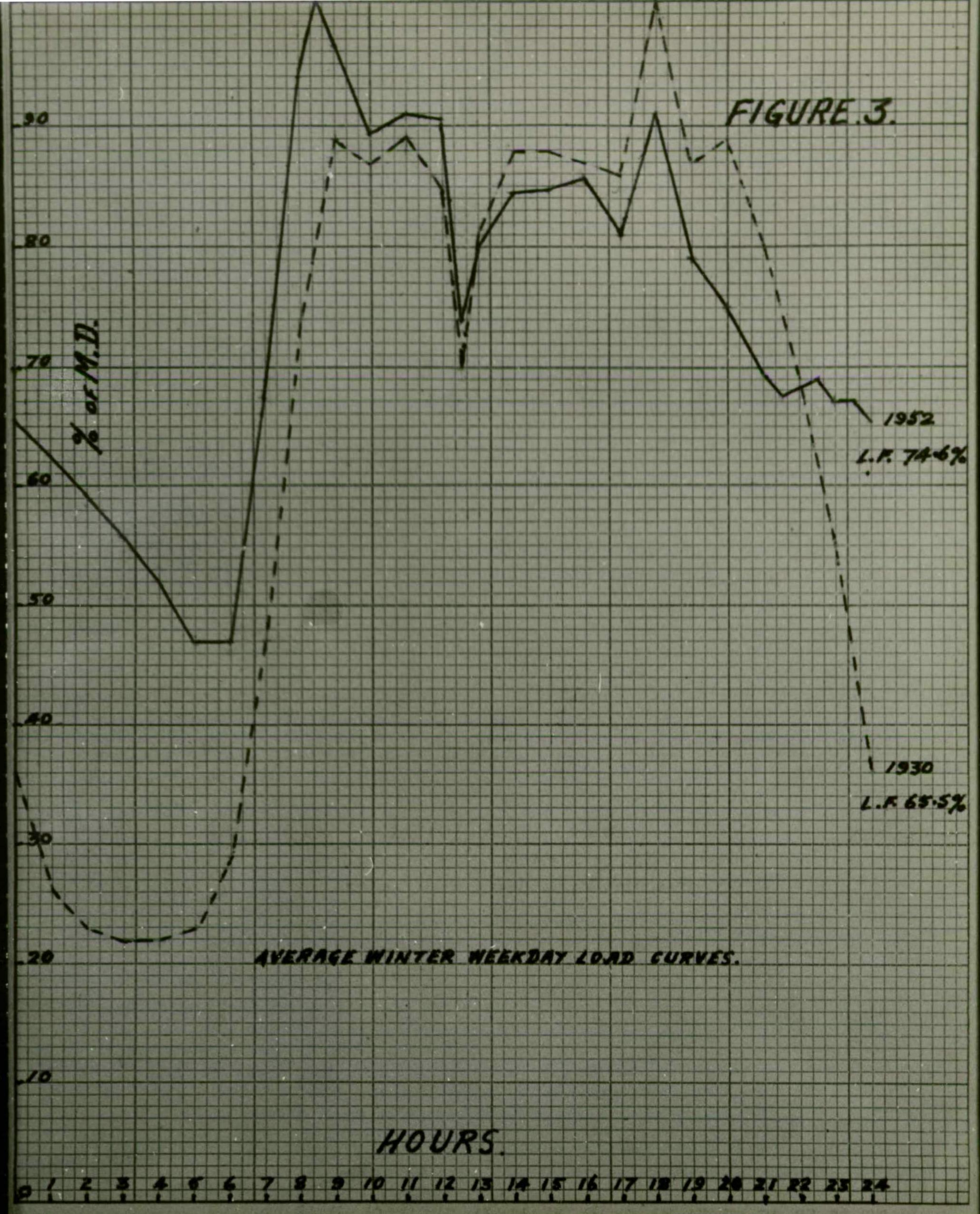


FIGURE. 3.
90
80
70
60
50
40
30
20
10
0
% of M.D.
1952
L.F. 74·6%
1930
L.F. 65·5%
AVERAGE WINTER WEEKDAY LOAD CURVES.
HOURS.
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

(iv) Street lighting.

(v) Display lighting.

(vi) Domestic lighting, heating and cooking.

The different characteristic shapes and magnitude of working weekday, Saturday, Sunday and holiday loading is shown on Figure 4. Advantage is taken of reduced loading at weekends and holiday periods to carry out short term maintenance which is a more frequent requirement on thermal than on hydro generating plant.

The magnitude of the peaks on individual working days during a particular week is influenced mainly by weather and temperature conditions which also affect the load throughout the day by altering lighting and thermal loads in accordance with visibility and temperature.

Monthly and seasonal variations in the magnitude of the peaks on daily load curves are caused by :-

(i) Weather and temperature changes which are of a wider range than those producing the weekly variations previously mentioned.

(ii) Seasonal loads such as :-

(a) Fruit and vegetable processing and canning.

(b) Dairying and milk product processing.

(c) Refrigeration and cool storage.

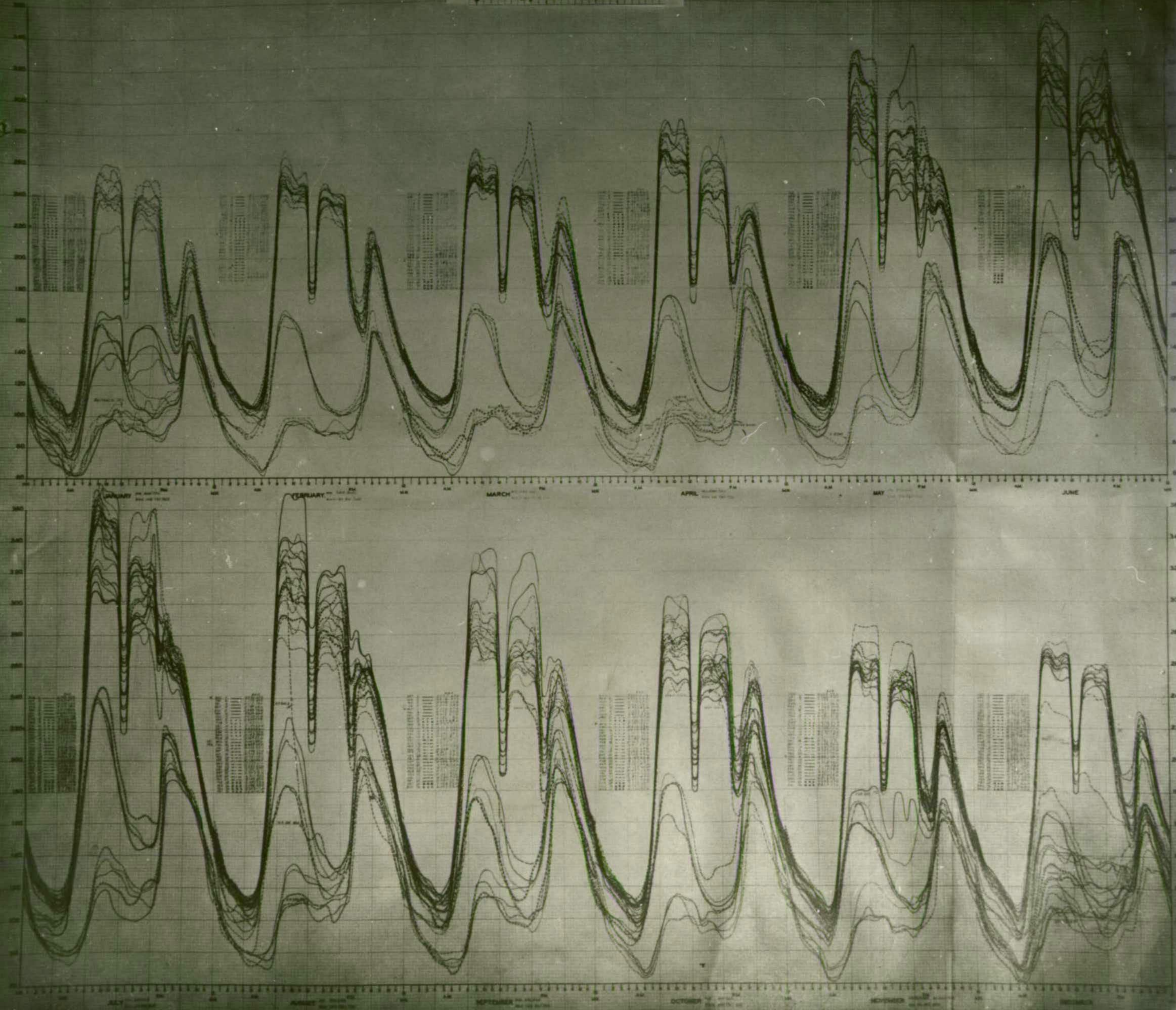
(d) Irrigation and other water supply pumping loads.

(iii) Seasonal changes in consumer habits.

System daily load curves form the basis for all studies which are directed toward load moulding, forecasting future loads, and deciding on the type, unit size, and amount of new generating plant required to meet them, methods of dealing with the problem of peak loads, improvement in system operating efficiency, and determination of load factors at which different types of generating plant will be required to operate.

There is, as yet, no generally approved set of standards laid down for the preparation of these curves and their derivatives, and in some instances lack of adequate metering

FIGURE 4


JANUARY
FEBRUARY
MARCH
APRIL
MAY
JUNE
JULY
AUGUST
SEPTEMBER
OCTOBER
NOVEMBER
DECEMBER

facilities prevents the preparation of accurate statistics. Loads may be plotted at hourly or half hourly intervals and measurements of load may be either instantaneous or integrated at or over these times. Maximum demand readings may be instantaneous or integrated readings over any period up to one hour; and rectangular block, straight line and smooth curves may be used for plotting.

The British Electricity Authority has continued a method developed when the Central Electricity Board commenced operation some 23 years ago. It has a high standard of accuracy and ensures that readings are taken and recorded simultaneously at all main stations on the system. Printometer charts are stamped every half hour with printed sets of readings obtained by impulsing from integrating meters. Check meters are incorporated and routine timing checks are carried out. Megawatt and Megavar readings are given on generator and auxiliary summated loads, import and export at power stations, and at all main load centres.

On other systems (where switchboard indicating instruments, integrating meters or chart recorder figures are logged at intervals) timing, observation, and instrument errors reduce the accuracy of the records obtained.

Several types of presentation of daily load curves are in use. One method is to assemble cut out figures of daily load curves in sequence throughout the year to form a block. This gives a three dimensional picture of the whole of the load variations throughout the year, but does not permit comparison and analysis of the curves as readily as the superimposed monthly mass curve method.

The latter method is illustrated in Figure 4 which shows the general arrangement, but is on too small a scale to allow detailed examination. An actual layout about 5 feet by 2 feet 6 inches with different symbols or colours for each day of the month permits individual identification, and shows clearly the variation in daily load throughout each month in a year.

An interesting operational feature which is shown by monthly mass curves is the necessity to synchronise generating plant and pick up a stabilising load on it in advance of requirements at times of rapidly rising load. For instance the magnitude of the load half way up the morning rise can be seen to occur at times which vary up to half an hour in the course of a month and which are not predictable with accuracy.

From the foregoing it follows that the system annual load factor is only a very approximate measure of system loading and operating conditions. It is dependent on the combination of daily load factors, the amount of load reduction at week ends and on holidays, and the monthly and seasonal variation in demand. An annual load factor of 60% for example could be obtained by a combination of high daily load factors on a system with moderately wide seasonal demand variations. The same annual load factor could be obtained alternatively by a combination of lower daily load factors with more narrow seasonal demand variations than in the first case.

It is thus possible to draw up two sets of quite different daily and seasonal loading conditions which, when formed into annual load duration curves, appear identical. Load duration curves for shorter periods have similar limitations and must be used in conjunction with sets of daily load curves for assessment of future load estimates, maintenance schedules, and load factors and operating requirements on groups of plant.

The application of methods for using monthly mass curves, load duration curves and integrated load duration curves (Reference 10) is covered in the following sections of the thesis.

Spare or Reserve Plant.

At the present time (1953) the major electricity generating systems in Australia and overseas are operating with little or no reserve plant margin, due mainly to the effects of the war and difficulties in obtaining finance or installing new plant quickly enough to meet the increasing demand. Interruptions to supply due to plant shortage are becoming less frequent as the deficiency is overcome and attention is being focussed again on the problem of the optimum margin which should be adopted for reserve plant.

The following considerations were taken into account during the writer's investigations.

The current costs per kilowatt of new generating plant installed in Australia are approximately £80 for steam plant operating on black coal or oil fired boilers. For steam plant operating on brown coal fired boilers the figure is about 25% higher, and at existing wage levels large installations of hydro-electric generating plant (outside Tasmania) are likely to cost two to three times as much per kilowatt as black coal fired steam plant.

When the system reserve plant margin has been lost it can only be re-established by the purchase of new plant although the plant actually assigned to this duty will usually consist of older and less efficient units.

The Royal Commission (1947) on the anticipated demand for electricity in Victoria proposed 25% maximum reserve plant. The S.E.C.V. subsequently indicated that a margin of about 20% of reserve based on the anticipated co-incident M.D. would be aimed at in view of the degree of interconnection. Other interconnected systems have used the figures of 25% and 20% reserve for planning purposes.

