THE PROBLEM OF
ESTIMATING THE BENEFITS FROM WATER
RESERVOIR CAPACITY FOR POWER PURPOSES

A Thesis
Presented to
the Faculty of Graduate Studies and Research
The University of Manitoba

THE UNIVERSITY OF MANITOBA
ELIZABETH DAFOE LIBRARY

In Partial Fullfillment
of the Requirements for the Degree
Master of Science in Civil Engineering

by
Karl Johann Maximilian Renger
November 1963

ABSTRACT

A study was made of ways and means to estimate the benefits expected from the provision of storage capacity for power purposes in reservoirs with controlled outflow.

First, the problem was analyzed to establish the factors having a bearing upon the magnitude of the benefits from storage capacity. These factors are: runoff, precipitation-evaporation-difference over the reservoir; load, relative reservoir size, methods of reservoir operation; affected head, cost relations of hydro-electric and thermal-electric generating and transmission facilities. Their relative importance, the degree of predictability, and the joint effect of influences in combinations were considered.

Then, methods of solution were studied, grouped, and discussed. As a representative of the simple methods the mass-curve method was described in greater detail. Methods endeavouring to arrive at a more reliable estimate by means of simulating future system and reservoir operations approximately were described featuring use of the basic rule curve and economy guide lines.

Modifications and extensions were developed for two specific applications. Namely, for estimating (a) the benefits of regulation of Lake Winnipeg for assumed Nelson River power

developments and loads, and (b) the benefits of storage capacity increments of the Grand Rapids reservoir.

The studies led to the following conclusions:

(1) Various different methods can be used to estimate the benefits for electricity generation which can be derived from water storage regulation, but the results from all methods, even the most refined ones, will be affected by the assumptions which were made regarding future flows, loads, system composition, cost of energy from alternative sources, degree of downstream development, and other factors.

(2) Because of the impossibility of knowing most of these factors with any degree of accuracy far into the future, one should resist the temptation to go to great refinements in the methods solely for the purpose of estimating the future storage benefits.

(3) Every reservoir problem seems to be different in some respect from the others. Many variations to the main solution methods are possible. Modification of the selected solution method, to suit the reservoir problem to be solved, is advantageous.

TABLE OF CONTENTS

CHAPTER PAGE

LIST OF TABLES

LIST OF FIGURES

FIGURE PAGE

INTRODUCTION

As is well known, unregulated river flow is subject to daily, seasonal, and year to year fluctuations. The demand for hydro-electric power is also subject to daily, weekly, seasonal changes, and to year to year changes. Water storage ranging from daily pondage to long term storage, extending over years, is therefore an important means to match the water supply more closely to the power requirements.

The provision of reservoir capacity for storage purposes is often the by-product of providing head for a hydro-electric plant at the reservoir outlet. In the planning of most hydro-electric power projects, however, additional expenditures are being considered solely for the purpose of providing storage capacity (or additional storage capacity) for flow regulation. In order to make an economic selection of the storage capacity to be provided, it is necessary to weigh the costs of providing that additional storage against the benefits estimated to be derived from the additional storage. Therefore, for economic reasons it is important to know at least approximately the benefits of different amounts of storage capacity for the hydro-electric project under consideration, in addition to the costs involved. Also knowledge of the benefits of storage for power purposes is often desirable because other interests may press for a reduction in the fluctuations of the reservoir level, forcing the power interests to defend their position by emphasizing quantitatively the economic value of the storage at stake for future hydro-electric energy generation.

This thesis is restricted to the power benefit aspect of seasonal and over-year storage. In the first chapter the factors having a bearing on the power benefits of storage are discussed. The difficulty or impossibility of predicting these factors is emphasized. The second chapter is devoted to the description of various methods of estimating the power benefits of the storage capacity. The third chapter presents the solution approaches which were developed for two specific cases in Manitoba, namely, for future Lake Winnipeg regulation and for the Grand Rapids Reservoir. The illustration of the methods is emphasized rather than the presentation of the results. The Lake Winnipeg regulation study referred to was concluded in 1958 using potential site developments on the Nelson River and load assumptions as of that date.

CHAPTER I

FACTORS INFLUENCING THE AMOUNT OF BENEFITS FROM STORAGE

The most important characteristic of the drainage basin that influences the benefits from a given storage capacity is the runoff amount and its pattern. The most important characteristics of the power system with respect to storage benefits are the firm load and its variation with time, the affected developed head, and the generation sources: hydro-electric plants with regulated flow, run-of-river plants, conventional steam plants, nuclear plants etc.

Although these factors are discussed separately in the following, it is really the way these factors are combining that determines the benefits from storage. For instance, if the high natural runoff season nearly coincides with the high load season (as in Great Britain),[3*] storage would tend to be less valuable than if natural flow pattern and load pattern were mismatched as is the case in Manitoba.

---

*Raised numerals designate references contained in the Bibliography on pages 105 and 106.

RUNOFF AND
PRECIPITATION-EVAPORATION-DIFFERENCE OVER THE RESERVOIR

The runoff from a drainage basin may either constitute inflow to a reservoir or a group of reservoirs, from which the flow is then released in suitable magnitudes, or it may enter a river stretch between the reservoir outlet and the downstream hydro-electric power plant as unregulated runoff. In both situations, the runoff volume and its seasonal and over-year fluctuations have a profound effect on the required storage capacity and the benefits accrueing from it. The accumulated difference between the inflow upstream of the reservoir dam and the outflow has to be accommodated in the reservoir or released from it. The unregulated runoff downstream of the dam calls for appropriate outflow changes from the reservoir upstream and is thus influencing the value of the upstream reservoir too.

Since the runoff is the most important factor in determining storage capacity and benefits, the expected runoff has received the greatest attention in numerous studies. Although it would be desirable to know the runoff sequence in advance, for the useful life of the reservoir, it is generally recognized that it is impossible to make such predictions with any degree of confidence. In attempts to predict long term weather cycles, the correlations between sun spot cycles and low rainfall periods, or long term fluctuations in river flows, have been studied, especially during the early 1930's.[13,14] In at least one reservoir study, the prediction of sun spot maxima and minima (in conjunction with past flow records) was utilized to construct a hydrograph extending 20 years into the future.[8]

Most frequently, however, a repetition of past flow records in chronological sequence, eventually modified for expected future upstream water uses, is assumed. Some investigators, in studying long term storage problems on the Nile, employed past flow records as basic data for probability studies of the expected range of the magnitude of accumulated deficiency.[10,7] Their special approach was made possible by the use of the year as time element. In the vast majority of storage problems this time unit would prove too large. Short term runoff predictions, for instance, of the spring runoff based on antecedent flow conditions, snow cover, precipitation and temperature rise during the melting season, are frequently employed. Their significance for the subject of the thesis, however, appears to be limited to the effect it has on the method of reservoir operation.

The precipitation-evaporation-difference over the reservoir area, positive or negative, can be considered part of the inflow. The total inflow is then conveniently referred to as inflow-available-for-outflow. In general, the precipitation-evaporation-difference over the reservoir is only a small fraction of the inflow. However, evaporation from the reservoir surface is of importance in arid or semi-arid regions, especially for long term storage reservoirs with large surface areas. In some regions, the long term averages of evaporation and precipitation balance. This is sometimes considered enough reason to ignore the effect of evaporation and precipitation over the reservoir. But even when precipitation and evaporation balance over a long period of time, it is very likely that during summer seasons of low inflow evaporation will predominate and during flood seasons in wet years the precipitation will predominate, especially if the flood season coicides with the low temperature season.

Since the inflow component (positive or negative) resulting from the precipitation-evaporation-difference over the reservoir is a function of the reservoir surface area, the total inflow-available-for-outflow is somewhat influenced by the changing storage content of the reservoir. In most cases, however, this influence can be neglected, especially where the surface area changes relatively little with the water surface elevation. Long term predictions of precipitation and evaporation appear just as impossible to make at the present time as runoff predictions, and repetition of past sequences of occurrence is usually assumed.

LOAD, RELATIVE RESERVOIR SIZE AND METHODS OF RESERVOIR OPERATION

The reservoir may be used to modify the natural river flow into an outflow that should be as nearly constant as possible or it may have to transform a large spring runoff into small spring and summer outflows and large winter releases. Many other variations, depending on the annual load curve and the system resources, are possible. Depending on the reservoir size relative to the annual runoff, the reservoir may be used for seasonal storage only, for predominately over-year storage, or even long term storage extending over many years.

If the hydro-electric plant (or plants) served by the reservoir supplies power exclusively to large industrial consumers, for instance, the load may be fairly constant the year round indeed. If the further condition of negligible unregulated inflow between the reservoir outlet and the power plant is fulfilled, the reservoir will have to be regulated to a constant outflow rate. The storage will be valued in accordance with the severity of the consequences of power shortage, or the costs of alternative power (e.g., steam-electric power), and the estimated extent of such shortages which would occur without storage. As the ratio of required outflow to mean inflow increases, the frequency and extent of shortages will increase and this will increase the benefits of incremental storage at a given reservoir capacity.

Most reservoirs, however, are regulated for varying outflows; for instance, to supply a seasonally changing load, to supplement the output of run-of-river hydro-electric plants, or to compensate for the changes in unregulated local inflows between the reservoir and downstreams river plants. This required outflow pattern is frequently just the opposite of the inflow pattern, requiring large storage capacity, i.e., increasing the value of incremental capacity for a given total storage capacity.

On the other hand, a large amount of conventional steam-electric generating capacity in the system may permit very flexible reservoir operation and the adjustment of the outflow pattern to the inflow conditions, the given reservoir size, and momentary content, thus reducing the chances of spillage and shortage. Obviously, with such a method of reservoir operation, the value of incremental storage tends to decrease. Nuclear plants in the system, by virtue of their requirement of a fairly constant base load, have the opposite effect upon reservoir regulation requirements and therefore tend to increase the benefit of storage.

It appears that the methods of reservoir operation can be grouped into three main types:

(a) Regulation for a constant outflow rate.

(b) Regulation for seasonally varying outflow rate but following a fixed pattern.

(c) Flexible regulation with outflow rates adjusted to requirements, taking into consideration the season of the year, the momentary storage content, the costs of energy from other sources, expected future inflow, and eventually the consequences of power shortage.

The last mentioned type of regulation is the most important, it permits the optimum use of the water resources. The composition of most power systems calls for this type of regulation.

In the foregoing, attention was given to regulation for power requirements. Frequently, the regulation is influenced by conflicting other interests as irrigation, navigation, recreation, malaria control, etc. These constraints, imposed upon regulation, have to be taken into account when assessing the benefits of storage.

AFFECTED HEAD, COST RELATIONS OF HYDRO-ELECTRIC AND THERMAL-ELECTRIC GENERATING AND TRANSMISSION FACILITIES

The magnitude of the developed head at the reservoir and downstream of the reservoir is one of the most important factors affecting the storage benefits. The storage benefits may increase linearly with the developed head or to a lesser degree, depending on the way the importance of the upstream storage diminishes in a downstream direction, for instance, through the regulating effect of other downstream reservoirs, natural lakes and swamps, or just through greater diversity in the runoff as tributaries enter and the size of the basin draining into the river increases.

The flow regulation affects the cost of electric power in two principal ways. Firstly, it usually permits the installation of larger amounts of firm hydro-electric capacity than would be feasible without storage. This results in so-called capacity benefits if the cheapest alternative of providing capacity costs more on a yearly charge basis than the additional firm capacity made feasible by increasing the storage capacity. Secondly, flow regulation permits increased firm hydro-electric energy production as it reduces spillage and the production of interruptible hydro-electric energy. This permits either increased revenue from larger energy sales and from a shift in the quality of part of the energy or it permits cost reduction of producing the required amount of firm energy. Often the result is a combination of both, increased revenue from sales and reduced production costs. To distinguish these benefits from the capacity benefits, they are commonly referred to as energy benefits. In most cases of flow regulation, capacity and energy benefits are achieved. However, it depends on the peculiarities of the situation which benefit predominates. During the life of the reservoir the relative value of the benefits may shift. Initially capacity benefits could be of importance, later the energy benefits may surpass the capacity benefits in importance. Even at a certain time in the life of a reservoir, the incremental capacity benefits could predominate if a relatively small storage capacity for the reservoir were selected, but would diminish with increasing reservoir volume at a faster pace than the incremental energy benefits to an extent that the energy benefits might be more important when a large storage capacity were selected.

To illustrate the effect of cost relations, two cases are considered.

Case 1: A reservoir serves a hydro-electric plant which was designed for high capacity factor operation in spite of favourable site conditions for a larger plant. The annual costs for incremental hydro-electric plant capacity are relatively small. The main purpose of additional reservoir capacity would be to increase the dependable flows, thus making the additional hydro-electric capacity firm. Further, let it be assumed that the most suitable alternative to the hydro-electric plant capacity addition would be construction of a high efficiency thermal-electric base load plant near the load center. The cost for electric energy from this source would be relatively low but the annual fixed charges would be high, hence the capacity benefits of the incremental reservoir capacity are likely to predominate.

Case 2: A reservoir serves a river where a new low head development appears to be the only feasible addition to the existing hydro-electric plants. The main purpose of additional reservoir capacity would be to increase the firm energy output of all plants by decreasing the spillage of water through improved regulation. Further, let it be assumed that the alternative to increasing the reservoir capacity and construction of the low head hydro-electric plant would be the construction of a steam-electric plant of low efficiency for peaking, but to be base loaded when adverse river conditions demand. In such case, the firming up of additional hydro-electric capacity may not in itself result in a capacity benefit since the thermal-electric capacity may be cheaper, but the reduction in firm energy production costs, made possible over the years by virtue of increased reservoir capacity, is likely to be important. Part of the energy benefit may even have to compensate for an excess of incremental hydro-electric capacity costs ober the costs of thermal-electric capacity.

Chapter I shows that many factors influence the amount of benefits from storage. These factors should be known over the useful life of the reservoir in order to determine the optimum reservoir capacity to be selected by comparing the benefits with the costs of providing additional storage. All the factors, even the developed head and cost relations, are subject to considerable change during the useful life of the reservoir. Predictions of most of these factors are hardly more than speculation.

Nevertheless attempts have to be made to estimate the benefits of storage over a prolonged time period in order to get some guidance when assessing how much storage capacity appears economically warranted. It also happens that the storage capacity of a reservoir allocated to power has to be justified to enable rejection of claims of other interests.

The next chapter describes and discusses several methods in use for the purpose of estimating storage benefits or capacity requirements. From the contents of the preceding chapter, one may conclude that a high degree of refinement in the mechanics of solution is hardly justified since even the most refined procedure cannot give more reliable results than the reliability of the assumptions permits.

CHAPTER II

METHODS OF SOLUTION

In the following sections several methods that are helpful in the assessment of the effect of storage capacity, and consequently of its benefits, are described. The methods in use are grouped according to the effort required rather than according to applicability to different situations.

SIMPLE METHODS

One of the best known means for studying the effect of storage capacity is the mass-curve. It was first suggested by Rippl, a British engineer.[1] Figure 1 illustrates the method. The cumulative inflows (preferably net inflows adjusted for evaporation and seepage losses) in the appropriate units (cfs-days, cfs-weeks, or cfs-months) are plotted as ordinates y against the time (days, weeks, or months) as abscissas x. The resulting curve is the mass-curve of inflows.

Usually, past inflows in chronological order are employed, assuming that the pattern would be representative of the future; however, the same procedure can be used for any predicted future inflow sequences.

The slope of the curve at any time represents the rate of inflow (in cfs) at that date.

The outflows from the reservoir are represented in the same way as the inflows. The simplest case is, of course,

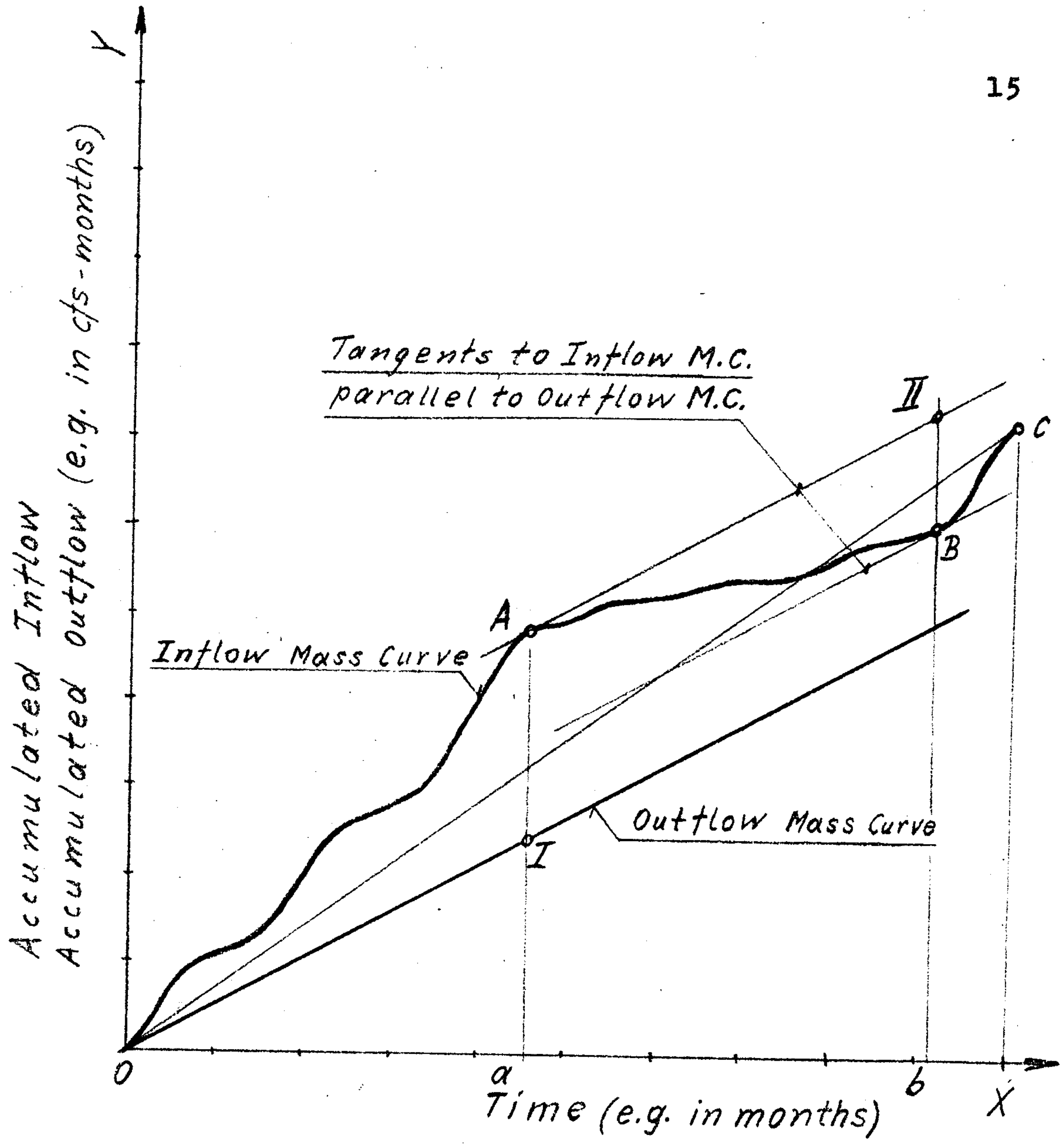


Fig. 1 Mass Curves (constant outflow rate)

outflow from the reservoir at a constant rate, represented by the slope of the straight line outflow-mass-curve. Most frequently, the mass-curve method is used in connection with constant rates of outflows, but it represents no difficulties to use any other pattern of outflows, e.g., repeating seasonal variations as shown in Figure 2. In this case, it is expedient to have the outflow-mass-curve plotted on a separate sheet of transparent paper and to shift it over the inflow-mass-curve (in the direction of the ordinate) to the most unfavourable possible positions to determine the storage requirements. The difference in slopes between the inflow-mass-curve and the outflow-mass-curve represents the rate in cfs by which the inflow exceeds the outflow, and is the rate of replenishment of storage; if this difference is negative, it represents the rate of draw from storage. The difference in the ordinates represents the accumulated storage (replenishment or draw) since the time of coincidence of the two curves, e.g., the distance A-I in Figure 1 represents the total storage replenishment during the time interval o to a. The outflow-mass-curve A-II has been drawn tangent to the inflow-mass-curve at A. The distance B-II represents the total draw from storage to maintain the rate of outflow O-I during the time elapsed from o to b. Since at B the slope of the inflow-mass-curve equals that of the outflow-mass-curve and increases with time near B, the distance B-II

