NEWFOUNDLAND AND LABRADOR HYDRO

AN INVENTORY OF SMALL HYDRO SITES FOR ENERGY SUPPLY TO THE ISLAND GRID

VOLUME I

METHODOLOGY & FINDINGS

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EXECUTIVE SUMMARY

A comprehensive survey of small scale hydro sites on the Island of Newfoundland was undertaken in this study. The purpose of this survey was to compile an inventory of small scale hydro sites (1 MW - 20 MW) which could be feasibly connected to the existing Island power grid. This survey encompassed the entire Island, with the exception of the following areas:

-- Gros Morne National Park
-- Terra Nova National Park
-- Bay du Nord, Main and Terra Nova river basins.

It was based primarily on topographical information taken from 1:50,000 topographic mapping, regionalized hydrologic relationships and standardized conceptual plant layouts. Extensive use was made of the SHYDRO computer model and other computational aids to facilitate the examination of the very large number of sites involved.

Site investigations also included examination of the advantages of significant watershed diversion, upstream storage developments and group developments.

Altogether a total of 198 sites were selected for cost analysis, from which 160 were found to be potentially feasible, benefit/cost ratios $\geq$ 1.0. Of this number, seven sites were judged to be very attractive (B/C $\geq$ 2.8) and probably feasible under current economic conditions. Fifteen sites were relatively attractive (B/C 2.2 - 2.8) and possibly feasible under current economic conditions; while the remaining 138 sites may be feasible at some future date. These results are summarized in Table 3.1.

In the analyses all plants were assumed to operate as run-of-river plants and were treated essentially as "fuel savers" for the purposes of economic evaluation.

EXECUTIVE SUMMARY (Cont'd)

The results of analyses of the benefits of upstream storage developments, watershed diversions and group developments are shown in Tables 3.5, 3.6 and 3.7, respectively. These results confirm that substantial economic advantages may be obtained from including these features in the scope of small scale hydro developments.

- RECOMMENDATIONS

The following recommendations are noted to assist Hydro in planning the next phase of the investigation into Small Scale Hydro potential on the Island. It is recommended:

(i) that more detailed investigations be carried out on all sites having benefit/cost ratios greater than 2.2 with priority given to sites with B/C > 2.8. Such investigations should include, as a minimum, preparation of 1:2000 scale maps with 2m contours from aerial photos, API, site reconnaissance (walk-over) visits and preliminary environmental evaluation;

(ii) that investigations should be on a group basis where several sites are close together or form a natural unit;

(iii) that possibilities for upstream storage and watershed diversions be further reviewed. [In areas where access to upstream structures is difficult, consideration should be given to innovative design and construction approaches, such as use of winter roads, transport by all terrain vehicles, etc.].

EXECUTIVE SUMMARY (Cont'd)

- RECOMMENDATIONS (Cont'd)

(iv) that the advantages of providing additional storage to permit operation of plants to maintain a significant level of firm monthly energy production be investigated [Under the assumed run-of-river mode of operation many plants would be out-of-service during periods of low flow, which often occur during winter months when system capacity and energy demands are at their maximum].

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1. INTRODUCTION

1.1 Background

Nature has generously endowed the Island of Newfoundland with the landforms, abundant and evenly distributed precipitation which favour the development of small scale hydro electric schemes (capacity between 1 MW and 20 MW). Although many studies of individual small hydro schemes have been carried out in recent years, as yet no comprehensive survey of the entire Island has been undertaken. It was the objective of this study to undertake a comprehensive survey of hydro power resources on the Island of Newfoundland and to compile an inventory of small hydro sites which may be economically developed within the foreseeable future.

1.2 Scope of Work

Newfoundland and Labrador Hydro's Terms of Reference called for an inventory survey of small hydro schemes meeting the following guidelines:

(a) the study were to be limited to schemes with capacities ranging from 1 MW to 20 MW (schemes greater than 20 MW were to be identified but not analysed),

(b) the study was to consider only those schemes which could be economically connected to the existing Island transmission system,

(c) small hydro sites previously studied were to be excluded,

1.2 Scope of Work (Cont'd)

(d) the following areas were to be excluded:

Gros Morne National Park
Terra Nova National Park
Bay du Nord River, Main River and Terra Nova River basins

(e) potential environmental impacts were to be noted, but no further investigations undertaken.

1.3 Authorization

This study was authorized by L. G. Sturge, Manager of Engineering, Newfoundland and Labrador Hydro and confirmed by means of Purchase Order #66505 dated May 30, 1986 following acceptance of ShawMont's proposal of April 30, 1986.

2.0 METHODOLOGY

2.1 Introduction

The scope of work to be undertaken in this study required examination of a very large number of sites in a preliminary fashion, assessing site conditions from 1:50,000 topographic mapping for the most part. These site investigations included four inter-related tasks:

- site identification (search techniques)
- water supply assessment
- conceptual design
- cost estimation and benefit/cost analyses.

In order to handle a large number of site investigations efficiently, standardized methods were developed for each of the above tasks, to provide quick and reliable means for site analysis.

Development and application of these methods is summarized in this section, under the headings:

- Water Supply Assessment
- Conceptual Design
- Cost Estimation
- Search Techniques

2.2 Water Supply Assessment

In order to assess the energy potential of a scheme and to select appropriate plant and spillway design flows, the following characteristics of the water supply must first be determined:

2.2 Water Supply Assessment (Cont'd)

- mean annual flow
- usable flow for the given plant design flow and live storage volume
- design flood

These characteristics were determined as below:

2.2.1 Mean Annual Flow

Mean annual runoff, was determined from the iso-runoff map [Figure 2-1, in envelope at back of report]. For computation of mean annual flow, the runoff in mm of water is taken at the centroid of the drainage area and applied to the project drainage area.

2.2.2 Usable Flow

Usable, or turbinable, flow was estimated from parametric curves relating unit usable flow to unit plant flow capacity and available storage as below:

$$q_T = fn\ [q_p, S]$$

Where: $q_T = \dfrac{\text{Usable flow}}{\text{Mean annual flow}}$

$q_p = \dfrac{\text{Plant flow capacity}}{\text{Mean annual flow}}$

$S = \dfrac{\text{Live storage volume}}{\text{Mean annual flow volume}}$

2.2.2 Usable Flow (Cont'd)

The parametric curves give water use for a run-of-river type of operation and account for the effects of flow variability and benefits of storage.

Since previous studies* had indicated that there were significant differences between runoff patterns from one region to another, it was decided to undertake a regionalization study for the Island to delineate regions of homogeneous hydrology, to identify index rivers in each region and to develop parametric curves for each region. Figure 2.2 shows the resulting four hydrologic regions while Figure 2.3 shows water use factors as a function of storage for each region, for a plant design flow, Qp = 1.50 Qav.

In addition, simulation studies were carried out to assess the effectiveness of upstream storage remote from a plant. Figure 2.4 gives a typical plot showing variation of usable flow as a function of storage and % of project flow through the reservoir, for a plant design flow of Qp = 1.5 Qav.

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* Ingledow and Associates, "Hydrometric Network Plan for the Provinces of Newfoundland, New Brunswick, Nova Scotia and P.E.I. Govt. of Canada - Energy, Mines & Resources, Ottawa (1970).

Acres Consultants Ltd. "Hydrologic Design Methodologies for Small Scale Hydro at Ungauged Sites - Phase II"
Environment Canada - IWD (Atlantic) and E.M.R. Ottawa (1985).

2.2.2 Usable Flow (Cont'd)

Complete details of these regional hydrology studies are given in Appendix I.

2.2.3 Design Floods

A design flood nomograph [Figure 2.5] was developed to facilitate determination of design flood flows. This graph relates flood peaks for selected return periods as a function of drainage area, area controlled by lakes and swamps and mean annual runoff. It was developed primarily from the results of a recent regional flood frequency analysis for the Island.* These results were extended as required, by applying the SCS techniques, as given in "Design of Small Dams, 1977 Edition", BUREC. Further details on the development of the flood nomograph are also given in Appendix I.

2.3 Conceptual Design

Standard conceptual designs and practical design guidelines have been developed to facilitate layout and costing of power plants, upstream storage and diversion schemes. The essential elements of these designs are noted in the following sub-sections:

2.3.1 Power Plants

The majority of plant layouts were based on a standard conceptual design, comprising the following structures:

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* "Regional Flood Frequency Analysis for the Island of Newfoundland" by U.S. Panu, D.A. Smith and D.C. Ambler. Canada-Newfoundland Flood Damage Reduction Program, St. John's (1984).

2.3.1 Power Plants (Cont'd)

- a forebay dam [timber crib, concrete or earthfill construction were considered]
- a spillway [a separate chute spillway is provided with earthfill construction, timber crib and concrete dams were designed as overflow weirs]
- an intake
- a buried or semi-buried penstock [penstock materials considered include polyethylene, fibreglass reinforced plastic or steel]
- a single unit powerhouse
- a sub-station
- a transmission line, and
- a site access road

This conceptual design corresponds to the SHYDRO costing program employed in this study. Where required, non-standard features can be incorporated in the SHYDRO cost analysis by employing an option which permits entry of costs of such items into the analysis.

Eight geometric and four hydrologic flow parameters are required by the SHYDRO program, as input data while the program itself calculates three additional design parameters for a total of fifteen design parameters to define each plant.

Table 2.1 lists the basic plant design parameters [Features of the SHYDRO program are given in Sub-Section 2.4.1].

TABLE 2.1 PLANT DESIGN PARAMETERS

[adapted from SHYDRO User's Guide]

PARAMETER	COMMENTS
NAME OF WATERSHED	- For site identification
SITE NUMBER	- For site identification
RATED HEAD (m)	- Height between reservoir and tailwater from best available mapping
PLANT DESIGN FLOW (m^3/s)	- Calculated by Program (Qav input as data).
PENSTOCK LENGTH (m)	- From best mapping [Program calculates optimum diameter]
ACCESS ROAD LENGTH (km)	- From best available mapping
TRANSMISSION LINE LENGTH (km)	- From best available mapping
DAM HEIGHT (m)	- Maximum dam height to spillway crest from best mapping
DAM LENGTH (m)	- From best mapping
DISTANCE TO TOWN (km)	- From best mapping
DISTANCE TO CONCRETE PLANT (km)	- From best mapping
FLOOD FLOW (m^3/s)	- Determined from Figure 2.5, [Use Q150 for concrete and timber crib and Q1000 for earthfill].
INSTALLED CAPACITY (MW)	- Calculated by program
NUMBER OF UNITS	- = 1
USEABLE FLOW RATIO	- Determined from Figure 2-3.
PLANT DESIGN FLOW RATIO	- = 1.5
FISHWAY REQUIRED	- Enter 1 if required, 0 if not.

2.3.1 Power Plants (Cont'd)

The following additional guidelines were developed to facilitate power plant layouts:

Items (a) to (d) govern "high head" plants

where: H plant >> h dam

(a) Height of forebay dam h to be based on intake submergence requirements, plus a 1m allowance for daily pondage.

(b) Length of forebay dam from best mapping. Where topographic detail is inadequate, compute length of dam as below:

$$L = 5\sqrt{Q2} + 10\,h \qquad (m)$$

Where: L = min. dam length (m)
Q2 = mean annual flood (m^3/s)
h = height of dam (m)

(c) Length of penstock generally not to exceed 20 x H (beyond this point a surge tank is normally required).

Where: H = rated head (m)

(d) Plant flow capacity = 1.50 Qav

Where: Qav = mean annual flow (m^3/s)

Items (e) to (g) apply to "low head" plants where a river is dammed to create head and where, typically

H plant $\approx$ h dam,

2.3.1 Power Plants (Cont'd)

SHYDRO simulations indicated an optimum head of 30.5 m for typical dam profiles, hence the following layout guidelines:

(e) H = 30.5 m, and

(f) Penstock length = 129 m,

(g) Plant flow capacity = 1.50 Qav,

Items (h) and (i) apply generally.

(h) Where forebay dams control the level of an existing lake, 2.0 m of live storage would be developed.

(i) Outgoing transmission lines to be connected to inter-community tie lines [min. 25 kV on NLH system and 15 kV on the NL&P system].

2.3.2 Upstream Storage Schemes

Most river basins contain lakes upstream of the power plant which are suitable for storage development. The feasibility of upstream storage schemes was found to be very dependent on the cost of site access, volume of storage and percentage of drainage area regulated by the reservoir. In addition, estimating height and length of storage dams, and hence dam costs ~~was~~ were found to be difficult. In view of these problems only order of magnitude estimates are possible from the limited data which can be inferred from 1:50,000 mapping. For the purposes of this study it was decided to limit investigations to sites where upstream storage was significant enough to improve overall B/C ratio by +10% or greater; hence the following criteria:

2.3.2 Upstream Storage Schemes (Cont'd)

- negligible storage available in forebay reservoir, and
- surface area of lake > 10% of project drainage area

Other guidelines for layout of upstream storage sites, included:

- dam height sufficient to provide 2.0 m of live storage above the existing lake level,
- where detailed topography was unavailable, a minimum length of 20 x dam height was used, and
- control structure design flow = plant design flow.

Dams would be of timber crib construction with a sluice way controlled by stoplogs.

Cost formulae were developed for estimating the cost of upstream storage development for application on a Hewlett-Packard HP97 programmable calculator. Design parameters for upstream storage schemes are given in Table 2.2.

TABLE 2.2 Design Parameters for Upstream Storage Schemes

Parameter	Comments
Length of Access Road (km)	From best mapping
Height of Storage Dam (m)	Timber crib construction
Length of Storage Dam (m)	Timber crib construction
Design Flow of Control Structure (m^3/s)	Equal to Qp
Reservoir Area, As (km^2)	Clearing of reservoir margins $\propto \sqrt{As}$

2.3.3 Diversion Schemes

The post-glacial topography typical of the plateau areas in the interior of the Island offer many opportunities for flow diversions from one watershed to another. Opportunities for minor diversions were found on many projects. Unfortunately, the same difficulties which beset the assessment of upstream storage developments also affect diversion schemes. Accordingly, it was decided to limit investigation of diversion possibilities to relatively large diversion schemes, where:

-- diverted D.A. > 20% of basic project D.A., or
-- (exceptionally) where it appeared that diversions could enhance an otherwise non-viable scheme or increase the output of a marginally sized site sufficiently to meet the minimum size criteria.

Diversion schemes were assumed to comprise a diversion dam and spillway [of timber, concrete or earthfill construction] and excavated diversion canal across the height of land separating the two watersheds.

Other layout guidelines included:

-- minimum height of dam = 2.0 m,
-- minimum length of dam = 20 x dam height [if detailed topography is unavailable], and
-- minimum height of land, relative to water level at diversion point, = 3.0 m [if detailed topography is unavailable].

Canal excavation was assumed (optimistically) to be in overburden.

Costing formulae were developed for diversion schemes for solution using a Hewlett Packard HP97 programmable calculator. Design parameters for watershed diversion schemes are given in Table 2.3.

TABLE 2.3 Design Parameters for Watershed Diversion Schemes

Parameters		Comments
Length of Access Road	(km)	From best mapping
Height of Diversion Dam	(m)	From best mapping
Length of Diversion Dam	(m)	From best mapping
Design flood, Q150	(m^3/s)	Q1000 for spillway of earthfill dam estimated as 1.39 x Q150.
Height of Land above Diversion	(m)	
Length of Diversion Canal	(m)	
Design Flow, for Canal	(m^3/s)	

Program selects the cheapest of timber, concrete or earthfill dam.

2.4 Cost Estimates

Estimates of costs and computations of benefits were made using mathematical models solved by micro-computer or programmable calculator.

All costs are in constant 1986 dollars, including IDC at an effective rate of 6%, but not EDC.

2.4.1 Description of Costing Models

(a) Power Plants

Cost estimates and benefit cost analyses for power plants were done using the SHYDRO costing model developed by Monenco. This model computes cost estimates for the major components of a standard small hydro layout, as described in the preceeding section. Costing procedures employ parametric equations which give structure costs as a function of geometrical and flow/power parameters. The

2.4.1 Description of Costing Models (Cont'd)

(a) Power Plants (Cont'd)

program also calculates appropriate allowances for contractor's overhead, engineering and management, Owner's costs and interest during construction; then totals these costs to obtain the total project cost in constant 1986 dollars.

Benefits are calculated by applying a pre-selected energy value to the average annual energy output for the plant as determined from the plant capacity and usable flow.

The program also calculates a "least cost" estimate , for comparison, using formulae derived by statistical analysis of normalized costs of recent small hydro developments from around the world.* The SHYDRO User's Manual suggests that this "least cost" estimate be used as a check on the accuracy of input cost data; however, in this study input costs have been verified by calibrating the SHYDRO model against detailed estimates from small hydro studies in Newfoundland, as discussed in Section 2.4.3.

Further details on the basis of the SHYDRO model are given in Appendix II of this report.

Several modifications have been made to the basic SHYDRO model to adapt it for use on this study. These modifications are briefly described below:

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* "Hydropower Cost Estimates"
by J. L. Gordon
Water Power and Dam Construction, November 1983.

2.4.1 Description of Costing Models (Cont'd)

(a) Power Plants (Cont'd)

-- Modifications to Data Entry

The standard SHYDRO version was modified so that the computer would determine plant capacity (MW) and plant design flow capacity (m^3/s) from Qav and the plant design flow ratio supplied as input. Previously, these factors were calculated by the user and entered as data. This change eliminated two opportunities for making errors. In addition, the plant efficiency has been changed to account for hydraulic losses in the penstock (a standard head loss of 2% of head has been assumed). This further simplifies data input requirements, by allowing the user to enter gross plant head directly, instead of net head, thus avoiding the need to compute head losses.

-- Modifications to Computations of Penstock Costs

The standard SHYDRO version was developed for medium or low head sites and calculated penstock costs from the minimum pipe thickness, as determined by handling requirements. This assumption is not true for high head plants where pipe wall thickness is normally governed by stress requirements. This deficiency has been corrected by computing the maximum pipe thickness for steel penstocks [typically used for high head applications] and using the resulting mean pipe thickness [the greater of t min or $\frac{t\ min + t\ max}{2}$] in the cost equation for steel penstocks. A further modification has been introduced to limit the application of polyethylene

2.4.1 Description of Costing Models (Cont'd)

(a) Power Plants (Cont'd)

and fibreglass reinforced plastic penstocks to plants having heads less than 60 m.

-- Modification to Computation of Powerhouse Costs

Powerhouse costs have been modified to allow for a pressure relief valve when the penstock length/head ratio exceeds 7. The cost of a pressure relief valve is estimated as 12.5% of major equipment costs.

-- Option to Enter Cost of Non-Standard Item

The program has been modified to permit the capital cost of a non-standard item to be added into the Total Project Cost and be included in the computation of the project benefit/cost ratio. This feature causes program execution to be halted at the step preceding compilation of the Total Project Cost, in order to permit entry of the cost and an identifying label for a non-standard item. When this option is employed, the label is printed as a footnote to the printout of results, otherwise there is no change in execution or printout.

Further details on these modifications to SHYDRO are given in Appendix II.

(b) Upstream Storage and Watershed Diversions

Cost estimates for upstream storage and watershed diversion schemes are likewise computed using sets of parametric equations programmed for solution on a Hewlett

2.4.1 Description of Costing Models (Cont'd)

(b) Upstream Storage and Watershed Diversions (Cont'd)

Packard HP97 programmable calculator. Details on the development of these parametric equations are also provided in Appendix II.

2.4.2 Unit Costs

The SHYDRO program requires that unit costs for selected civil work items be supplied by the user. For the purposes of this study representative unit costs have been chosen, based on current (1986) cost values for average site conditions. These values are also shown in Table 2.4.

These "standard" values were applied in the majority of site analyses. Exceptions were made only where it was known that site conditions were much different from "average". In such cases, alternative unit costs were utilized in site analyses and recorded on site data sheets.

Total powerhouse costs were computed from cost formulae developed by J. L. Gordon* in 1981, adjusted for inflation to give estimates in 1986 dollars. Civil, equipment supply and equipment erection costs were then computed as fractions of this cost, as further explained in Appendix II.

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* Estimating Hydro Station Costs
by J. L. Gordon
Water Power & Dam Construction, September 1981

TABLE 2.4 COST DATA

Item	Unit	Selected Unit Cost [1986 dollars]
SHYDRO UNIT COSTS:		
Timber Crib Work	m^3	$300/$m^3$
Dam Concrete	m^3	$400/$m^3$
Spillway Concrete	m^3	$500/$m^3$
Excavation/Backfill	m^3	$ 15/m^3
Access Road	km	$100,000/km
Fishway	m	omitted
Interest Rate	% p.a.	6%
O & M	% p.a.	1.5%
Benefit	$ MWh	$60/MWh [= 60 mills/kWh]
OTHER UNIT COSTS:		
Access Roads to Upstream		
Reservoir or Diversion Works	km	$40,000
Reservoir Clearing	ha	$4,000

2.4.3 Verification of SHYDRO Model

Monenco reports good agreement (± 10%) between SHYDRO estimates and detailed cost estimates for plant where accurate site information was available. However, they caution that costs based on preliminary map layouts should "only be regarded as having an accuracy in the region of 25 to 50 percent".* In general, greater accuracy can be expected for estimates of high head plants than for low head plant, for two reasons:

(i) errors in estimation of plant heads, normally ± 8 m, are relatively larger at low head sites,

(ii) dam costs are relatively larger on low head sites, than for high head sites; hence costs of low head plants are more sensitive to variabilities in dam topography and foundation conditions.

Appropriate unit costs were initially estimated from cost data collected from recent projects in Newfoundland. SHYDRO costs estimates were then compared with detailed cost estimates for Paradise River and the initial unit cost values "fine tuned" to obtain close agreement between both estimates.

Further verification was then obtained by comparing SHYDRO estimates versus L'Anse au Clair feasibility study costs (FENCO, 1985), Roddickton construction costs (1979) and Island Pond prefeasibility costs (SNL, 1986). When suitable adjustments were made for variations in site conditions and differences in design approaches, agreements within 10% were obtained between SHYDRO estimates and the more detailed estimates for L'Anse-au'Clair and

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* "User's Guide to SHYDRO PC", Monenco Maritimes Ltd, Halifax, (1986), page 10.

2.4.3 Verification of SHYDRO Model (Cont'd)

Roddickton. Agreement with Island Pond was less satisfactory [SHYDRO costs were about 60% of the detailed estimate]. However, it should be noted that the Island Pond layout - a typical "low head", site is much different from the layout assumed in SHYDRO; also Island Pond at 30 MW is outside the range of interest in this study.

2.5 Search Techniques

2.5.1 Guidelines

A set of search guidelines were developed to permit quick identification of potentially viable sites while minimizing the number of spurious cost analyses required. These guidelines were developed by applying the SHYDRO model to a series of plant layout scenarios to examine the impact on economic feasibility due to variations in major plant design parameters. Other guidelines were dictated by requirements of good design practice or imposed by the Terms of Reference. The following notes summarize search guidelines adopted in this study:

(a) Minimum capacity of development, the greater of:

$$1 \text{ MW} \quad \text{or} \quad \frac{\text{Access distance (km)}}{7}$$

Where: access distance = 1/2 [access road length + T.L. length] km

(b) Maximum capacity = 20 MW [sites of 20 MW or greater to be identified but not analysed].

2.5.1 Guidelines (Cont'd)

(c) Drainage area required to develop the minimum capacity from (a), for a site with a head of H:

$$A = \frac{2,500,000}{H \times MAR}$$

Where: A = required drainage area (km^2)
H = available head (m)
MAR = mean annual runoff (mm)

(d) Maximum length/head ratio for penstocks, generally limited to 20 unless site conditions dictate otherwise [Beyond L/H = 20 a surge tank is normally required for frequency control].

Guidelines (a) through (d) govern searches for "high head" plants where, typically, plant head is much greater than height of fore-bay dam, i.e.

$$H \text{ plant} \gg h \text{ dam}$$

For "low head" plants where head is created by damming the river and plant head and dam height are approximately equal, i.e

$$H \text{ plant} \approx h \text{ dam}$$

the following guidelines (e) to (g) govern:

(e) Minimum drainage area for low head development
$= \frac{500 \times 1000}{MAR}$ km^2
[Whence minimum capacity = 5.9 MW]

(f) Optimum dam height = 30.5 m

(g) Penstock length = 129 m, min. (for H = 30.5 m)

2.5.1 Guidelines (Cont'd)

For upstream storage schemes, only relatively large sites were identified as below:

> acceptable sites would be ponds having surface areas > 10% of project drainage area.

[Where a forebay dam happens to control a pond of significant area, 2 m of live storage above natural lake level is provided in the basic plant layout and the resulting benefits taken into account].

For watershed diversion schemes, only relatively large watershed diversions were investigated, as below:

> diverted areas generally > 20% of original project drainage area; exceptionally, down to 10%, where diversion could "save" an otherwise unacceptable scheme.

Terrain in Newfoundland lends itself to development of an enormous number of upstream storage and watershed diversion possibilities. It was judged impractical to completely investigate every such possibility. Instead, only significant sites were investigated, where there was an opportunity to significantly improve the overall economics of a development (i.e. to increase Benefit/Cost Ratio by 10% - 15%).

2.5.2 Search Procedures

Site identification searches were carried out, in a step wise fashion in accordance with the following procedures:

(a) Delineate the entire boundary of the major river basin of interest.

2.5.2 Search Procedures (Cont'd)

(b) Start search on any tributary, moving in downstream direction.

(c) At each head concentration encountered [falls or rapids], check if site meets basic search criteria, as enumerated in Section 2.5.1.

(d) If site appears acceptable, layout development and record flow and plant parameters on site data sheets. Also record any unusual/original features of the scheme. Check in the Catalogue of Rivers* to see if the site is accessible to salmon and note if this is the case. Other potential environmental problems should also be noted if known or apparent (for further discussion, see Section 3.2).

(e) Note potential upstream storage sites and diversion possibilities.

(f) On a second pass, check watershed perimeters for diversion possibilities, note significant upstream storage sites and verify original layouts to ensure the accuracy of data take-offs.

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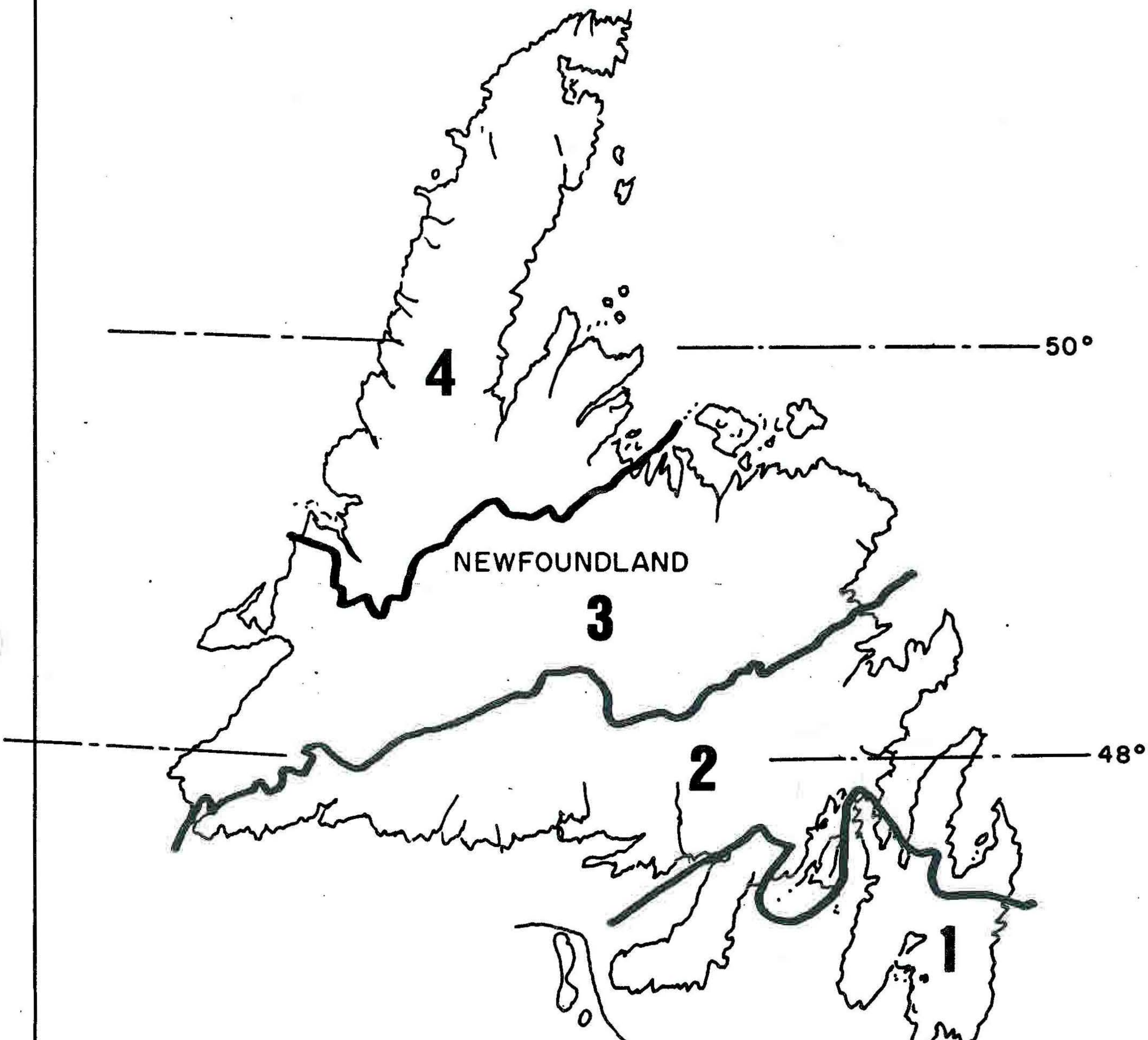
* "Catalogue of Rivers in Insular Newfoundland, by T. R. Porter, L. G. Riche and G. R. Traverse, Resources Development Branch, Fisheries and Marine Service, Department of Environment (Canada), St. John's (1978) in Four Volumes.