Margins of this magnitude on large systems are very costly and if a lower figure of about 10% could be proved adequate, valuable reductions in capital expenditure could be obtained.

For example on a system with no margin and a present M.D. of 700 M.W. a reserve of plant up to 25% might be established by the time the M.D. reached 1000 M.W. Table 1 shows different ways in which this reserve plant could be purchased and the cost of 25% and 10% reserve plant.

Table 1.

Reserve Plant on a System with 1000 M.W. M.D.

Plant Reserve Margin	Total Plant installed M.W.	M.W. Reserve provided by purchase of Hydro Plant	Cost of Reserve Hydro Plant at £240/K.W.	M.W. Reserve provided by purchase of Brown Coal Plant.	Cost of Reserve Brown Coal Plant £100/K.W.	Total Cost £x10^6
25% Assigned 100/150 Hydro/Brown Coal	1250	100	£24 x 10^6	150	£15 x 10^6	£39
25% Assigned 50/200 Hydro/Brown Coal	1250	50	£12 x 10^6	200	£20 x 10^6	£32
10% Assigned 40/60 Hydro/Brown Coal	1100	40	£9.6x10^6	60	£6 x 10^6	£15.6
10% Assigned 20/80 Hydro/Brown Coal	1100	20	£4.8x 10^6	80	£8 x 10^6	£12.8

It has been assumed that there is already sufficient black coal and oil burning plant to give a system balance at 1000 M.W. M.D. or more and that new plant will be comprised of hydro and brown coal burning units.

Thus a saving of the order of £20,000,000 is possible if the lower margin can be adopted, and in addition there would be progressive annual savings on all new plant installed to meet the growth of system load.

It is emphasised that the purchase of this new plant is necessary to regain a requisite operating reserve and that once the best economical combination and amount of generating plant is installed it will be operated in order of incremental costs. That is, hydro plant will be operated for as many running hours per annum as is possible according to the amount of water available and brown coal plant will be run to the maximum capacity factor permitted by available load and maintenance requirements. Other plant will be operated in sequential order of variable costs. Because of the relatively high capital cost of hydro plant it will not pay to install and use more than the essential minimum as non-spinning reserve plant (bearing in mind the fact that such system reserve plant must be capable of running on load at unpredictable times and possibly for protracted periods). In any case, with the exception of race lines, hydro installations have the inherent advantage that they are more reliable than steam stations and so for their own coverage require a smaller margin of reserve. It will usually pay to provide spinning reserve by that steam plant which runs more economically at varying load than on cycles of loading and boiler banking, or on steam plant which is running partially loaded due to limitations of the transmission system.

In view of the importance of savings in capital expenditure of the high order indicated, developments and trends in respect to reserve plant practice overseas were studied.

During the intermediate stages of development when independent local generating units had been replaced by the central station, it was accepted practice to carry spare plant sufficient to meet the annual M.D. on the

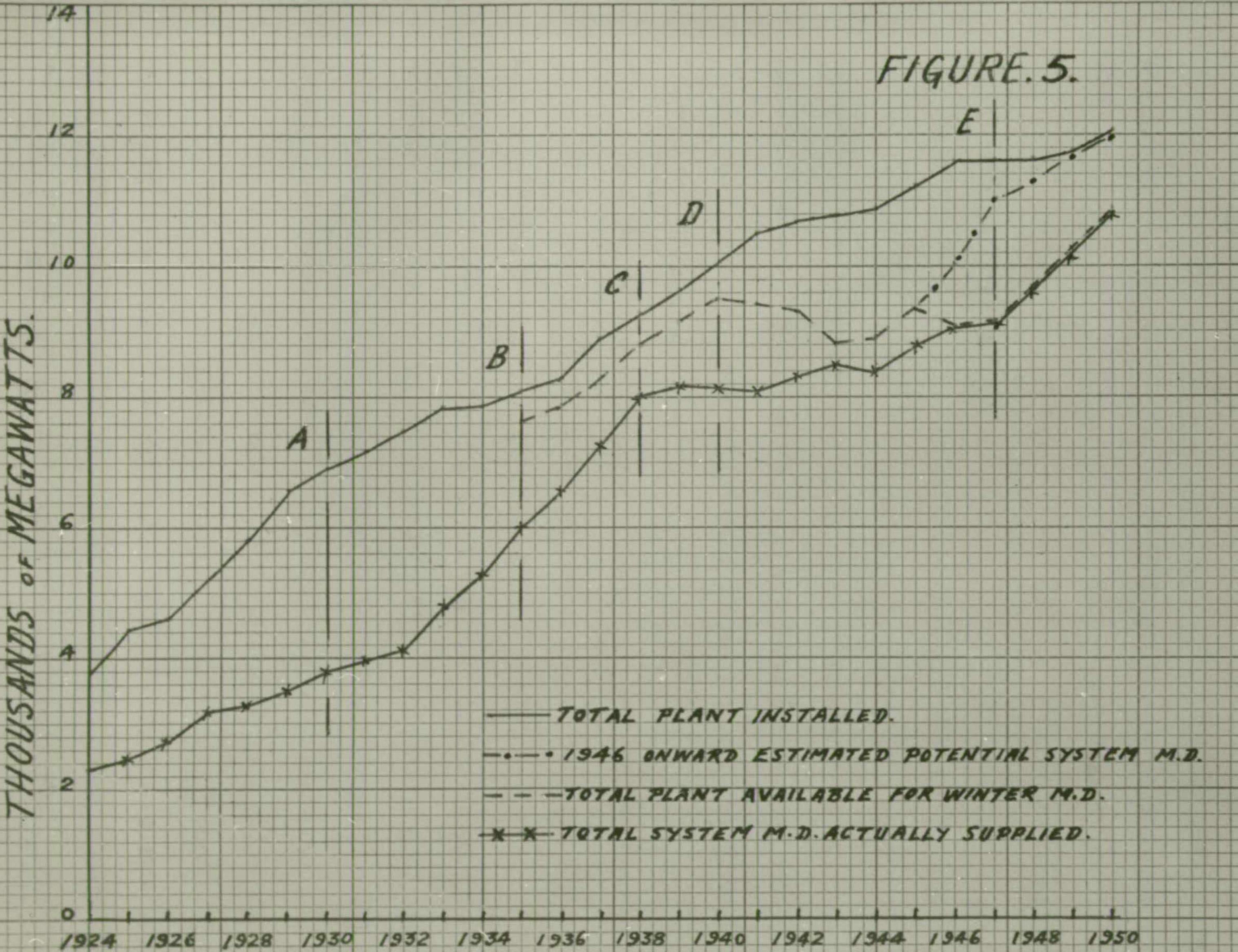


FIGURE. 5.

GENERATING PLANT AND LOAD - BRITAIN.

station allowing for outage of the largest unit. The trend towards increasing the size of generating units coupled with the desire of individual supply undertakings to install more efficient plant and become 'selected' prior to the establishment of the National Grid in Britain resulted in a reserve plant margin there of about 80% in 1930 (Line A, Figure 5). Following interconnection, this margin was progressively reduced to 15% of total installed and 10% of available plant in 1938, and the system was satisfactorily operated under these conditions.

The impact of the war, breakdowns due to curtailed maintenance, and the onset of a very high number of alternator rotor failures caused by copper deformation reduced the amount of plant available. At one period over 400 M.W. of generating plant was out of commission due to rotor failures alone. (References 25 and 26).

In spite of these reductions and the loss of main tie lines and some generating stations the standard of power supply was very high.

Since the war the effects of inadequate war time maintenance, the obligation to use lower grades of fuel than those for which the plant was designed and the decision of the Government during the war to reduce the new generating plant programme submitted by the C.E.B., have resulted in load shedding.

However, improved rotor designs and operating methods have reduced the rotor failure hazard, and normal maintenance and suitable fuel should permit operation without load shedding when the reserve plant margin which existed immediately prior to the war has been re-established.

Similar trends toward reduction in reserve plant margins were found to have taken place in U.S.A. due to the benefits of the increasing extent of interconnection, and the necessity to keep capital expenditure to a minimum.

There was, however, one peculiarity with regard to seasonal variations. It was noticed (Reference 34) that a levelling out of the curve of monthly M.D.S. had taken place in some instances.

The fall in demand which occurs in spring, summer, and autumn, and permits extended maintenance of steam plant to be carried out, had decreased to the stage where maintenance was being restricted.

It will be advisable to watch for such a trend on Australian systems and to curb it by load moulding in order that extra plant will not be required to enable adequate maintenance programmes to be met.

Professor A.H.Lovell (Chairman of the Electrical Engineering Department of the University of Michigan), with whom the subject of reserve plant has been raised in correspondence, has advised that in U.S.A. during the past three years systems they have managed to meet their M.D.s with only 5% to 7% reserve plant and that it is possible they will consider a reserve of 10% to be adequate in future.

Attempts in recent years to determine the margin of reserve plant which is necessary by calculation of probabilities (References 27, 28 and 29) are of value in indicating the relative effects of changes in separate variables. Nevertheless it is firstly difficult to obtain reliable basic records of plant breakdowns over a period of 20 to 30 years for a particular system; and, secondly, variables such as the following cannot be evaluated accurately :-

(i) The outage frequency, and duration of outages on new generating plant.
This plant may be of different design from that existing, boiler pressures and temperatures may be higher, methods of boiler firing, and the extent of duplication of auxiliaries may also differ. Bearing in mind that within ten years half the plant on a system can be of altered design (allowing for system growth and plant replacement) it would seem that the period

over which reliable data is obtainable would not be long enough to permit precise assessment.

(ii) The effect of changing standards of maintenance which depend not only on higher level direction and skill of personnel, but also on circumstances beyond the control of the supply authority.

(iii) Troubles such as rotor failures on steam turbo-alternators are not likely to be recurrent to the same extent.

(iv) Alterations to the transmission system or restrictions on its extension can affect the amount of reserve plant required in certain parts of a system.

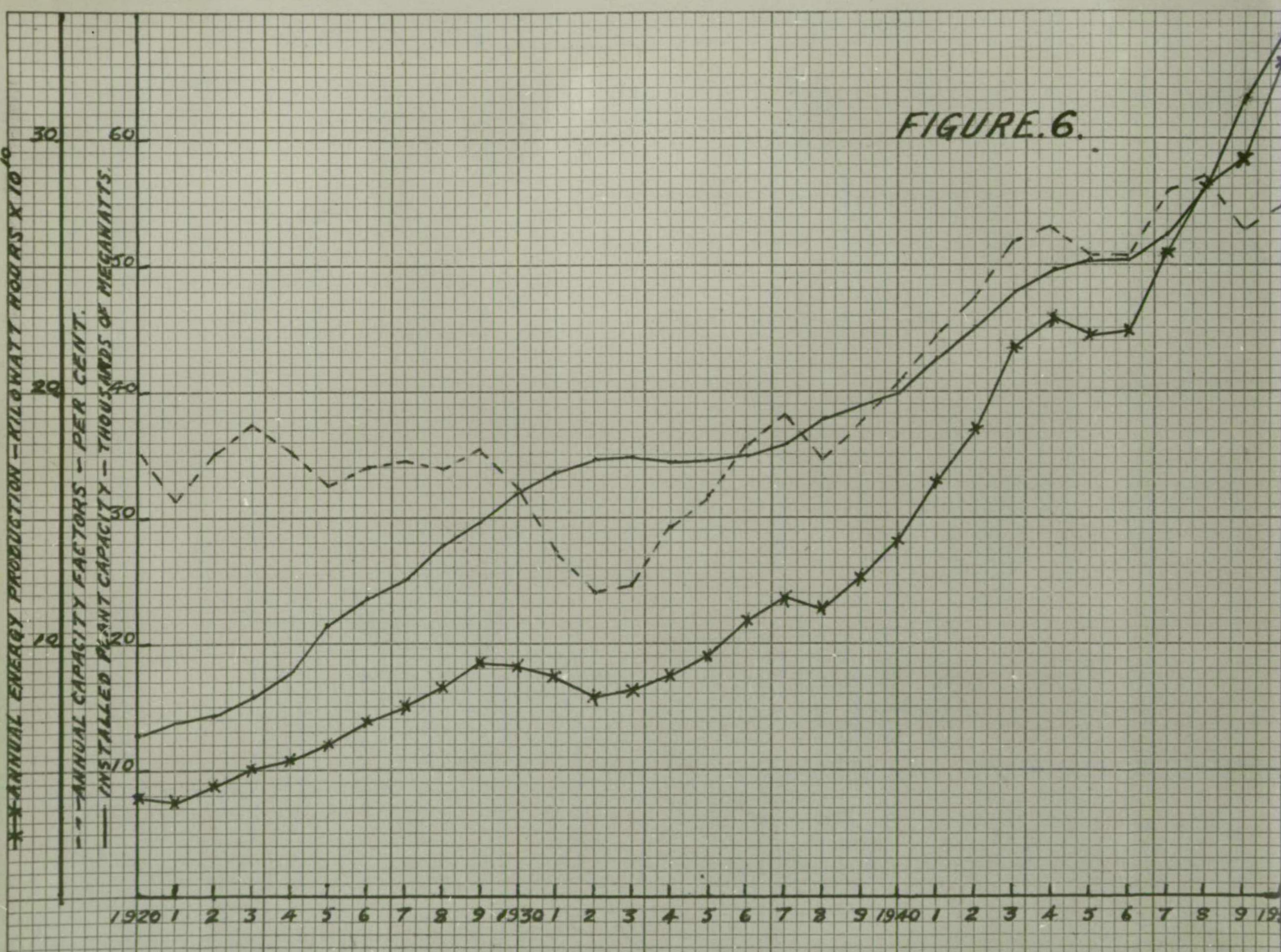
The amount of reserve required on a combined hydro-thermal system which has the added variable of some "run of the river" stations has been calculated by probabilities (Reference 27).