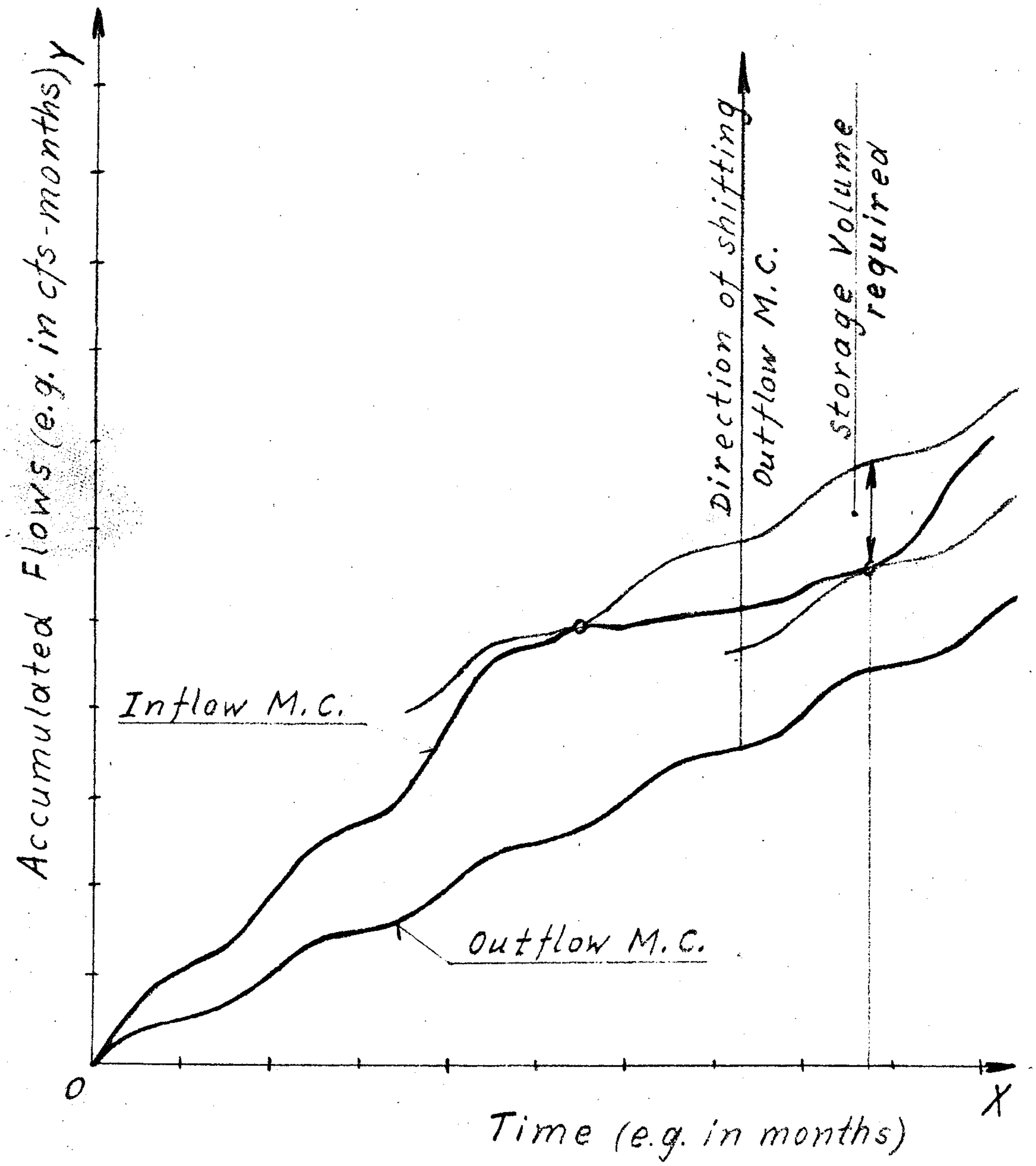


Fig. 2 Mass Curves
(seasonally varying outflow)

may be representative of the maximum usable storage requirement for the outflow rate shown.

In view of the assumptions made in any storage study regarding the future, results measured from the mass-curve diagram may be adequate, but in general it is preferred to use the mass-curve only for determination of the critical periods and to find the quantities of storage or outflow by computation using the accumulation data which were already required for plotting of the mass-curve.

Often it is convenient to plot only the accumulated departures from the mean flow line O-C (Figure 1) as ordinates, the resulting curve is referred to as residual mass-curve.

Assuming constant outflow requirements, the mass-curve study gives the relationship between usable reservoir capacity and maximum dependable outflow. This relationship can be plotted and is represented by a series of straight lines. Each straight line stretch is representative for one particular critical storage depletion period. As storage and outflow increase, the time periods change abruptly to greater length. Obviously, if there were many inflow records of similar length available as the one on which the storage dependable flow polygon was based, many such polygons could be drawn with the straight line portions and the breaking points at different locations. The series of polygons would be best represented by a continuous curve. It seems therefore justified to replace the polygon by a smooth curve, preferably enveloping the points on the safe side (low outflows). (See Figure 11, page 55)

The increase in maximum dependable outflow, associated with a storage capacity increase, is an indication of the benefits associated with that storage increment when circumstances are such that large dependable outflow rates, extending over periods of many years, are called for.

If, however, the method of reservoir operation is on a yearly reservoir depletion basis (yearly use of storage), the mass-curve method can be applied too. Certain storage capacities would be assumed, the annual hydro-electric output deficiences determined and averaged over many years and thus the effect of storage capacity increments evaluated. This method of evaluation would be more appropriate when alternative power supplies are available, e.g., thermal-electric plants.

The mass-curve method can be very easily applied as long as the unregulated local inflow between reservoir and power plant is not exceeding the magnitude of the required flow at the plant minus the minimum permissible outflow from the reservoir, imposed for other reasons than power production. As long as this condition is met, the unregulated local inflow can be added to the actual inflow and the sum supplemented for the actual inflow in the mass-curve. The true outflow required from the reservoir is then, of course, the outflow used in the mass-curve study minus the unregulated local inflow. Evidently, if unregulated local inflow is in excess of the above mentioned limit, the excess has to be first deducted before application of the mass-curve procedure since this excess cannot be stored but has to be spilled (unless the excess local inflow will be pumped into the reservoir).

When the power plant or plants are using considerable quantities of unregulated flow, it is usually more convenient to use the hydrograph method for studying the effect of storage capacity, especially if the controlled inflow is relatively small.[1]

The analysis starts from the hydrograph of the unregulated inflow downstream of the reservoir. With the available water in storage in the upstream reservoir, augmented by the inflow to the reservoir, one tries to fill the valleys of the given hydrograph in such a way as to get what one considers the optimum flow pattern at the plant. As the storage capacity is increased, the flow conditions at the plant can be improved. The improvement will be an indication of the storage benefits.

Sometimes the change in the outflow duration curve due to reservoir regulation is considered indicative of the storage value. If the aim is constant outflow, this is justified; but with variable outflow rates required or permissible, the change in the duration curve or lack of change could be very misleading. To make this clear, let it be assumed that load and system conditions call for an outflow hydrograph exactly the same as the inflow hydrograph except that it is required in a different season and, further, that this shift is accomplished with the help of a reservoir having a certain storage capacity. Evidently, the outflow duration curves, with and without the flow modification through the reservoir, would be identical over a long period of time. (With appropriate selection of beginning and end of the period for which the duration curves are determined, the qualification regarding length of time period does not apply.)

The mass-curve method and the hydrograph method require that the desired flow pattern at the plant is known and are most suited if this is the highest possible constant flow. In most actual cases, however, the optimum flow pattern toward which regulation should aim is not given initially. Therefore, these simple methods are likely to be of limited value when studying storage benefits for power systems with alternative power and energy sources available and varying loads. In the following section methods better suited for more thorough investigations will be discussed.

MORE ELABORATE METHODS

These methods are attempting to approximate the expected future system and reservoir operations for different storage capacities. Increases in storage capacity will in general be accompanied by reductions in system operating costs. These cost reductions are approximately computed and represent the incremental storage benefits, which have to be weighed against the costs of providing that storage increment.

In order to enable at least a rough simulation of the expected future operation of the reservoir (or reservoirs) similar rules will have to be observed as in actual operations.

One of the most important conditions is frequently imposed by the minimum hydro-electric energy output requirements. These requirements will vary from week to week or month to month in an annual cycle, frequently with a load growth factor superimposed or they may also suddenly drop, because of the commissioning of a new thermal-electric plant or for other reasons.

To safeguard the minimum hydro-electric energy requirements, certain amounts of water will have to be kept in storage at certain dates. These minimum storage amounts plotted versus the date are referred to as basic rule curves.[4,6] (See also Appendix for definition). The basic rule curve may simply represent the envelope of the storage requirements for the most critical dry periods on record,[4] or it may be based on all flow periods with storage requirements and incorporate the probability aspect. In the latter case a series of basic rule curves are arrived at, each for a certain probability (expressed in percent) that the storage prescribed by this curve for a certain date will be adequate in the future with the same load and system composition.[6]

Figure 3 shows a basic rule curve of the first type. The storage content is expressed in MW-months, plotted against time. It is found by plotting the accumulation, in reverse order of time, of the deficiency between the minimum required firm hydro-electric energy and the energy available from recorded unregulated streamflow during periods of critically low flow. The accumulation starts from the end of the low flow period. With reference to Figure 3, e.g., at the end of January 1941 (as abscissa), the sum of the March and February deficiency was plotted (as ordinate) because March 1941 was the last month with deficient unregulated streamflow. After this date the energy from unregulated streamflow is greater than the minimum firm hydro-electric energy requirements. In this context unregulated streamflow is the flow at the plant which would have occurred without the action of the reservoir, namely the sum of reservoir inflow plus unregulated local inflow between reservoir and plant adjusted for time lag

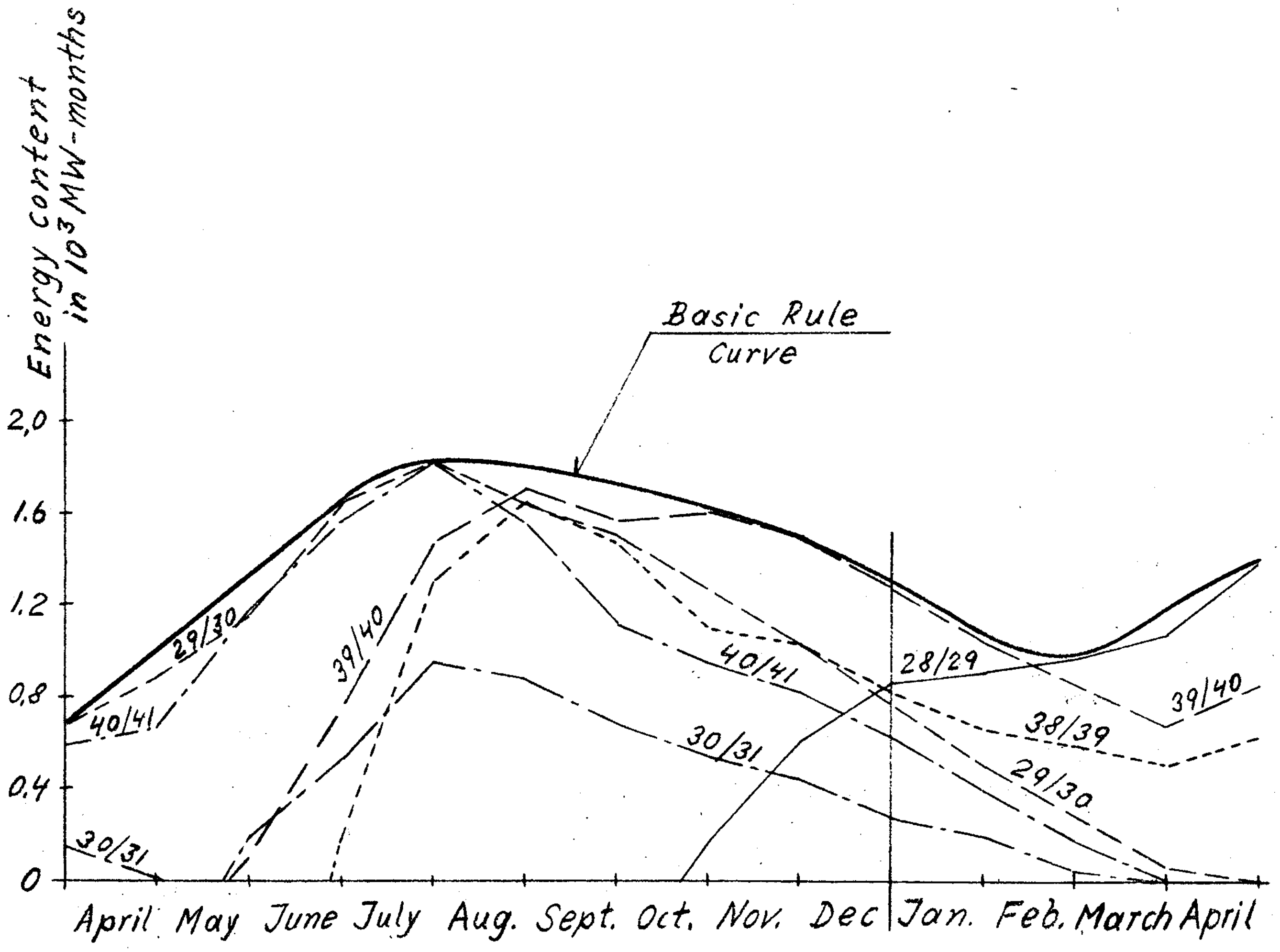


Fig. 3 Basic Rule Curve

with storage requirements during past critical periods as its basis as required. Each low flow period gives a different plot. The basic rule curve represents the envelope of all the individual plots. The same reasoning as given on page 18 as justification for replacing the storage-dependable flow polygon by a smooth curve is valid here too. Consequently, it is considered correct to draw a smooth curve (enveloping curve) instead of following exactly the highest individual plots.

Figure 3 shows an enveloping basic rule curve together with the storage requirements for the critical periods on which it is based.

The basic rule curve may refer to a simple reservoir or it may refer to the combined storage content of several reservoirs. In the former case the ordinate may represent the volume of water in storage or its equivalent energy if used over a certain developed head. In the case of several reservoirs, obviously the storage contents have to be expressed in energy units, e.g., MWh, unless the flow from all the reservoirs is utilized with equal developed head. If at any date the energy content of the reservoirs is at or below the basic rule curve the use of hydro energy should be reduced to the minimum requirements. While the total energy content is defined by the basic rule curve the total water content of the reservoirs (or any individual reservoir) is not because the volume of water corresponding to the energy content depends on the distribution of the stored water among the individual reservoirs.

The stored energy contents, called for by the basic rule curve, are counted from the minimum permissible reservoir levels for power purposes (energy content zero). These levels may not be fixed at the beginning of the storage study and determination of the benefits of increasing the storage range by lowering the minimum permissible reservoir levels may be part of the study. Frequently, however, a physical limitation to this process is soon encountered. Usually, more freedom exists with respect to the selection of the upper limiting reservoir level. The maximum permissible storage level for power purposes may be constant the year round, but frequently this level varies with the season, being lowest during the time of the year when the largest floods can be expected in order to provide room for excessive flood runoff.

In evaluating the effect of incremental storage on a certain reservoir, different maximum permissible reservoir levels are assumed for this reservoir whereas for the other existing or contemplated reservoirs of the system the maximum and minimum permissible levels are assumed to be fixed.

Minimum permissible level, basic rule curve, maximum permissible level, minimum and maximum usable hydro-electric energy, supplemented by some reasonable and simple assumptions concerning storage distribution among the reservoirs, if there is more than one reservoir in the power system, define roughly the reservoir operations. The firm load requirements and the available electric energy sources such as hydro-electric and thermal-electric generating stations and interconnections with other power systems determine the firm maximum and minimum hydro-electric energy requirements to be observed in simulating approximately the future reservoir operations.

In reality additional factors usually exist which may influence the reservoir regulations. These are interruptible power sales, cost differences in thermal-electric generation, and different price levels for energy interchange with other power systems.

In many cases, it is necessary and justified to keep the work to a minimum by ignoring these influences.

Even so, the amount of work required frequently turns out to be rather large and being of a repetitive nature the use of a digital computer is justified, even though it is in general still possible, though rather time consuming, to perform the simulation study manually.

A representative period of past flow records (reservoir inflows and unregulated local inflows) extending over twenty or more years of the past (or as guessed for the future) are used in the simulation studies which determine the average annual operating costs for several storage ranges. This method can be used in many situations dealing with small and large storage capacities and variable hydro-electric requirements. The benefits from capacity increments of the Grand Rapids reservoir were estimated by this method.

Other methods were developed to determine capacity requirements for long term storage on the Nile, using statistical approaches which are briefly described in the following. The year was used as time unit which is an indication that "long term" means indeed storage over many years. Dr. H. E. Hurst studied 75 phenomena and 690 series of years, ranging from 3o to 2000 years.[10] The characteristic studied, the range R, is the difference between the highest and lowest accumulated departures of observations from the mean. When dealing with inflows to a reservoir this means R is the vertical distance from the highest to the lowest point of the residual mass-curve (working with mean annual flows and the year as time unit). Hurst found that $\log\frac{R}{\sigma} = K \log\frac{N}{2}$ σ represents the standard deviation and N the number of events, $K = 0.75$ for river statistics.

For the required storage S to guarantee an outflow B he found $\frac{S}{R} = 0.94 - 0.96\sqrt{\frac{M-B}{\sigma}}$

where M is the mean of the observations. This equation too was not only based on river discharges, but many natural phenomena such as rainfall, temperatures, tree rings, etc.

Noteworthy, with respect to storage evaluation, is the finding that records of natural phenomena extending over long periods show considerable variations of means and standard deviations from one period to another. This would indicate the probability that a storage evaluation which had to be based on a past period of flow records could be somewhat in error because the flows during the future life of the project are different in an unpredictable way, even when everything else was predicted correctly.

A. Fathy and Aly S. Shukry in their treatment of the long term storage problem worked with the deviations of the arithmetic mean for groups of observations instead of the deviation of one observation.[7] E.g., mean flows for 3, 5, 7, or 10 year periods were used. This was done to allow for the tendency of hydrological phenomena towards grouping of high or low years.

The main tool in this method is the "deviation curve". This curve is based on a plot of maximum relative deviations $/\delta/$maximum versus the number of years in the periods (groups) for which the relative deviation was computed.