FIGURES

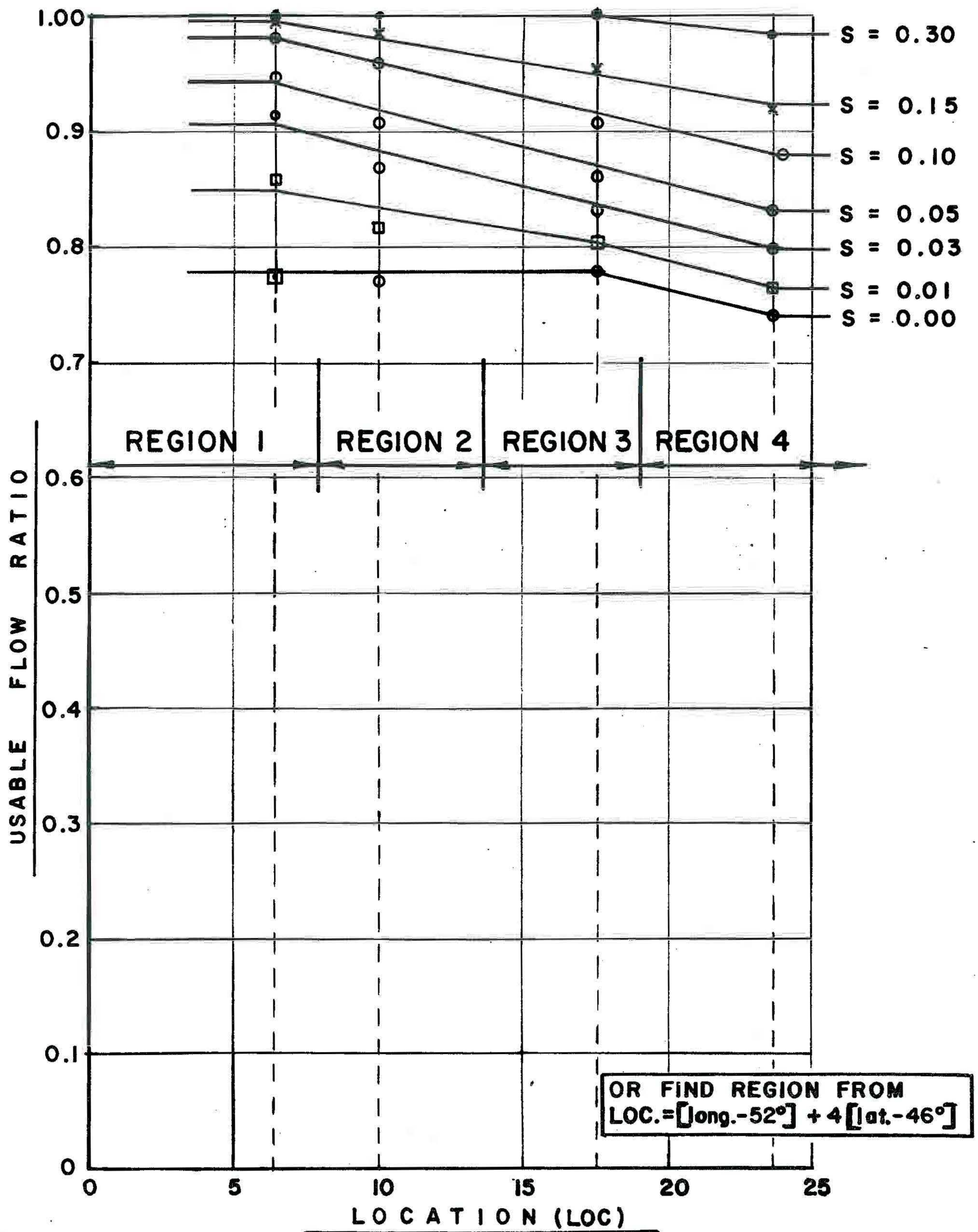
FIGURE 2.2



HYDROLOGIC REGIONS

FIGURE 2-3

WATER USE CURVES FOR HEAD POND RESERVOIRS AT PLANTS HAVING PLANT FLOW RATIOS = 1.5



PARAMETRIC CURVES OF USEFUL TURBINE DISCHARGE vs REGULATED BASIN RUNOFF

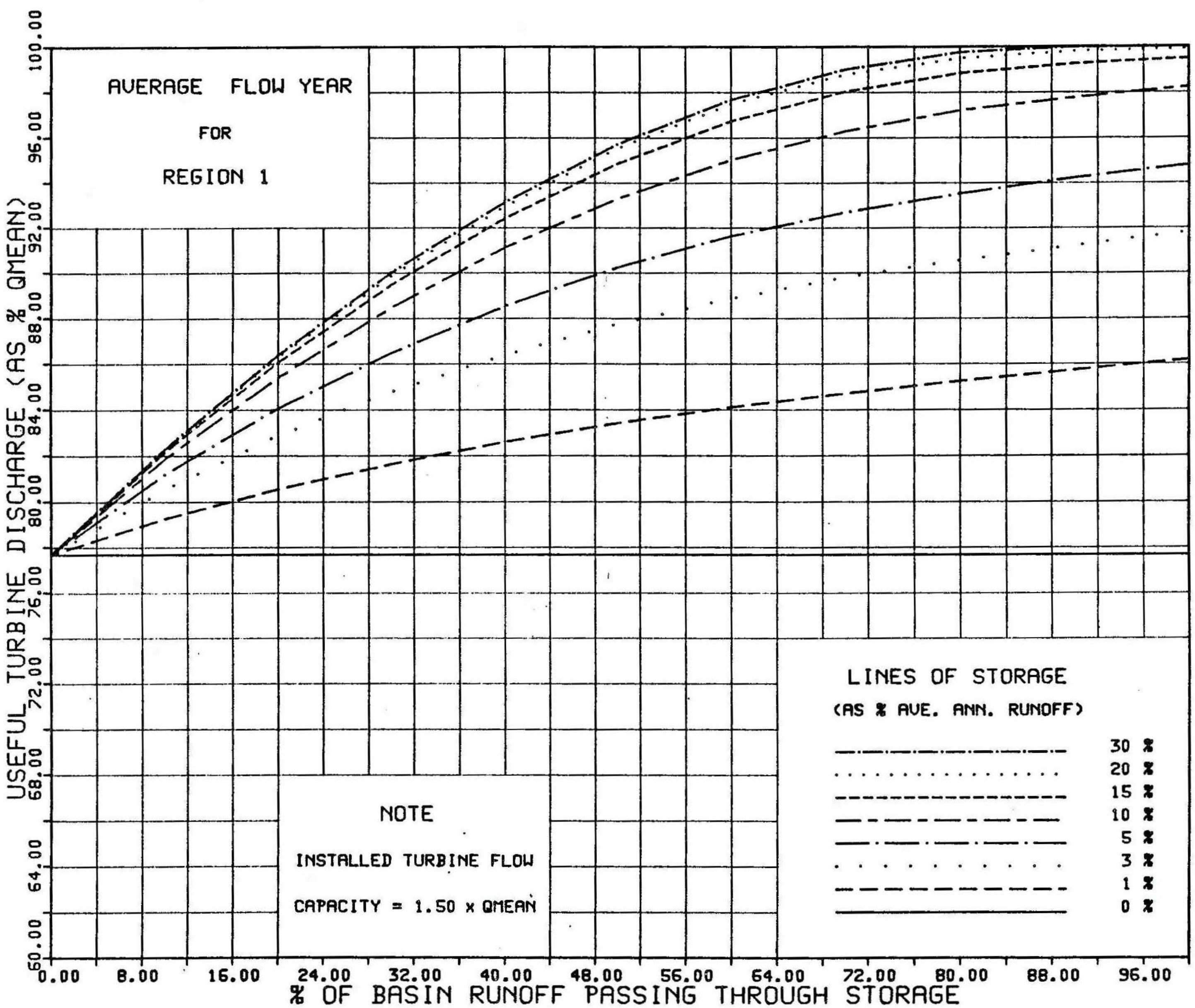


FIGURE 2-4

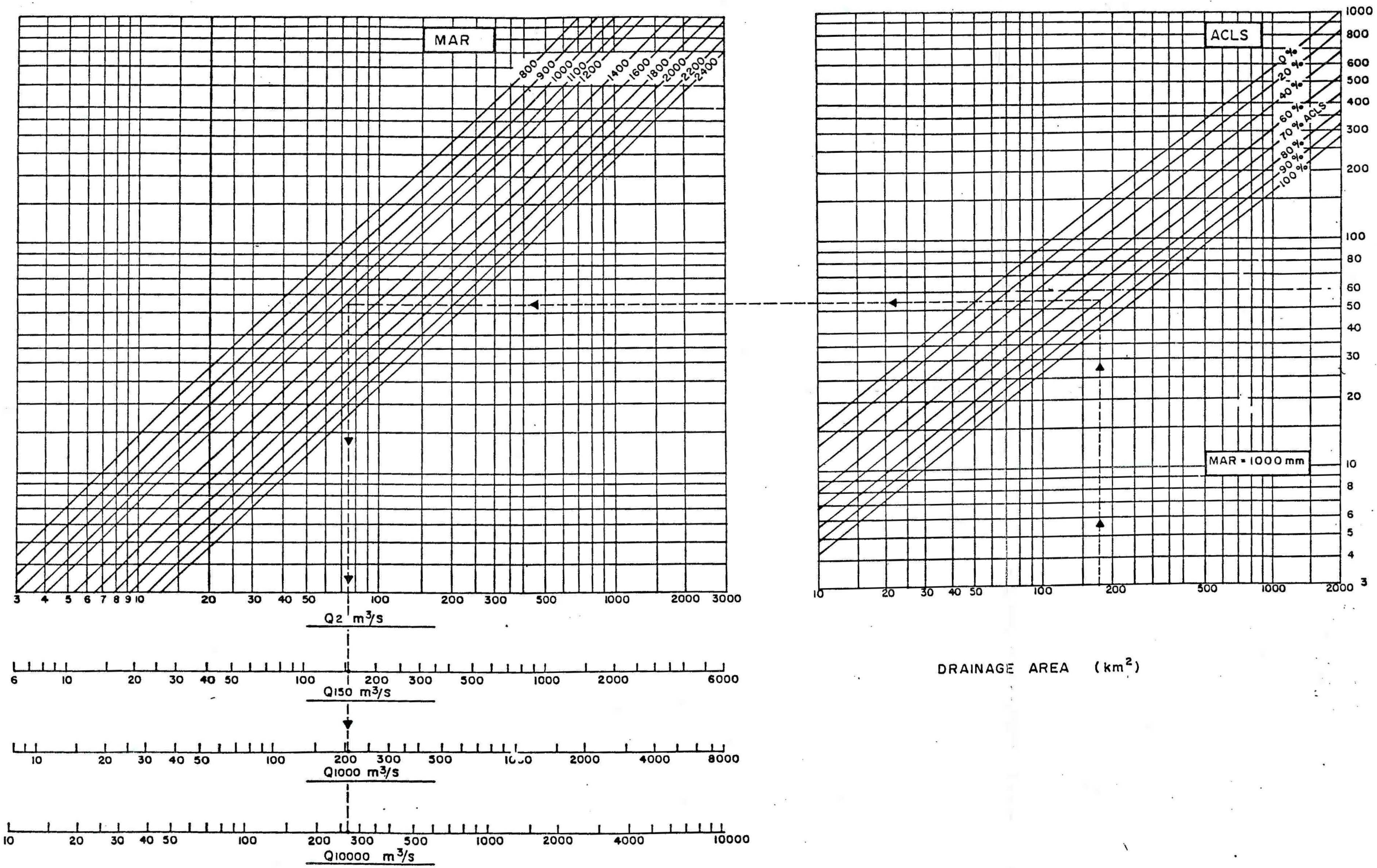
FIGURE 2.5

EXAMPLE: FOR $A = 180\ km^2$ FIND $Q_2 = 75\ m^3/s$

ACLS = 80 % $Q_{150} = 155\ m^3/s$

MAR = 1200 mm $Q_{1000} = 210\ m^3/s$

$Q_{10000} = 270\ m^3/s$



FLOOD NOMOGRAPH
FOR ISLAND OF NEWFOUNDLAND

3. FINDINGS

3.1 Preamble

The methodologies applied in this study were designed to meet the standards normally expected in preliminary studies; that is, to provide order of magnitude estimates of costs and benefits of sufficient accuracy to reasonably separate potentially feasible schemes from non-feasible schemes.

As noted previously, the unit cost assumed for civil works were based on assumed average conditions, that might be optimistic in some cases. In instances, where site conditions were known to be much different from average, suitable adjustments to unit costs have been made; however the majority of site analyses were based on "average" unit costs.

Economic feasibility was evaluated from benefit-cost analyses in which annual costs were based on an effective interest rate of 6% = 1.5% to cover insurance, interim replacement and O & M; while annual benefits were evaluated at a "levelized" rate of 60 mills/kWh, in constant 1986 dollars, as suggested by Hydro. Schemes having benefit/ cost ratios greater than 1.0 were considered as being potentially viable. The above economic assumptions, imply a relatively high evaluation of benefits and optimistic estimates of cost, due to ommission of the usual conservatism in unit cost estimates. The resulting benefit/cost ratios may thus be regarded as giving optimistic assessments of Island hydro potential.

It should be emphasized, that these benefit-cost ratios are only intended to provide a relative ranking of site feasibility and should not be taken as absolute indicators of economic feasibility. However, for this type of study, it was judged preferable to err on the optimistic side so that the inventory of sites obtained would comprise a complete list of all sites which could be ultimately viable within the foreseeable future.

3.2 Environmental Observations

The Terms of Reference for this study did not include detailed environmental assessment of hydro sites; but requested only that potential environmental problems be identified where-ever possible. In most of the areas studied the major environmental problem would be adverse impacts on salmon habitat. Such impacts could include obstruction of salmon migration routes, inundation and/or silting of salmon spawning areas and reduction in flows on schemes involving watershed diversions. Where sites were upstream of spawning areas or inaccessible to migrating salmon, there should be no adverse impact on salmon habitat; accordingly, environmental problems related to salmon, were only identified (*in Tables 3.1 and 3.2) at sites on sections of river accessible to salmon [typically at sites on the lower sections of the larger rivers]. Data collected in the "Catalogue of Rivers in Insular Newfoundland" by Porter et al, Environment Canada (Fisheries & Marine Service), 1978 was used to identify areas of salmon habitat.

3.3 Site Analysis

Each site analysis comprises a data sheet(s), cost analyses and, in the case of sites having B/C ratios > 1.0, a site map showing a schematic layout of the scheme is also included. Potential environmental problems and other observations or suggestions were also noted on the data sheet(s). In essence, each such compilation is a miniature engineering report. These miniature reports are filed by Hydrologic Region and compiled in Volume II of this report.

3.4 Discussion of Results

The main objective of this study was to produce an inventory list of all potentially feasible small hydro schemes [1MW - 20MW] which could be economically connected to the existing Island power grid [including the proposed transmission line into the Hope Brook Mine]. The entire Island, excluding the Gros Morne and Terra Nova

3.4 Discussion of Results (Cont'd)

National Parks, Bay du Nord, Main River and Terra Nova river basins, was searched for potential small hydro schemes. A total of 198 sites were selected for preliminary cost analysis of which 160 were found to be potentially feasible [with B/C $\geq$ 1]. These sites are listed in Table 3.1 in descending order of benefit/cost ratio.

Hydro schemes analysed and found to be infeasible [with B/C < 1.0] are listed in Figure 3.2.

In order to facilitate interpretation of the results, Table 3.1 has been sectioned by drawing two lines through it, one corresponding to a benefit cost ratio of 2.80 with the other corresponding to 2.2. The lines permit classification of the results as follows:

B/C $\geq$ 2.8   <u>sites very attractive</u>, probably feasible under current economic conditions

B/C 2.2 - 2.8   <u>sites relatively attractive</u>, possibly feasible under current economic conditions

B/C 1.0 - 2.2   sites that may be <u>feasible in the future</u>.

The first of these dividing lines (B/C = 2.2) was based on an assumed "current" interest rate of 12% [+1.5% for O + M] and a"levelized" energy value of 50 mills/kWh, in constant 1986 dollars, as suggested by Hydro. The second line (B/C = 2.8) assumes, in addition, a contingency of +30% on project capital cost to allow for unfavourable site conditions and prices.

On the basis of this classification, seven schemes were judged to be very attractive, a further fifteen to be relatively attractive and 138 to be marginal.

3.4 Discussion of Results (Cont'd)

For the sake of completeness, small hydro sites previously studied [and therefore outside of the scope of work of this study] are listed in Table 3.3; while sites larger than 20 MW are listed in Table 3.4, which includes sites previously studied as well as several large sites identified for the first time, in this study.

The post-glacial topography of the interior of the Island offers many opportunities for development of upstream storage reservoirs or watershed diversions; but, as previously noted, only relatively large upstream storage and watershed diversion schemes were studied. In cases where diversion schemes robbed water from neighbouring plants, the pros and cons of such diversions were investigated and only those diversions where the benefits outweighed the losses* were included in the final site analysis.

The results of analyses of upstream storage and watershed diversion schemes are summarized in Table 3.5 and 3.6 (details are included with the corresponding site analyses in Volume II). As can be seen in these summaries the benefit/cost ratios of upstream storage and watershed diversion schemes can be very high and thus substantially improve economics of the related hydro schemes.

In areas where several sites are located close together, substantial economic advantages may be obtained by group development since common facilities such as access roads, transmission lines, construction camps, etc. may be shared among several sites.

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* Where B/C ratio of diversion was greater than B/C ratio of neighbouring plant/plants.

3.4 Discussion of Results (Cont'd)

Several such groupings have been evaluated, on an approximate basis, using SHYDRO and the results are summarized in Table 3.7. Two facts emerge from an examination of Table 3.7.

(i) the advantages of group developments tend to be more substantial at remote sites and

(ii) several group developments have combined installed capacities and energy outputs in excess of 30 MW and 140 gWh per annum approaching the same order of magnitude as some "large" hydro sites.

3.5 Conclusions

On the basis of this inventory study it is estimated a total potential of 850 MW in small hydro schemes may be available on the Island within reach of the existing Hydro power grid. Of this total, 172 MW in 22 plants is considered to be relatively attractive in terms of current benefit and cost parameters. The most attractive sites are generally to be found on the Northern Peninsula, West and South West coasts, where topographic relief is greatest.

The following recommendations are noted to assist Hydro in planning the next phase of the investigation into Small Scale Hydro potential on the Island. It is recommended:

(i) that more detailed investigations be carried out on all sites having benefit/cost ratios greater than 2.2 with priority given to sites with B/C > 2.8. Such investigations should include, as a minimum, preparation of 1:2000cale maps with 2m contours from aerial photos, API, site reconnaissance (walk-over) visits and preliminary environmental evaluations;

3.5 Conclusions (Cont'd)

(ii) that investigations should be on a group basis where several sites are close together or form a natural unit;

(iii) that possibilities for upstream storage and watershed diversions should be further reviewed [In areas where access to upstream structures is difficult, consideration should be given to innovative design and construction approaches, such as use of winter roads, transport by or all terrain vehicles, etc.]

(iv) that the advantages of providing additional storage to permit operation of plants to maintain a significant level of firm monthly energy production be investigated [Under the assumed run-of-river mode of operation many plants would be out-of-service during periods of low flow, which often occur among winter months when system capacity and energy demands are at their maximum].

TABLE 3.1

LIST OF POTENTIALLY FEASIBLE SMALL HYDRO SCHEMES

Rank	River	Site No	Location Latitude	Location Longitude	D.A. (sq. km)	Head (m)	Qav (cu.m/s)	Capacity MW	Energy GWh	Cost $(million)	Benfit \ Cost
1	Great Coney Arm River	1	49 53 18	56 50 15	83.0	153.0	3.16	5.9	25.5	$4.86	4.20
2	Lewaseechjeech Brook *	3	48 34 15	57 48 20	58.0	200.0	2.02	4.9	28.8	$6.76	3.41
3	Parsons Pond	1A	49 56 15	57 29 30	84.0	282.0	2.80	9.6	46.2	$11.48	3.22
4	Steady Brook	1	48 57 05	57 49 15	72.0	182.9	2.51	5.6	24.2	$6.03	3.22
5	Great Cat Arm River	1	50 08 15	56 45 40	55.0	198.0	2.09	5.1	21.8	$5.51	3.17
6	Kings Harbour River	3	47 39 35	57 32 00	214.0	137.0	9.16	15.3	69.8	$18.21	3.07
7	Northwest Brook (Garia Bay)	1	47 42 43	58 35 17	108.0	137.2	6.16	10.3	47.0	$12.93	2.91
8	Northwest Arm Brook (Connoire Bay)	2	47 45 30	57 54 45	222.0	61.0	11.26	8.4	38.2	$11.06	2.76
9	Castors River	2	50 52 15	56 46 30	82.0	114.0	3.25	4.5	20.6	$6.12	2.69
10	Grand Lake	3	48 39 45	58 02 45	44.0	159.0	1.81	3.5	17.6	$5.39	2.62
11	Torrent River	4	50 36 50	57 08 15	615.0	25.0	24.37	7.4	34.8	$10.74	2.59
12	Gisborne Lake	1	47 48 00	54 55 45	158.0	160.0	5.51	10.8	62.9	$19.53	2.57
13	Paradise River	1	47 36 40	54 26 15	490.0	37.0	18.63	8.4	38.3	$12.08	2.54
14	Black River	1	47 54 10	54 10 00	155.0	45.0	5.89	3.2	14.7	$4.66	2.53
15	Red Indian Brook (Grand Lake)	5	48 44 25	57 39 55	170.0	234.0	6.20	17.7	80.7	$25.56	2.53
16	Eel Brook	1	49 06 00	55 13 00	80.0	90.0	1.65	1.8	9.8	$3.22	2.45
17	Lloyds River	5A	48 26 00	57 27 15	1020.0	38.0	37.18	17.3	82.6	$27.30	2.42
18	Rose Blanche Brook	1	47 39 15	58 43 30	56.0	91.4	3.19	3.6	16.2	$5.68	2.29
19	Castors River	4X	50 54 45	56 52 30	483.0	37.0	17.60	8.0	34.4	$12.29	2.24
20	Gull Pond (White Bay)	1	49 49 30	56 24 30	76.0	122.0	1.93	2.9	12.4	$4.48	2.22
21	Lloyds River (Portage Lake)	4A	48 25 30	57 27 45	181.0	92.0	6.14	6.9	34.6	$12.57	2.20
22	D'Espoir Brook	1	47 53 45	56 11 30	278.0	77.4	11.46	10.8	49.3	$17.93	2.20
23	Portland Creek	2	50 05 45	57 21 00	65.0	400.8	2.36	11.5	52.6	$20.32	2.07
24	Little Coney Arm River	1	49 57 42	56 47 30	21.0	198.0	0.73	1.8	7.6	$2.95	2.07
25	Bottom Brook	1	47 47 55	56 19 50	175.0	107.0	6.66	8.7	39.6	$15.41	2.06
26	Grand Lake	1	48 50 42	57 41 55	40.0	173.0	1.60	3.4	14.6	$5.68	2.06
27	Crabbes River	1	48 00 10	58 37 30	80.0	106.7	5.58	7.3	33.1	$13.03	2.03
28	Torrent River	1A	50 38 55	56 53 50	218.0	79.3	9.50	9.2	41.4	$16.29	2.03
29	Cinq Cerf Brook	1	47 48 50	58 05 30	88.0	144.8	4.18	7.4	33.7	$13.35	2.02
30	Kings Harbour River	2	47 39 20	57 34 40	118.0	76.2	4.86	4.5	20.6	$8.24	2.00
31	Portland Creek	7	50 11 08	57 27 45	407.0	61.0	12.26	9.1	43.7	$17.52	2.00
32	Crabbes River	4A	48 04 30	58 39 25	258.0	45.7	18.60	10.4	47.3	$19.00	1.99
33	Northwest River (Clode Sound)	1	48 25 00	54 16 00	570.0	30.0	16.50	6.0	29.3	$11.81	1.98
34	White Bear River	2	47 51 45	57 16 50	99.0	125.0	4.39	6.7	30.5	$12.36	1.98
35	Little Barachois Brook	1	48 25 50	58 03 35	18.0	198.1	0.66	1.6	7.6	$3.10	1.97
36	South Brook	1	49 16 15	56 08 15	370.0	30.0	7.62	2.8	12.7	$5.20	1.96
37	Northern Arm River (Fourche Hr.)	1	50 32 13	56 22 30	160.0	168.0	6.34	13.0	56.2	$23.00	1.95
38	Great Rattling Brook *	1	48 55 45	55 31 30	1260.0	15.3	29.96	5.6	25.5	$10.47	1.95
39	Shanadithit Brook	1	48 40 00	57 10 15	250.0	61.0	8.56	6.4	29.0	$12.06	1.93
40	Grand Lake (Conners Brook)	6	48 49 15	57 33 15	74.0	158.0	2.58	5.0	22.7	$9.53	1.90
41	Pipers Hole River	1	47 56 00	54 17 30	768.0	30.0	26.78	9.8	44.7	$18.98	1.88
42	Lloyds River (Otter Brook)	6	48 29 15	57 20 15	48.0	113.0	1.60	2.2	11.1	$4.71	1.88
43	Maccles Lake	1	48 38 30	54 03 30	202.0	55.0	5.60	3.8	21.5	$9.16	1.88
44	Paradise River	2	47 39 20	54 28 20	460.0	30.0	17.49	6.4	29.2	$12.45	1.87
45	Three Brooks	1	48 22 00	58 21 30	71.0	107.0	3.04	4.0	18.1	$7.75	1.87
46	Whites River (Upper Humber)	2X	49 27 30	57 18 15	255.0	90.0	10.90	12.0	51.8	$22.17	1.87
47	Barneys Brook	1	49 21 45	56 11 00	274.0	45.0	6.94	3.8	17.4	$7.46	1.86
48	Shoal Brook (Chimney Bay)	1A	50 54 45	56 16 05	197.0	61.0	7.49	5.6	24.1	$10.56	1.83
49	Grand Lake (Little Pond Brook)	7	48 58 01	57 20 15	64.0	158.0	2.13	4.1	18.7	$8.22	1.82
50	Crabbes River	2	48 03 35	58 36 40	53.0	137.2	4.03	6.8	30.8	$13.68	1.80

TABLE 3.1

LIST OF POTENTIALLY FEASIBLE SMALL HYDRO SCHEMES (Cont'd)

Rank	River	Site No	Location Latitude	Location Longitude	D.A. (sq. km)	Head (m)	Qav (cu.m/s)	Capacity MW	Energy GWh	Cost $(million)	Benfit \ Cost
51	Torrent River	2	50 39 40	56 57 15	46.0	137.0	2.04	3.4	14.5	$6.49	1.79
52	Hughes Brook	1	49 03 50	57 48 50	41.0	106.7	1.43	1.9	9.6	$4.30	1.79
53	Southwest Brook (St.Georges Bay)	4	48 27 40	57 59 20	69.0	84.0	2.41	2.5	11.3	$5.05	1.78
54	Great Coney Arm River	3	49 50 40	56 51 42	18.0	153.0	0.60	1.1	4.8	$2.18	1.78
55	Cascade River	1	50 23 40	56 32 10	178.0	76.2	7.34	6.8	29.5	$13.30	1.77
56	Spout River	1	47 00 45	52 58 30	85.0	76.0	3.77	3.5	15.9	$7.28	1.75
57	Crabbes River	3A	48 03 20	58 30 50	142.0	76.2	10.38	9.7	44.0	$20.21	1.74
58	Middle Arm Brook (White Bay)	3	49 48 05	56 20 50	222.0	33.0	5.63	2.3	11.4	$5.28	1.73
59	Noel Paul's Brook *	1	48 45 00	56 16 30	961.0	21.0	25.89	6.6	30.2	$14.36	1.68
60	Little Rattling Brook	1	48 55 30	55 37 45	112.0	52.0	2.49	1.6	7.2	$3.43	1.68
61	Northwest Brook (Bay le Moine)	1	47 40 40	58 06 40	46.0	106.7	2.19	2.9	13.0	$6.22	1.67
62	Adies Pond (Upper Humber)	1	49 21 00	57 14 15	466.0	42.0	19.94	10.2	50.2	$24.01	1.67
63	Long Harbour River (Fortune Bay) *	1	47 54 45	54 55 30	630.0	46.0	21.97	12.3	56.2	$27.11	1.66
64	Southwest River (Port Blandford)	1	48 17 00	54 13 00	415.0	53.3	12.50	8.1	37.1	$17.90	1.66
65	Southeast River (Placentia) *	1A	47 14 00	53 53 35	135.0	53.0	4.92	3.2	14.5	$7.12	1.63
66	Sheffield Lake	1	49 20 00	56 38 45	340.0	45.0	10.23	5.6	30.5	$15.01	1.63
67	Grand Lake	4	49 40 00	57 49 15	73.0	127.0	2.66	4.1	18.8	$9.24	1.63
68	Great Coney Arm River	2	49 53 20	56 49 15	86.0	61.0	3.27	2.4	10.5	$5.21	1.62
69	White Bear River	1	47 53 25	57 17 15	96.0	97.5	4.26	5.1	23.1	$11.44	1.62
70	Victoria River	1	48 43 30	56 41 07	782.0	37.0	23.55	10.6	48.5	$24.09	1.61
71	Back River (Salmonier)	1	47 12 30	53 21 50	65.0	38.0	2.47	1.1	5.2	$2.61	1.60
72	Rocky River *	1	47 13 25	53 33 30	296.0	16.7	11.25	2.3	10.6	$5.32	1.60
73	Little Harbour River	1	47 07 55	53 28 00	220.0	46.0	7.67	4.3	19.6	$9.96	1.58
74	White Hills	1	47 53 00	54 15 00	36.0	91.0	1.26	1.4	6.4	$3.24	1.58
75	Clench Brook	1	48 46 20	56 52 15	107.0	61.0	3.31	2.5	11.2	$5.73	1.57
76	Grey River *	1	47 41 15	57 00 15	1387.0	30.5	52.76	19.6	89.5	$45.88	1.56
77	Portland Creek	10	50 05 35	57 21 10	124.0	152.0	4.52	8.4	36.3	$18.75	1.55
78	Dolland Brook	2	47 44 15	56 36 10	688.0	46.0	26.17	14.7	67.0	$34.84	1.54
79	Lloyds River	3	48 18 45	57 39 00	690.0	30.5	27.34	10.2	46.4	$24.29	1.53
80	Conne River	2	48 18 50	55 34 55	216.0	30.5	7.53	2.8	12.8	$6.71	1.52
81	West Arm Brook	1A	49 16 15	55 31 45	285.0	60.0	4.97	3.6	16.6	$8.73	1.52
82	Crabbes River	6A	48 07 35	58 43 25	470.0	30.5	31.70	11.8	53.8	$28.36	1.52
83	Nameless River (near Paradise River)	1	47 35 30	54 27 00	203.0	45.0	7.70	4.2	19.3	$10.21	1.51
84	Old Mans Brook	1A	49 07 15	57 55 00	139.0	85.3	5.07	5.3	22.8	$12.10	1.51
85	Salmonier Cove River	1	47 41 25	55 44 15	69.0	107.0	2.30	3.0	13.7	$7.36	1.49
86	Dolland Brook	1	47 46 55	56 37 30	526.0	46.0	20.01	11.2	51.2	$27.67	1.48
87	Little River	1	47 52 10	55 40 20	175.0	61.0	6.66	4.9	22.6	$12.30	1.47
88	Grey River	2	47 49 10	56 57 55	972.0	30.5	36.97	13.8	62.7	$34.18	1.47
89	New Bay River (Point Leamington)	1	49 19 15	55 24 00	188.0	46.0	3.28	1.8	9.9	$5.42	1.46
90	Castors River	1	50 54 30	56 45 30	44.0	92.0	1.67	1.9	8.1	$4.44	1.46
91	Grand Codroy River	1	47 55 45	58 50 00	66.0	61.0	5.02	3.7	17.0	$9.36	1.46
92	Middle Arm Brook (White Bay)	1	49 50 40	56 25 20	343.0	45.0	8.69	4.8	20.6	$11.39	1.45
93	Whites River (Upper Humber)	1	49 28 30	57 18 45	245.0	61.0	10.48	7.8	33.7	$18.77	1.44
94	Squid Cove Brook	1	50 53 30	56 56 45	21.4	213.0	0.75	2.0	8.4	$4.70	1.43
95	Lewaseechjeech Brook *	2	48 34 40	57 39 55	150.0	76.0	4.99	4.6	21.1	$11.78	1.43
96	Lomond River *	1	49 21 30	57 37 45	163.0	30.5	6.72	2.5	10.8	$6.09	1.42
97	Exploits River at Exploits Dam	1	48 45 45	56 36 00	4823.0	7.0	138.00	1.0	5.8	$3.28	1.41
98	Mary March's Brook *	1	48 54 30	56 27 15	450.0	21.0	12.13	3.1	17.8	$10.10	1.41
99	Middle Arm Brook (White Bay)	2	49 49 20	56 23 00	240.0	53.0	6.09	3.9	17.0	$9.72	1.40
100	Goose Arm Brook	1	49 14 05	57 43 45	61.0	76.0	2.32	2.2	9.3	$5.33	1.40