On that system a total reserve of 21.3% was estimated to be necessary for 1,870 M.W. peak load, including the amount for covering the hydro plant. It was further estimated that, if all the latter were dependable, a system reserve of 13.3% would be adequate.

By applying Seelye's curves (Reference 28) to a system with 1000 M.W. maximum demand supplied by 76 generators, a reserve of 8% is obtained using the same basic assumptions.

It appears that Seelye has made no allowance for re-arrangement of maintenance schedules following breakdown of generating plant. If, as is common practice, breakdown repairs and routine maintenance are done simultaneously on a particular unit and other routine maintenance is deferred, then the figure of 8% could be reduced.

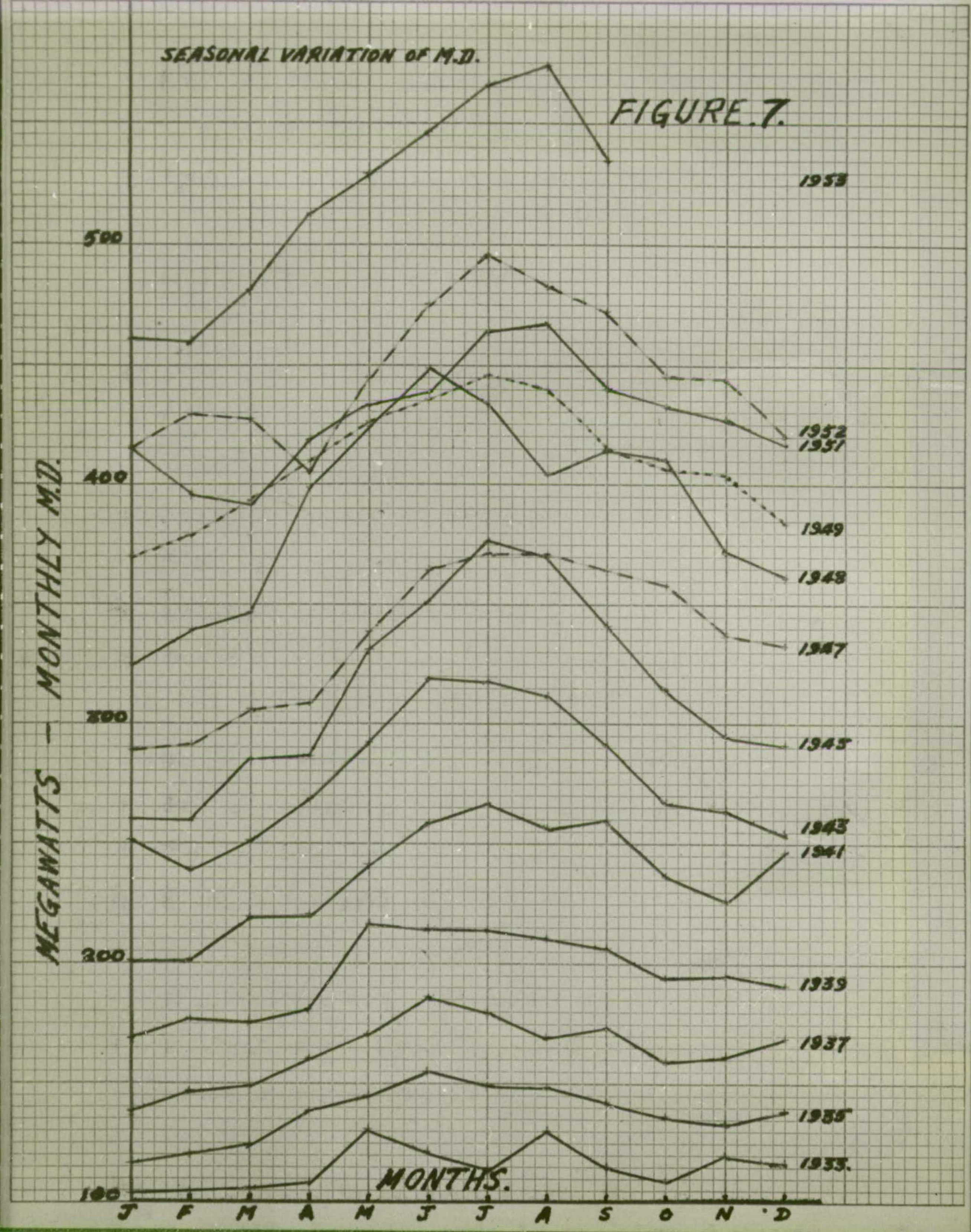
The evidence available therefore indicates that a



LOAD AND CAPACITY FACTOR TRENDS – U.S.A.

margin of 10% for the 1000 M.W. system should be sufficient.

It is proposed that reserve plant be installed up to this level, and that the margin be modified later, if found necessary, according to the result of operating experience under these conditions.



SEASONAL VARIATION OF M.D.
FIGURE. 7.
MEGAWATTS - MONTHLY M.D.
500
400
300
200
100
1953
1952
1951
1949
1948
1947
1945
1943
1941
1939
1937
1935
1933.
MONTHS.
J
F
M
A
M
J
J
A
S
O
N
D

Plant Availability and Trend of System Load Factor.

Maximum availability of all plant on the system is required for about three months during the year and the reduced maximum demand during the remaining period is usually sufficient to permit routine maintenance on steam generating plant.

Statistics show that steam plant availability varies from 85% to 90% per annum and that hydro electric generating plant has an average annual availability of about 95%.

Thus on independent hydro electric systems plant availability is unlikely to be a limiting factor in system development, and the optimum annual load factor will depend largely on natural seasonal variations in steam flow and the costs of providing storage.

On a system comprised of steam plant only, the limiting feature of an annual plant availability of 85% to 90% directly determines the extent of seasonal variation in maximum demand which can be allowed and imposes a restriction on the optimum annual load factor of the system.

Figure 7 shows a typical group of curves of monthly maximum demand plotted on a Megawatt scale. The incidence of maximum demand, the growth of system load, the effect of plant shortages in the post war period, and the nature of seasonal variations are indicated.

Similar curves expressed as a percentage of the yearly M.D. are given in Figure 8, and as a percentage of the total prospective installed capacity each year in Figure 9.

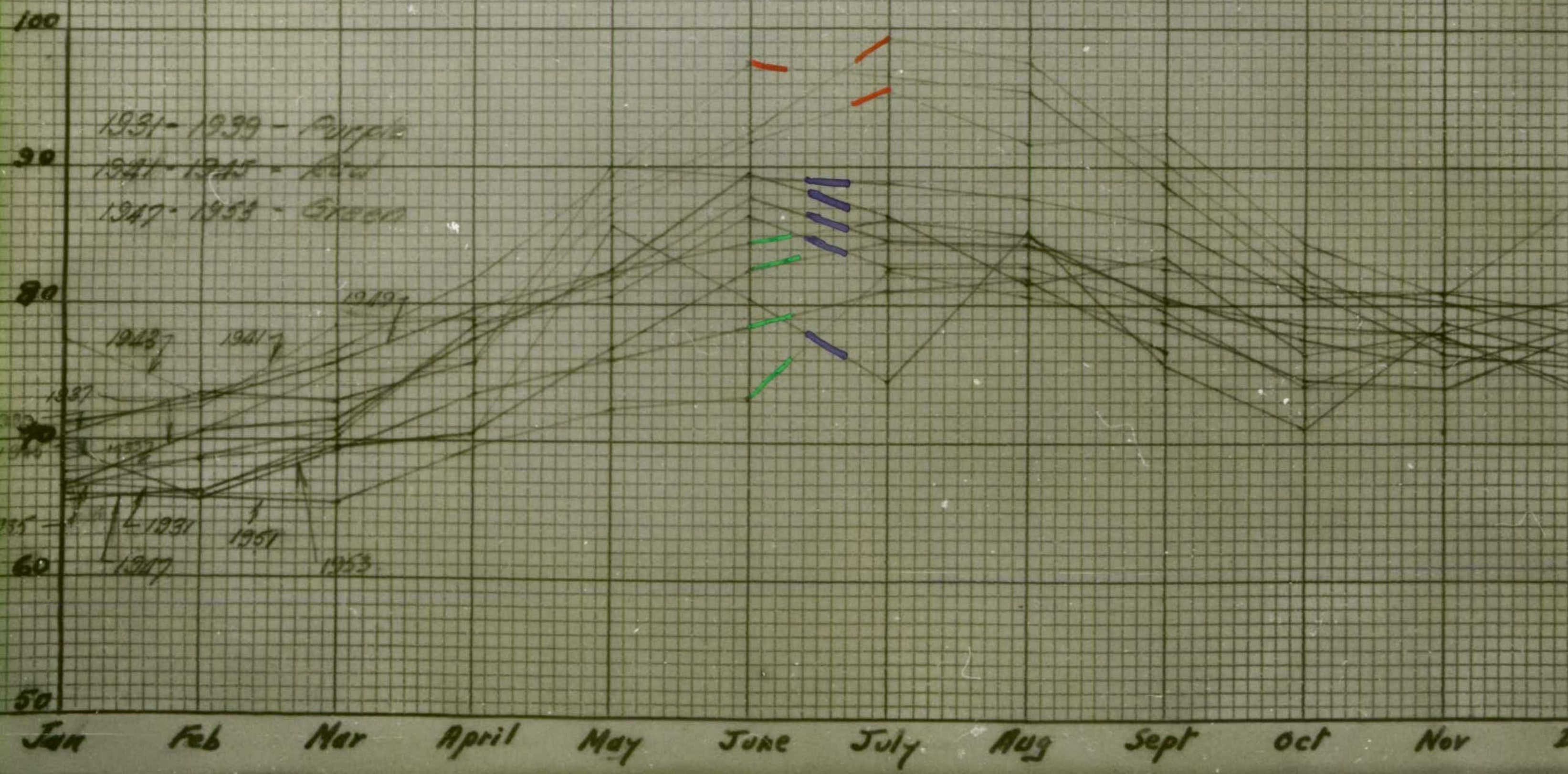
The basis of the last figure is artificial in that the winter M.D. which would have occurred with an average rate of load growth has been substituted for the actual winter M.D.

Throughout this period it has been possible to carry out annual routine maintenance of boilers and turbo-alternators on a day work schedule.

MONTHLY SYSTEM MAXIMUM DEMAND
1931 - 1953

FIGURE. 9.

Expressed as a % of Kilowatt Curve plus 10% Reserve



MONTHLY SYSTEM MAXIMUM DEMAND

1931 - 1953

FIGURE. 8.

Expressed as a % of Yearly M.D.