The maximum negative relative deviation, plotted against, say $N = 10$, is the difference between the absolute (long term) mean flow and the mean flow for the 10 year period with the lowest average flow. Figure 4 shows the deviation curve for the Nelson River (based on negative

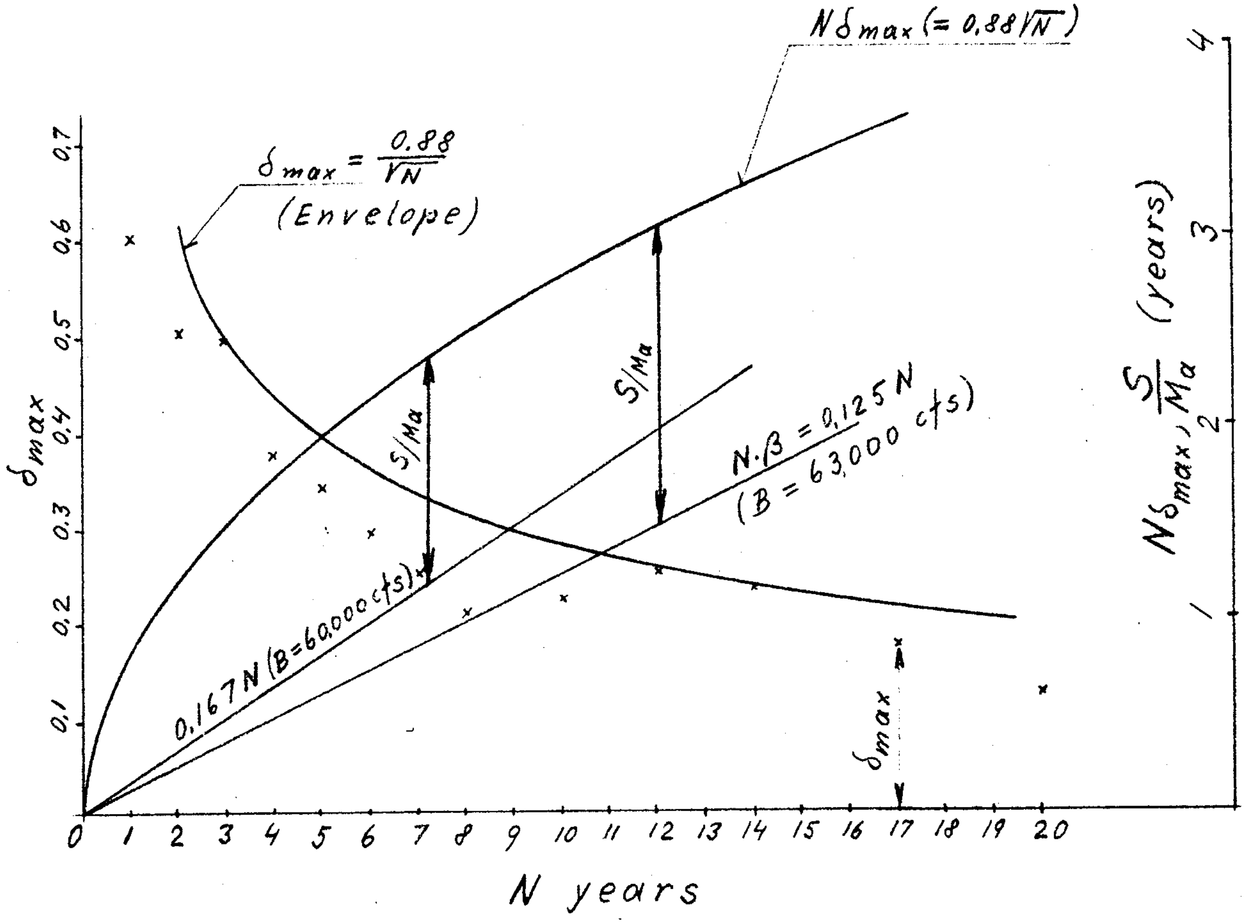


Fig. 4 Illustration of the Deviation Method for Longterm storage by Fathy and Shukry

(applied to Lake Winnipeg Inflow)
assumed M_a = 72.000 cfs
Results plotted on Fig. 8 for comparison

deviations only).

The relation is of the form $/\delta/\text{maximum} = \frac{C}{N^m}$.

The question to be answered is: how much storage S is required for a given constant outflow B. If N_d is the length of period of maximum deficit and M_d is the mean flow during the deficit period then evidently $S = N_d\ (B - M_d)$. If the relative deficiency $\delta = \frac{M_a - M_d}{M_a}$, and $\beta = \frac{M_a - B}{M_a}$ the relative reduction of the outflow B below the "absolute" mean flow M_a, then $\frac{S}{M_a} = N_d(\delta - \beta)$.

Consequently, the deviation curve needs only to be multiplied by N to give curve N maximum in Figure 4. The largest distance of this curve from the straight line N in the direction of the ordinate represents $\frac{S}{M_a}$, which answers the question for the required storage. Figure 4 illustrates the method. The resulting dependable flow storage relationship is plotted on Figure 11* for comparison with the corresponding relation found from a mass-curve study. As can be seen, the Fathy-Shukry method calls for higher storage capacities. Comparing the slopes of the curves in Figure 11, which are indicative of the benefits from storage capacity increments (inverse relation), it appears that the Fathy-Shukry method

---

*page 55

gives higher values of these benefits for most, practicable ranges on Lake Winnipeg.

At first glance, the difference in storage requirements may appear excessive. However, comparison of the 100% curve and the 98% curve (both found by the mass-curve method) shows, e.g., at 50,000 cfs dependable outflow that the relative change in storage requirements from 98% to 100% is larger than that from 100% to the Fathy-Shukry curve.

Since the two methods developed for the Nile work with the year as the time unit, it is necessary to treat the seasonal fluctuations, which occur in supply and demand, separately in addition.

In some cases, the methods described in this section may be considered still too approximate and additional factors influencing system operation will be included in the studies as described in the next section.

REFINED METHODS

By using electronic computers, it is possible to simulate the expected future system operations. Depending on the importance of the evaluation, various degrees of refinement may be selected and the influence of varying assumptions studied.

Before the actual simulation studies can be performed, it is necessary to establish the rules for the future system operations. Basic rule curves, maximum permissible levels, maximum and minimum flows do not yet define the most economical operation; it is necessary to supply additional parameters, such as incremental water values at certain storage contents occuring at certain dates. For clarification, it is pointed out that the term "incremental water value" does not refer to the benefits from the storage capacity increments, the estimating of which is the theme of the thesis. The incremental water value represents the probable value of the top increment of energy in kWh stored at a certain date and is expressed in mills/kWh or $/MWh, whereas the benefits of incremental storage capacity refer to the expected benefits from the last increment of storage capacity, e.g., the uppermost foot over a period of many years,preferably the life of the project, and is conveniently expressed in average benefits per annum per foot increment of the maximum permissible reservoir level. The lines connecting points of equal incremental water value on the storage content versus time graph are called economy guide lines* in a paper by Brudenell and Gilbreath which presents also an approximate method of determining the incremental water values.[4] These lines indicate up to which maximum incremental cost level thermal-electric generation should be used depending on the storage content

---

*See Appendix for definition.

at a certain date. At high storage contents (to which low incremental water values correspond) the lines may indicate whether interruptible load with a certain low revenue rate should be supplied or dropped.

The mentioned paper was found very helpful in establishing reservoir operating rules and a brief description of its content is therefore given.

Part I of the paper discusses the general theory of the economic operation of thermal-electric energy supply sources with hydro-electric energy sources with appreciable water storage possibilities.

Part II discusses the application of the theory to the operation of the integrated Tennessee Valley Authority system of hydro-electric plants, reservoirs, and steam-electric plants.

In Part I the theory was developed starting from the simplest case, a hydro storage system without auxiliary steam-electric power supply and for firm load only, progressing in steps to a hydro storage system with a variety (multi-cost) of auxiliary steam-electric power supply for firm and interruptible type loads. The development of the operating rules had as its objective long range storage operation which would result in minimum annual power production costs, on the average, consistent with guaranteeing supply of the load under the most adverse runoff conditions on record and without use of runoff predictions.

The concepts of basic rule curve, no-spill rule curve, economy guide line were introduced progressing from the simple to the complex case as mentioned before.

Basic rule curve and no-spill rule curve present no particular difficulties as to understanding and determination, but some discussion of incremental water value and economy guide lines appeared useful.

The simplest case in which an economy guide line would be useful in guiding operation of the reservoirs is supply of firm load by hydro storage system (with head affected by reservoir levels) with single-cost source of auxiliary (e.g., thermal-electric) power supply.

The firm load is larger than the firm energy supply of the hydro-electric system, but not greater than the firm energy supply of the hydro-electric thermal-electric combination. If the content of the reservoirs is below the no-spill rule curve of that date, full use should be made of the available auxiliary supply to increase the head because there is no chance of spilling (based on past flow records). Also, if the content of the reservoirs is below the basic rule curve, full use must be made of the auxiliary supply in order to safeguard the firm load during the low flow period that may follow.

If, however, the storage content is above the no-spill rule curve (and at the same time above the basic rule curve), it may, or may not, be beneficial to operate the auxiliary power source depending on what will predominate - benefits from increased head or the disadvantage from spilling subsequently the water first saved by using the auxiliary energy source. The criterion for economic operation is to achieve the greatest usable hydro-electric output. If the flow were known in advance, optimum use of the auxiliary power could be determined for the "Governing Period". This period was defined as the period ending with reservoirs just drawn to the basic rule curve or just filled by the beginning of a subsequent period of drawdown, whichever occurs later. To maximize the head during the Governing Period would call for maximum use of the auxiliary source until the date is reached from which on the storage content is sufficient for the hydro-electric system alone to carry the load for the remainder of the Governing Period. The period of maximum use of auxiliary power within the Governing Period was called "Determinant Period". The top increment of storage content at the starting date of the Governing Period equivalent to one kWh was retained in storage with a gain in head until the end of the Determinant Period when it finally was used to replace the auxiliary power. Thus its replacement value equalled then one kWh of generation by the auxiliary source plus the energy equivalent to the corresponding average increase in head during the Determinant Period. Thus, it is evident that this kWh of storage is worth more than the cost of a kWh from the auxiliary source.

In reality, the flow is not known in advance as was assumed above, but past flow records can be used for each year and the ideal operation simulated and the incremental value for each year can be found and the average value for all years with flow records determined. Depending on the predominance of head gain or spillage the average value may be more or less than the cost of one kWh from the auxiliary source. By choosing several levels of storage contents at the various dates of the year, points, representing these storage contents and dates, can be labelled with the incremental water values and the economy guide line, corresponding to the cost of auxiliary power, can be drawn through the field of points (like a contour line through point elevations).

The more general case of multi-cost sources of auxiliary energy was considered next. Maximizing the usable hydro-electric output cannot be the criterion for economic operation anymore. The objective in this case is to concentrate the reduction of maximum auxiliary generation, made possible over a period of years by the margin of average hydro-electric generation over the minimum required hydro-electric generation, as much as possible to the highest cost blocks of available auxiliary energy. As in the previous case, the flow was assumed to be known in advance. Ignoring the change in head, ideal operation in any Governing Period would be a constant auxiliary output during the Governing Period to draw the reservoirs just to the basic rule curve or to fill without spilling. The foregoing statement assumed uniform availability of auxiliary energy and a gradual increase in auxiliary energy costs with the required rate.

As in the case of a single cost auxiliary energy source, increased use of the auxiliary energy sources in the first portion of the Governing Period, at least to the maximum of the particular price block which must be used anyway, is beneficial because of the head gain. Depending on the circumstances there may be also justifiacation for replacing some lower cost auxiliary power at the end of the Governing Period by higher cost auxiliary power at the start in order to gain additional head. Using the same methods as described for the simpler case, several economy guide lines are found, one for every cost block of auxiliary power.

If not only firm load but also load interruptible at the will of the supplier is served, the case is not further complicated since dropping of interruptible load is analog to using a (fictitious) equivalent supply of auxiliary energy at a cost equal to the revenue from the interruptible load.

Part II of the paper deals with the application of the principles developed in Part I to the system of the

Tennessee Valley Authority. Necessary and permissible simplifications are discussed and the "Storable Energy Curves" as a tool for the approximate determination of the system economy guide lines are introduced. The Storable Energy Curves are mass-curves of hydro energy which is available for storage. Consider first a mass-curve of system hydro energy based on a repetition of the streamflow records assuming everage constant heads at the hydro-electric plants and unlimited generating capacities. From this mass-curve deduct the mass-curve for a constant hydro-electric load. The remainder curve is essentially a Storable Energy Curve and represents a simplified version of the TVA Storable Energy Curves. The actual curves used took into account the head variations and downstream spillage effects. The appendix of the TVA paper gives practical information on the preparation of the Storable Energy Curves.

Figure 5 shows portions of Storable Energy Curves which were determined for the Winnipeg River in Manitoba in order to establish approximate economy guide lines for the Winnipeg River upstream storage (Lake of the Woods and Lac Seul) with respect to the use of Winnipeg River flow in Manitoba.

The use of the Storable Energy Curves for estimating the incremental water value at a certain storage content and date is then described. By superimposing a base graph

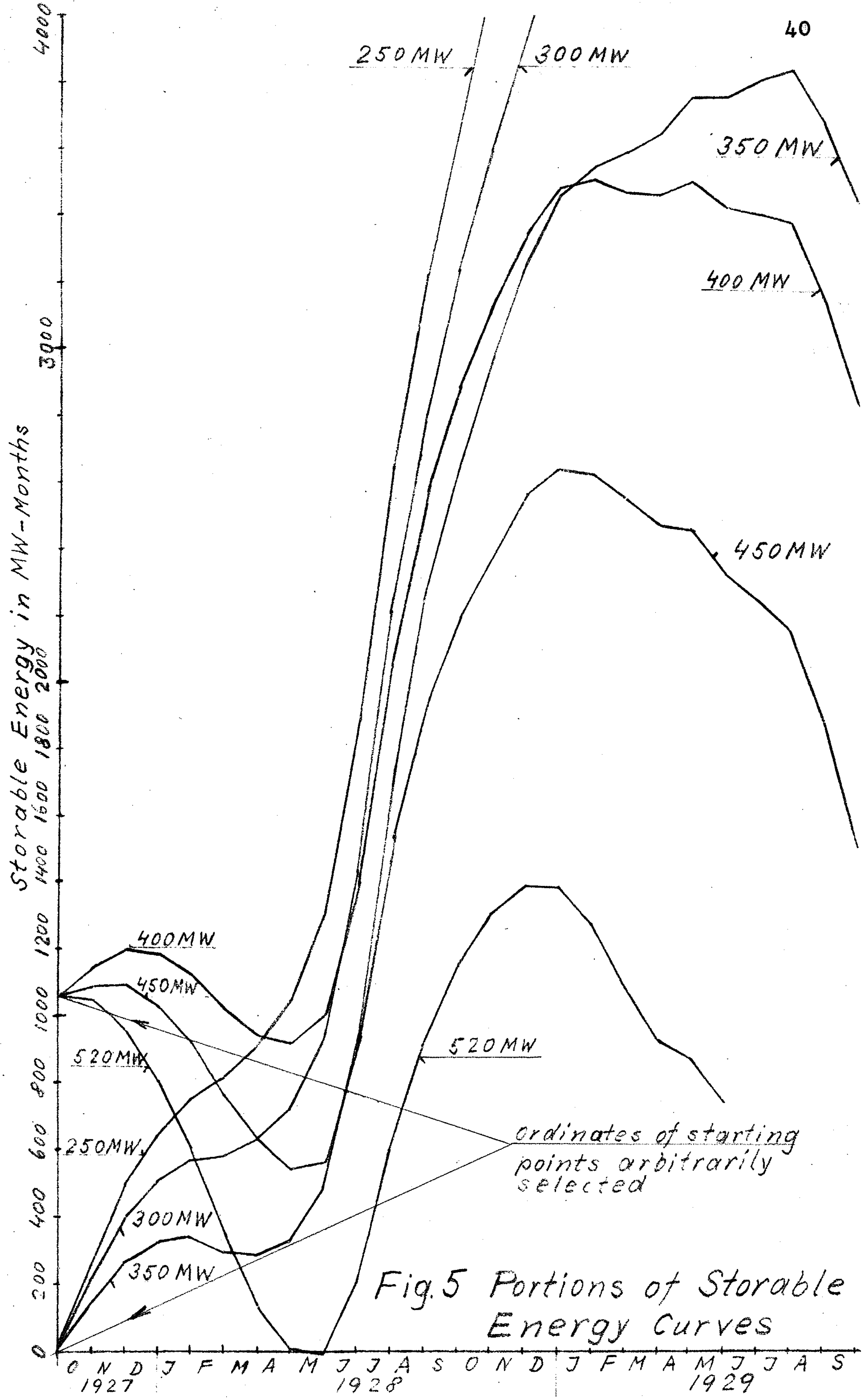


Fig. 5 Portions of Storable Energy Curves

consisting of the system basic rule curve and system spill line for future load years over the Storable Energy Curves, that Storable Energy Curve is selected which remains within the space between the two curves of the base graph furthest into the future (without cutting the curves in the meantime). This requires interpolation between the drawn Storable Energy Curves. Figure 6 illustrates the procedure.

From the difference between the energy requirements and the hydro-electric supply corresponding to the selected Storable Energy Curve the supplementary thermal-electric energy requirements are found. The highest cost thermal-electric energy that must be used to meet the demand determines the water value of the top increment of storage at that particular date in the flow year. Adjustments for loss of efficiency through spillage at downstream plants are made as required.

The average of the incremental water values for the same date and same content for all considered flow years is the most probable incremental water value for that date and content. Figure 7 shows a storage content versus time graph with the average incremental water values entered, which serve as the basis for drawing the economy guide lines.

Further refinements and improvement possibilities are discussed. Since publication of the paper, the Tennessee Valley Authority has further developed and applied improvements

