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FEASIBILITY STUDY
OF
HYDRO GENERATION SITES
BURGEO, NEWFOUNDLAND

<u>Prepared For:</u> Newfoundland and Labrador Hydro

<u>Prepared By:</u> Blake Bartlett
Geoff Carnell
~~John Dawe~~
Edward Finn
George Wilson

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Introduction

In light of the increasing rate of inflation, particularly refined petroleum products (fuel and lube) and the increasing public demand for electric power, the cost of thermal diesel generation is extremely expensive. It has therefore been proposed that an investigation of any possible hydro-electric power sites be carried out for Burgeo, Newfoundland. This investigation should determine the economic feasibility of supplementing, or completely replacing, the existing diesel generation with hydro generation.

Preliminary investigation by Newfoundland and Labrador Hydro suggested that there may be a potential site along the Grandy Brook[1] or any of its tributaries. Water diversion for the Bay D'Espoir hydro project has virtually eliminated any possible development of the White Bear River[2] or any of its tributaries. For this reason, the focus of this study has been restricted to that area lying west of White Bear River.

Because no site investigation is possible, the level of detail is limited to what can be gleaned from a study of topographical maps. Subsequently then, this report is a conceptual feasibility. More detailed studies should follow if the results of this study warrant it.

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[1] See site plan

[2] See site plan

Summary

Five possible hydro power sites were located from an area investigation. The potential energy output of each site was developed to the extent that its full potential would be realized by 1990. Two alternatives obviously involved extra costs without any benefit. The remaining three alternatives and an all diesel alternative were then evaluated using present worth analysis. Two hydro alternatives, located on a tributary of the Grandy Brook about nine miles from Burgeo, were found to be the most economically feasible. The present worth, in 1977 dollars, of both of these alternatives is about $12 million as compared to $19 million for the all diesel alternative. They do however include diesel units to meet reserve capacity requirements.

Inventory of Present Conditions

At present, Burgeo has a population of about 3,000 people and is supplied by a diesel generating plant located near the town. The plant consists of two 1250 KVA generators and two 625 KVA generators feeding power directly into the distribution system at 25 KV. Past fuel, lube and maintenance costs of these electric sets were supplied by Newfoundland and Labrador Hydro and are shown in Table I.

In the past two years, approximately $4 million has been spent by the Newfoundland Government developing the Burgeo fishing industry. Included in these improvements is a new fish plant and related facilities.

The only access to Burgeo at the present time is by a coastal boat or seaplane but there is a new road under construct-ion from Buchans to Burgeo and it is hoped that this link will be completed and open to traffic within two or three years.

For the purposes of this study, the hydrological conditions were assumed to be similar to those of the Victoria Reservoir[3] of the Bay D'Espoir system because of its proximity to the area in question. If there is any deviation from this assumption, the actual rainfall should be more than that assumed

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[3] See Victoria Hydrological Data Appendix D

according to a study of the Newfoundland hydrological conditions done by Shawinigan Engineering Company[4].

The entire Burgeo area is rugged and rocky with very thin soil cover with trees in small isolated patches. The exposed rock is mostly granite and large quantities of natural aggregates are virtually non-existent. They would either have to be transported into the area or produced by crushing plants at the site.

The load forecast used in this study (see Table 2) was supplied by Newfoundland and Labrador Hydro and is based on past energy consumption patterns. A graphical representation is given in Appendix B.

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4 See Shawinigan Report, Appendix A

Criteria

The recommendation for future study of an alternative is based on an economic comparison of all the alternatives. The Present Worth Analysis is the technique that has been implemented basically because this is the technique most generally employed by the client, Newfoundland and Labrador Hydro. This technique requires that technically equivalent alternatives be generated to meet the demand up to 1990. Using present worth, each alternative is converted to 1977 dollars so that they may be reasonably compared. Included in the annual cash determinations were any required diesel supplements. These were compared with the present all diesel generation alternative.

In the study of the topographic maps, the following search procedure was implemented.

Primary consideration for initial selection was given to those sites with high heads and large catchments. Secondary consideration was then based on proximity to Burgeo and/or accessibility to the different site structures.

Reservoir sites were chosen optimizing on a minimum size dam contouring a maximum water storage volume. Reservoir dam locations were preferred when the maximum drainage area possible was controlled barring any physical constraints. Forebay Dam locations were preferred where the penstock lengths between the powerhouse and forebay were minimal to minimize loss of head due to friction.

A more detailed cost estimate is undertaken on dams as compared to the other components as dams will comprise the major cost component.

Constraints

This study is to be an investigation of the generating potential of each site rather than a design to meet projected demands. However, some preliminary calculations were done to determine approximately the heads, flows, areas, etc. needed to provide 100% hydro generation in 1990. These figures served as the reference points for the investigation.

Since fifty foot contour interval maps were the only source of site information, certain assumptions regarding land elevations between contour lines were made. Usually standard methods of linear interpolation were used. The calculation of such quantities as dam size, reservoir storage and excavation are dependent on these assumptions. However these quantities should be within 25% of those computed from detailed site information.

From available information of the area it was assumed that all earthwork, whether fill or excavation, will deal with solid rock as soil cover is known to be minimal. If any further degree of detail was used other than what was carried out, it would produce no greater accuracy without some actual site visits and investigation.

For the purposes of this report, it was assumed that the impact of any development interferring with a fisheries resource would be minimal since the developments were at the top of very steep falls, preventing access to salmon. Topographic information available indicated that there are no forest resources in the area which would be damaged. Again these assumptions would have to be verified by an in-depth environmental study if development is planned.

For further information on environmental considerations, see Appendix C.

Generation of Alternatives

The first step was a search for possible developments worth further investigation. This began with a general scan of the appropriate topographic maps. Then using the previous criteria of high head and large catchment, two power house locations were chosen, both had a head of approximately 250 feet. The first site is located approximately 9 miles north of Burgeo. The second site is located 17 miles north-west of Burgeo, at the head of Northwest Arm. These distances are derived from the length of transmission line required.

The drainage area for each site was determined as well as a possible diversion of Top Pond into Stephenson's Pond, using a few dykes and a canal. Potential reservoir sites were selected with particular notice given to the amount of drainage area they could control. A summary of drainage areas and reservoir capacities is found in Table 4. The table includes the five most feasible sites that were examined. The less feasible small remote sites were excluded.

The water runoff records for Victoria Reservoir, Bay D' Espoir were the best available. These gave a computed average runoff rate of 3.1 cu.secs/sq. mi. Inflow rates to the reservoirs were computed with 1974 runoff records. The design was based on 1974 flows because it was a drier than average year as demonstrated by the records.

Using this data, the variating monthly flows determined the maximum sustainable flow from each reservoir over a yearly period. This was a trial and error calculation requiring full reservoir conditions at the beginning and end of the one year period.

The maximum yields determined the generating capacity of each site at 100% capacity factor. The installed capacity of the power plant was determined from the ratio generating capacity/capacity factor. The capacity factor for such hydro generation is taken as 0.40.

The topographical maps were studied to select preliminary transmission line routes[5] and distances. Using a power factor of 0.90[6], the preliminary distances and the generating capacity of each plant, the size of transmission[7] was determined for each alternative site using Voltage Drop Charts. A range of (4-6%)[8] voltage drop was selected as optimum. Voltages and wire sizes were selected to allow the voltage drop to fall within this range. An additional design constraint was added in that Newfoundland and Labrador Hydro use standard lines of 25 KV and 69 KV in this generation range. Hence a 34.5 KV requirement might be taken as two 25 KV lines.[9]

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[5] See Appendix F, Transmission Route Selection

[6] Recommended by R. Young, P. Eng., Nfld. & Labrador Hydro

[7] See Appendix E, Preliminary Sizing of Transmission Lines

[8] Recommended by E. H. Bartlett, P. Eng., Terra Nova Engineering

[9] See Appendix E, Preliminary Sizing, Alternative E

For the Northwest Arm alternative, the power house was located at the top of the Arm, for all Grandy Brook alternatives the power house was located 11 miles up Grandy Brook. The delivery point for all alternatives was a substation on the outskirts of Burgeo.

Any additional diesel required in the life of an alternative was to be installed in the existing diesel plant. This was selected for two main reasons: greater reliability of service independent of transmission lines and the economics of using existing capital investment in plant facilities as opposed to larger hydro plant being required.

Description of Alternatives

Alternative A

This alternative has a generating station located at latitude 47°46'N and longitude 57°55'W approximately, on a river at the head of Northwest Arm. At this point on the river, water flows from a drainage area of 88 square miles.

The main reservoir is located about 3 miles north of the power station at latitude 47°48'N and longitude 57°54'W just down stream of a fork in the river and it is filled by a drainage area of 81.6 square miles. Its capacity is 205.5 million cubic feet and can supply a constant rate of flow of 139 cubic feet per second. The dam is estimated to be 1800 feet long with a maximum height of 28 feet and a volume of approximately 457,000 cubic yards of material.

The forebay is constructed at the top of the falls and a 1500 foot penstock runs to the power house below. The available head is 250 feet.

It is estimated that this site could generate 28.9 million kilowatt hours of energy annually.

Inside the power house there are three 2100 kilowatt generators and one 1950 kilowatt generator giving a total installed capacity of 8.25 megawatts.

The transmission line to Burgeo is approximately 17 miles long and has a potential of 69,000 volts.

Alternative B

This alternative has a generating station located at latitude 47°43'N and longitude 57°41'W approximately, at the mouth of the Dry Pond River into Grandy Brook. The water flowing past this point in the Dry Pond River comes from a drainage area of 56 square miles.

The main reservoir is located about 7 miles upstream of the power house at latitude 47°50'N and longitude 57°31'W and it is filled by a drainage area of 18.6 square miles. Its capacity is 173 million cubic feet and it can supply a steady flow of 48 cubic feet per second. There are two dams containing the water, one being 1260 feet long with a maximum height of 50 feet and the other 250 feet long and a maximum height of 40 feet. The total volume of dam material is approximately 298,000 cubic yards.

The forebay is constructed at the top of the falls and a 1600 foot penstock runs to the power house below. The available head is 250 feet.

It is estimated that this site could generate 9.9 million kilowatt hours of energy annually and would need turbines of 3800 horsepower total utilizing all the water power available.

Within the power house, there are two 1000 kilowatt generators and one 825 kilowatt generator, giving a total installed capacity of 2.85 megawatts.

The transmission line to Burgeo is approximately 9 miles long and has a potential of 25,000 volts.

In order to maintain the required reserve capacity, the following diesel generating units will be required - retain an existing 1250 kilowatt diesel in 1980, install another 1250 kilowatt diesel in 1982 and install a 675 kilowatt diesel in 1987.

Alternative C

This alternative has the exact layout as Alternative B, except that at the upstream portion of the drainage area, there is a channel that diverts water from the Top Pond water shed area into Stephenson's Pond which is in the Dry Pond drainage area. A dam about 30' long and 10' high is placed across the river leading out of Top Pond. The trench is about 3500 feet long with a 20 foot average width and a 20 foot average depth.

This diversion adds about 13.5 square miles onto the original drainage area for a total of 69.5 square miles. The new drainage area controlled by the reservoir now totals at 32.2 square miles and this increases the output of the generating station to 17.3 million kilowatt hours of energy annually and would need turbines of 6500 horsepower total utilizing all the water power available.

Inside the power house there are three 1250 kilowatt and one 1100 kilowatt generators giving a total installed capacity of 4.85 megawatts.

The transmission line to Burgeo is approximately 9 miles long and has a potential of 25,000 volts.

In order to maintain the required reserve capacity, one 1150 kilowatt diesel unit will be required in 1986.

Alternative D

This alternative is an attempt really to control the drainage area between the forebay and the reservoir that the reservoir has no control over by locating a much larger dam just upstream a bit from the original forebay. This new reservoir location increased the drainage area controlled from 18.6 square miles to 56 square miles. The dam is approximately 2600 feet long with a maximum height of 55 feet. The volume of dam material is approximately 654,000 cubic yards. The total storage capacity is about 175 million cubic feet. The continuous flow available from the reservoir is 99 cubic feet per second. The available energy from this flow is 20.4 million kilowatt hours annually.

Inside the power house there are four turbines of 1500 horsepower each and four generators of 1125 kilowatts each.

The transmission line to Burgeo is approximately 9 miles long and has a potential of 25,000 volts.

In order to maintain the required reserve capacity, one 500 kilowatt diesel unit will be required in 1988.

Alternative E

The drainage area into Top Pond is diverted into Stephenson's Pond and the main reservoir is again just above the power house as in Alternative D. The dam is approximately 2600 feet long with a maximum height of 55 feet as before. The total storage capacity remains at 175 million cubic feet. The continuous flow available is 118 cubic feet per second. The available energy from this flow is 24.3 million kilowatt hours annually. The drainage area controlled by the dam is increased by 13.6 square miles to 69.5 square miles.

The power house will have three 1750 KVA generating units and one 1675 KVA generating unit. The total installed capacity of the plant will be 6.925 megawatts and the total horsepower output is 4300 horsepower.

The transmission line to Burgeo is approximately 9 miles long and the potential required would be 34,500 volts. Hence using the standard construction of Newfoundland and Labrador Hydro, two 25 KV lines should be constructed, a total length of 18 miles of construction.

Discussion of Alternatives

Of the five alternatives first considered, the capacity of A, D and E was reduced because the energy available from these three as first layed out was greater than energy required to supply the town in 1990. Alternatives A, D and E had available 28.9, 20.4 and 24.3 million kilowatt hours per year respectively, but based on the load growth of the town, only 15.8 million kilowatt hours per year could be used at the end of the evaluation period. Therefore, the reservoir size and generating capacity was reduced so that all available energy would be utilized at the end of the simulation period.

When the sizes of A, D and E were so reduced, Alternatives A and E were excluded from the economic analysis. Alternative A was excluded because the power house, generating units and the available energy were identical to Alternative D but the cost was obviously greater. Alternative A was seventeen miles from Burgeo and would necessitate either the construction of a wharf at Northwest Arm or seventeen miles of access road with a bridge across Grandy Brook.

Alternative E consisted of the development of the same site as Alternative D but with an additional diversion canal and a dam in the Top Pond area. The available energy from the additional catchment area could not be used, therefore Alternative E was also eliminated from the Present Worth Analysis.

This reduced the alternatives to B, C and D for economic comparison, as shown in Table 4. Alternative C seems the most feasible. Based on the Present Worth Analysis[10], of the three remaining hydro alternatives and the all diesel alternative, Alternative C has the best present worth in 1977 dollars. This can be seen in the following table which contains a summary of that economic analysis.

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[10] See Appendix G, Present Worth Analysis

Summary of Economic Comparison

Note: All costs are in 1977 dollars.

Alternative	Capital Cost	Present Worth	Energy Produced[1]	Mil Rate[2]
B	6,718,000 102	13,964,161	920.7×10^6	15.2 mils
C	9,286,000 81	11,507,659	920.7×10^6	12.5 mils
D	10,072,000 14	12,327,575	920.7×10^6	13.4 mils
Diesel Alternative	1,471,000	18,803,643	920.7×10^6	20.4 mils

[1] Note the calculation of the total energy produced which is shown on the next page.

[2] Mil rate is defined as the average unit cost of energy in 1977 dollars over the life of the system, i.e. up to the year 2040.

Calculation of Total Energy Produced

Year	Energy Produced (kWh x 10^6)
1977	6.4
1978	6.9
1979	7.4
1980	7.9
1981	8.5
1982	9.1
1983	9.7
1984	10.4
1985	11.2
1986	12.0
1987	12.8
1988	13.7
1989	14.7
1990 - 2039	15.8 x 50 = 790
Total	920.7

Conclusions

(1) As a background, it should be stated Engineering News Record figures were often preferred over Statistics Canada figures for producing time adjustments for costs. The preferred figures always seemed to produce a larger, more realistic adjusted cost.

Normally a report such as this would be expected to have an accuracy of ±40%. Certain factors however have affected this limit of error. The first was the reduced time available for the study. The second was the limited experience of the students. In light of these factors, this study could not be expected to have a limit of error of less than ±50%.

(2) Results from Present Worth Analysis

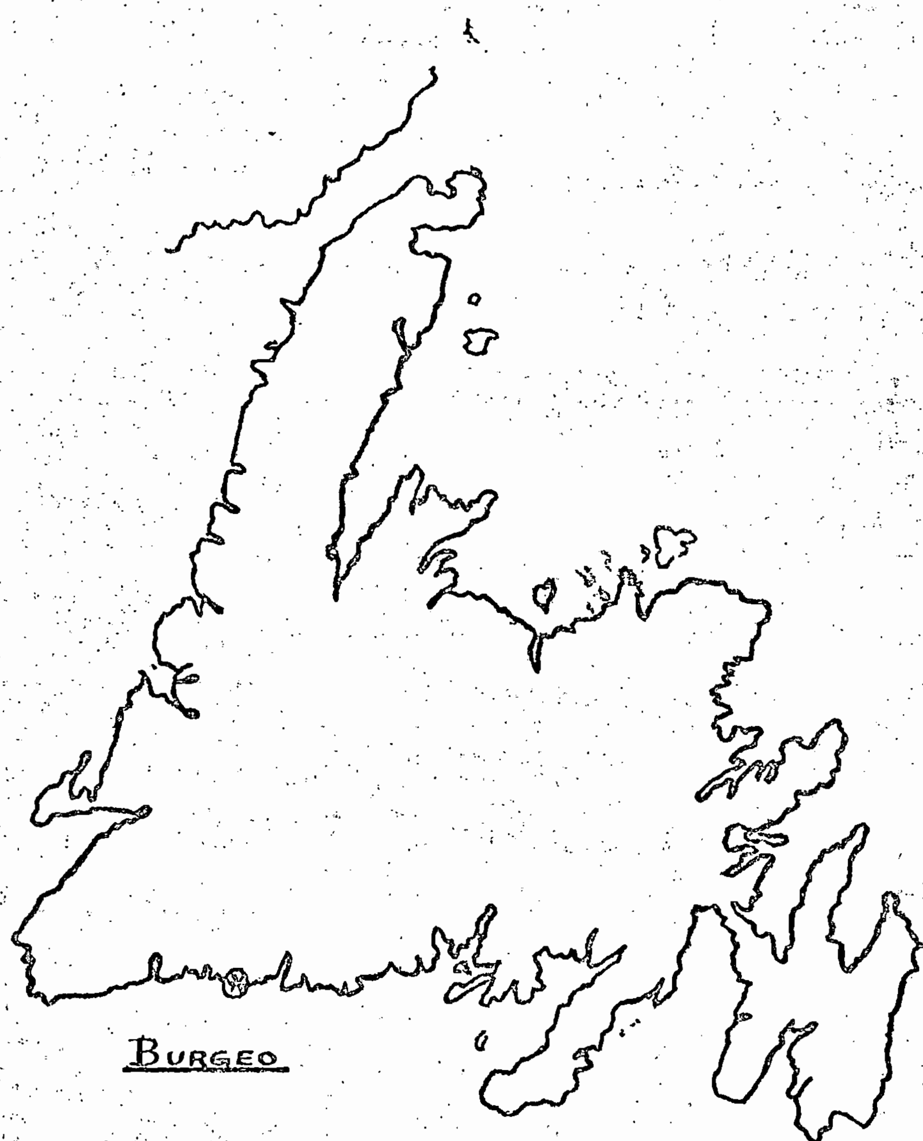
Since there does not seem to be any physical advantage in choosing between Alternatives C and D, and within the limit of accuracy of this report, both Alternatives C and D are considered to be the most economically feasible alternatives. Each of these alternatives has a present worth of approximately $12 million in 1977 dollars.

3 Recommendations for Future Study

It is recommended that prior to any further investigation of Alternatives B, C and D, an extended simulation period be used to ensure use of all the available energy of the various sites. This would demonstrate any advantages of developing higher energy alternatives such as Alternative A and E.

When the extended simulation studies have been carried out, the more attractive alternatives should be investigated in a more detailed manner. This would include actual site investigation and surveys; more detailed design and more accurate, more detailed and more up-to-date cost estimates.

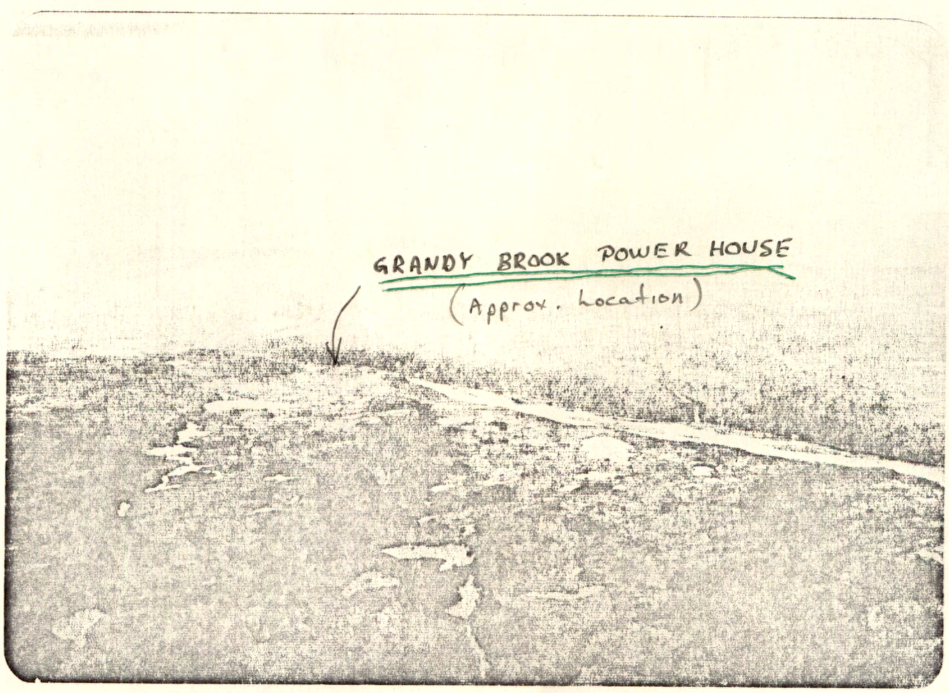
SITE LAYOUTS


BURGEO

TYPICAL TOPOGRAPHY

GRANDY BROOK SITE

TYPICAL TOPOGRAPHY



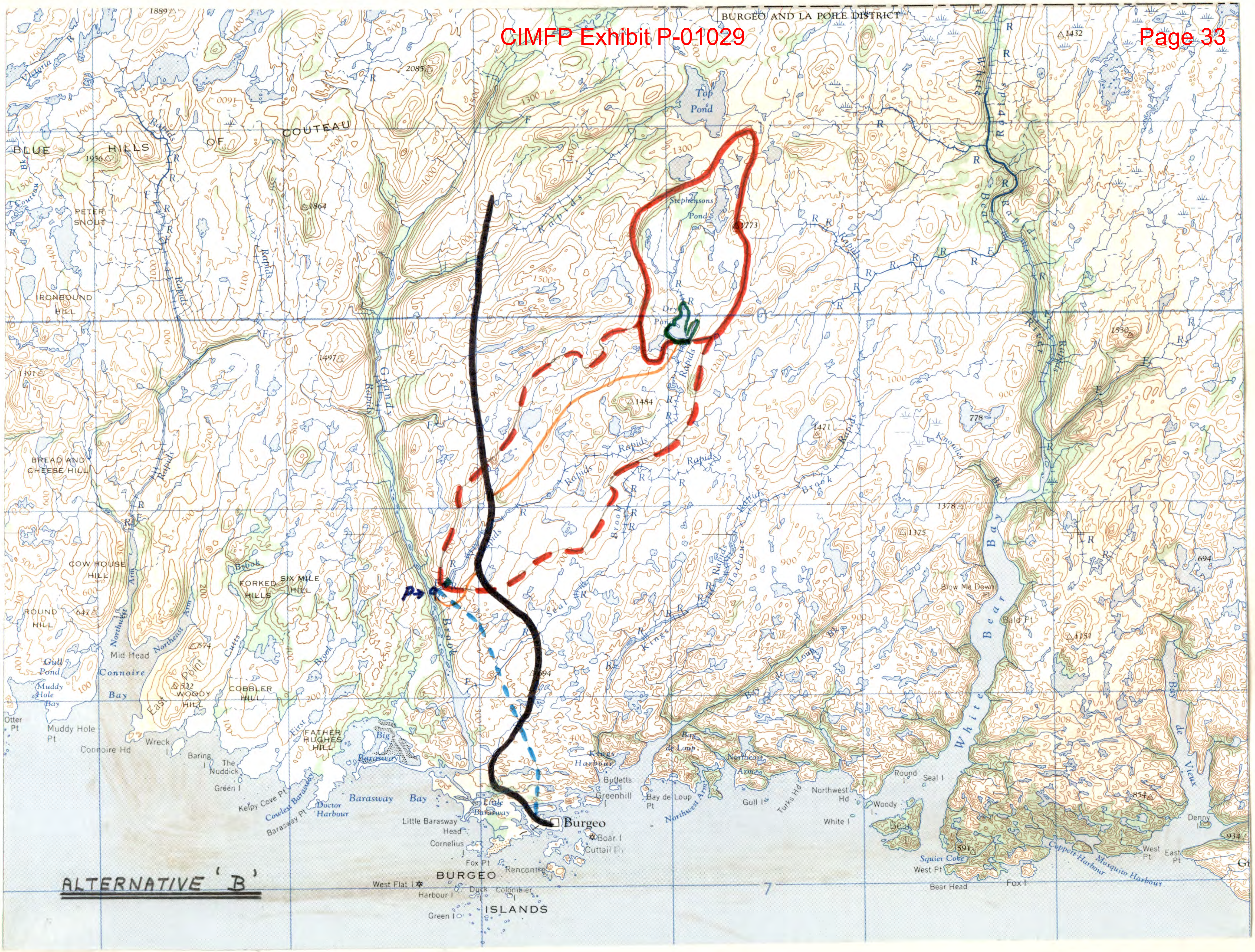
GRANDY BROOK SITE

LOCATION MAP KEY

Power House ----------------------------------	P → O
Dams and Reservoirs --------------------------	
Total Drainage Area --------------------------	
Reservoir Controlled Drainage Area ----------	
Canals --------------------------------------	
Transmission Lines --------------------------	
Site Roads ----------------------------------	
Burgeo Road ---------------------------------	

Scale: 1 : 250,000


BURGEO AND LA POILE DISTRICT
BLUE HILLS OF COUTEAU
PETER SNOUT
IRONBOUND HILL
BREAD AND CHEESE HILL
P → O
COW HOUSE HILL
ROUND HILL
FORKED HILLS
SIX MILE HILL
Mid Head
Connoire Bay
Gull Pond
Muddy Hole Bay
Muddy Hole Pt
Connoire Hd
WOODY HILL
COBBLER HILL
FATHER HUGHES HILL
Wreck I
Baring I
The Nuddick
Green I
Kelpy Cove Pt
Coulest Barasway
Barasway Pt
Doctor Harbour
Barasway Bay
Big Barasway
Little Barasway
Little Barasway Head
Cornelius I
Fox Pt
Rencontre
West Flat I
BURGEO
ISLANDS
Harbour I
Duck
Colombier
Green I
Burgeo
Boar I
Cuttail I
Kings Harbour
Buffetts
Greenhill
Bay de Loup Pt
Bay de Loup
Northwest Arm
Northeast Arm
Gull I
Turks Hd
Northwest Hd
White I
Round I
Seal I
Woody I
Squier Cove
West Pt
Bear Head
Fox I
Cuppett Harbour
Mosquito Harbour
West Pt
East Pt
Denny
White Bear Bay
Bay de Vieux
Blow Me Down Pt
Bald Pt
Top Pond
Stephensons Pond
Dry Pond
Grandy Brook
Seal Brook
Kings Harbour Brook
Knowles Bk
White Bear River
Rapids
ALTERNATIVE 'A'