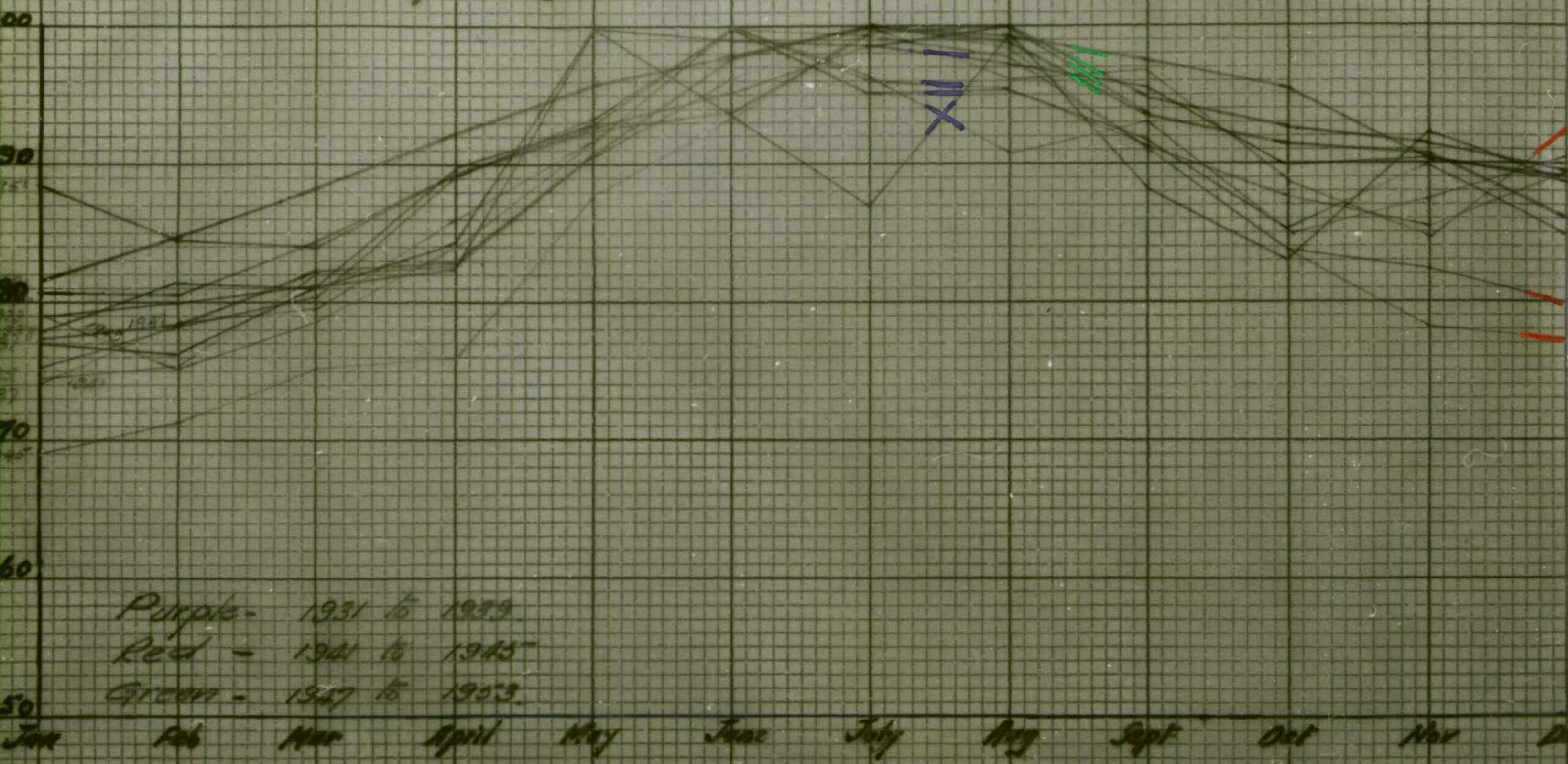


Figure 10 shows the actual annual load factors on the system and indicates the trend towards higher A.L.F.s as a result of load moulding. This trend is seen to be due more to improvement in daily load factor (Reference Figures 2 and 3 which apply to the same system) than to reduction in seasonal M.D. ratios, when due allowance is made for suppressed winter peaks between 1948 and 1952.

The variable shape of the monthly M.D. curves necessitates periodical review and re-arrangement of maintenance schedules to cope with demand, but until maintenance is forced on to a two shift or three shift programme there is still opportunity for accepting heavier summer, spring and autumn loads.

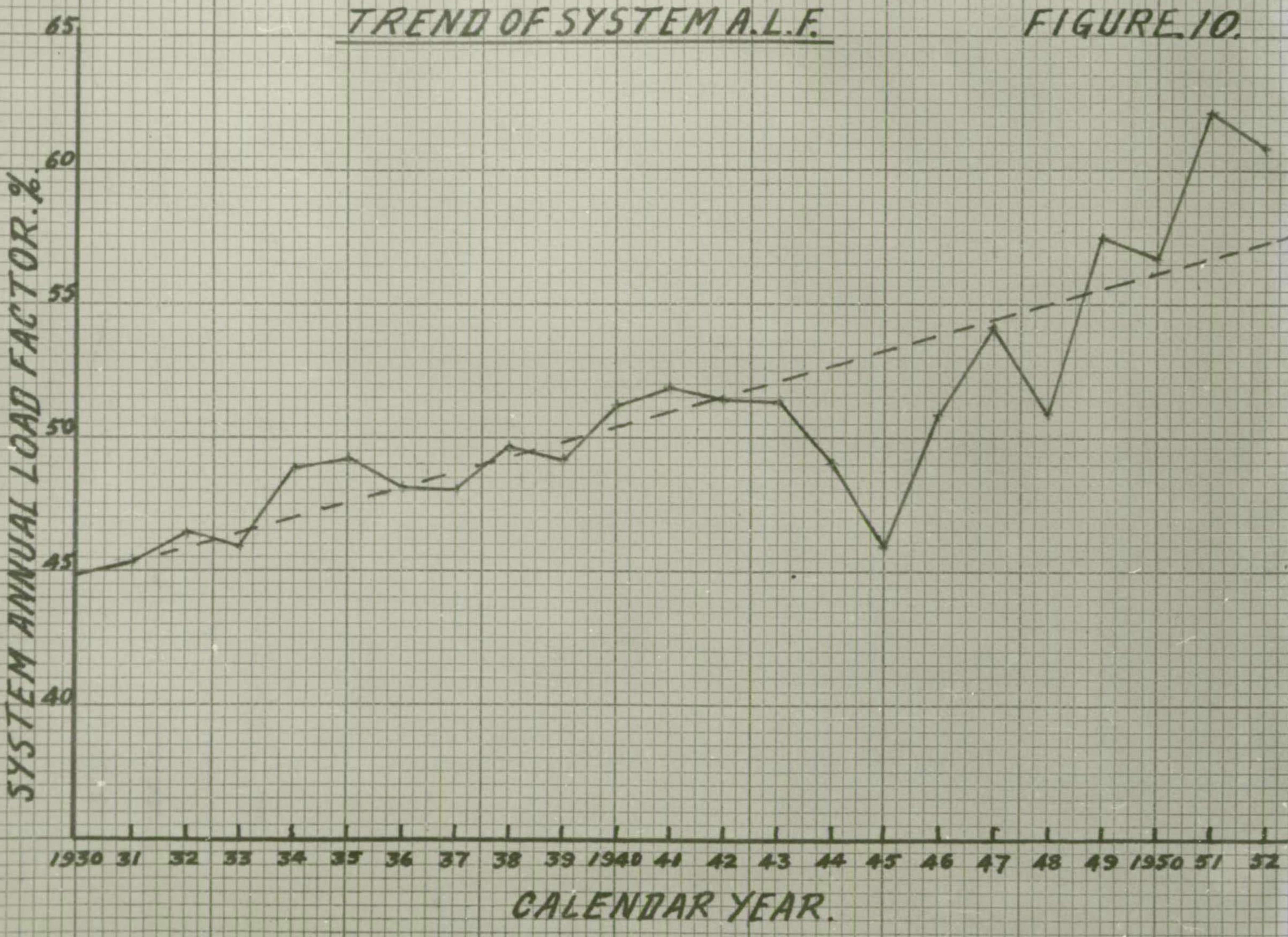
The optimum annual load factor on a system comprised only of steam plant will be that load factor at which the plant can operate without the provision of additional plant for the special purpose of carrying out routine maintenance.

The limitation of steam plant availability would under ideal loading conditions restrict the A.L.F. to between 85% and 90%, but the prospective working day load factors on general purpose systems are unlikely to exceed 85% average, and the week end, holiday and other reductions introduce a factor of approximately 88%.

The indicated upper limit of economic development of purely thermal systems therefore lies between 65% and 70% annual load factor. Above this limit additional capital expenditure will be needed for plant which returns little revenue. Plant operated below the limit will not produce the full revenue of which it is capable.

The trend towards higher system load factors is a relatively slow one, so that when adding a block of plant which can operate only at load factors below the system annual load factor it should be satisfactory to design the combination to operate at the overall annual load factor anticipated at the time of completion of the new

FIGURE 10.


TREND OF SYSTEM A.L.F.
SYSTEM ANNUAL LOAD FACTOR. %
65
60
55
50
45
40
1930
31
32
33
34
35
36
37
38
39
1940
41
42
43
44
45
46
47
48
49
1950
51
52
CALENDAR YEAR.

plant. Then system load growth will automatically adjust the relative proportions of plant to permit operation at increasing system annual load factors.

In the case of long term projects which can operate only at load factors below the system load factor and which are installed in stages, it is necessary to compensate for load factor trend.

The trend of annual load factors in both Britain and the U.S.A. is upward, but no comparable data has been obtained because of different methods of assessment.

Figure 6 shows the plant, load and capacity factor trend in U.S.A.

System Losses and Reactive Loading.

The total of system losses and energy used for supplying station auxiliaries is seen from Figure 1 to be between 20% and 25% of the energy generated on a general purpose system.

The losses include those in transmission, transformation and distribution; and the saving in capital charges, running, and fuel costs which could result from their reduction is again of a high order.

The principle of balancing the value of energy lost against the extra capital charges of plant, equipment and conductors necessary to reduce the losses is practised as far as possible, but it seldom approaches the ideal relation. While it is a simple matter to design for economic balance on an individual section which carries a fixed maximum demand or a steadily increasing annual M.D., it is very difficult to deal with a complex system which has varying rates of load growth from year to year and from one area to another. When, as at present, there is a restriction on finance available for development coupled with a plant shortage, the improvement of loss balance on transmission and distribution systems is liable to become a secondary consideration.

However, two methods of loss reduction which may be used with financial advantage on a long term basis are as follows :-

(i) There are few interconnected systems which do not have an unnecessary and uneconomic multiplicity of voltage levels between the upper limit of E.H.V. transmission and the lower limit of distribution. In many cases these voltages result from the perpetuation of those used when loads were lighter and areas were smaller or when reliability of cables and plant at voltages above 6.6 kV was questionable. In other cases short term economics have prejudiced long term

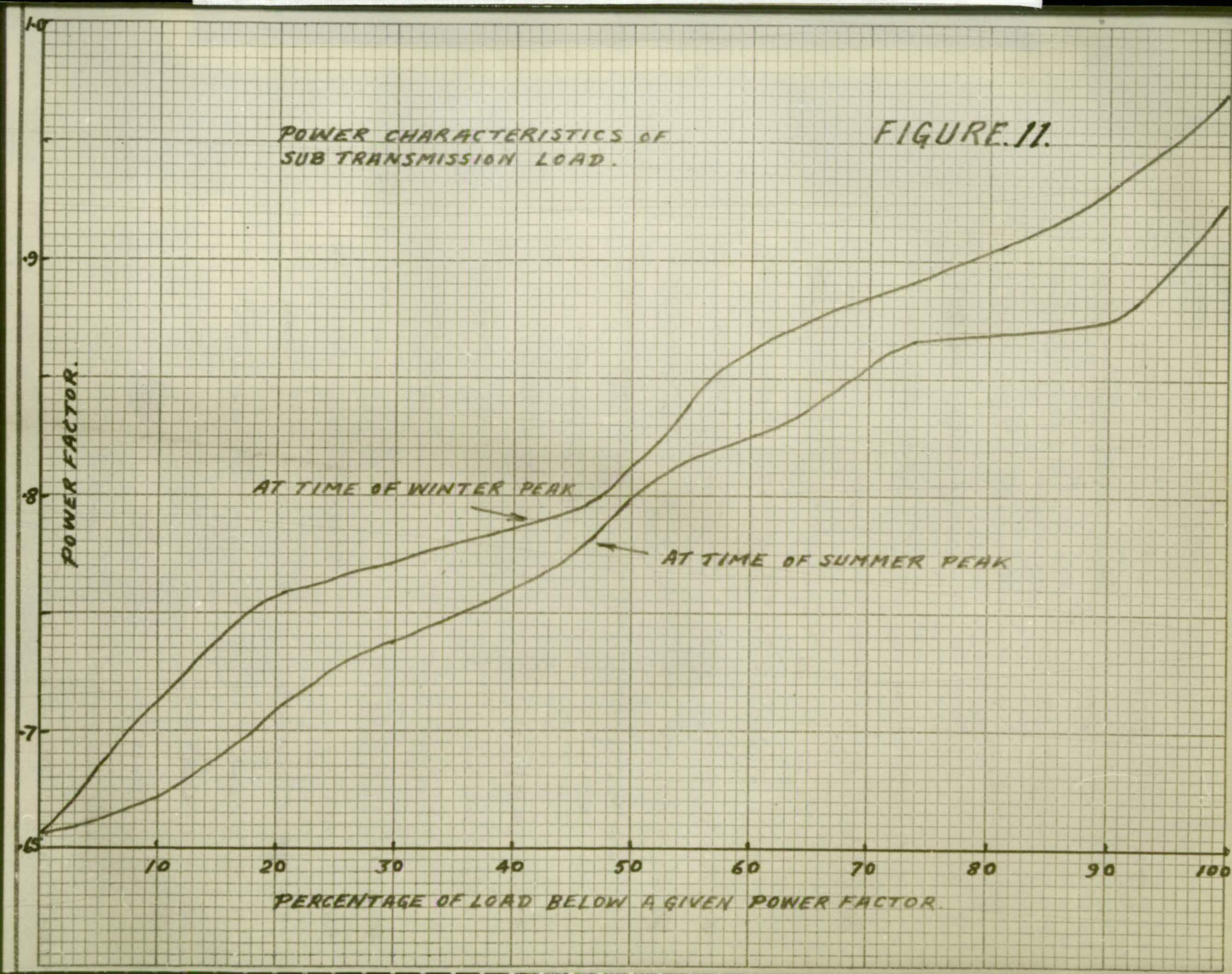


FIGURE. 11.
POWER CHARACTERISTICS OF
SUB TRANSMISSION LOAD.
AT TIME OF WINTER PEAK
AT TIME OF SUMMER PEAK
POWER FACTOR.
PERCENTAGE OF LOAD BELOW A GIVEN POWER FACTOR.
1·0
·9
·8
·7
·65
10
20
30
40
50
60
70
80
90
100

developments.

The number of stages of transformations with their associated losses becomes excessive and at times transfers of load between two points at the same voltage level is found to take place via step up and step down transformers. The minimisation of the number of voltages on a system by the gradual elimination of obsolete or non-essential voltage levels and multiple transformations, and the encouragement of development of medium and large size 11 kV. motors will therefore be of economic advantage.