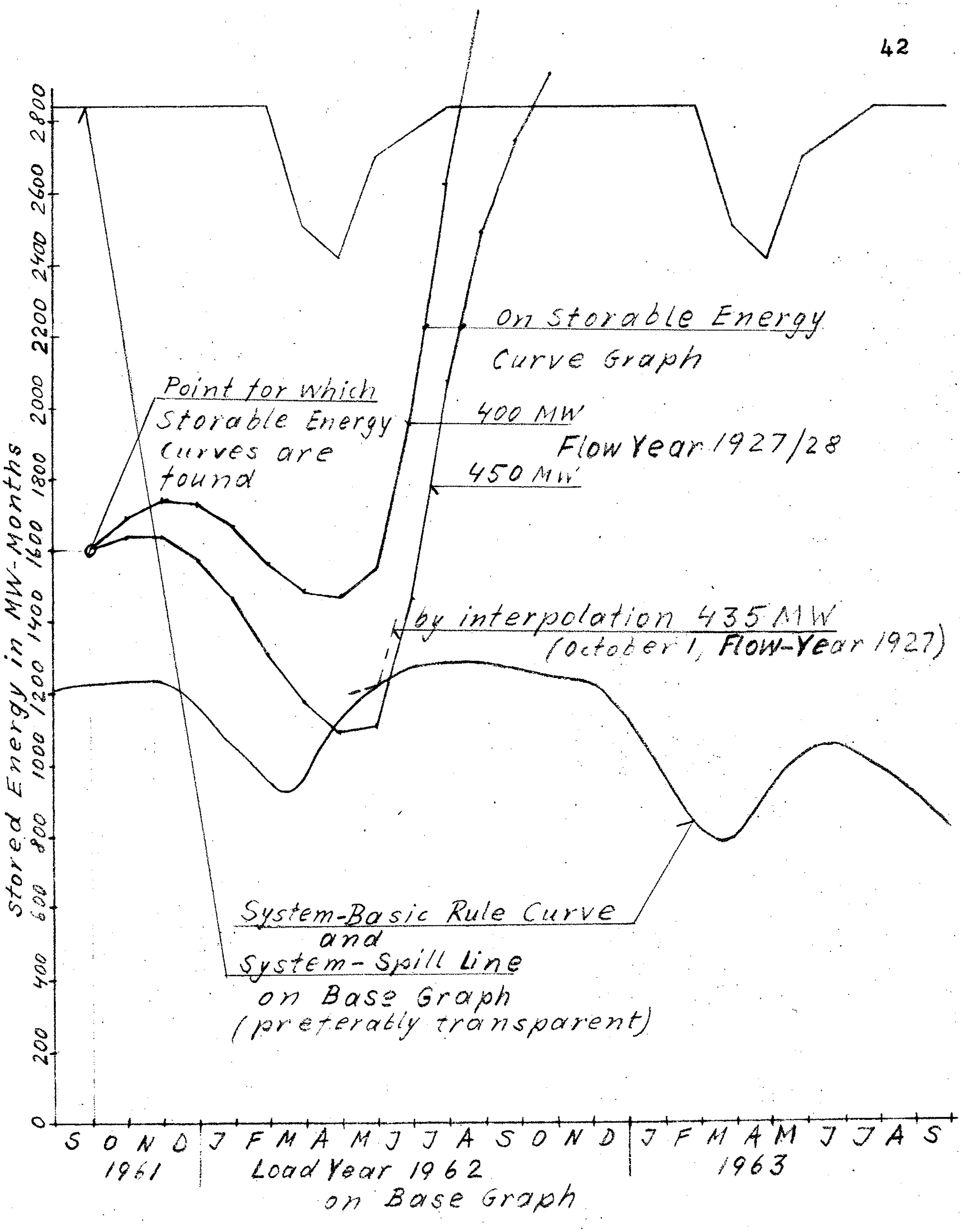


Fig. 6 Selection of the Appropriate Storable Energy Curve

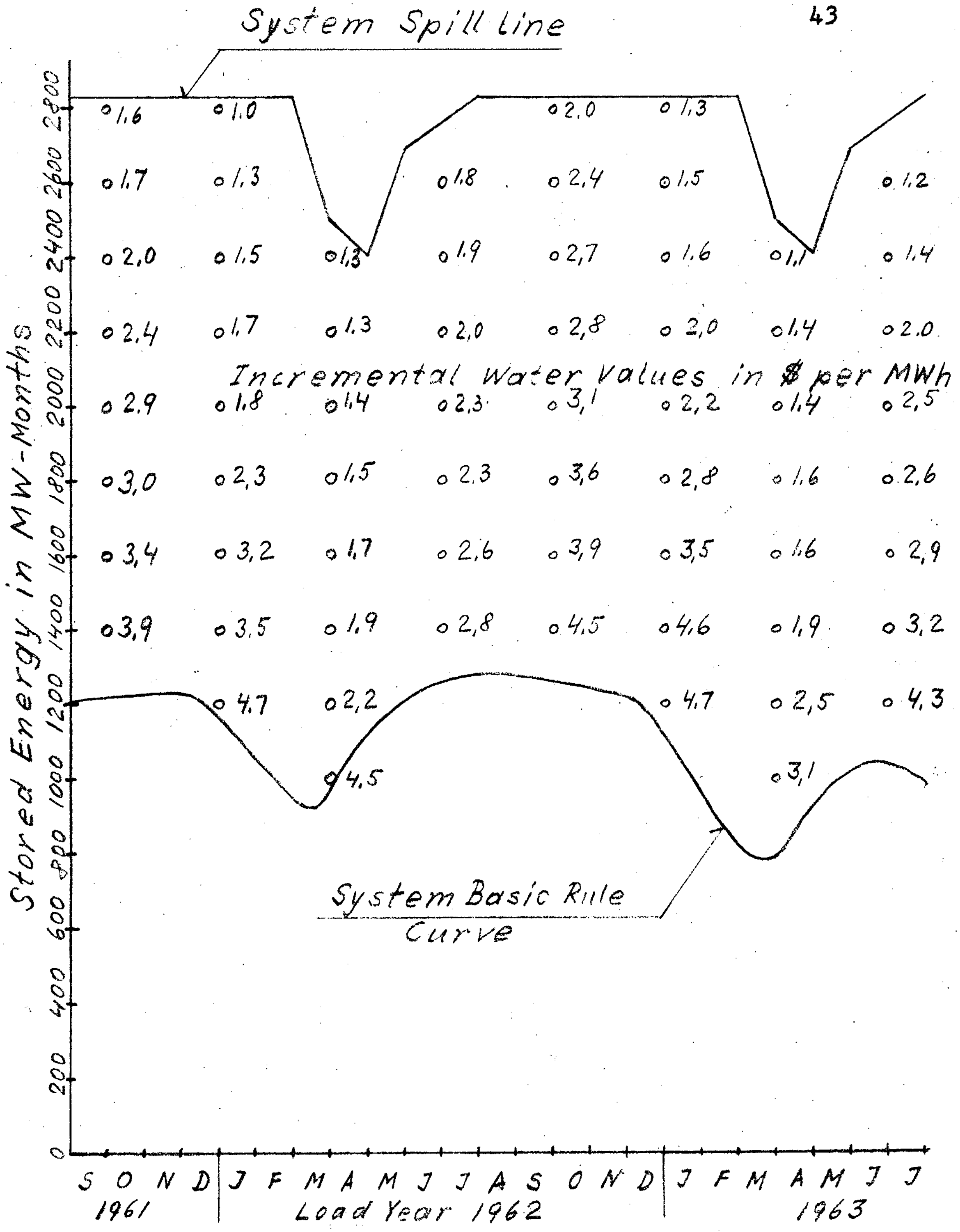


Fig. 7 Average Incremental Water Values

of the methods for system operating purposes.[5] However, the amount of work is prohibitive for estimating the benefits of additional reservoir capacity.

References 6 and 14 suggest water value computations based on successive approximation procedures. For the case of a single reservoir, different cost blocks of thermal-electric power and interruptible load, they suggest to assume water values as function of date and storage content at a number of points which are uniformly distributed over the storage content versus time graph between the basic rule curve and the spill line. To find a second approximation of water value for a point (date and storage content) one starts from that point and computes the subsequent storage contents corresponding to system operation as dictated by the previously assumed water values being passed (interpolating the water value between points as required). The calculation is discontinued after some twenty weeks (the week was used as time unit) or earlier if the storage content reached the upper permissible limit or the basic rule curve. This is done for the same point for every flow year, e.g., 30 years. As second approximation of the water value for the point in question is taken the mean water value of all the termination points reached. It is therefore advisable to find the closer approximations starting at points of later dates so that the correction of water values at earlier dates can benefit from these closer approximations as the system operating calculations proceed in chronological order and are influenced by the water values of the later dates.

Application of the trial and error method is possible also for a system with several reservoirs with drawdown distribution among the reservoirs avoiding unnecessary spillage.

Regardless of the method of water value determination, rules for proper distribution of storage among several reservoirs may be required to keep the reservoir contents "in balance".[13] In balance means that the storage contents are such that a unit of stored energy would have the same probable future value to the system, regardless of into which of the reservoirs it is placed. This is approximately the case if the contents of the reservoirs are such that the chance of future spilling is the same for all reservoirs.

Obviously, to establish the rules of operation for the simulation study is an extensive computer study itself. The main purpose of it would be to establish the rules for economic, actual long range operation of a combined hydro-thermal system, the use of these rules for the storage benefit evaluation being of secondary importance. The rule curves and economy guide lines will vary somewhat with the assumed storage capacity. Consequently, for evaluating the benefits from incremental storage capacity more than one set of rules will be required. The operation of the reservoirs can be done according to these rules without incorporating runoff forecasts. In reality, however, these rules will frequently be modified by giving some weight to runoff predictions, for instance, for the spring runoff. Further refinement would be to incorporate these modifications of the operation into the simulation program. Fixed rules for this have to be established, based on the known conditions at that time as antecedent runoff magnitudes, snow cover, precipitation, temperature, and other suitable indices.

Although the simulation runs on the computer can be done for a nearly unlimited variety of assumptions, using past flow records or speculation on future flow pattern, different load growths and system composition, and different capacities of the reservoir whose storage benefits are to be assessed, economic considerations and time limitations will impose restrictions in this regard. Finally, it may happen that the variations in the assumptions yield different answers with the result that need for applying judgment will not be completely eliminated, but judgment will have to be exercised in giving different weight to the varying answers in making a decision on the storage capacity to be provided.

In the next chapter, two specific cases are discussed, illustrating the application of simple and of more elaborate methods.

CHAPTER III

SOLUTION APPROACHES USED IN TWO SPECIFIC CASES

For the first case, Lake Winnipeg regulation, the mass-curve method was further developed for application to specific problems of regulation.

The second case, dealing with the Grand Rapids reservoir capacity, is more typical of the storage benefit problems generally encountered, and an approximate simulation approach was used.

LAKE WINNIPEG REGULATION

The studies of the Lakes Winnipeg and Manitoba Board, undertaken from 1956 to 1958, included an appraisal of the benefits to be expected from Lake Winnipeg regulation.[12]

Benefits from lake regulation are, of course, not the same as the benefits from storage capacity, but the problem of evaluating them is quite similar. The difference between storage benefits and regulation benefits lies in the original situation to which the improved condition is compared. When evaluating storage benefits the improvement is counted from a negligible or small uncontrolled storage capacity to a large controlled storage capacity. When evaluating lake regulation benefits the large storage capacity already exists and the improvement consists only in controlling its use, which may increase, leave unchanged, or reduce the natural live storage capacity (range of lake level fluctuations).

In order to assess the expected benefits, assumptions had to be made regarding the use of hydro-electric power to be produced using the outflow from Lake Winnipeg. Lake Winnipeg is drained by the Nelson River which flows into Hudson Bay (Figure 8). Over a distance of 410 miles, the river descends 712 feet. Many potential power sites, totalling more than 600 feet in head, exist (Figure 9). Depending on the degree of development and the nature of the market to be supplied with Nelson River power, the benefits from lake regulation will vary. Regulation of Lake Winnipeg was therefore studied for three different situations: first, partial development of the available head for the southern Manitoba system; second, development of all power sites for an unchanging monthly load having a load factor of 0.8; and third, partial development, combined with regulation permitting postponement or elimination of development of less favourable sites, for an assumed load type as in situation two above.

The first situation was considered the most likely to become reality. More effort and time was devoted to its study than to the other two situations combined. In principal, the study was conducted along the same lines as the Grand Rapids reservoir study, discussed in the next section.

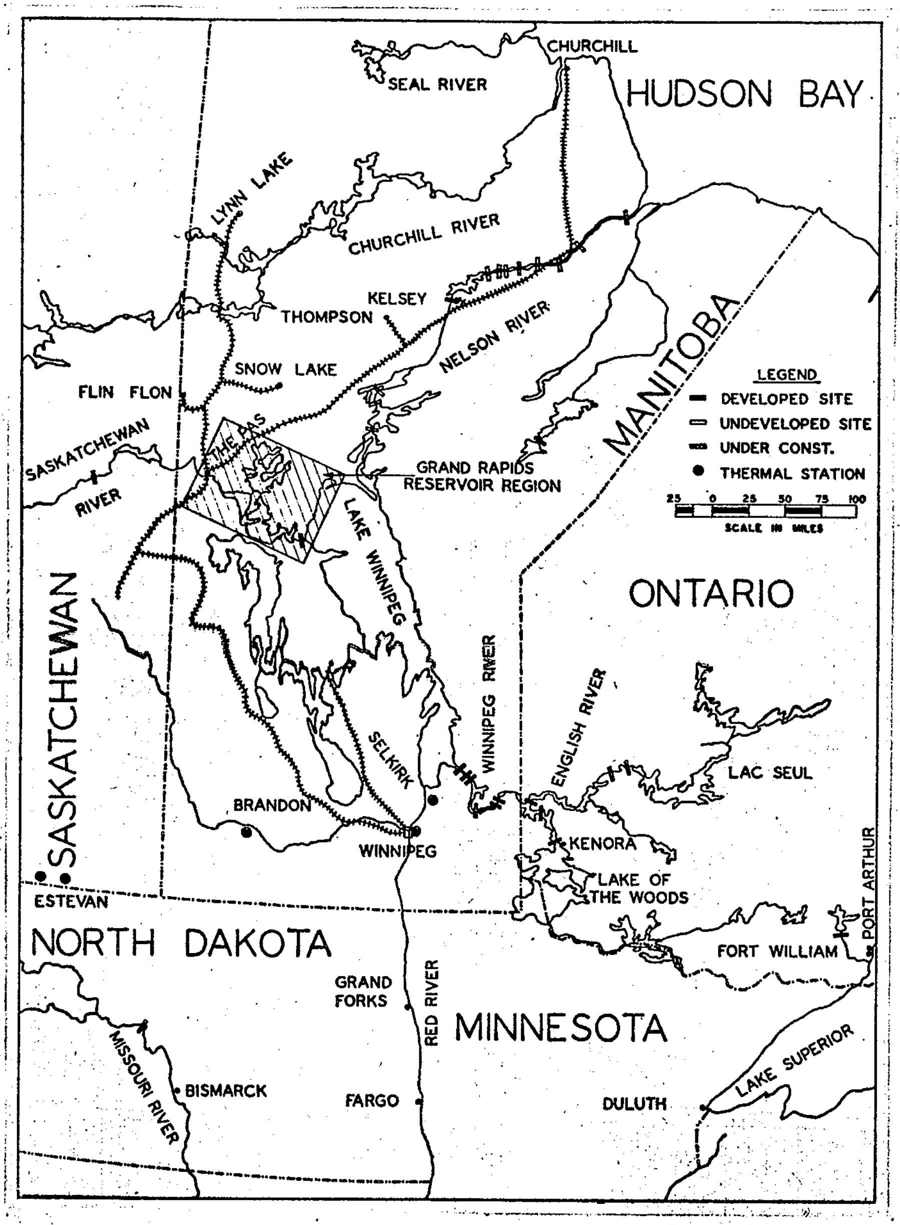
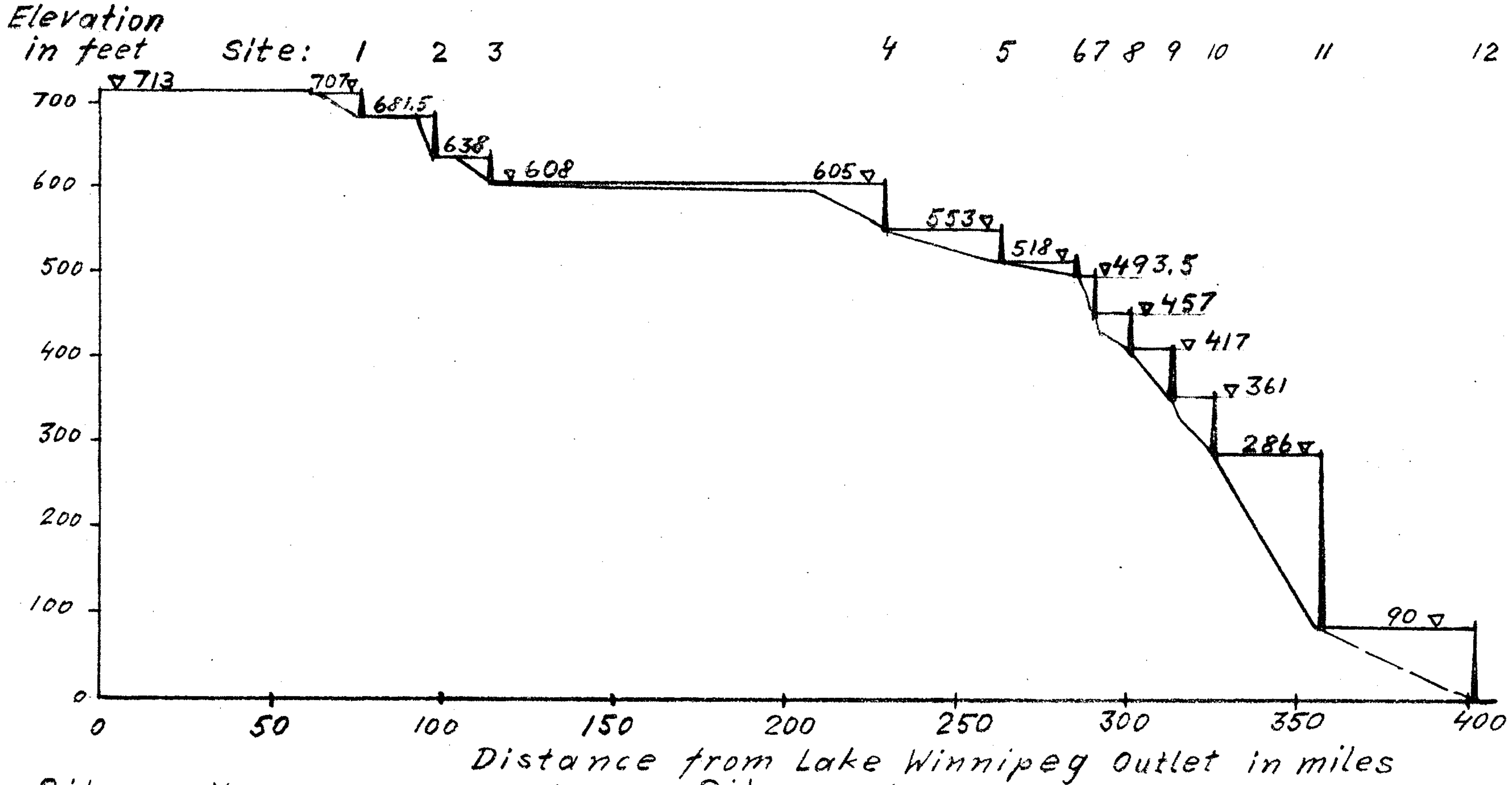


Fig. 8 Reference Map
for Chapter III



Site	Name	Head ft	Site	Name	Head ft
1	Whiskey Jack	25	7	Lower Gull Rapids	34.5
2	Whitemud Falls	41.5	8	Big Hill	38
3	Red Rock Rapids	30	9	Kettle Rapids	54
4	Kelsey (partially devel.)	50	10	Long Spruce Rapids	69
5	Birthday Rapids	33	11	Limestone Rapids	186
6	Upper Gull Rapids	24	12	Gillam Island	70

Fig. 9 Profile of Nelson River with Power Sites as proposed in 1958

Further discussion of the benefit evaluation for this situation is therefore omitted, except for the remark that the study was done without the help of an electronic computer and with a considerable degree of arbitrariness in simulating expected regulation of the reservoirs of the system as compared to the Grand Rapids study.

The load assumptions for the other two situations made it possible to evaluate the potential benefits of different storage ranges by methods based on the use of the inflow-available-for-outflow mass-curve.

The Evaluation of the Regulation Benefits after Development of All Nelson River Sites

In evaluating the regulation benefits it was considered that an increase in hydro-electric energy production will always be advantageous provided there is a market, but the value of firming up capacity will depend on the nature of the market and on the cost of incremental hydro-electric and thermal-electric capacity. Not knowing the requirements of the future market the benefits of regulation were studied for outflows (a) dependable during 100% of the time and (b) dependable during 90% of the time. The procedure was as follows:

Using the mass-curve and the tabulation of cumulative inflow-available-for-outflow (from which the mass-curve was plotted) the maximum 100% dependable flows corresponding to certain storage capacities were found in the usual manner. The relationship between storage and outflow of reduced dependability was determined as follows: A certain desired outflow was assumed and combined with various reservoir capacities all inadequate to make the flow 100% dependable using the inflow records of the past. Further, regulation was assumed such that the outflow equals the inflow whenever the lower or upper limit of regulation was reached, keeping the reservoir level constant. Figure 10 illustrates the method used to find the percentage of time the flow would be dependable with a certain storage capacity and the assumed inflows. As shown in the sketch, the time periods during which the reservoir would remain "empty" (at its lower permissible level) and the inflow less than the desired outflow were determined for the total period of record, verified with the tabulated figures and deducted from the total time of record. Desired outflow and storage capacity represented a point on the plot of storage versus outflow which was labelled with the percentage of time the outflow would equal or exceed the plotted value. This was done for many storage and outflow combinations, each yielding a labelled point. Smooth equi-percentage lines were then drawn just like one would draw contour lines using the percentage labels as elevations. Figure 11 shows the relationships