BURGEO AND LA POILE DISTRICT
ALTERNATIVE 'B'
BLUE HILLS OF COUTEAU
PETER SNOUT
IRONBOUND HILL
BREAD AND CHEESE HILL
COW HOUSE HILL
ROUND HILL
FORKED HILLS
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Dry Pond
Gull Pond
Muddy Hole Bay
Mid Head
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The Nuddick
Green I
Kelpy Cove Pt
Couleé Barasway
Barasway Pt
Doctor Harbour
Barasway Bay
Big Barasway
Little Barasway
Little Barasway Head
Cornelius I
Fox Pt
Burgeo
Boar I
Cuttail I
Rencontre
BURGEO ISLANDS
West Flat I
Harbour I
Duck
Colombier
Green I
Kings Harbour
Buffetts
Greenhill
Bay de Loup
Bay de Loup Pt
Northwest Arm
Northeast Arm
Gull I
Turks Hd
Northwest Hd
White I
Round I
Seal I
Woody I
Squier Cove
West Pt
Bear Head
Fox I
Coppett Harbour
Mosquito Harbour
West Pt
East Pt
Denny
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Grandy Brook
Broom Brook
Bear R
Rapids
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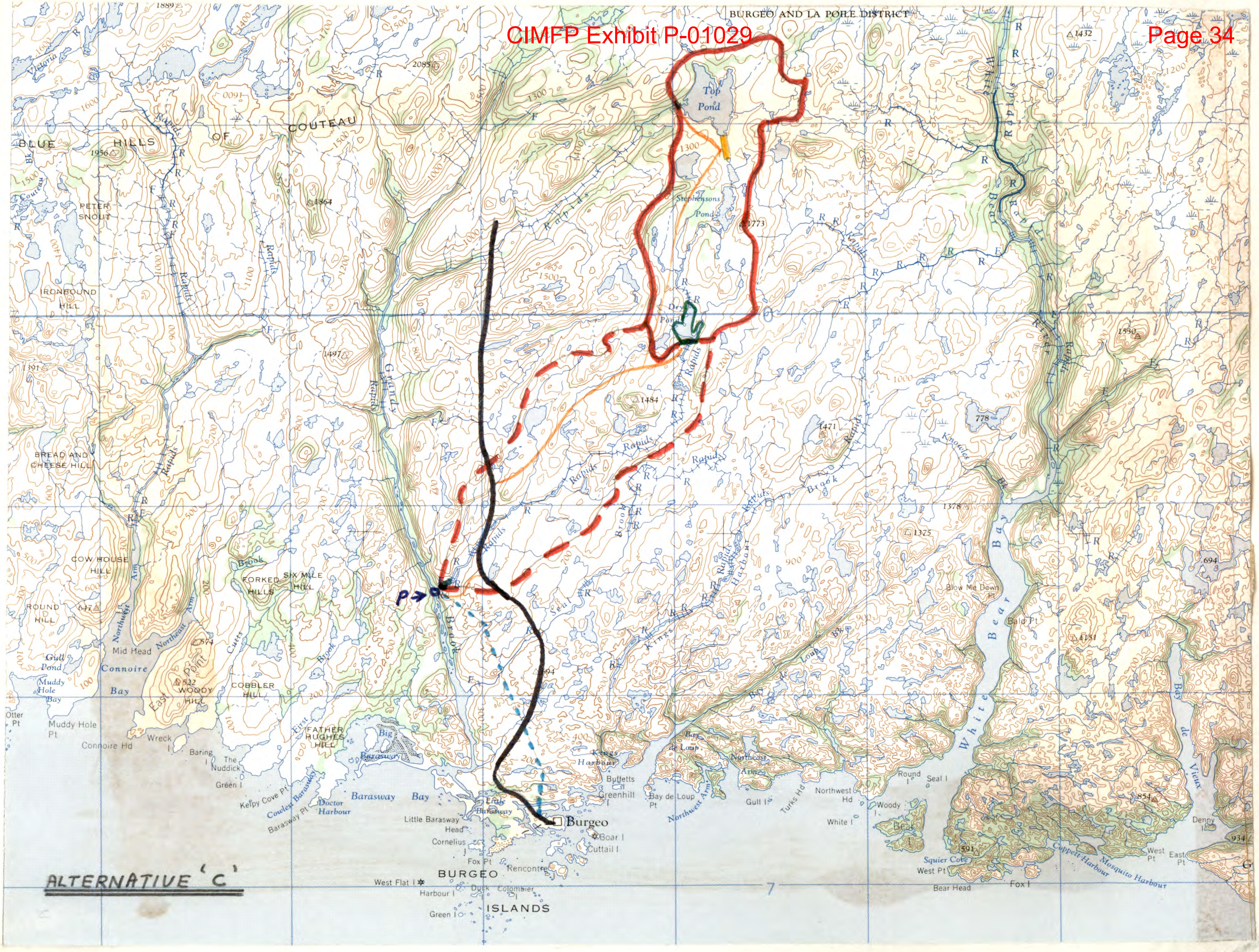
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Cuppett Harbour
Mosquito Harbour
East Pt
Denny I
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Blow Me Down Pt
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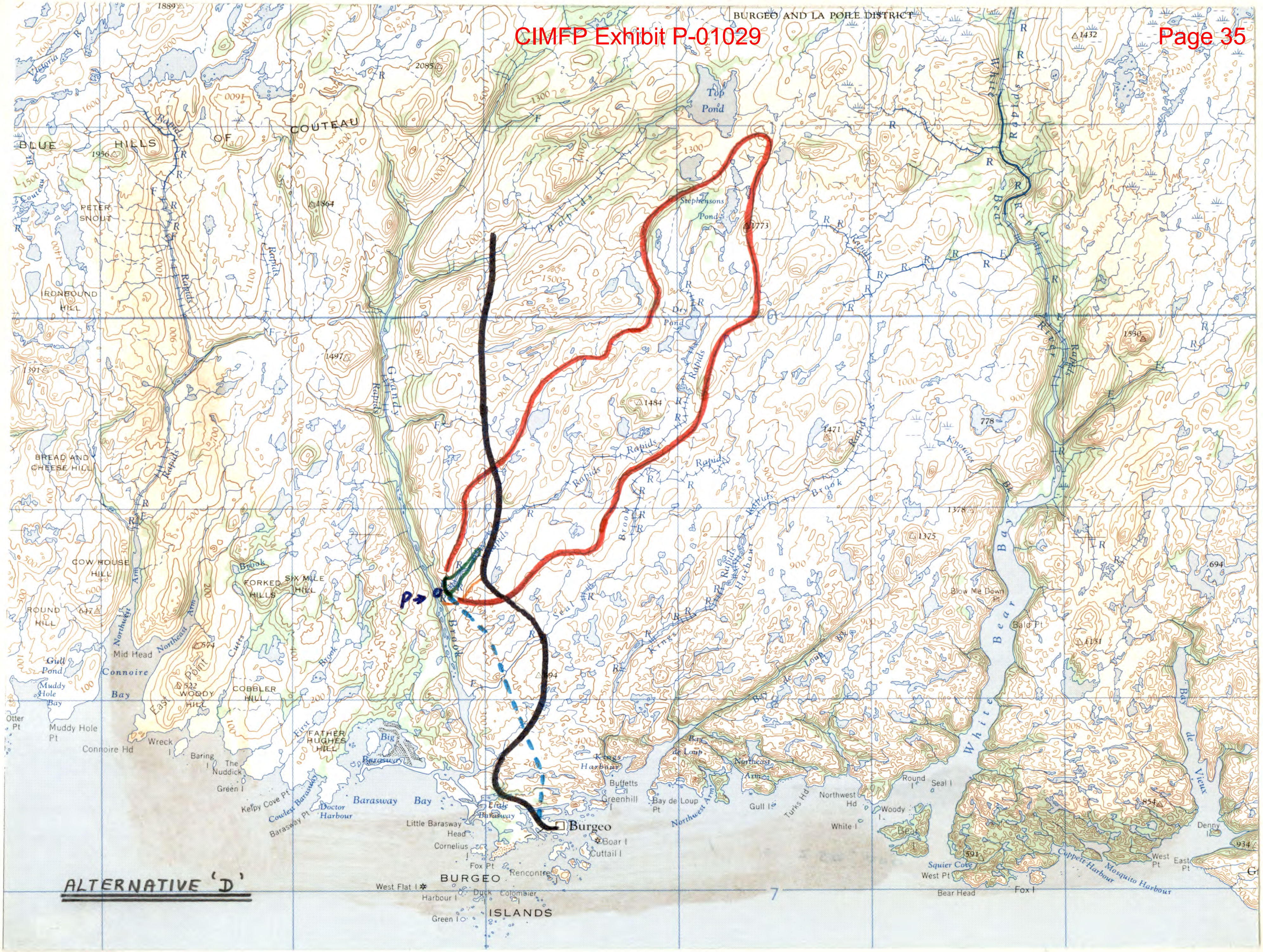
White Bear Bay
White Bear River
Grandy Brook
Rapids
Knowles
P→
ALTERNATIVE 'C'



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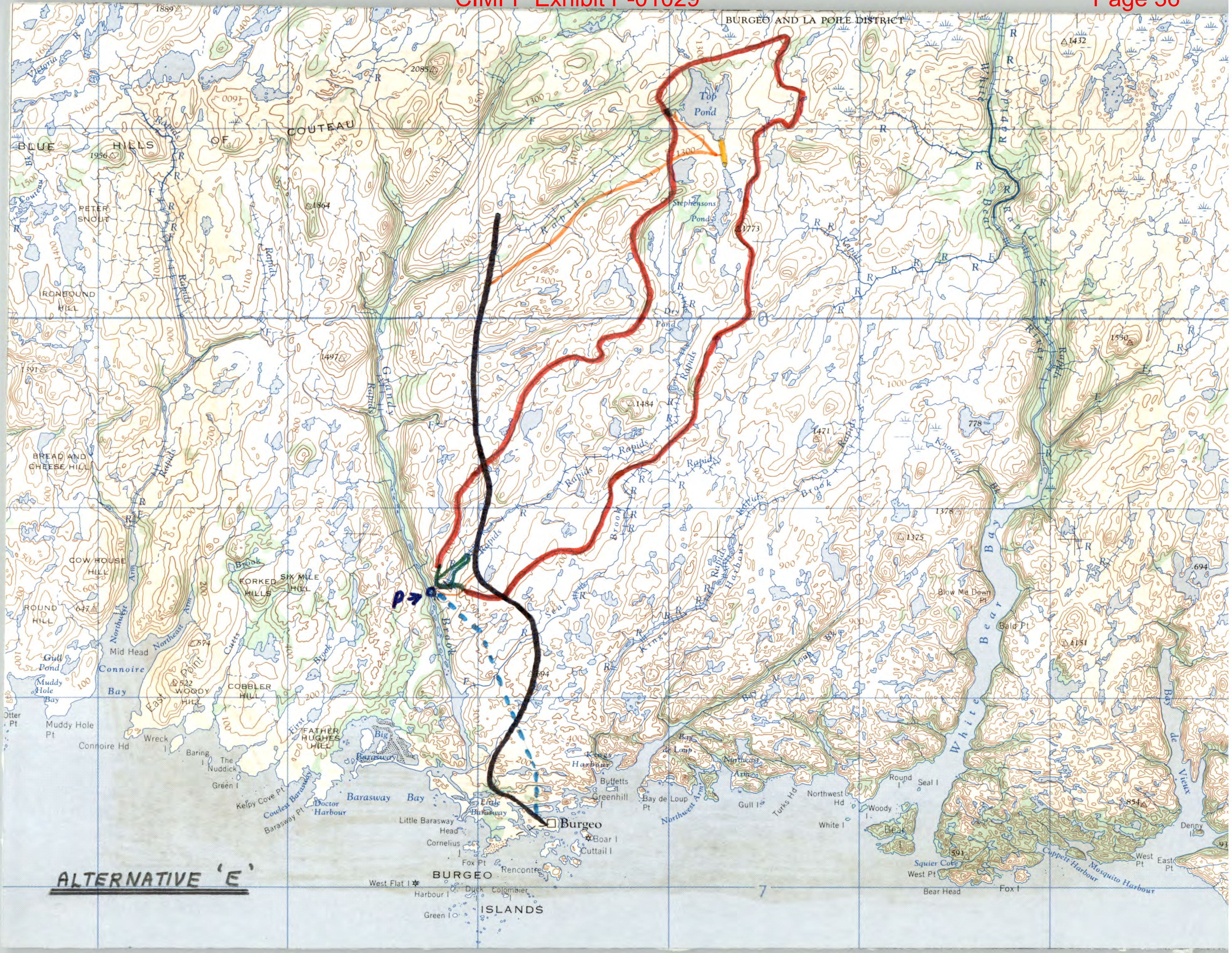
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Wreck
Barasway Bay
Little Barasway
Little Barasway Head
Burgeo
BURGEO ISLANDS
Kings Harbour
Buttetts
Greenhill
Bay de Loup
Northwest Arm
White Bear Bay
Blow Me Down Pt
Bald Pt
Squier Cove
West Pt
Bear Head
Fox I
Cuttail I
Boar I
Rencontre
Fox Pt
West Flat I
Harbour I
Green I
Denny
P
ALTERNATIVE 'E'

TABLES

LIST OF TABLES

TABLE I

MAINTENANCE AND FUEL COSTS

	1976		1975		1974	
	gal. Fuel	gal. Lube	gal. Fuel	gal. Lube	gal. Fuel	gal. Lube
January	46,360	464	43,674	423	42,651	840
February	43,400	478	44,302	275	42,650	533
March	45,402	559	40,494	395	46,900	516
April	38,132	613	50,007	506	39,681	882
May	35,829	423	34,940	353	34,307	890
June	34,245	346	35,582	360	30,674	2,400
July	34,183	450	32,517	453	30,210	250
August	32,541	540	35,253	253	27,048	300
September	33,451	514	34,410	595	27,012	310
October	36,233	529	41,310	439	36,252	300
November	40,798	542	43,485	425	39,571	484
December	51,268	890	42,388	976	42,873	305
TOTALS	471,842	6,348	478,362	5,476	439,829	8,010

Price paid for fuel and lube delivered ($/gal.)

0.515 $/ gal.	2.40 $/ gal.	0.4015 $/ gal.	2.10 $/ gal.	--	2.15 $/ gal.

Maintenance costs

1976 - $137,000; 1975 - $117,000 (est.); 1974 - $96,330 (est.)

TABLE 2

FORECAST LOADS, BURGEO

Load Forecast:

Year	KVA	KW	kWh x 10^6
1977	2029	1826	6.4
1978	2188	1969	6.9
1979	2358	2112	7.4
1980	2506	2255	7.9
1981	2696	2426	8.5
1982	2886	2597	9.1
1983	3076	2768	9.7
1984	3298	2968	10.4
1985	3551	3196	11.2
1986	3806	3425	12.0
1987	4059	3653	12.8
1988	4344	3910	13.7
1989	4661	4195	14.7
1990	5010	4509	15.8

TABLE 3

HISTORIC LOADS, BURGEO

Year	KVA (winter)	kWh x 10^6	Load Factor (%)
1969	1200	1.2	13
1970	1450	2.7	24
1971	1800	4.3	30
1972	?	5.4	--
1973	1950	5.4	32
1974	1600	5.7	41
1975	1950	6.4	37
1976	?	6.0	--

Load Factor (L.F.) $= \dfrac{\text{kWh}}{\text{KVA x p.f. x 8760}}$

8760 = 24 hrs. x 365 days

Power Factor (p.f.) = 0.90

TABLE 4

COMPARISON OF ALTERNATIVES

Name	Location Lat.	Location Long.	Drainage Area Behind Power House Sq. Mi.	Drainage Area Controlled By Reservoir	Diversion	Reservoirs Capacity Million cft.	Reservoirs Location	Volume of Dam Material	Head	Sustainable ~~Substation~~ Flow cu.ft/sec.	Energy kWhr/yr. x 10^6	Power MW	Installed Capacity MW
Alt. A (Northwest Arm)	47°46'N	57°55'W	88	81.6	N/A	205.5	47°48'N 57°54'N	N/A	250	139	28.9	3.3	8.25
Alt. B (Grandy Brook)	47°43'N	57°41'W	56	18.6	N/A	174	47°50'N 57°31'W		250	48	9.9	1.13	2.85
Alt. C (Grandy Brook)	47°43'N	57°41'W	69.5	32.2	Top Pond into Stephenson's Pond.	307	47°50'N 57°31'W		250	84	17.3	1.97	4.85
Alt. D (Grandy Brook)	47°43'N	57°41'W	56	56	N/A	175	47°43'N 57°41'W		250	99	20.4	2.33	5.83
Alt. E (Grandy Brook)	47°43'N	57°41'W	69.5	69.5	Top Pond into Stephenson's Pond	175	47°43'N 47°43'N	N/A	250	118	24.3	2.77	6.9
									REQUIRED	-----	15.1	1.72	4.31

APPENDICES

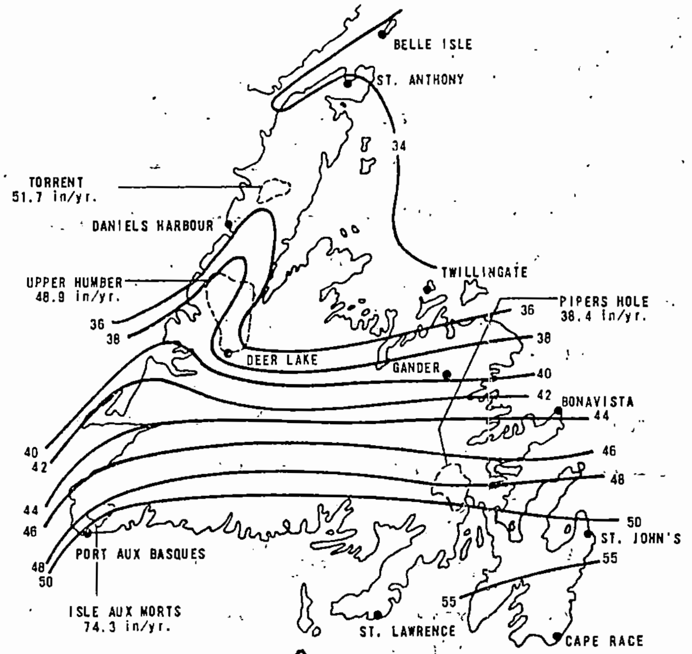
LIST OF APPENDICES

APPENDIX A

The Shawinigan Engineering Company Report

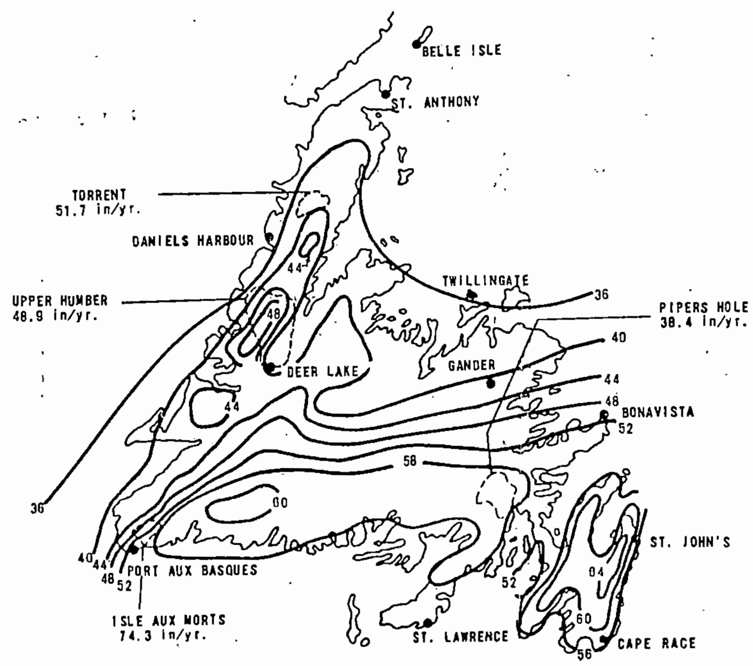
Rainfall Data - Newfoundland and Labrador

NEWFOUNDLAND
MEAN ANNUAL PRECIPITATION DISTRIBUTION



A

ANNUAL PRECIPITATION DISTRIBUTION (INCHES)
ACCORDING TO THE ATLAS OF CANADA
(DEPARTMENT OF MINES AND TECHNICAL SURVEYS, 1957)



B

REVISED ANNUAL PRECIPITATION DISTRIBUTION (INCHES)
(DEPARTMENT OF TRANSPORT -
METEOROLOGICAL BRANCH WORKING DOCUMENT)

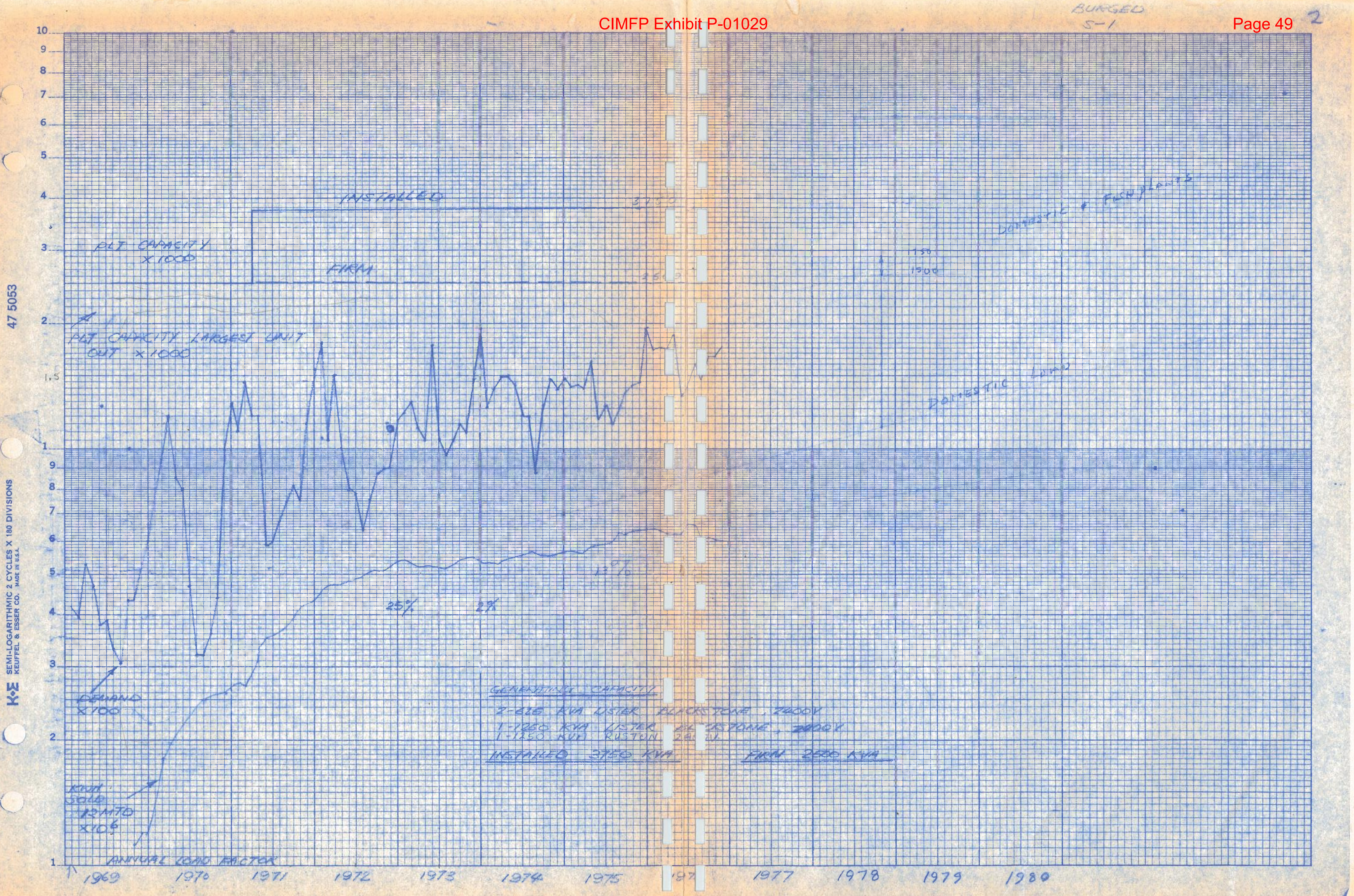
FIGURE 8-12A

APPENDIX B

Historical Load Graph 1969 - 1976

Burgeo, Newfoundland

APPENDIX B


BURGEO
S-1
2
PLT CAPACITY
X 1000
INSTALLED
FIRM
PLT CAPACITY LARGEST UNIT
OUT X 1000
DOMESTIC + FISH PLANTS
DOMESTIC LOAD
DEMAND
X 100
KWH
SOLD
12 MTD
X 10^6
ANNUAL LOAD FACTOR
25%
2%
GENERATING CAPACITY
2-626 KVA LISTER BLACKSTONE, 2400V
1-1250 KVA LISTER BLACKSTONE, 2400V
1-1250 KVA RUSTON 2400V.
INSTALLED 3750 KVA
FIRM 2500 KVA
1969
1970
1971
1972
1973
1974
1975
1977
1978
1979
1980
47 5053
K+E SEMI-LOGARITHMIC 2 CYCLES X 180 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

APPENDIX C

ENVIRONMENTAL CONSIDERATIONS

APPENDIX C

Environmental Considerations

For the purpose of an economic feasibility study of a basic conceptual nature, environmental factors cannot be considered to be of prime importance at this stage. However a mention of some factors at this point will definitely benefit any further investigation.

Some points that may be of interest are taken from the Land Use Atlas for Newfoundland which is an analysis and classification of potential land use.

Recreation and Wildlife

The power house locations of all alternatives is classed "recreational high priority". Northwest Arm forebay is classed "wildlife high priority" and Grandy Brook forebay is classed "recreational high priority". All reservoir areas are classed "wildlife high priority". The Burgeo area generally has low moose capability and high caribou capability. It is the contention of this report that the small areas affected will not affect any caribou population. It may however merely alter an existing caribou route. The power house sites will be sufficient elevation that it is likely there will be no fish affected by the forebay dams. Recreation may basically be evaluated in terms of good hunting areas and again the water structures, etc., should not adversely affect any hunting.

Forestry

Only the Grandy Brook Valley, which would contain the power house for the Grandy Brook alternatives, has any potential commercial use, and even then, it is only given a Class 6. Productivity, that is 11-30 cu. ft/acre/year. It would be advisable however, to ensure as little timber as possible is damaged. Basically, the whole area surrounding Burgeo has severe limitations precluding forests. Wood to the people of Burgeo may very well be a highly prized item. All timber is presently owned by the crown in the study areas.