TABLE 3.1

LIST OF POTENTIALLY FEASIBLE SMALL HYDRO SCHEMES (Cont'd)

Rank	River		Site No	Location Latitude	Longitude	D.A. (sq. km)	Head (m)	Qav (cu.m/s)	Capacity MW	Energy GWh	Cost $(million)	Benfit \ Cost
101	Southwest Brook (St.Georges Bay)		6	48 30 30	58 12 00	482.0	50.0	16.80	10.3	46.7	$26.92	1.39
102	Isle aux Morts River		2	47 38 47	59 00 00	74.0	30.5	5.28	2.0	9.0	$5.16	1.39
103	Sandy Harbour River		2	47 48 15	54 27 20	67.0	45.0	2.54	1.4	6.4	$3.67	1.38
104	Lloyds River		2	48 13 55	57 50 55	500.0	15.2	23.78	4.4	22.2	$12.81	1.38
105	Conne River	*	1	47 55 40	55 40 35	604.0	30.5	21.06	7.8	35.7	$20.69	1.38
106	Isle aux Morts River		1	47 43 00	59 00 00	33.0	45.7	2.51	1.4	7.5	$4.37	1.38
107	Portland Creek		3	50 03 40	57 20 25	71.0	152.0	2.48	4.6	21.0	$12.22	1.37
108	Stony Brook		1	48 55 25	55 40 15	186.0	32.0	4.13	1.6	7.4	$4.31	1.36
109	Southwest Gander	*	1	48 42 00	54 59 00	560.0	30.5	14.20	5.3	24.1	$14.13	1.36
110	Southwest Brook (St.Georges Bay)		1	48 28 00	57 51 55	29.0	99.0	1.06	1.3	6.2	$3.66	1.36
111	Grand Codroy River		2	47 56 40	58 56 35	45.0	45.7	3.14	1.8	8.0	$4.74	1.35
112	Grand Bay River		1	47 38 10	59 08 30	46.0	61.0	2.33	1.7	7.9	$4.74	1.33
113	Little Harbour Deep River		5	50 15 28	56 40 15	409.0	46.0	16.85	9.5	40.9	$24.57	1.33
114	Thomey Cove Brook		1	47 52 28	56 10 10	34.0	107.0	1.35	1.8	8.0	$4.87	1.32
115	Grandys Brook (Burnt Island)		1	47 47 10	58 50 00	143.0	30.5	10.88	4.1	18.5	$11.19	1.32
116	East Arm Brook (Hooping Harbour)		1	50 37 55	56 12 45	174.0	110.0	6.07	8.2	35.2	$21.50	1.31
117	Harry's River		4	48 41 45	58 14 30	510.0	21.0	21.00	5.4	24.5	$15.04	1.30
118	Great Rattling Brook		2	48 58 00	55 32 45	1470.0	32.0	34.90	13.6	62.1	$38.11	1.30
119	Crabbes River		5	48 04 30	58 39 25	162.0	30.5	11.30	4.2	19.2	$11.87	1.29
120	Sandy Harbour River		1	47 43 20	54 23 00	426.0	30.0	16.20	5.9	27.0	$16.76	1.29
121	Harry's River		5	48 37 15	58 17 45	550.0	23.0	22.60	6.3	28.9	$17.93	1.29
122	Sandy Brook via Diversion Lake		1	48 51 15	55 50 50	290.0	30.0	6.90	2.5	13.1	$8.19	1.28
123	River of Ponds		2	50 28 15	57 00 20	92.0	61.0	3.79	2.8	12.2	$7.74	1.26
124	Devil Brook		1A	47 17 00	55 17 30	82.0	83.0	3.25	3.3	15.0	$9.56	1.26
125	River of Ponds		1	50 25 45	57 03 55	100.0	61.0	4.12	3.1	13.8	$8.80	1.26
126	East River		1	50 39 15	57 07 05	123.0	46.0	4.48	2.5	10.9	$6.94	1.25
127	Northwest Arm Brook (Connoire Bay)		1	47 45 00	57 54 50	74.0	61.0	3.52	2.6	11.9	$7.64	1.25
128	Lewaseechjeech Brook	*	1A	48 33 15	57 42 15	166.0	46.0	5.75	3.2	15.1	$9.67	1.25
129	Northwest Gander	*	2	48 35 30	55 27 00	1000.0	30.5	25.40	9.5	43.1	$27.68	1.25
130	Portland Creek		4	50 07 15	57 21 30	36.0	266.0	1.31	4.3	18.4	$12.04	1.22
131	Little Harbour Deep River		6	50 14 30	56 34 30	462.0	30.3	19.00	7.1	30.6	$20.06	1.22
132	South Brook (Baie Verte)		1	49 57 00	56 08 18	86.0	61.0	1.77	1.3	5.7	$3.76	1.21
133	Bay de Vieux Brook		1	47 42 30	57 11 10	43.0	152.0	1.63	3.0	17.5	$11.55	1.21
134	Buchans Brook		1	48 49 10	56 47 40	104.0	31.0	3.21	1.2	5.5	$3.67	1.21
135	Grand Lake		2	48 40 48	58 06 58	88.0	61.0	3.77	2.8	12.1	$8.05	1.21
136	North Brook (Deer Lake)		1	49 10 30	57 33 55	49.0	76.0	1.63	1.5	6.5	$4.39	1.19
137	Southwest Brook (St.Georges Bay)		3	48 27 00	57 58 30	64.0	69.0	2.23	1.9	9.1	$6.13	1.19
138	Little Harbour Deep River		2	50 17 15	56 42 50	205.0	76.0	8.77	8.1	35.2	$23.71	1.19
139	North East Brook (East Bay)		1	47 45 05	55 19 50	125.0	76.2	4.56	4.2	21.6	$14.62	1.18
140	Cooks Brook		1	48 58 15	58 04 00	95.0	27.4	3.61	1.2	5.2	$3.55	1.18
141	Red Harbour River #1		1	47 18 30	55 00 00	49.0	91.0	1.78	2.0	9.0	$6.13	1.18
142	Salmon River (Pool's Cove)		1	47 42 30	55 29 35	178.0	30.5	6.21	2.3	11.9	$8.17	1.16
143	White Bear River		3	47 55 15	57 17 05	440.0	46.0	19.53	11.0	50.0	$34.82	1.15
144	Rocky Brook (Gambo Pond)		1	48 35 45	54 33 15	60.0	122.0	1.67	2.5	11.3	$8.05	1.13
145	Pacquet Brook		1	49 56 10	55 54 00	102.0	67.0	1.77	1.4	6.3	$4.55	1.11
146	Little Chouse Brook		1	49 37 45	56 46 00	38.0	105.0	1.02	1.3	5.7	$4.07	1.11
147	Southwest Gander (Dead Wolf Brook)		2	48 42 00	54 57 00	192.0	30.0	5.00	1.8	8.3	$6.03	1.11
148	Tommys River		1A	49 25 45	55 55 00	370.0	30.0	7.39	2.7	12.3	$8.92	1.11
149	Kane Brook		1	47 50 15	54 56 20	148.0	46.0	5.16	2.9	13.2	$9.69	1.09
150	Little Barachois Brook		2	48 25 30	58 00 00	118.0	30.5	4.30	1.6	7.3	$5.37	1.09

TABLE 3.1

LIST OF POTENTIALLY FEASIBLE SMALL HYDRO SCHEMES (Cont'd)

Rank	River	Site No	Location Latitude	Location Longitude	D.A. (sq. km)	Head (m)	Qav (cu.m/s)	Capacity MW	Energy GWh	Cost $(million)	Benfit \ Cost
151	Portland Creek	6	50 13 55	57 15 15	78.0	91.4	2.35	2.6	11.3	$8.38	1.08
152	Parsons Pond (Gambo Pond)	1	48 39 00	54 21 00	88.0	46.0	2.37	1.3	6.1	$4.50	1.08
153	North West River (Great Gull River)	3	48 34 00	55 21 00	350.0	30.0	8.90	3.3	14.9	$11.19	1.06
154	Southwest Brook (St.Georges Bay)	2	48 28 10	57 52 10	315.0	27.4	10.98	3.7	16.7	$12.67	1.06
155	Great Gull River	1	48 35 00	55 20 50	260.0	61.0	7.21	5.4	24.5	$18.69	1.05
156	Chance Cove Brook	1	46 45 00	53 02 00	72.0	97.0	2.97	3.5	16.0	$12.27	1.04
157	Portland Creek	9	50 04 00	57 20 30	42.0	198.0	1.53	3.7	16.0	$12.29	1.04
158	Isle aux Morts River	3	47 37 00	59 00 20	200.0	15.2	13.95	2.6	11.8	$9.20	1.03
159	Harry's River (North Brook)	2	48 43 00	58 17 00	92.0	69.0	3.79	3.2	14.5	$11.43	1.02
160	Bottom Brook	1A	48 32 13	57 59 58	87.0	76.2	3.31	3.1	14.0	$11.13	1.01

TABLE 3.2

LIST OF INFEASIBLE SMALL HYDRO SCHEMES INVESTIGATED

Rank	River	Site No	Location Latitude	Location Longitude	D.A. (sq. km)	Head (m)	Qav (cu.m/s)	Capacity MW	Energy GWh	Cost $(million)	Benfit \ Cost
1	Robinsons River	1	48 10 32	58 26 40	280.0	15.2	13.31	2.4	11.3	$9.17	0.98
2	White Bear River	4	47 51 35	57 16 35	682.0	46.0	30.27	17.0	77.4	$65.12	0.95
3	Red Harbour River #2	2	47 17 45	55 00 50	63.0	61.0	2.49	1.9	8.4	$7.11	0.95
4	Southwest Brook (Bloomfield)	1	48 22 00	53 55 00	145.0	20.0	4.60	1.1	5.1	$4.33	0.95
5	Great Cat Arm River	2	50 07 00	56 51 15	42.0	76.0	1.66	1.5	6.7	$5.69	0.94
6	Torrent River	3	50 37 08	57 00 45	315.0	30.5	12.98	4.8	21.7	$18.87	0.92
7	Pipers Hole River	2	47 57 45	54 19 50	33.0	76.0	1.15	1.1	4.9	$4.34	0.90
8	Otter Point Brook	1	49 41 45	56 44 30	25.0	137.0	0.67	1.1	4.8	$4.37	0.89
9	Shoal Harbour River	1	48 12 00	54 00 00	116.0	30.0	4.00	1.5	6.7	$6.07	0.88
10	Castors River	3	50 56 45	56 42 30	50.0	61.0	1.90	1.4	6.1	$5.57	0.88
11	Middle Brook	1	48 46 10	54 24 20	118.0	76.0	2.99	2.8	12.6	$11.68	0.87
12	Little Harbour Deep River	4	50 15 50	56 41 05	40.0	198.0	1.52	3.7	15.9	$14.80	0.86
13	Barachois Brook	1	48 09 20	58 31 25	73.0	30.5	3.24	1.2	5.5	$5.15	0.85
14	Morgan Brook	1	47 43 18	56 30 50	178.0	46.0	6.77	3.8	17.3	$16.59	0.83
15	Lloyds River	1	48 10 00	58 00 15	125.0	31.0	6.34	2.4	10.9	$10.62	0.82
16	Second Burnt Pond	1	48 45 10	54 24 30	118.0	76.0	2.99	2.8	12.6	$12.30	0.82
17	Harry's River	1	48 48 13	58 02 10	124.0	15.2	5.11	1.0	4.7	$4.65	0.82
18	White Bear River	5	47 56 00	57 18 15	64.0	46.0	2.84	1.6	7.3	$7.18	0.81
19	Grand Codroy River	4	48 00 48	58 46 50	95.0	15.2	6.63	1.2	5.6	$5.54	0.81
20	Salmon River (Main Brook)	1	51 06 45	56 09 15	413.0	15.0	12.44	2.3	10.2	$10.13	0.81
21	Indian Bay Brook *	1	49 02 30	53 56 30	530.0	15.0	12.60	2.3	11.3	$11.34	0.80
22	Salmonier River (Pinsents Fall) *	1	47 14 00	53 31 50	141.0	18.2	5.36	1.2	5.4	$5.43	0.79
23	Northern Arm River (Fourche Hr.)	2	50 32 13	56 22 30	36.0	153.0	1.31	2.4	10.6	$11.01	0.77
24	Salmon River (Clode Sound)	1	48 23 00	54 14 00	100.0	30.0	2.90	1.1	4.8	$5.12	0.76
25	Southwest Brook (St.Georges Bay)	5A	48 28 40	58 00 30	465.0	15.2	16.21	3.0	13.7	$14.71	0.75
26	Little Cat Arm River	1	50 09 32	56 37 45	38.0	168.0	1.20	2.5	10.6	$11.50	0.74
27	Phillips Brook	1	47 47 13	58 08 15	22.0	137.2	1.05	1.8	8.0	$8.75	0.73
28	Mint Brook	1	48 44 00	54 18 00	336.0	15.0	9.00	1.6	7.5	$8.23	0.73
29	Bottom Brook	2	48 32 30	58 04 00	134.0	46.0	5.10	2.9	13.0	$14.47	0.72
30	Colinet River *	1	47 15 00	53 32 40	193.0	15.0	7.34	1.3	6.1	$6.79	0.72
31	Popes Harbour River	1	48 16 00	53 36 45	56.0	45.0	1.77	1.0	4.4	$5.06	0.70
32	Grand Codroy River	3	47 59 15	58 46 10	73.0	15.2	5.55	1.0	4.7	$5.41	0.69
33	Fischells Brook	1	48 18 10	58 36 45	307.0	15.2	13.14	2.4	11.1	$13.57	0.66
34	Little Harbour Deep River	1	50 17 10	56 43 40	112.0	61.0	4.79	3.6	15.4	$19.19	0.64
35	Northwest Gander *	1	48 31 00	55 31 00	808.0	30.5	20.50	7.6	34.8	$44.42	0.63
36	Portland Creek	1	50 07 00	57 15 45	32.0	77.0	1.17	1.1	5.4	$7.27	0.59
37	Fox Island River	1	48 42 00	58 36 30	167.0	61.0	6.62	4.9	22.5	$31.98	0.56
38	Little Harbour Deep River	3	50 16 40	56 41 40	25.0	122.0	0.95	1.4	6.1	$12.41	0.39

* Possible environmental problems, see site data sheets - Volume 2.

TABLE 3.3 - LIST OF SMALL HYDRO SITES PREVIOUSLY STUDIED

RIVER SITE	LOCATION LATITUDE	LONGITUDE	AREA km^2	HEAD m	CAPACITY MW	ENERGY gWh	COST $ X 10^6	BENEFIT-COST RATIO	REMARKS
Ten Mile Lake	50°32'30"	56°51'30	355		6.3				From NLH files
Castor's River	50°55'10"	56°53'10"	435		6.8				From NLH files
Torrent River	50°35'10"	57°08'30"	355		4.6				From NLH files
Lake Michel	50°19'10"	57°07'10"	103	288.0	12.0	64			From SNL Report SMR-9-79
Little Grand Lake	48°37'20"	57°56'00"	466	76.0	12.0	84			Recent SNL studies indicated it was worthwhile to raise the level of Little Grand Lake to build head.
Great Rattling Brook	48°57'50"	55°32'10"	1458	36.0	15.0	49			ADB - Volume 4
Dry Pond Brook	47°43'10"	57°41'40"	144	96.3	5.2	37.2			From SNL Report SMR-9-79
Cloud River	50°48'40"	56°17'10"	435	90.5	14.5	72			From SNL Report SMR-9-79

TABLE 3.4 - SCHEMES WITH CAPACITY GREATER THAN 20 MW

RIVER	SITE	LOCATION LATITUDE	LOCATION LONGITUDE	AREA km^2	HEAD m	CAPACITY MW	ENERGY gWh	COST $ \$ X 10^6 $	BENEFIT-COST RATIO	REMARKS
Bay du Nord	1	47°48'10"	55°25'40"	1075	145	63	367	--	--	Paper by R. A. Robertson, Presented at 92nd EIC Annual Conference (1978).
Bay du Nord	2	47°48'10"	55°25'40"	3080	145	175				Same site as Bay du Nord #1, with diversions from neighbouring watersheds. NLH files.
Gisborne Lake		47°47'00"	54°56'00"	2608	--	172	--	--	--	Includes diversions from neighbouring rivers, NLH files,(Development without diversions listed in Small Hydro Inventory).
Grey River	1	47°41'15"	57°00'15"	1387	46	29.6	142	60.87	1.87	New
Exploits [Red Indian Falls]	2	48°52'00"	56°13'45"	6376	18.2	26.0	157	--	--	From paper by R. Robertson, Optimum head probably be higher than 18.2m. Dam would improve ice conditions in vicinity of Badger but would have negative environmental impact on salmon.
Exploits [Badger Chute]	3	48°56'20"	55°58'45"	7455	15.0	22.0	175	--	--	SNL files.
Exploits [Grand Falls Extension]	4	48°55'30"	55°40'30"	8415	43.0	21.0	125	--	--	Extension to utilize surplus flow and entire head between Goodyear Dam and Exploits Canyon (SNL files)
Lower Exploits	5	48°57'00"	55°35'30"	8749	13.0	23.0	180	--	--	Develops most of head between Grand Falls and Bishops Falls (SNL Files)
Terra Nova River [Mollyguajeck]	1	48°22'40"	54°28'20"	1826	57.9	44.0	239			From paper by R. A. Robertson
Terra Nova River [Clode Sound]	2	48°26'00"	54°07'20"	2538	89.9	100.0	543			From paper by R. A. Robertson
Star Lake		48°33'30"	57°12'10"	691	146	46	240			SNC Study for Newfoundland & Labrador Hydro.
Kitty's Brook	1	49°12'15"	56°54'15"	431	162	25.7	121	--	--	Includes Diversions from - Barney's, Burnt Berry, Upper Sheffield and Chain Lakes Brooks.

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TABLE 3.4 - SCHEMES WITH CAPACITY GREATER THAN 20 MW (Cont'd)

RIVER	SITE	LOCATION LATITUDE	LOCATION LONGITUDE	AREA km^2	HEAD m	CAPACITY MW	ENERGY gWh	COST $ X 10^6	BENEFIT-COST RATIO	REMARKS
Island Pond [Bay d'Espoir]		48°22'40"	56°22'40"	3359	23.0	30.0	187	--	--	From SNL Report SMR-19-86
Granite Canal [Bay d'Espoir]		48°10'50"	56°47'50"	2238	39.5	38.0	191	--	--	Acres study for Newfoundland and Labrador Hydro.
Upper Humber	1	49°32'50"	57°07'30"	486	256.0	100.0	327	--	--	From ADB Report Vol. 4 and SNL files. Dam located at lat. 49°35'50" long. 57°18'40" on plateau with tailrace discharging into Birchy Lake
Upper Humber [Little Falls]	2	49°17'15"	57°16'45"	1907	34.0	30.1	98	39.5	2.64	Results in extensive flooding inundating Squires Memorial Provincial Park; etc. also obstacle to salmon migration
Main River		49°47'00"	56°58'20"	759	248.1	110.0	490	--	--	From paper by R. A. Robertson
River-of-Ponds		50°29'10"	57°15'10"	679	61.6	35	108			From ADB Report Volume 4, also see Table 3.7 and River-of-Ponds S3, in Vol. 2
Pipers Hole	1	47°55'10"	54°15'10"	2499		~~126~~ 80	128 --	--	--	Same site as Pipers Hole #2, including diversions from neighbouring watersheds, NLH files.
Pipers Hole	2	47°55'10"	54°15'10"	754		80	N/A	--	--	NLH files.
Southwest Brook [St. George's Bay]		48°30'50"	58°12'10"	583	77.1	30	98			Involves diversion of Southwest Brook into Bottom Brook. From ADB Report, Vol. 4.

TABLE 3.5 - UPSTREAM STORAGE DEVELOPMENTS

SCHEME	DRAINAGE AREA (km^2)	CAPACITY (MW)	ENERGY (Storage Ratio)		COST in \$ x 10^6		PROJECT BENETIT/COST RATIO		BENEFIT/COST RATIO
			NO STORAGE (gWh)	STORAGE (gWh)	NO STORAGE	STORAGE	NO STORAGE	STORAGE	UPSTREAM STORAGE ONLY
Maccles Lake S-1	202	3.8	17.09	21.50	8.44	9.16	1.62	1.88	4.93
Goose Arm Brk. S-1	61	2.2	7.50	9.30	5.00	5.33	1.20	1.40	4.33
Southwest Brook S-3	64	1.9	6.95	9.10	5.61	6.13	0.99	1.19	3.28
Harry's River, S-4	510	5.4	21.81	24.50	14.13	15.04	1.23	1.30	2.38
Southwest Brook S-2	315	3.7	16.16	16.70	12.34	12.67	1.05	1.06	1.32

TABLE 3.6 - WATERSHED DIVERSION SCHEMES

SCHEME	DRAINAGE AREA (km^2)			ADD'N PLANT CAPACITY (MW)	ADD'N ENERGY gWh p.a.	COST OF DIVERSION $ X 10^6			BENEFIT/COST RATIO DIVERSION	REMARKS
	BASE	DIVERTED	TOTAL			DIVERSION	PLANT EXTENSION	TOTAL		
Crabbes River S-4A	193	65	258	2.55	30.90	1.05	2.76	3.81	6.49	
Lloyds River S-4A	110	71	181	2.79	18.90	2.28	1.00	3.28	4.61	Benefits Lloyds S-4 Grand Falls, Bishops Falls Diversion and plant extension improve overall project B/C ratio from 2.55 to 3.22.
Parson's Pond, S-1A	38	46	84	5.30	22.80	1.07	3.40	4.48	4.07	
Crabbes River S-3A	77	65	142	4.25	30.90	1.75	4.67	6.42	3.85	
Portland Creek, S-6	61	17	78	--	3.21	0.715	-	0.715	3.59	Diversion improves overall project B/C ratio from 1.08 to 1.28.
Portland Creek S-2	28	37	65	6.55	29.87	3.22	3.93	7.15	3.34	
Shoal Brook S-1A	42	155	197	4.40	19.10	2.08	3.71	5.79	2.64	
Lewaseechjeech S-1A	96	70	166	1.40	11.10	1.86	1.82	3.68	2.41	
West Arm Brook S-1A	179	106	285	1.37	6.19	1.34	1.19	2.53	1.96	
Devil Brook S-1A	46	36	82	1.45	6.61	1.23	1.90	3.13	1.69	
Torrent River S-1	168	50	218	1.98	5.79	1.16	1.94	3.10	1.49	
Old Mans Brook S-1A	101	38	139	1.44	6.29	2.63	1.20	3.81	1.31	
Back River [Salmonier] S-1A	65	77	142	1.50	6.64	3.44	1.45	4.89	1.09	
Tommys River S-1A	212	158	370	1.23	5.62	2.62	1.62	4.24	1.06	

TABLE 3.7 - GROUP DEVELOPMENTS

GROUP (and development sequence)	DRAINAGE AREA (km^2)	CAPACITY (MW)	ENERGY gWh p.a.	COST $ x 10^6	B/C RATIO STAND ALONE	B/C RATIO IN GROUP	REMARKS
Portland Creek							
S-4A	137.0	16.2	70.0	19.66	2.85	2.85	There are several possible groupings of sites in the Upper Portland Creek area. The optimal grouping, based on order-of-magnitude cost cost estimates, involves diversions from S-2 and S-10 via S-8 into S-4. This layout eliminates S-2 and S-9 and reduces the potential of S-10. On the other hand S-8 can be developed to exploit a head concentration along the diversion route from S-2 to S-4. See Figure 3.1.
S-8	98.0	4.3	20.7	5.37	N/A	--	
S-3	71.0	4.6	21.0	6.57	1.37	2.56	
S-10A	82.0	5.5	24.0	9.24	N/A	--	
S-1	32.0	1.1	5.4	3.11	0.60	1.39	
TOTALS		31.7	141.1	43.95		2.57	
Cinq Cerf & Vicinity							
N. W. Arm S-2	222.0	8.4	38.2	11.06	2.76	2.76	
Cinq Cerf S-1	88.0	7.4	33.7	10.73	2.01	2.51	
N. W. Arm S-1	61.0	2.6	11.9	5.10	1.25	1.88	
Phillips Bk. S-1	22.0	1.8	8.0	4.39	0.74	1.46	
TOTAL GROUP		20.2	91.8	31.28		2.35	See Figure 3.2.
River of Ponds & Lake Michel							
Lake Michel	103	12.0	64.1	20.81	2.46	2.46	Lake Michel cost based on SHYDRO estimate using layout from SNL report SMR-9-79.
River of Ponds S-3X	690	21.1	107.5	38.69	2.22	2.23	
River of Ponds S-1	100	3.1	13.8	6.57	1.26	1.68	
River of Ponds S-2	92	2.8	12.2	7.65	1.26	1.26	
TOTAL GROUP		39.0	197.6	73.72		2.14	See Figure 3.3.
Crabbes River							
Crabbes River S-1	80.0	7.3	33.1	13.03	2.03	2.76	A common powerhouse can be used for S-4 and S-5.
Crabbes River S-4	193.0	7.9	35.8	13.53	1.89	2.51	
Crabbes River S-5	162.0	4.2	19.2	6.92	0.74	2.41	
Crabbes River S-2	53.0	6.8	30.8	11.84	1.80	1.88	
Crabbes River S-3	77.0	5.5	24.8	11.55	1.44	1.46	
TOTAL GROUP		31.7	143.7	56.87		2.02	See Figure 3.4.

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TABLE 3.7 - GROUP DEVELOPMENTS (Cont'd)

GROUP (and development sequence)	DRAINAGE AREA (km^2)	CAPACITY (MW)	ENERGY gWh p.a.	COST $\$ \times 10^6$	B/C RATIO STAND ALONE	B/C RATIO IN GROUP	REMARKS
Lewaseechjeech Brook & Vicinity							
Lewaseechjeech S-3	58	4.9	28.8	6.76	3.41	3.41	
Grand Lake S-4	73	4.1	18.8	8.69	1.63	1.73	
Lewaseechjeech S-2	150	4.6	21.1	9.84	1.43	1.72	
Lewaseechjeech S-1A	166	3.2	15.1	9.03		1.34	
TOTAL GROUP		16.8	83.8	34.32		1.95	See Figure 3.5.
Torrent River							
Torrent River S-4	615	7.4	34.8	10.74	2.59	2.59	
Torrent River S-2	46	3.4	14.5	5.25	1.79	2.22	
Torrent River S-1	218	9.2	41.4	16.29	2.03	2.03	
Torrent River S-3	315	4.8	21.7	16.62	0.92	1.05	
TOTAL GROUP		24.8	112.4	48.90		1.84	See Figure 3.6.
Northern Arm River & Vicinity							
Northern Arm River S-2	36	2.4	10.6	3.13	0.77	2.70	A common powerhouse can be used for
Northern Arm River S-1	160	13.0	56.2	23.00	1.95	1.95	S-1 and S-2 of Northern Arm River.
Eastern Arm River S-1	174	8.2	35.2	18.51	1.31	1.53	See Figure 3.7.
TOTAL GROUP		23.6	102.0	44.64		1.83	
Middle Arm Brook & Vicinity							
Gull Pond	76	2.9	12.4	4.48	2.22	2.22	
Middle Arm Brook S-3	222	2.3	11.4	5.17	1.73	1.77	
Middle Arm Brook S-1	343	4.8	20.6	10.78	1.45	1.53	
Middle Arm Brook S-2	240	3.9	17.0	9.28	1.40	1.47	
TOTAL GROUP		13.9	61.4	29.71		1.65	See Figure 3.8.