(ii) Reduction of losses by the wider use of on load tap changing transformers, in preference to the more expensive combination of fixed ratio transformers and series regulators is possible in a number of instances.

The practice of installing fixed ratio or off load tap changing transformers was adopted by some authorities because of frequent faults experienced with early designs of on load tap changing transformers. The need for voltage regulation was met later by installing regulating transformers in series with the fixed tap transformers.

Modern on load tap changing transformers are reasonably reliable and even if voltage regulation is not essential initially, their installation at major subtransmission points will pay eventually.

Figure 11 shows power factor/load curves of a large subtransmission system, and indicates that nearly half the H.V. sub-stations supply peak loads at below 0.8 power factor and only about 20% of them supply peak loads with a power factor above 0.9.

Loads of this kind increase voltage regulation difficulties, and a wasteful excess of transformer capacity and circuit conductors is needed to carry them.

Present costs of power factor correction in the form of static or synchronous condensers (including buildings, structures, switchgear and control gear) are from £4 to £6/10/- per k.V.A.

The most economical method of power supply is to ensure an adequate measure of power factor correction at the points of consumer load. Not only are the relative costs of correction apparatus lower, but the size and cost of equipment on the supply system is also less.

In the case of small loads and for apparatus driven by small motors it should be sufficient for the supply authority to specify the types of equipment which it will permit to be connected to the mains.

For larger loads, kilovar as well as kilowatt metering, and maximum demand tariffs on both, are practicable and economically justified.

If these policies are accompanied by an active campaign of consumer education, mutually beneficial savings can be made.

Methods of Dealing with Peak Loads.

The following methods have been used to deal with peak loads and the choice in a particular case is generally made on the basis of cost comparison. (Other factors whose value is difficult to assess in terms of money may influence selection when estimated costs are approximately equal.)

(i) Specially designed peak load steam plant.

(ii) Peak load hydro plant.

(iii) Off peak pumped storage hydro plant.

(iv) Use of the short duration overload capability of steam plant for carrying the extreme peaks.

(v) Oil fired gas turbines.

(vi) Time expired or written off steam plant.

(vii) Load shedding.

Peak load steam plant has the advantage that it can be operated in emergency at load factors higher than those required for peak load duty without additional capital cost. Reliable estimates of the ultimate cost of steam plant are more readily obtainable than those for major long term hydro-electric projects.

Peak load hydro plant may be used only for short periods to supply load factors in excess of those required for peak load duty unless storages are increased or if surplus water is available in wet years. However, it has the alternative advantages that :-

(a) It is more flexible and can be loaded and unloaded more rapidly and at shorter notice than steam plant. It is therefore better suited to operation on frequency control.

(b) It is more reliable than steam plant.

(c) National fuel resources are conserved by its use.

(d) As it has a very long life, particularly in respect to the civil engineering works, some allowance should be made for the probable decrease in the value of money during its life. Longer periods than the 60 to 80 years normally used for depreciation of civil works could be adopted.

Because the productive capacity required from peak load generating plant is less than that for base load plant (i.e. it is required to produce fewer kilowatt hours per annum per kilowatt of installed plant, and to operate for shorter times) it is possible to install a cheaper type of steam plant for peak load operation.

An example of such plant is that built by the Montana Power Co. (Reference 37). 66 Megawatts of steam plant were designed to operate at a long term average annual load factor of 30%. A high proportion of the plant is of the outdoor type, there is no duplication of auxiliaries and non-essentials are eliminated. The boilers are suitable for oil or alternative fuel and the same type of plant could be added to hydro, thermal or combined systems.

Total cost was 90 dollars per kilowatt including land, all plant and structures, switchgear and step up transformers. The measure of the saving is seen by comparison with the 1952 costs in U.S.A. for base load steam plant of 135 to 155 dollars per kilowatt.

Converted to Australian rates this would represent approximately £56 per kilowatt. The present fuel cost for oil fired plant is between 0.6 and 0.8 pence per kilowatt hour, and there is likely to be a surplus of fuel oils and a reduction in price following the completion of refineries now under construction in Western Australia, Victoria and New South Wales.

Table 2 gives estimated costs for this type of steam peak load plant which would be installed at the load centre, and shows equivalent allowable costs for peak load hydro plant and transmission capitalised from 6.5% to 8.0%.

Table 2.

		10% A.L.F.	20% A.L.F.	30% A.L.F.
Peak Load Steam Plant Annual Charges Pence/K.W.H. (1)		0.958	0.479	0.319
Operation and Maintenance Pence/K.W.H.		0.562	0.285	0.197
Oil Fuel Cost Pence K.W.H. (2)		0.762	0.675	0.655
Total Cost Pence/K.W.H.		2.282	1.439	1.171
Total Cost per Annum per Kilowatt Installed		£8.33	£10.5	£12.83
Equivalent Capital Cost	(a)	£128	£162	£197.5
Allowable per Kilowatt	(b)	£119	£150	£184
for Peak Load Hydro Plant	(c)	£111	£140	£171
and Transmission (3)	(d)	£104	£131	£161

(1) Interest at 4.75 % } on £56/K.W.
Depreciation at 1.5% }

(2) Fuel oil at 180/- per ton delivered.

(3) Interest, depreciation, operation and maintenance capitalised at :-

(a) 6.5%

(b) 7.0%

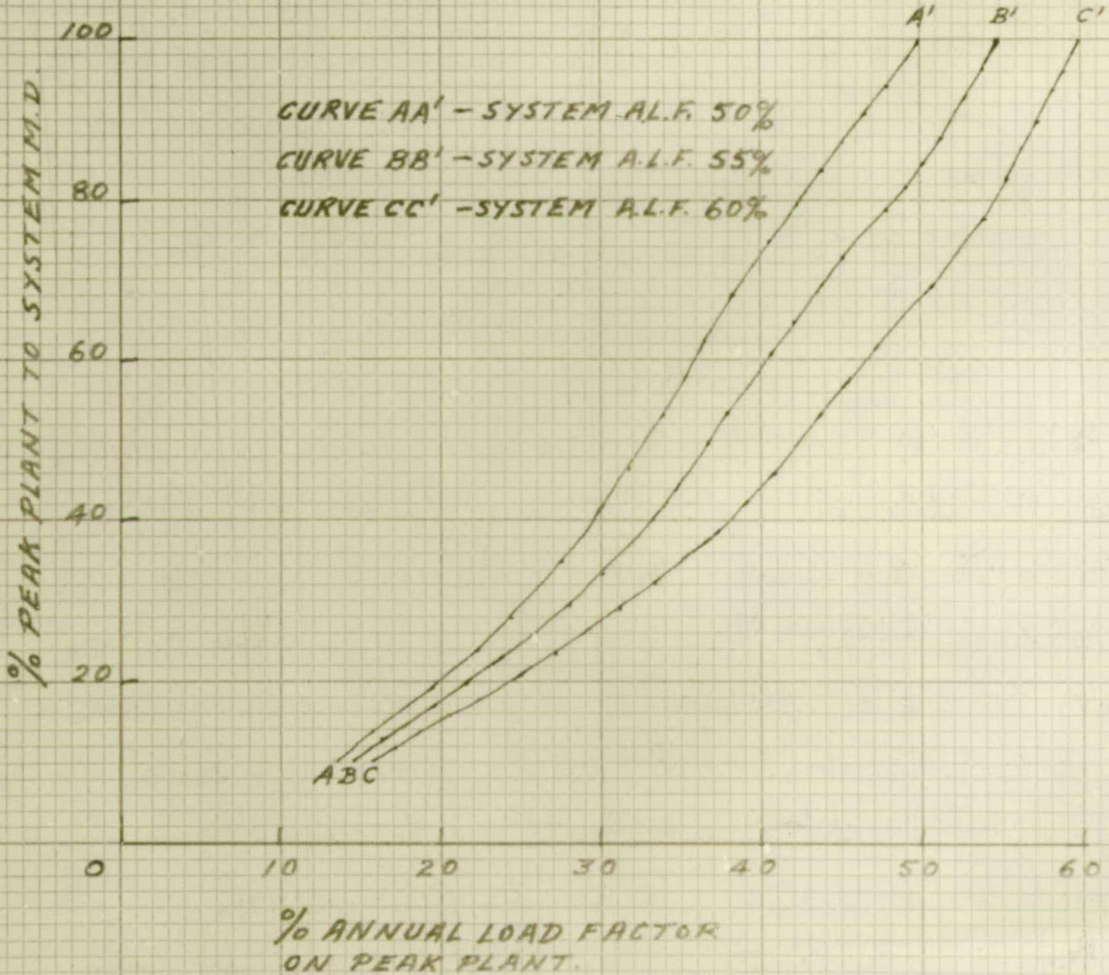
(c) 7.5%

(d) 8.0%

Peak load hydro plant has the advantages previously mentioned and if it can operate at an adequate load factor and comparable cost it is preferable to other types of plant.

In determining the minimum load factor required it is necessary to allow for :-

FIGURE 15.



CURVES SHOWING THE EFFECT OF SYSTEM A.L.F ON ANNUAL LOAD FACTORS REQUIRED ON PEAK PLANT WITH BASE LOAD STEAM PLANT CAPABLE OF 80% A.L.F.

(a) The varying availability of base load steam plant including reductions in availability during spring, summer and autumn, and at weekends.

(b) The maximum practicable load factors on steam plant.

(c) The loss in water turbine efficiency when operated on varying load.

(d) An operating margin to allow for variations from "straight line" or steady loading of steam stations.

(e) The probable trend of system load factor and shape of the daily load curves, if the project is a long term one.

(f) The extent to which the tops of the peaks in the daily load curve can be covered by steam overload capacity.

A close approximation may be made by comparing monthly weekday, monthly, weekend and holiday load duration curves (allowing for the above items) with the monthly water availability, provided that the duration curves are fully compensated and representative of prospective conditions. If, however, water availability varies appreciably during the worst months the more accurate, but tedious, method of comparison with daily load curves is necessary.

Figure 15 shows annual load factors for a particular system, and indicates the effect of change in shape of the daily load curves. In view of the many variables involved these curves have only a restricted application.

Accurate cost comparisons are best made by taking the overall system costs using alternative types of plant (Reference 31), but comparisons such as Table 2 may be used if the functions of the alternative types of plant are interchangeable.

Off peak pumped storage plant was installed on a large scale in Germany prior to the 1939-1945 war.

Rheinische- Westphalische- Electrisitatswerke A.G. had approximately 300 Megawatts of pumped storage plant equivalent to 16% of its total capacity. This plant operated at an overall efficiency of 65%, and the cost was 65% to 68% of equivalent steam plant. The primary steam plant was located on the Brown coal fields.

Pumped storage plant has a restricted application which depends on the location of suitable sites. It proved to be a weakness in the German defences during the last war when bomb damage to the primary steam generating plant had a cumulative effect in causing protracted power failures over a wide area.

The short time overload capacity of steam plant may be allocated to peaks which have a one to two hour duration and overloads up to 10% of the continuous rating of the plant may be carried economically in this way.

Oil fired gas turbines are emerging from the experimental stage. No reliable cost data is yet available, but indications are that they may be suitable and economic for duties up to 30% annual load factor.

Load shedding, although a drastic means of dealing with peak loads is worth consideration under the following circumstances.

If the system is arranged so that blocks of domestic load can be disconnected in rotation for short periods on extreme peaks, then any one district need be affected only two to three times per annum.

An examination over a 20 year period showed that the average annual loss in revenue would have been £1,170.

The capital cost of plant to supply this load would have been £1,780,000 and the annual charges allocated on a pro rata basis would have been £214,000.

The wide discrepancy between cost and revenue raises the point as to whether the small inconvenience suffered warrants such expenditure. Extension of ripple control or domestic feeder switching to cover all domestic supplies and not only hot water loads may be justified.

Operation of Peak Load Hydro Electric Plant in Conjunction with Base Load Steam Plant.

This very interesting problem, in its most complex form, requires consideration of the following variables :-

(a) Quantity of water available daily at each hydro station.

(b) Head of water available daily at each hydro station.

(c) Kilowatt capacity available daily at each hydro station resulting from (a) and (b).

(d) Kilowatt hour output available daily at each hydro station resulting from (a) and (b).

(e) Shape of the system daily load curve.

(f) Daily maximum demand on the system.

(g) Kilowatt capacity available daily at steam generating stations.

(h) Range and duration of frequency variation on the system.

(i) Degree of accuracy with which steam stations can hold load, and be controlled relative to the estimated section of the daily load curve allocated to them. This in turn partly depends on (h).

(j) Degree of accuracy of the forecast daily load curve.

(k) Degree of accuracy of the estimates for (a), (b), (c) and (d).