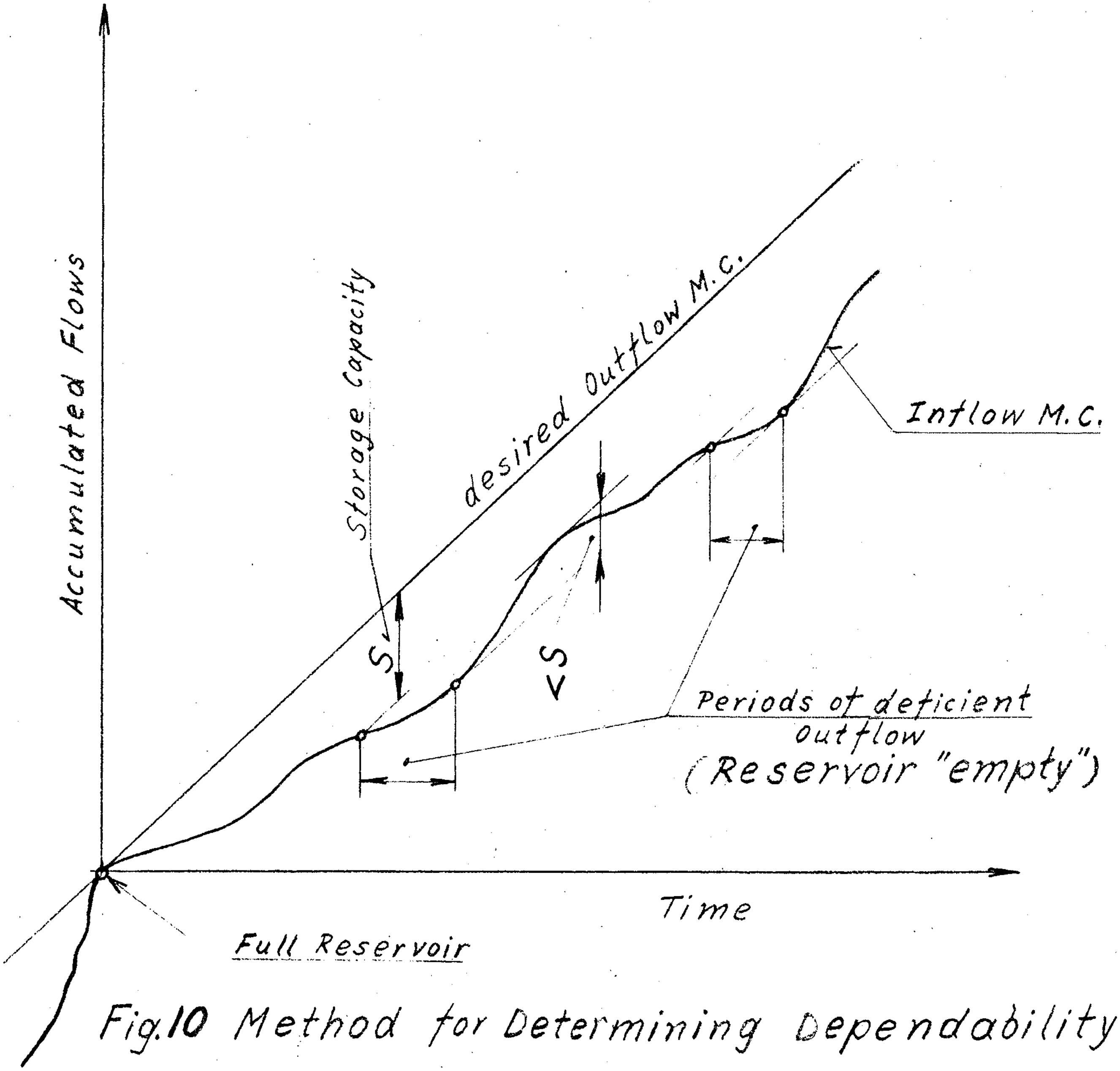


Fig.10 Method for Determining Dependability of Outflow

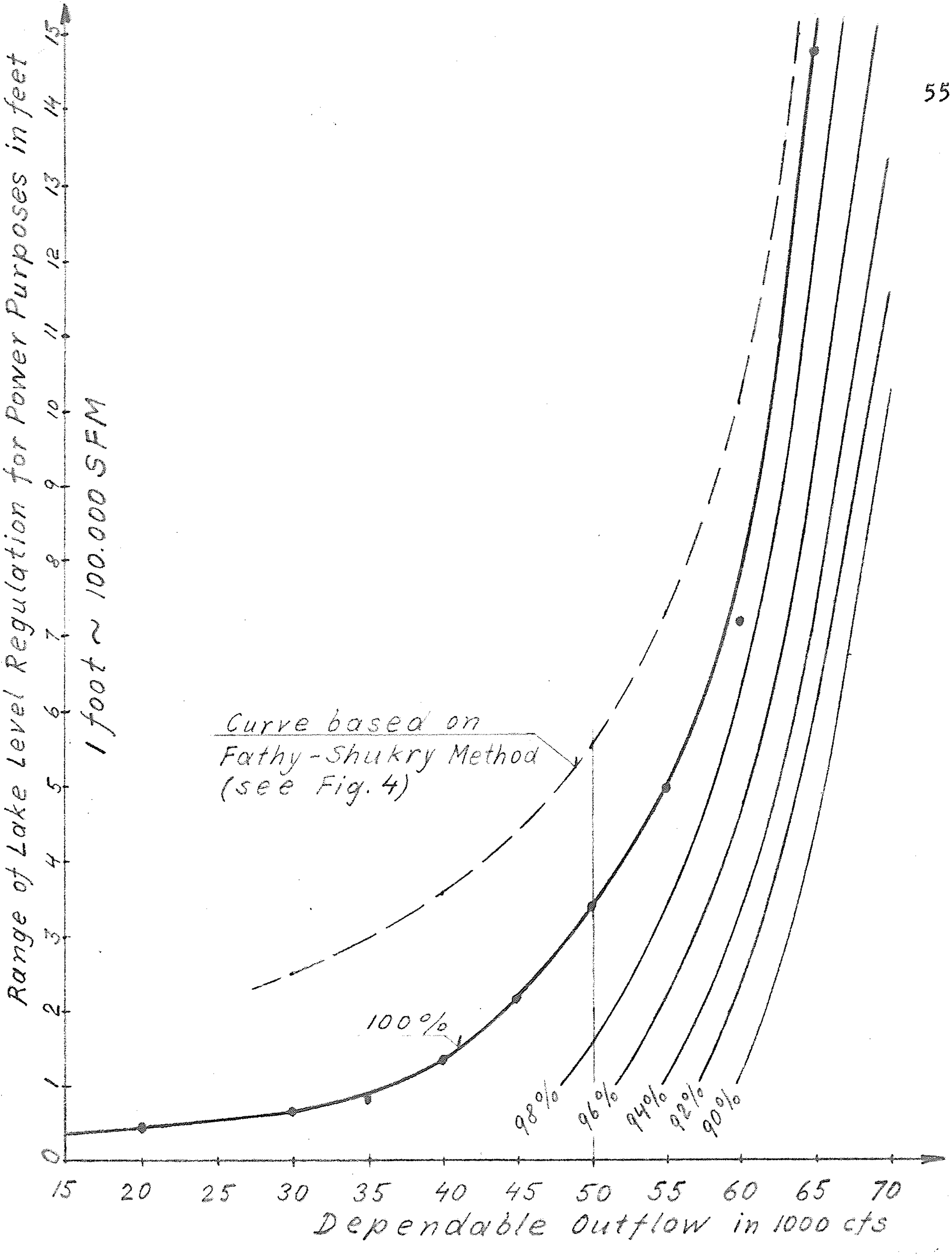


Fig. 11 Storage Capacity-Dependable Outflow Curves for Lake Winnipeg

between outflow and regulation range for different degrees of dependability. In view of the large surface area of Lake Winnipeg this area was assumed constant, independent of surface elevation. This permitted substitution of the regulation range in feet for the storage capacity without defining the actual elevations.

The next step was to convert the dependable outflows into capacity and energy gains. This was done in a somewhat different way for 100% dependability and for 90% dependability:

(a) For dependability during 100% of the time the installed capacity was based on the maximum outflow dependable during 100% of the time, assuming repetition of past inflow patterns in the future, except for anticipated man-made modifications. Applying the earlier mentioned load factor of 0.8, 10% spare capacity, and a developed head of 655 feet, the installed capacity that can be supported by a certain storage range was found. If the same hydro-electric installation were provided to make use of the uncontrolled outflow from Lake Winnipeg, a certain amount of stand-by capacity (an auxiliary power source) would be required and a certain amount of energy would have to be supplied from it. The elimination of the annual costs associated with the auxiliary power and energy source is representative of the benefits from controlling Lake Winnipeg outflows over a certain range for power purposes.

To find approximately the magnitude of the power and energy required from the auxiliary source, with Lake Winnipeg unregulated, the change in the outflow duration curve, or more correctly the change in the corresponding producible power and energy (associated with Lake Winnipeg regulation), could be considered in this case, because of the assumptions made regarding constancy of load. It was further assumed that all plants will have adequate pondage to permit study of the lake regulation on a monthly basis. Figure 12 illustrates the principle.

As long as head and efficiency (or strictly speaking their product) can be assumed to remain the same for all flows, the same curves in Figure 12 can serve for flow rates through the turbines and power outputs there being only a difference in scale. In reality the head useful for power production, and to some extent also the efficiency, will change with the flow. This is indicated in Figure 12 for the higher flows. Evidently, some compensation for this effect is possible by temporarily encroaching upon the 10% spare capacity provided. In view of all the other assumptions made, and because of inadequate knowledge of the increase in head losses, ignoring the change in head appeared justifiable. It was found expedient to plot the energy gain area (hatched in Figure 12), expressed in cfs, versus the corresponding dependable flow, also in cfs, in order to get a continuous

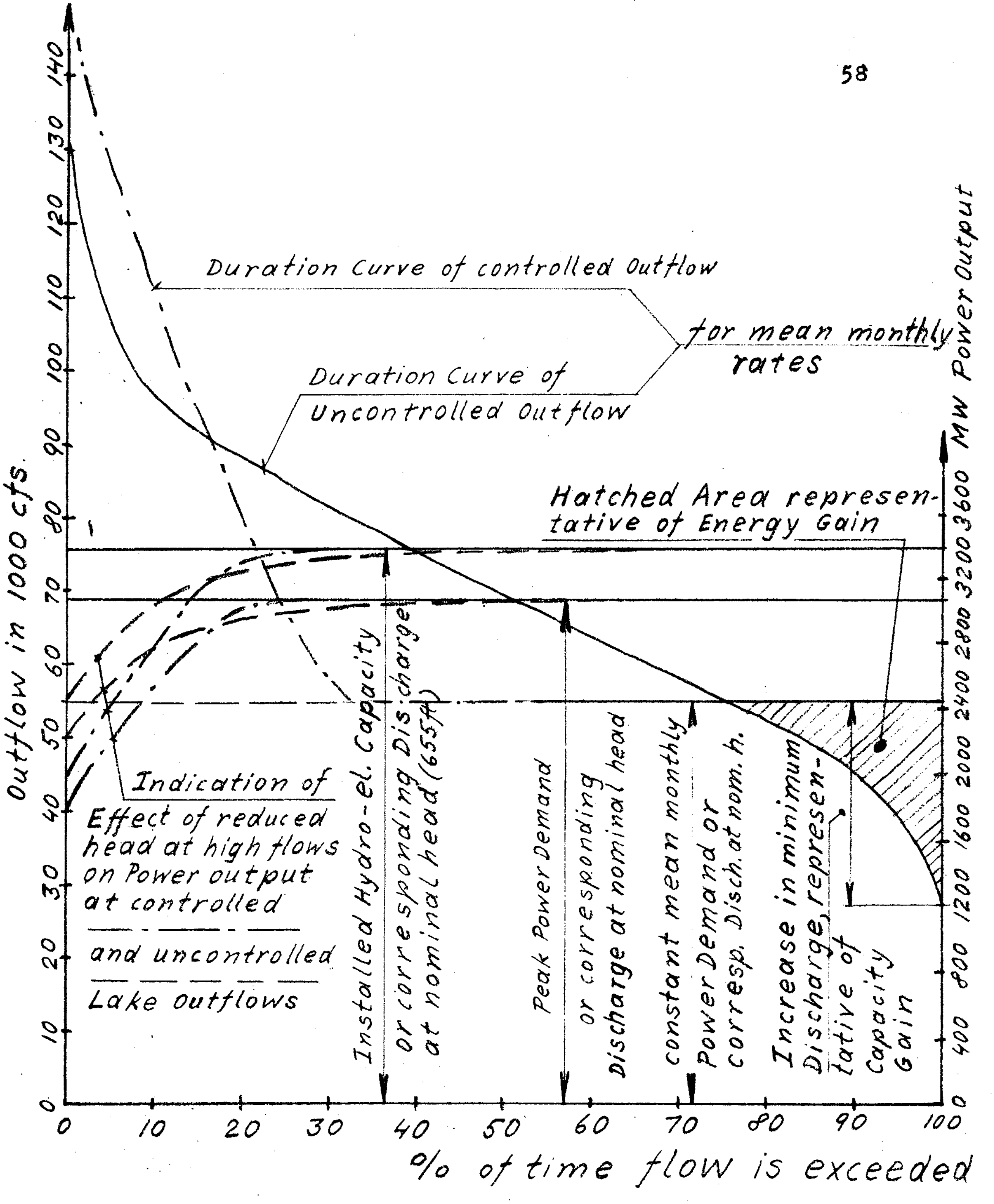


Fig. 12 Use of Duration Curve for Estimating Value of Regulation (Lake Winnipeg)

Effect of reduced head and left portion of controlled Outflow Duration Curve assumed only for illustration relationship between energy gain and maximum 100% dependable outflow which itself is related to the regulation range on Lake Winnipeg (Figure 13). The capacity gain is proportional to the difference between maximum 100% dependable outflow and the minimum mean monthly outflow on record, as long as the changes in head losses can be ignored. This was assumed to be the case.

(b) For dependability during 90% of the time, the capacity gain (analog to the above) is proportional to the difference between the 90% dependable outflow (dependable during 90% of the time) and the lowest mean monthly natural outflow.

To find the energy gain, use was made of the plot of energy gain, expressed in cfs, for 100% dependable flow versus the 100% dependable flow. From this graph (Figure 13) the flow increase corresponding to a 100% dependable outflow of the same magnitude as the 90% dependable outflow was read. From this value the deficiency in inflow, occurring during 10% of the time, had to be deducted. This shortage was found from the inflow mass-curve (or more accurately from the table of accumulated inflow-available-for-outflow from which the mass-curve was plotted) as indicated in Figure 14. It is recalled that the determination of the 90% dependable outflow was based on the assumption that the outflow equals the inflow-available-for-outflow when the lower limit of regulation is reached as long as the inflow-available-for-outflow

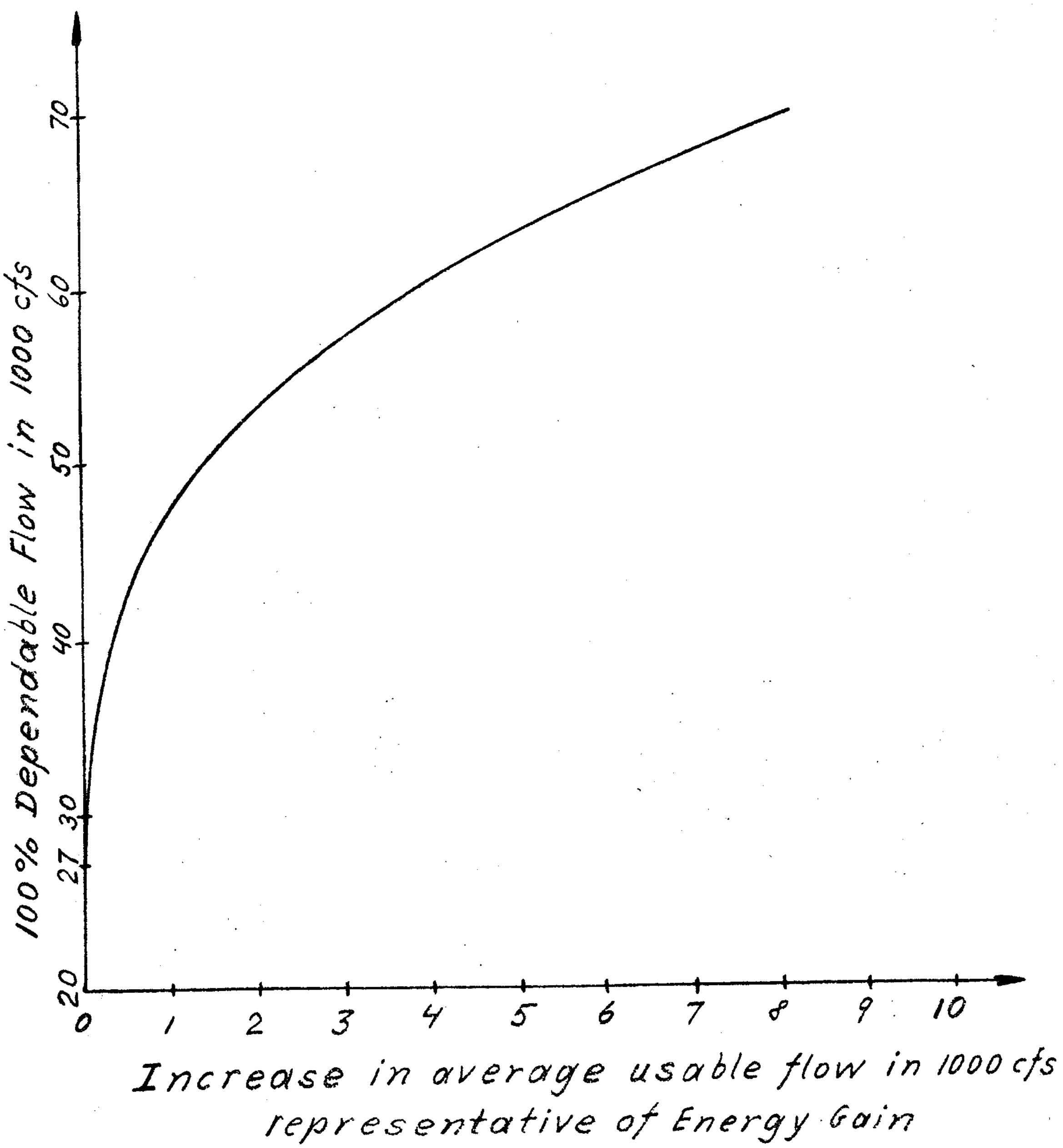


Fig. 13 Dependable Flow – Energy Gain Curve for Lake Winnipeg Regulation

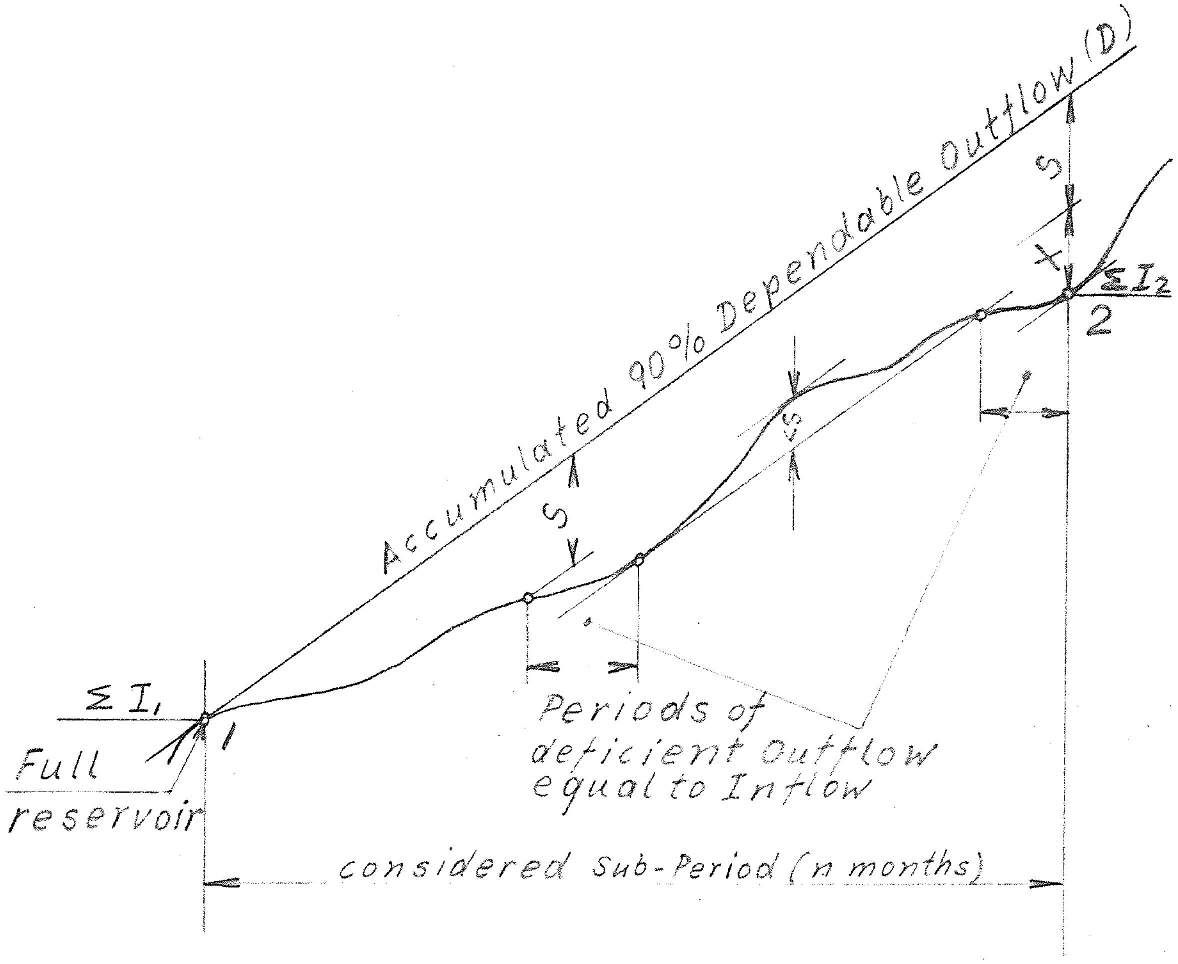


Fig. 14 Method for Determining the Decrease in Energy Gain for 90% dependable Outflow

does not exceed the 90% dependable flow.

The period of record was divided into sub-periods like the one illustrated in Figure 14. For each sub-period having a shortage X, same was computed from equation

$$nD = I_2 - I_1 - S - X$$

where n number of months in the considered sub-period

D the 90% dependable outflow in cfs

I_2 accumulated inflow-available-for-outflow in cfs-months up to time 2.

S available storage capacity in cfs-months for power purposes (excludes flood reserve capacity)

X flow deficiency accumulated in the considered sub-period, in cfs-months.