.....Continued

TABLE 3.7 - GROUP DEVELOPMENTS (Cont'd)

GROUP (and development sequence)	DRAINAGE AREA (km^2)	CAPACITY (MW)	ENERGY gWh p.a.	COST $ x 10^6	B/C RATIO STAND ALONE	B/C RATIO IN GROUP	REMARKS
Little Harbour Deep River							
Little Harbour Deep River S-4	40	3.7	15.9	4.56	0.86	2.79	
Little Harbour Deep River S-2	205	8.1	35.2	15.58	1.19	1.80	
Little Harbour Deep River S-3	25	1.4	6.1	3.32	0.39	1.47	
Little Harbour Deep River S-5	409	9.5	40.9	24.57	1.33	1.33	
Little Harbour Deep River S-6	462	7.1	30.6	18.49	1.22	1.32	
Little Harbour Deep River S-1	112	3.6	15.4	10.88	0.64	1.13	
TOTAL GROUP		33.4	144.1	77.40		1.49	See Figure 3.9.
White Bear River							
White Bear S-2	99	6.7	30.5	7.43	1.98	2.08	S-2 powerhouse would be raised by
Bay de Vieux S-1	43	3.0	17.5	7.39	1.21	1.90	about 20 m to avoid flooding by
White Bear S-1	96	5.1	23.1	11.44	1.62	1.62	head pond of S-5.
White Bear S-3	440	11.0	50.0	30.95	1.15	1.29	S-6 becomes economic in a group
White Bear S-5	64	1.6	7.3	3.87	0.81	1.50	Total cost assuming stand-alone
S-6		1.8	8.2	4.65	0.92	1.41	development = $142.48 x 10^6.
S-4	682	17.0	77.4	59.09	0.95	1.05	
TOTAL GROUP		46.2	214.0	124.78		1.37	See Figure 3.10

FIGURES

FIGURE 3.1

Portland Creek

Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
S.4A	266.0	16.2	70.0
S.8	99.0	4.3	20.7
S.3	152.0	4.6	21.0
S.10A	152.0	5.5	24.0
S.1	77.0	1.1	5.4
Group Total		31.7	141.7

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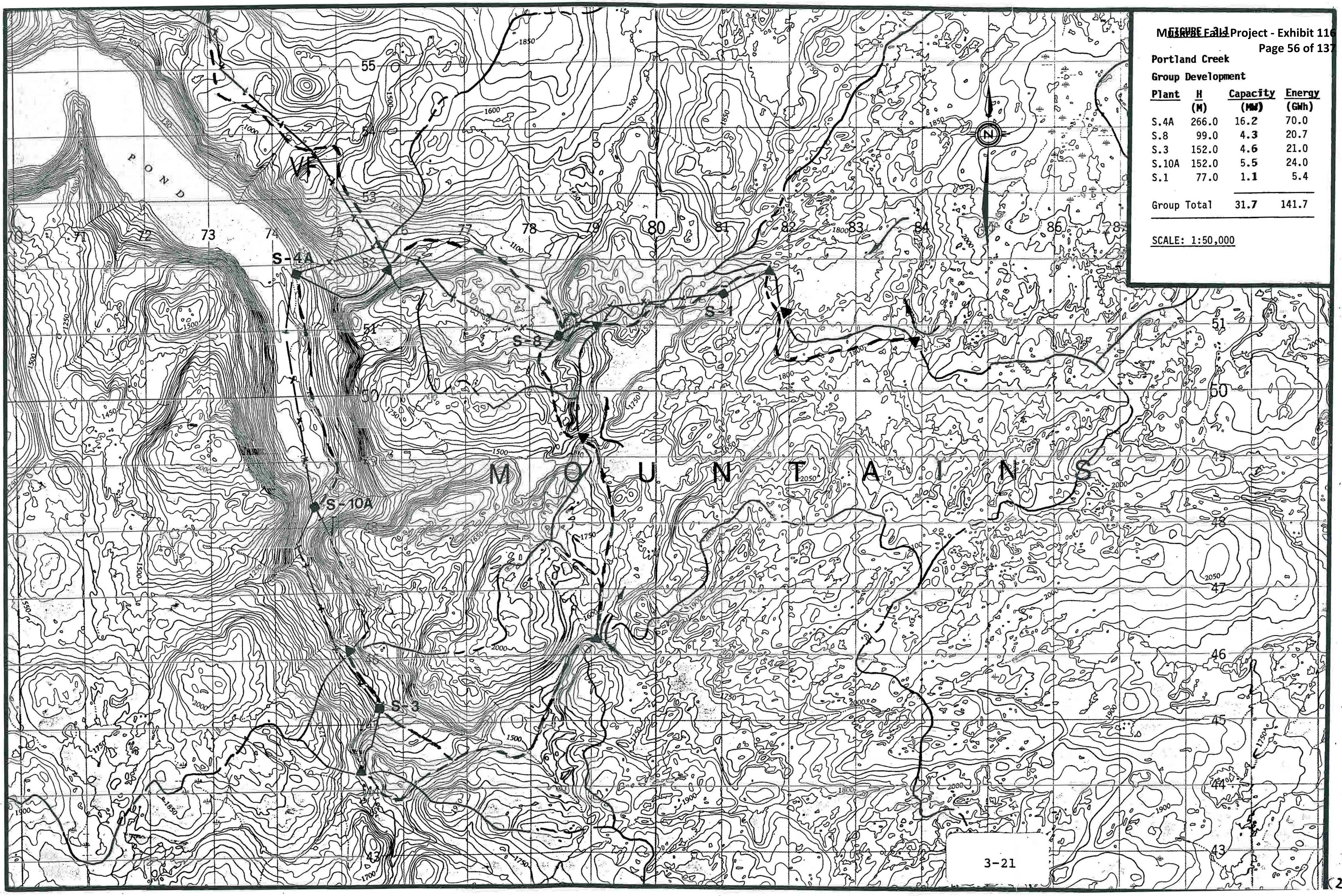

FIGURE 3.2

Cinq Cerf and Vicinity

Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
N.W. Arm			
S.2	61.0	8.4	38.2
Cinq Cerf			
S.1	144.8	7.4	33.7
N.W. Arm			
S.1	61.0	2.6	11.9
Philips			
S.1	137.2	1.8	8.0
Group Total		20.2	91.8

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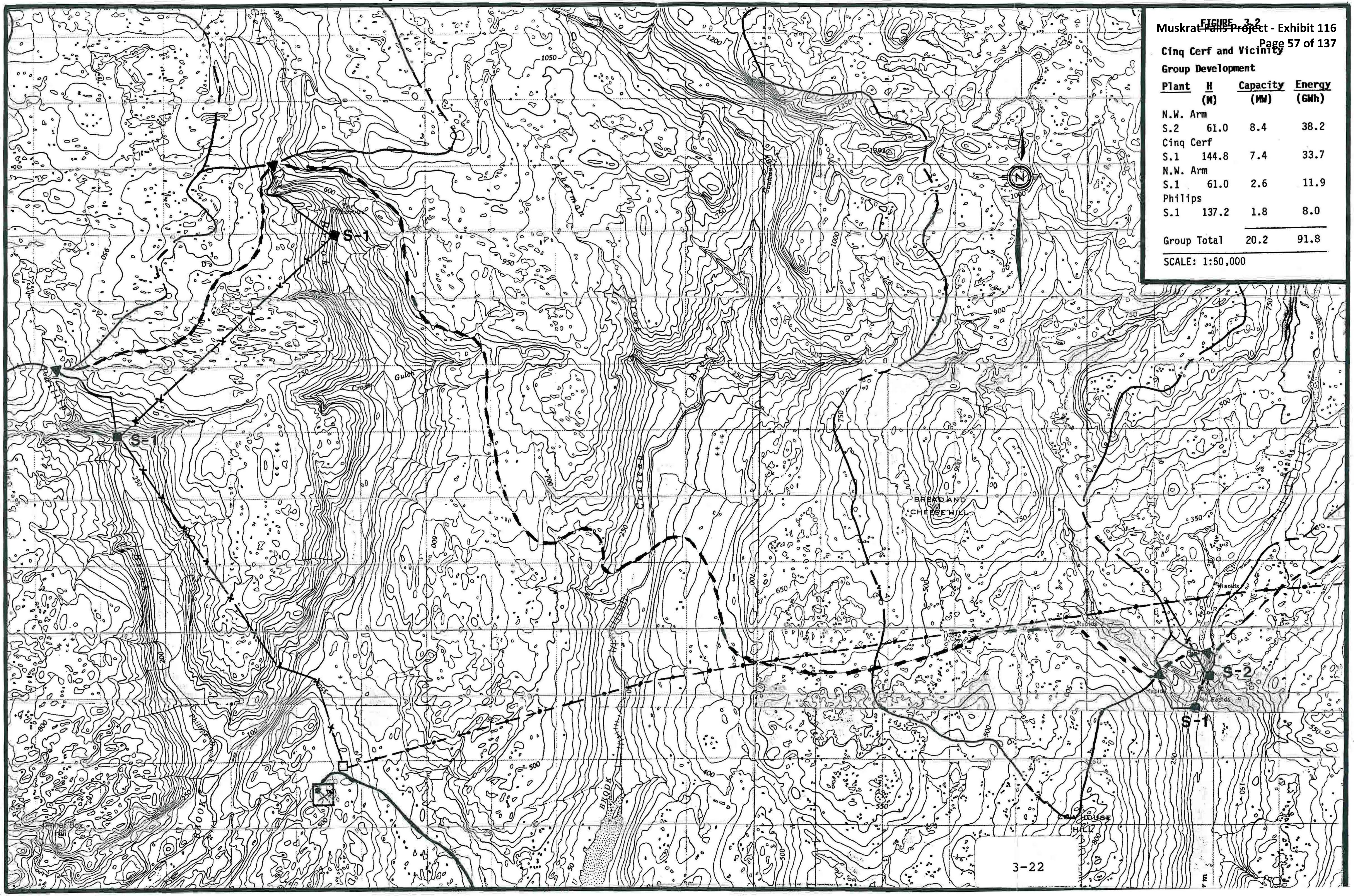

FIGURE 3.3

River of Ponds
& Lake Michel
Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
Lake Michel		12.0	64.1
River of Ponds			
S.3X	37.0	21.1	107.5
S.1	61.0	3.1	13.8
S.2	46.0	2.8	12.2
Group Total		39.0	197.6

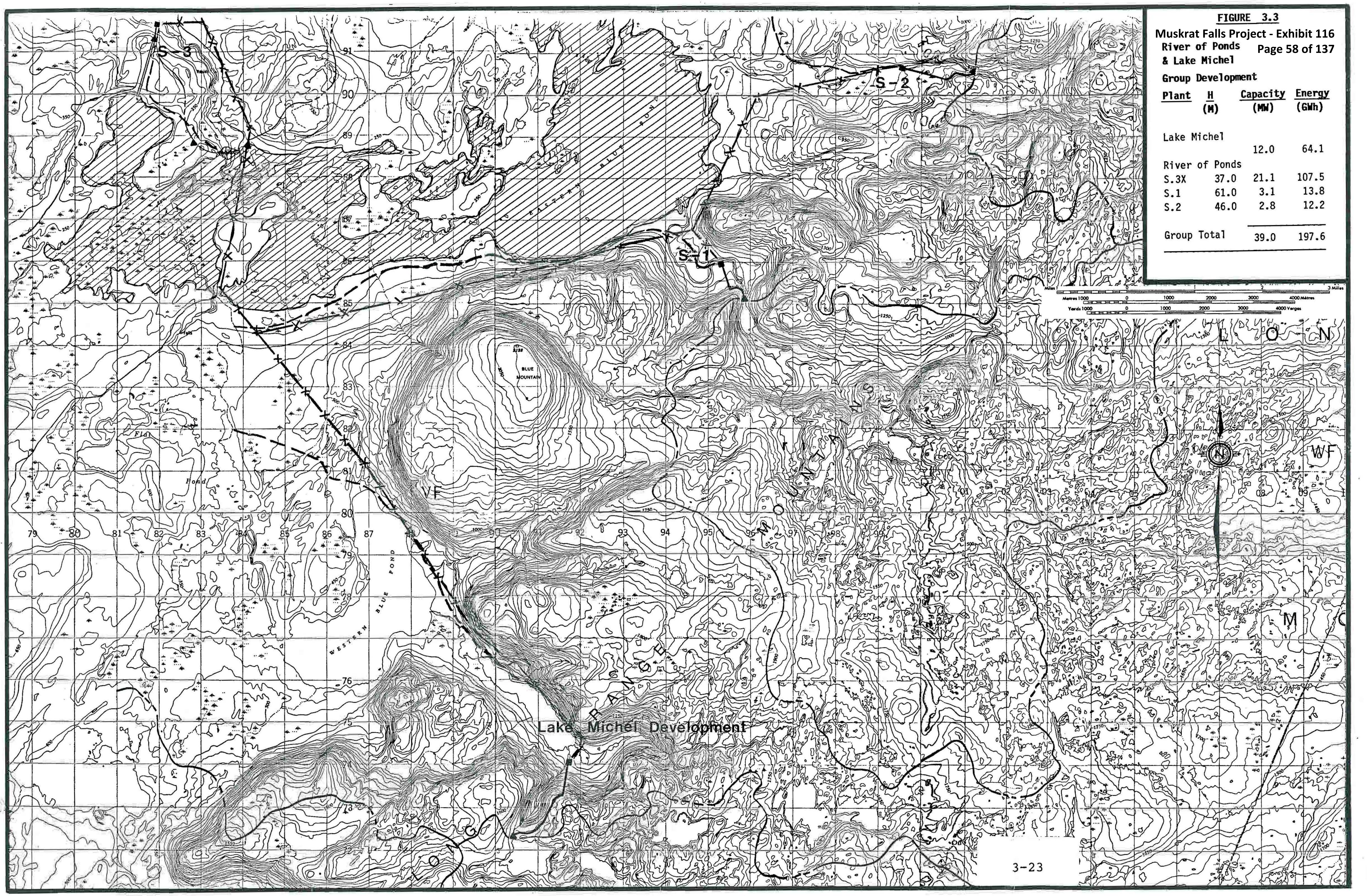

FIGURE 3.4

Crabbes River

Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
S.1	106.7	7.3	33.1
S.4	45.7	7.9	35.8
S.5	30.5	4.2	19.2
S.2	137.2	6.8	30.8
S.3	67.2	5.5	24.8
Group Total		31.7	143.7

SCALE: 1:50,000

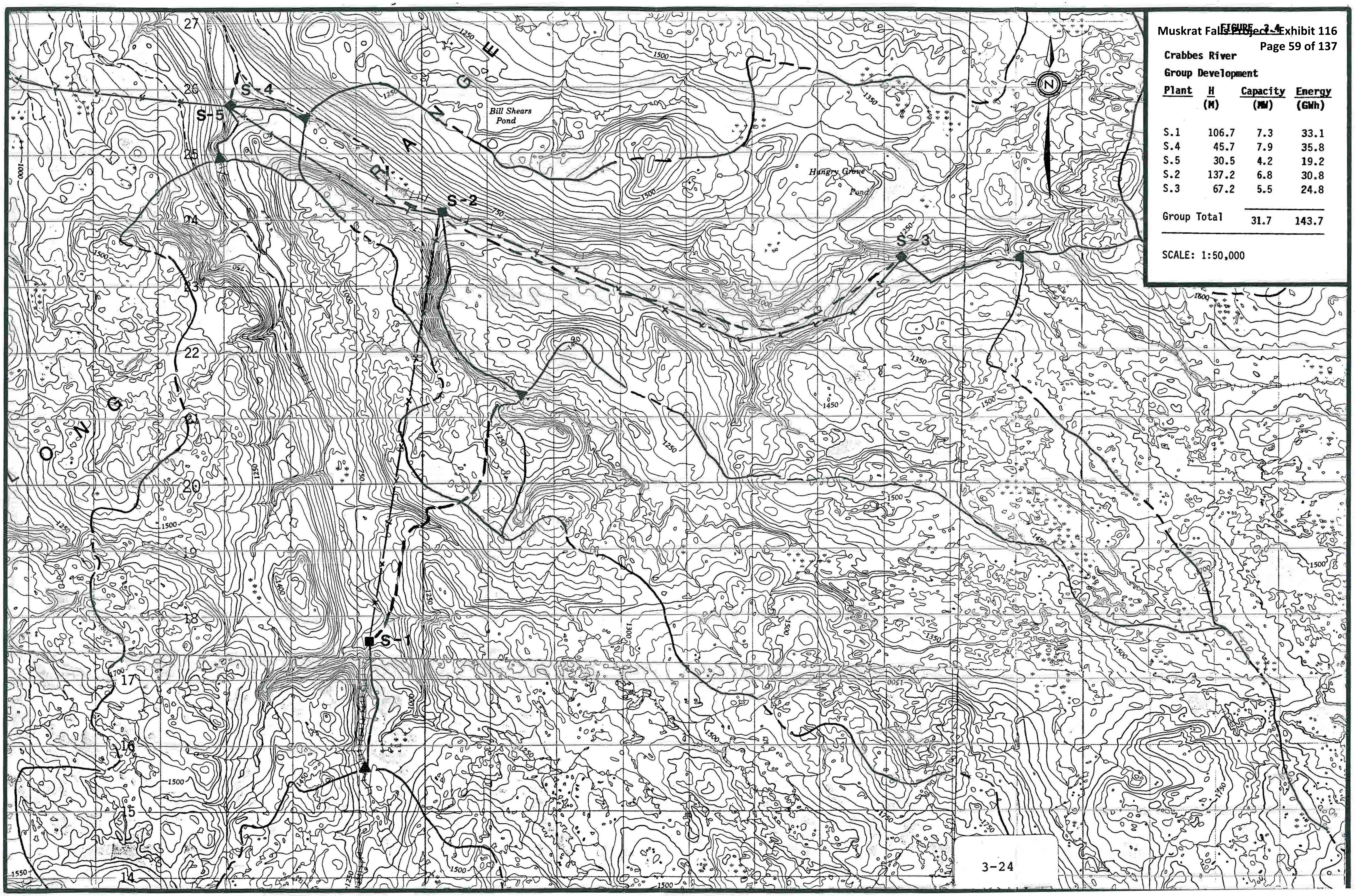

FIGURE 3.5

Lewaseechjeech Brook & Group Vicinity

Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
Lewaseechjeech			
S.3	200.0	4.9	28.8
Grand Lake			
S.4	127.0	4.1	18.8
Lewaseechjeech			
S.2	76.0	4.6	21.1
S.1A	46.0	3.2	15.1
Group Total		16.8	83.8

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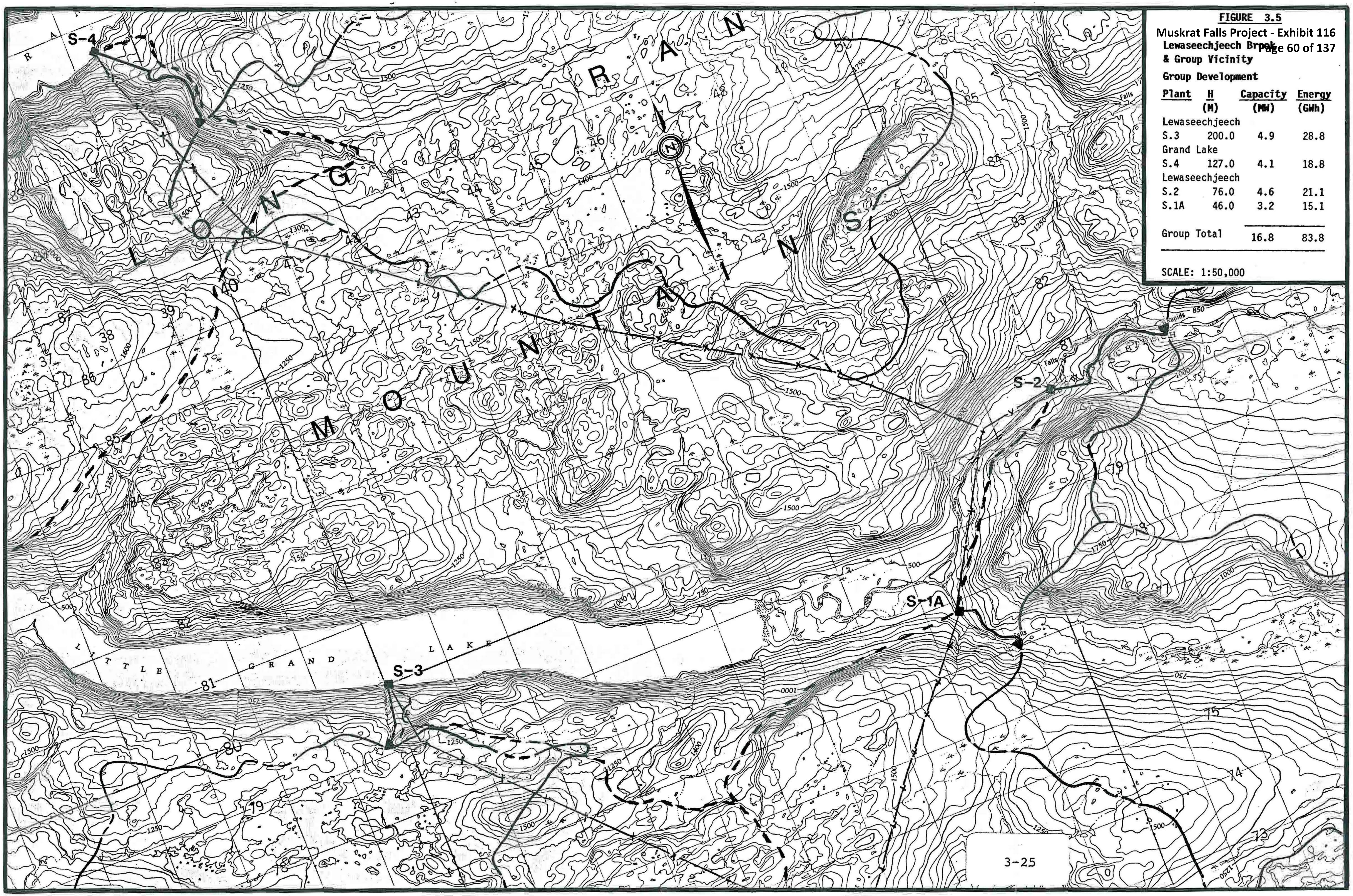

FIGURE 3.6

Torrent River
Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
S.4	25.0	7.4	34.8
S.2	137.0	3.4	14.5
S.1	79.3	9.2	41.4
S.3	30.5	4.8	21.7
Group Total		24.8	112.4

SCALE: 1:50,000

FIGURE 3.7

Northern Arm River & Vicinity

Group Development

Plant	**H (M)**	**Capacity (MW)**	**Energy (GWh)**
Northern Arm River			
S.2	153.0	2.4	10.6
S.1	168.0	13.0	56.2
Eastern Arm River			
S.1	110.0	8.2	35.2
Group Total		23.6	102.0

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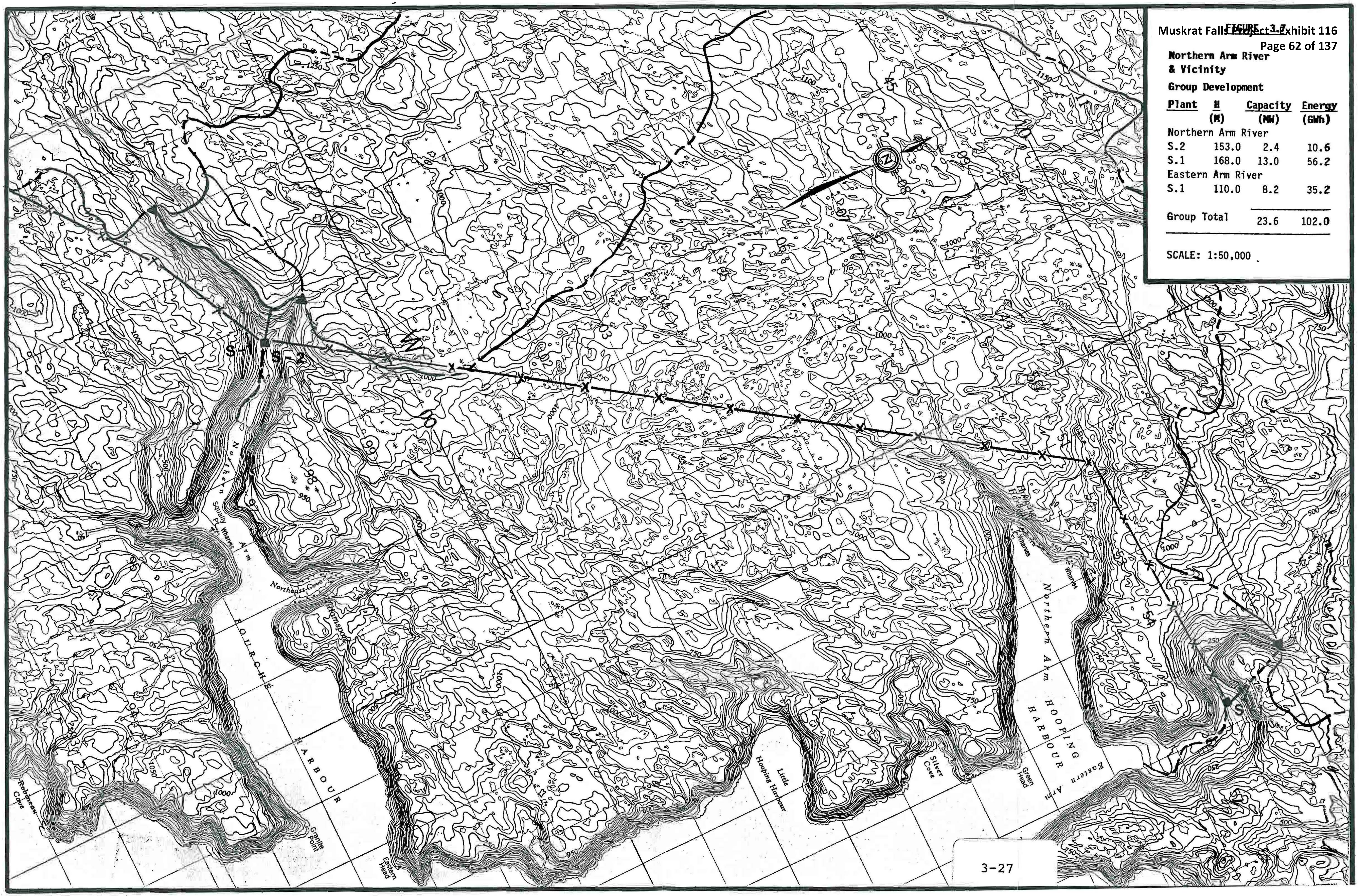

FIGURE 3.8

Middle Arm Brook & Vicinity

Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
Gull Pond			
	122.0	2.9	12.4
Middle Arm Brook			
S.3	33.0	2.3	11.4
S.1	45.0	4.8	20.6
S.2	53.0	3.9	17.0
Group Total		13.9	61.4

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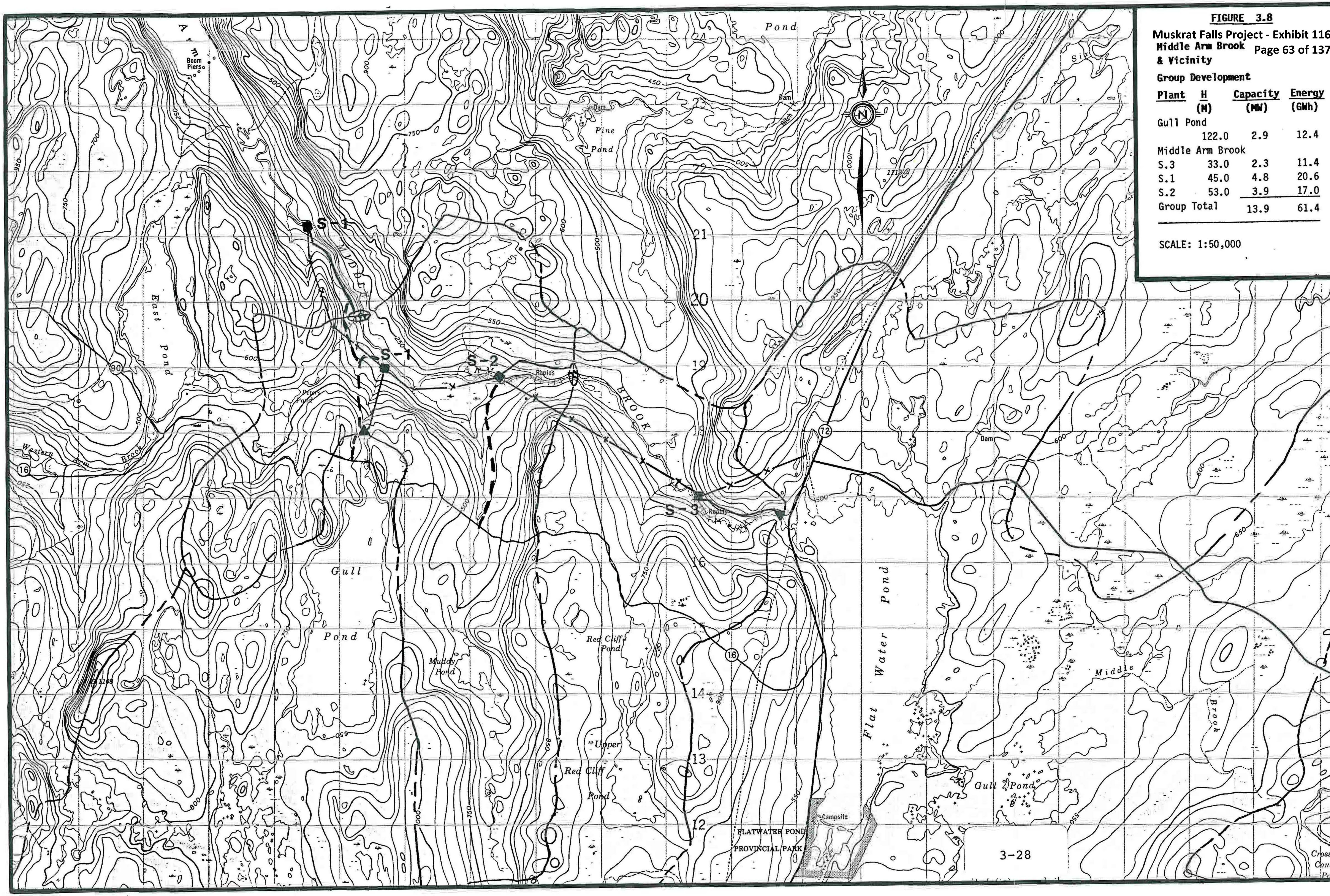