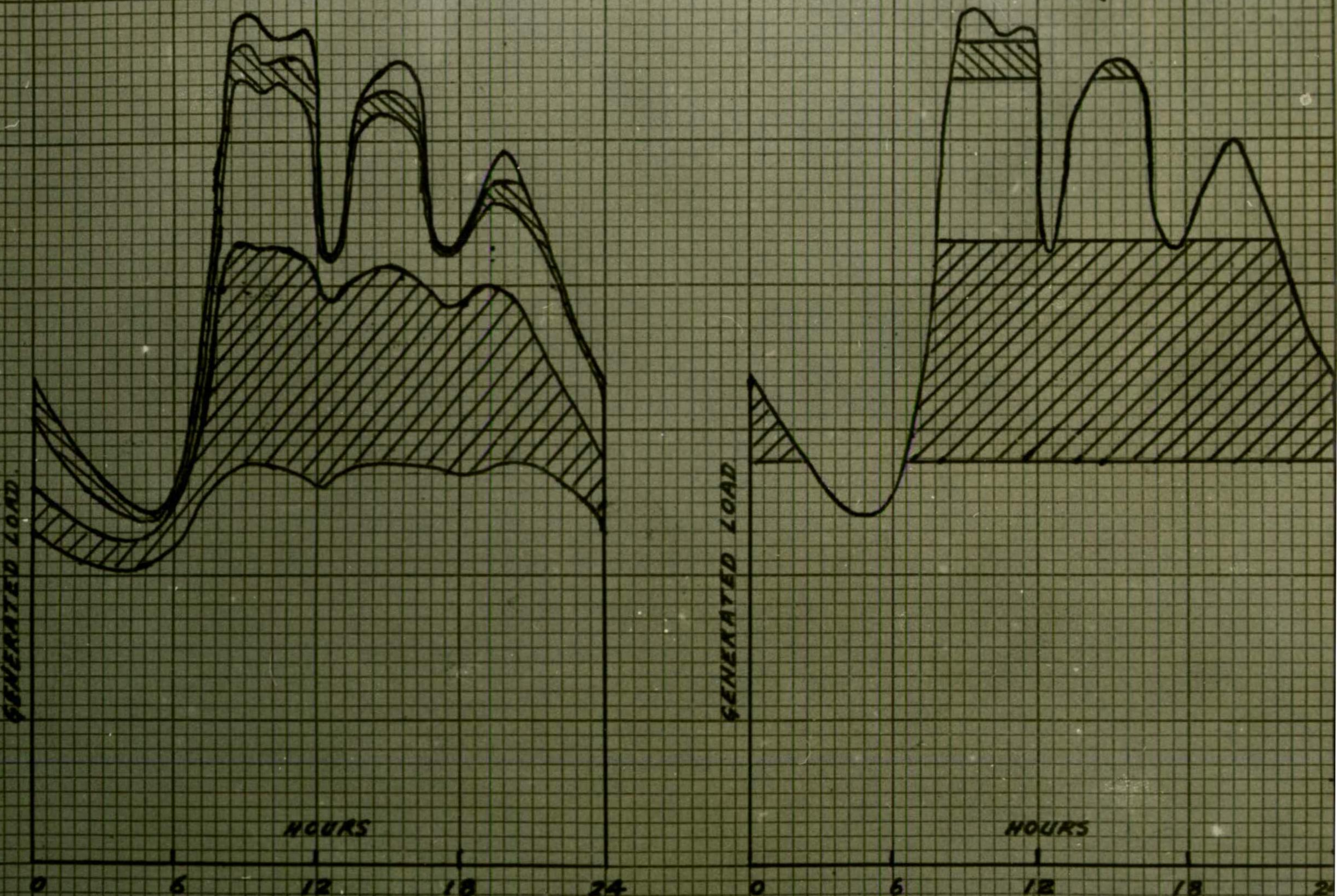
Peak load hydro plant could be operated on schedule, on frequency control or on a combination of the two methods.

Scheduled operation is simpler, but its use does not take advantage of the valuable superiority of hydro plant for rapid load changing nor does it permit the maximum use of the kilowatt capacity and available energy of the hydro scheme.

As far as the writer is aware the following proposed method of operation has not been published elsewhere.

TYPICAL DAILY LOADING OF STEAM GENERATING STATIONS.

FIGURE. 12.



ACTUAL STEAM PLANT LOADING, SHOWING THE EFFECTS OF SYSTEM LIMITATIONS AND STEAM PLANT OPERATING CHARACTERISTICS.

IDEAL SUBDIVISION OF LOAD IN ORDER OF RUNNING COSTS.

It is proposed that all hydro-electric stations be operated entirely on frequency control except on occasions when high water availability permits continuous 24 hour operation as base load plant.

The three pre-requisites are :-

(i) Reliable daily estimation of anticipated kilowatt and kilowatt hour capacity of hydro stations to be notified to the system control room in the evening of each preceding day.

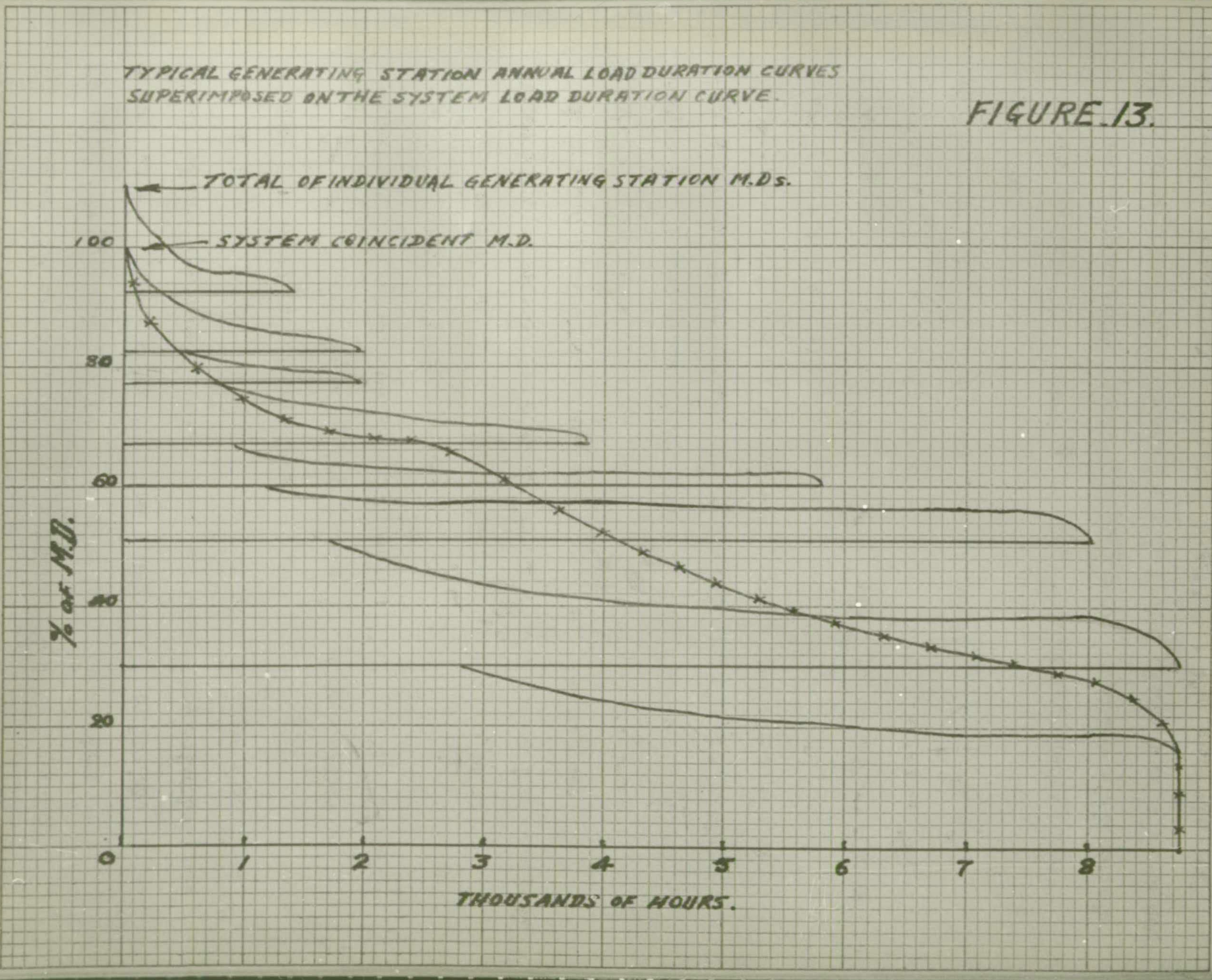
(ii) A means of automatic frequency control which keeps the speed variation of the system within narrow limits and allows simultaneous rapid load change on any number of selected stations, or alternatively sequential loading of selected stations.

(iii) An easily applied method for allocating the disposition of the hydro stations in the forecast daily load curve.

(i) Preparation of the hydro output estimates will require correlation of storage, pondage and inflow data from a number of sources, and provision of a special staff for this work is warranted.

(ii) The automatic frequency control equipment recently developed in Sweden (References 36 and 38) using electronic electric-hydraulic governor control gear appears to be well suited for standardised application for this purpose. This is an essential feature of the proposal, because the installation of machines with different or inadequately controllable governor characteristics will increase operational difficulties and errors.

(iii) The correct disposition of the hydro plant in the forecast daily load curve depends first on the accuracy of the hydrological information. It is unlikely that variations in the forecast water inflow during the actual operating period can be allowed to affect the current


TYPICAL GENERATING STATION ANNUAL LOAD DURATION CURVES
SUPERIMPOSED ON THE SYSTEM LOAD DURATION CURVE.
FIGURE 13.
TOTAL OF INDIVIDUAL GENERATING STATION M.Ds.
SYSTEM COINCIDENT M.D.
100
80
60
40
20
0
% of M.D.
1
2
3
4
5
6
7
8
THOUSANDS OF HOURS.

operation programme, it must be used in adjustment of the output for the following day. The complexity of the operating sequence and the short duration of some of the peaks would make progressive daily alteration extremely difficult.

Figure 12 shows the way in which it is necessary to load steam stations on a wholly thermal system in order to cope with rate of load change, transmission limitations and steam station operating characteristics. The effect of this operation on the annual load duration curves is shown in Figure 13.

In using peak load hydro plant it is necessary to endeavour to operate as nearly as possible to the ideal condition shown in Figure 12.

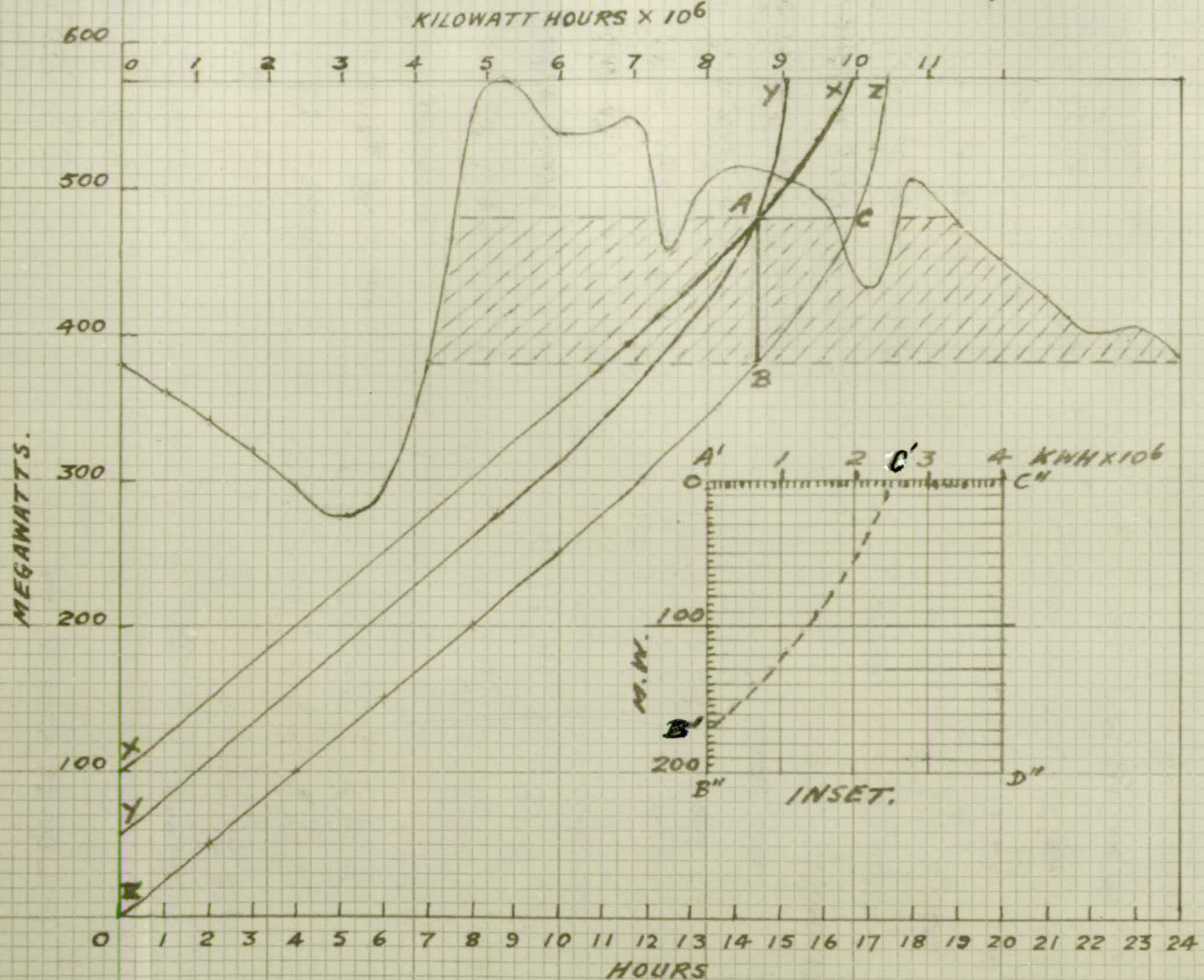
If an independent steam generating system were required to operate on a daily load curve which had several flat topped peaks it should be capable of doing so provided its rate of load pick up and drop off were adequate for the conditions imposed by the curve. When such a system is operated in parallel with hydro peak plant there will probably be variations from the ideal conditions due to difficulties in accurate timing of bringing in and cutting out peak plant and at other times in maintaining a steady load on the steam stations. The latter function will depend partly on the accuracy of frequency control.