Agriculture

All of the land affected by any possible hydro development has no agricultural significance. As such, agriculture will really have no consideration.

Minerals

There are presently no known mineral occurrances located on the sites under consideration.

APPENDIX D

VICTORIA RESERVOIR MONTHLY INFLOW DATA

APPENDIX D

NO	YEAR	JANUARY CFS	JANUARY BCF	FEBURARY CFS	FEBURARY BCF	MARCH CFS	MARCH BCF	APRIL CFS	APRIL BCF	MAY CFS	MAY BCF	JUNE CFS	JUNE BCF	J[illegible] CFS	J[illegible] BCF	AUGUST CFS	AUGUST BCF	SEPTEMBER CFS	SEPTEMBER BCF	OCTOBER CFS	OCTOBER BCF	NOVEMBER CFS	NOVEMBER BCF	DECEMBER CFS	DECEMBER BCF	TOTAL CFS	TOTAL BCF	MEAN CFS	MEAN BCF
1	1950	799	2.14	492	1.19	425	1.14	1508	3.91	3454	9.25	1084	2.81	2207	5.[illegible]	1811	4.85	247	0.64	325	0.87	856	2.22	1004	2.69	14212	37.62	1184	3.14
2	1951	881	2.36	1509	3.65	974	2.61	2982	7.73	1404	3.76	961	2.49	855	2.29	904	2.42	752	1.95	855	2.29	2369	6.14	1161	3.11	15607	40.80	1300	3.40
3	1952	874	2.34	1106	2.77	568	1.52	1242	3.22	3946	10.57	1817	4.71	885	2.[illegible]	459	1.23	224	0.58	467	1.25	1979	5.13	788	2.11	14355	37.80	1196	3.15
4	1953	1359	3.64	868	2.10	579	1.55	2870	7.44	1348	3.61	1470	3.81	680	1.82	594	1.59	826	2.14	1370	3.67	988	2.56	1266	3.39	14218	37.32	1185	3.11
5	1954	1045	2.80	1145	2.77	1821	4.88	1481	3.84	2602	6.97	837	2.17	49[illegible]	1.[illegible]	1404	3.76	293	0.76	1187	3.18	1863	4.83	1923	5.15	16094	42.43	1341	3.54
6	1955	1011	2.71	806	1.95	492	1.32	1123	2.91	2539	6.80	1327	3.44	355	0.95	1083	2.90	1343	3.48	1447	3.88	1134	2.94	736	1.97	13396	35.25	1116	2.94
7	1956	2225	5.96	(523)	(1.31)	336	0.90	1254	3.25	3211	8.60	2060	5.34	62[illegible]	1.[illegible]6	519	1.39	748	1.94	586	1.57	1119	2.90	1348	3.61	14549	38.43	1212	3.20
8	1957	1004	2.69	471	1.14	508	1.36	532	1.38	3211	8.60	1894	4.91	104[illegible]	2.[illegible]	747	2.00	1281	3.32	1755	4.70	1022	2.65	2423	6.49	15890	42.03	1324	3.50
9	1958	1243	3.33	649	1.57	952	2.55	1520	3.94	2009	5.38	1200	3.11	108[illegible]	2.89	1445	3.87	2060	5.34	1605	4.30	2307	5.98	1131	3.03	17201	45.29	1433	3.77
10	1959	492	1.32	496	1.20	325	0.87	1373	3.56	3203	8.58	1416	3.67	418	1.[illegible]	378	1.01	841	2.18	952	2.55	1393	3.61	1676	4.49	12963	34.16	1080	2.85
11	1960	511	1.37	(838)	(2.10)	328	0.88	1327	3.44	3539	9.48	1123	2.91	444	1.19	157	0.42	395	1.02	1445	3.87	1277	3.31	821	2.20	12205	32.19	1017	2.68
12	1961	399	1.07	165	0.40	168	0.45	563	1.46	3256	8.72	2284	5.92	511	1.[illegible]	273	0.73	413	1.07	1303	3.49	1366	3.54	945	2.53	11646	30.75	970	2.56
13	1962	568	1.52	558	1.35	444	1.19	2488	6.45	2968	7.95	1597	4.14	1016	2.72	844	2.26	424	1.10	1131	3.03	2635	6.83	933	2.50	15606	41.04	1301	3.42
14	1963	1695	4.54	814	1.97	373	1.00	1424	3.69	3946	10.57	1674	4.34	110[illegible]	2.[illegible]	388	1.04	779	2.02	780	2.09	1701	4.41	1501	4.02	16184	42.66	1349	3.55
15	1964	343	0.92	(427)	(1.07)	556	1.49	1975	5.12	3476	9.31	2060	5.34	1363	3.65	497	1.33	625	1.62	1142	3.06	1111	2.88	833	2.23	14408	38.02	1201	3.17
16	1965	650	1.74	207	0.50	1392	3.73	444	1.15	2524	6.76	2342	6.07	519	1.[illegible]	336	0.90	313	0.81	1228	3.29	1794	4.65	960	2.57	12709	33.56	1059	2.79
17	1966	414	1.11	331	0.80	471	1.26	1285	3.33	2431	6.51	1590	4.12	497	1.[illegible]3	717	1.92	725	1.88	1157	3.10	1678	4.35	1411	3.78	12707	33.49	1059	2.79
18	1967	761	2.04	455	1.10	350	0.94	355	0.92	3730	9.99	938	2.43	378	1.01	1490	3.99	482	1.25	1210	3.24	2600	6.74	2061	5.52	14810	39.17	1234	3.26
19	1968	1180	3.16	(1381)	(3.46)	1090	2.92	1150	2.98	1520	4.07	1871	4.85	225[illegible]	6.[illegible]	799	2.14	687	1.78	1034	2.77	2160	5.60	1930	5.17	17061	44.95	1422	3.75
20	1969	892	2.39	3538	8.56	695	1.86	1204	3.12	3793	10.16	856	2.22	210	0.56	489	1.31	529	1.37	918	2.46	2662	6.90	2670	7.15	18456	48.06	1538	4.01
21	1970	(2001)	(5.36)	513	1.24	392	1.05	903	2.34	1665	4.46	926	2.40	896	2.[illegible]	982	2.63	1539	3.99	974	2.61	3098	8.03	470	1.26	14359	37.77	1197	3.50
22	1971	2035	5.45	1757	4.25	1381	3.70	4668	12.10	2259	6.05	509	1.32	896	2.40	1374	3.68	826	2.14	1004	2.69	2446	6.34	1079	2.89	20234	53.01	1686	4.42
23	1972	672	1.80	535	1.34	1908	5.11	1188	3.08	3875	10.38	3376	8.75	515	1.[illegible]3	276	0.74	594	1.54	3293	8.82	2164	5.61	1217	3.26	19613	51.81	1634	4.32
24	1973	619	1.66	1310	3.17	515	1.38	1408	3.65	3756	10.06	1030	2.67	904	2.42	1542	4.13	197	0.51	933	2.50	1520	3.94	2039	5.46	15773	41.55	1314	3.46
25	1974	537	1.44	545	1.32	873	2.34	1748	4.53	3162	8.47	1138	2.95	44[illegible]	1.[illegible]0	582	1.56	671	1.74	1990	5.33	1123	2.91	1605	4.30	14422	38.09	1202	3.17
26	1975	515	1.38	260	0.63	993	2.66	1435	3.72	3581	9.59	478	1.24	302	0.81	250	0.67	745	1.93	1206	3.23	1941	5.03	2520	6.75	14225	37.64	1185	3.14
27	1976	1624	4.35	1435	3.48	792	2.12	2666	6.91	2494	6.68	490	1.27	444	1.[illegible]	332	0.89	914	2.37	1740	4.66	1578	4.09	2666	7.14	17179	45.15	1432	3.76
28	1977																												
29	1978																												
30	1979																												
31	1980																												
TOTAL		26349	70.59	23,138	56.39	19,701	52.48	42,116	109.17	79,001	211.6	38,348	99.4	21,34[illegible]	57.[illegible]	20672	55.36	19,473	50.47	33,037	88.5	47,884	124.12	39,117	104.77	410,082	1080.04	34171	90.35
MEAN		976	2.61	857	2.09	730	1.94	1560	4.04	2926	7.84	1420	3.68	791	2.12	766	2.05	721	1.87	1224	3.28	1774	4.60	1445	3.88	15,188	40.0	1266	3.35

No	DATE	REVISIONS	BY	CKD
1	MAY 26 76	MINOR CORRECTIONS	TKL	

NEWFOUNDLAND & LABRADOR POWER COMMISSION

ST. JOHN'S, NEWFOUNDLAND

SCALE
DRAWN BY
CHECKED BY
APPROVED BY

VICTORIA

MONTHLY INFLOW (OR RUNOFF) IN CFS AND BCF

DRAINAGE AREA 408 SQUARE MILES

DATE
PROJECT No
DWG. No B-1137

APPENDIX E

PRELIMINARY SIZING OF TRANSMISSION LINES

Preliminary Sizing
Of
Transmission Lines

Sizing was developed from General Electric's Performance Charts for 60-Cycle Transmission Lines. The following procedure was followed in all calculations:

1) Estimate appropriate voltage and use that chart,
2) Select a reasonable wire size,
3) Use 0.90 power factor[1],
4) From the intersection of the above two criteria proceed vertically downward on the G.E. Voltage Drop Charts to intersect with the load in KW,
5) Take the load in KW to be the maximum required output of the hydro facility in the future based on the present installed capacity,
6) From this second point of intersection, proceed horizontally to the right to the length in transmission. (Nine miles for Grandy Brook, seventeen miles for Northwest Arm),
7) From this third and final point of intersection read the voltage drop in percent of the horizontal axis,

---

[1] Established by Mr. R. Young, Electrical Engineer, Newfoundland and Labrador Hydro.

8) Check to see if the voltage drop is between (4 - 6%)[2], recommended voltage drop for this feasibility study,

9) If it does not fall in this range, select another appropriate wire size and repeat,

10) If this is not successful, after trying the appropriate wire sizes, go to next voltage drop chart.

Note: Adjustments have to be made on voltage drop percentages for conversion to 25 KV from 22 KV Charts and for conversion to 69 KV from 66 KV Charts.

<u>Results</u>

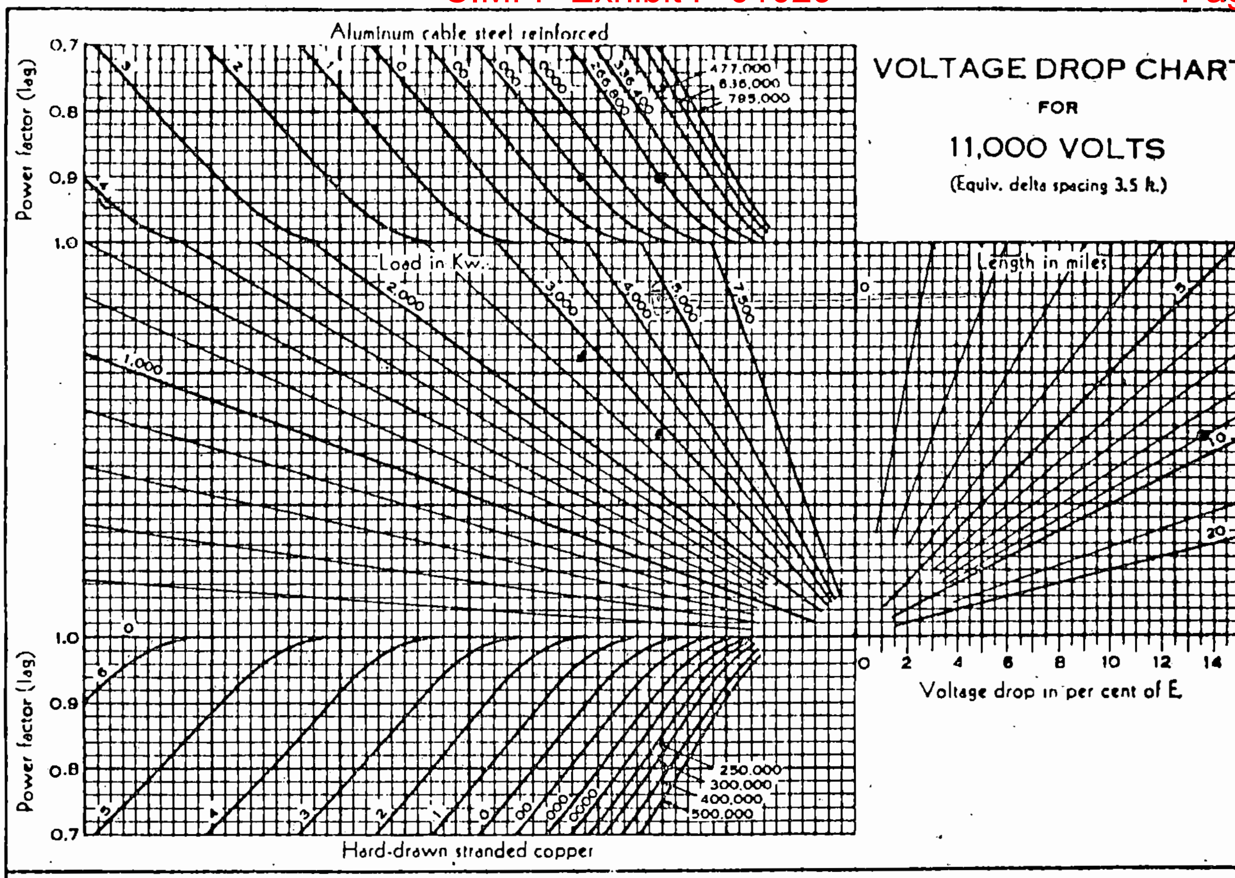
1.	69,000	volts	Alternative A
2.	25,000	volts	Alternatives B, C and D
3.	(34,500)	volts	Alternative E

∴ use 2 - 25,000 volt lines

---

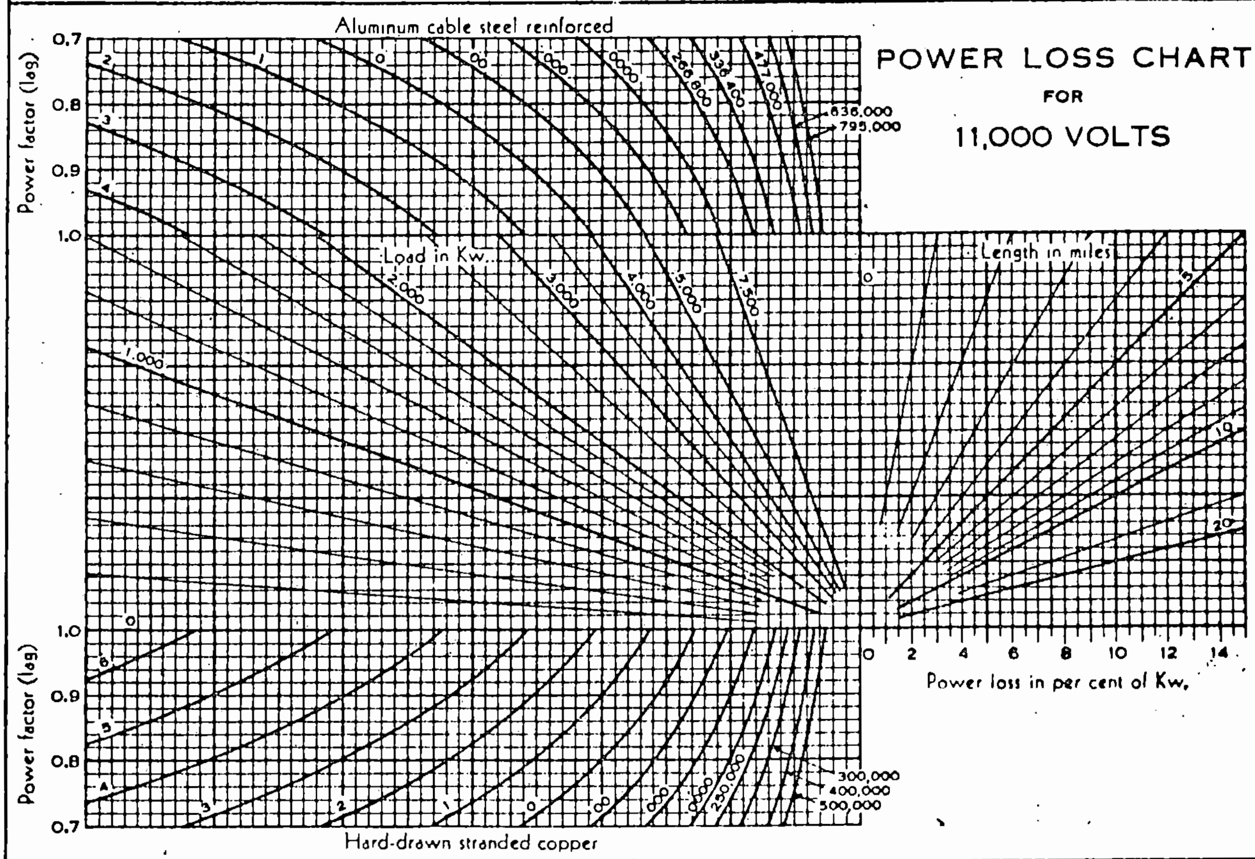
[2] Recommended by Mr. E. H. Bartlett, Power Engineer, Terra Nova Engineering Limited, (see 33,000 Voltage Drop Chart in this Appendix).

E-4



VOLTAGE DROP CHART FOR 11,000 VOLTS

(Equiv. delta spacing 3.5 ft.)

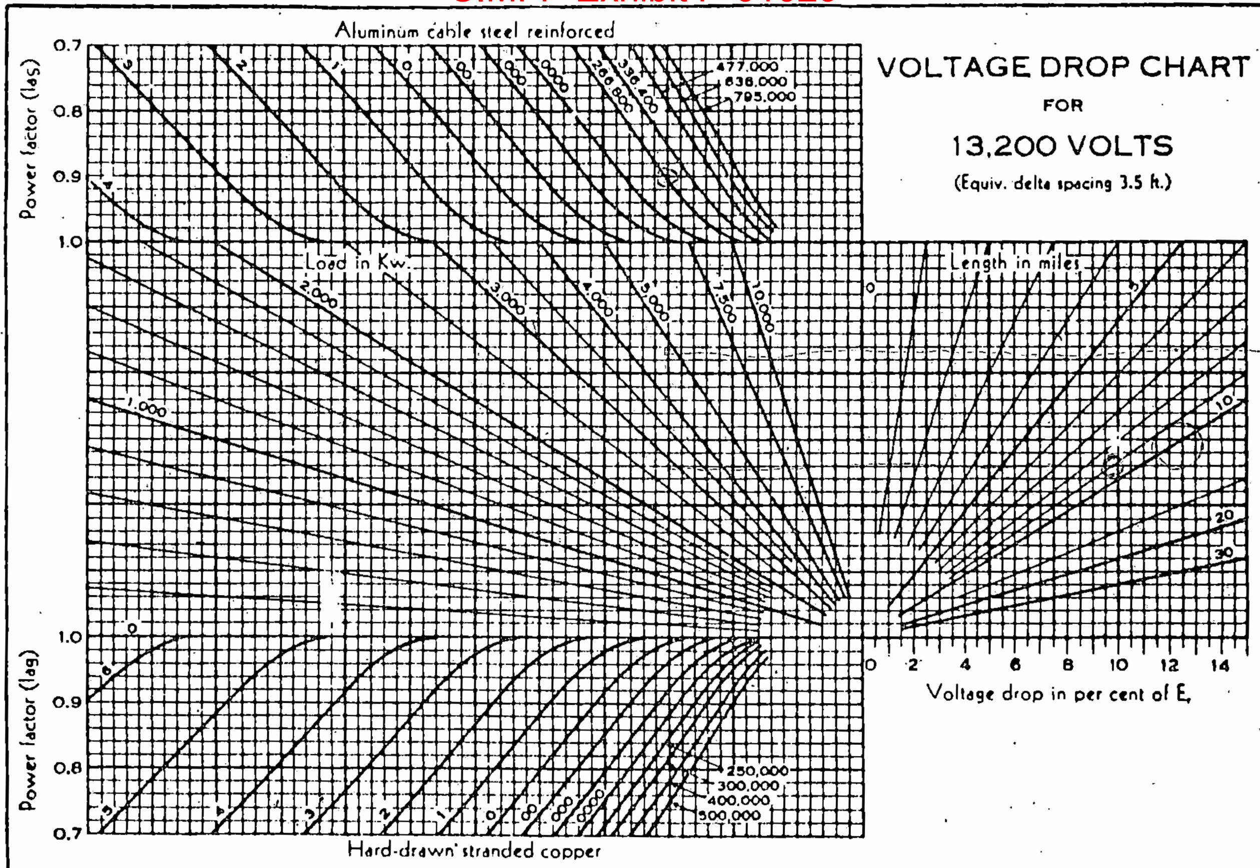


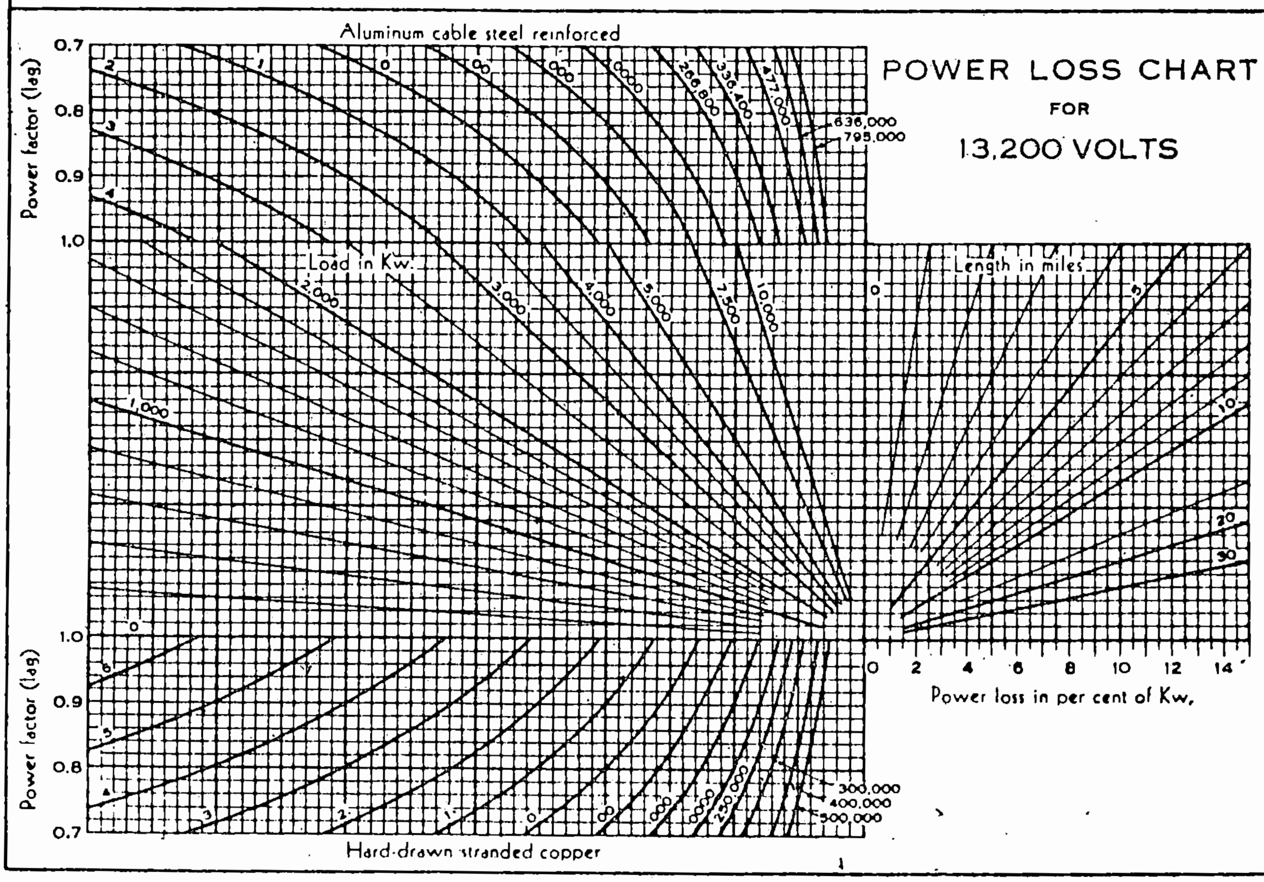
POWER LOSS CHART FOR 11,000 VOLTS

LOAD MULTIPLIERS FOR DIFFERENT RECEIVER VOLTAGES

Receiver kv.	9.9	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9	**11.0**	11.1	11.2	11.3	11.4	11.5	11.6	11.7	11.8
Kw. multiplier	1.234	1.210	1.186	1.163	1.141	1.119	1.097	1.077	1.057	1.037	1.018	**1.000**	0.982	0.965	0.948	0.931	0.915	0.899	0.884	0.869