Having determined X from all sub-periods, the total average deficiency in flow was computed as $\frac{X}{N}$ cfs where N is the total number of months of the period of record. This is the amount by which the energy gain, found as described earlier, had to be reduced to get the energy gain when regulating for 90% dependable outflow. The rest of the evaluation procedure was the same whether regulation for full or for reduced dependability was assumed. The flow rate increases in cfs representative of capacity gain and of energy gain, were first converted into MW and "continuous MW" respectively and finally into average annual dollar-benefits. (For convenience, energy was not expressed in MWh but in "continuous MW" representing the average power output over a time period.

A constant developed head of 655 feet, an overall efficiency of 0.8, and a capacity factor of 0.727 (0.8 load factor and 10% spare capacity) were assumed for the first conversion. Figure 15 shows the benefits in MW and continuous MW as a function of the regulation range.

Expressing the benefits in terms of money permitted combining capacity and energy benefits into total benefits. The following considerations guided this last step of the evaluation.

In order to achieve the same power and energy output without Lake Winnipeg regulation as with regulation, it was assumed that Nelson River power would be supplemented by conventional steam-electric power. Two possibilities of supplementing Nelson River power under natural storage conditions (Lake Winnipeg unregulated) were compared:

(1) Duplication of that portion of hydro-electric capacity that is not dependable (90% or 100% of the time) by steam-electric capacity.

(2) Hydro-electric plant installation under unregulated conditions is limited to the dependable capacity for natural Lake Winnipeg outflows (including 10% spare capacity).

Since in the first case the same amount of hydroelectric capacity would be installed with Lake Winnipeg

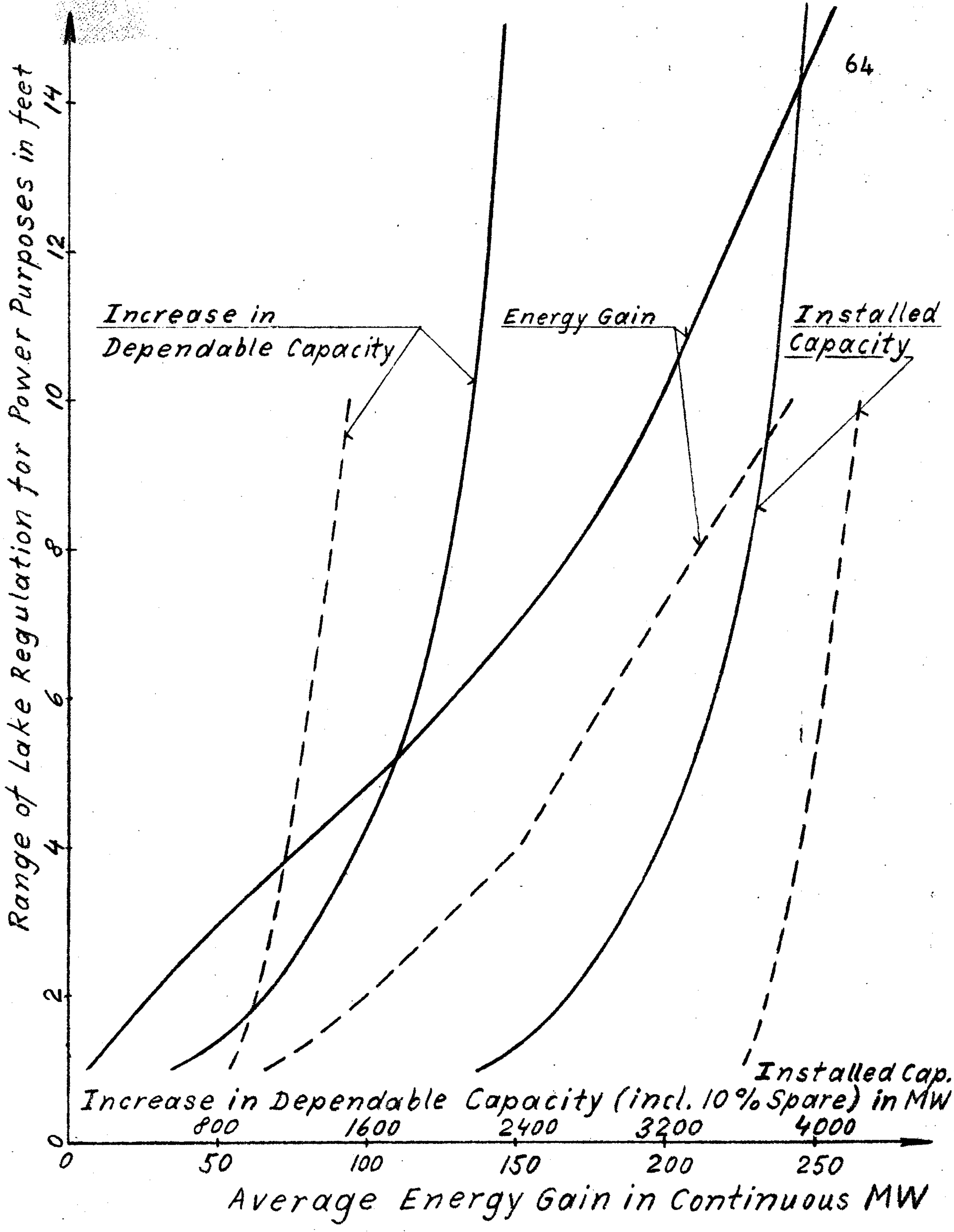


Fig. 15 Benefits of Regulation in MW and continuous MW (Lake Winnipeg for 655 ft. head)

unregulated as under the range of regulation being evaluated, the energy gain from regulation would be relatively small, but the cost of having a large portion of the installed hydro-electric capacity duplicated by steam-electric capacity would be high.

In the second case there would be no duplication of capacity. The investment cost for the combination of hydro-electric and steam-electric capacity was expected to be less than the investment costs for an all hydro-electric development. The amount of energy to be supplied by the steam-electric plants would be much greater than in the first case.

Whichever of the two methods of steam-electric support, or combination thereof, results in the lowest overall costs should be used for the benefit estimate. When evaluating Lake Winnipeg regulation combinations of the two methods were not investigated. Duplication of the not dependable hydro-electric capacity was found to result in lesser overall costs for regulation ranges of at least two feet.

Evaluation of the regulation benefits using the costs of steam-electric power was based on the assumption that no alternative sites exist for hydro-electric plants that could supply firm power cheaper than steam-electric plants.

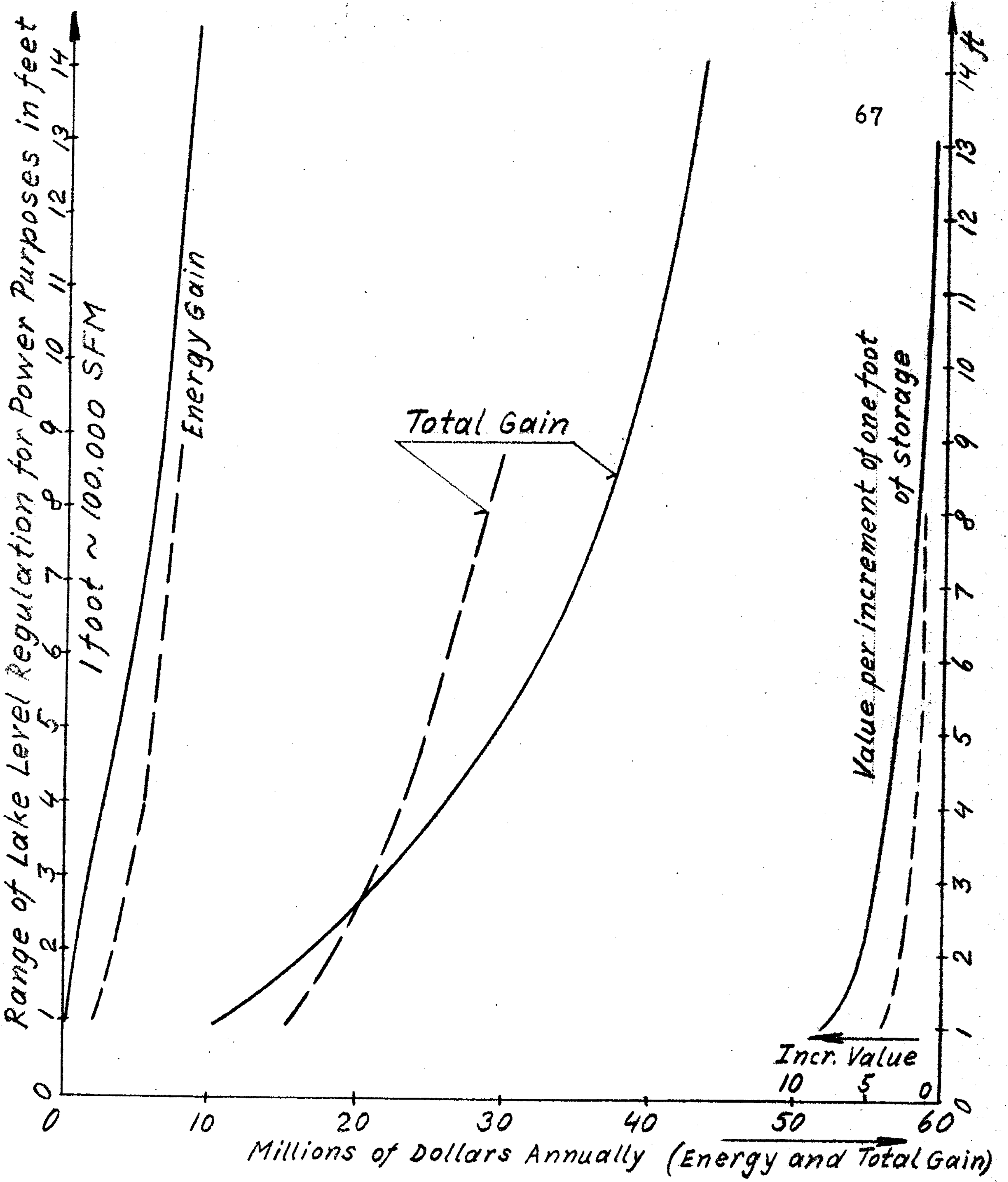
In accordance with the foregoing, the benefits of regulation, for regulation ranges of two feet and greater on Lake Winnipeg, were defined as the cost of electrical energy from steam-electric plants, and the cost of providing the steam-electric capacity required in combination with the Nelson River plants to yield the same amounts of firm power and energy without Lake Winnipeg regulation as the Nelson River plants alone could supply with Lake Winnipeg regulation.

Figure 16 shows these benefits as a function of the regulation range as found in the studies for the Lakes Winnipeg and Manitoba Board.

One of the most important assumptions on which this benefit evaluation was based was development of all sites to the same utilization of flow, i.e. equal plant discharge capacity. However, it may be more advantageous not to develop some of the more expensive sites and to compensate for the lost head by increasing the capacity of the less costly sites and increasing the regulation range as required accordingly. Regulation benefits based on this criterion were determined as described in the next section.

Potential Benefits of Regulation After Partial Development Trough Postponement of Development at the Less Advantageous Sites

As long as the power demand is less than the power potential of the Nelson River (power available at full development of all sites with the largest practicable Lake



Note: 100% of the time dependable ———— Load factor 0.8
90% of the time dependable — — — Spare capacity 10%
Steam-electric Cost-Assumptions: $15/kW per annum
(Equal installed Hydro-el. Cap. $4/MWh
with and without regulation)

Fig. 16 Average Annual Power Benefits of Regulation expressed in Dollars (Lake Winnipeg for 655 ft. head)

Winnipeg regulation range for power purposes) it may be possible to supply the demand either by adding capacity at existing plants and providing the necessary increase in storage capacity or by development of additional sites without increase in storage. Although it is likely that a combination of both would be the cheapest provision for certain increased power demands, the benefits of storage were estimated by comparing only the above mentioned two ways of adding capacity. The cost advantage of extending existing plants may be considered as the benefit of regulating over the required range. Calculations were performed for load conditions requiring 90% dependability.

The same approach could have been used for 100% dependability.

Estimating the benefits proceeded as follows:

The potential energy production dependable during 90% of the time was determined assuming all sites developed and the lake regulated over a nominal range of one foot in lieu of using the natural outflow rates from Lake Winnipeg. This expedient was used because the attempt to base the benefits on the unregulated state showed that many of the low head plants could be eliminated by compensating with additions at the remaining sites requiring only a very small regulation range (around one foot) until the "Limestone Rapids" project with the largest head concentration

(186 feet) would have to be dropped as being finally the most expensive of the remaining sites. Elimination of such a large portion of the head would have required an excessive range of regulation. As already mentioned earlier, a load factor of 0.8 and 10% spare capacity were assumed as well as constant mean monthly energy demand and constant monthly peak demand. The following basic figures (for one foot regulation range) were found:

Flow rate dependable during 90% of the time 60,000 cfs,
Rate of average flow usable for conversion into energy 58,000 cfs (determined as described in the previous section).
With a total developed head of 655 feet and assuming 80% efficiency, the total installed capacity amounts to 3,660 MW producing 3,330 MW of peak power.

The elimination of the most expensive project, "Whiskey Jack", reduced the head by 25 feet from 655 feet to 630 feet. To compensate for the head reduction, the 90% dependable flow and the average flow convertible into energy have to be increased. The power output, which is to remain unchanged, is proportional to the product of flow rate times head. The flow rates required with decreased head were therefore found to be 62,400 cfs and 60,300 cfs for 90% dependability and for average energy output respectively. From the dependable flow curves it was found that a regulation range of two feet would yield a flow of 63,200 cfs dependable during 90% of the time. The average flow deficiency (found as described in the previous section) would be 2,250 cfs. Accordingly, the flow representative of the possible energy production would be (63,200 - 2,250) cfs = 60,950 cfs. Comparing these flows with the required flows showed that adequate energy production potential is the criterion for the required regulation range. Interpolating linearly gave the required increase

$$\left(\frac{60,300 - 58,000}{60,950 - 58,000} \times (2 - 1) \text{ ft.} = 0.78 \text{ ft.} \right)$$

of the nominal one-foot regulation range. Thus it was found that an increase of the regulation range from one foot to 1.8 feet would permit elimination or postponement of the costly "Whiskey Jack" development. In order to utilize the improved flows and to have the same total plant capacity on the Nelson River without the Whiskey Jack plant, the capacities at the remaining sites have to be larger by

$$\frac{655}{655 - 25} - 1 = 4\%.$$

The cost of the Whiskey Jack plant was estimated to be $67,000,000, whereas the cost of the incremental capacity at the remaining plants was estimated at only $23,000,000. Applying 8.3% annual charges on the investment difference, the annual benefit for increasing the regulation range from one foot to 1.8 feet was found.

This procedure was repeated a few times, at each repetition eliminating the most expensive site to develop from those remaining. The resulting benefit regulation range relation is shown in Figure 17 for a 90% dependable output of 3,333 MW.

The same method can be applied to other power outputs (degree of development). A second curve, for a smaller power output, was determined for the Lakes Winnipeg and Manitoba Board.

The benefit estimates for Lake Winnipeg regulation referred to possible development in the distant future and assumed fixed load and system conditions. In reality loads and power systems will be changing, requiring sequences of load years to be analysed.

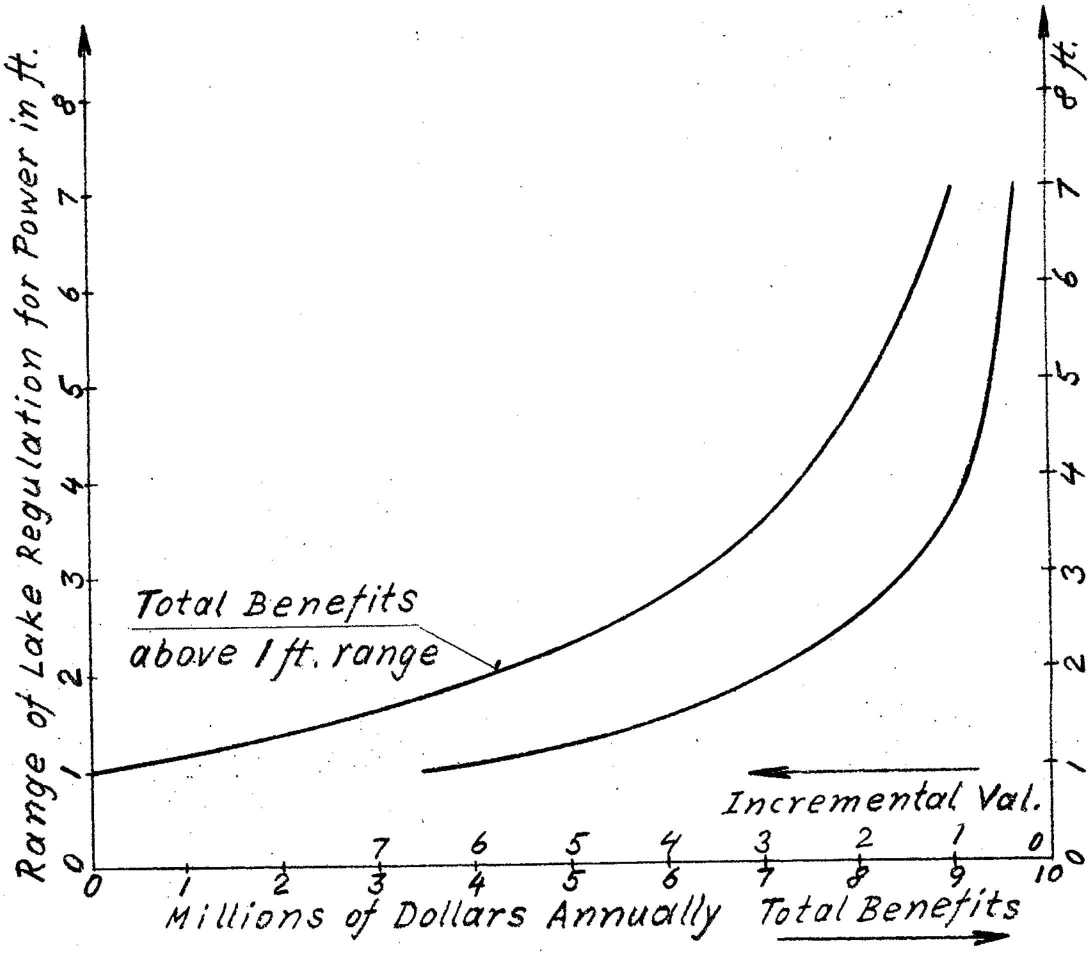
The last portion of the thesis describes the methods used for evaluating the benefits of incremental storage at the Grand Rapids plant considering a period nearer in time, namely from 1967 to 1976.

BENEFITS FROM CAPACITY INCREMENTS OF THE GRAND RAPIDS RESERVOIR

Several studies eneavoured to determine the optimum upper storage level for the Grand Rapids reservoir.[9,11,2]

The following deals with the last study as an illustration of more elaborate methods for estimating the benefits of storage capacity increments.

The Grand Rapids plant is under construction at the



Note: The benefits of regulating over a range of one foot were abritraly set equal to zero.
Peak Power 3333 MW, Loadfactor 0.8, dependable 90% of time spare capacity 10%

Fig. 17 Temporary Benefits from Increases in Regulation Range permitting the postpone- of the development of additional sites mouth of the Saskatchewan River (Figure 8, page 50, and Figure 18). The first two units, of 150,000 h.p. each, are scheduled for commissioning in the fall of 1964. The useful life of the plant is expected to extend well into the next century. For purposes of selecting the "Full Supply Level" (i.e. the maximum reservoir surface elevation permissible for storage of water for energy production), the storage benefits would have to be estimated over the useful life of the facilities. Such a comprehensive study would be very time consuming and costly. The influencing factors would have to be estimated far into the future. Consequently, the study was restricted to the early years (1967 - 1975) of the developments life. The assumptions to be made for these early years have a greater chance of being close to the actual conditions than speculation about a more distant future. Further, the annual costs and benefits in the near future are more important than those in the later years, i.e. their reduction to present worth is less.