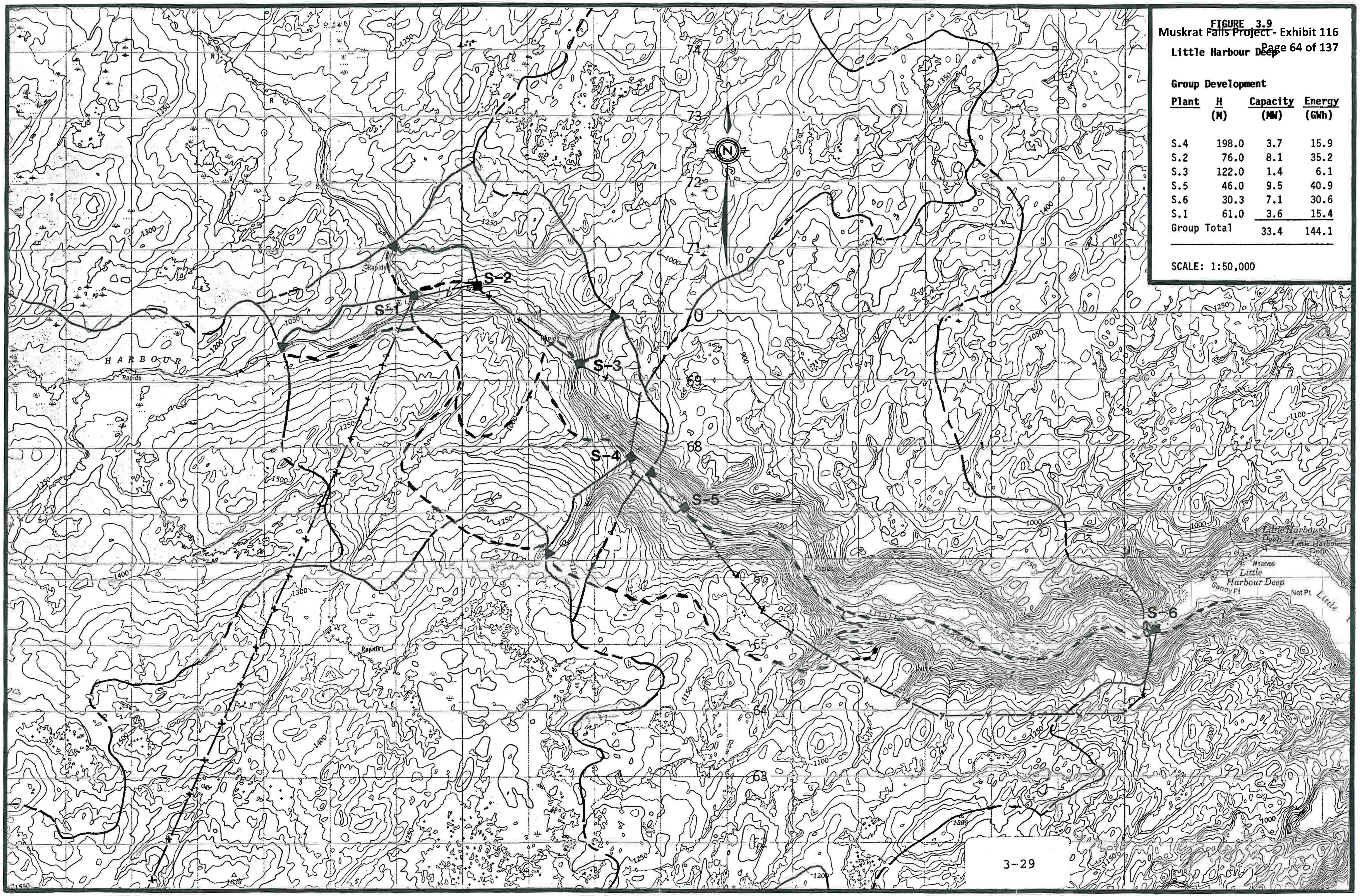
FIGURE 3.9

Little Harbour Deep

Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
S.4	198.0	3.7	15.9
S.2	76.0	8.1	35.2
S.3	122.0	1.4	6.1
S.5	46.0	9.5	40.9
S.6	30.3	7.1	30.6
S.1	61.0	3.6	15.4
Group Total		33.4	144.1

SCALE: 1:50,000



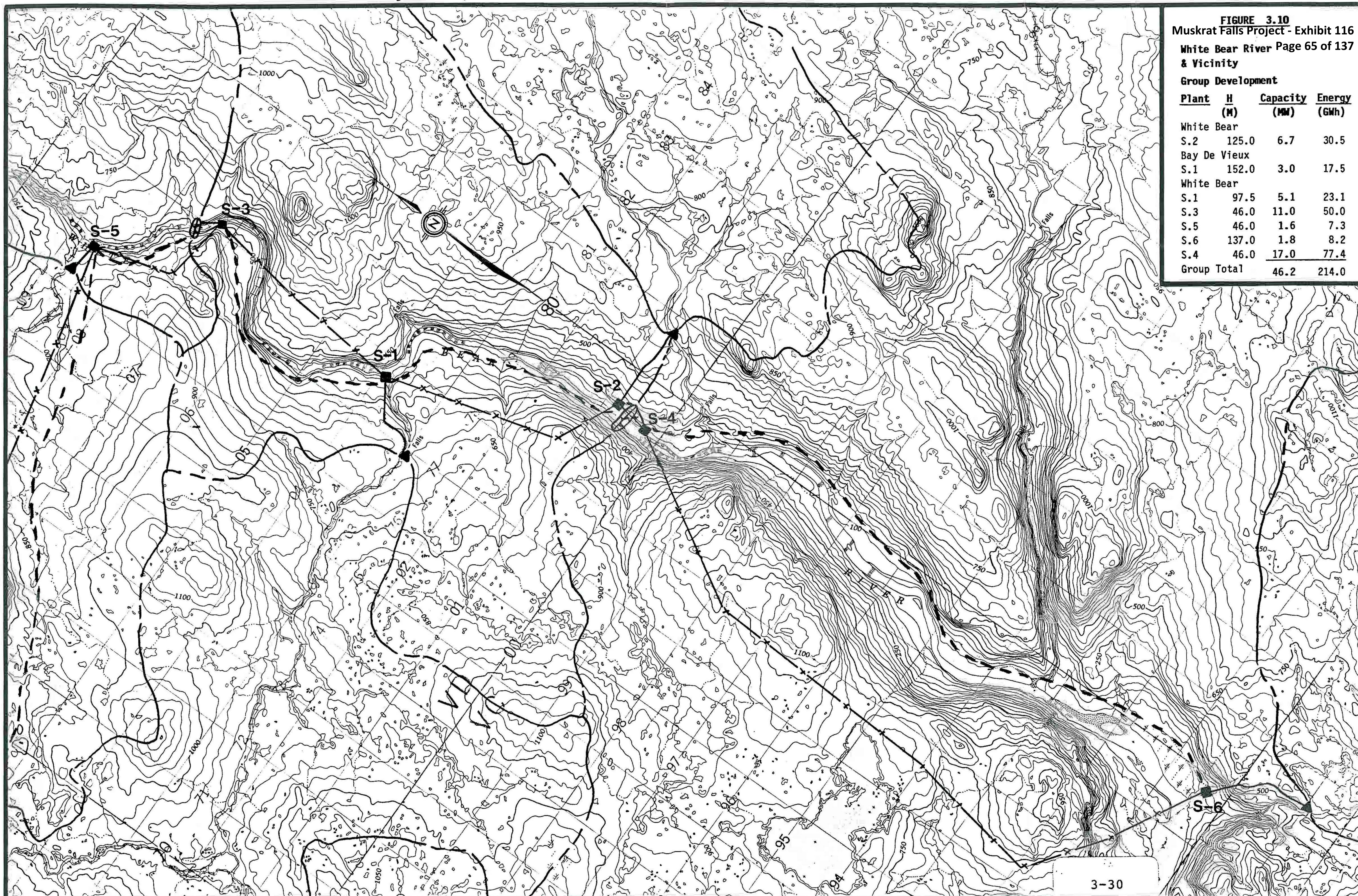


FIGURE 3.10

White Bear River
& Vicinity

Group Development

Plant	H (M)	Capacity (MW)	Energy (GWh)
White Bear			
S.2	125.0	6.7	30.5
Bay De Vieux			
S.1	152.0	3.0	17.5
White Bear			
S.1	97.5	5.1	23.1
S.3	46.0	11.0	50.0
S.5	46.0	1.6	7.3
S.6	137.0	1.8	8.2
S.4	46.0	17.0	77.4
Group Total		46.2	214.0

APPENDIX I
HYDROLOGY

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August, 1986

I.1 Introduction

The hydroelectric potential of river is evaluated from its hydrology and topography. Hydrologically the magnitude and distribution of stream flows have the greatest influence on hydroelectric potential.

In Newfoundland a measure of the expected magnitude of stream flows can be obtained by referring to the iso-runoff map in Exhibit 2.1 (at back of report). Integration between the isopleths of this iso-runoff map yields the expected average annual runoff for any river. The second component of the stream flow properties of a river is the distribution of flows; from year to year and within the year.

The temporal distribution of rivers in Newfoundland has been examined using two analytical techniques:

- daily flow duration analysis
- monthly flow statistical analysis

Flow duration analysis shows what proportion of time the flow will exceed a certain value. When storage is small in relation to annual runoff, the flow duration curve can give a reasonable comparative measure of the energy potential of a site. However, the flow duration analysis cannot show how the flows are distributed within the year.

As storage increases, the 'real time' distribution within the year becomes more important. If low flows are interspersed with high flows throughout the year, storage

I.1 Introduction (Cont'd)

can be used to substantially increase minimum energy potential. On the other hand, if most of the low flows occur in a continuous sequence, uninterrupted by high flows, a far larger storage would be needed for the same increase in minimum energy.

I.2 Regionalization

I.2.1 Purpose

Since many sites do not have any stream flow records, a regional approach is required to define flow distributions.

In a previous study Ingledow (1970) divided Newfoundland into four homogeneous hydrologic regions on the basis of statistical analysis of flows and floods. In a feasibility level study Acres (1985) adopted these regions, with slight adjustments for physiographic delineations. Acres regressed run-of-river turbinable flow curve coefficients on physiographic characteristics to establish general region wide relationships for two of the four regions.

Application of these relationships is time consuming since several parameters must be measured at each site; hence this approach is unsuitable for a preliminary island-wide inventory study. Consequently, an independent regionalization study has been conducted for the Island of Newfoundland to give comparative inventory level estimates of hydro potential in all regions of the Island.

I.2.1 Purpose (Cont'd)

The hydrologic analyses undertaken in this study, and in previous studies for the Island of Newfoundland, suggest that there exists a geographic trend in the variation of the timing of most hydrologic characteristics from north to south and, less significantly, from west to east. To make use of this trend in the regionalization analysis a geographic location parameter LOC was defined thus:

$$LOC = (\text{Longitude} - 52^{\circ}) + 4\ (\text{Latitude} - 46^{\circ})$$

NOTE: The co-ordinates 46° N and 52° W were selected as an appropriate datum to make the LOC parameter specific to the Island of Newfoundland.

I.2.2 Stream Flow Data

Water Survey of Canada (WSC), a division of the Water Resources Branch, Inland Waters Directorate, Environment Canada, publishes daily flow data from 56 current and 14 discontinued 'natural' flow gauging stations in the Island of Newfoundland. These data were available on magnetic tape for the period up to 1985 for the study. Many of these gauges are recent additions to the WSC network but complete data sets were available for the years 1981-85 at 33 locations.

It was assumed that flow conditions during this period would show a similar departure from mean flow conditions all over the island, (i.e. if this was a higher than average flow period in one region, it would be a higher than average flow period in all regions). Thus, although

I.2.2 Stream Flow Data (Cont'd)

the 1981-85 flow distributions might not be exactly the same as the long-term average distributions, the relative variations between different regions of the island should be preserved.

These gauging stations and six additional gauges with flow periods other than 1981-85, which were included to verify regional boundaries, are shown in Table I.1 and Figure I.1.

I.2.3 Flow Duration Analysis

A daily flow duration analysis was performed on each gauging station record. The flows exceeded 50 to 100% of the time were abstracted, at 10% intervals from each distribution and expressed as a percent of mean annual flow for the period (QMEAN). These six flow values were then accumulated for each station and the 39 values were ranked from maximum to minimum (i.e. the gauge with rank one has the highest flows over the lower 50% of the duration curve). This statistic gives an indication of how low flows drop during less than average flow periods.

A second measure of hydroelectric potential that can be derived from this analysis is the proportion of time that full use can be made of the flow in the river, under run-of-river conditions. Assuming an installed turbine discharge capacity of 1.5 x QMEAN at all locations, the percent of time for which flows exceed this value were extracted from the flow duration curve. During this period flow greater than the turbine discharge capacity would be wasted.

TABLE I.1

WSC GAUGING STATIONS USED IN THIS STUDY

WSC No.	Latitude N	Longitude W	LOC
02YA001	51 08	56 48	25.3
02YC001	50 36	57 09	23.6
02YD001	50 55	56 09	23.8
02YD002	50 56	56 07	23.9
02YF001	50 05	56 55	21.3
02YJ001	48 35	58 22	16.7
02YJ002	48 33	58 34	16.8
02YK002	48 37	57 56	16.4
02YK004	49 04	57 11	17.5
02YK005	49 20	56 40	18.0
02YL001	49 14	57 22	18.3
02YM001	49 31	56 07	18.1
02YM003	49 54	56 13	19.8
02YN002	48 15	57 50	14.8
02YO006	49 06	55 25	15.8
02YQ001	49 01	54 51	14.9
02YR001	48 48	54 13	13.4
02YR002	49 24	54 06	15.7
02YR003	49 02	53 53	14.0
02YS001	48 26	54 22	12.1
02ZA001	48 27	58 24	16.2
02ZB001	47 37	59 01	13.4
02ZD002	47 45	56 56	11.9

TABLE I.1 (Cont'd)

WSC GAUGING STATIONS USED IN THIS STUDY

WSC No.	Latitude N	Longitude W	LOC
02ZE001	47 57	55 55	11.7
02ZF001	47 45	55 26	10.4
02ZG001	47 13	55 20	8.2
02ZG002	47 07	55 16	7.7
02ZG003	46 52	55 47	7.2
02ZG004	47 27	54 51	8.6
02ZH001	47 57	54 17	10.0
02ZH002	47 55	53 57	9.6
02ZJ001	48 23	53 41	11.2
02ZK001	47 13	53 34	6.4
02ZK002	47 16	53 50	6.9
02ZL003	47 49	53 09	8.4
02ZM006	47 38	52 50	7.3
02ZM008	47 32	52 45	6.8
02ZM009	46 51	52 58	4.3
02ZN001	46 51	53 18	4.7

I.2.3 Flow Duration Analysis (Cont'd)

The results of these two flow duration analyses are given in Table I.2 and are plotted against the LOC parameter for each gauging station in Figure I.2. It is apparent from this diagram that there is very little evidence of regional grouping of gauges on the basis of these flow duration characteristics. From the accumulated exceedance analysis there is a slight tendency for rivers in the southeast to have proportionally higher low flows, during low flow periods, and rivers in the northwest to have proportionally lower low flows. However, in the intermediate central regions no pattern at all emerges.

From the second flow duration analysis results in Table I.2 it can be seen that the duration of flows less than 1.5 x QMEAN varies very little throughout the island (Mean 82%, standard deviation 2.3%) and shows no regional correlation.

Thus neither of these two flow duration characteristics is suitable to define homogeneous regions of hydroelectric potential.

I.2.4 Mean Monthly Flow Analysis

The mean monthly flow analysis was performed on the same data sets as the flow duration analysis. The results are presented in the form of three histograms. The central histogram presents the monthly means and the upper and lower histograms show the monthly means ± the monthly standard deviations, respectively. Preliminary observations of these mean monthly flow distributions show the following general trends from the northwest to the southeast of the Island:

TABLE I.2

FLOW DURATION RESULTS

WSC No.	Sum of Exceedences at 50,60,70,80,90,100% as % QMEAN	Rank	% Time Flow < 1.5xQMEAN	Rank
02YA001	282	2	82	18
02YC001	191	27	85	3
02YD001	111	39	81	21
02YD002	157	34	85	3
02YF001	121	37	83	11
02YJ001	263	7	85	3
02YJ002	192	26	82	18
02YK002	220	19	83	11
02YK004	249	11	83	11
02YK005	230	15	85	3
02YL001	179	31	83	11
02YM001	212	21	84	9
02YM003	119	38	85	3
02YN002	202	23	89	1
02YO006	144	35	80	30
02YQ001	255	9	81	21
02YR001	271	4	80	30
02YR002	190	29	80	30
02YR003	259	8	79	39
02YS001	275	3	83	11
02ZA001	208	22	82	18
02ZB001	163	33	81	21

TABLE I.2 (Cont'd)

FLOW DURATION RESULTS

WSC No.	Sum of Exceedences at 50,60,70,80,90,100% as % QMEAN	Rank	% Time Flow < 1.5xQMEAN	Rank
02ZD002	191	27	81	21
02ZE001	251	10	80	30
02ZF001	293	1	85	3
02ZG001	271	4	80	30
02ZG002	268	6	80	30
02ZG003	185	30	80	30
02ZG004	216	20	81	21
02ZH001	222	17	80	30
02ZH002	198	25	81	21
02ZJ001	175	32	81	21
02ZK001	240	12	87	2
02ZK002	238	13	83	11
02ZL003	222	17	84	9
02ZM006	138	36	81	21
02ZM008	201	24	83	11
02ZM009	234	14	80	30
02ZN001	226	16	81	21

I.2.4 Mean Monthly Flow Analysis (Cont'd)

- the lowest flow month changes from February to August;
- the critical year low flow month shifts from February to October;
- the peak flow month moves from May to April;
- the peak monthly flow decreases by approximately 50% in terms of QMEAN;
- the pronounced single peak distribution changes to a two-peak distribution, with the winter peak almost as high as the spring peak.

These changes are generally attributable to the variation in winter temperatures across the island and the consequent effect on winter runoff. In the northwest a large proportion of winter precipitation occurs as snow, making winter runoffs small, but providing a large volume of stored water for spring snowmelt. As a result runoff in the spring is dramatically higher than during the rest of the year. In the southeast much of the winter precipitation falls as rain, giving high flows in both winter and spring. Flows in the summer are low due to low rainfall and exhausted snowmelt runoff.

Five measures of the mean monthly flow distributions were abstracted from each gauging station summary, as below:

(i) the maximum mean monthly flow;
(ii) the maximum three consecutive mean monthly flows.

[These two characteristics are negative aspects of the flow pattern for a hydro potential development. This is because the higher the peak flow months are, the greater will be the volume of flow lost to energy generation].

I.2.4 Mean Monthly Flow Analysis (Cont'd)

(iii) the minimum mean monthly flow;
(iv) the minimum three consecutive mean monthly flows.

[These measures indicate how low and how persistent the minimum energy potential at a site might be, under run-of-river conditions].

(v) the maximum cumulative departure below QMEAN.

[This measure is important if a storage scheme is being considered. A large cumulative departure below mean annual flow indicates the need for proportionally higher storage to maintain a constant turbine discharge than a small cumulative departure]. The values for these measures were then ranked from lowest to highest, parameters (i), (ii) and (v) and from highest to lowest (iii) and (iv).

All of these flows are expressed as % QMEAN. Each series of these five measures was ranked, with low rank indicating a value favourable to hydroelectric energy generation. The ranking of these five characteristics for each of the study gauges is presented in Table 2.3. Figure 2.3 shows the sum of these five flow ranks (RANK) of each gauging station plotted against the location parameter LOC. This diagram shows a definite relationship between RANK and geographic location of each gauging station. The linear regression equation describing this relationship has a correlation coefficient of 0.89 and can be expressed as:

$$\text{RANK} = 8.4\ \text{LOC} - 13$$

TABLE I.3

RANKING OF MEAN MONTHLY FLOW CHARACTERISTICS

WSC No.	Max Month Rank	Max 3 Month Rank	Min Month Rank	Min 3 Month Rank	Cummulative Departure Rank	Sum of Ranks (RANK)
02YA001	27	31	13	23	31	125
02YC001	32	34	34	37	35	172
02YD001	38	38	37	39	39	191
02YD002	37	39	32	34	38	180
02YF001	36	36	36	38	37	183
02YJ001	28	27	6	10	25	96
02YJ002	22	21	17	24	22	106
02YK002	29	26	15	18	23	111
02YK004	31	30	13	19	30	123
02YK005	35	33	22	26	33	149
02YL001	34	35	31	33	34	167
02YM001	33	32	17	20	32	134

TABLE I.3 (Cont'd)

RANKING OF MEAN MONTHLY FLOW CHARACTERISTICS

WSC No.	Max Month Rank	Max 3 Month Rank	Min Month Rank	Min 3 Month Rank	Cummulative Departure (RANK)	Sum of Ranks
02YM003	39	37	39	35	36	186
02YN002	30	28	23	22	27	130
02YO006	25	29	32	24	29	139
02YQ001	23	17	23	12	14	89
02YR001	17	19	19	27	21	103
02YR002	20	25	38	36	28	147
02YR003	21	23	30	31	24	129
02YS001	10	8	9	3	2	32
02ZA001	26	21	28	17	19	111
02ZB001	18	20	2	13	20	73
02ZD002	24	18	6	7	18	73
02ZE001	16	13	23	30	17	99
02ZF001	13	12	9	15	16	65
02ZG001	1	2	3	4	2	12
02ZG002	7	6	21	16	12	62

TABLE I.3 (Cont'd)

RANKING OF MEAN MONTHLY FLOW CHARACTERISTICS

WSC No.	Max Month Rank	Max 3 Month Rank	Min Month Rank	Min 3 Month Rank	Cummulative Departure Rank	Sum of Ranks (RANK)
02ZG003	5	5	11	1	1	23
02ZG004	2	3	12	2	4	23
02ZH001	12	14	26	29	15	96
02ZH002	11	10	1	6	7	35
02ZJ001	19	24	35	32	26	136
02ZK001	3	1	5	4	5	18
02ZK002	4	4	6	8	8	30
02ZL003	7	11	19	11	6	54
02ZM006	14	15	27	27	11	94
02ZM008	15	16	29	21	13	94
02ZM009	9	7	15	14	10	55
02ZN001	5	9	3	9	9	35

I.2.4 Mean Monthly Flow Analysis (Cont'd)

This mean monthly flow distribution characteristic has been used as the basis for regionalization in the Island of Newfoundland.

I.2.5 Regional Definition

The analysis undertaken in this study suggests that there are no discrete, homogeneous hydrologic regions within the Island of Newfoundland. Rather there exists a general trend for mean monthly flow patterns to change uniformly in an approximate NNW to SSE direction.

However, the parametric curve analysis, used later to estimate turbinable flow, requires the use of a number of representative regional index gauges, with long periods of record, from which estimates of turbinable flow for ungauged locations can be made. Thus it is convenient to divide the Island of Newfoundland into discrete regions from which index gauges can be selected.

Four regions have been defined, similar to those from earlier studies, with a like number of gauges in each. On the basis of the geographic location parameter LOC, regional boundaries would be straight lines with a constant value of LOC. However, straight line divisions are impractical in hydrology as they cut through river basins and topographic divides, so regional boundaries have been structured on WSC drainage divides.

The four regions proposed are shown in Figure I.4. The following numbering and nomenclature has been adopted:

I.2.5 Regional Definition (Cont'd)

Region 1 : South-East

This is the smallest of the four regions, comprising the Burin Peninsula and the southern half of the Avalon Peninsula. Included in this region are WSC groups 2ZG, 2ZK, 2ZM (south of Tors Cove) and 2ZN. Winter temperatures are highest in this part of the island and runoff peaks occur in both spring and winter. Lowest flows occur in summer.

Introduction of minimal storage can appreciably increase the turbinable flow potential of rivers in this region.

Region 2 : South-Central

The South-Central Region comprises basins draining to the south coast of Newfoundland, excluding Region 1, plus areas on the east coast, south of Bonavista Bay. This includes WSC groups 2YS, 2ZB, 2ZC, 2ZD, 2ZE, 2ZF, 2ZH, 2ZJ, 2ZL and 2ZM (north of Tors Cove). Runoff patterns are similar to Region 1, but spring peaks are more pronounced and winter peaks are lower.

Turbinable flows can still be improved by relatively small storages.

Region 3 : North-Central

Region 3 stretches across the island from the west coast to the east coast, draining mainly to the north. The WSC groups included in this region are 2YJ, 2YK, 2YN, 2YO, 2YP, 2YQ, 2YR and 2ZA. The North-Central Region has the least stable flow pattern of the four regions. Flows are

I.2.5 Regional Definition (Cont'd)

still low in summer but also fall significantly in winter. Spring runoff occurs later than in the south, rising and falling dramatically. A second, smaller peak still occurs in late fall.

Significant storage is required to improve turbinable flows.

Region 4 : North-West

The North-West Region is composed mainly of the northern peninsula of the Island of Newfoundland. The region encloses the WSC groups, 2YA, 2YB, 2YC, 2YD, 2YE, 2YF, 2YG, 2YH, 2YL and 2YM. The typical flow pattern for Region 4 is virtually single peaked, with the snowmelt peak persisting for two months and low flows occurring in winter.

Large storage is needed to provide constant turbinable flows.

I.2.6 Regional Index Gauges

Having defined the hydrologic regions, flow records representative of each region were required for further hydro potential assessment. The following criteria were used to chose index gauge records that are typical of each region:

- a long flow record, for a period common to all four index gauges;
- a mean monthly flow distribution typical of the region;

I.2.6 Regional Index Gauges (Cont'd)

- a drainage area near the average of the stations used to define the region;
- a central location in the region.

The four regional index gauges selected are shown in Table I.4.

I.3 PARAMETRIC CURVE ANALYSIS

I.3.1 Introduction

The methodology used in this study to compare the potential hydroelectric energy benefits at different sites, and for various combinations of storage and installed capacity at individual sites, is called parametric curve analysis, Monenco (1984). The parametric curves developed here give an indication of the percent of mean annual flow at a particular location that can be used to produce energy for different storage/installed capacity scenarios. An option has also been included to assess the affect of having storage remote from the head pond for a fixed turbine discharge capacity equal to 1.5 QMEAN.

I.3.2 Preparation of the Curves

The parametric curves are prepared using a reservoir simulation program PCURVE. This program converts flows, storage and installed discharge capacity to percentages of mean annual flow, then performs a daily water balance, using the last two parameters as boundary conditions, for

TABLE I.4

REGIONAL INDEX GAUGES

Region	River Gauge	WSC No.	Drainage Area Km^2	Flow Record
1	Rocky River near Colinet	02ZK001	285	1950 - 1985
2	Piper Hole River near Mothers Brook	02ZH001	764	1953 - 1985
3	Hinds Brook near Grand Lake	02YK004	529	1957 - 1979*
4	Torrent River at Bristol's Pool	02YC001	624	1960 - 1985

* Years 1980-85 were synthesized from gauge 02YK005, the Sheffield River near Trans Canada Highway (1973-85).

After extending Hinds Brook record to 1985 a common flow period of 26 years, 1960-85, was available for the parametric curve analysis. Mean monthly flow distributions for the index gauges for this period of record are shown in Figure I.5.

26 complete years. The simulation is repeated for a specified range of boundary conditions giving a three dimensional matrix of storage, installed discharge capacity and turbinable (energy-producing) flow. This matrix is plotted to give the parametric curves.

PCURVE is run twice for each region. Once to produce typical annual energy-producing flow estimates against installed turbine discharge capacity and again to give estimates of energy producing flows against the percent of basin runoff, passing through storage. These two sets of curves are shown in Figures I.6 to I.15.

I.3.3 Use of the Curves

To make use of the parametric curves for a potential hydroelectric site, the following data must be collected:

- The drainage area to the site from topographic mapping.
- The average annual runoff at the site from the iso-runoff map.
- The latitude and longitude of the site in degrees and decimals.
- An estimate of available storage, converted to a percentage of mean annual runoff.
- An estimate of the average operating head.
- The total rated discharge capacity of the turbines to be installed, as a percentage of mean annual flow.
- The total efficiency of the system.

I.3.3 Use of the Curves (Cont'd)

If storage is remote from the head pond the percent of the total basin runoff passing through storage must be estimated as:

$$\frac{\text{Drainage area above storage x MAR* above storage dams}}{\text{Drainage area at site x MAR at site}}$$

NOTE: The lines of storage in the curves of turbinable flow vs. % basin runoff passing through storage are expressed as % of average annual runoff above the storage location.

The geographic location parameter LOC is computed from the latitude and longitude (in degrees and decimals) of the site using:

$$\text{LOC} = (\text{Longitude} -52^{\circ}) + 4\ (\text{Latitude} -46^{\circ})$$

Using this value of LOC and Figure 2.4, find the corresponding value of RANK for the site and also which regional index gauges have LOC values above and below that of the site.

TABLE I.5

LOC AND RANK VALUES FOR THE INDEX GAUGES

REGION	LOC	RANK
1	6.4	18
2	10.0	96
3	17.5	123
4	23.6	172

*MAR = mean annual runoff in mm from Exhibit I.

I.3.3 Use of the Curves (Cont'd)

Using the appropriate regional curves (with index gauge LOC values above and below the site value), two estimates of turbinable flow, expressed as percentages of mean annual flow, Ka and Kb are abstracted for the required combination of storage and installed capacity. The turbinable flow percentage, Ks, for the site is then estimated as:

$$Ks = \frac{(RANKS - RANKb)\ Ka + (RANKa - RANKs)\ Kb}{(RANKa - RANKb)}$$

Where: RANKa,b are the RANK values for regional index gauges with LOC values above and below LOCs, from Table 5.

NOTE: If LOCs is less than 6.4 or greater than 23.6, Ks is read directly from the parametric curves for Region 1 or 4, respectively.

The average annual energy potential of the site is then computed using the equation:

$$E = HKsQg \times 8760$$

Where: E = the annual energy in kWh per annum
= the total efficiency of the energy system, expressed as a decimal
g = acceleration due to gravity in m/s^2
H = the average net head in metres
Q = the mean annual flow at the site in m^3/s
Ks = turbinable (useable) flow factor.

I.4 FLOOD HYDROLOGY

I.4.1 Background

Several attempts have been made to produce a regional flood estimation formula for the Island of Newfoundland: Poulin (1971), Ryan (1982), Acres (1985) and Panu et al (1984). These attempts were all based on the "index flood" method or derivatives thereof. In the Index method a statistical correlation is developped between the mean annual flood (Q2) and hydrologic and physiographic parameters that effect flood peak magnitudes. This method pre-supposes that similar climatic conditions prevail throughout the area of interest, thus the correlations apply only within a region of homogeneous hydrology. Where large geographic areas are of interest it may be necessary to sub-divide the area into several hydrologically homogeneous regions (for floods).

The most detailed analysis, completed to data, is the "Regional Flood Frequency Analysis for the Island of Newfoundland" by Panu et al (henceforward RFFA). They sub-divided the Island into two hydrological regions - a southern region (including the Avalon Peninsula) and a Northern Region. They developed sets of correlations for both regions and a set for the Entire Island - relating Q2, Q10, Q20 and Q100 and significant hydrologic and physiographic parameters.

The most important parameters affecting flooding were found to be (in order of significance), drainage area, area [A], mean annual runoff [MAR], area controlled by lakes and swamps [ACLS]*, shape [SH] and latitude [LAT] (for Northern Region). Several other parameters were also

* Defined as shown in Figure I.14.

tested in development of these formulae, notably: basin slope and drainage density. These parameters were not found to be statistically significant based on the data set used in the RFFA analysis.

Factors, such as the basin slope may nonetheless be of the physical significance, and the RFFA formula may give erroneous results if applied to basins having slopes that are much different from those in the RFFA data set [reproduced in Table I.6].

ShawMont's experience in using the RFFA formulae indicate that they give good results when applied within the parameter range for which they were derived - see Table I.7. The principal difficulties were found to arise in the Southern and Entire Island correlation when ACLS < 55% and in the Northern formula when A < 240 km^2.

Because of these shortcomings the RFFA does not provide a convenient "universal" formula of the type required for an extensive hydro inventory survey. Instead a three parameter (Figure I.15) flood nomograph has been developed to facilitate quick estimation of design flood peaks. In developing this nomograph a number of comprises had to be made, as explained below:

i) Q2 was computed from an Entire Island correlation giving Q2 as a function of A, MAR and ACLS [for values of ACLS > 55%]. Omissions of SH results in a small loss in accuracy.