E-5

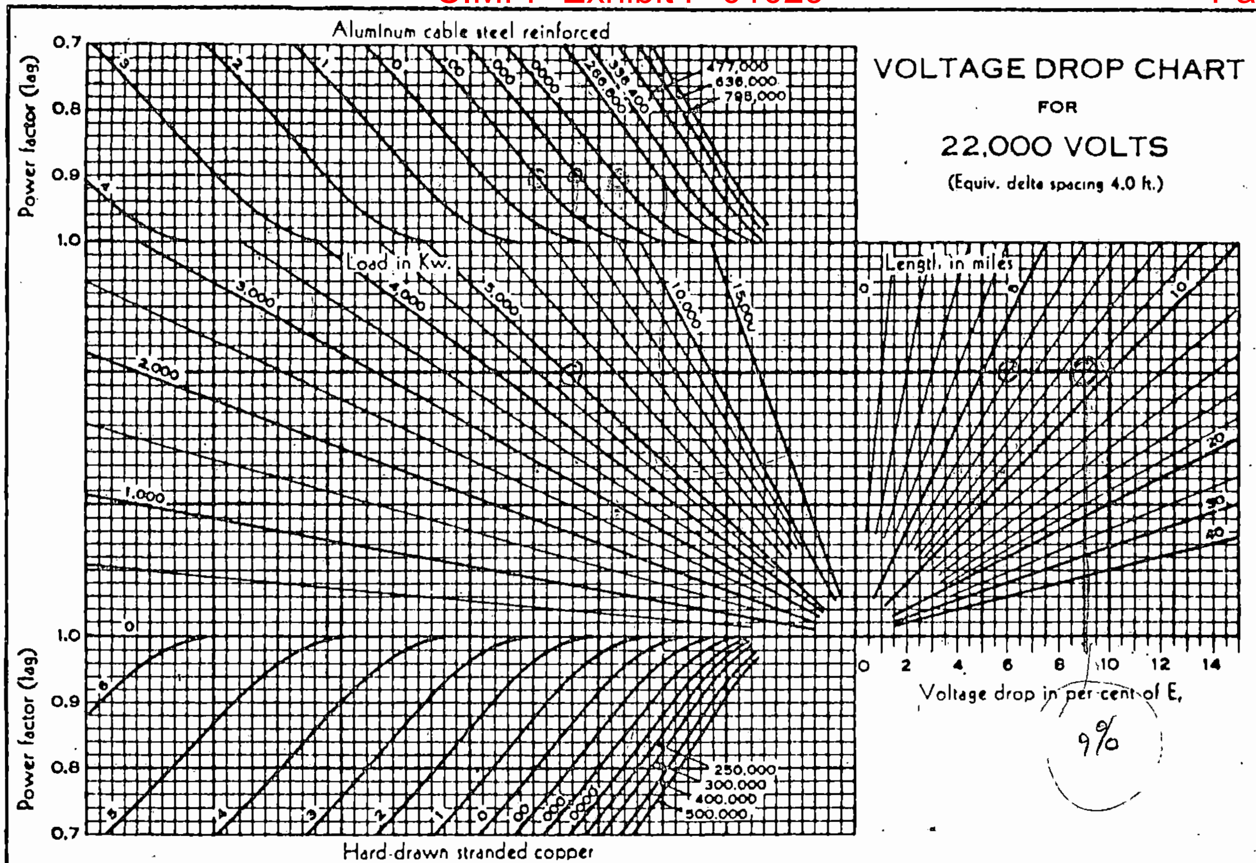


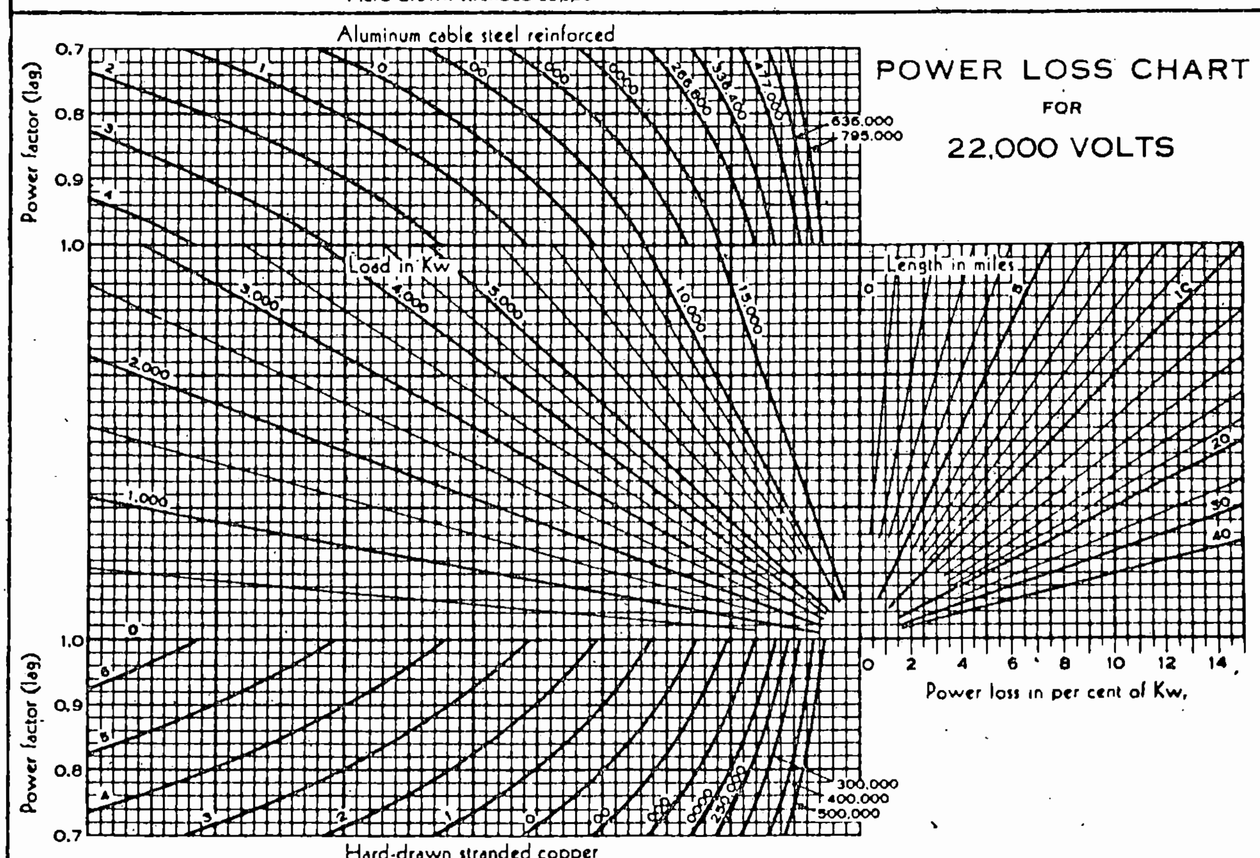


LOAD MULTIPLIERS FOR DIFFERENT RECEIVER VOLTAGES

Receiver kv.	11.9	12.0	12.1	12.2	12.3	12.4	12.5	12.6	12.7	12.8	12.9	13.0	13.1	**13.2**	13.3	13.4	13.5	13.6	13.7	13.8
Kw. multiplier	1.230	1.210	1.190	1.171	1.152	1.133	1.115	1.097	1.080	1.063	1.047	1.031	1.015	**1.000**	0.985	0.970	0.956	0.942	0.928	0.915

E-6

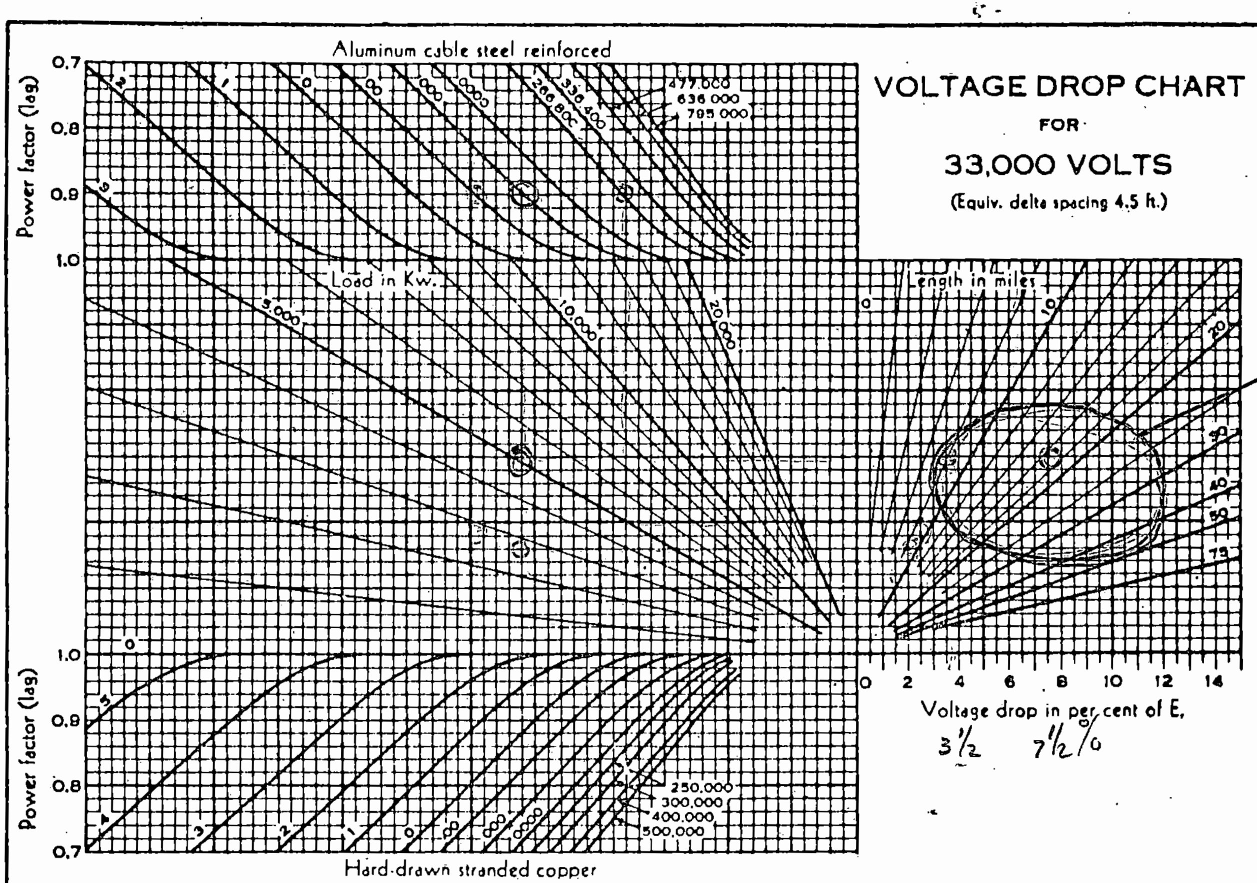




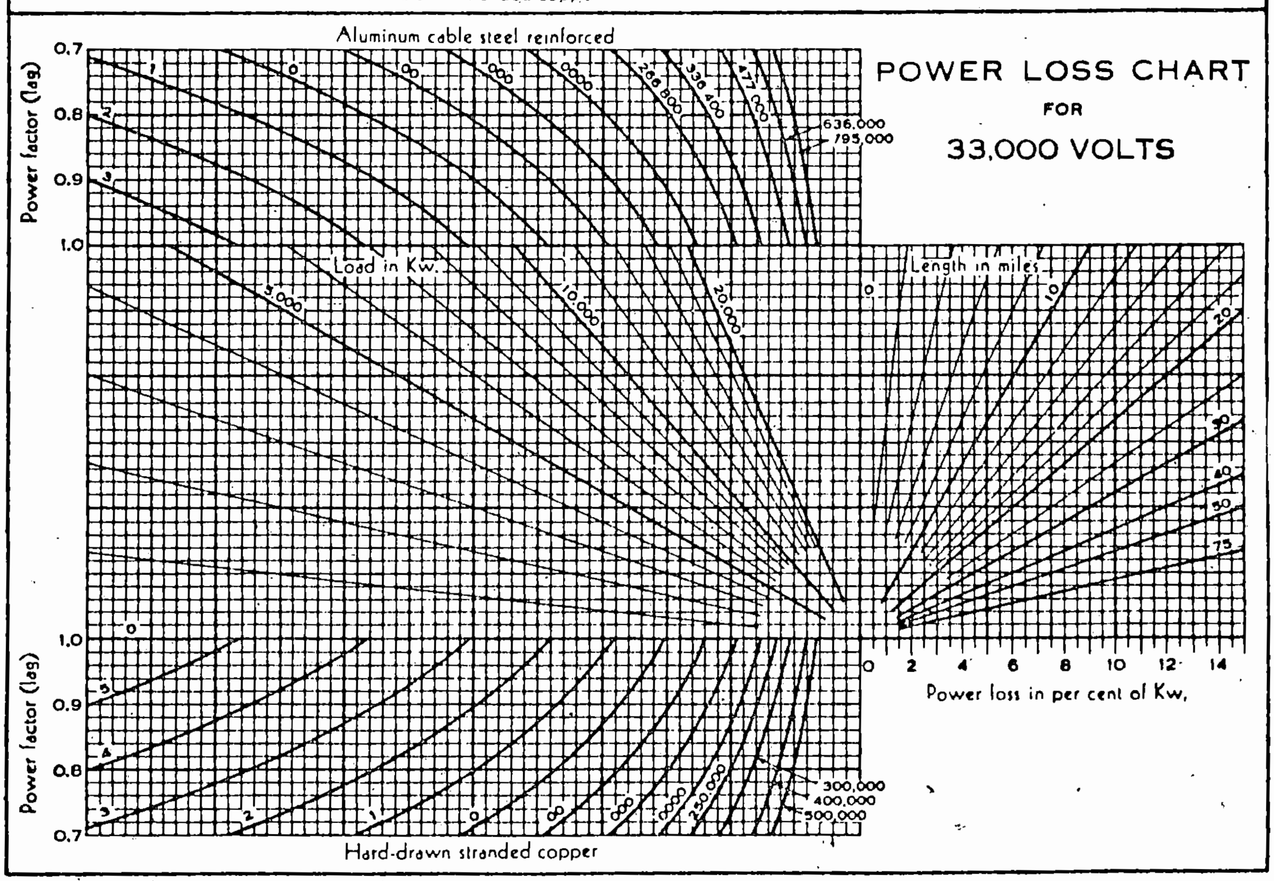
LOAD MULTIPLIERS FOR DIFFERENT RECEIVER VOLTAGES

Receiver kv........	19.2	19.4	19.6	19.8	20.0	20.2	20.4	20.6	20.8	21.0	21.2	21.4	21.6	21.8	22.0	22.2	22.4	22.6	22.8	23.0
Kw. multiplier......	1.313	1.286	1.260	1.234	1.210	1.186	1.163	1.141	1.119	1.097	1.077	1.057	1.037	1.018	1.000	0.982	0.965	0.948	0.931	0.915

E-7



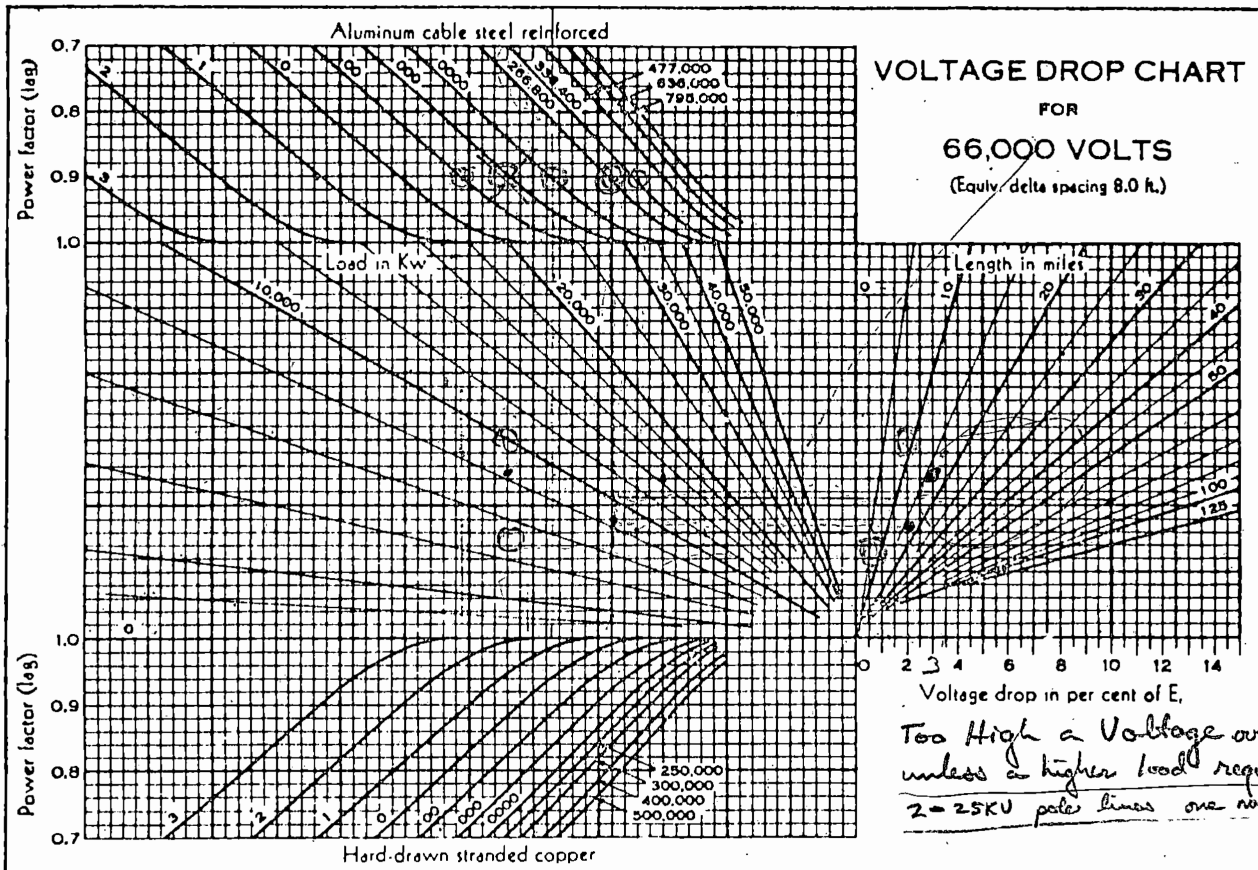
ROUGH IDEA WHERE ECONOMICAL RANGE IS.



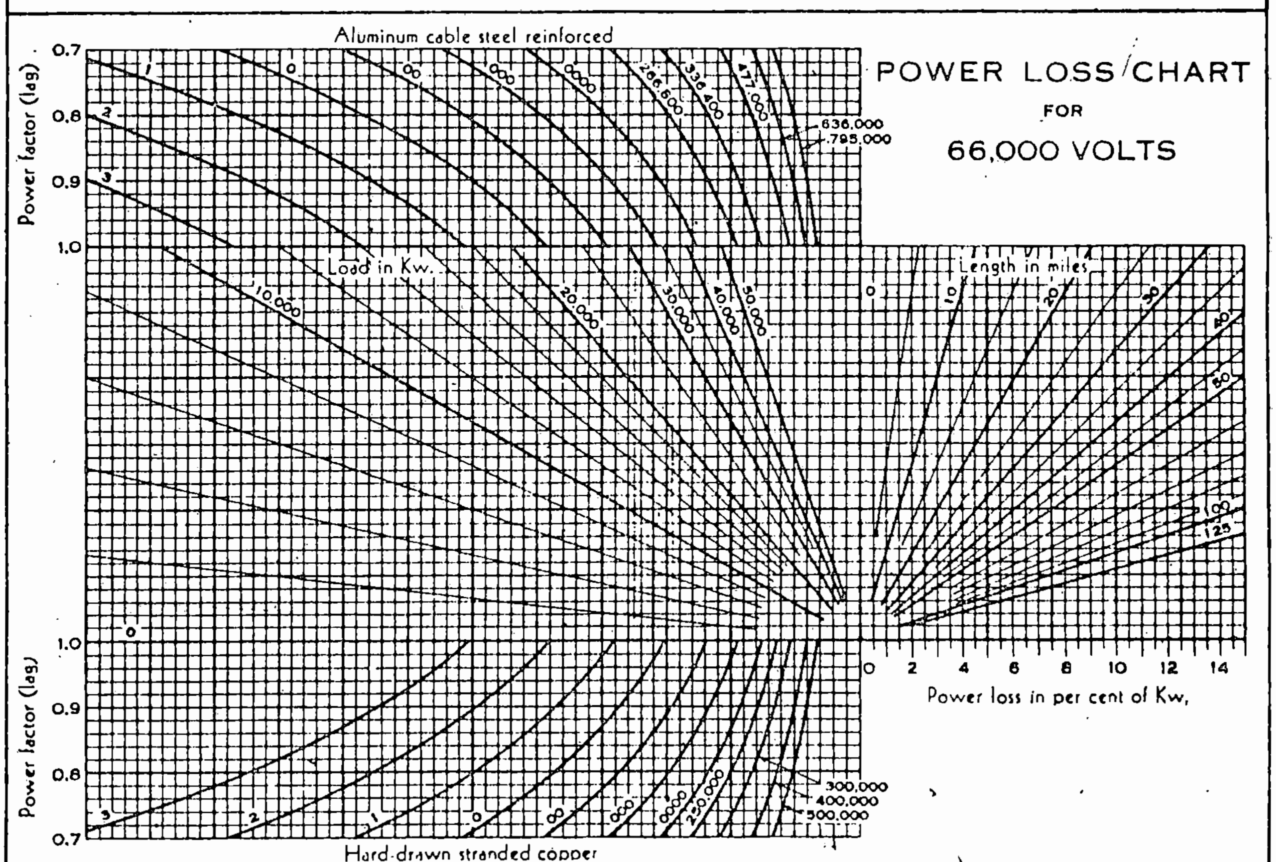
LOAD MULTIPLIERS FOR DIFFERENT RECEIVER VOLTAGES

Receiver kv.	28.5	29.0	29.5	30.0	30.5	31.0	31.5	32.0	32.5	33.0	33.5	34.0	34.5	35.0	35.5	36.0	36.5	37.0	37.5	38.0
Kw. multiplier	1.341	1.295	1.251	1.210	1.171	1.133	1.097	1.063	1.031	1.000	0.970	0.942	0.915	0.889	0.864	0.840	0.817	0.796	0.774	0.754

2 - 25KV Lines.
1 - 69KV Lines.
E-8



Too High a Voltage over 17 miles unless a higher load required.
2 - 25KV pole lines one now one later



LOAD MULTIPLIERS FOR DIFFERENT RECEIVER VOLTAGES

Receiver kv.	59.5	60.0	60.5	61.0	61.5	62.0	62.5	63.0	63.5	64.0	64.5	65.0	65.5	66.0	66.5	67.0	67.5	68.0	68.5	69.0
Kw. multiplier	1.230	1.210	1.190	1.171	1.152	1.133	1.115	1.097	1.080	1.063	1.047	1.031	1.015	1.000	0.985	0.970	0.956	0.942	0.928	0.915

APPENDIX F

Transmission Route Selection

And Transmission Costs

TRANSMISSION ROUTE SELECTION

Basically, the shortest route possible is chosen. Minimal direction changes are used as ~~these are~~ angles increase costs. Adjustments are made to avoid bad contours such as steeply rising hills and bad sidehills.

The largest spread between contours is obviously the best terrain as this will be the most gradually sloping areas. Simple river crossings of short distances are of no disadvantage.

The route to Northwest Arm was kept inland when possible as this can reduce salt contamination.

Transmission Costs

Standard costs in dollars per mile were available from Newfoundland and Labrador Hydro of $22,000/mile for 12.5 KV, $25,000/mile for 25 KV.

Grandy Brook power hosue - transmission line

25 KV	9 miles	$225,000

Northwest Arm power house - transmission line

69 KV	17 miles	not required

APPENDIX G

PRESENT WORTH ANALYSIS

Outline of Techniques

Power-time curves

1) Original five hydro alternatives,

2) All diesel alternative,

3) Revision of Alternatives A, D and E

Energy-time curves

Alternatives B, C and D

Present worth tabulated calculations

Alternatives B, C, D and diesel

Present Worth Analysis

Following steps were used in the economic analysis of alternatives, as tabulated following.

1. Development of Technically Equivalent Alternatives

The two criteria by which technical equivalence was established were:

a) the firm energy capability of the system should be greater than or equal to the energy load forecast in each year. Firm energy for the hydro part of the system is determined from the maximum sustainable yield from the reservoir. For diesel units, the firm energy capability is calculated assuming an 80% capacity factor,

b) the system should always have power capacity equal to the power forecast in each year, plus a reserve capacity which is the greater of:

i) 15% of the system load,

ii) largest single unit plus 5% of the system load.

These alternatives were developed through the use of power-time graphs. These graphs extended for the duration of the available load forecast, and lines were plotted representing the actual demand, and each of the reserve requirement lines.

Assuming hydro generation to start in 1980, the hydro power capacity was also plotted, and extra diesel units were added as necessary to keep the installed capacity lines above the higher reserve requirement line.

This was done for all five hydro alternatives, and for an all-diesel alternative, based on additions to the existing system.

2. Simulation and Evaluation Periods

The period of time over which the demand forecast is known is called the simulation period. After this, any further additions required to the system should be the same, regardless of which alternative is being used, provided that all available energy from the developed sources is being used at that time.

Analysis of the system is made over the full economic life of the hydro system, the additional time being known as the Evaluation Period. Over this period, hydro production is constant at the maximum available, with diesel energy production used if necessary to reach the full energy requirements.

3. <u>Check on Energy Use at End of Similation Period</u>

The analysis of these technically equivalent alternatives is representative of true return on investment only if all the available energy from the alternative is being fully used at the end of the similation period. It was for this reason that alternatives with a firm hydro capability in excess of 15.8 x 10^6 kWh/year was reduced in size to this maximum forecast figure. As discussed in previous sections of this report, this eliminated two alternatives from consideration.

The energy-time curves for the remaining three hydro alternatives were plotted as a visual representation of the relative hydro and diesel generation quantities required. Also, the power-time curve was re-plotted for the alternatives which were reduced in size.

4. <u>Costs Considered in the Analysis</u>

a) capital costs of any new construction, including the hydro development, transmission lines and new diesels. Escalation is applied to the 1977 dollar estimates at 6.0% per year.

b) operation-maintenance and overhead costs for each year. These costs are:

$4.00/KW in 1977 for hydro units,

$8.00/KW in 1977 for diesel units.

These figures are escalated at 6% per annum for each year past 1977.

c) insurance and interim replacement of new units. These costs are computed as a percentage of the initial capital costs, and again escalated at 6%.

