KPL HYDRO POWER SYSTEMS

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Our File: PB 3591 0101

November 25, 1985

TRM Engineering Ltd.
Suite 701
744 West Hastings Street
Vancouver, British Columbia
V6C 1A5

Mr. T. Van Wollen

Surf Inlet Mine Hydro Study

Dear Sir:

We are pleased to submit our pre-feasibility study on hydroelectric power potential for the proposed gold mine to be located near Surf Inlet on Princess Royal Island. The study has been carried out without benefit of a site visit or any site investigations.

We have prepared approximate capital cost and annual operating cost estimates for four alternative schemes, two each for a 300 t/day and 500 t/day mine throughput. We believe the cost estimates represent the correct order of magnitude for this level of study, however further work as described in the report is required to refine the estimates. In particular, the condition of the existing concrete dam is unknown and a detailed field inspection of this structure should be considered a priority item for the next phase of work.

We trust this report is adequate for your purposes at this time and would be pleased to provide any further assistance that you may require during the next phase of work. Thank you for this opportunity to provide consulting services on this project.

Yours very truly,

KLOHN LEONOFF LTD.

Peter S. McCreath, P.Eng.
Project Manager

att.

PSMc/ld

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REPORT

PROJECT: SURF INLET POWER STUDY

LOCATION: PRINCESS ROYAL ISLAND, BRITISH COLUMBIA

CLIENT: TRM ENGINEERING LTD.

OUR FILE: PB 3591 0101 NOVEMBER 25, 1985

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DRAWING

1. INTRODUCTION

1.1 BACKGROUND

TRM Engineering Ltd. requested that KPL Hydro Power Systems, a joint venture of Klohn Leonoff Ltd. and Pacific Diesel Company, carry out a pre-feasibility level study to estimate power demands and the potential for a small hydroelectric power plant for a 300 to 500 t/day gold mine located near Surf Inlet on Princess Royal Island south of Prince Rupert.

The mine, which operated successfully for a number of years earlier this century, is located about 10 km from the head of Surf Inlet. As described in various reports provided by TRM to KPL, when the mine was in operation power was obtained from a low head hydroelectric plant constructed at the head of the inlet. A reinforced concrete dam of the Ambursen type (13.7 m high and 140 m in length) was constructed across the outlet of Cougar Lake thereby raising Cougar Lake to the same elevation as Bear Lake. A 1.8 m diameter penstock carried water from the reservoir over a distance of about 100 m to the powerhouse, developing a gross head of from 18.9 m to 25.6 m, depending on tidal conditions in Surf Inlet. The powerhouse, a reinforced concrete building, contained two Pelton-Francis turbines rated at 750 hp (560 kW) each. The plant reportedly developed 1230 hp (920 kW). Power was transmitted to the mine site by pole line over a distance of about 9 km.

This pre-feasibility study has been carried out without the benefit of a site inspection. Thus a number of significant assumptions have had to be made based on the data available to us and discussions with Messrs. T. Van Wollen, M. McClaren and J. Schearer of TRM Engineering Ltd.

1.2 OBJECTIVES

The objectives of this pre-feasibility study include:

a) assess the potential electric power demands and heating requirements for a 300-500 t/day gold mining operation;

b) assess the potential for and costs of generating hydroelectric power from the Cougar Lake/Bear Lake catchment at the site of the abandoned hydro plant;

c) assess the potential for generating hydroelectric power from a new scheme constructed closer to the mine;

d) assess the costs of meeting all power requirements by diesel generation; and

e) assess the potential for and costs of a combined hydro/diesel installation.

To accomplish these objectives we have made use of data, maps and reports provided by TRM, available government topographic and streamflow data, and the results of a similar study recently carried out by KPL for a proposed 1000 t/day Bear Totem Project for Chevron Canada Resources Ltd.