TABLE I.6

FLOOD ANALYSIS: PHYSIOGRAPHIC AND HYDROMETEORLOGIC DATA BASE

STATION NAME AND NUMBER	DRAINAGE AREA (km^2)	LAKE AREA (km^2)	SWAMP AREA (km^2)	FOREST AREA (km^2)	BARREN AREA (km^2)	LENGTH OF MAIN CHANNEL (km)	ELEVATION OF BASIN DIVIDE IN VICINITY OF MAIN CHANNEL (m)	SLOPE OF MAIN CHANNEL (%)	DRAINAGE DENSITY (km/km^2)
Torrent River at Bristol's Pool (02YC001)	624	82.36	21.96	208.83	310.85	48.28	478.6	.991	.755
Beaver Brook near Roddickton (02YD001)	237	10.93	8.56	191.03	26.50	40.62	327.7	.807	.339
Cat Arm River above Great Cat Arm (02YF001)	611	51.39	28.91	420.69	110.01	30.17	250	.829	.582
Harry's River below Highway Bridge (02YJ001)	640	35.43	55.24	505.48	43.85	60.00	509	.848	1.120
Lewaseechjeech Brook at Little Grand Lake (02YK002)	470	46.47	29.05	258.25	136.23	54.88	506.8	1.022	.627
Sheffield River near TransCanada Highway (02YK003)	391	37.36	29.70	264.59	59.34	38.09	378	.992	.191
Hinds Brook near Grand Lake (02YK004)	529	62.54	125.41	186.26	154.79	49.29	320.1	.649	.637
Upper Humber River near Reidville (02YL001)	2110	110.0	132.20	1561.8	306.01	118.8	678.1	.571	.786
Gander River at Big Chute (02YAQ001)	4400	375.3	366.80	3355.2	302.78	133.8	297.2	.222	.452
Middle Brook near Gambo (02YR001)	267	46.75	18.33	199.66	2.26	49.25	176.7	.359	.255
Terra Nova River at Eight Mile Bridge (92YS001)	1290	117.5	266.77	715.2	190.5	105.0	207.3	.197	.726
Southwest Brook at Terra Nova National Park (02YS003)	36.7	0.78	5.06	30.68	0.18	11.17	143.2	1.282	.641
Isle Aux Morts River below Highway Bridge (02ZB001)	205	14.54	12.88	17.21	160.37	33.27	443.5	1.333	.720
Salmon River at Long Pond (02ZE001)	2640	358.5	55.0	918	1308.5	100.4	122	.120	.363
Bay du Nord River at Big Falls (02ZF001)	1170	216.4	60.03	377.18	516.37	69.11	282	.408	.612
Garnish River near Garnish (02ZG001)	205	18.70	1.98	54.29	130.03	44.74	370.3	.828	.547
Piper's Hole River at Mothers Brook (02ZH001)	764	137.5	365.77	82.00	178.72	50.86	207.2	.407	.709
Come by Chance River near Goobies (02ZH002)	43.3	3.41	0.86	17.52	21.51	17.00	109.7	.645	1.110
Rocky River near Colinet (02ZK001)	285	29.39	4.61	145.27	105.73	45.22	165.4	.366	1.005
Northeast Pond River at Northeast Pond (02ZM006)	3.90	0.15	0.67	2.94	0.14	2.63	64.1	2.437	1.038
Northwest Brook at Northwest Pond (02ZN001)	53.3	6.68	0.01	4.60	42.02	14.60	93	.634	1.089

From Panu et al (1984)

I.4.1 Background (Cont'd)

ii) Treatment of the entire Island as a single homogeneous hydrologic zone, extends the data base and parameter range, but with some loss of precision as the assumed similarity of hydro-meteorlogical conditions is less true. The practical effects of this were not found to be significant when predictions from the Southern and Entire Island correlations are compared. Comparisons between predictions using the Northern and Entire Island correlations were found to be less satisfactory. However, the predictions of the Northern formula were found to be manifestly incorrect when applied to small drainage areas < 240 km^2, Sharp and Kendal (1986).

It is typically these smallar drainage areas that will be of interest in this study. For such drainage area sizes the Entire Island formula gives larger, and hence more conservative values for Q2.

iii) To account for values of ACLS < 55%, a relationship for ACLS = 0%, for a region having a MAR = 1000 mm was developed. This derivation uses the SCS Method, as described in the Design of Small Dams, BUREC (1976). A spring flood event was assumed comprising a spring rainfall and snowmelt. Rainfall-intensity-duration analysis from Deer Lake, an area with MAR = 1000 mm was used. Typical main channel lengths ($L = 2.1\sqrt{A}$, km) and slopes (S = 0.8%) were assumed and the time of concentration computed using Ogievshii's formula, as suggested in the ADB Water Resources Report - Shawinigan and MacLaren (1968). Analyses were carried out for drainage areas of 500 km^2 and 50 km^2 to establish a line of ACLS = 0%. Intermediate values for ACLS were estimated by linear interpolation between ACLS = 55% and ACLS = 0%.

I.4.1 Background (Cont'd)

iv) Design flood peaks are estimated by multiplying the estimated value of Q2 by factors, as below:

Q150	=	2.06 x Q2
Q1000	=	2.75 x Q2
Q10000	=	3.60 x Q2

I.4.2 Application of FLood Nomograph

Flood peak determination requires collection of the following input data:

i) Drainage Area [A] in km^2, planimeter off 1:50,000 topo maps.

ii) Area Controlled by Lakes and Swamps [ACLS], as a percent of A, planimeter off 1:50,000 topo maps following procedures shown in Figure I.14.

iii) Mean Annual Runoff [MAR], in mm, value at centroid of basin, from Exhibit 1.

Use of the flood nomograph is illustrated in Figure I.15.

The value of the design flood obtained from the nomograph should be treated as a preliminary estimate. For design an experienced hydrologist should be consulted.

TABLE I.7

REGIONAL FLOOD FREQUENCY ANALYSIS,

PARAMETER RANGE

	ENTIRE ISLAND	NORTH REGION	SOUTH REGION
A	3.9 - 4400 km^2	240 - 4400 km^2	3.9 - 2600 km^2
MAR	790 - 2100 mm	790 - 1400 mm	930 - 2100 mm
ACLS	55 - 100%	-	55 - 100%
LAT	-	48.379 - 50.943°	-
SHAPE	1.24 - 2.45	-	1.24 - 2.45
NO. OF STATIONS USED IN ANALYSIS	21	10	11

Where:

A = Drainage Area (km^2)

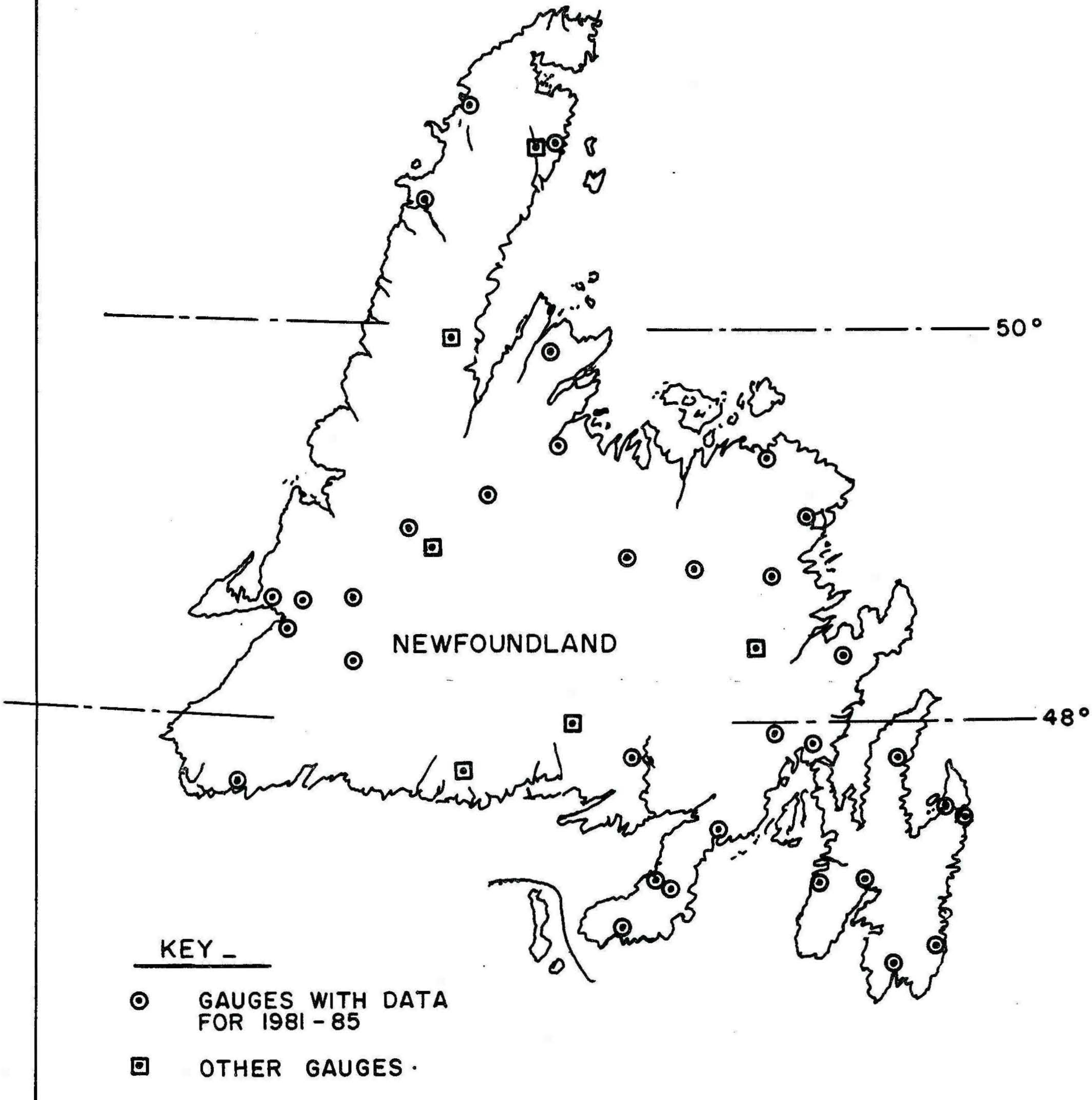
MAR = Mean Annual Runoff (mm)

ACLS = Area Controlled by Lakes and Swamps (%)

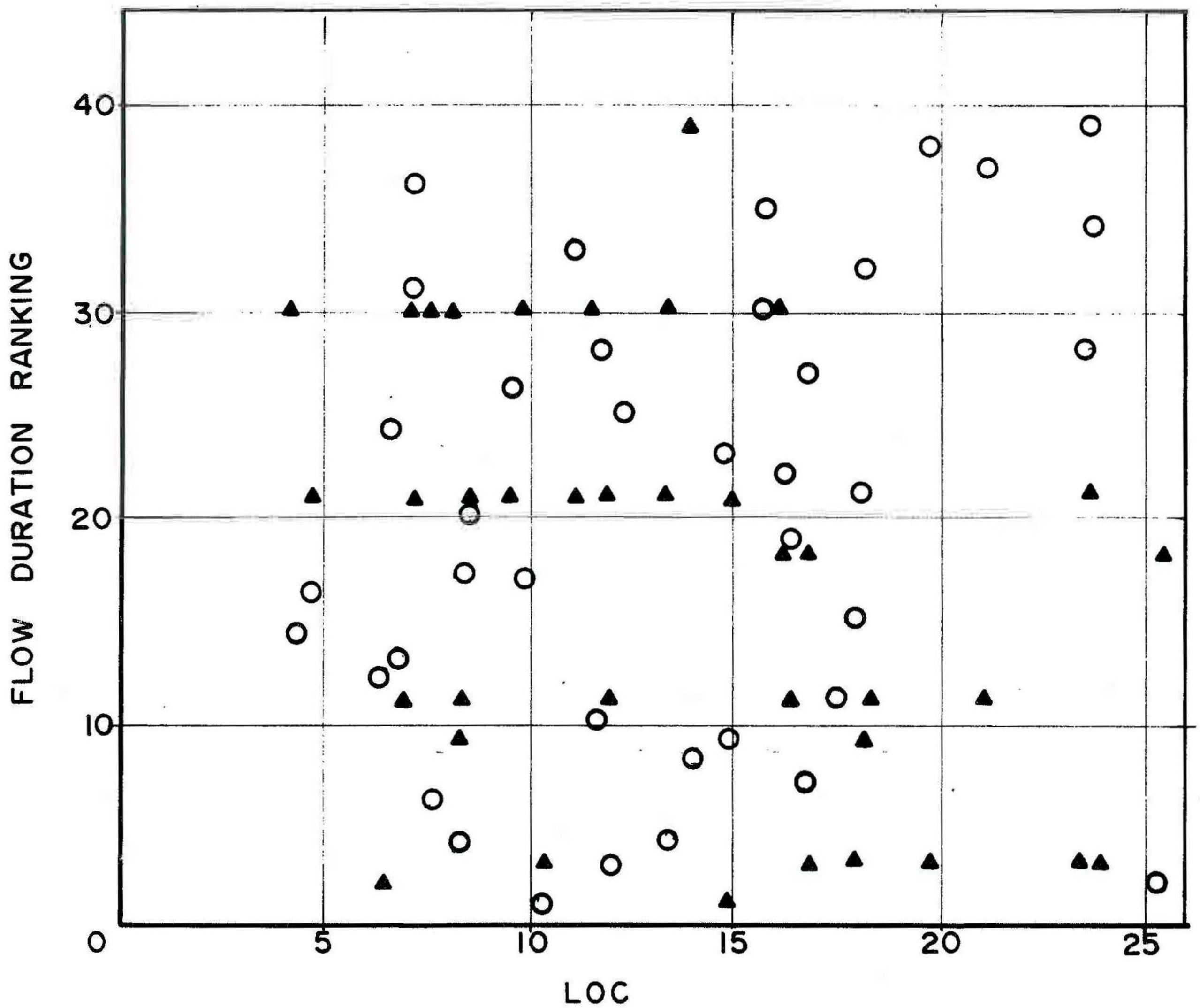
LAT = Latitude

SH = Shape factor = $\frac{0.28 \times [\text{Basin Perimeter in km}]}{\sqrt{A}}$

FIGURES



WATER SURVEY OF CANADA GAUGING STATIONS USED IN THE STUDY.

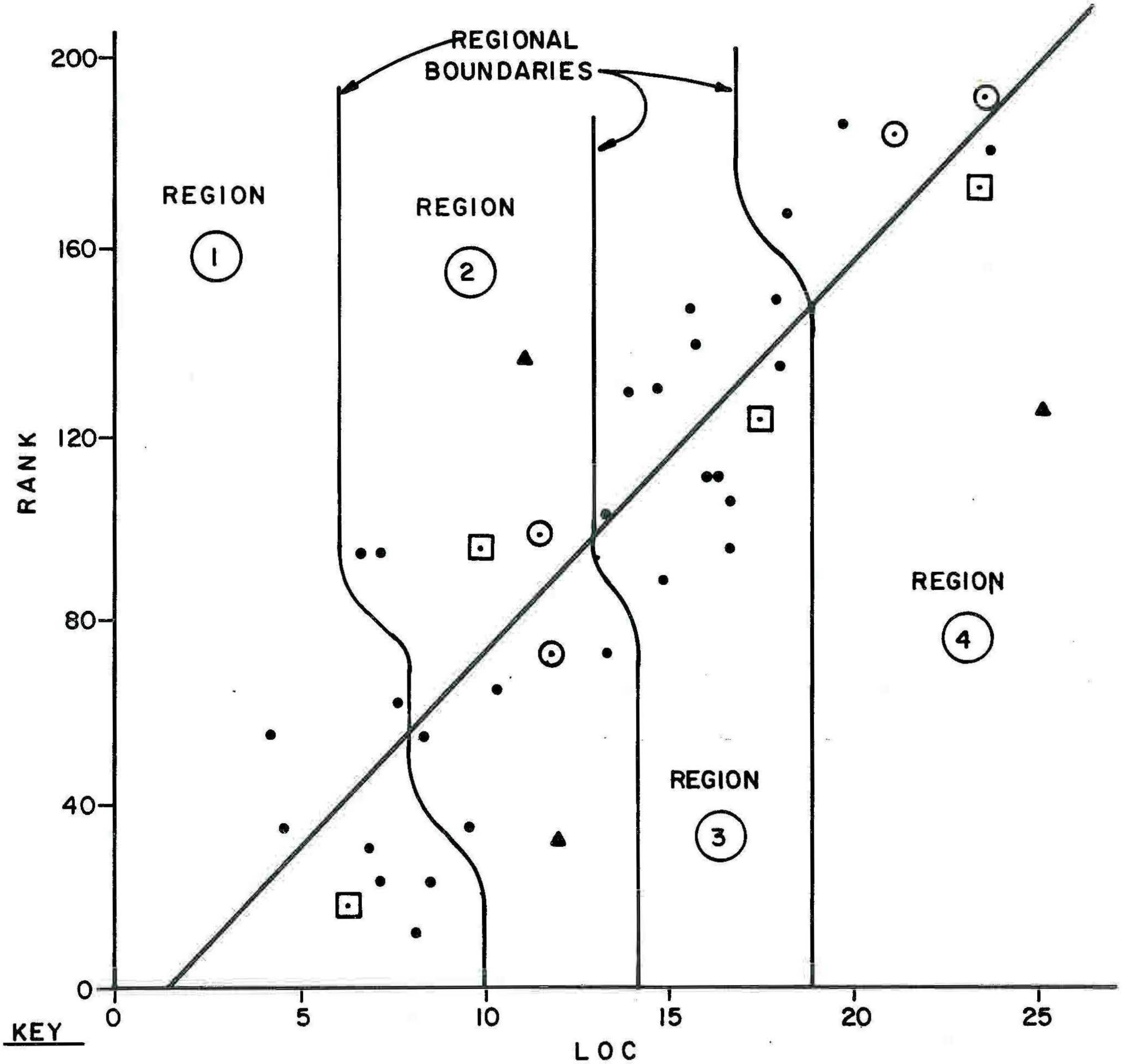


KEY

○ SUM OF EXCEEDENCES RANKING

▲ % TIME < 1.5 Q MEAN RANKING

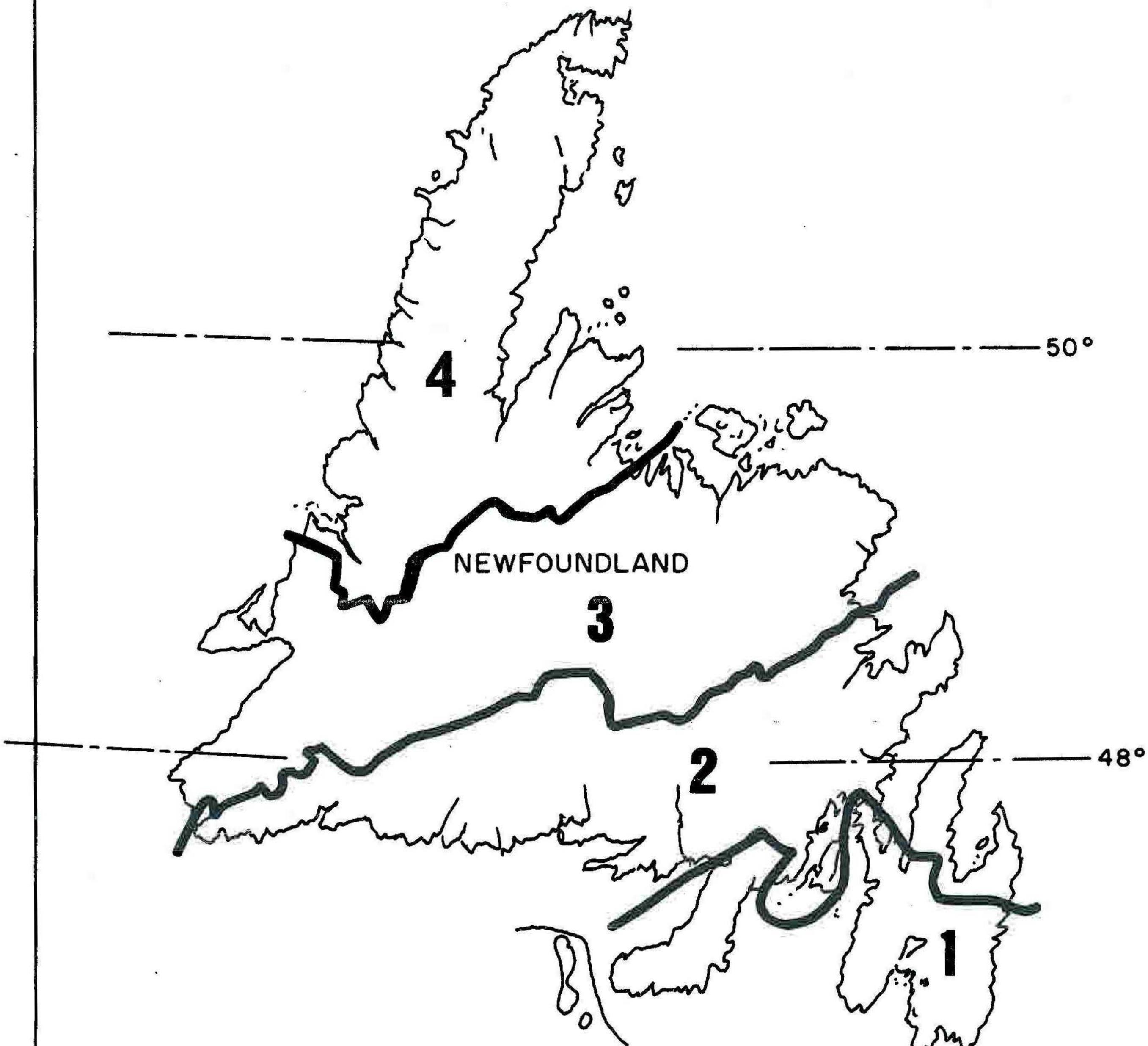
FLOW DURATION RANK vs LOC PARAMETER



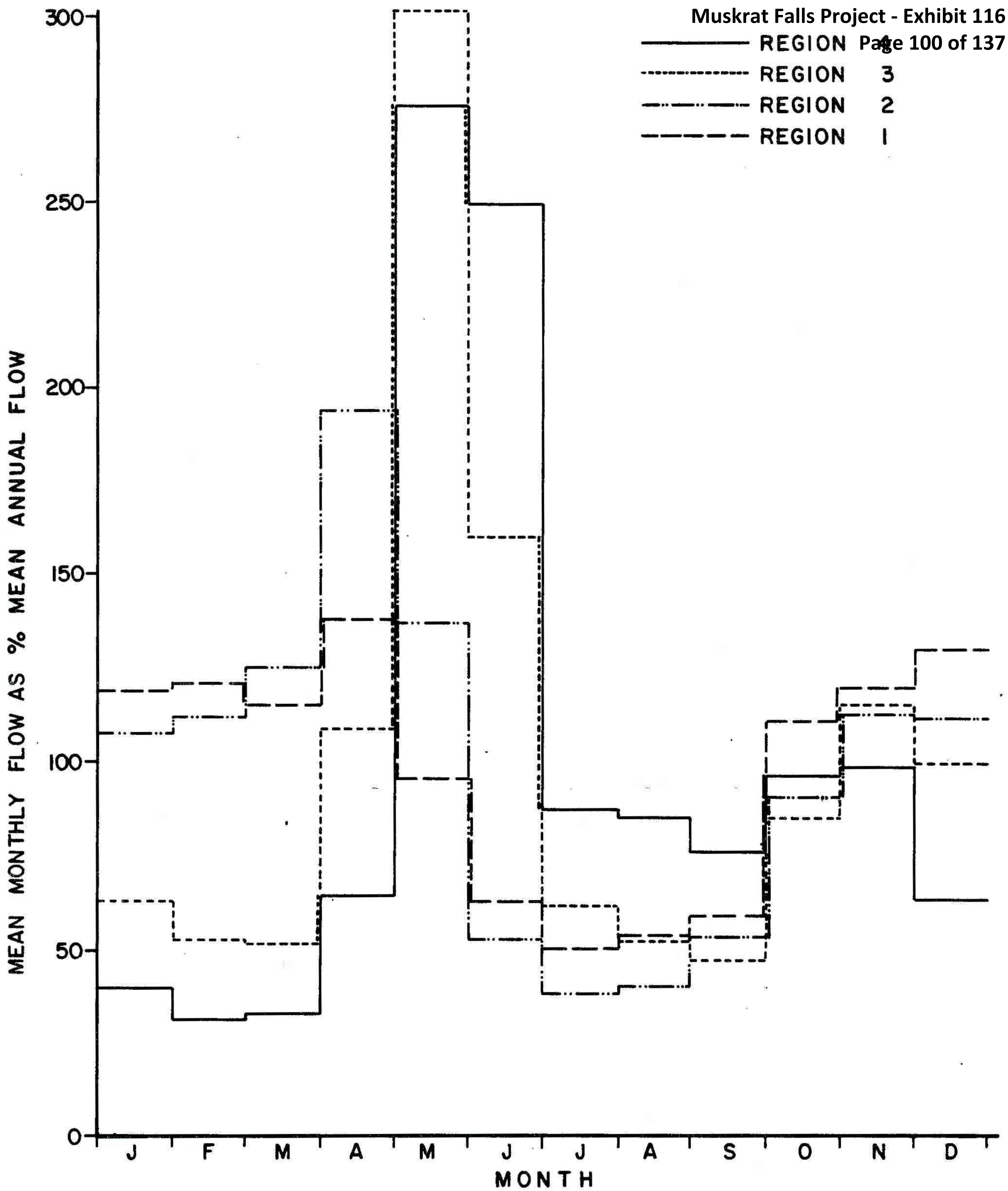
KEY

- 1981 - 85 FLOWS
- FLOWS FROM OTHER PERIODS
- REGIONAL INDEX GUAGE
- POINT EXCLUDED FROM REGRESSION ANALYSIS

MEAN MONTHLY FLOW RANK vs LOC PARAMETER



HYDROLOGIC REGIONS



REGIONAL HISTOGRAMS OF MEAN MONTHLY FLOWS
FROM 26 YEARS OF DATA (1960-85)

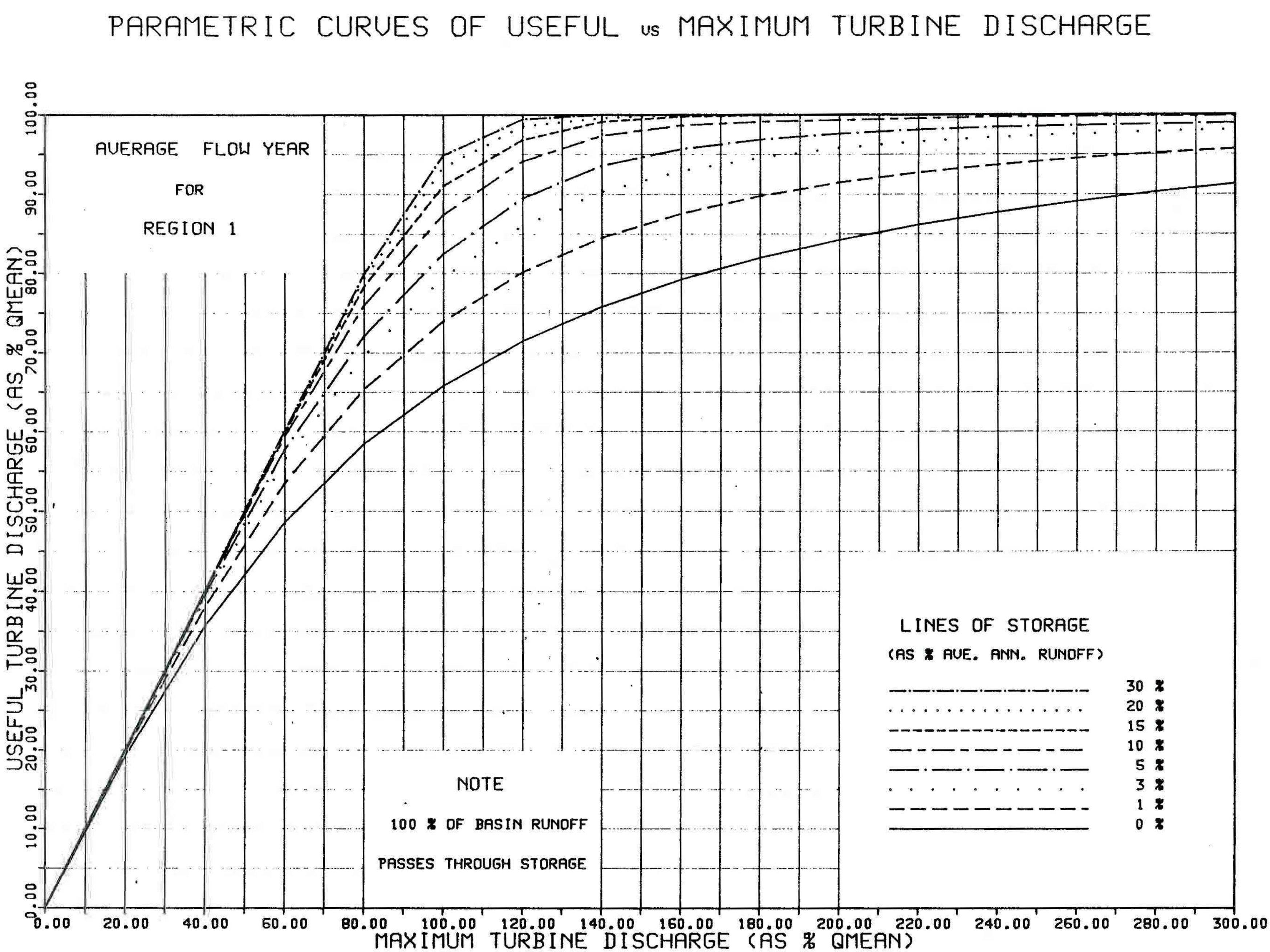

PARAMETRIC CURVES OF USEFUL vs MAXIMUM TURBINE DISCHARGE
AVERAGE FLOW YEAR
FOR
REGION 1
USEFUL TURBINE DISCHARGE (AS % QMEAN)
MAXIMUM TURBINE DISCHARGE (AS % QMEAN)
0.00
10.00
20.00
30.00
40.00
50.00
60.00
70.00
80.00
90.00
100.00
120.00
140.00
160.00
180.00
200.00
220.00
240.00
260.00
280.00
300.00
NOTE
100 % OF BASIN RUNOFF
PASSES THROUGH STORAGE
LINES OF STORAGE
(AS % AVE. ANN. RUNOFF)
30 %
20 %
15 %
10 %
5 %
3 %
1 %
0 %