	Hydro Units	Diesel Units
Insurance	0.10%	0.25%
Interim Replacement	0.20%	0.35%

d) annual fuel and lube oil costs for diesel units, based on historical consumption per kWh, with unit costs being escalated 6% per annum.

e) capital cost of replacement of system components which have a shorter economic life than the hydro system. These economic lives are:

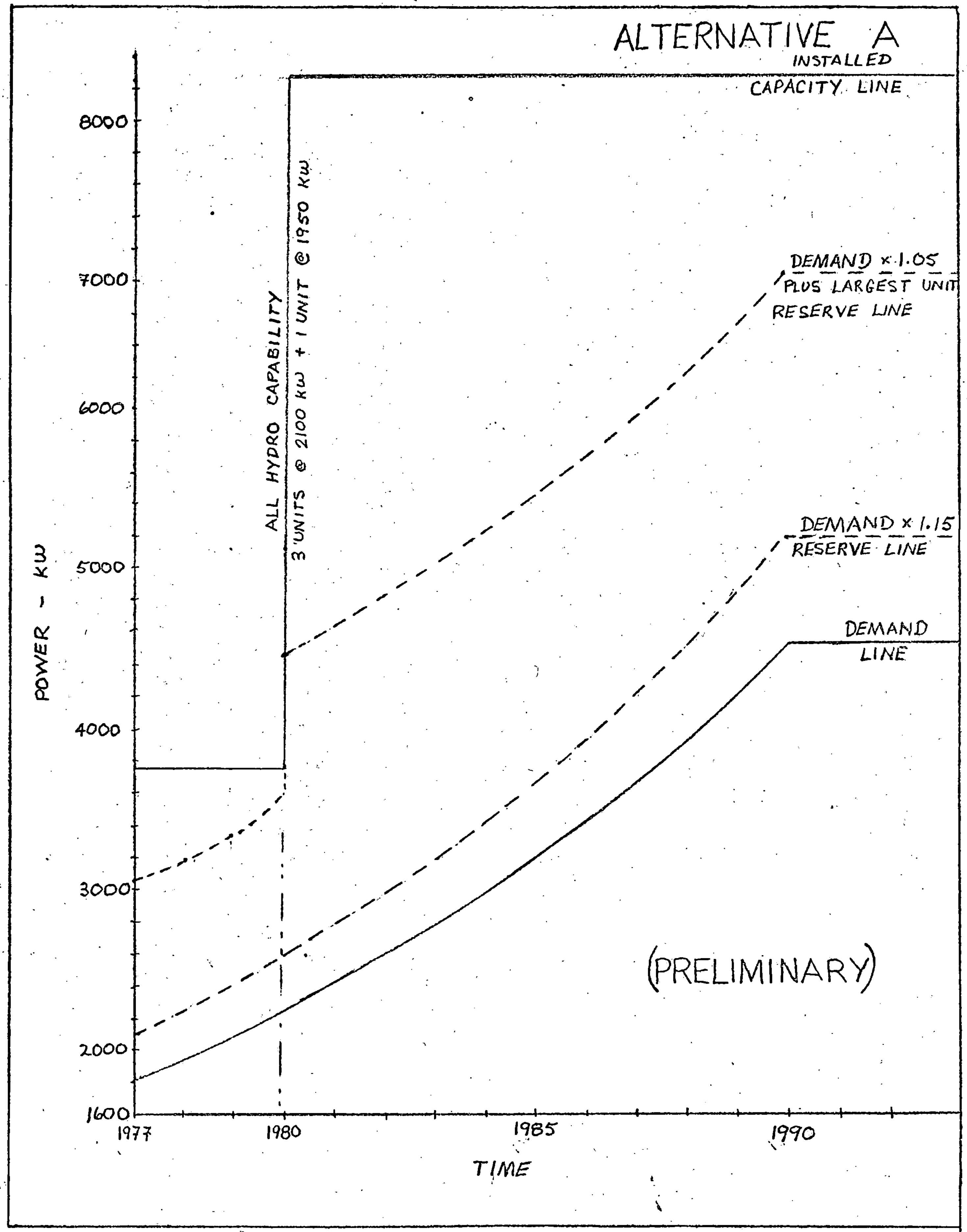
hydro units	60 years
diesel units	30 years
transmission line and sub station	40 years

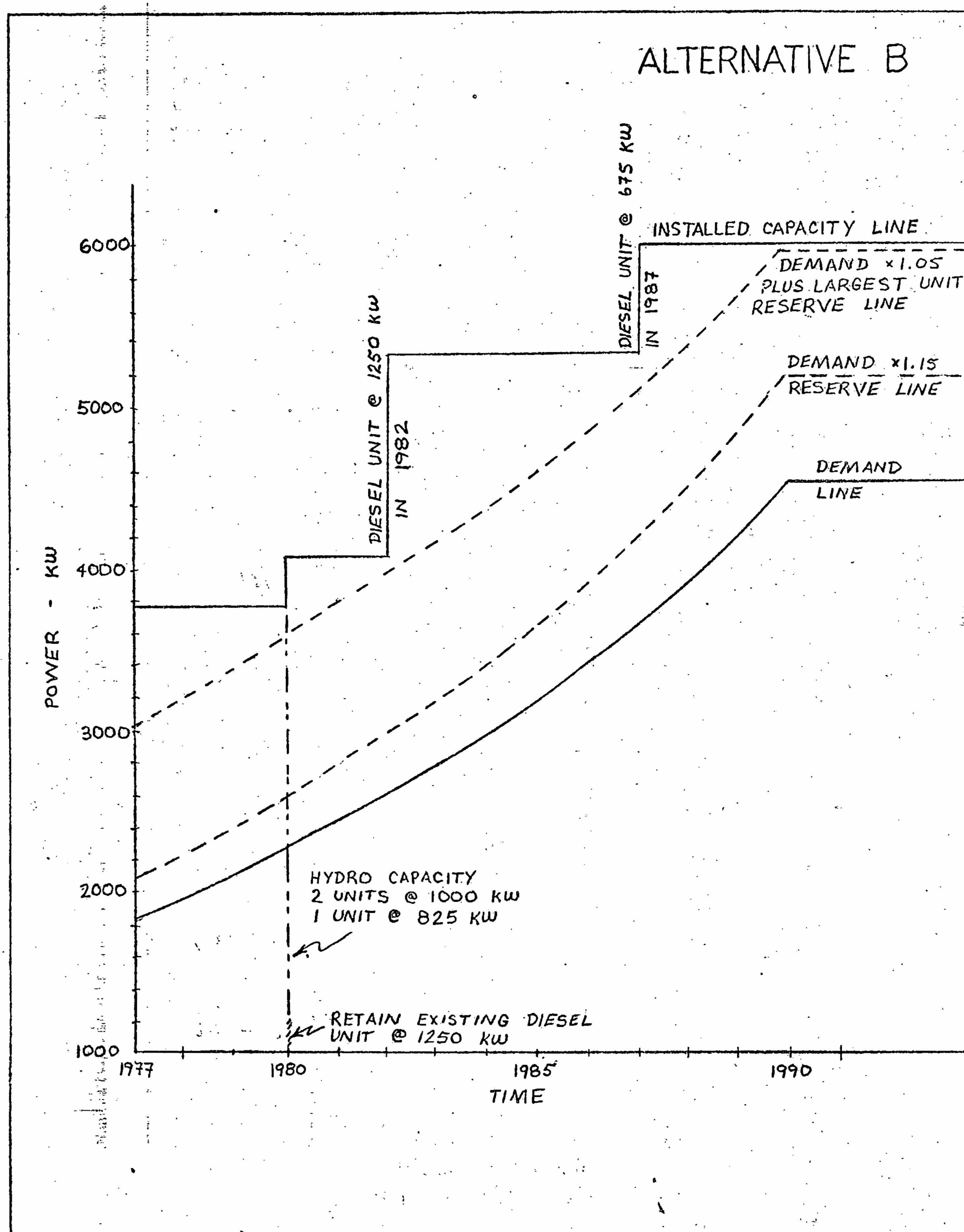
It was assumed that existing diesel units were put into service in 1969, since this is the year in which given historical production figures start.

f) since production is assumed constant over the evaluation period from 1991 to 2040, cash flows in these years can be treated as a uniform series of payments, (at an equivalent discount rate) and present worthed to 1990 as one lump sum.

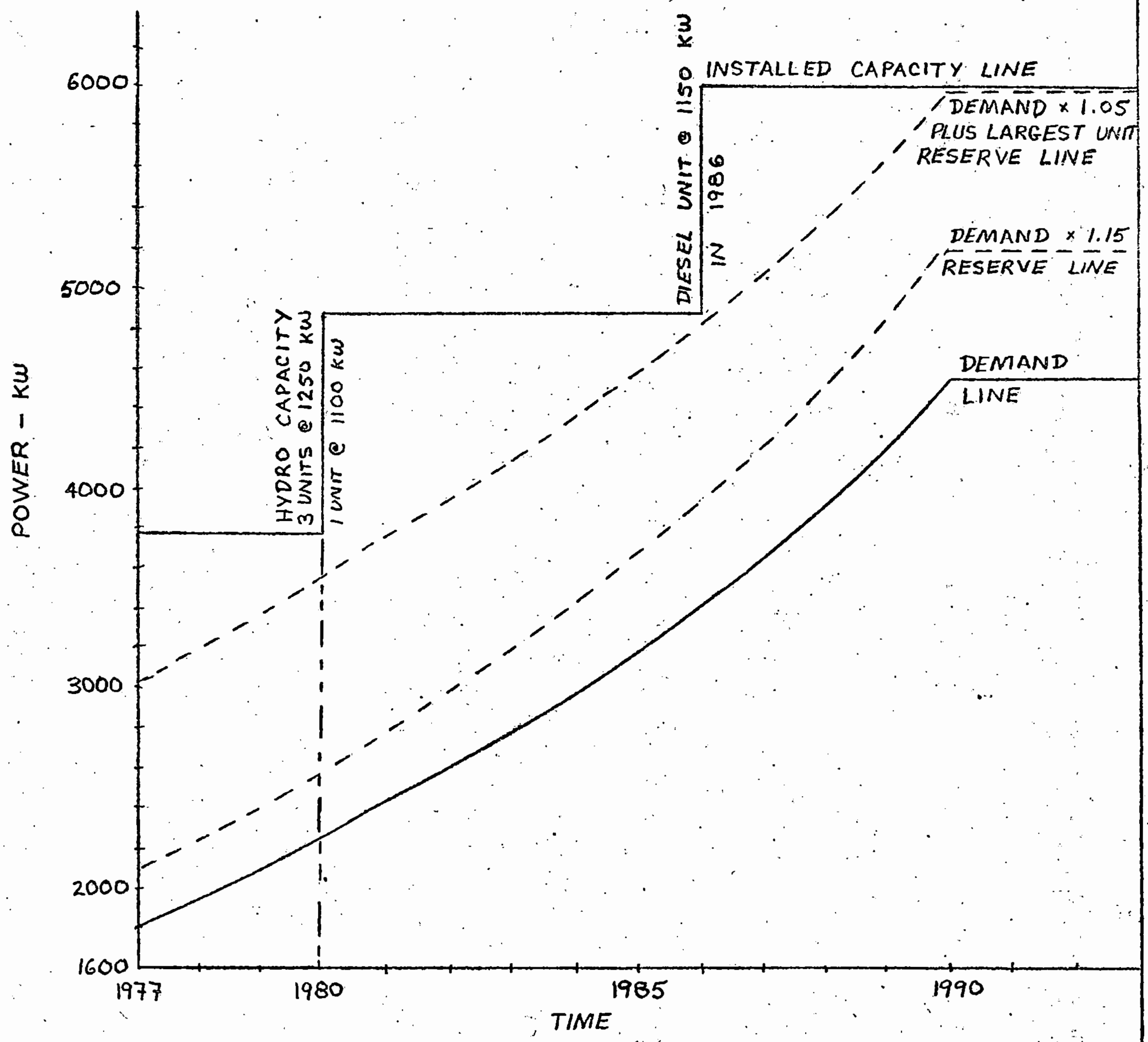
5. Table of Comparison

For each alternative, including the diesel alternative, these costs were summed for each year to 1990, and the present worth in 1977 computed. Then the present worth adjustment for the evaluation period, and replacement costs, were added to get the total present worth of each alternative.

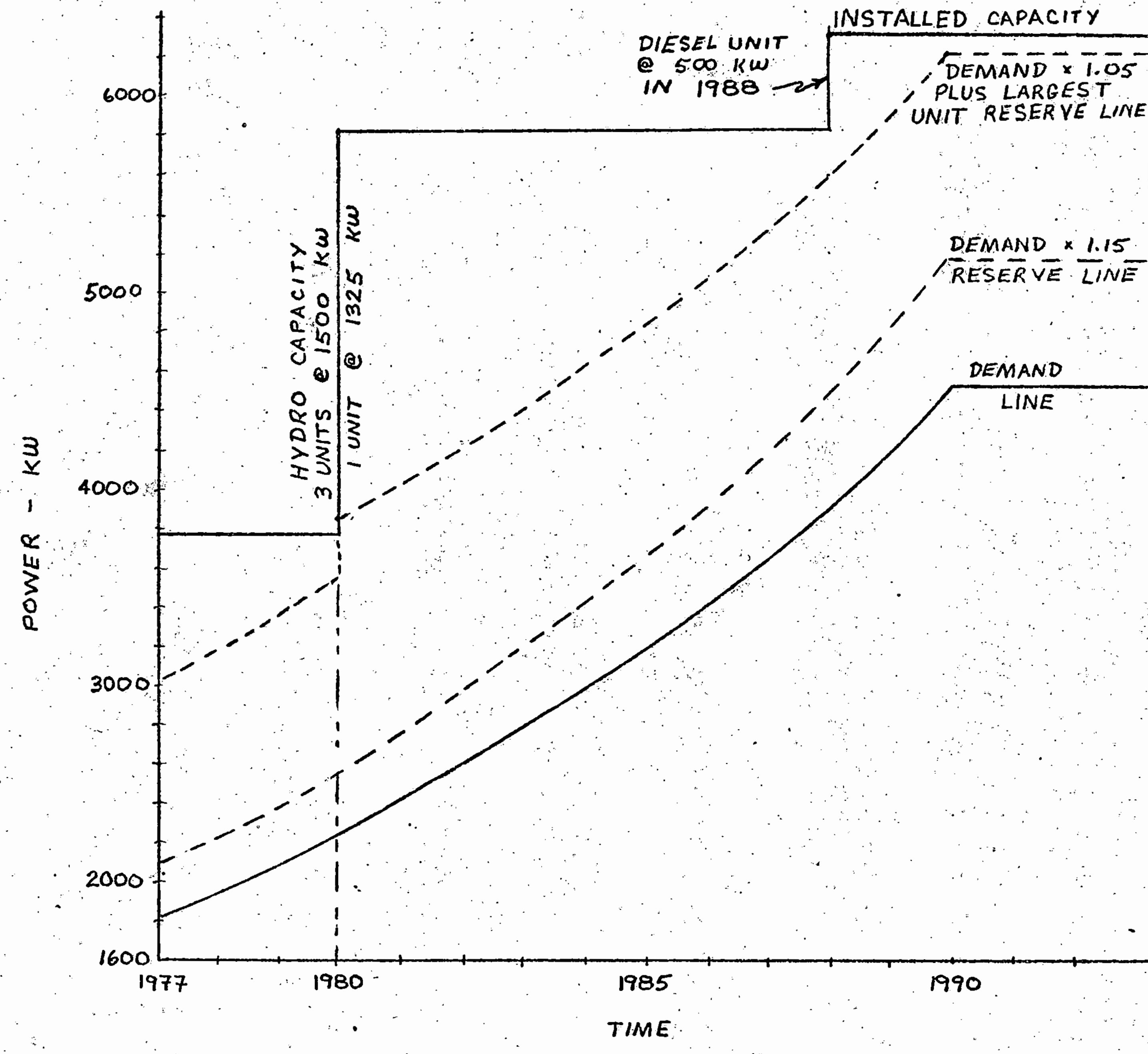

ALTERNATIVE A
INSTALLED CAPACITY LINE
DEMAND × 1.05 PLUS LARGEST UNIT RESERVE LINE
DEMAND × 1.15 RESERVE LINE
DEMAND LINE
ALL HYDRO CAPABILITY
3 UNITS @ 2100 KW + 1 UNIT @ 1950 KW
POWER - KW
8000
7000
6000
5000
4000
3000
2000
1600
1977
1980
1985
1990
TIME
(PRELIMINARY)


ALTERNATIVE B
INSTALLED CAPACITY LINE
DEMAND x1.05
PLUS LARGEST UNIT
RESERVE LINE
DEMAND x1.15
RESERVE LINE
DEMAND
LINE
DIESEL UNIT @ 675 KW
IN 1987
DIESEL UNIT @ 1250 KW
IN 1982
HYDRO CAPACITY
2 UNITS @ 1000 KW
1 UNIT @ 825 KW
RETAIN EXISTING DIESEL
UNIT @ 1250 KW
POWER - KW
6000
5000
4000
3000
2000
1000
1977
1980
1985
1990
TIME

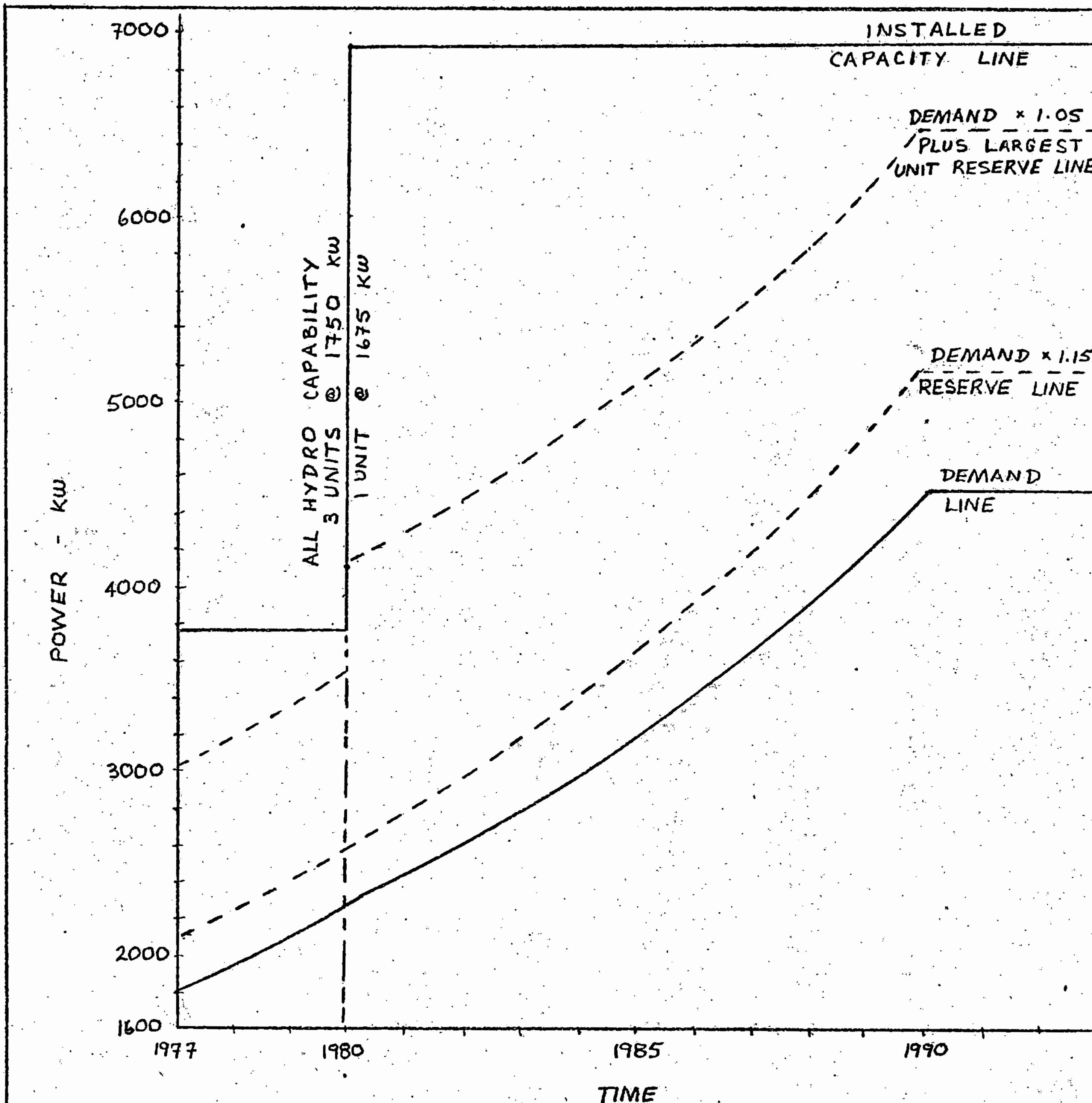
ALTERNATIVE C



ALTERNATIVE D

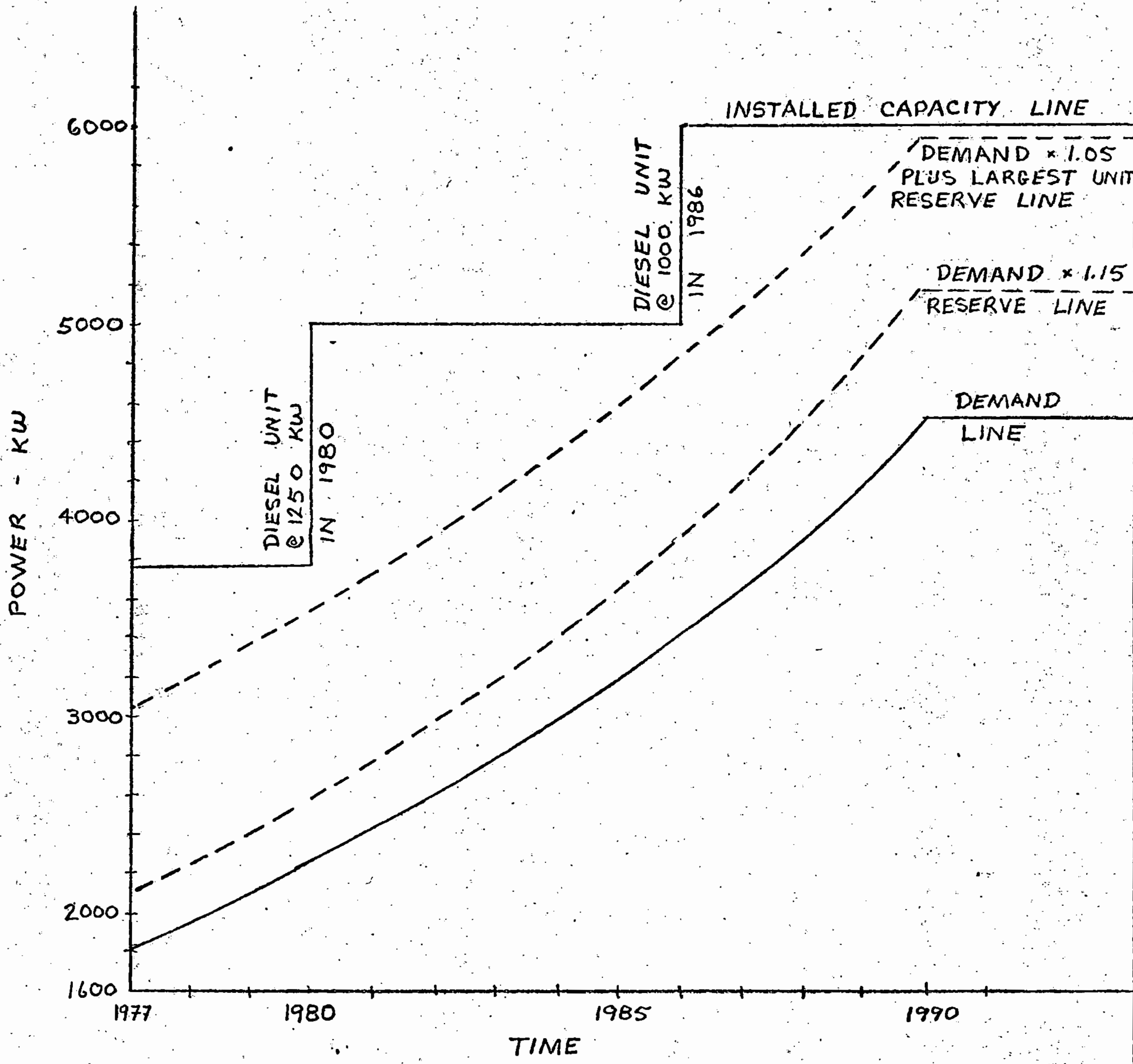


(PRELIMINARY)



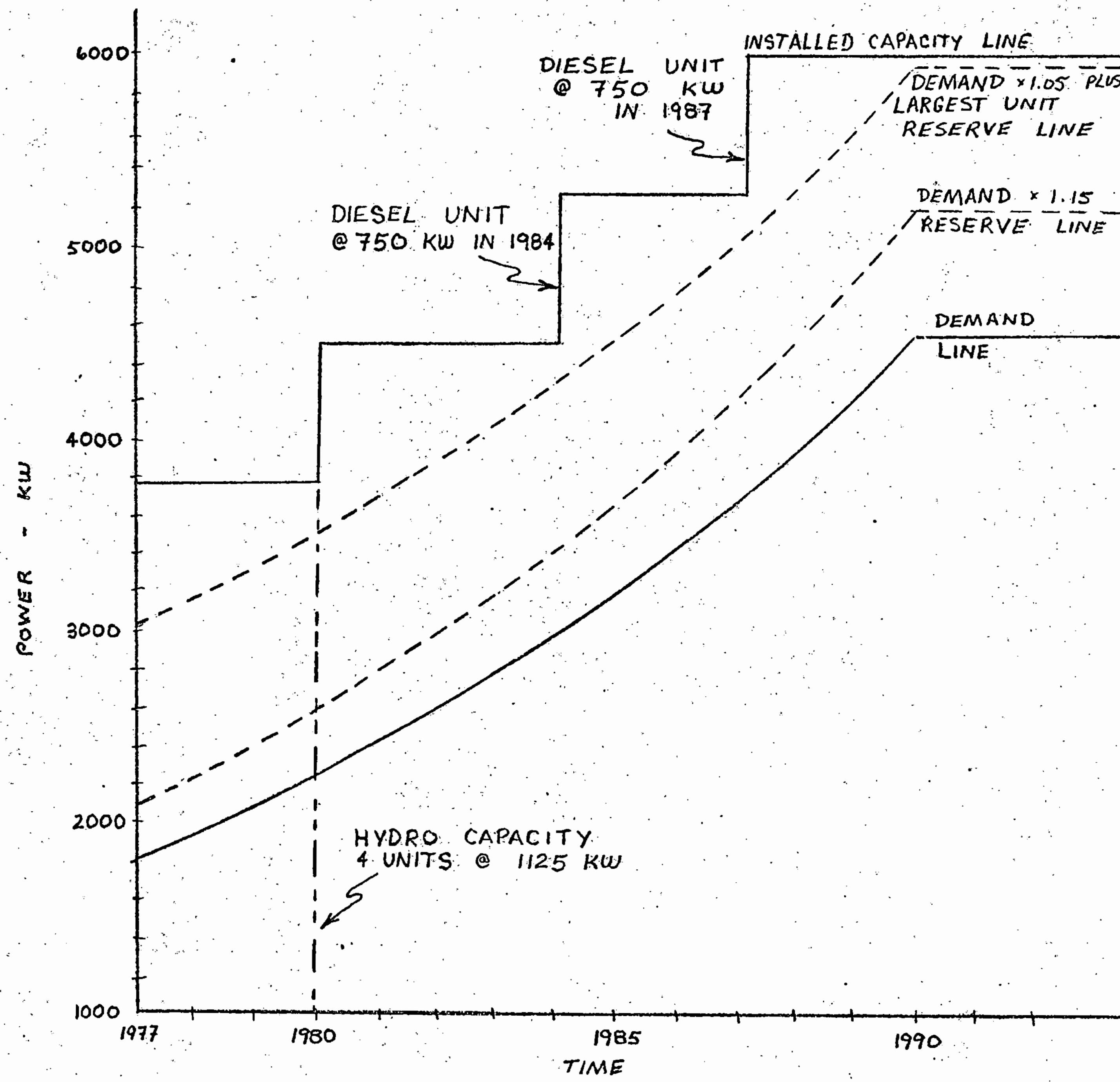
(PRELIMINARY)