POWER AND HEATING DEMANDS

From the report of the Minister of Mines (1918) on the Skeena Mining Division, the old mine operated at a feed rate of about 300 t/day and had a total power demand of about 820 kW (1100 hp). Actual power demand for the new operation will depend on, among other things, the actual gold extraction process utilized.

For this study we have assumed that a suitable pre-feasibility estimate of total power demand, including mine operation and camp services, can be obtained by prorating the demand calculated for the 1000 t/day Bear Totem project. We estimate the power demand for the proposed 500 t/day operation to be about 1500 kW (1.5 MW). A 300 t/day operation would require about 900 kW (0.9 MW).

In addition, we estimate that heating requirements for the 500 t/day mine will average about 2 million Btu/hr, or approximately 600 kW, 600 kW

over and above the mine demand (1.2 million Btu/hr or 360 kW for 300 t/day). Assuming mine operation 365 days of the year results in annual energy demand of 13.1 million kWh for the mine and 5.3 million kWh for heating requirements, for a total annual energy requirement (electricity plus heat) of 18.4 million kWh (18.4 GWh per year). Respective figures for 300 t/day operation are 7.9 million kWh electrical, 3.2 million kWh heating, total 11.1 GWh per year. G = giga = 10^9
M = mega 10^6

3. STREAMFLOW, HEAD AND HYDROELECTRIC POWER AVAILABILITY

3.1 COUGAR LAKE

Based on 1:50,000 scale government topographic maps, the catchment area to the existing dam on Cougar Lake was estimated to be 136 km^2. The maps imply that Cougar/Bear Lakes are about 27 m above mean sea level in Surf Inlet, however the old hydroelectric plant has been reported as having a gross head between 18.9 m and 25.6 m, depending on tidal conditions. Without benefit of site surveys, these latter values have been adopted as the potentially available gross head.

Water Survey of Canada streamflow data used for this study are listed below:

Station Number	Name	Catchment Area (km^2)	Period of Record
08EG001	Brown Creek near Port Essington	56.2	1928 - 32
08FA001	Sandell River near Wadhams	130*	1923 - 32
08FA004	Wadhams Creek at Wadhams Cannery	4.92	1947 - 52

(*published area for their gauge is 391 km^2 - WSC confirms that 130 km^2 is correct)

Correct symbol for kilo watt hours = kWh
small k.

The Sandell River gauge streamflow records were adopted as representative for the 136 km^2 Cougar Lake/Bear Lake catchment. A flow duration curve was prepared, based on average monthly flows over the eight complete years of record, and is presented in Drawing No. B-1001. The flow duration curve was converted to a power duration curve (Drawing No. B-1001) applicable to the outlet of Cougar Lake, assuming a net head of 21 m (estimated average for the old plant). For an average net head of 21 m the drawing shows that, with no regulating storage, a hydroelectric power output of 1200 kW may be generated 73% of the time (about 9 months of the year) and an output of 1500 kW may be realized about 63% of the time (7.5 months). The full demand of 2100 kW for a 500 t/day operation could only be produced about 45% of the time (5.5 months per year).

The above assumes only sufficient natural regulating storage in the lakes to produce average monthly flows similar to those recorded at the Sandell River gauge, a conservative assumption considering the size of the lakes in the project relative to total catchment area.

PARADISE CREEK

Upper Paradise Creek near the mine has been identified as a possible hydropower site due to the available gross head of about 110 m. The catchment area of the creek is only about 2.4 km^2 though, and using the flow duration curve of Drawing No. B-1001 prorated to a 2.4 km^2 catchment, this site could only produce about 180 kW for 6 months of the year. The Upper Paradise Creek site has therefore been eliminated from further consideration due to its very limited power potential.

OTHER CONSIDERATIONS

HEAT RECOVERY

Heating requirements may be met by electric heating, or by hot water or steam heat produced using either an oil-fired furnace or by using waste heat from diesel generators. A 1.5 MW diesel generator set will produce

4 million Btu/h of recoverable heat in addition to 1500 kW of electricity. The heat exchangers required are standard equipment. About 2 million Btu/h could be recovered from the coolant in the form of 170°F water and about 2 million Btu/h could be recovered from the exhaust gas in steam at 15 psig.