Figure I.6

PARAMETRIC CURVES OF USEFUL vs MAXIMUM TURBINE DISCHARGE

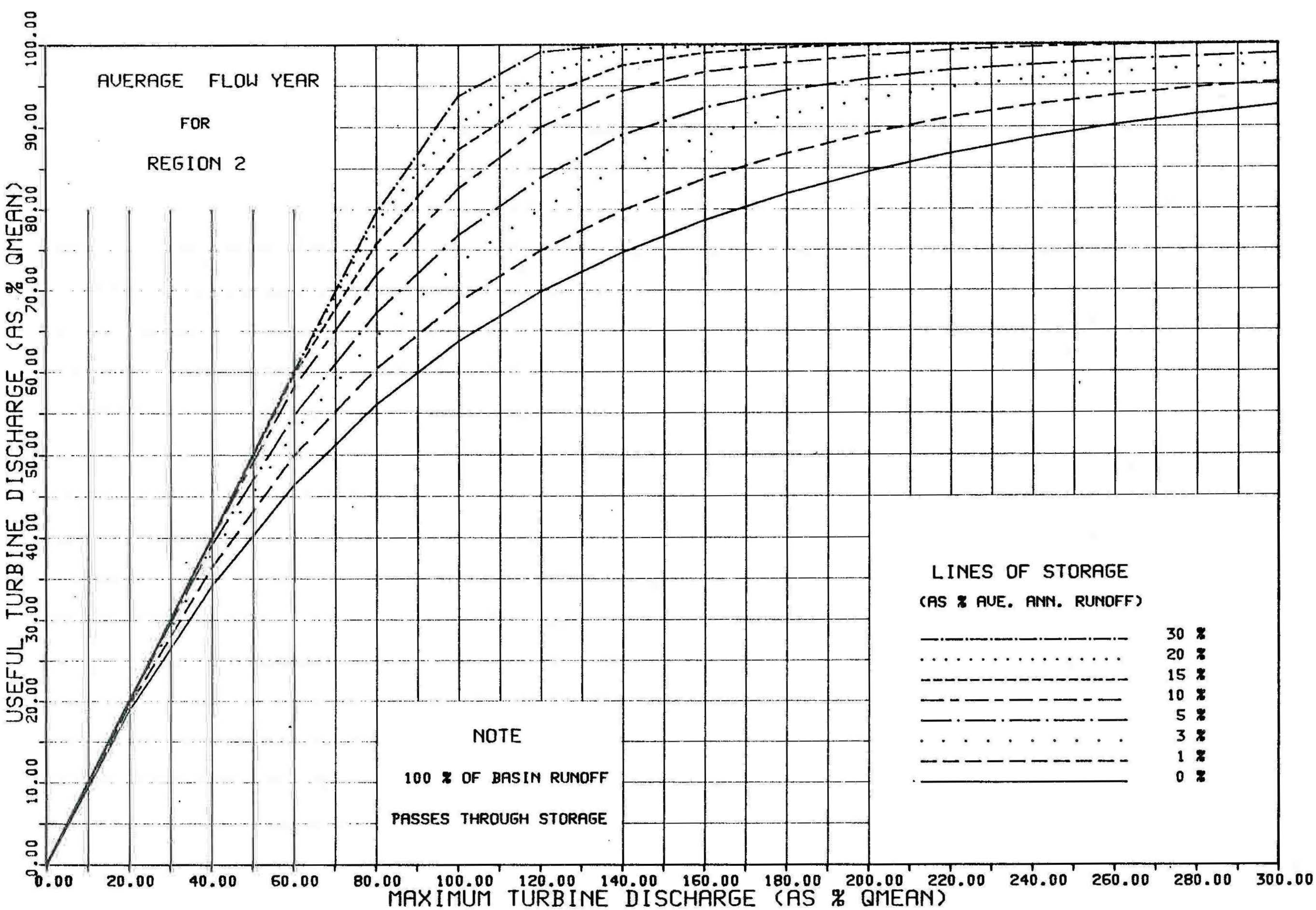


Figure I.7

PARAMETRIC CURVES OF USEFUL vs MAXIMUM TURBINE DISCHARGE

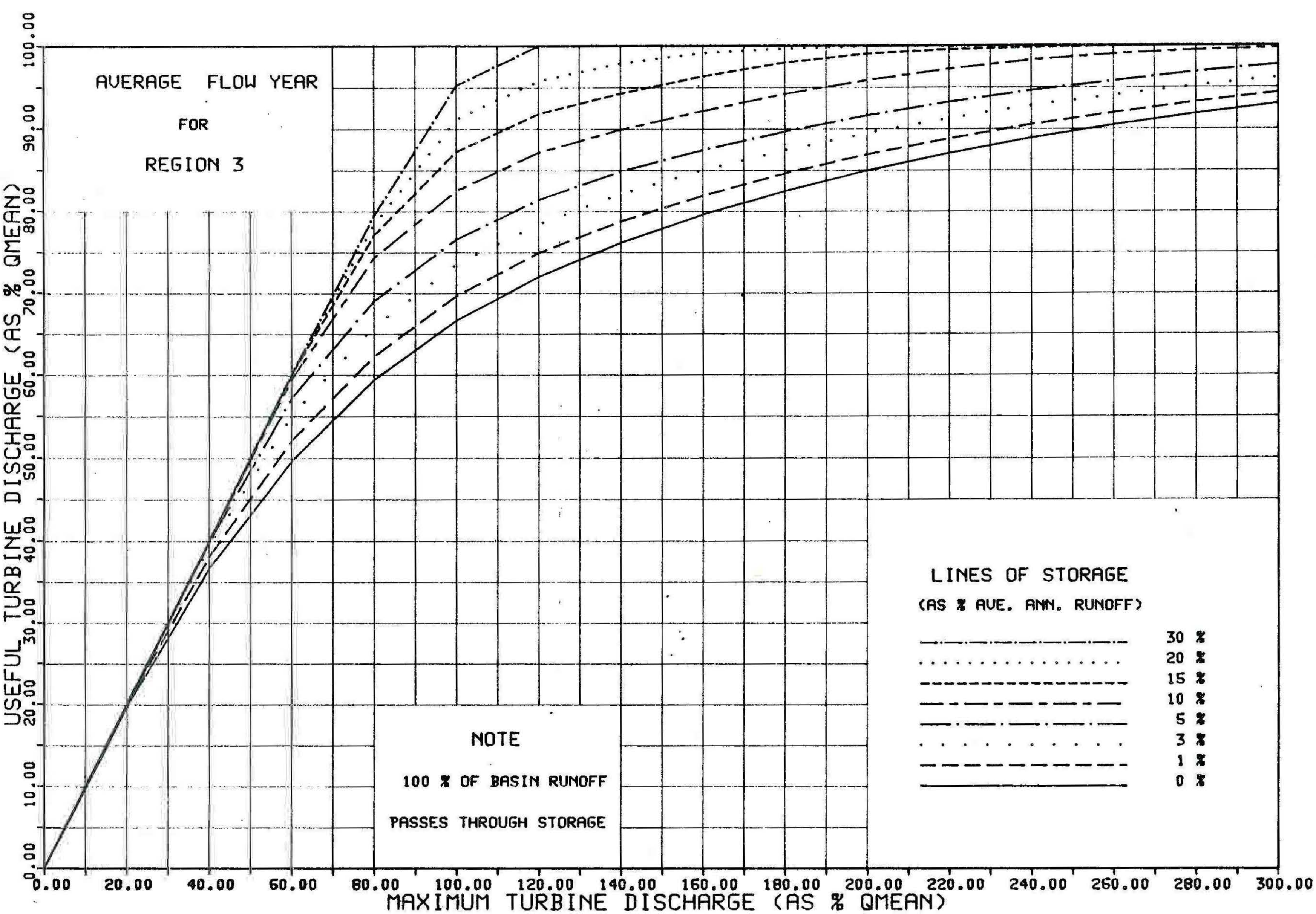


Figure I.8

PARAMETRIC CURVES OF USEFUL vs MAXIMUM TURBINE DISCHARGE

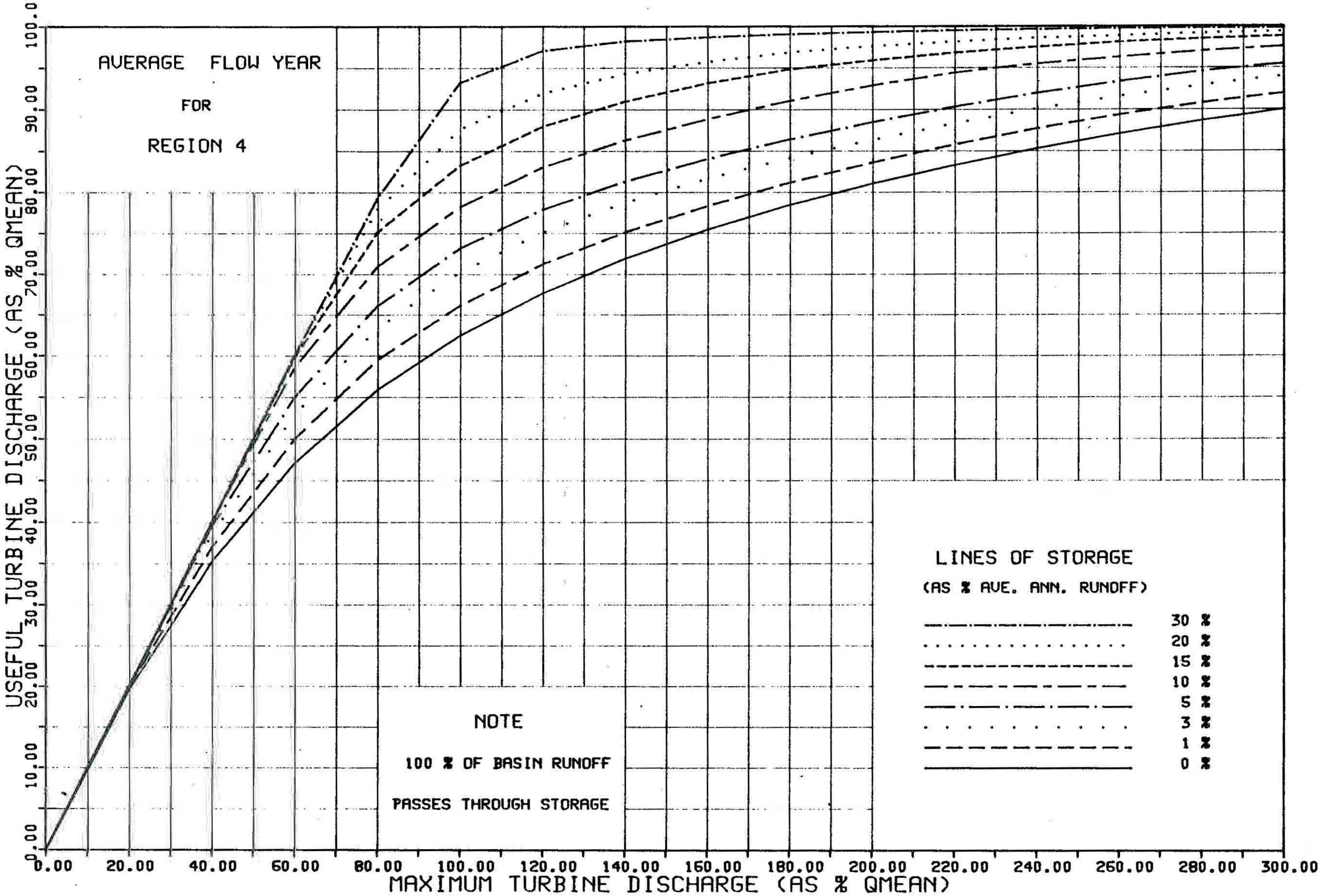


Figure I.9

PARAMETRIC CURVES OF USEFUL TURBINE DISCHARGE vs REGULATED BASIN RUNOFF

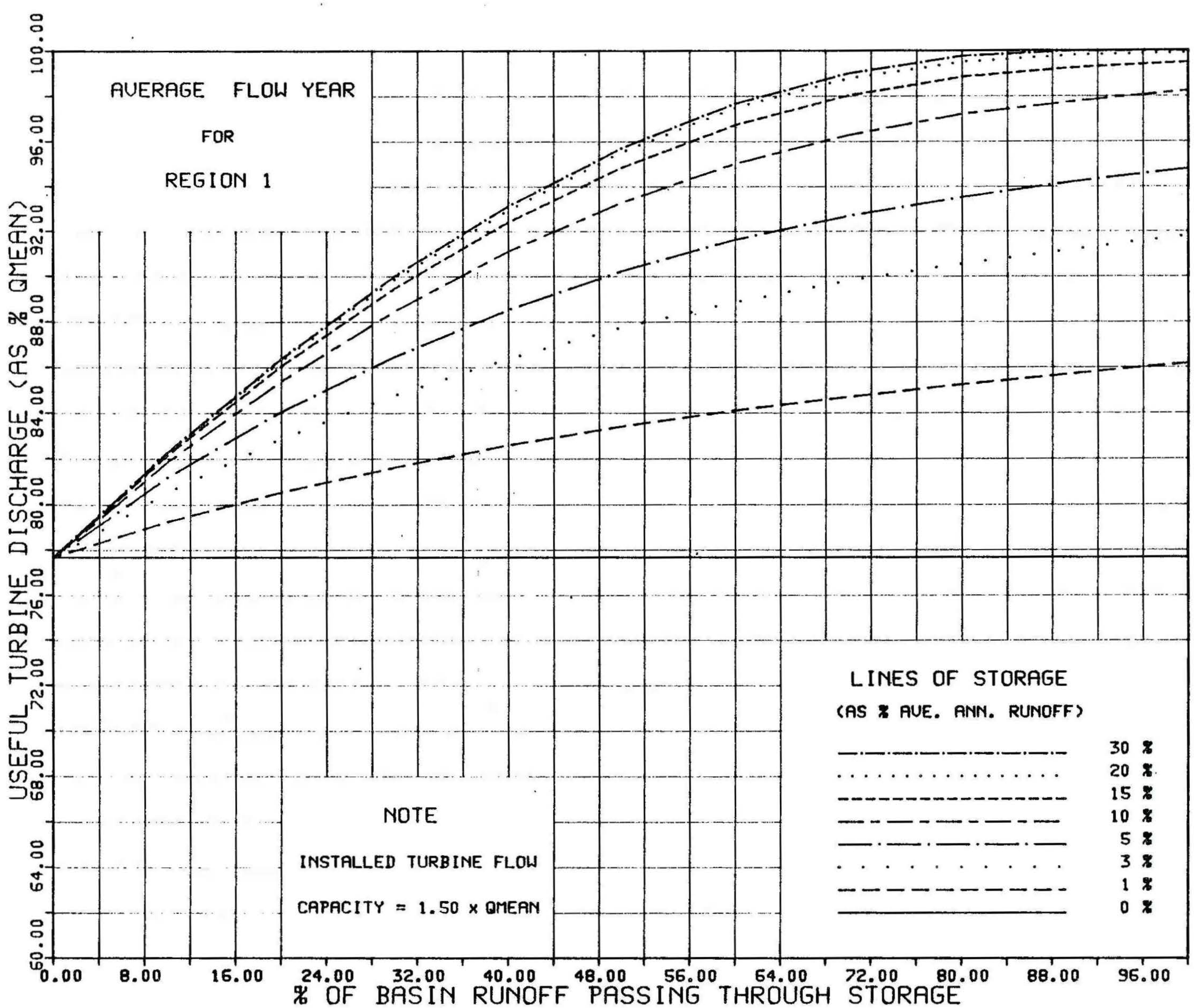


Figure I.10

Charts-Inc CHART NO. CI-1002-RB 03991

PARAMETRIC CURVES OF USEFUL TURBINE DISCHARGE vs REGULATED BASIN RUNOFF

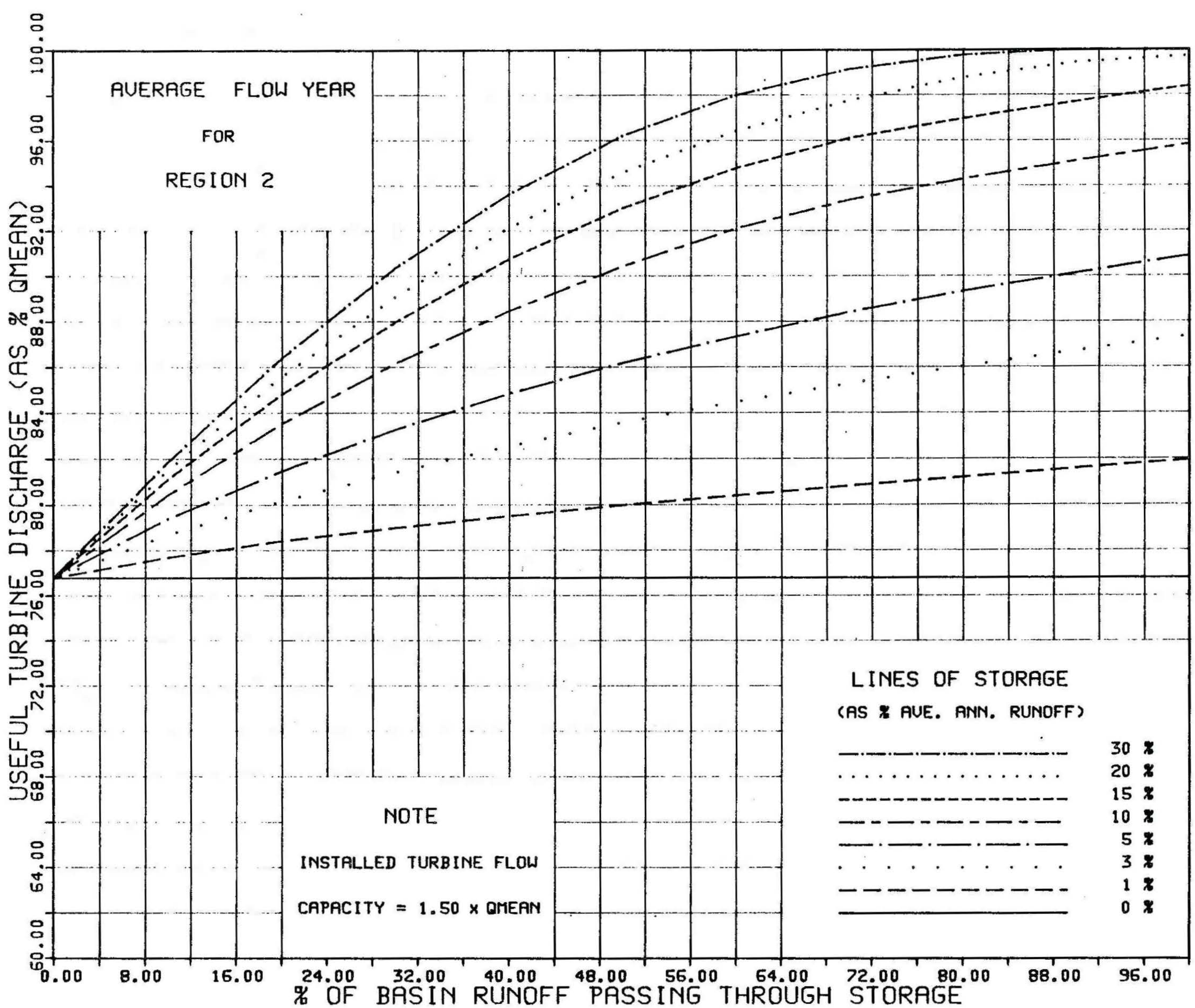


Figure I.11

Charts Inc CHART NO. CI-1002-RB (0399)

PARAMETRIC CURVES OF USEFUL TURBINE DISCHARGE vs REGULATED BASIN RUNOFF

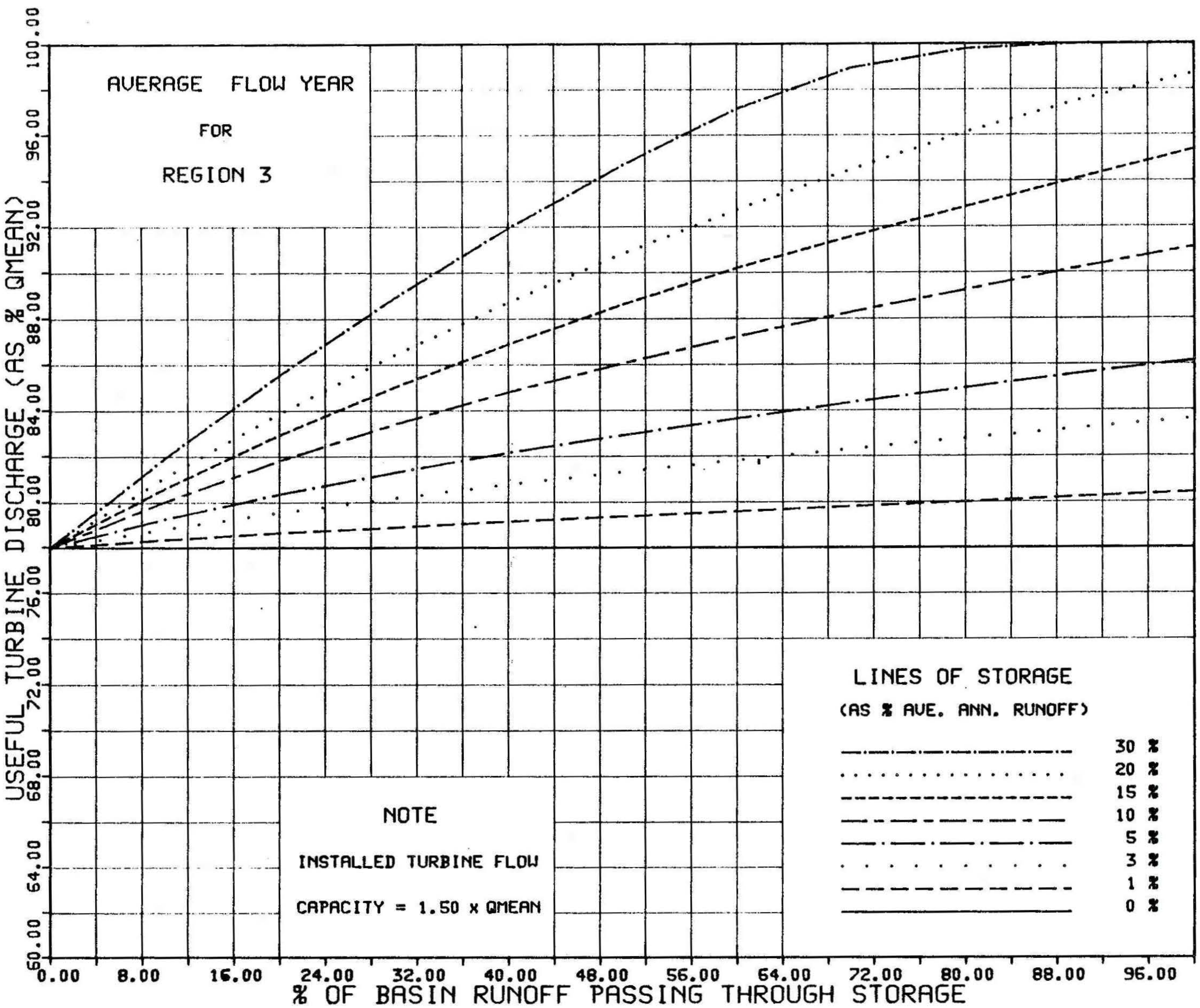


Figure I.12

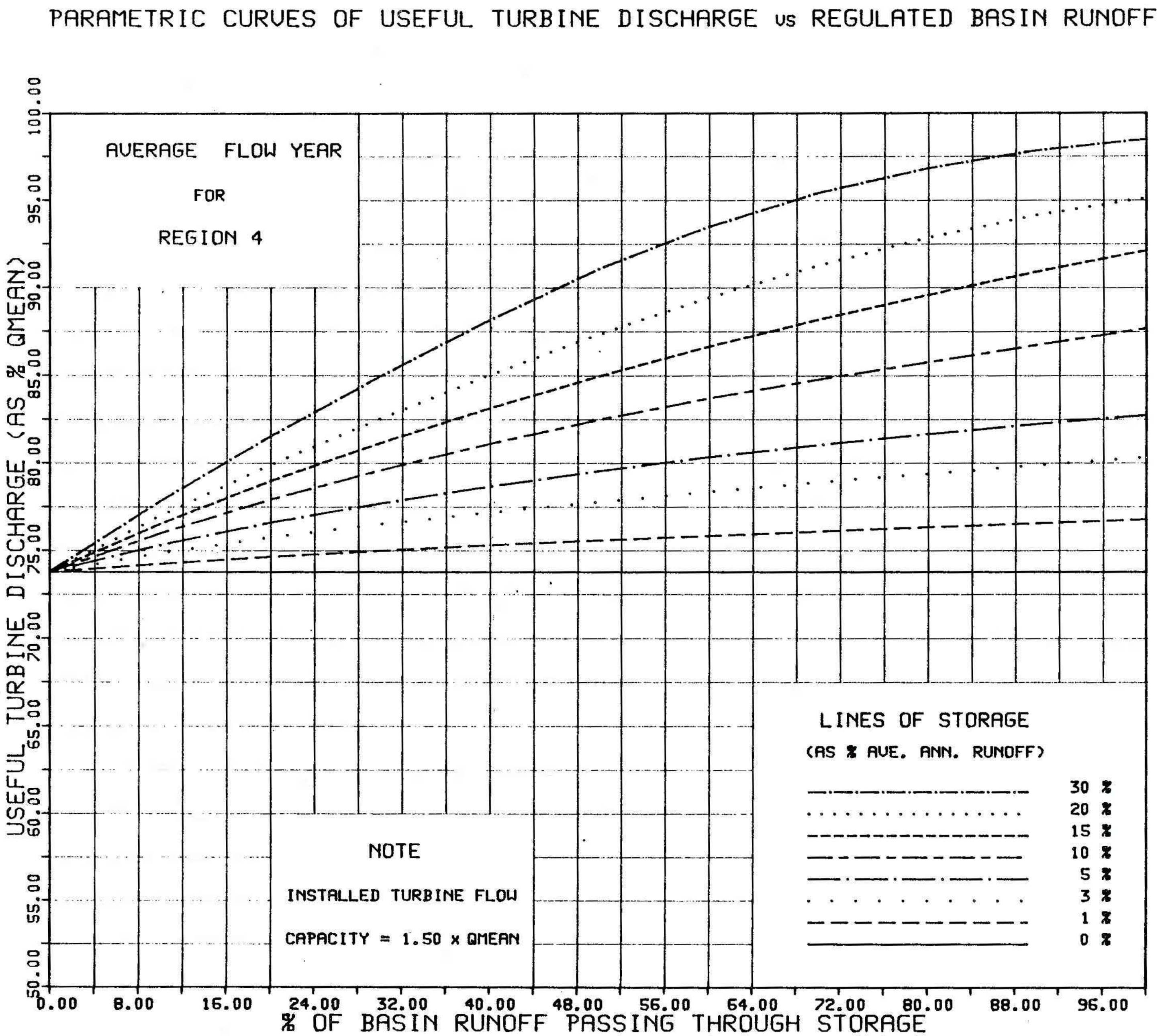
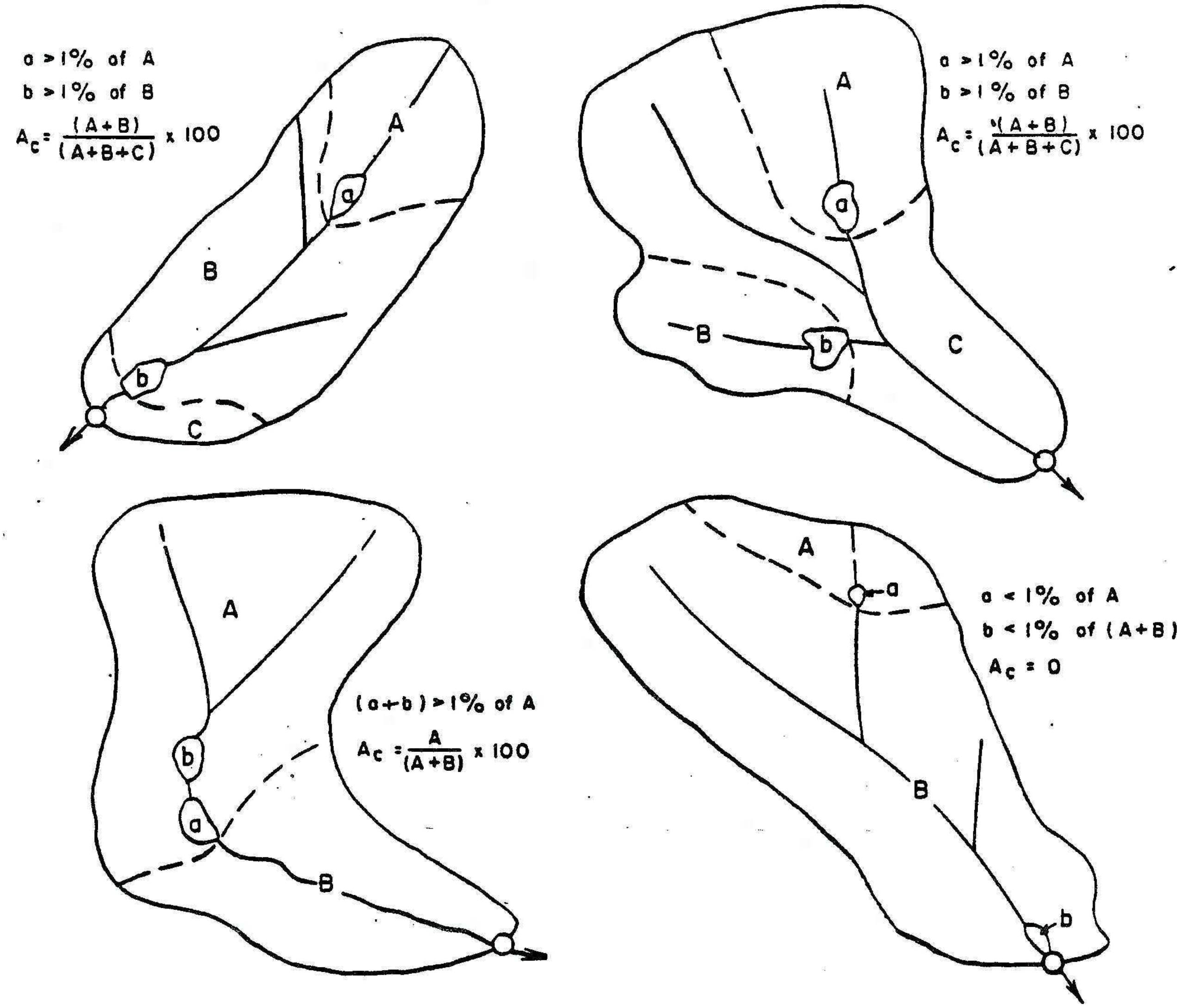

PARAMETRIC CURVES OF USEFUL TURBINE DISCHARGE vs REGULATED BASIN RUNOFF
AVERAGE FLOW YEAR
FOR
REGION 4
USEFUL TURBINE DISCHARGE (AS % QMEAN)
100.00
95.00
90.00
85.00
80.00
75.00
70.00
65.00
60.00
55.00
50.00
0.00
8.00
16.00
24.00
32.00
40.00
48.00
56.00
64.00
72.00
80.00
88.00
96.00
% OF BASIN RUNOFF PASSING THROUGH STORAGE
NOTE
INSTALLED TURBINE FLOW
CAPACITY = 1.50 x QMEAN
LINES OF STORAGE
(AS % AVE. ANN. RUNOFF)
30 %
20 %
15 %
10 %
5 %
3 %
1 %
0 %

Figure I.13



LEGEND:

a,b — AREA OF LAKE OR SWAMP

A,B — AREA CONTROLLED BY LAKE OR SWAMP

C — UNCONTROLLED AREA

NOTE:

TAKEN FROM FLOOD FREQUENCY ANALYSIS FOR NEWFOUNDLAND STREAMS BY ROGER Y. POULIN, 1968.