ALTERNATIVE E

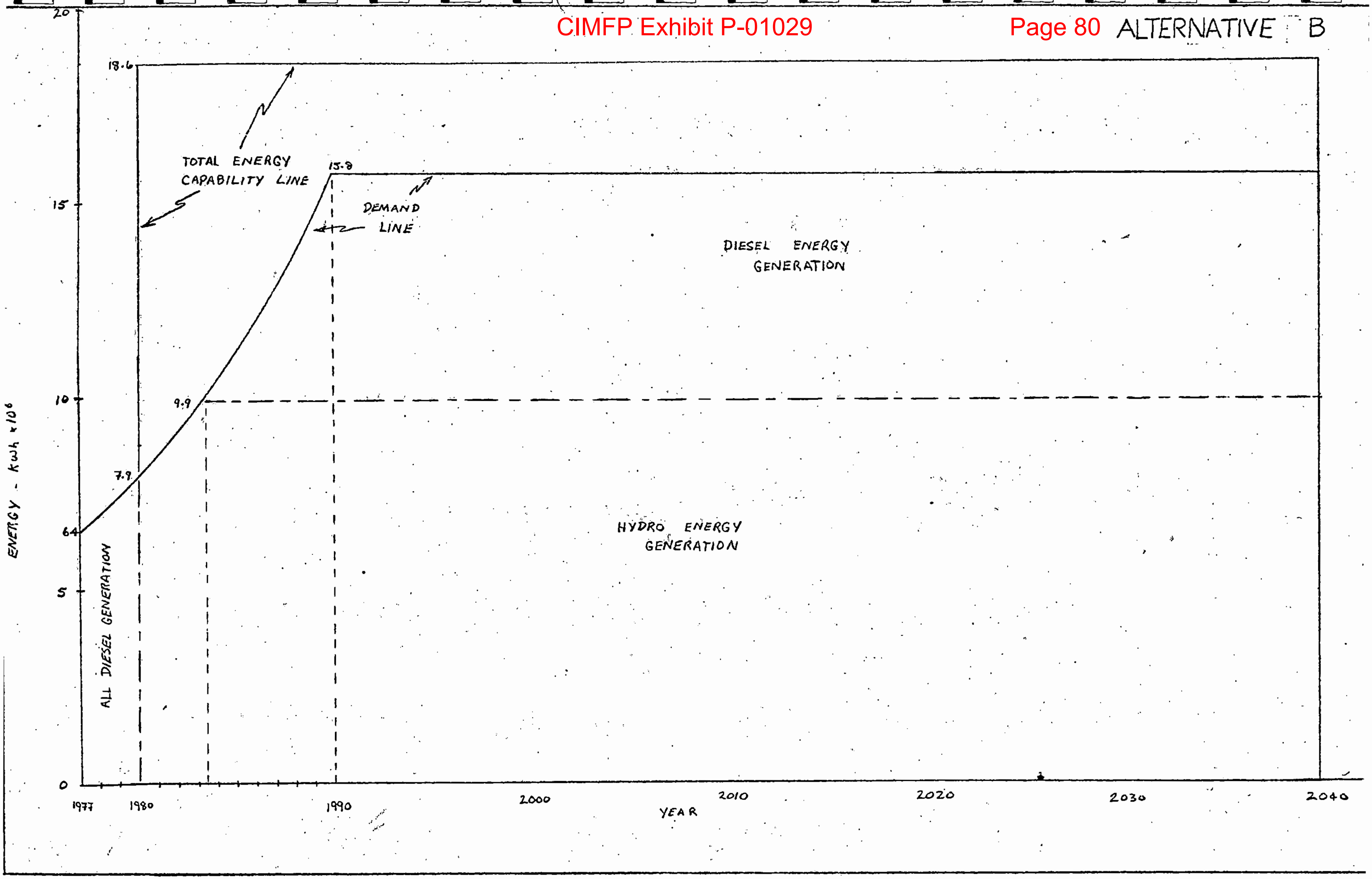


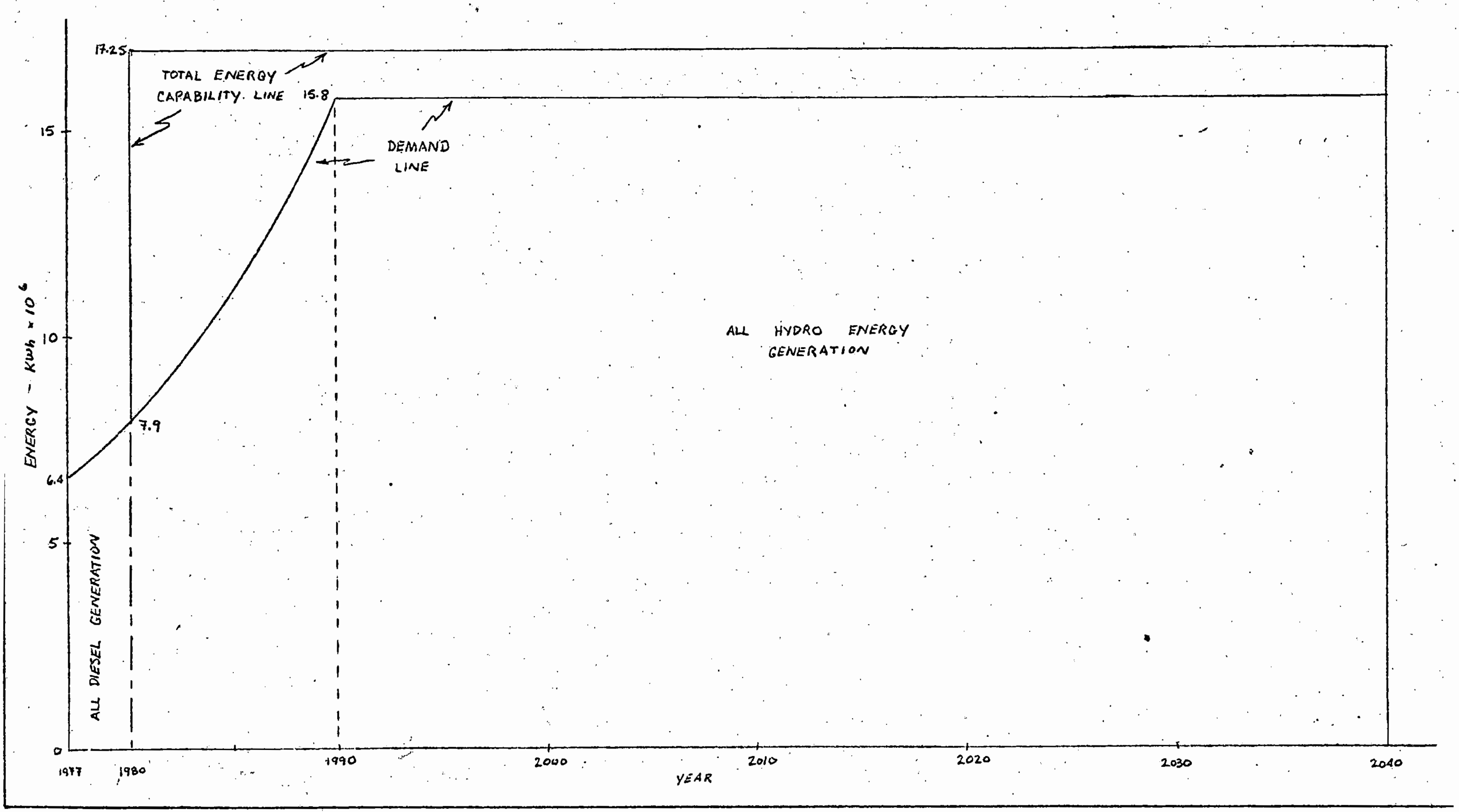
ALL DIESEL
ALTERNATIVE

ALTERNATIVES A, D & E (REVISED)

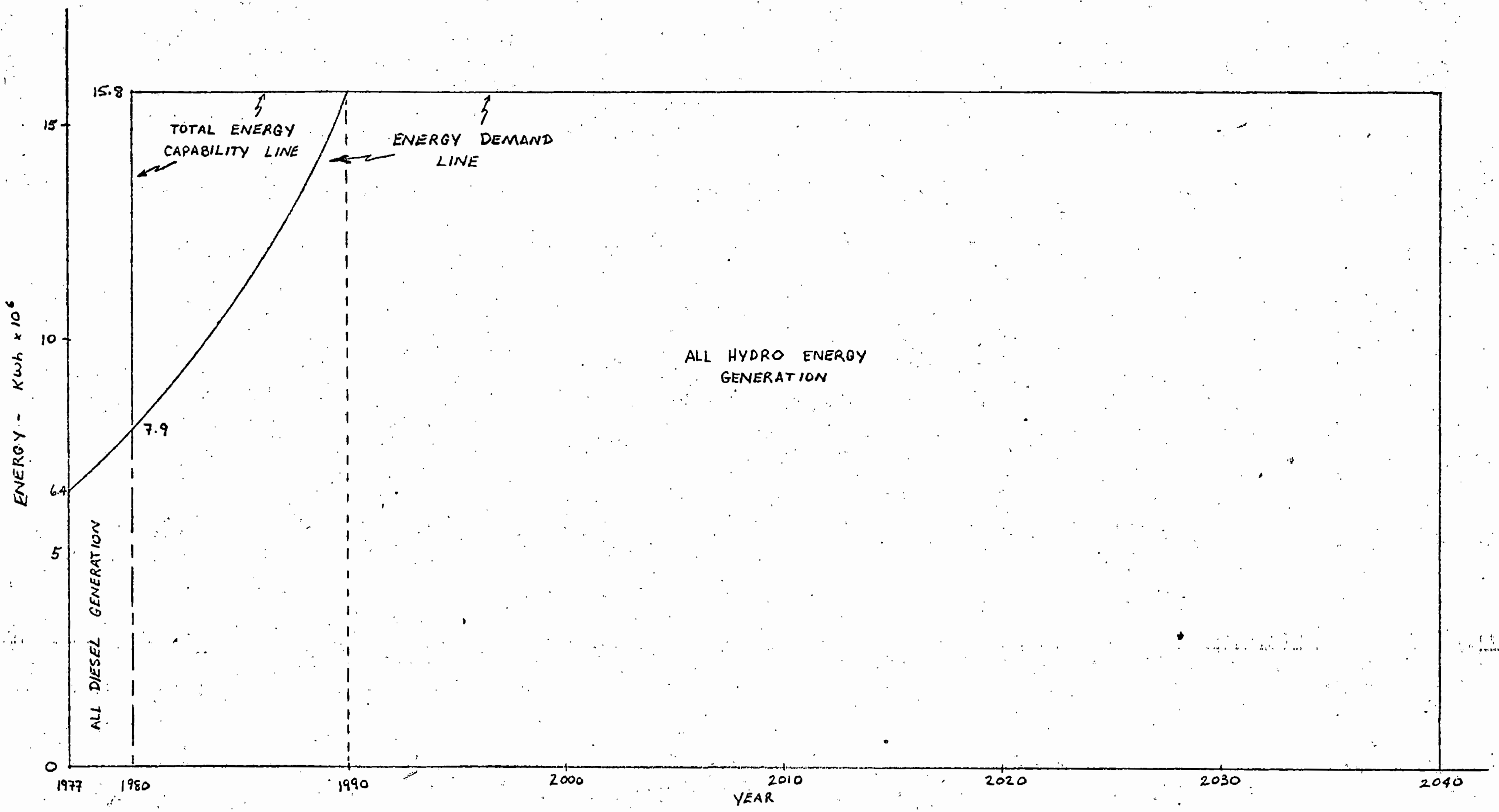


ALTERNATIVE B




17.25
TOTAL ENERGY CAPABILITY LINE
15.8
DEMAND LINE
15
10
7.9
6.4
5
0
ENERGY - KWh × 10⁶
ALL DIESEL GENERATION
ALL HYDRO ENERGY GENERATION
1977
1980
1990
2000
2010
2020
2030
2040
YEAR

ALTERNATIVE D



Present Worth Analysis.. Unit 1 = Hydro unit @ 2825 kw in 1980
Alternative B. Unit 2 = Diesel unit @ 1250 kw not taken out of service
Unit 3 = Diesel unit @ 1250 kw taken out of service for only 2 years
Unit 4 = New diesel unit @ 675 kw added in 1987
Existing unit = 2 × 1250 kw + 2 × 675 kw.

Year	Capital Costs ($) Unit 1	Capital Costs ($) Unit 4	Operation, Maintenance & Overhead ($) Existing Unit	O.M.&O. Unit 1	O.M.&O. Unit 2	O.M.&O. Unit 3	O.M.&O. Unit 4	Insurance & Interim Replacement ($) Existing Unit	Ins. Unit 1	Ins. Unit 2	Ins. Unit 3	Ins. Unit 4
1977			30,000					16,675				
1978	2,575,000		31,800					17,676				
1979	4,377,000		33,708					18,736				
1980				13458	11 410				45,191	6620	6620	
1981				14265	10,600				47,902	7017	7017	
1982				15121	11,236	13392			50,777	7438	7438	
1983				16029	11,910	14185			53,823	7885	7885	
1984				16990	12,625	15036			57,053	8358	8358	
1985				18009	13,382	15938			60,476	8859	8859	
1986		619,688		19070	14,185	16894			64,104	9391	9391	
1987				20235	15,036	17907	5400		67,951	9954	9954	3718
1988				21447	15,938	18983	5724		72,023	10,551	10,551	3941
1989				22736	16,895	20122	6067		76,349	11,184	11,184	4178
1990				24101	17,908	21329	6431		80,930	11,855	11,855	4429

Year	Energy (kw×10⁶) Total Demand	Energy Hydro Production	Energy Diesel Requirement	Oil Costs Fuel (¢/gal)	Oil Costs Lube ($/gal)	Total Fuel Oil Quantity (gal)	Total Fuel Oil Cost ($)	Total Lube Oil Quantity (gal)	Total Lube Oil Cost ($)	Total Amount ($)	Present Worth Factor	Present Worth ($ - A77)	Cumulative Present Worth ($)
1977	6.4		6.4	0.499	2.49	491520	245268	7040	17530.	309493.	1.000	309,493	309,493
1978	6.9		6.9	0.529	2.64	529920	280328.	7590	20038.	2923342	0.9091	2,657,155	2,966,648
1979	7.4		7.4	0.561	2.30	568320	318828	8140	22792.	4772064	0.8265	3,944,111	6,910,759
1980	7.9	7.9	0.6	0.594	2.97	46080.	27371	660	1960.	113130	0.7513	84,995	6,995,754
1981	9.5	8.5	0.6	0.630	3.14	46080.	29030	660	2072.	117903	0.6830	80,528	7,076,282
1982	9.1	9.1	1.1	0.668	3.33	84720.	56433	1210	4029.	165854	0.6209	102,979	7,179,261
1983	9.7	9.7	1.1	0.708	3.53	84480.	59812	1210	4271.	175800	0.5645	99,239	7,278,400
1984	10.4	9.9	1.1	0.750	3.74	84480.	63360	1210	4525.	186305	0.5132	95,612	7,374,012
1985	11.2	9.9	1.3	0.795	3.97	99840.	79373	1430	5677.	210575	0.4665	98,232	7,472,244
1986	12.0	9.9	2.1	0.843	4.21	161280.	135939	2310	9725.	898407	0.4241	381,014	7,853,258
1987	12.8	9.9	2.9	0.894	4.46	222720	199112	3190	14227.	363558	0.3855	140,152	7,993,410
1988	13.7	9.9	3.8	0.947	4.73	291840	276372.	4180	19771.	455308	0.3505	159,585	8,152,995
1989	14.7	9.9	4.8	1.004	5.01	368640	370115	5280	26453.	565283	0.3186	180,099	8,333,094
1990	15.8	9.9	5.9	1.064	5.31	453120	482120	6490	34462	695419	0.2897	201,463	8,534,557

	Total Amount ($)	Present Worth Factor	Present Worth ($ - A77)	Cumulative Present Worth ($)
Present worth of cash flow (1990 - 2040) = $695,419 × 22.24 = $15,466,118	15,466,118	0.2897	4,480,534	—
Replacements :				
Unit 2 in 1998	2,309,140	0.1351	312,035	—
Unit 3 in 2000	2,594,551	0.1117	289,755	—
Unit 4 in 2016	3,559,183	0.0243	86,504	—
Trans line & sub stn in 2019	3,455,503	0.0183	63,100	—
Unit 2 in 2028	13,262,562	0.0077	102,707	—
Unit 3 in 2030	14,835,791	0.0064	94,951	13,964,161

Present Worth Analysis
Alternative C

Unit 1 = Hydro unit @ 4850 KW in 1980
Unit 2 = Diesel unit @ 1150 KW in 1986
Existing plant = 2 × 1250 KW + 2 × 625 KW

Year	Capital Cost ($) Unit 1	Capital Cost ($) Unit 2	Operation Maintenance & Overhead ($) Existing Plant	Operation Maintenance & Overhead ($) Unit 1	Operation Maintenance & Overhead ($) Unit 2	Insurance & Interim Replacement ($) Existing Plant	Insurance & Interim Replacement ($) Unit 1	Insurance & Interim Replacement ($) Unit 2	Energy (Kwh × 10⁶) Total Demand	Energy (Kwh × 10⁶) Hydro Production	Energy (Kwh × 10⁶) Diesel Requirement
1977			30,000			16,675			6.4		6.4
1978	2917000		31,800			17,676			6.9		6.9
1979	6,675,000		33708			18,736			7.4		7.4
1980				23,106			31,160		7.9	7.9	0.5
1981				24492			33,030		8.5	8.5	0.5
1982				25,962			35,011		9.1	9.1	0.5
1983				27,519			37112		9.7	9.7	0.5
1984				29,170			39339		10.4	10.4	0.5
1985		996,005		30,921			41699		11.2	11.2	0.5
1986			—	32,776	15,543		44,201	6,335	12.0	12.0	0.5
1987				34,742	16,476		46,853	6,715	12.8	12.8	0.5
1988				36827	17,464		49,664	7118	13.7	13.7	0.5
1989				39,037	18,512		52,644	7,545	14.7	14.7	0.5
1990				41379	19,623		55,803	7997	15.8	15.8	0.5

Year	Oil Costs Fuel ($/gal)	Oil Costs Lube ($/gal)	Total Fuel Oil quantity (gal)	Total Fuel Oil Cost ($)	Total Lube Oil quantity (gal)	Total Lube Oil Cost ($)	Total Amount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
1977	0.499	2.49	491520	245,268	7040	17,530	309,473	1.0000	309,473	309,473
1978	0.529	2.64	529920	280,328	7590	20038	3,296,842	0.9091	2,997,159	3,306,632
1979	0.561	2.80	568320	318828	8140	22792	7,069,264	0.8265	5,842,581	9,149,213
1980	0.594	2.97	38,400	22,810	550	1634	78,710	0.7513	59,135	9,208,348
1981	0.630	3.14	38,400	24,192	550	1,727	83,441	0.6830	56,990	9,265,338
1982	0.668	3.33	38,400	25,651	550	1,832	88,456	0.6209	54,922	9,320,261
1983	0.708	3.53	38,400	27187	550	1,942	93,760	0.5645	52,928	9,373,188
1984	0.750	3.74	38,400	28,800	550	2,057	99,366	0.5132	50,995	9,424,183
1985	0.795	3.97	38,400	30528	550	2184	1102337	0.4665	517,972	9,942,155
1986	0.843	4.21	38,400	32,371	550	2,316	133,522	0.4241	56,635	9,998,790
1987	0.894	4.46	38,400	34330	550	2,453	141,569	0.3855	54,575	10,053,365
1988	0.947	4.73	38,400	36365	550	2602	150,044	0.3505	52,590	10,105,955
1989	1.004	5.01	38,400	38,554	550	2,756	159,048	0.3186	50,673	10,156,628
1990	1.064	5.31	38,400	40,858	550	2921	168,581	0.2897	48,838	10,205,466

	Total Amount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
Present worth adjustments (1990-2040) = $168,581 × 22.24 = 3,749,241	3,749,241	0.2897	1,086,155	—
• Replacements:				
Unit 2 in 2016	5,720,560	0.0267	152,938	—
Trans Line & Sub Stn in 2019	3,455,563	0.0183	63,100	11,507,659

Present Worth Analysis.
Alternative D

Unit 1 Hydro plant @ 4500 kw in 1980.
Unit 2 Diesel unit @ 750 kw in 1984
Unit 3 Diesel unit @ 750 kw in 1987.
Existing Plant = 3750 kw.

Year	Capital Costs ($) Unit 1	Unit 2	Unit 3	Operation, Maintenance & Overhead ($) Existing Plant	Unit 1	Unit 2	Unit 3	Insurance & Interim Replacement ($) Existing Plant	Unit 1	Unit 2	Unit 3	Energy (kwh x10⁶) Total Demand	Hydro Production	Diesel Production	Oil Costs Fuel ($/gal)	Lube ($/gal)	Total Fuel Oil quantity (gal)	Cost ($)	Total Lube Oil quantity (gal)	Cost ($)	Total Amount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
1977				30,033				16,675				6.4		6.4	0.499	2.49	471 520	245268	7040	17530	309473	1.0000	309,473	309,473
1978	3,060,000			31,700				17,676				6.9		6.9	0.529	2.64	529 920	280328	7590	20038	3409824	0.9091	3,099,871	3,409,344
1979	7,377,000			33,708				18,736				7.4		7.4	0.561	2.80	558 320	318828	8140	22792	7771064	0.8265	6,422,784	9,832,128
1980					21,458				33,774			7.9	7.9	—	0.594	2.97	—	—	—	—	55 212	0.7513	41,481	9,873,609
1981					22,724				35,800			8.5	8.5	—	0.630	3.14	—	—	—	—	58 524	0.6830	39,972	9,913,581
1982					24,088				37,948			9.1	9.1	—	0.668	3.33	—	—	—	—	62,036	0.6209	38,518	9,952,099
1983		578,114			25,533				40,225			9.7	9.7	—	0 708	3.53	—	—	—	—	643,872	0.5645	363,466	10,315,565
1984					27,065	4256			42,639	3469		10.4	10.4	0.3	0.750	3.74	23040	17280	330	1234	95943	0.5132	49,238	10,364,803
1985					28,689	4511			45,197	3677		11.2	11.2	0.3	0.795	3.97	23040	18317	330	1310	101 701	0.4665	47,444	10,412,246
1986			688,542		30,410	4782			47,909	3898		12.0	12.0	0.3	0.843	4.21	23040	19423	330	1389	796 356	0.4241	337,735	10,749,981
1987					32,235	5069	5069		50,784	4132	4132	12.8	12.8	0.6	0.894	4.46	46080	41196	660	2944	145, 561	0.3855	56,114	10,806,095
1988					34,169	5373	5373		53,831	4380	4380	13.7	13.7	0.6	0.947	4.73	46080	43638	660	3120	154,264	0.3505	54,070	10,860,164
1989					36,219	5695	5695		57,060	4642	4642	14.7	14.7	0.6	1.004	5.01	46 080	46264	660	3306	163,523	0.3186	52,098	10,912,263
1990					38,392	6037	6037		60,484	4921	4921	15.8	15.8	0.6	1.064	5.31	46080	49029	660	3506	173,327	0.2897	50,213	10,962,476

Present worth adjustment = 173,327 x 22.24 = 3,854,792

Replacements :

Unit 2 in 2013

Unit 3 in 2016

Trans line & Sub station in 2019

	Total Amount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
Present worth adjustment	3,854,792	0.2897	1,116,723	—
Unit 2 in 2013	3,320,298	0.0324	107,412	—
Unit 3 in 2016	3,954,649	0.0243	96,115	—
Trans line & Sub station in 2019	3,455,563	0.0183	44,039	

TOTAL PRESENT WORTH $ 12,327,575

Present Worth Analysis
All-Diesel Alternative

Unit 1 1250 kw in 1980
Unit 2 1000 kw in 1986.
Existing 2 × 1250 kw
2 × 625 kw.

Year	Capital Costs ($)		Operation, Maintenance & Overhead ($)			Insurance & Interim Replacement ($)			Energy Required (Kwh × 10⁶)	Oil Costs.		Total Fuel Oil		Total Lube Oil		Total Ammount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
	Unit 1	Unit 2	Existing Plant	Unit 1	Unit 2	Existing Plant	Unit 1	Unit 2		Fuel ($/gal)	Lube ($/gal)	Quantity (gal)	Cost ($)	Quantity (gal)	Cost ($)				
1977			30,000			16,675			6.4	0.499	2.49	491,520	245,268	7040	17,530	309,473	1.0000	309 473	309,473
1978			31,800			17,676			6.9	0.529	2.64	529,920	280,328	7590	20,038	349,842	0.9091	318,041	627,514
1979	1,040,920		33,708			18,736			7.4	0.561	2.80	568,320	318,828	8140	22,792	1,434,934	0.8265	1,186,014	1,813,529
1980			35,730	11,910		19,860	6246		7.9	0.594	2.97	606,720	360,392	8690	25,809	459,947	0.7513	345,558	2,159,087
1981			37,874	12,620		21,052	6621		8.5	0.630	3.14	652,800	411,264	9350	29,359	518,794	0.6830	354,336	2,513,423
1982			40,146	13,382		22,315	7018		9.1	0.668	3.33	698,880	466,851	10,010	33,333	583,045	0.6209	362,013	2,875,436
1983			42,555	14,185		23,654	7439		9.7	0.708	3.53	744,960	527,437	10,670	37,665	652,929	0.5645	368,578	3,244,015
1984			45,109	15,036		25,073	7885		10.4	0.750	3.74	798,720	599,040	11,440	42,786	734,929	0.5132	377,166	3,621,180
1985		866,090	47,815	15,938		26,577	8359		11.2	0.795	3.97	860,160	683,827	12,320	48,910	1,697,516	0.4665	791,891	4,413,071
1986			50,684	16,895	13,516	[illegible]	8860	5197	12.0	0.843	4.21	921,600	776,909	13,200	55,572	955,625	0.4241	405,357	4,818,428
1987			53,725	17,909	14,327	29,862	9392	5509	12.8	0.894	4.46	983,040	878,838	14,080	62,797	1,072,359	0.3855	413,394	5,231,822
1988			56,949	18 984	15,187	31,654	9955	5839	13.7	0.947	4.73	1,052,160	1,111,045	15,070	71,281	1,320,894	0.3505	462,973	5,694,795
1989			60,366	20 123	16,098	33,553	10,552	6190	14.7	1.004	5.01	1,128,960	1,133,476	16,170	81,012	1,361,370	0.3186	433,732	6,128,527
1990			63,988	21,330	17,064	35,566	11,185	6561	15.8	1.064	5.31	1,213,440	1,291,100	17,380	92,288	1,539,082	0.2897	445,872	6,574,400

		Total Ammount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
Present worth adjustments: (1990 - 2040)	value in 1990 of series of payments $1,539,082 × 22.24 = $34,229,183	34,229,183	0.2897	9,916,195	—
Replacement of units:	Existing plant @ 3750 kw in 1998	11,041,265	0.1351	1,491,675	—
	——— " ——— in 2028	63,415,582	0.0077	488,300	—
	Unit 1: @ 1250 kw in 2009	4,383,412	0.0474	207,775	
	Unit 2: @ 1000 kw in 2015	4,692,822	0.0267	125,298	18,303,643

APPENDIX H

CALCULATION OF POTENTIAL GENERATION

(OF EACH SITE)

Calculation of the Generating Potential of Each Site

The generating potential of a site is governed by the amount of runoff from the drainage area which can be controlled. This control depends on the storage capacity of the reservoir, hence giving the maximum water flow which can be withdrawn constantly over the year.

This maximum sustainable yield is determined by a trial and error calculation, where the varying inflows into the reservoir are compared on a monthly basis to an assumed constant outflow. This flow must be such that the reservoir is never completely empty and the reservoir must be full again at the end of the year, assuming it was full at the start.

The design inflow used is the average runoff in cubic feet per second from one square mile of drainage area, using the runoff records for the Victoria Reservoir of Bay D'Espoir in 1974. This year was chosen as being representative of a year in which the rainfall was slightly less than the average figure.

The monthly runoff of 1974 was as follows;

Month	Runoff ($ft^3/sec/mile^2$)
January	1.32
February	1.34
March	2.14
April	4.28
May	7.75
June	2.80
July	1.10
August	1.43
September	1.64
October	4.88
November	2.75
December	3.93

Alternative A

Drainage area controlled by reservoir = 81.6 sq. mi.

Reservoir capacity = 205.5 million cubic feet.

Assume a trial flow of 139 ft^3/sec.