4.2 INCREMENTAL SIZE OF UNITS

Diesel generator sets less than 1.5 MW capacity are generally not recommended for this application due to poorer reliability associated with higher speed engines. It is also desirable that multiple units should be of the same size. Generally speaking, the diesel sets should be loaded to the maximum possible as they are more efficient at higher loads. Depending on the demand and the portion of the load met by hydroelectric generation, however, the diesel sets will operate satisfactorily at lower output than the rated capacity. For the hydroelectric units, the variation in available streamflow should be taken into account in selecting units. With the variations in flow that may be necessary at the Surf Inlet site, depending on the amount of regulating storage available, two units would be generally more efficient than a single unit. At low flow, only one unit would be operating.

4.3 STORAGE

In order to develop a greater hydroelectric generating potential, regulating storage would be required on Cougar/Bear Lake. The estimated average annual flow at the dam site is about 13.4 m^3/sec. If regulating storage could be developed to use 100% of this flow on a firm basis, with 21 m of net head, it may be possible to develop almost 2000 kW of firm hydroelectric power. The use of average monthly flows for the flow-duration curve takes into account the natural regulating effects of the existing dam structure. A brief inspection of the eight years of flow data for the Sandell River indicated that, for the driest 6 to 8 month period on record, in excess of 75 x 10^6 m^3 of water would have had to be drawn from live storage on the lake. No elevation volume curve is available for the lake but, based on the plan area of the lake estimated from the 1:50000 scale government topographic maps, this volume would result in a lake drawdown of 8 to 10 m (26 to 33 ft). That is almost half the assumed average head, and development of this degree of regulating (live) storage would probably entail construction of a new and higher dam and control structure at or near the site of the existing dam. A firm hydro output of 1260 kW (300 t/day mine) would require a regulated flow of about 8-10 m^3/s. The driest three month period on record indicates a total storage requirement of about 25 x 10^6 m^3, or a drawdown of about 3 m. This may be feasible using the existing structure but must be confirmed during the next phase of study.

3. ALTERNATIVE SCHEMES

3.1 GENERAL

After consideration of the various factors described above, four alternative power generation schemes were selected, two each for 500 t/day and 300 t/day mine production rates, as described below.

Alternative I - Hydro/Diesel

IA - for 500 t/day mine

Hydroelectric - 1.5 MW installed capacity (2 units @ 750 kW each)
Diesel - 1 of 1.5 MW unit operating
- 1 of 1.5 MW unit standby

IB - for 300 t/day mine

Hydroelectric - 1.25 MW installed capacity (1 unit @ 1250 kW)
Diesel - 1 of 0.9 MW unit standby

Alternative II - Diesel Only

IIA - for 500 t/day mine

Hydroelectric - none
Diesel - 1 of 1.5 MW unit operating
- 1 of 1.5 MW unit standby

IIB - for 300 t/day mine

Hydroelectric - none
Diesel - 1 of 0.9 MW unit operating
- 0.9 MW unit standby

5.2 ALTERNATIVE I - COMBINED HYDRO/DIESEL

5.2.1 Alternative IA - 500 t/day Mine

The hydroelectric component of Alternative IA would utilize the existing reinforced concrete dam structure at the outlet of Cougar Lake. For this study it has been assumed that the existing dam is structurally sound and will not require major repair work or complete reconstruction. The existing intake structure would be renovated as required and a 100 m long steel or high density polyethylene single or twin line penstock would lead to a new powerhouse constructed at or near the site of the abandoned powerhouse on Surf Inlet. A single line penstock would be about 1600 mm diameter and would require a bifurcation upstream of the powerhouse to the turbine intakes and turbine inlet closure valves. Conversely twin 1100 mm diameter penstocks could be installed leading directly from the dam to the powerhouse with unit isolation using the inlet gates.