The entire functioning of the base load steam plant will be characteristic of the particular system with which it is associated and the reliability of plant, the efficiency of local and central operating staff, and the rapidity of response of staff and plant will determine how closely actual operation approaches the ideal.

Zlatopolski (Reference 6) describes a method of determining the disposition of peak hydro-electric plant in the daily load curve and gives a series of curves to assist this determination. The method requires firstly the preparation

DISPOSITION CURVE FOR HYDRO-ELECTRIC PLANT

FIGURE. 14.



of a forecast daily load curve and secondly the forecast of daily maximum demand, minimum load, and calculation of average load. His method would be faster and more simple than the method described below, only if integrated daily load curves had to be prepared individually each day. If a graphical method is developed as follows it should be preferable.

Figure 14 shows the daily load curve, the integrated daily load duration curve (ZZ), and displacements of the latter in respect to the kilowatts (XX) and kilowatt hours (YY) anticipated for the day from the peak load hydro plant. From the point of intersection A of XX and YY, the line AB to the curve ZZ gives the boundaries and location of the section of load (in the shaded area) which the hydro plant is capable of carrying on frequency control and with full use of its power and energy.

If a transparent scale A"B"D"C" (inset) is set up on a draughting machine and moved squarely along the integrated load duration curve ZZ until the daily kilowatt allocation A'B' and kilowatt hour allocation A'C' meet the curve as shown, then the load range through which the hydro plant can be operated on frequency control is quickly and easily determined. The calculation can be simplified still further if typical daily load curves and integrated daily load duration curves are prepared in advance on a percentage scale and the forecast maximum demand for the day is used as a factor. A check may be made by planimeter measurement of the shaded area.

Operating tolerances can be incorporated as a result of experience to cover items previously mentioned.

It is considered that the foregoing proposal is practicable and capable of ensuring that the best use is made of both the steam and hydro generating plant in a combined system.

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Appendix 1.

Examples of the use of the daily load curve in conjunction with the integrated daily load duration curve for determining the disposition of Hydro-Electric Plant which has a variable day to day output have been derived from Figure 16. and the attached tracing.

Daily load curves were plotted on a Megawatt scale (lower group of curves), and also on a scale representing each daily load in percentages of its maximum demand (upper group of curves).

The days chosen were four consecutive Tuesdays, in February.

It will be seen that, in the upper group, the last three Tuesday load curves show relatively little variation from one another. The most marked deviation occurs on the last Tuesday (blue - - -) between 18.00 and 19.15 hours and was caused by very dull evening weather conditions.

The pronounced deviations of the curve for the first Tueasday (brown - - -) from the others are due to the effects of :-

(i) A public holiday on the previous day (resulting in lower night loading).

(ii) Weather conditions, reference Table 3. (resulting in higher afternoon and evening loading).

Table 3. gives the key to colours used and shows weather conditions in terms of temperature and relative light intensity at the main load centre. The effects of the two most important weahher variables from the loading point of view can be measured by using Table 3. in conjunction with Figure 16.

By compensating for loading in accordance with predictions and late hour measurements of weather and other conditions, forecast load curves on a scale representing percentage 6f daily maximum demand can be prepared with sufficient accuracy for Hydro-Electric disposition purposes.

Table 3.

Tuesday	Weather	Time. 00.00	05.00	07.00	08.00	12.00	17.00	18.00	24.00
First	Temp.C.	10	7			14	12.5	12	11
Brown	Light Intensity			9	14	9	8	3.2	
Second	Temp.C.	24	22			30	19	19	16.5
Yellow	Light Intensity			5	15	13	8	6.5	
Third	Temp.C.	16	15.5			21	19.5	19	16.5
Red	Light Intensity			3	8	25	13	6.5	
Fourth	Temp.C.	19	18			20	18	17	14.5
Blue	Light Intensity			4	9	30	6	3	

For ease of reference in the case of the examples shown, the integrated load duration curve for the third Tuesday has been plotted on the Megawatt scale and used in conjunction with its associated daily load curve. (As mentioned on page 29, groups of forecast daily load curves would be prepared in advance on a percentage of maximum demand scale for routine operational purposes.)

Examples are given in Table 4. for various Megawatt and Megawatt Hour combinations. These basic figures would be obtained from the hydrological data and adjusted by a factor to cover forecasting and operational limitations. This factor can only be determined by experience on any particular system as it depends both on the skill and efficiency of the estimating and operating staffs and on the design of system load control and frequency control equipment.

To obtain the required disposition band, the tracing is moved along the integrated daily load duration curve in a way similar to that in which the transparent graduated scale (proposed in the Thesis) would be used in a draughting machine, ie. by keeping the Megawatt and Megawatt Hour lines squarely on the graph paper markings and sliding the tracing along the intergrated load duration curve until the two points representing available power and energy both lie on the curve. In this position the two points will mark, on the Megawatt scale, the upper and lower limits of the disposition band for the Hydro-Electric Plant.

Table 4.

Example.	Hydro-Electric Output.			Disposition Band.
	M.W.	M.W.H.	% Load Factor	M.W.
AA'	100	640	26.7	441 to 541
BB'	145	995	28.6	416 to 561
CC'	180	1590	36.8	381 to 561
CD'	180	2310	53.5	340 to 520

BB' and CC' represent the top limits on the curve and the full Megawatt capacity could only be used if the Megawatt Hour output were not less than the figures shown.

The disposition band indicates the total system loads between which the Hydro-Electric Plant should operate and maintain system frequency control throughout the periods when it is picking up and dropping load.

These examples have been given for one co-ordinated group of hydro-electric stations which would have adequate pondages to permit group operation.

If the method were applied to several separate groups of hydro-electric stations, each group could be treated in a similar way.

Provided that the disposition bands did not overlap, the groups could be operated satisfactorily.

If prior investigation of the operation of the schemes showed that overlap of the disposition bands could occur, the upper band would be raised to a suitable position on the daily load curve. Any surplus of water resulting from this adjustment might be used at another period of the day or week according to the economics of storage.

APPENDIX. II

Since the publication of References 30 and 31 (with which the writer was closely associated) and the completion of the body of this thesis, several contentions in them which were disputed at the time, have now been supported by leading World Authorities. The development of gas turbines has also reached the stage where practical cost comparisons cam be made with regard to their suitability for meeting peak load demands and also providing emergency reservs at other times on interconnected systems

T.G.N. Haldane, Past President of the Institution of Electrical Engineers London, in his publication (Reference 43, Section 2.2) agrees that the annual load duration curve, (which had previously used) and even monthly load duration curves are inadequate for the purpose of settling the maximum practical installed capacity of a hydro - electric project designed to meet peak loads.

Derivatives from daily load curves, the use of mass curves, the careful study of load trends and the analysis of individual daily load curves are necessary for the correct design of combined hydro- thermal generating systems.

In Switzerland it was found, when selecting new hydro - electric projects for development, that varies planning authorities had used different technical and economic bases for their schemes and that a true comparison of the respective real values could not be made.

It was then decided to establish a set of standard conditions prepared by a Commission on behalf of the Government.

While these standards are designed to apply particularly to conditions in Switzerland, they provide a basis which could be suitably adapted for use elsewhere.

It is of considerable interest and significance that Megawatt capability of projects is not valued as much, but that the market value of the energy which could be produced is the criterion.

Projects are compared in relation to their "Evaluation Quotient" which is basically equal to

$$\frac{\text{Market Value of Energy}}{\text{Annual Costs}}$$

The value of energy is in turn determined by its availability.

Full value is given to 'firm' energy or to that which is available in the dry or minimum year.

Reduced value is given to energy which is available at other times.

Energy values are also variable according to the season of the year.

Costs include transmission liabilities outside the main consumer area.

There is thus a degree of similarity with the methods which the writer assisted in developing here.

System Losses.

Further to the section on this subject (commencing on page 17 of this Thesis) a new method has been developed in the Electrical Operations Branch of the S.E.C.V. for calculating System Losses (a) Between alternator terminals and main supply points.

(b) Between alternator terminals and consumer terminals.

The following data are used:-

(i) Total K.W.H. generated at all power stations (metered)

(ii) Total K.W.H. used to supply power station and terminal station auxiliary plant (metered and calculated).

(iii) Total Iron losses in all items of plant between the power station generators, main supply points and also the consumers' terminals, including iron losses in consumers' meters. (calculated)

(iv) Total K.W.H. ex main supply points and also sold to consumers. (metered)

(v) Total K.W.H. ex main supply points (metered)

(vi) Annual load duration curve.

(vii) List of average power factors for various total loads.

(viii) Annual current duration curve derivative of (vi) and (vii).

(ix) Annual copper loss duration curve (derivative of (viii)

The total copper losses are derived for the two sets of conditions (a) and (b) and the ordinates of the annual copper loss duration curves then determined.

From this information three groups of curves on plotted for (a) and for (b) to show system copper losses against load, system copper and iron losses against load, and system copper and iron losses plus units used in station auxiliaries against load. Finally annual loss trends in the two main sections of the System throughout the full range of load variation will be determined.

This method gives a reasonably accurate representation of average conditions. However the losses vary at any given load level at different times of the day and year according to the make up of the total load ie. the proportions of resistive and reactive consumer demand.

Refinements of the method are being developed by staff under the direction of the writer in order to evaluate the effects of these variations.

<u>Load Schedules for Hydro - Electric Plant, with Limited Pondages Operating in a Combined Hydro - Thermal System.</u>

A special problem has arisen recently during an interim stage in the development of the Kiewa Hydro - Electric scheme.

Kiewa No.3 power station which is upstream from Kiewa No. 4 power station has an installed nominal capacity of 26 M.W. and a capability up to 28 M.W. depending on head and tail water levels.

It is supplied with water via a tunnel from Junction Dam which is best used as a weekly pondage. The discharge from Kiewa No.3 power station flows into Clover Dam which has a storage capacity suitable for use only as a daily pondage.

Kiewa No.4 power station is supplied through another tunnel from Clover Dam, and will have a nominal ultimate installed capacity of 4-15.4 MW. generators. At present 2- generators are in operation and the capability is up to 33 M.W.

The discharge from Kiewa No.3 power station when on full load provides water at a rate per hour which is equivalent to approximately 1.6 hours full load running time at Kiewa No.4.

The fuel cost Variable on thermal stations is within the range of 0.2 pence to over 2 pence per Kilowatt hour at different stations.

When inflows to Junction Dam are high as at present, and the morning peak load on the system can be estimated with reasonable accuracy(of the order of 800 M.W.), the afternoon load varies by as much as 100M.W. between approximately 620 and 720 M.W. from day to day at the same times.

The availability of thermal plant to meet the load is also variable on a daily basis and may be restricted at any level within the range of fuel costs mentioned.

The high inflows to Junction Dam are such that the water can be used in two ways

(a) To maintain maximum Kilowatt output from power stations, Kiewa No.3 and No.4, during the working day and evening peak with a view to reducing output on high fuel cost thermal stations to a minimum. This can however cause spilling at Clover Dam and loss of Kilowatt hours which are in effect produced at zero fuel cost.

(b) To reduce Kilowatt output at Kiewa No.3 power station during the day, so that spilling does not occur at Clover Dam and the maximum possible number of zero fuel cost Kilowatt hours are generated at both stations. This can in turn result in off loading low fuel cost thermal stations during the night, while highest fuel cost thermal station load is kept up during the day. It is therefore necessary to strike on economic balance between the two conditions so that the total cost of meeting the daily load curve is kept to a minimum.

The schedules for Kiewa No.3 and No.4 power stations must also be capable of modification at short notice to cover changed conditions due to deviation of the actual system load from the estimated load curve and the reduced output due to limitations on any particular thermal station. These latter reductions occur several times in each week and often without notice.

Schedules for this purpose have been prepared by staff under the writers direction. Operating costs of the order of £2000 per week are involved for limited periods.

These schedules and the system loss curves referred to previously are of a confidential nature, but could be made available for inspection at the discretion of the State Electricity Commission of Victoria.

APPENDIX III

The attached reports on "Rotor Winding Deformation on Turbo-Alternators", and "Behaviour of Overhead Line Conductors under Short Circuit Conditions" were prepared in connection with investigations carried out by the writer.

Two unusual features were in evidence with regard to the former, as distinct from the deformation usually experienced on Turbo-alternators, which has occurred on machines subjected to frequent starting and stopping such as those on peak load duty or single or two shift operation.

They are:-

(i) The turbo- alternators affected were operated as base load machines, with infrequent starting and were run at steady rated load for long periods within specified temperature limits.