Month	Inflow (ft^3/sec)	Outflow (ft^3/sec)	Net flow (ft^3/sec)	Volume Change ($ft^3 x10^6$)	Reservoir Contents ($ft^3 x10^6$)
January	+106.1	-139	-32.9	-85.3	120.2
February	+110.2	-139	-28.8	-74.6	45.6
March	+175.4	-139	+36.4	+94.3	139.9
April	+350.9	-139	+211.9	+65.6	205.5
May	+632.4	-139	+493.4	Spill	205.5
June	+228.5	-139	+89.5	Spill	205.5
July	+89.8	-139	-49.2	-127.5	78.0
August	+114.2	-139	-24.8	-64.3	13.7
September	+134.6	-139	-4.4	-11.4	2.3
October	+395.8	-139	+256.8	+203.2	205.5
November	+224.4	-139	+85.4	Spill	205.5
December	+318.2	-139	+179.2	Spill	205.5

140 ft^3/sec would completely empty the reservoir, so the maximum sustainable yield is 139 ft^3/sec.

$$\text{Power available} = \frac{XQH \times 746}{550 \times 0.9 \times 10^6}$$

$$= \frac{62.4 \times 139 \times 250 \times 746}{550 \times 0.9 \times 10^6} = 3.3 \text{ MW}$$

$$\text{Capacity to be installed} = \frac{\text{available power}}{\text{capacity factor}}$$

$$= \frac{3.3}{0.4} = 8.25 \text{ MW}$$

Alternative B

Drainage area controlled by reservoir = 18.6 sq. mi.

Reservoir capacity = 174 million cubic feet

Assume a trial flow of 48 ft^3/sec

Month	Inflow (ft^3/sec)	Outflow (ft^3/sec)	Net flow (ft^3/sec)	Volume Change ($ft^3/sec \times 10^6$)	Reservoir Contents ($ft^3/sec \times 10^6$)
January	+24.8	-48.0	-23.2	-60.1	113.9
February	+25.1	-48.0	-22.9	-59.4	54.5
March	+40.0	-48.0	-8.0	-20.7	33.8
April	+80.0	-48.0	-32.0	+82.9	116.7
May	+144.2	-48.0	+96.2	+57.3	174
June	+52.1	-48.0	+4.1	Spill	174
July	+20.5	-48.0	-27.5	-71.3	102.7
August	+26.0	-48.0	-22.0	-57.0	45.7
September	+30.7	-48.0	-17.3	-45.5	0.2
October	+90.2	-48.0	+42.2	+109.4	109.6
November	+51.2	-48.0	+3.2	+8.3	117.9
December	+72.5	-48.0	+24.5	+56.1	174

49 ft^3/sec would completely empty the reservoir, so the maximum sustainable yield is 48 ft^3/sec.

$$\text{Power available} = \frac{XQH \times 746}{550 \times 0.9 \times 10^6}$$

$$= \frac{62.4 \times 48 \times 250 \times 746}{550 \times 0.9 \times 10^6} = 1.13 \text{ MW}$$

$$\text{Capacity to be installed} = \frac{\text{available power}}{\text{capacity factor}}$$

$$= \frac{1.13}{0.4} = 2.825 \text{ MW}$$

Alternative C

Drainage area controlled by reservoir = 32.2 sq. mi.

Reservoir capacity = 307 million cubic feet

Assume a trial flow of 84 ft^3/sec

Month	Inflow (ft^3/sec)	Outflow (ft^3/sec)	Net flow (ft^3/sec)	Volume Change ($ft^3/sec \times 10^6$)	Reservoir Contents ($ft^3/sec \times 10^6$)
January	+41.9	-84.0	-42.1	-109.1	197.9
February	+43.5	-84.0	-40.5	-105.0	92.9
March	+69.2	-84.0	-14.8	-38.4	54.5
April	+138.5	-84.0	+54.5	+141.3	195.8
May	+249.6	-84.0	+165.6	+111.2	307.0
June	+90.2	-84.0	+6.2	Spill	307.0
July	+35.4	-84.0	-48.6	-126	181.0
August	+45.1	-84.0	-38.6	-100.1	80.9
September	+53.1	-84.0	-30.9	-80.1	0.8
October	+156.2	-84.0	+72.2	+187.1	187.9
November	+88.6	-84.0	+4.6	+11.9	199.8
December	+125.6	-84.0	+41.6	+106.2	307.0

85 ft^3/sec would completely empty the reservoir, so the maximum sustainable yield is 84 ft^3/sec.

$$\text{Power available} = \frac{XQH \times 746}{550 \times 0.9 \times 10^6}$$

$$= \frac{62.4 \times 84 \times 250 \times 746}{550 \times 0.9 \times 10^6} = 1.97 \text{ MW}$$

$$\text{Capacity to be installed} = \frac{\text{available power}}{\text{capacity factor}}$$

$$= \frac{1.97}{0.4} = 4.85 \text{ MW}$$

Alternative D

Drainage area controlled by reservoir = 56 sq. mi.

Reservoir capacity = 175 million cubic feet

Assume a trial flow of 99 ft^3/sec.

Month	Inflow (ft^3/sec)	Outflow (ft^3/sec)	Net flow (ft^3/sec)	Volume Change (ft^3/sec $x10^6$)	Reservoir Contents (ft^3/sec $x10^6$)
January	+72.8	-99.0	-26.2	-67.9	107.1
February	+75.6	-99.0	-23.4	-60.7	46.4
March	+120.4	-99.0	+21.4	+55.5	101.9
April	+240.8	-99.0	+141.8	+73.1	175.0
May	+434.0	-99.0	+335.0	Spill	175.0
June	+156.8	-99.0	+57.8	Spill	175.0
July	+61.6	-99.0	-37.4	-96.9	78.1
August	+78.4	-99.0	-20.6	-53.4	24.7
September	+92.4	-99.0	-6.6	-17.1	7.6
October	+271.6	-99.0	+172.6	+167.4	175.0
November	+154.0	-99.0	+55.0	Spill	175.0
December	+218.4	-99.0	+119.4	Spill	175.0

100 ft^3/sec would completely empty the reservoir, so the maximum sustainable yield is 99 ft^3/sec.

$$\text{Power available} = \frac{XQH \times 746}{550 \times 0.9 \times 10^6}$$

$$= \frac{62.4 \times 99 \times 250 \times 746}{550 \times 0.9 \times 10^6} = 2.33 \text{ MW}$$

$$\text{Capacity to be installed} = \frac{\text{available power}}{\text{capacity factor}}$$

$$= \frac{2.33}{0.4} = 2.825 \text{ MW}$$

Alternative E

Drainage area controlled by reservoir = 69.6 sq. mi.

Reservoir capacity = 175 million cubic feet

Assume a trial flow of 118 ft^3/sec.

Month	Inflow (ft^3/sec)	Outflow (ft^3/sec)	Net flow (ft^3/sec)	Volume Change (ft^3/sec $x10^6$)	Reservoir Contents (ft^3/sec $x10^6$)
January	+90.5	-118.0	-27.5	-71.3	103.7
February	+94.0	-118.0	-24.0	-62.2	41.5
March	+149.6	-118.0	+31.6	+81.9	123.4
April	+229.3	-118.0	+181.3	+51.6	175.0
May	+539.4	-118.0	+421.4	Spill	175.0
June	+194.9	-118.0	+76.9	Spill	175.0
July	+76.6	-118.0	-41.4	-107.3	67.7
August	+97.4	-118.0	-20.6	-53.4	14.3
September	+114.8	-118.0	-3.2	-8.3	6.0
October	+337.6	-118.0	+219.6	+169.0	175.0
November	+191.4	-118.0	+73.4	Spill	175.0
December	+271.4	-118.0	+153.4	Spill	175.0

119 ft^3/sec would completely empty the reservoir, so the maximum sustainable yield is 118 ft^3/sec.

$$\text{Power available} = \frac{XQH \times 746}{550 \times 0.9 \times 10^6}$$

$$= \frac{62.4 \times 118 \times 250 \times 746}{550 \times 0.9 \times 10^6} = 2.77 \text{ MW}$$

$$\text{Capacity to be installed} = \frac{\text{available power}}{\text{capacity factor}}$$

$$= \frac{2.77}{0.4} = 6.925 \text{ MW}$$

APPENDIX I

SIZE REDUCTION
OF
ORIGINAL
HIGH ENERGY ALTERNATIVES

Criteria

- Check energy used by each alternative.
- Installed capacity must be such that all available energy is used. If not, money is wasted in installation of longer plant.
- Required energy in 1990 = 15.8×10^6 kWh.

Alternative A

Installed capacity = 8250 KW.

Firm capability of site = 3300 KW.

Energy capability = $3300 \times 365 \times 24 = 28.9 \times 10^6$ (too high)

reduce installed capacity to generate only what is required, leaving diesels to meet peaks only.

Required capacity = $\frac{15.8 \times 10^6}{365 \times 24}$ = 1803 KW

Installed capacity will be $\frac{1803}{0.4}$ = 4508 KW

Install 4 units @ 1125 KW each = 4500 KW

This alternative, however, has sufficient capacity to install more hydro units when energy demand grows.

Alternative B

Installed capacity = 2825 KW

Firm capacity of site = 1130 KW = 9.90×10^6 kWh

this is less than required in 1990, so diesels will have to be used to a limited degree to meet energy requirements.

Alternative C

Installed capacity = 4850 KW.

Firm capacity = 1970 KW = 17.25×10^6 kWh

this is only slightly above requirement, so diesel will be used only to meet peaks.

Alternative D

Installed capacity = 5825 KW

Firm capacity = 2330 KW = 20.41×10^6 kWh.

Required energy = 15.8×10^6 kWh

Required capacity = $\frac{15.8 \times 10^6}{365 \times 24}$ = 1803 KW

as before, install 4500 KW, @ 4 x 1125 KW units.

This alternative is technically equivalent to Alternative A - revised.

Alternative E

Installed capacity = 6925 KW

Firm capacity = 2770 KW = 24.26×10^6 kWh.

again, this is too high, so the alternative will be reduced to same (technically) as A and D.

Since Alternatives A, D and E have been reduced to identical installations, the capital cost of construction can be used as a base for eliminating two of them.

Obviously, Alternative A will be much more expensive than one of the Grandy Brook sites, due to difficulty of access for construction and maintenance, and length of transmission line. Alternative E is simply Alternative D with an extra diversion, which is not needed. Hence, Alternative D remains reasonable.

APPENDIX J

CAPITAL COST ESTIMATE SUMMARY

Capital Cost Estimate Summary

Hydro power stations, similar in size, have been built around the Island and a record of construction costs was available for several of these from Newfoundland Light and Power Company records. Where possible, the construction costs of the generating stations have been broken down into unit prices. By using Statistics Canada, Engineering News Record and other estimating aids, construction cost estimates were determined for each of the proposed alternatives.

The lack of site investigation of sub-surface conditions makes it difficult, if not impossible, to arrive at a detailed estimate this early in the project's evaluation. For a comparative study and budget estimates, the prices should be sufficient as determined. However, it will be necessary to obtain reliable field information before actual construction costs can be accurately determined.

Capital Cost Summary in 1977 Dollars

	Alternatives		
	B	C	D
Land and clearing	$ 38,000	$ 57,000	$ 38,000
Roads, trails and bridges	472,000	849,000	142,000
Buildings and structures	952,000	1,227,000	1,227,000
Canals, penstocks, surge tanks and tailraces	1,219,000	1,424,000	1,219,000
Dams and reservoirs	2,617,000	3,749,000	5,414,000
Prime movers	282,000	443,000	416,000
Generators and auxiliaries	249,000	415,000	386,000
Electrical plant	89,000	151,000	204,000
Transmission lines and sub-stations	317,000	317,000	317,000
Interest during construction	483,000	654,000	709,000
TOTAL CAPITAL COST	$6,718,000	$9,286,000	$10,072,000

APPENDIX K

DESIGN AND COST OF EARTH DAMS

A. Design of Earth Dams

In comparison to other dams, the ones required to be built in the Burgeo area are fairly small and simply but yet their design is as important as that of the largest ones in existence. Their failure could have disasterous results including loss of property and life. For this reason, careful attention should be paid to their design and construction.

Any possible filtration of water through such dams or their foundations is dangerous and can cause ultimate failure. In order to prevent this, a central trench is usually sunk into the impermeable stratum and filled with an impervious material which is extended above the maximum water level. This is known as the 'core wall' and usually consists of clay and some sand, which can be well compacted. Because of the inherent difficulty of obtaining sufficient quantities of this core material, it is suggested that a mass concrete core be used. The determination of the core wall thickness is a matter of judgement based on experience. Concrete core walls with a top thickless of 12 inches and sides battered 1 horizontal to 100 vertical have proven to be satisfactory. As mentioned, the core wall should be sufficiently high to extend above the top of the earth embankment to act as a parapet and factor of safety. During construction, the earth pressures on the sides of the core can be balanced by maintaining the rising fill at the same elevation on each side of the wall.

The materials to be used in earth dams must be carefully selected with the more impervious material being placed in the upstream part of the dam. Because of the area's topography, a well graded material is suggested to be used. This material will be obtained from borrow excavation and should include a granular mixture of gravel and rock fragments up to a maximum size of 6 inches and also a coarse filler of well graded gravel and sand ranging in size 1 1/2 inches to # 10 sieve with a minimum dimension larger than 3/8 inches. On the upstream slope of the dams, an 18 inch. layer of rip-rap, which is hard dense durable fieldstone, rock fragments or cobblestones, should be used.

Embankment slopes may be governed by the stability of the material under all probable conditions of moisture content, bearing power of the foundation, and resistance of the materials of the dam and of the foundation to perculation. In general, for structures 25 feet or less in height, stable embankments may result if the upstream slope is built not steeper than 2.5 horizontal to 1 vertical and the downstream slope 2 horizontal to 1 vertical. In this case, since the dams to be constructed will be higher than 25 feet, a 3:1 slope is recommended for both the upstream and downstream embankments.

1:3

The top width of an earth dam is usually a function of its height with a minimun of 8 to 10 feet. The relation is sometimes expressed as W = (H +25)/5 in which W is the top width of the dam in feet. A standard design of this type of dam can be found in this Appendix.

B. Water Control Methods

There are two primary water control methods which can be incorporated into the design of an earth dam. These are spillways and control structures. It is recommended that both methods be employed in the dam~~s~~ to be constructed in the Burgeo area.

1. Control Structure

A control structure consists of a reinforced concrete intake structure and conduit which passes through the bottom of the dam. The conduit may be constructed with reinforced concrete but it is recommended that fusion welded steel conduit be used. The downstream side of the dam should be equipped with a sluice gate or valve which can be turned on or raised, whatever the case, to control the water level. At the upstream end the intake structure should be equipped with a heated trash rack to prevent blockages caused by accumulations of ice and also to preclude branches, trees, shrubs, roots, debris, etc. A standard design for a control structure can be found in this Appendix.

With this type of water control, additional safety features are being incorporated into the design to handle the excessive runoffs. At all times, the water level can be kept several feet below the crest of the spillway thus providing storage for the initial flood waters. At the same time, the valve could be opened full bore thereby providing additional relief while the basin was filling up. It should also be remembered that this structure also regulates the flow of water entering the fore-bay reservoir during dry periods to ensure that the reservoir is up to its required capacity to keep the power house functioning efficiently.

2. Spillway

The purpose of the spillway is to conduct excess water away from a reservoir without endangering the safety of the dam. Hence the capacity of the spillway must be sufficient to pass the greatest flood expected so that the dam will not be over-topped, and the shape of the spillway must be such that the falling water will not undermine the dam or spillway. To avoid danger to the dam or spillway, the spillway may be located on the rim of the reservoir where the distance of fall of water is low. A chute spillway, which is recommended to be used here, in general, leads water down the hillside at one side of the dam. Chute spillways minimize the height of the vertical fall of water. For low maintenance, the spillway should be constructed of concrete. A concrete spillway should have a well rounded crest, sides to contain the water within the concrete apron and specially shaped toe, which will divert the water from the foundations of the dam. A standard design of a spillway can be found in this Appendix.

C. <u>Capital Description and Preliminary Estimate of Earth Dams</u>

The following section deals with the formulation of the capital cost for the actual construction of the dams needed in Alternative B. A detailed description is given of each item estimated and it is assumed these items are identical for the construction of the dams in Alternatives C and D.

The unit costs used in the preliminary estimate for Alternative B were obtained from two sources (see Bibliography # 7 and 9) from which costs were obtained in 1957 and 1968 dollars. These costs were converted to present day costs by using the Engineering News Record indices for time and hansdowne indices for location (refer to Table 1 of this Appendix for the complete cost breakdown of the construction of access roads and dams for Alternative B). The capital costs of the construction of the dams needed in Alternatives C and D were obtained by first finding the price per cubic yard to construct each dam in Alternative B, then finding the quantities involved for the dams in Alternative C and D and multiplying these quantities by the unit costs of the comparative dams. Where necessary, new costs were found for the spillway and control structure. The costs for the construction of the dams needed can be found in Alternative C and D. The forebay dam estimated in Alternative B is basically the same for all alternatives. Quantities were taken from cross sections of a typical dam spillway and control structure, (see drawing in this Appendix).

1. <u>Capital Description - Alternative B</u>

   See next page.

   1. <u>Land</u> - assume all the land is crown land - no charge.

   2. <u>Land Clearing</u> - each reservoir and forebay dam site will be cleared of all usuable timber. This includes cutting, piling, drying, burning, etc.

Eg.

Rugged topo.	+ Med. Density	+ 50% Brush	+ 50% Trees	+ Medium Size
$125	$60	$60		$55

= $300/acre

3. Roads and bridges - permanent access roads running from the Burgeo Highway to dam sites and site of power house and forebay are included in this item.

4. Dams and reservoirs:

4.1 Main Dam and Spillway with Control Structure

Homogeneous rolled earth filled dam with concrete core, approximately 1260 feet long with boulder rip-rap (18 inches thick), a reinforced concrete spillway structure approximately 250 feet long (assume 20% of dam length needed for spillway) with reinforced concrete sides, a reinforced concrete intake structure, trash racks fusion welded steel conduit and Armco 96 inches x 96 inches Model 50-10 sluice gate complete with HM-3-60 limitorque electrically operated lift.

a) common excavation - includes stripping of embankment foundations, borrow areas, and stockpile areas, as well as excavation of unsuitable materials from borrow areas and river diversion.

b) embankment foundation excavation - includes excavation of cut-off trenches and the preparation of embankment foundation and upstream blank areas, the river diversion channel and the river channel where required.

c) granular slope protection - includes coarse gravel,rock fragments or suitable mixtures of gravel and rock fragments up to maximum size of approximately 6 inches. Use 70% of total well graded material.

d) coarse filler - includes well graded, gravel, sand or gravel and sand mixture and generally range in size 1 1/2 inches to # 10 sieve with minimum larger than 3/8 inches. Use 30% of total well graded material.

e) rip-rap - hard dense durable fieldstone, rock fragments, cobblestones or suitable mixtures of fieldstone, rock fragments and cobblestone.

f) mass concrete - concrete requiring little or no reinforcing steel.

g) rock excavation - includes removal of all rock which cannot be removed until loosened by blasting, barring or wedging and all boulders or detached pieces of solid rock more than 1 cubic yard in volume.

spillway - includes concrete, formwork, reinforcing steel, reinforced spillway walls.

h) control structure or intake - includes reinforced concrete intake structure, 7.5 feet O.D. fusion welded steel conduit of 3/8 inches, 45 feet long, electrically heated steel trash racks, Armco 96 inches x 96 inches Model 50-10 sluice gate, bronze facing, complete with HM-3-60 limitorque lift for 220 volts, 3 phase, 60 cycle housed in electrically heated wood frame gatehouse.

4.2 Secondary Dam

Homogeneous rolled earth dam with concrete core, approximately 250 feet long with boulder rip-rap.

Sections (a) through (g) are the same.

4.3 <u>Forebay Dam</u>

Spillway and Intake - homogeneous rolled earth dam with concrete core, approximately 450 feet long with boulder rip-rap, a reinforced concrete spillway structure approximately 250 feet long (should be the same length as the spillway in the main dam) with reinforced concrete sides, a reinforced concrete intake structure, trash racks, fusion welded steel conduit and Armco 96 inches x 96 inches. Model 50-10 sluice gate complete with HM-3-60 limitorque electrically operated lift. Sections (a) through (h) are the same.

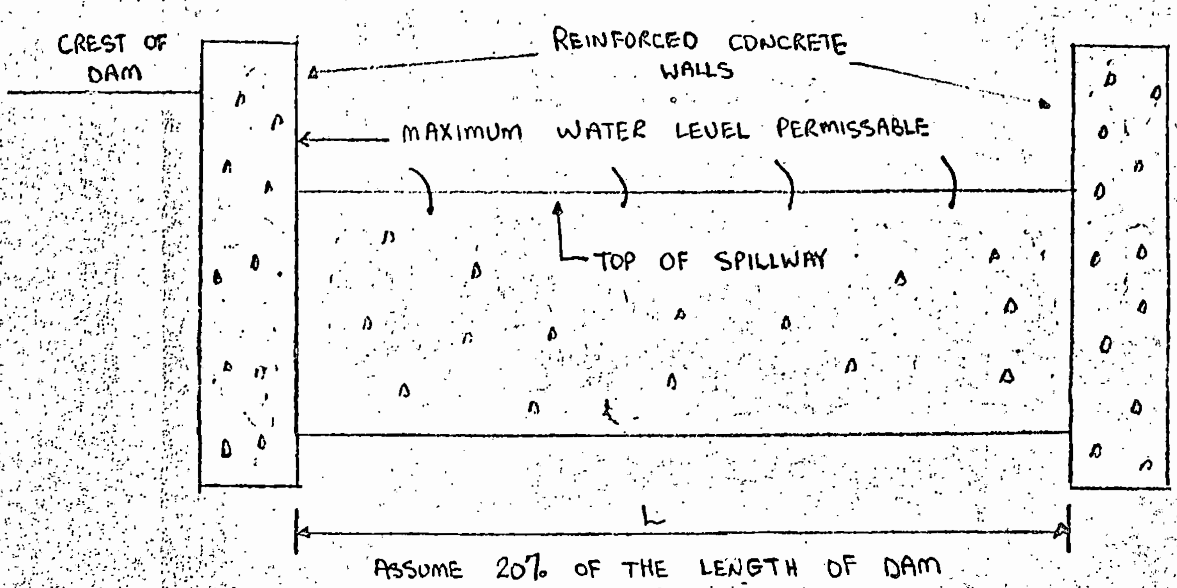
2. <u>Preliminary Estimate - Alternative B - Sample Sheet</u>

See next page.

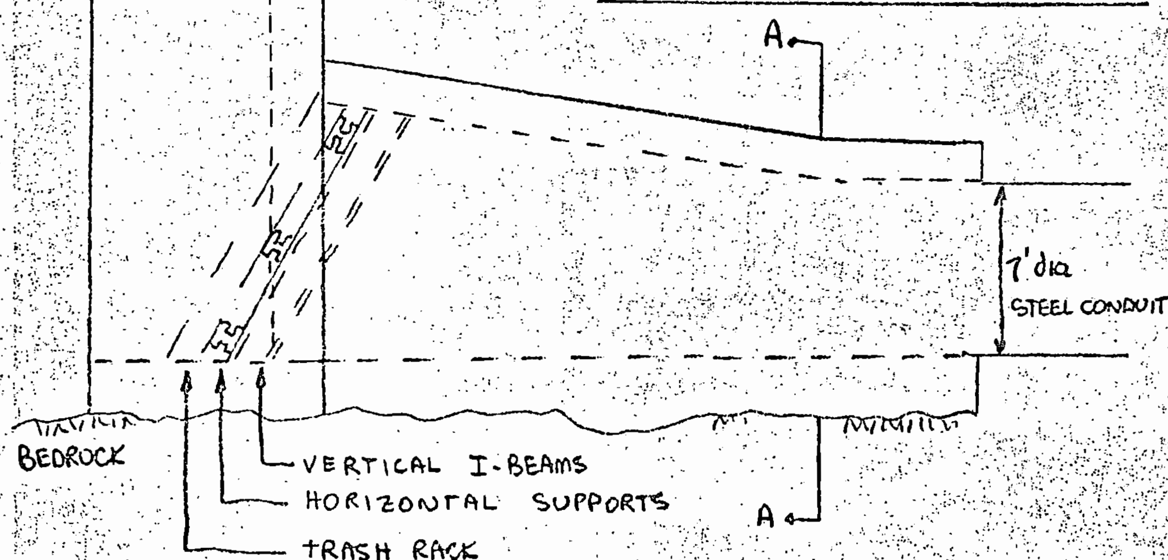
Table #1 Preliminary Estimate - Alternative B - Sample Calculation

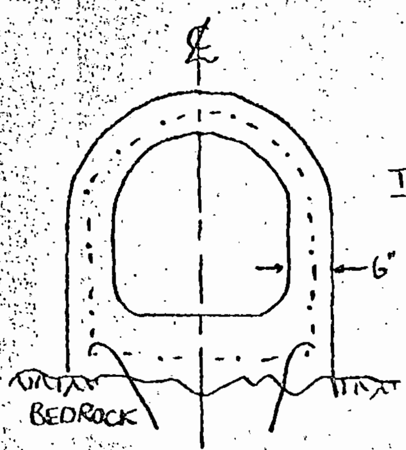
SECTION NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	COST	PRESENT DAY COST	TOTAL CUM. COST / ITEM	TOTAL CUM. COST
1.	Land - crown land	–	–	–	–	–	–	
2.	Land clearing - main & secondary dams	15	acre	$300.00	$4500.00	$10,234.00	$10,234.00	$10,234.00
	- forebay (1968)	10	"	"	$3000.00	$6823.00	$17,057.00	$27,291.00
3.	Permanent access road (current cost)	10	mi	$50,000	$500,000	$500,000	$500,000.00	$527,291.00
4.	Dams & Reservoirs							
4.1	Main Dam & Spillway with control structure							
	Common excavation (1968)	8000	CY	$0.60	$4800.00	$10917.00	$10,917.00	$538,208.00
	Embankment foundation excavation (1968)	5000	CY	$1.10	$5500.00	$12,508.00	$23,425.00	$550,716.00
	Granular Slope protection (1968)	178,500	CY	$2.00	$357,000.00	$811,884.00	$835,309.00	$1,362,600.00
	Coarse Filler (1968)	76,500	CY	$2.50	$191,250.00	$434,938.00	$1,270,247.00	$1,797,538.00
	Rip-Rap (1968)	7400	CY	$4.00	$29,600.00	$67316.00	$1,337,563.00	$1,864,854.00
	Mass Concrete (1968)	2850	CY	$50.00	$142,500.00	$324,071.00	$1,661,634.00	$2,188,925.00
	Rock excavation (1968)	1000	CY	$7.00	$7,000.00	$15,919.00	$1,677,553.00	$2,204,844.00
	Spillway (1957)	650	CY	$85.00	$55,250.00	$162,468.00	$1,840,021.00	$2,367,312.00
	Control structure or intake (1957)	LS	–	$91,200	$91,200	$268,182.00	$2,108,203.00	$2,635,494.00
4.2	Secondary Dam							
	Common Excavation (1968)	3000	CY	$0.60	$1800.00	$4095.00	$4095.00	$2,639,589.00
	Embankment foundation excavation (1968)	2000	CY	$1.10	$2200.00	$5003.00	$9098.00	$2,644,592.00
	Granular Slope protection (1968)	22,050	CY	$2.00	$44,100.00	$100,292.00	$109,390.00	$2,744,884.00
	Coarse Filler (1968)	9450	CY	$2.50	$23,625.00	$53728.00	$163,118.00	$2,798,612.00
	Rip-Rap (1968)	1125	CY	$4.00	$4,500.00	$10,234.00	$173,352.00	$2,808,846.00
	Mass Concrete (1968)	450	CY	$50.00	$22,500.00	$51 170.00	$224,522.00	$2,860,016.00
	Rock excavation (1968)	500	CY	$7.00	$3,500.00	$7,960.00	$232,482.00	$2,867,976.00
4.3	Forebay dam, Spillway & Intake							
	Common Excavation (1968)	4000	CY	$0.60	$2400.00	$5,458.00	$5,458.00	$2,873,434.00
	Embankment foundation excavation (1968)	3000	CY	$1.10	$3300.00	$7505.00	$12,963.00	$2,880,939.00
	Granular Slope protection (1968)	23,100	CY	$2.00	$46,200.00	$105,067.00	$118,030.00	$2,986,006.00
	Coarse Filler (1968)	9900	CY	$2.50	$24,750.00	$56,286.00	$174,316.00	$3,042,292.00
	Rip-Rap (1968)	1600	CY	$4.00	$6,400.00	$14555.00	$188,711.00	$3,056,847.00
	Mass concrete (1968)	625	CY	$50.00	$31,250.00	$71,068.00	$259,939.00	$3,127,915.00
	Rock excavation (1968)	500	CY	$7.00	$3,500.00	$7960.00	$267,899.00	$3,135,875.00
	Spillway (1957)	300	CY	$85.00	$25,500.00	$74,985.00	$342,884.00	$3,210,860.
	Control structure or intake (1957)	LS	–	$77,950	$77950.00	$229,219.00	$572,103.00	$3,440,079.00