An installed capacity of 1.5 MW is proposed for Alternative IA which would be capable of satisfying the mine power demand about 60% of the time assuming a net average head of about 21 m can be developed. The remainder of the power demand would be met by diesel generation.

For the installed capacity of 1.5 MW, two 750 kW turbine generator sets would be used. The turbines would be horizontal shaft Francis turbines operating at about 600 rpm with synchronous generators and associated governors, switchgears and controls. From the generators the power would go through a circuit breaker to a transformer bank. The transmission line to the mine would be about 9 km long assuming it followed the previously used transmission line route.

For this alternative it is proposed to install two 1.5 MW diesel generator sets. One unit would be operated to supplement as required the hydroelectric power plant in meeting the 1500 kW mine demand, and to generate sufficient electricity and/or waste heat to satisfy heating requirements (average 2 million Btu/hr or 600 kW). A more efficient means of meeting heating requirements whenever the hydro plant is satisfying 100% of the mine demand (1.5 MW) would be to use an oil-fired boiler. This option has not been costed herein but should be investigated in the next stage of study. If the hydro plant has to be taken completely out of service a single 1.5 MW diesel set can satisfy both the mine power demand and heating requirements. The second generator would be on standby. Depending on the firm hydro power that can be installed, the need for the second (standby) diesel unit may not be required and this should be reviewed in the next phase of work.

A preliminary equipment selection has been made for costing. Each 1.5 MW diesel generator set would be skid-mounted and would consist of Deutz BV 9M628 nine cylinder engine operating at 900 rpm. This engine is known worldwide for its reliability, ease of maintenance and its long life. Performance data for this engine are attached.

Each diesel engine would be direct-connected to a two bearing Kato or Newage 900 rpm, 1500 kW, 18 kva brushless alternator, 80° rise, 4160 volts. The governor would be a Woodward 2301 with automatic synchronizing and load sharing. Switchgear would be a 5 kv breaker and associated relays and meters. Perfex exchangers would transfer heat from liquid coolants to process hot water and a Maxim silencer-exchanger would transfer heat from the exhaust to process steam.

Alternative IB - 300 t/day Mine

This alternative involves meeting 100% of both the mine electrical demand and heating requirements by hydroelectric power generation. Assuming that 3-5 m of regulating storage can be developed on Cougar/ Bear Lake an installed capacity of about 1.25 MW would satisfy the power requirements on a year-round basis.

The layout would be generally as described for Alternative IA, except that a single 100 m long 1600 mm diameter penstock would lead directly to a single turbine unit. The unit, with installed capacity of 1250 kW, would be a horizontal shaft Francis turbine with synchronous generator. Transmission and other electrical controls would be similar to Alternative IA.

The diesel component for IB would be used purely as standby to the hydroelectric plant. A single 900 kW diesel generator set would be adequate to satisfy mine demand, and waste heat from the unit would satisfy heating requirements. The 900 kW diesel generator set and associated controls would be similar to the 1500 kW sets described previously for Alternative IA.

Capital Costs

Capital cost estimates for this study have been made without the benefit of site investigations or surveys. Therefore a contingency of 25% has been added to the hydroelectric components to allow for uncertainties in site conditions. It has been further assumed that the existing concrete dam structure will not require complete reconstruction - this item presents the major uncertainty in the capital cost estimates. Further studies should include a detailed inspection and evaluation of the existing dam. Complete reconstruction has been assumed for the powerhouse and transmission line. Total capital costs are estimated to be $4,280,000 for IA and $2,800,000 for IB. The capital cost estimates for these Alternatives are summarized on Table I.