The first step in the study was to estimate the future load growth of the southern Manitoba power system and to assume additions of new generating stations and extension of existing plants to meet the estimated load growth. According to these assumptions, the Grand Rapids reservoir would be, up to 1971, the only reservoir regulated exclusively by Manitoba Hydro. The last five years (1971 - 1975) studied

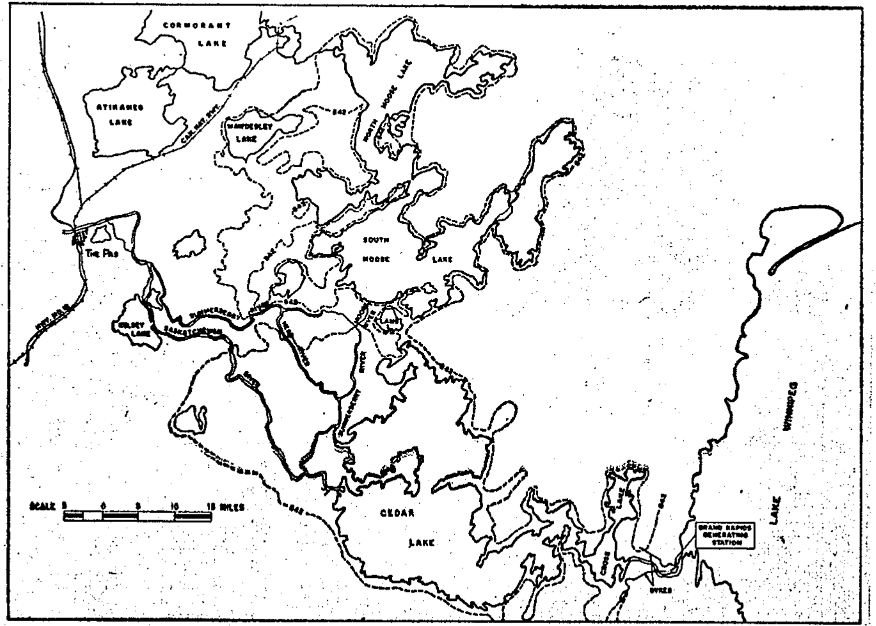


Fig. 18 Grand Rapids Reservoir Region

show the effect of Lake Winnipeg regulation and the effect of increasing Nelson River power production on the value of Grand Rapids storage.

No attempt was made to forecast the inflows to the reservoirs, instead a period of past flow records (1928 to 1955), containing dry and wet cycles, were applied in chronological order to future load years. The Grand Rapids reservoir inflows were adjusted to allow for increased upstream irrigation use as estimated by the Prairie Provinces Water Board and the Prairie Farm Rehabilitation Administration.

Figure 19 shows schematically the system of rivers, reservoirs, and hydro-electric plant groups of which the Grand Rapids project becomes a part. The hydro-electric generating capacity is supplemented by thermal-electric generating capacity, increasing from 290 MW to 390 MW net output. Also presented on the scheme are: the average river flows for the flow period used in the study, the storage capacities os the major reservoirs, the existing and assumed future installed generating capacities, and the heads of the hydro-electric plant groups and of the Grand Rapids plant. The growth in installed generating capacity and head is indicated by the ranges noted. In the following table are listed the assumed capacity additions.

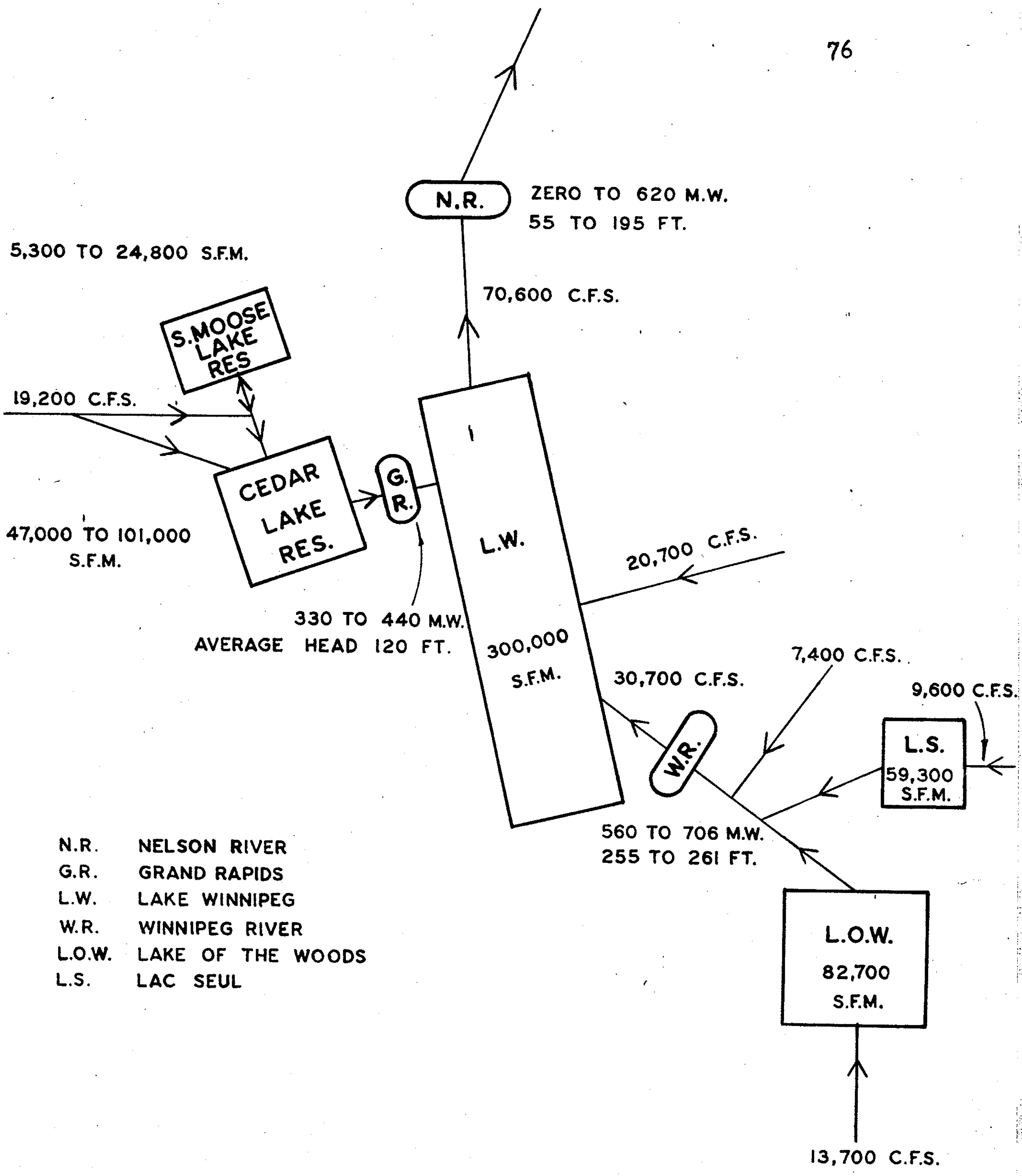


Fig.19

SKETCH OF HYDRO-ELECTRIC GENERATING SYSTEM AVAILABLE FOR THE LOAD IN SOUTHERN MANITOBA

TABLE I

ASSUMED CAPACITY ADDITIONS TO THE GENERATING SYSTEM FOR THE LOAD IN SOUTHERN MANITOBA

1967, December 1	100 MW	Selkirk (thermal-el.)
1968, December 1	146 MW	Winnipeg River plants additions
1970, November 1	92 MW	Nelson River
December 1	70 MW	Nelson River
1971, December 1	109 MW	Grand Rapids
1972, December 1	97 MW	Nelson River
1973, December 1	160 MW	Nelson River
1974, December 1	192 MW	Nelson River
1975, December 1	96 MW	Nelson River

The surface area of the Grand Rapids reservoir changes considerably with the elevation. The assumption of a constant surface area independent of the water surface elevation, which was considered permissible for Lake Winnipeg, was therefore not applicable for the Grand Rapids reservoir. A further complication, as compared to Lake Winnipeg regulation, is that the head utilized by the Grand Rapids turbines will be affected by the reservoir level. The minimum reservoir level below which the Cedar Lake reservoir (Figure 18, page 74) should not be drawn, had to be decided upon first. The topographic features of the Cedar Lake outlet area facilitated the selection of the minimum reservoir level. The outflow rating curve of

Cedar Lake indicated that the maximum outflow rate that would be desirable at depleted storage conditions could be drawn from Cedar Lake at a water surface elevation of 831 feet. To allow for the back water effect of the raised Cross Lake level, one half foot was added, giving a minimum reservoir level of 831.5 feet. This elevation does not represent a definite minimum. Drawdowns below this elevation appear feasible, but the gain in storage capacity would be relatively small and the reduction in discharge capacity might sometimes be undesirable.

The earlier studies had indicated that maximum reservoir elevations from 838 to 846 feet would be economically desirable. Hand computations were made for the load year 1967/68 and for storage capacities limited by maximum reservoir elevations of 838, 841 and 844 feet. Digital computer use was finally resorted to because the hand computations proved very time consuming. In spite of the shift to computer application, several simplifying approximations were retained. The more important departures from an exact treatment were: (1) The future storage benefits to the growing system were estimated by applying, to one load year at a time, the representative period of past flow records in chronological order, repeating the same future load year with each of the flow years of the past period instead of progressing in the actual sequence of load years.

(2) About fifteen years of past records (1913 to 1927) were not utilized, instead November 1, 1927 was selected as the beginning of the flow period, assumed representative for future conditions. In the year 1927 very high river flows were experienced in regions draining into Lake Winnipeg; consequently, it could be assumed that all reservoirs would have been full on November 1, 1927. It might be argued that selecting a period which starts with a full Grand Rapids reservoir introduced bias in favour of larger storage capacities. If the flow period used ended with low flows and empty reservoirs, it would be justified to object. However, the selected flow period ended in the fall of 1955 after several years of above average flow so that it was expected that the Grand Rapids reservoir would again be filled completely or almost completely. The alternative would have been to assume arbitrarily the initial water contents of the reservoirs and also apply the flow records for the years preceding 1927. In this case, it would have been advisable to discard the first few years of the computer output until the influence of the error in the assumed initial content could be considered negligible. Obviously, this alternative would have required more computer time.

(3) The thermal-electric plants at Selkirk, Brandon and Winnipeg, and in the neighbouring provinces are supplying energy at different costs per kWh. As mentioned in the

section on refined solution methods, to take the differences in incremental thermal-electric costs into account when simulating the reservoir operations would have necessitated a time consuming pre-study, preferably with digital computer use, in order to determine sets of economy guide lines (lines of equal incremental water value) for every load year from 1967 to 1975.[4,6] To avoid this work, it was assumed that all electric energy other than that produced by the hydro-electric plants in Manitoba for the southern Manitoba system would be available at one uniform incremental cost. Because the "No-Spill Rule Curves" (see appendix for definition) were estimated to be lower than the basic rule curves during most of the time, it was considered uneconomical to conserve water that could be used to supply firm energy at a time when the storage contents of the reservoirs were above the basic rule curve, solely for the purpose of increasing the head at the Grand Rapids plant slightly. The frequency and volume of subsequent spilling would more than offset the gains from increased head. Consequently, only one or more basic rule curves for every load year needed to be determined; no economy guide lines were required. It would have been possible though to assume reasonable looking curves as substitutes for actually determined economy guide lines, but it was felt that the additional programming work was not justified by the minor improvement in accuracy. In fact, ideal simulation would not have to work to economy guide lines for the southern Manitoba system, but would have to simulate the future decisions of the Lake of the Woods Control Board. Since most of these decisions are not governed by rigid rules, they can hardly be written into a computer program. The simplified way of regulation tends to reduce spillage compared to what actually will happen. Therefore, the results will be slightly biased in favour of the lower storage capacities.

(4) Operation of Lake of the Woods and Lac Seul storage was assumed to be possible within the permissible range of lake levels for the requirements of Manitoba exclusively, except for the restriction that the average monthly outflow rates from Lake of the Woods and Lac Seul were not permitted to drop below 4,000 cfs and 3,000 cfs respectively. In order to assess the magnitude of the error introduced by this assumption, computations were repeated for three load years for maximum Grand Rapids reservoir levels of 841 and 844 feet with predetermined regulation of the Winnipeg River. The results confirmed the expectation that taking into account other interests in regulating the reservoirs of the Winnipeg River basin increases the value of Grand Rapids reservoir storage.

(5) Application of the constraints: minimum outflow, minimum and maximum plant output, minimum and maximum reservoir levels,

and one basic rule curve for the reservoir system in the part of the computer study covering the years from 1967 to 1971, does not define how much each reservoir is to be drawn upon or replenished. Application of the balancing principle (see previous section on "Refined Methods") would have filled that need ideally. However, another pre-study would have been necessary to establish the rules for apportioning draw and replenishment based on the criterion of most economic balancing of reservoir contents. The reason which led to discarding the use of economy guide lines prevented also the strict application of the balancing principle. As a substitute measure, when simulating reservoir operations for the load years 1967 to 1970, the storage content of any reservoir was kept in the same proportion to its storage capacity as the sum of the storage contents of all reservoirs bears to the total storage capacity of all reservoirs. For this purpose the storage contents and capacities were taken exclusive of any surcharge for flood storage.

(6) In the preliminary hand computation and the computer study for the load years 1967 to 1970, the factor for converting average monthly Grand Rapids plant discharge into monthly energy output was assumed to be a function of the Cedar Lake level only. The effects of the changes in Lake Winnipeg level and of changing head losses were neglected. The computer study for the load years 1971 to 1976, which

includes regulation of Lake Winnipeg, took into account that the conversion factor is not only a function of the Cedar Lake level but also of the Lake Winnipeg level, the plant discharge, and the number of units running. Only the back water effect of the spillway discharge was neglected. This omission would tend to favour the lower storage capacities because the smaller the storage capacity the more frequently and in larger quantities would spillige occur.

(7) The reservoir operation rules assumed advance knowledge of the unregulated runoff extending over one time unit used in the study (one month). Although this assumed advance knowledge resulted in less water wastage than would actually be the case, this was considered tolerable with respect to the objective of the study. The effect of this assumption becomes more important in studies dealing with relatively small reservoir capacities. Use of smaller time units, e.g., one week, would reduce the effect.

(8) To allow for the possibility that a large portion of the marsh area east of The Pas (see Figure 18, page 74) would be reclaimed during the useful life of the Grand Rapids project, only the southern portion of Moose Lake was treated as part of the Grand Rapids reservoir during all the load years studied although it appears that reclamation will not proceed in the near future.

The above list of approximations gives an indication that, even with a powerful electronic computer and the assistance of professional programmers, some sacrifices in accuracy were considered advisable in order to reduce the study costs.

The inclusion of Lake Winnipeg regulation into the simulation study represented a considerable complication. For this reason the study was initially restricted to simulating system operations for the load years 1967 to 1970. Without Lake Winnipeg regulation, only a two reservoir system had to be regulated because the two large reservoirs of the Winnipeg River basin could essentially be treated as one reservoir.

For every load year the conditions to be observed by the reservoir operations were determined by hand calculations and used as input data for the computer, in addition to the other input data required. As an example, Table II shows the limiting conditions for the load year 1967/68 for every month. Column 8 lists the basic rule curve values referred to when discussing the simplifying assumptions. The basic rule curve data are not truly limiting values rather they are the criterion for minimum or maximum hydro-electric energy output within the limitations imposed by the other limiting conditions.

The Grand Rapids reservoir comprises large marsh areas and already existing lakes. The more important ones of the

TABLE II

LIMITING VALUES FOR LOAD YEAR 1967/68

	1	2	3	4	5	6	7	8	9	10	11	12
MONTH	END OF MONTH LAKE OF THE WOODS CFS-MONTHS	MAX. LAC SEUL	MAX. HYDRO	MIN.	MIN. STEAM	MIN. (STEAM GR.R.) GWh	TOTAL EN.	DESIRED TOTAL STORAGE	MAX. STEAM	MAX. GR. R.	MAX. US. W.R. CFS	MAX. W.R. PL. GWh
APRIL	71,000	53,300	434	277	3	79	437	870	160	232	31,000	358
MAY	74,900	59,300	436	268	3	87	439	1,080	165	239	31,000	352
JUNE	78,800	59,300	409	252	3	76	412	1,300	160	232	29,700	336
JULY	82,700	59,300	407	240	4	64	411	1,470	165	173	29,700	347
AUG.	82,700	59,300	411	245	5	70	416	1,450	165	178	29,700	346
SEPT.	82,700	59,300	429	282	13	100	442	1,360	160	173	31,000	342
OCT.	82,700	59,300	475	308	4	97	479	1,250	165	239	35,200	382
NOV.	82,700	59,300	490	335	5	99	495	1,110	160	232	35,500	396
DEC.	82,700	59,300	561	353	17	150	578	970	225	239	35,800	413
JAN.	82,700	59,300	575	369	19	163	594	810	225	239	35,800	413
FEB.	82,700	59,300	514	326	16	146	530	690	204	216	35,800	370
MARCH	63,000	59,300	519	300	6	122	525	680	225	239	35,800	395

Key to abbreviations on next page

Key to abbreviations used in Table II:

MAX.	maximum
MIN.	minimum
EN.	energy
GR. R.	Grand Rapids
US.	usable
W. R.	Winnipeg River
PL.	plants
GWh	Giga-Watthours (10^9Wh)

Relations between column values in Table II:

col. 7 = col. 3 + col. 5 = col. 4 + col. 9

For April to November only:

col. 12 = col. 7 − col. 6

latter are: Cedar Lake, Cross Lake, North and South Moose Lake, and Mawdesley Lake (see Figure 18, page 74).

As mentioned earlier, a portion of the reservoir area was assumed to be reclaimed. Therefore, North Moose Lake, Mawdesley Lake, and the surrounding low-lying areas were excluded from the reservoir available for storage in the simulation sudies. Cedar Lake and Cross Lake are so well connected hydraulically at the reservoir elevation ranges studied that it appeared justified to treat these storage fluctuations as occurring simultaneously in one reservoir in the regulation studies which used the month as the time unit.

Unfortunately, South Moose Lake and the main body of the reservoir are separated by higher ground at low reservoir stages. The only connection of South Moose Lake to the Cedar Lake region is via a small creek, Moose River, which connects to the Summerberry River, a branch of the Saskatchewan Delta. At higher stages very substantial overland flow improves the tie between the reservoir bodies considerably.

In the preliminary hand computations, South Moose Lake and the main reservoir were treated as one body of water with a common level, in spite of the gross violation of the realities, to keep the work in reasonable limits. Computer application permitted this oversimplification to be dropped. Recognition of South Moose Lake as a separate (though not separately controlled) reservoir required determination of the monthly volume of water flowing to or from South Moose Lake (via Moose River and overland) in order to determine the differing levels of Cedar Lake and of Moose Lake at the end of each month.

The knowledge of the Cedar Lake level was, of course, needed for the observation of regulation limits and for the determination of the average monthly head at the Grand Rapids plant and the appropriate conversion factor for converting monthly flow through the hydro-electric units into monthly energy output. The Moose River discharge and the rate of overland flow are both a function of Cedar Lake and Moose Lake stage. The Moose River discharge is in addition influenced by the rate of inflow to the reservoir, represented by the discharge at The Pas.

Based on time consuming hand computations, one graph was prepared for each different Saskatchewan River flow showing Moose River flow as ordinates, plotted versus Moose Lake elevations as abscissae, using Cedar Lake elevations as parameter. As it turned out, the completely worked out relationships were unsuitable for computer application because they required an excessive amount of storage space on the computer. It was necessary to feed the computer relationships from an intermediate stage of hand computations requiring very little storage and letting the computer do the rest of the calculations, when and as required.

Obstruction of flow between South Moose Lake and Cedar Lake due to ice conditions was roughly accounted for by assuming that overland flow between these two bodies of water would be nil from January to April inclusive regardless of lake elevations, and neglecting the back water effect of a possible ice cover on the Moose River flow.