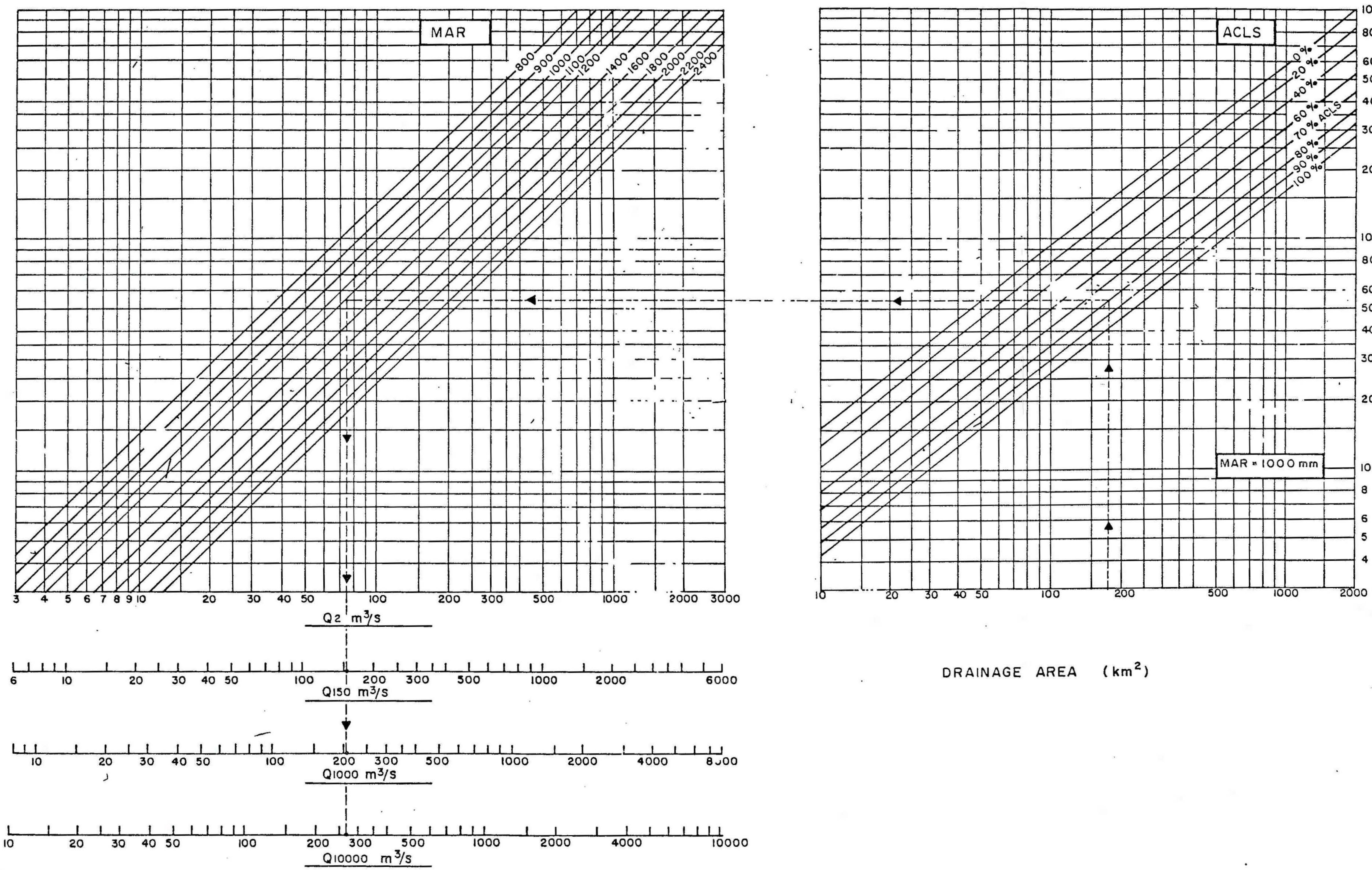
PERCENTAGE AREA OF BASIN CONTROLLED

— DEFINITION —

FIGURE 1.15

EXAMPLE:

FOR A = 180 km² | FIND Q_2 = 75 m³/s
ACLS = 80 % | Q_{150} = 155 m³/s
MAR = 1200 mm | Q_{1000} = 210 m³/s
 | Q_{10000} = 270 m³/s



FLOOD NOMOGRAPH
FOR ISLAND OF NEWFOUNDLAND

REFERENCES FOR APPENDIX I

REFERENCES FOR APPENDIX I

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APPENDIX II

BACKGROUND ON SHYDRO, UPSTREAM STORAGE AND DIVERSION COSTING

APPENDIX II

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APPENDIX II

BACKGROUND ON SHYDRO

To permit costing of a large number of potential sites, a computer program called SHYDRO has been developed by Monenco Limited. This program estimates the cost of a hydro development on the basis of sixteen site-specific parameters. These parameters are used in formulae developed from in-house and published data on the cost of similar development components. The formulae and the resulting cost relationships for each component are given in the following sections.

Least Cost of Development

A simple methodology was developed for checking the first order of magnitude costs for hydro projects, based on a statistical analysis of cost data obtained from over 170 projects ("Hydropower Cost Estimates", by J.L. Gordon, Water Power, November, 1983).

It is well known that project costs per unit of installed capacity tend to decrease with increasing capacity, and that powerhouse costs for a fixed capacity tend to decrease with increasing head. Hence, it is to be expected that total project costs, including all overheads, but excluding transmission cost, should tend to be a function of $(MW/H^x)Y$, where MW is the installed capacity, H is the project head, and x and y are unknown components.

There are many other factors which affect project costs, such as the project layout, site location, spillway capacity and foundation conditions. However, if these are disregarded for this initital evaluation, an estimate of the values for x and y can be obtained from historical costs.

The least (minimum) cost for small-scale hydro development, based on the 1983 work of Gordon, is given as follows:

$$\text{Least Cost (\$Can.1986)} = 8.3 \times 10^{6} \times (MW/H^{0.3})^{0.82}$$

The cost of approximately 20 micro and mini-hydro projects in rural Canadian communities have recently been analyzed and the least cost based on these projects can be given as:

$$\text{Least Cost (\$Can.1986)} = 2350 \times (kW/H^{0.3})^{1.25}$$

This latter formula has been determined to apply to mini/micro sites with a $\frac{kW}{H^{0.3}}$ ratio less than 338.

The formulae represent the probable minimum cost of development for a small-scale hydro project with preferred site characteristics. The formulae is intended primarily for projects under 10 MW capacity and does not include transmission costs or interest during construction. The formulae cannot, at this time, be used with confidence for estimation of the capital cost of development.

The "least cost" formulae are used as a check of the SHYDRO program cost. If the latter was found to be lower, then the site-specific input parameters must be checked to determine the reason for the apparent lower cost.

Project Cost Estimation

The SHYDRO Program calculates the cost of the following components:

1. Dam and Spillway
2. Intake
3. Penstock
4. Unwatering
5. Powerhouse Civil
6. Equipment Supply and Erection
7. Access Road

8. Transmission Line and Substation
9. Fishway (where required)
10. Contractor's Overhead
11. Engineering and Owner's Cost
12. Interest During Construction

(a) Costs Not Included

The following costs have not been included in the project cost estimate:

1. Land purchase;

2. Land clearing;

3. Relocation of roads, railways, powerlines, bridges, due to reservoir flooding, etc.; and

4. Relocation or purchase of buildings affected by reservoir flooding.

(b) Dam and Spillway Cost

Input parameters used to estimate the cost of the dam are height of dam, length of dam, and base unit price. The formula for cost of dam has the form:

$$\text{Cost of Dam} = K\, C_x (V\, A_d L)^y$$

where K = a constant
C_x = base unit price
V = valley shape factor
A_d = maximum cross-sectional area
L = dam length
Y = exponential factor

The valley shape factor represents the ratio between the maximum dam volume based on the maximum dam section and the actual dam volume based on the site topography. A U-shaped valley would have a factor approaching 1.0, while a V-shaped valley would have a factor of approximately 0.4. A valley shape factor of 0.55 is used in the current version of the SHYDRO program. If local topography dictates the use of another shape factor, modifications are required for each of the dam formulae used within the program.

Three dam types are considered, with the computer program estimating the cost of each type and using the lowest price alternative. Dam types considered and their applicable dam height and cross-sectional characteristics are summarized below.

	Height Range (m)	Crest Width (m)	U/S Slope	D/S Slope
Timber Crib	8.0	1.2	1:1	1:4
Concrete (gravity)	16.0	1.0	vertical	0.75:1
Earthfill (with concrete chute spillway)	all	8.0	3:1	2.5:1

An exponential reduction in unit price is used in the program to compensate for economy of scale for larger dam volumes. The following base quantities are used for determining the appropriate unit prices:

	Base Quantity m^3
Earthfill Dam	5000
Concrete Dam	1000
Timber Crib Dam	800

The Program estimates the dam cost on the basis of the following formulae:

Timber Crib

Cost of Timber Crib Dam = $1.4 \times C_1 (V \times A \times L)^{0.95}$

where C_1 = timber crib unit price
A = maximum cros-sectional area
L = dam crest length
V = valley shape factor

Concrete

Cost of Concrete Dam = $2.0 \times C_2 \times (V \times A \times L)^{0.9}$

where C_2 = concrete dam unit price

Earthfill

Cost of Earthfill Dam (with volume less than/equal to 15000 m^3)
$= 17.9 \times C_4 \times (V \times A_1 \times L)^{0.70}$

where C_4 = earthfill unit price for excavation and backfill
A_1 = maximum cross sectional area based on height 4.0 m above spillway crest

Cost of Earthfill Dam (with volume greater than 15000 m^3)
$= 2.6 \times C_4 (V \times A \times L)^{0.90}$

Spillway

The input parameters used to estimate the cost of the spillway are flood flow, dam height, and base unit price. For the purposes of standardizing the basis of estimating the cost for inventory purposes, a concrete chute spillway with a chute length three times the dam height was selected. The cost formula has the form:

$$\text{Cost of Spillway} = C_3 \times [F \times 3\ (D + 4)]^{0.78}$$

where C_3 = base unit price for spillway concrete

D = maximum height to spillway crest plus 4.0 m

F = flood flow

The chute length is taken as three times the earthfill dam height. The unit price is exponentially reduced for larger spillways due to economics of scale and has a base unit price which is determined from a representative quantity of 1000 m^3.

(c) Intake

The site-related input parameters required for estimating the cost of the intake are the design flow, number of units, and unit prices for earthwork and concrete. The intake cost formula is:

$$\text{Cost of Intake} = U \times 1.12 \times (125C_4 + 37.5C_3) \times (Q/U)^{0.9}$$

where C_3 = unit price for spillway concrete

C_4 = unit price for excavation and backfill

Q = design flow

U = number of units

(d) Penstock Cost

The input parameters and calculated data required for calculation of penstock cost are the penstock length, rated head, unit prices for earthwork, and computed diameter.

A sub-routine within the program calculate the economic penstock diameter. The economic diameter is calculated using the following formula (Reference: Fahlbusch, "Power Tunnels and Penstocks: The Economics Re-Examined," Water Power and Dam Construction, June 1983)

$$\text{Penstock Diameter } (P_1) = 1.26 \frac{(Q/U)^{0.43}}{H^{0.14}}$$

where Q = design flow
H = rated head
U = number of units

The Program estimates the cost of polyethylene, steel and fiberglass penstocks as follows:

	Lower Range of Diameter	Upper Range of Diameter	Depth of Burial
	(m)	(m)	
Polyethylene	N/A	1.0	Above Ground
Fiberglass	0.5	2.5	To Spring Line
Steel	0.3	N/A	1.0 m Above Top of Pipe

The Program estimates the penstock cost on the basis of the following formulae:

<u>Polyethylene</u>

$$\text{Cost of Polyethylene Penstock} = P \times U\ (800P_1^2 + 0.5C_4)$$

where P = penstock length
U = number of units
C_4 = unit price for excavation and backfill
P_1 = penstock diameter

Steel

Penstock Thickness (minimum) $7.5 + \frac{P_1}{0.8} = P_2$

Cost of Steel Penstock = $P \times U\,[109P_1 \times P_2 + C_4 \times P_1(P_1 + 1.5) + 0.5 \times C_4 \times (P_1 + 1.5)^2]$

Fibreglas

Cost of Fibreglas Penstock = $P \times U\,[460P_1 + C_4\,(P_1 + 0.6)(0.5P_1 + 0.5) - 1.6C_4(0.5P_1)^2]$

(e) Unwatering Cost

Unwatering concepts are site specific and depend largely on the site topography and plant layout. Several alternatives can be considered when providing an allowance for the cost of unwatering, such as cofferdams, pumping and diversion work. A relationship between the diversion flow at a site and the cost of unwatering has been developed. It must be emphasized that this is merely an expedient used to arrive at a reasonable sum of money for unwatering.

The diversion flow selected approximates the ten-year flood and is estimated in the Program by factoring the flood flow. The diversion flow is given to be 50 percent of the flood flow. Variations for different hydrological regions will require modification of the unwatering formula.

Cost of Unwatering = $100 \times C_4 \times (0.5 \times F)$

where C_4 = unit price for earthwork

F = flood flow

(f) Powerhouse Civil Works Costs

Cost formulae have been previously developed for estimating hydro station costs. Total powerhouse cost, including all civil work, mechanical and electrical equipment, direct and indirect costs, and engineering and owner's administration, is given in 1986 Canadian dollars as:

Total Powerhouse Cost (for installed capacity less than 5 MW)

$$= 5.55 \times 10^6 \times \frac{MW^{0.7}}{H^{0.35}}$$

Total Powerhouse Cost (for installed capacities greater than or equal to 5MW)

$$= \frac{4.00 \times 10^6 \times MW^{0.92}}{H^{0.32MW^{0.058}}}$$

The powerhouse civil cost is estimated in the program to be 17 percent of this total powerhouse cost.

(g) Powerhouse Equipment Supply and Erection Costs

The cost of powerhouse equipment supply is estimated to be 34 percent of the total powerhouse cost given above.

Cost of erection has been estimated to be 30 perent of the supply cost.

(h) Access Road Cost

The input parameters required for costing the access road are its length and base unit price. An average unit cost for constructing the access road is estimated on the basis of a length of road of 5 km. Allowance was made for exponential reduction of the unit cost for longer access roads:

$$\text{Cost of Access Road} = 1.27 \times C_7 \times (A)^{0.85}$$

where C_7 = access road unit price
A = access road length

(i) Transmission Line and Substation Costs

Transmission Line

Input parameters and calculated data used to estimate the cost of the transmission line are installed capacity and transmission line length. The transmission line cost in 1986 Canadian dollars is given as follows:

Cost of Transmission Line (for installed capacity less than 1 MW)

$$= 38000T$$

where T = transmission line length (km)

Cost of Transmission Line (for installed capacity greater or equal to 1 MW)

$$= 8800\ [4.28 + (MW-1)^{0.5}] \times MW^{0.1} \times T^{0.9}$$

Substation

Substation costs have been included in the powerhouse equipment costs for plants with installed capacities greater than or equal to 5.0 MW.

The installed capacity is the basis for estimating the cost of substations for sites smaller than 5.0 MW. The formula used for estimating the cost of substations in 1986 Canadian dollars is given as:

$$\text{Substation Cost} = 1350 \times (MW \times 1000)^{0.6}$$

(j) Fishway Cost

Input data required for calculation of the fishway cost, if required, are the dam height unit cost and fishway factor.

$$\text{Fishway Cost} = C_8 \times D \times S_2$$

where C_8 = unit price
D = dam height to spillway crest
S_2 = fishway factor

(k) Contractor's Overhead Cost

The estimate for contractor's overhead cost reflects the remoteness of the site and the cost of transportation and travel. The upper limit of this component is set at 40 percent of the cost of the following work:

- dam unwatering
- intake
- dam and spillway
- penstock earthwork
- powerhouse civil
- access road
- fishway (if required)

Input data used to calculate this component are the distance to the nearest concrete plant and the distance to the nearest town. The formula for the cost of the contractor's overhead cost has the form:

$$\text{Contractor's Overhead Cost} = (0.005R_1 + 0.001R_2)B$$

or

$$0.40\ (B)$$

whichever is less

where B = cost of the above components which reflect the remoteness of site

R_1 = distance to nearest town

R_2 = distance to nearest concrete plant

(l) Engineering and Owner's Costs

Engineering and Owner's costs are estimated as a sliding-scale percentage of the total project cost, excluding interest during construction. The estimating formula has the form:

$$\text{Engineering and Owner's Cost} = 0.60 \times (E)^{0.89}$$

where E = project cost, excluding interest during construction

(m) Interest During Construction

The cost of interest during construction is dependent on the project cost, length of construction and the interest rate based on the real cost of money. A formula for construction time based on the installed capacity has been developed. A real interest rate of 6 percent has been used in the formula development. The formula for the cost of interest during construction has the form:

$$\text{Cost of Interest During Construction} = \frac{R \times 0.06}{2} \times C$$

where R = construction time

C = capital cost of development

A formula for construction time, based on the installed capacity is given as:

For installed capacities less than 5MW:

$$\text{Construction Time (R)} = 0.172\ (\text{MW} \times 1000)^{0.25}$$

For installed capacities greater than or equal to 5MW:
Construction Time (R) = $0.0134 (MW \times 1000)^{0.55}$

(n) Total Project Cost

The SHYDRO Program accumulates the above costs and calculates the cost per installed kW. The Program has been tested against small-scale hydro project costs and has been found to estimate the project cost within 10 percent of the constructed plant cost. However, due to unrealibility of the input data, the computed costs can only be regarded as having an accuracy in the region of 25 to 50 percent.

Benefit/Cost Ratio

The Program calculates a simple benefit/cost ratio which can be used for preliminary screening and ranking of sites.

Annual Cost

Input data required for estimation of the annual cost are the interest rate and the operating and maintenance percentage. The formula for estimating the annual cost is as follows:

$$\text{Annual Cost} = G \times (I + C_q)/100$$

where G = total project cost
I = interest rate
C_q = operating and maintenance cost as percentage of capital cost

Annual Benefit

Input data required to estimate the annual benefit include the available turbine flow ratio, maximum turbine flow ratio, installed capacity, and the value of generated power. The formula used for estimating the annual benefit is as follows:

$$\text{Annual Benefit} = (Q_1/Q_2) \times MW \times 8760 \times M_1$$

where Q_1 = useful turbine flow ratio

Q_2 = maximum turbine flow ratio

MW = installed capacity

M_1 = value of power generated (\$/kW/hr)

II.2 MODIFICATIONS TO SHYDRO

(a) Modifications to Data Entry

The program was modified to compute plant design flow and plant capacity from Q_{av} and plant design flow ratio.

Computation of Plant Design Flow

Input data:

Mean Basin Flow, Q_{av} = C(14)

Plant Design Flow Ratio = C(11)

whence:

Plant Design Flow, Q = C(14) * C(11)

Computation of Plant Capacity

$$kW = \eta \cdot H_n \cdot Q \cdot g$$

Assume:	ηturb.	=	90%
	ηgen.	=	96%
	ηtrans.	=	99%
	ηplant	=	99%
∴	ηoverall	=	84.7%

Assume 2% hydraulic losses whence

$$H_n = 0.98H$$

$$\therefore \ kW = 0.847 \times 0.98 \times H \times Q \times 9.81$$

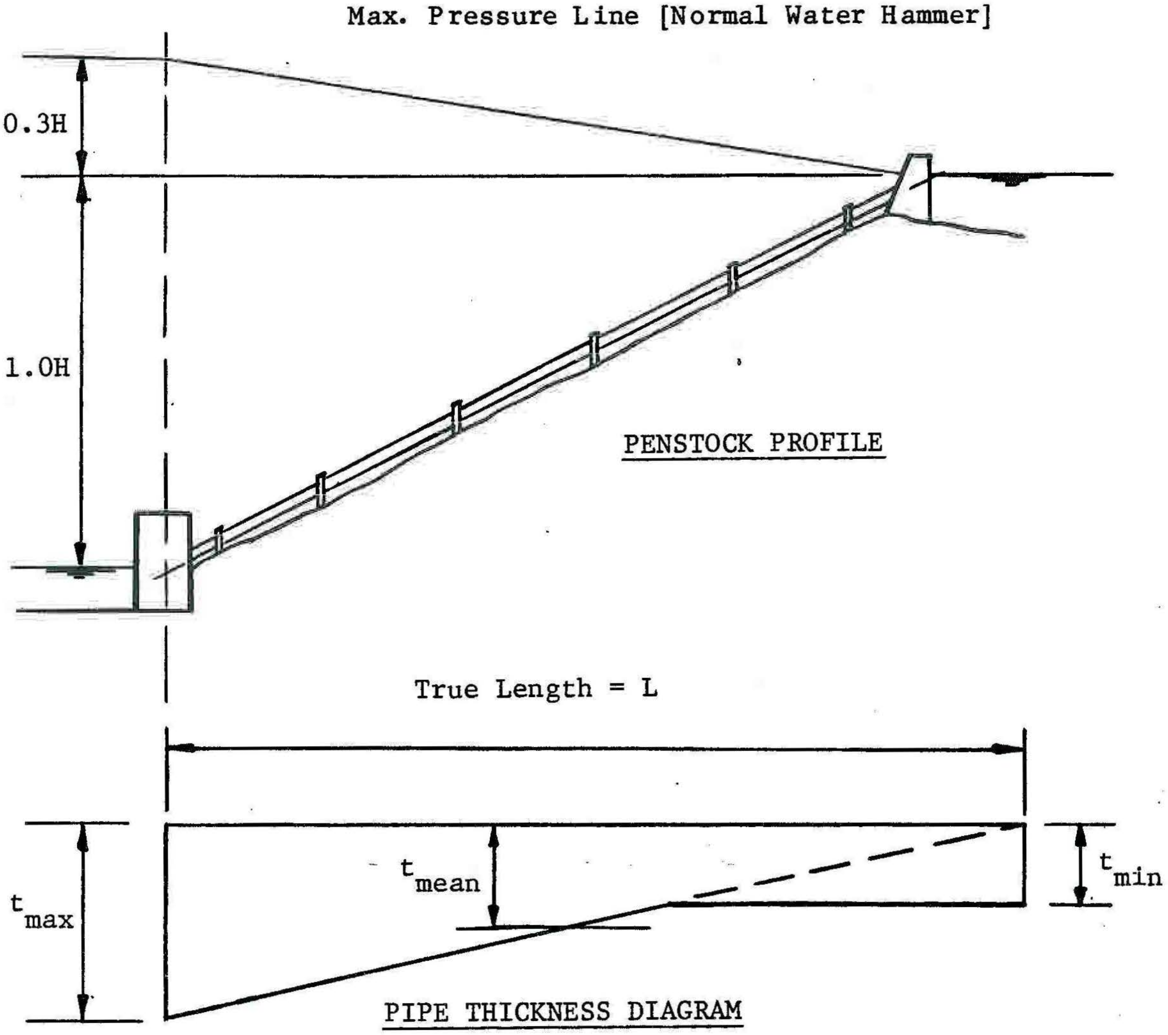
$$= 8.14 \ HQ$$

whence

M = 0.00814 * H * Q

where M = Plant capacity in MW

(b) Correction to Steel Penstock Computation



From consideration of the pipe thickness diagram above, it can be shown that

$$t_{mean} = \frac{t_{max}^2 + t_{min}^2}{2t_{max}}$$

t_{min} is determined from handling criteria,

$$t_{min} = 7.5 + \frac{P1}{0.8}$$

where P1 = penstock diameter

t_{max} is determined using the hoop stress formula, as below:

$$t_{max} = \frac{pr}{s}$$

where p = pressure (MPa)

$r = \frac{P1}{2}$ = penstock radius (m)

S = allowable tensile stress in (MPa)

If penstock is constructed of CSA G40.21M 300WT

$S = 148$ MPa [$\approx 53\% \ F_Y$]

$$p = \frac{1.3H \times 1000 \times 9.81}{10^6} \text{ MPa}$$

$$t_{max} = \frac{1.3H \times 1000 \times 9.81}{158 \times 10^6} \times \frac{P1}{2} (\times 1000) \text{ mm}$$

$\uparrow$ to convert to mm

$\therefore t_{max} = 0.0405 * H * P1$

The program computes t_{min}, t_{max} and then t_{mean}. The program then sets the pipe thickness, P2 equal to the greater of t_{mean} and t_{min} and computes the cost of a steel penstock, PS, as before.

(c) Head Limitation for Polyethylene and FRP Penstocks

To avoid selection of polyethylene and FRP penstocks, when the H > 60 m, the program logic was modified to assign arbitrarily high costs to both polyethylene and FRP penstocks when H > 60 m [$20,000,000 was used]. This "trick" results in polyethylene and FRP pensocks being de-selected in a subsequent cost comparison routine.

(d) Inclusion of Costs for Pressure Relief Valves

Pressure relief valves normally cost about 25% of turbine costs, which in turn, can be estimated as about 50% of equipment costs.

Whenever the penstock L/h ratio is greater than 7.0, the program adjusts powerhouse costs by applying a factor of 1.12 against equipment supply and erection costs. Impact on powerhouse civil costs are assumed to be negligible. The program also prints out a message: "NOTE PENSTOCK LENGTH EXCEEDS 7 * H (PRESSURE RELIEF VALVE ADDED TO POWERHOUSE EQUIPMENT COST)

(e) Option to Enter Cost of Nonstandard Item

This modification causes the computer to halt execution at the step preceding computation of the total project cost. The program prompts the user to supply the additional information, or to enter 0 if nothing is to be added. If a new costs is added the computer then prompts for a brief description, which is later printed out as a note. If 0 is entered execution continues as before and no note is produced.

II.3 UPSTREAM STORAGE SCHEMES

A standard layout for upstream storage schemes was assumed, comprising the following structures:

- Storage dam ... timber crib construction
- Control structure ... sluiceway controlled by stoplogs
- Access road

Other direct costs included dewatering and clearing reservoir margins. Indirect costs included contractor's overhead, E & M Owners cost and IDC.

The following cost equations were used:

- Dam: $\underline{A1 = C2 * 0.575 * H * (0.625 * H + 1.2) * L_D}$

where:

C2	= unit cost for timber crib	$\$/m^3$
H	= height of dam	m
L_D	= length of dam	m

The same dam cross section as in SHYDRO was assumed.

- Control Structure: $\underline{A2 = 5000 + 3000 * Q_p}$

where: Q_p = design flow m^3/s

- Underwatering: $\underline{A3 = 0.3 * \text{Control Structure}}$

- Reservoir Clearing: $\underline{A4 = C3 * 6 * \sqrt{As}}$

where

C3	= unit cost of clearing	$/ha
As	= surface area of reservoir	km^2

Perimeter lengths of similar shapes can be scaled as a function of the square root of area. For a typical reservoir shape the perimeter can be estimated as $6\sqrt{As}$. It was further assumed that ~ 50% of the perimeter would require clearing over a width of 20m.

- Access Road: $\underline{A5 = C1 * L_R}$

where:

$C1$ = unit cost of access road $/km

L_R = length of access road km

- Total Direct Cost: $A_D = A1 + A2 + A3 + A4 + A5$

- Total Indirect Cost $A_{IN} = \underline{0.55 * A_D}$

$\therefore$ Total Project Cost $= 1.55 * A_D$

Costs are in constant 1986 Canadian dollars. Markup for indirects was based on SHYDRO formulae.

II. 4 WATERSHED DIVERSION SCHEMES

A standard layout for watershed diversion schemes was assumed, comprising the following structures:

- Diversion dam-cum-spillway
- Diversion canal traversing the height of land
- Access Road

The following cost equations were used:

- Dam:

(a) Timber Crib

Compute, $A = h[1.2 + 0.625h]$, then

Cost, $A_t = 0.79 * C2 * (A * L_D)^{0.95} + 750 * Q_{150}$

(b) Concrete

Compute, $A = h[1.0 + 0.375h]$, then

Cost, $A_c = 1.17 * C4 (A * L_D)^{0.90} + 750 * Q_{150}$

(c) Earthfill Dam and Spillway

Compute, $A = h[8.0 + 2.75h]$, then

Cost, $A_e = 1.52 * C5 * (A * L_D)^{0.90} + 7500 * Q150$

Set cost of dam, A1, at lesser of A_t, A_c or A_e

where:

C2, C4 and C5 are unit costs of timber crib, concrete and earthfill respectively $\$/m^3$

A	=	cross section area	m^2
h	=	height of dam	m
L_D	=	length of dam	m
Q_{150}	=	design flood	m^3/s

The costs equations for dams are essentially the same as in SHYDRO except that the computations of unwatering and spillway costs have been simplified.

- <u>Diversion Canal</u>

A shallow canal in overburden is assumed having a bottom width of 4m and side slopes of 1V:2.5H. The canal longtitudinal profile is assumed to be trapezoidal, having a crest elevation H metres above the upstream water level. The computation procedes as below:

Calculate flow area, $A_Q = Q_p \div 1.5$

Calculate depth of flow, $y = \dfrac{-4 + \sqrt{16 + 10 * A_o}}{5}$

Calculate $A_{max} = H * [4.0 + 2.5 * H]$

Then,

$$\text{Cost of Canal, } A2 = C5 * 0.65 * [A_o + A_{max}] * L_c + C5 * 10 * A_o * y + 12 * L_c$$

where:

Q_p	= canal design flow	m^3/s
H	= elevation of height of land above upstream W.L.	m
L_c	= length of canal	m
A_o	= canal flow area	m^2
y	= design depth of flow	m
A_{max}	= maximum canal area	m^2
C5	= unit cost of earth cut/fill	$\$/m^3$

- <u>Access Road</u>, $A3 = C1 * L_R$

where:

C1	= unit cost of access road	$/km
L_R	= length of access road	km

Total Direct Costs, $A_D = A1 + A2 + A3$

Total Indirect Costs, $A_{IN} = 0.55 * A_D$

Total Project Cost, $A_T = 1.55 * A_D$

As before, indirects were determined from SHYDRO formulae and include contractor's overhead, E & M, Owners cost and IDC. EDC is excluded, hence costs are in constant 1986 Canadian dollars.