(ii) Deformation occurred on salient pole synchronous condensers which are usually free from this trouble; although such machines are subjected daily to widely varying loads (including changes from full load leading to full load lagging). and starting and stopping is of the same order as that on non base load alternators.

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ENGINEER FOR TECHNICAL SERVICES

ENGINEER FOR ELECTRICAL OPERATIONS 2nd March, 1953.

ROTOR WINDING DEFORMATION ON TURBO-ALTERNATORS

This report summarises the causes and effects of rotor winding deformation on turbo-alternators and describes the operating procedure of rotor pre-heating which has been used to reduce the extent of copper shrinkage.

During the last ten to fifteen years a large number of lengthy outages of turbo-alternators has occurred due to rotor winding deformation causing interturn short circuits. The failures have taken place on alternators of British, European and U.S. manufacture, and were particularly serious in England in 1943 when 410 MW of generating plant were out of service due to this cause.

The trouble has occurred mainly on two pole rotors of alternators above 20 MVA, but has also been reported on four pole rotors of large generators. Failure is more common on alternators which are used for peak load duties than on those at base load stations.

If alternators are operated above the designed rotor current, it is likely to aggravate the trouble seriously, in cases where normal temperature rise is close to standard specified limits. Deformation has occurred on rotors wound with aluminium conductors, but the problem has been investigated mainly on the usual copper wound rotors.

The following factors contribute to rotor winding deformation:-

1. Centrifugal force on the conductors.
2. Friction between layers of conductors.
3. The maximum temperature of the rotor winding.
4. The effect on 3. of the inlet temperature of cooling water.
5. The effect on 3. of the magnitude, duration and cycles of Megawatt and Megavar loading.
6. The temperature gradient between inner and outer conductors.
7. The extent to which the mica bonding medium is softened by heat and thrown outward by centrifugal force, and the positions at which this displacement occurs.
8. Metal used for conductors (pure or alloyed), and whether it is initially hard drawn or annealed.
9. Differential temperatures.
10. Method of clamping end turns.
11. Axial contraction of rotor body at operating speed.

Deformation of the rotor conductors is caused by centrifugal force and friction preventing free expansion or contraction of the conductors due to temperature stresses and the point is reached where copper flow and permanent deformation results. The effect can be either to shorten or lengthen conductors depending on the sequence of heating and cooling the conductors in relation to rotor speed.

The process is cumulative and the degree of movement can eventually produce shorted turns on the end windings.

The usual operating sequence, namely, to run a machine up to speed before the rotor conductors have been heated by field current, and to shut it down (or at least reduce speed and centrifugal force) before the rotor has cooled appreciably is conducive to conductor shortening.

The reverse cycle, namely, preheating the rotor by current injection at low speed, bringing it up to full speed while hot, and shutting down or reducing speed only after cooling down, would tend to produce conductor lengthening.

Preheating rotors at low speed, preferably on the barring gear (when fitted) or through special slip ring clamps while the rotor is stationary, running up to speed, loading and shutting down in the normal manner, greatly reduces conductor deformation on machines which are liable to this trouble on account of their design and construction.

It has been found that it is sufficient to heat the rotors up to maximum working temperature minus 40°C, before bringing them up to speed and to keep cooling water out off air coolers while running up. The time taken to preheat is dependent on the period elapsed since the last run on load, and the operating procedure during shutting down.

The following operating method has been used on machines shut down for six or seven hour periods overnight in order to reduce preheating necessary prior to putting on load next morning:-

1. Cut off cooling water to air coolers as load is reduced prior to shutting down.
2. If necessary, in addition to 1., increase reactive loading as MW loading is reduced.
3. If the machine has to be kept running at no MW load prior to shutting down to reduce turbine rotor temperature, maintain sufficient Megavar loading to keep rotor temperature up.

J. V. Brooks

ENGINEER FOR TECHNICAL SERVICES

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9. "Copper Data" - Copper Development Association Publication No.12, Sixth Edition 1943.

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Plant Affected

(i) Four 25 MW Alternators Nos. 7, 8, 9 and 10 at Yallourn Power Station (Rotors - two pole cylindrical). End windings on the rotors were distorted, with the effects most severe on turns nearest the periphery. Turns on several adjacent coils had clearances reduced almost to the point of contact.

Temporary repairs were made by reforming the copper, re-insulating and blocking.

A spare rotor wound with silver bearing copper alloy was supplied by the manufacturers.

(ii) Two 40 MVA Synchronous Condensers Nos. 1 and 3 at Brunswick Terminal Station (Rotors - six salient poles).

Distortion of rotor copper was most pronounced on turns nearest the pole face. Axial contraction severely damaged bakelite insulation at the pole ends, and radial displacement of the outer turns occurred along the length of the poles.

Re-design of the rotors has been necessary with a view to reducing friction and allowing free expansion and contraction of the windings, and additional bracing has been added to prevent radial movement of the copper.

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ENGINEER FOR TECHNICAL SERVICES

ENGINEER FOR ELECTRICAL OPERATIONS 19th December, 1952

(Copy - Electrical Operations Superintendent, Yallourn)

BEHAVIOUR OF OVERHEAD LINE CONDUCTORS UNDER SHORT CIRCUIT CONDITIONS

(With particular reference to the faults on Nos. 1 and 3, 11 kV General Service Ties at Yallourn at 11.14.41 and 11.14.43 a.m. respectively on Saturday, 29th November, 1952.)

General

Repulsion of overhead line conductors results from the electro-magnetic forces set up by the flow of fault current through them on either a phase to phase or a three phase fault. Conductor swinging on an unfaulted line which follows the incidence and clearance of a fault on an adjacent circuit may cause a further fault.

The movement of overhead line conductors under such conditions is not calculable on a purely theoretical basis, due to the fact that some of the variables involved are not accurately determinable. However, the initial movement of two horizontally spaced conductors carrying fault current approximates closely to horizontal repulsion at midspan, and the likelihood of contact on the somewhat erratic return swing is indicated by the magnitude of the outward swing. This initial movement can be estimated from the semi-empirical formula given later.

An increase in conductor length takes place due to stretching by the electro-magnetic forces and the heating effect of the fault current.

The displacement of conductors is approximately proportional to span length to the power 3/2, so that reduction of span length may be used effectively in cases where increased spacing is not a practicable method of preventing swing contact. Intermediate rigid insulated spacers can be used for this purpose on voltages up to 11 kV.

The burning of line conductors caused by contact following the clearance of an adjacent fault usually takes place near midspan and is very difficult to detect from the ground. The automatic opening of the second line faulted under these conditions follows the first one so closely that unless accurate recording devices are installed the faults may appear to have been simultaneous.

Maloperation of protective gear may be incorrectly assigned when faults of this nature are not located. In doubtful cases, calculation of line swings should be made to check the possibility of contact.

The variables which affect conductor swinging under fault are:-

(i) Nature of the fault, i.e., whether between two or three phases, and with or without fault to ground.

(ii) Magnitude of the fault current.

(iii) Duration of the fault current.

(iv) Tension (or sag) of the conductors.

(v) Span length.

(vi) Conductor size.

(vii) Conductor spacing.

(viii) Direction and velocity of the wind.

The maximum movement occurs with a fault between two phases. In the case of a three phase fault, each conductor is acted upon by a force due to its own current and the resultant field set up by the currents in the other two conductors. The conductors tend to move away from one another and the forces are smaller than for the same effective values with faults between two phases. With a flat arrangement of three conductors on a three phase short circuit, the two outer conductors are thrown outwards and the centre conductor has little movement.

Estimation of the movement on a fault between two phases covers the worst condition and can be obtained by use of the following semi-empirical formula which is based on a series of over 330 field tests by the Los Angeles Bureau of Power and Light.

Other effects can be observed if required by the use of scale models.

$$\left(0.0447 Y_o \frac{I^2}{A} \log_e \left(\frac{C + 1.5 H}{C} \right) \right) \div K_o H =$$

$$\frac{(18 \times 10^6 K_o H^2)}{T_1^2 Y_o} + 2 - \frac{5.33 \times 10^6 I^2 t}{A^2 T_1}$$

where:-

A = Cross section of the conductor in circular mils.

I = Effective single phase short circuit current in each of the two conductors in amp.

Y_o = Initial sag at centre of span in feet.

C = Spacing between conductors in feet.

H = Maximum horizontal distance moved by conductor at centre of span in feet.

K_o = Initial loading ratio (for covered cables), i.e., ratio of weight of cable loaded with weather-proof or other covering to weight of bare cable.

T_1 = Initial tension in cable in lb./sq.in.

t = Time in seconds to reach maximum deflection.

This formula applies to horizontally spaced conductors and must be solved by trial and error due to its logarithmic form.

The empirical formula for 't' is:-

$$t = 0.25 \sqrt{Y_o} + \frac{2.65}{\left(\frac{I^2}{AC}\right)^{2/3}}$$

Application to the Yallourn Fault

The cable fault on No.1 General Service tie was finally a three phase fault to ground and could have initiated as a fault between two phases or single phase to ground.

Data are:-

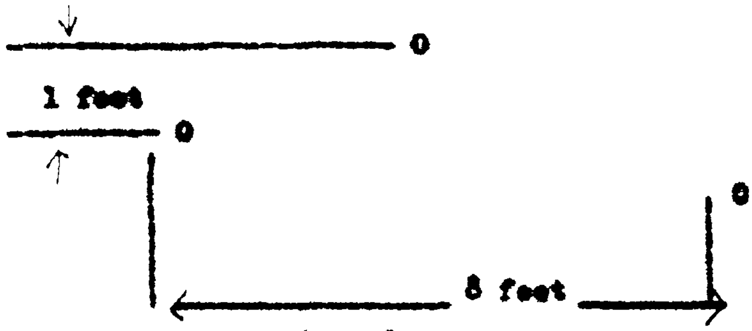
Fault current in No.3 General Service tie approximately 12,000 amperes

Span length = 200 feet

Sag = 9.8 feet at 62.6°F.

conductor = 37/.103, O.D. 0.721 inches
cross sectional area 0.3 square inches
382,000 circular mils.

Spacing as in sketch below:-



$$\text{sag (feet)} = \frac{S^2\, s\, e^2}{8T_1}$$

T_1 = tension in conductor in lb./sq.in.

$$= \frac{40{,}000 \times 3.93}{8 \times 9.8}$$

= 2,010 lb./sq.in.

$$t = 0.25 \times 3.13 + \frac{2.65}{\left(\frac{12{,}000^2}{4 \times 382{,}000}\right)^{\frac{2}{3}}}$$

$$= 0.783 + \frac{2.65}{20.7}$$

= 0.911

A = 382,000

I = 12,000

Y_e = 9.8

C = 4.0

Ko = 1

$$\frac{0.447 \times 9.8 \times 12{,}000 \times 12{,}000}{382{,}000} \log_e \frac{4 + 1.5H}{4} =$$

$$\frac{18 \times 10^6\, H^2}{2{,}010 \times 2{,}010 \times 9.8} + 2 - \frac{5.11 \times 10^6 \times 12{,}000 \times 12{,}000 \times .911}{382{,}000 \times 382{,}000 \times 2{,}010}$$

$$\frac{1{,}650 \log_e \frac{4 + 1.5H}{4}}{H^2} = \frac{H^2}{2.2} - 0.27$$

<u>1st Trial assume H = 9</u>

$$\frac{1{,}650 \log_e 4.375}{81} = \frac{81}{2.2} - 0.27$$

$$\frac{1{,}650 \times 1.475}{81} = 36.9 - 0.27$$

30.03 = 36.63

<u>2nd Trial Assume H = 8.5</u>

$$\frac{1{,}650 \log_e 4.19}{72.2} = \frac{72.2}{2.2} - 0.27$$

$$\frac{1.650 \times 1.433}{72.2} = 32.8 - 0.27$$

$$32.8 = 32.53$$

Therefore, maximum outward swing at midspan = 8.5 feet approx.

This swing could only occur under worst conditions, i.e., with a phase to phase fault supplied through the middle and one of the outer conductors of the overhead line for a duration of 0.91 seconds, and the return swing if the fault cleared at this instant would probably be less than 7 feet at midspan on each conductor.

It is evident that with the low conductor tension and consequent large sag of 9.8 feet on the span investigated conductor contact could occur under the fault conditions of 29th November.

(Signed) J.V. Brooks,
ENGINEER FOR TECHNICAL SERVICES

Action Taken

As a result of this investigation intermediate line supports have been provided and no further trouble has occurred during the ensuing three-year period.

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APPENDIX IV.

In addition to the reports in Appendix III two other reports of a confidential nature have been submitted to the Examiners.

These reports deal with:-

(i) Analysis of System Losses.

(ii) The Combined Operation of

(a) Thermal Generating Plant.

(b) Hydro Generating Plant with limited storage and capable of output only at load factors below the System load factor.

(c) Hydro Generating Plant installed in association with an Irrigation Scheme.

This report covered an estimate of operating conditions up to nine years ahead and took into account the complementary nature of the three different types of plant. It was prepared for the purpose of ascertaining the adequacy of water storage requirements for Plant (b) andinvolved the detailed analysis of day to day operation.

While these reports cannot be published, the writer is able to discuss the principles involved with any interested Authorities.