Table III shows an example of the calculations necessary to regulate the reservoirs in accordance with the foregoing for firm load requirements only. The inflow-available-for-outflow was assumed equal to the past flow records (adjusted for known man-made changes) and was listed in columns 1, 4, and 10 for Lake of the Woods, Lac Seul, and the Grand Rapids reservoir respectively. The unregulated runoff was also assumed equal to the flow observed in the past and was listed in column 7. The computations started with November 1927 with the assumption that all reservoirs were full to capacity, because of the high flows which occurred in 1927. For the month of November and several subsequent months it was evident without checking that the storage content of the reservoirs was above the basic rule curve values in column 8 of Table II even when regulating to the maximum hydro-electric output (column 3, Table II). The total monthly storage drawdown required for maximum hydro-electric output was computed and taken from the three reservoirs in proportion of their storage capacities. Thus the end of November storage contents

TABLE III

EXAMPLE OF REGULATION CALCULATIONS

for the load year 1967/68 and Grand Rapids F.S.L. 838 feet

	1	2	3	4	5	6	7	8	9	10	11
	LAKE	OF THE	WOODS		LAC SEUL		WINNIPEG R.		FIRM	THE PAS	
MONTH	Infl.	Outfl.	Cont.	Infl.	Outfl.	Cont.	Unreg.	Total	Outp.	Inflow	
					cfs				GWh	cfs	GWh
1927											
Oct.	11,200	11,200	82,700	10,040	10,040	59,300				45,206	
Nov.	10,600	11,333	81,967	9,540	10,067	58,773	7,700	29,100	341	25,351	146
Dec.	10,200	17,050	75,117	7,870	12,790	53,853	5,960	35,800	413	13,438	77
1928											
Jan.	10,620	19,120	66,617	6,480	12,560	47,773	4,120	35,800	413	11,194	64
Feb.	9,160	19,350	56,427	5,910	13,180	40,503	3,170	35,800	370	9,809	50
March	12,140	20,790	47,777	4,050	10,500	34,053	4,000	35,800	395	9,983	55
April	13,320	18,230	42,867	4,190	7,720	30,523	5,250	31,000	358	26,297	143
May	18,030	6,080	54,817	4,810	3,000	32,333	9,820	18,900	236	49,654	284
June	27,680	13,350	69,147	10,990	3,000	40,323	4,450	20,800	247	38,278	214
July	20,660	7,107	82,700	14,830	3,000	52,153	19,150	29,257	234	69,242	396
Aug.	8,970	8,970	82,700	21,000	13,853	59,300	20,150	40,823	300	56,126	
Sept.	13,810	13,810	82,700	16,600	16,600	59,300	9,400	39,810	329	27,948	
Oct.	21,800	21,800	82,700	13,500	13,500	59,300	2,600	37,900	382	13,126	77
Nov.	15,970	15,970	82,700	13,430	13,430	59,300	6,700	36,100	396	5,940	34
Dec.	10,940	14,140	79,500	12,840	15,130	57,010	6,530	35,800	413	4,382	25
1928											
Total	183,100	178,420		128,630	125,473		95,340	397,790	4,073	321,979	
Change			4,383			3,157					

Note: In the above calculations the average monthly rate of flow in cfs during the duration of any month was set equal to a volume of the same number of cfs-months. However, in the digital computer calculations the differences in the number of days in a month were allowed for.

TABLE III
(continued)

	12	13	14	15	16	17	18	19	20
	GR. R.	CEDAR LAKE		MOOSE LAKE				TOTAL	TOTAL
MONTH	Output GWh	Cont. GWh	Stage feet	Flow cfs	Content cfs	Content GWh	Stage feet	Hydro GWh	Steam GWh
1927									
Oct.		268	838.00	0	10,000	58	838.00		
Nov.	149	263	837.90	350	10,350	60	838.10	490	5
Dec.	148	192	836.36	100	10,450	60	838.10	561	17
1928									
Jan.	162	96	834.05	(625)	9,825	58	838.00	575	19
Feb.	144	7	831.70	(770)	9,055	53	837.72	514	16
March	68	0	831.50	(786)	8,269	47	837.35	463	56
April	76	69	833.30	(333)	7,936	45	837.23	434	3
May	200	148	835.30	671	8,607	50	837.53	436	3
June	162	193	836.38	1,117	9,724	57	837.95	409	3
July	173	268	838.00	1,501	11,225	64	838.35	407	4
Aug.	111	268	838.00	1,742	12,967	75	839.00	411	5
Sept.	100	268	838.00	518	13,485	77	839.13	429	13
Oct.	93	254	837.70	(463)	13,022	75	839.00	475	4
Nov.	94	197	836.45	(665)	12,357	72	838.82	490	5
Dec.	167	61	833.16	(928)	11,429	66	838.48	561	17
1928 Total	2,756							5,604	148

Note: Moose Lake flows in brackets are from Moose Lake to Cedar Lake.

were found. The same was tried for December 1927, but the resulting Winnipeg River flow would have exceeded the maximum usable amount in column 11 of Table II. It was therefore necessary to draw more water from the Grand Rapids reservoir than would correspond to balanced reservoir contents. Only the Lake of the Woods and Lac Seul content were kept in the proper proportion to each other.

January and February 1928 outflows were found in the same way, but in March the Grand Rapids storage was exhausted and the Grand Rapids output so much reduced that the steam-electric output had to be increased to the value required to complement the Grand Rapids output in order to meet the minimum requirement of column 6, Table II.

The April inflow to the Grand Rapids reservoir permitted to meet the condition of minimum combined Grand Rapids and steam-electric output with minimum steam-electric output.

Conditions during May permitted, with maximum hydro-electric output, to get the content of the Grand Rapids reservoir at the end of the month into the appropriate proportion to the sum of Lake of the Woods and Lac Seul reservoir content, but it was not possible to get the Lac Seul content up to the proper proportion to the Lake of the Woods content because this would have required reducing the Lac Seul outflow below the set limit of 3,000 cfs.

During June the outflow limitation prevented again a faster storage replenishment of Lac Seul. July inflows led to filling of the Lake of the Woods and Grand Rapids reservoir to the maximum permissible levels.

End of August and September saw all reservoirs filled to capacity and arbitrary distribution of firm hydro-electric energy output within the limitations of Table II.

Column 6 of Table II formed the criterion for the allocation of hydro-electric output during October and November 1928 due to the high inflows to the Winnipeg River reservoirs compared to the Grand Rapids reservoir inflow.

During December 1928 maximum energy output was taken from the Winnipeg River and the rest required to get maximum total hydro-electric output was taken from Grand Rapids. The storage drawdown of Lake of the Woods and Lac Seul was made proportional to the respective capacities of the two reservoirs; depletion of the Grand Rapids reservoir was much more severe.

The remaining flow years, 1929 to 1955, were processed similarly to the above. The annual output figures were then averaged. This was done for three different storage capacities of the Grand Rapids reservoir, and the differences in the average annual thermal-electric requirements computed for the load year 1967/68.

The whole process was repeated for other load years yielding the values for the third column of Table IV, namely, the increases in average annual thermal-electric energy requirements when lowering the full supply level by three feet. To these differences a unit cost of 4.2 mills per kWh was applied giving the average annual incremental system operating cost, i.e. the value of the storage increment. The unit costs are, of course, not known in advance. It was estimated that the difference in incremental costs for thermal-electric and hydro-electric generation would average 4.2 mills/kWh during the load years studied. (In addition to the firm energy output computations shown in Table III, the computer program included computation of the producible surplus energy.) To the differences in producible surplus energy a value could also be assigned, taking into account that only a fraction of the surplus might be sold at low interruptible power rates.

At this stage the studies could have been terminated. However, it was thought that regulation of Lake Winnipeg might reduce the benefits of the last increments of Grand Rapids storage capacity. For this reason the first five load years with Lake Winnipeg regulated, 1971/72 to 1975/76, were studied subsequently. The complications arising from the addition of Lake Winnipeg as a reservoir with controlled outflow led to a different approach, especially with regard to the computer program.

TABLE IV

AVERAGE ANNUAL INCREMENTAL THERMAL-ELECTRIC ENERGY REQUIREMENTS AND CORRESPONDING COSTS

Load Year	F.S.L. Feet	Winnipeg River Regulation for Manitoba		Winnipeg River Regulation fixed	
		GWh	$1,000	GWh	$1,000
1967/68	844				
		36	151	56	235
	841				
		66	277	-	-
	838				
1968/69	844				
		52	218	48	202
	841				
		50	210	-	-
	838				
1969/70	844				
		73	306	130	546
	841				
		92	386	-	-
	838				
1970/71	844				
		92	386	-	-
	841				
		91	382	-	-
	838				

Instead of one overall basic rule curve (changing from load year to load year) three basic rule curves were needed; one for the total minimum hydro-electric energy output, referring to the aggregate of the kWh in storage in Lake of the Woods, Lac Seul, Grand Rapids reservoir, and Lake Winnipeg; one for the hydro energy in storage available for use in the tributary plants (Winnipeg River group and Grand Rapids); the third basic rule curve referred to the total content of all reservoirs combined, in cfs-months. The purpose of these three basic rule curves was to guarantee, under the worst flow conditions on record, adequate total hydro-electric production, adequate output of the tributary plants, and adequate output from the Nelson River plants respectively.

Apart from the circumstance that during most of the load years studied, the developed head was increasing due to newly developed sites coming into service, which introduced uncertainty in establishing the basic rule curves, this set of three basic rule curves referring to several reservoirs (two of them to all reservoirs) created programming difficulties. Because it is impossible to fullfill all three basic rule curve conditions simultaneously, regulation of the storage reservoirs was intended to approach as closely as possible the storage conditions called for by the basic rule curves. However, it is much simpler, though less desirable (theoretically at least), to work with a separate rule curve for each reservoir. Therefore, another sacrifice of accuracy in favour of expediency was made; three separate rule curves, one for Winnipeg River storage, one for the Grand Rapids reservoir, and one Lake Winnipeg rule curve, were substituted. Applying judgment, the first determined basic rule curves, described earlier, were used as a basis for selecting the substitute rule curves.

Concerning distribution of draw and replenishment of the reservoirs, the following rules were applied as a substitute for the balancing principle:

(a) Storage excess above the rule curve was distributed among the reservoirs in proportion to their storage capacity between rule curve elevation and maximum permissible elevation.

(b) Storage deficiency below the rule curve was distributed among the reservoirs in proportion to their storage capacity between rule curve elevation and minimum permissible elevation.

Since this way of allocating draw and replenishment took into account the position of the basic rule curve, it was considered superior to the method used for the earlier load years.

Table V, for the load year 1971/72 for every month, shows the conditions to be met or to be approached as closely as possible by the operation of the reservoirs. In columns 9,

TABLE V

LIMITING VALUES FOR LOAD YEAR 1971/72

	1	2	3	4	5	6	7	8	9	10
MONTH	END OF MONTH LAKE OF THE WOODS	MAX. LAC SEUL	FOR POWER LAKE WINNIPEG	MAX. HYDRO	MIN. HYDRO	MIN. STEAM	MIN. (STEAM GR.R.)	TOTAL EN.	DESIRED TOTAL ENERGY	STORAGE TRIBUTARY
	1,000 CFS-MONTHS			GWh						
APRIL	71.0	53.0	300	568	355	5	60	573	1,750	950
MAY	74.9	59.3	300	570	350	6	72	575	2,100	1,135
JUNE	78.8	59.3	300	533	321	6	74	539	2,500	1,320
JULY	82.7	59.3	300	530	311	6	43	536	3,000	1,460
AUG.	82.7	59.3	300	537	318	6	45	543	2,850	1,425
SEPT.	82.7	59.3	300	561	359	16	77	577	2,650	1,350
OCT.	82.7	59.3	300	618	399	6	71	624	2,450	1,275
NOV.	82.7	59.3	300	636	427	9	80	645	2,250	1,200
DEC.	82.7	59.3	300	738	526	13	134	751	2,050	1,115
JAN.	82.7	59.3	300	761	549	13	146	774	1,850	1,015
FEB.	82.7	59.3	300	680	487	11	128	691	1,700	900
MARCH	63.0	59.3	300	678	458	5	99	683	1,650	800

Note: col. 8 = col. 4 + col. 6 = col. 5 + col. 11
col. 14 = col. 8 — col. 7 – (min. Nelson River generation, with 41,000 cfs flow,) for April to November, and for March.

TABLE V
(continued)

MONTH	11 MAX. STEAM	12 MAX. GR. R.	13 MAX. US. W. R.	14 MAX. W. R. PL.	15 MAX. US. N. R.	16 MAX. N. R. PL.	17 MIN. (W. R. GR. R.)	18 DESIRED TOTAL STORAGE
	GWh		CFS	GWh	CFS		GWh	CFS-MONTHS
APRIL	218	219	36,000	438	45,000	82	273	225
MAY	225	226	36,500	425	46,750	88	262	250
JUNE	218	219	36,500	390	46,750	85	236	268
JULY	225	164	33,400	415	46,750	88	223	276
AUG.	225	169	34,500	420	46,750	88	230	277
SEPT.	218	164	34,900	425	45,500	83	276	267
OCT.	225	226	38,200	475	53,000	100	299	258
NOV.	218	219	43,500	490	53,000	98	329	247
DEC.	225	295	48,300	517	53,000	98	428	238
JAN.	225	295	48,300	517	53,000	97	452	227
FEB.	204	269	48,300	467	53,000	87	400	218
MARCH	225	295	44,600	506	52,500	95	363	210

Note: col. 9, col. 10, and col. 18 end-of-month values, key to abbreviations on page 86, further, N. R. means Nelson River.

10 and 18 are listed the desired storage values corresponding to the three basic rule curves described on page 96. (As mentioned earlier, individual reservoir rule curves were used as subsitutes owing to programming difficulties.)

The unit costs to be applied to the differences in thermal-electric energy output requirements as found in this second simulation study are, of course, more uncertain than those applied to the results of the first simulation study. In this connection it is interesting to note that even one year in advance, the costs of some fuels and the purchase price of economy energy from neighbouring provinces is frequently unknown. For lack of better knowledge, the same unit costs as used for the earlier load years were applied, although one might speculate that the thermal-electric energy costs could go down; an increase of these costs appeared unlikely.

In spite of the very large effort, only nine consecutive load years were investigated. Although the incremental storage values were found to remain fairly stable over the load years considered, there remains doubt whether the storage value found for so small a sample will be truly representative for the much longer life of the reservoir.

SUMMARY AND CONCLUSIONS

As discussed in the introduction,the main reason for estimating the benefits expected from different amounts of reservoir capacity is the need for weighing these benefits against the costs of providing different amounts of reservoir capacity.

Chapter I focussed attention to the many various factors that have a bearing on the amount of benefits to be derived from an installed storage capacity. Runoff and precipitation-evaporation-difference over the reservoir; load, relative reservoir size, and methods of reservoir operation; affected head, cost relations of hydro- and thermal-electric generating and transmission facilities were discussed as the main factors influencing the benefits from storage capacity. The need to make assumptions was pointed out because many of the factors are unpredictable over periods of many years.

Chapter II dealt with methods of solutions. Under the heading "Simple Methods" the mass-curve method, hydrograph-analysis, and change in outflow duration curves were discussed and attention was drawn to the limitations of these methods. "More elaborate methods" were considered next. Future power system and reservoir operation can be roughly approximated by the use of basic rule curve, maximum permissible reservoir levels, and maximum and minimum flows. The benefits from reservoir capacity increments are then approximated by the differences in system operating costs over many years for the different reservoir capacities. The basic rule curve and its preparation was discussed. Although several factors influencing the storage benefits are still ignored in this method of estimating storage benefits, the amount of work calls already for digital computer use.

Briefly described and discussed were under the same heading two other methods that were used for capacity requirement determination for long term regulation of the Nile.

Finally, "Refined methods", which depend on the use of high-speed computers, were described. Because of its importance for the establishment of reservoir operating rules to supplement the basic rule curve, abstracts from pertinent references were included. The vast amount of work involved in using refined methods was stressed.

Chapter III showed the solution approaches used for two cases of benefit estimates. The first case, Lake Winnipeg regulation, served as an illustration of adapting the mass-curve method and use of flow duration curves to a pure hydro-electric system with an unchanging monthly load, and a single reservoir. The second case, benefits from capacity increments of the Grand Rapids reservoir, served to illustrate the application of more elaborate methods, involving use of an high-speed digital computer, to the problem of estimating the incremental storage benefits in a combined hydro-electric and steam-electric system with growing, seasonally varying load and several reservoirs. The many simplifying assumptions made, in spite of computer use, were pointed out and the reasons for the sacrifices in accuracy were given.

The following conclusions were drawn from the study:

(1) Various different methods can be used to estimate the benefits for electricity production which can be derived from water storage regulation, but the result from all methods, even the most refined, will be affected by the assumptions which were made regarding future flows, loads, system composition,cost of energy from alternative sources, degree of downstream development, and other factors.

(2) Because of the impossibility of knowing most of these factors with any degree of accuracy far into the future, one should resist the temptation to go to great refinements in the methods solely for the purpose of estimating the future storage benefits.

(3) Every reservoir problem appears to be different in some respect from the others. Many variations to the main solution methods are possible. Modification of the selected solution method, to suit the special reservoir problem to be solved, is advantageous.

BIBLIOGRAPHY

BIBLIOGRAPHY

1. Barrows, H. K. - *Water Power Engineering*. Third ed. New York and London: McGraw Hill Book Company, 1943.

2. Bateman, L. A. and K. Renger - "Forward Planning Studies Involving the Economic Full Supply Level of Grand Rapids Generating Station of Manitoba Hydro," *Division Paper of the E.I.C.*, EIC-63-HYDEL-11.

3. Brown, J. Guthrie (ed.) - *Hydro-Electric Engineering Practice*. 3 Vols. London, Glasgow: Blackie & Son Ltd., 1958.

4. Brudenell, Ross N. and Jack H. Gilbreath - "Economic Complementary Operation of Hydro Storage and Steam Power in the Integrated TVA System," *Transactions of the American Institute of Electrical Engineers*, Volume 78, 1959, Part III-A, Power Apparatus and Systems, pp. 136-156.

5. _______ ___ _______ "Computer Aids Hydro-Steam Dispatching," *Electrical World*, May 13, 1963. McGraw Hill Book Company, New York pp. 24-26.

6. Darin, Kjell and others - "Principles of Power Balance Calculations for Economic Planning and Operation of Integrated Power Systems," *Svenska Vattenkraft Foreningens Publikationer*, 1959:11 Publication 476.

7. Fathy, A. and Aly S. Shukry - "The Problem of Reservoir Capacity for Longterm Storage," *American Society of Civil Engineers Proceedings*. Paper No. 1082 (September, 1956).

8. Girand, John - "Water Supply on Upper Salt River Arizona" *Transactions of the American Society of Civil Engineers*, Paper No. 2106 (1941) pp. 398-409.

9. H. G. Acres & Company Limited - "Report on Grand Rapids Project Reappraisal of Site 1955" (Consulting Engineers' report to Manitoba Hydro-Electric Board).

10. Hurst, H. E. - "Methods of Using Longterm Storage in Reservoirs," *Proceedings of the Institution of Civil Engineers*, Paper No. 6059, London 1955-6.

11. Kuiper, E. - River Development, Chapter on Water Power University of Manitoba, Civil Engineering Department, Winnipeg 1963.

12. Lakes Winnipeg and Manitoba Board - "Report on Measures for the Control of the Waters of Lakes Winnipeg and Manitoba Province of Manitoba," (a report submitted to the Government of Canada, Department of Nothern Affairs and National Resources and to the Government of Manitoba, June 30, 1958).

13. Lane, E. W. - "The Control of the T.V.A. Reservoirs for the Most Economic Power Production," (an unpublished report for the Water Control Planning Department of the Tennessee Valley Authority, August, 1944).

14. Larsson, Y. and S. Stage - "Incremental Cost of Water Power," Conference Paper of the American Institute of Electrical Engineers, No. CP 60-844.

15. Mead, Daniel W. - Hydrology. Second ed. New York: McGraw Hill Book Company, 1950.

16. Streiff, A. - "Forecasting Water Supply for Hydro Developments" Power (April 30, 1929) pp. 704-706.

17. _______ "Sun Spots A Factor in Predicting Stream Flow for Power Generation," Power (April 16, 1929) pp. 632-635.

APPENDIX

DEFINITION OF SOME OF THE TERMS USED*

Basic Rule Curve

The term, basic rule curve, is given to the diagram that shows the storage requirements as of any date with a repetition of the most adverse stream flows. It represents the accumulation, in reverse order of time, of deficiency between the remainder of the firm load after supply with the maximum assured amounts from all the auxiliary sources and the energy available from recorded unregulated stream flow in critically dry periods.

The basic rule curve is constructed to guarantee that, with the reservoir contents above such a curve, the contents will not be exhausted before the end of a repetition of the most adverse flows in carrying minimum hydro load.

No-Spill Rule Curve

The term, no-spill rule curve, is given to the diagram of storage contents, as of any date, that would guarantee that all the inflow in excess of the outflow required for maximum hydro load can be contained in the periods of highest inflow experienced in the past.

In many cases, the no-spill rule curve would call for negative storage contents indicating the impossibility of not

---

*Adapted from reference (4).

spilling with the available reservoir capacity.

Economy Guide Lines

The term, economy guide line, is given to the curve connecting all points of a certain storage value, e.g., 4 mills per kWh stored, for the various dates of the year.

Above this guide line, the incremental storage value would average (over the period of past records used in its derivation) less than 4 mills per kWh; below this guide line it would average more than 4 mills per kWh.