"TYPICAL SPILLWAY SECTION"



"TYPICAL CONTROL STRUCTURE SECTION"



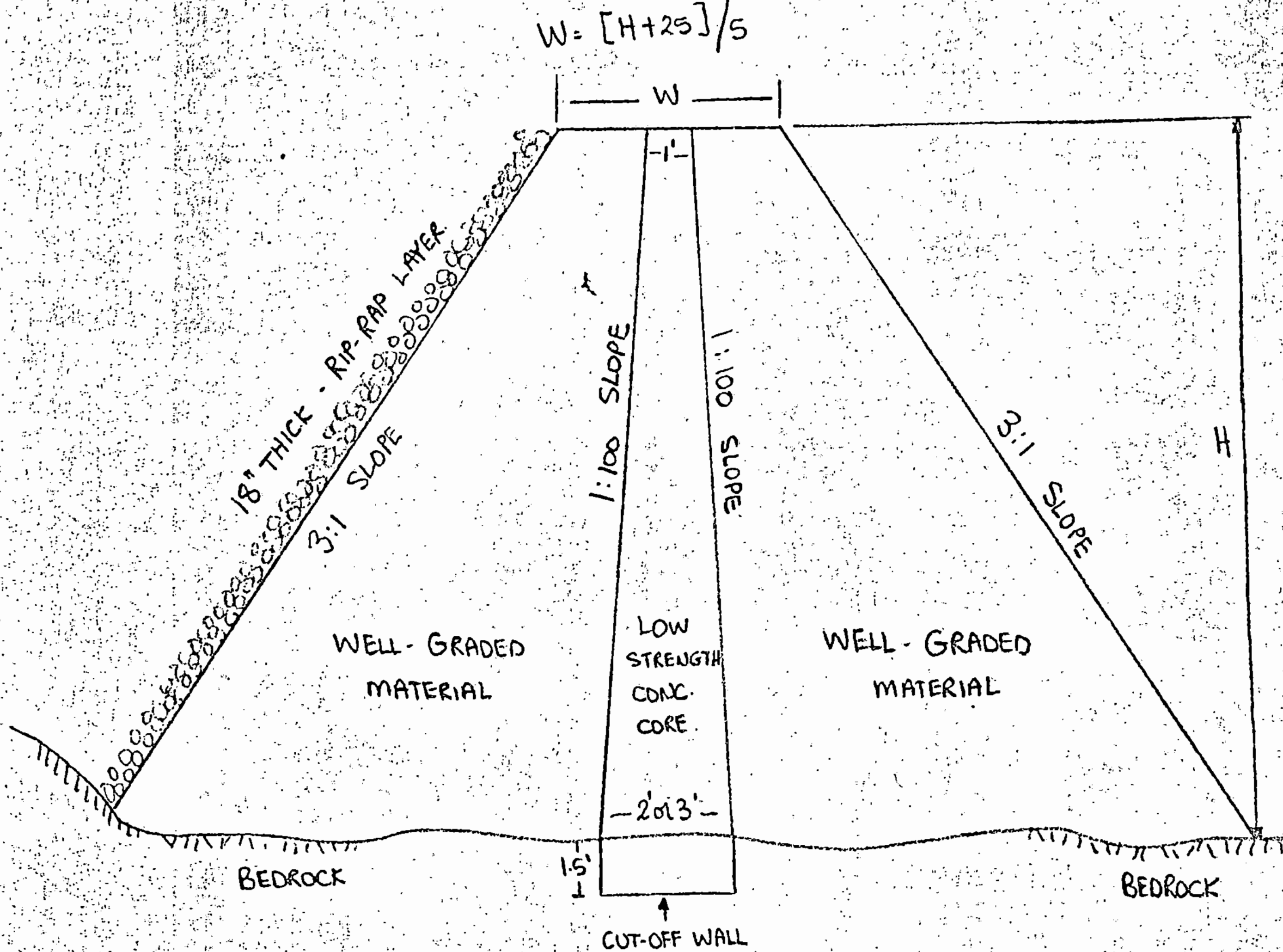


TYPICAL INTAKE STRUCTURE SECTION

SECTION A-A

TYPICAL CONTROL STRUCTURES

N.T.S.



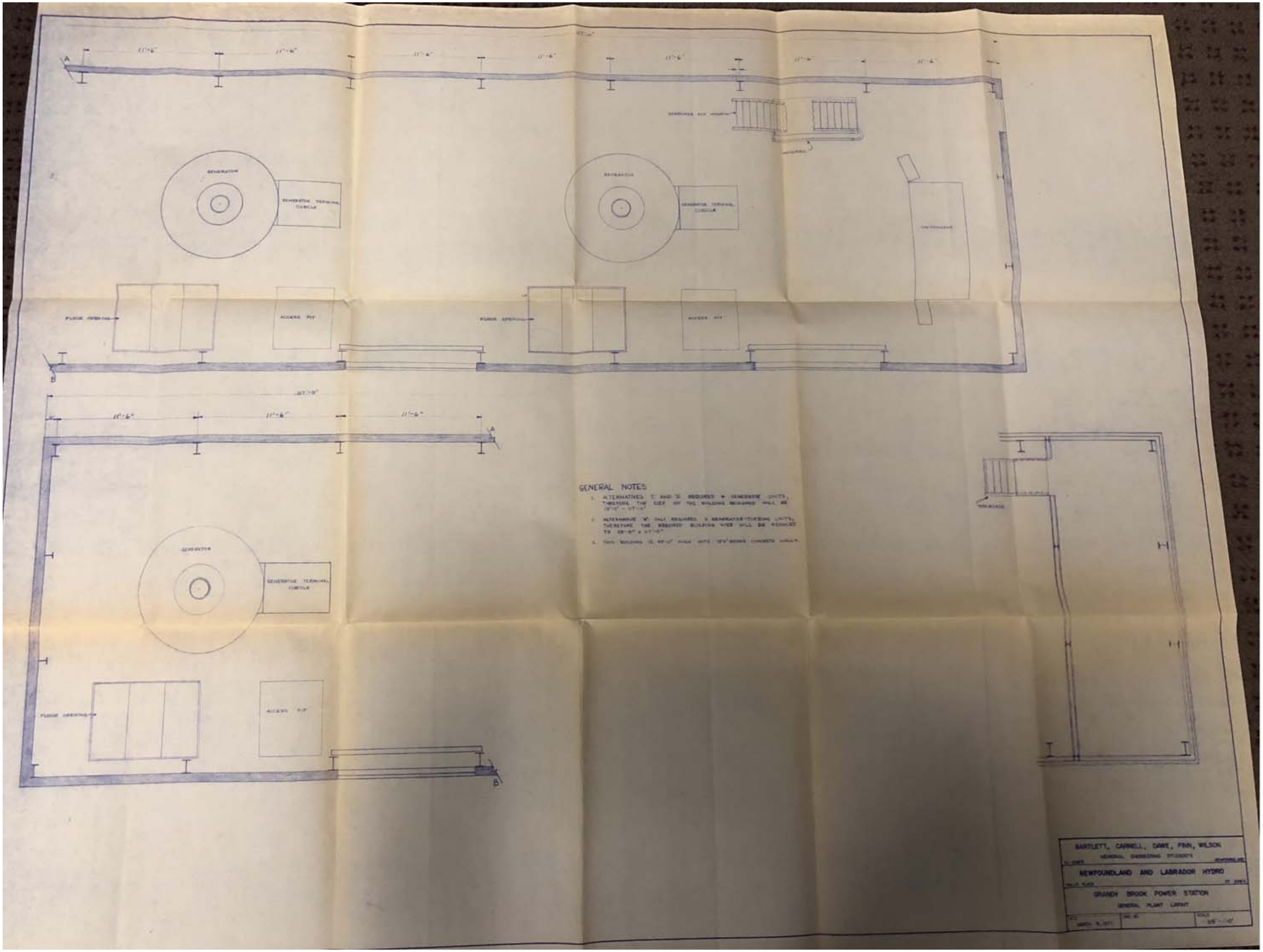
NOTE: NTS.

TYPICAL EARTH DAM SECTION

N.T.S.

APPENDIX L

GENERAL LAYOUT AND SIZE OF PROPOSED POWER HOUSES


GENERAL NOTES
GENERATOR
GENERATOR TERMINAL CUBICLE
FLOOR OPENING
ACCESS PIT
BARTLETT, CARNELL, DAWE, FINN, WILSON
NEWFOUNDLAND AND LABRADOR HYDRO
GRANDY BROOK POWER STATION
GENERAL PLANT LAYOUT

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Alternative A

8.25 MW 17 mile Transmission Distance
66,000 Voltage Drop Chart.

Try 000 wire 0.90 P.F. (power factor)
⇒ Voltage Drop 3.0 %
⇒ $\left(\frac{66}{69}\right)^2$ = 2.7 % for 69,000 Volts (69 KV)

Try 266.8 wire 0.90 P.F.
⇒ Voltage Drop = 2.0 %
⇒ 1.8 % for 69KV

Try 00 ⇒ 0.90 PF.
⇒ Voltage Drop 3.1 % 69 KV

69 KV Transmission Required.
but Alternative has been eliminated, not technically equivalent

Alternative B

2825 KW ≡ 2.825 MW 0.90 P.F. 9 miles

a) Try 12.5 KV (13,200 VOLT CHART)
0.9 P.F. – 2/0 ACSR OFF THE VOLTAGE DROP CHART

b) Try 25.0 KV (22,000 VOLT CHART)
0.9 P.F. – 4/0 ACSR 4.4 % Voltage Drop
Voltage Drop @ 25 KV 4.4 × $\left(\frac{22}{25}\right)^2$ = 3.41 %
uneconomical

0.9 P.F. – 2/0 ACSR (22 KV Chart) 6.0 %
Voltage Drop @ 25 KV 6.0 × $\left(\frac{22}{25}\right)^2$ 4.65 %

ALTERNATIVE E

6925 KW @ 0.90 P.F. for 9 miles.

a) Try 25 KV (22.0 KV chart)
0.90 447 mcm 7.0
at 25 KW Voltage Drop $= 7.0 \times \left(\frac{22}{25}\right)^2$ 5.4

b) Try 34.5 KV (33.0 KV Chart)
0.90 P.F. 3/0 ACSR 5.5
at 34.5 KV Voltage Drop $= 5.5 \times \left(\frac{33}{34.5}\right)^2$ 5.0

c) For 34.5 use multiplying factor (0.915 Table)
KW now = 6925 × .915 = 6336 KW
0.90 PF 3/0 ACSR = 5.0% as check only

Two 25 KV Lines OK

Present Worth Analysis
Alternative C

Unit 1 = Hydro unit @ 4850 kw in 1980
Unit 2 = Diesel unit @ 1150 kw in 1986
Existing plant = 2 x 1250 kw + 2 x 625 kw

	Capital Cost ($)		Operation Maintenance & Overhead ($)			Insurance & Interim Replacement ($)			Energy (Kw…	
…ear.	Unit 1	Unit 2	Existing Plant	Unit 1	Unit 2	Existing Plant	Unit 1	Unit 2	Total Demand	Hydro Production
1977			30,000			16,675			6.4	6.4
1978	2,947,000		31,800			17,676			6.9	6.9
1979	6,675,000		33708			18,736			7.4	7.4
1980				23,106			31,160		7.9	7.9
1981				24,492			33,030		8.5	8.5
1982				25,962			35,011		9.1	9.1
1983				27,519			37,112		9.7	9.7
1984				29,170			39,339		10.4	10.4
1985		996,005		30,921			41,699		11.2	11.2
1986				32,776	15,543		44,201	6,335	12.0	12.0
1987				34,742	16,476		46,853	6,715	12.8	12.8
1988				36,827	17,464		49,664	7,118	13.7	13.7
1989				39,037	18,512		52,644	7,545	14.7	14.7
1990				41,379	19,623		55,803	7,997	15.8	15.8

Present Worth Analysis.
Alternative D

Unit 1 Hydro plant @ 4500 kw in 1980
Unit 2 Diesel unit @ 750 kw in 1984
Unit 3 Diesel unit @ 750 kw in 1987.
Existing Plant = 3750 kw.

	Capital Costs ($)			Operation, Maintenance & Overhead ($)				Insurance & Intrim Replacement ($)				Energy (k	
ar	Unit 1	Unit 2	Unit 3	Existing Plant	Unit 1	Unit 2	Unit 3	Existing Plant	Unit 1	Unit 2	Unit 3	Total Demand	Hydro Product
977				30,000				16,675				6.4	[illegible]
978	3,060,000			31,800				17,676				6.9	[illegible]
979	7,377,000			33,708				18,736				7.4	[illegible]
980					21,438				33,774			7.9	7.9
981					22,724				35,800			8.5	8.5
982					24,088				37,948			9.1	9.1
983		578,114			25,533				40,225			9.7	9.7
984					27,065	4256			42,639	3469		10.4	10.4
985					28,689	4511			45,197	3677		11.2	11.2
986			688,542		30,410	4782			47,909	3898		12.0	12.0
1987					32,235	5069	5069		50,784	4132	4132	12.8	12.8
1988					34,169	5373	5373		53,831	4380	4380	13.7	13.7
1989					36,219	5695	5695		57,060	4642	4642	14.7	14.7
1990					38,392	6037	6037		60,484	4921	4921	15.8	15.8

OK

Energy (KW x 10^6)		Oil Costs		Total fuel Oil		Total Lube Oil		Total	Present	Present	Cumulative
Hydro Productn.	Diesel Requirement	Fuel ($/gal)	Lube ($/gal)	Quantity (gal)	Cost ($)	Quantity (gal)	Cost ($)	Ammount ($)	Worth Factor	Worth ($ - 1977)	Present Worth ($)
	6.4	0.499	2.49	491,520.	245268	7040	17530.	309493	1.000	309,493	309,493
	6.9	0.529	2.64	529,920.	280328.	7590	20038.	2922842	0.9091	2,657,155	2,966,64
	7.4	0.561	2.80	568,320.	318828	8140	22792.	4772064	0.8265	3,944,111	6,910,75
7.9	0.6	0.594	2.97	46080.	27371	660	1960.	113130	0.7513	84,995	6,995,75
8.5	0.6	0.630	3.14	46080.	29030	660	2072.	117903	0.6830	80,528	7,076,28
9.1	1.1	0.668	3.33	84480.	56433	1210	4029.	165854	0.6209	102,979	7,179,26
9.7	1.1	0.708	3.53	84480.	59812	1210	4271.	175800	0.5645	99,239	7,278,40
9.9	1.1	0.750	3.74	84480.	63360	1210	4525.	186305	0.5132	95,612	7,374,01
9.9	1.3	0.795	3.97	99840.	79373	1430	5677.	210573	0.4665	98,232	7,472,24
9.9	2.1	0.843	4.21	161280.	135939	2310	9725.	898407	0.4241	381,014	7,853,25
9.9	2.9	0.894	4.46	222,720	199112	3190	14227.	363558	0.3855	140,152	7,993,41
9.9	3.8	0.947	4.73	291840	276372.	4180	19771.	455308	0.3505	159,585	8,152,99
9.9	4.8	1.004	5.01	368640	370115	5280	26453.	565283	0.3186	180,099	8,333,09
9.9	5.9	1.064	5.31	453120	482120	6490	34462.	695419	0.2897	201,463	8,534,55

	Total Amount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
Present worth adjustments (1990 - 2040) = $695,419 x 22.24 = $15,466,118	15,466,118	0.2897	4,480,534	—
Replacements:				
Unit 2 in 1998	2,309,140	0.1351	312,035	—
Unit 3 in 2000	2,594,551	0.1117	289,755	—
Unit 4 in 2016	3,559,183	0.0243	86,504	—
Trans line & sub stn in 2019	3,455,563	0.0183	63,100	—
Unit 2 in 2028	13,262,562	0.0077	102,707	—
Unit 3 in 2030	14,835,781	0.0064	94,951	13,964,161

Present Worth Analysis.
Alternative B.

Unit 1 = Hydro unit @ 2825 kw in 1980
Unit 2 = Diesel unit @ 1250 kw not taken out of service
Unit 3 = Diesel unit @ 1250 kw taken out of service for only 2 years
Unit 4 = New diesel unit @ 675 kw added in 1987
Existing unit = 2 x 1250 kw + 2 x 625 kw.

	Capital Costs ($)		Operation, Maintenance & Overhead ($)					Insurance & Interim Replacement ($)					
Year	Unit 1	Unit 4	Existing Unit	Unit 1	Unit 2	Unit 3	Unit 4	Existing Unit	Unit 1	Unit 2	Unit 3	Unit 4	Tota Dema
1977			30,000					16,675					6.
1978	2,573,000		31,800					17,676					6.9
1979	4,378,000		33,708					18,736					7.4
1980				13458	11,910 ✓				45,191	6620	6620		7.9
1981				14265 ✓	10,600 ?				47,902	7017	7017		8.5
1982				15121	11,236 ?	13382			50,777	7438	7438		9.1
1983				16029	11,910	14185			53,823	7885	7885		9.7
1984				16990	12,625	15036			57,053	8358	8358		10.
1985				18009	13,382	15938			60,476	8859	8859		11.2
1986		619,688		19090	14,185	16894			64,104	9391	9391		12.
1987				20235	15,036	17908	5400		67,951	9954	9954	3718	12.
1988				21449	15,938	18983	5724		72,028	10,551	10,551	3941	13.
1989				22736	16,895	20122	6067		76,349	11,184	11,184	4178	14.
1990				24101	17,908	21329	6431		80,930	11,855	11,855	4428	15.

Present Worth Analysis
All-Diesel Alternative

Unit 1 1250 kW in 1980
Unit 2 1000 kW in 1986.
Existing 2 × 1250 kW
2 × 625 kW.

Year	Capital Costs ($)		Operation, Maintenance & Overhead ($)			Insurance & Interim Replacement ($)			Energy Required (kWh × 10^6)	Oil Fuel ($/gal)
	Unit 1	Unit 2	Existing plant	Unit 1	Unit 2	Existing Plant	Unit 1	Unit 2		
1977			30,000			16,675			6.4	0.499
1978			31,800			17,676			6.9	0.529
1979	1,040,920		33,708			18,736			7.4	0.561
1980			35,730	11,910		19,860	6246		7.9	0.594
1981			37,874	12,620		21,052	6621		8.5	0.630
1982			40,146	13,382		22,315	7018		9.1	0.668
1983			42,555	14,185		23,654	7439		9.7	0.708
1984			45,109	15,036		25,073	7885		10.4	0.750
1985		866,090	47,815	15,938		26,577	8359		11.2	0.795
1986			50,684	16,895	13,516	28,172	8860	5197	12.0	0.843
1987			53,725	17,909	14,327	29,862	9392	5509	12.8	0.894
1988			56,949	18,984	15,187	31,654	9955	5839	13.7	0.947
1989			60,366	20,123	16,098	33,553	10,552	6190	14.7	1.004
1990			63,988	21,330	17,064	35,566	11,185	6561	15.8	1.064

Present worth adjustments: value in 1990 of series of payments = $1,539,082 × 22.24 = $34,229,183
(1990 - 2040)

Replacement of units: Existing plant @ 3750 kW in 1998
————— " ————— in 2028
Unit 1 @ 1250 kW in 2009
Unit 2 @ 1000 kW in 2015.

Oil Costs		Total Fuel Oil		Total Lube oil		Total	Present	Present	Cumulative
Fuel ($/gal)	Lube ($/gal)	Quantity (gal)	Cost ($)	Quantity (gal)	Cost ($)	Ammount ($)	Worth Factor	Worth ($ - 1977)	Present Worth ($
	2.49	491,520	245,268	7040	17,530	309,473	1.0000	309 473	309,473
	2.64	529,920	280,328	7590	20,038	349,842	0.9091	318,041	627,514
	2.80	568,320	318,828	8140	22,792	1,434,984	0.8265	1,186,014	1,813,529
	2.97	606,720	360,392	8690	25,809	459,947	0.7513	345,558	2,159,087
	3.14	652,800	411,264	9350	29,359	518,794	0.6830	354,336	2,513,423
	3.33	698,880	466,851	10,010	33,333	583,0459	0.6209	362,013	2,875,43
	3.53	744,960	527,431	10,670	37,665	652,929	0.5645	368,578	3,244,015
	3.74	798,720	599,040	11,440	42,786	734,929	0.5132	377,166	3,621,180
	3.97	860,160	683,827	12,320	48,910	1,697,576	0.4665	791,891	4,413,071
	4.21	921,600	776,909	13,200	55,572	955,806	0.4241	405,357	4,818,428
	4.46	983,040	878,838	14,080	62,797	1,072,359	0.3855	413,394	5,231,822
	4.73	1,052,160	1,111,045	15,070	71,281	1,320,894	0.3505	462,973	5,694,79
	5.01	1,128,960	1,133,476	16,170	81,012	1,361,370	0.3186	433,732	6,128,527
	5.31	1,213,440	1,291,100	17,380	92,288	1,539,082	0.2897	445,872	6,574,408
						34,229,183	0.2897	9,916,195	—
						11,041,265	0.1351	1,491,675	—
						63,415,582	0.0077	488,300	—
						4,383,442	0.0474	207,775	
						4,692,822	0.0267	125,298	18,803,643

Oil Costs		Total Fuel Oil		Total Lube Oil		Total	Present	Present	Cumulative
Fuel ($/gal)	Lube ($/gal)	quantity (gal)	Cost ($)	quantity (gal)	cost ($)	Ammount ($)	Worth Factor	Worth ($ - 1977)	Present Worth ($)
0.499	2.49	491520	245,268	7040	17,530	309,473	1.0000	309,473	309,473
0.529	2.64	529920	280,318	7590	20038	3,296,842	0.9094	2,997,159	3,306,632
0.561	2.80	568320	318828	8140	22792	7,069,064	0.8265	5,842,581	9,149,213
0.594	2.97	38,400	22810	550	1,634	78,710	0.7513	59,135	9,208,348
0.630	3.14	38,400	24,192	550	1,727	83,441	0.6830	56,990	9,265,338
0.668	3.33	38,400	25,651	550	1,832	88,456	0.6209	54,922	9,320,261
0.708	3.53	38,400	27,187	550	1,942	93,760	0.5645	52,928	9,373,188
0.750	3.74	38,400	28,800	550	2,057	99,366	0.5132	50,995	9,424,183
0.795	3.97	38,400	31,528	550	2,184	1,102,337	0.4665	514,240 ~~517,772~~	9,942,155
0.843	4.21	38,400	32,371	550	2,316	133,542	0.4241	56,635	9,998,79
0.894	4.46	38,400	34,330	550	2,453	141,569	0.3855	54,575	10,053,36
0.947	4.73	38,400	36,365	550	2,602	150,044	0.3505	52,590	10,105,95
1.004	5.01	38,400	38,554	550	2,756	159,048	0.3186	50,673	10,156,62
1.064	5.31	38,400	40,858	550	2,921	168,581	0.2897	48,838	10,205,46
worth adjustments (1990-2040) = $168,581 × 22.24 = 3,749,241						3,749,241	0.2894	1,086,155	—
ments :									
it 2 in 2015						5,720,560	0.0267	152,938	—
ons Line & Sub Stn in 2019						3,455,563	0.0183	63,100	11,507,65

…) …ied …uction.	Oil Costs Fuel ($/gal)	Lube ($/gal)	Total Fuel Oil quantity (gal)	cost ($)	Total Lube Oil quantity (gal)	Cost ($)	Total Ammount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
6.4	0.499	2.49	491520	245268	7040	17530	309473	1.0000	309,473	309,473
6.9	0.529	2.64	529920	280328	7590	20038	3409824	0.9091	3,099,871	3,409,344
7.4	0.561	2.80	568320	318828	8140	22792	7771064	0.8265	6,422,784	9,832,128
—	0.594	2.97	—	—	—	—	55212	0.7513	41,481	9,873,609
—	0.630	3.14	—	—	—	—	58524	0.6830	39,972	9,913,581
—	0.668	3.33	—	—	—	—	62,036	0.6209	38,518	9,952,099
—	0.708	3.53	—	—	—	—	643,872	0.5645	363,466	10,315,565
0.3	0.750	3.74	23040	17280	330	1234	95943	0.5132	49,238	10,364,803
0.3	0.795	3.97	23040	18317	330	1310	101701	0.4665	47,444	10,412,246
0.3	0.843	4.21	23040	19423	330	1389	796356	0.4241	337,735	10,749,981
0.6	0.894	4.46	46080	41196	660	2944	145,561	0.3855	56,114	10,806,095
0.6	0.947	4.73	46080	43638	660	3120	154,264	0.3505	54,070	10,860,164
0.6	1.004	5.01	46080	46264	660	3306	163,523	0.3186	52,098	10,912,263
0.6	1.064	5.31	46080	49029.	660	3506	173,327	0.2897	50,213	10,962,476

	Total Ammount ($)	Present Worth Factor	Present Worth ($ - 1977)	Cumulative Present Worth ($)
Present worth adjustment = 173,327 × 22.24 = 3,854,792	3,854,792	0.2897	1,116,733	—
Replacements :				
Unit 2 in 2013	3,320,398	0.0324	107,412	—
Unit 3 in 2016	3,954,649	0.0243	96,115	—
Trans line & Sub station in 2019	3,455,563	0.0183	44,839	

TOTAL PRESENT WORTH $ 12,327,575