5.2.4 Operating Costs

At 100% capacity one 1.5 MW diesel generator will burn about 115 US gallons of fuel per hour producing about 13 kWh of electrical energy per US gallon of fuel. At lesser loads down to about 50% capacity the efficiency drops to about 12 kWh/US gallon. Using an on-site fuel cost of $0.41/L, fuel operating costs will be about $0.12/kWh running at full load and about $0.13/kWh at reduced load. These costs are also applicable to a 900 kW diesel generation unit.

Of the total estimated mine electrical demand of 13.1 million kWh for Alternative IA, the diesel portion will be approximately 2.1 million kWh. The total diesel output, with waste heat utilized to meet heating demands, will be about 6.9 million kWh. The total annual diesel cost is estimated to be $890,000. Maintenance and replacement parts will have an average annual cost of $40,000, and with three men assigned to the diesel and hydro plants annual manpower costs will be about $150,000. Total annual costs for fuel, parts and operation is thus estimated to be $1,080,000 for Alternative IA.

For Alternative IB 100% of power requirements would be met by hydro-electric power generation. Annual operating and maintenance costs have been estimated assuming $100,000 for two men assigned to the plants, $20,000 for replacement parts, and an allowance for 20 days/year diesel operation (fuel costs of $50,000) for a total annual cost for operation and maintenance of $170,000.

5.3 ALTERNATIVE II - DIESEL ONLY

5.3.1 Alternative IIA - 500 t/day Mine

The diesel equipment would be the same as described for Alternative IA, but one 1.5 MW diesel generator set would be operated continuously with all heating requirements met using waste heat recovery. The second diesel set would be a standby unit.

5. Alternative IIB - 300 t/day Mine

The diesel equipment would be the same as described for Alternative IB, except that two 900 kW diesel generator sets would be installed. One diesel set would operate continuously and heating requirements would be met using waste heat recovery. The second diesel set would be a standby unit.

..3.3 Capital Costs

Capital costs for IIA and IIB would be the same as the capital costs for the diesel components of IA and IB respectively, except that two 900 kW diesel sets would be required for IIB. The capital costs are summarized on Table I.

.3.4 Operating Costs

Fuel costs to generate 13.1 million kWh for the 500 t/day mine demand would be $1,577,000. Annual replacement parts cost would be about $30,000 and with two men assigned to the diesel plant annual manpower costs would be about $100,000. Total annual fuel, operating and maintenance cost would thus be about $1,707,000 for Alternative IIA.

For Alternative IIB annual fuel costs would be about $950,000, the annual cost of manpower and replacement parts would be about $120,000 for a total annual fuel, operating and maintenance cost of about $1,070,000.

TABLE I

CAPITAL COSTS SUMMARY

500TPD 300TPD

Item		Costs in Millions of $ For Alternative No.			
		IA 500/DAY	IB 300T/DAY	IIA	IIB
Hydroelectric Component					
Renovate existing dam and intake		0.15	0.15	-	-
Penstock		0.18	0.16	-	-
Powerhouse structure, tailrace		0.10	0.08	-	-
Turbines, generators, controls, switchgear		1.20	0.88	-	-
Transformers		0.11	0.09	-	-
Transmission line		0.22	0.22	-	-
	Sub Total	1.96	1.58	-	-
Engineering @ 10%		0.19	0.16	2x10² -	-
Contingency @ 25%		0.49	0.40	-	-
	Total Hydro Component	2.64	2.14	-	-
Diesel Component					
Generator sets, incl. heat exchange		1.32	0.40	1.32	0.80
Installation		0.05	0.03	0.05	0.05
Powerhouse		0.20	0.15	0.20	0.15
Misc. piping, stacks, etc.		0.09	0.07	0.09	0.08
	Total Diesel Component	1.66	0.65	1.66	1.08
	TOTAL CAPITAL COST	4.30	2.79	1.66	1.08

P6

IA Hydro Diesel 500 tons/day Hydroelectric 1.5 MW capac
Diesel 1 @ 1.5 MW op.
1 @ 1.5 MW STANDBY

IB Hydro Diesel 300 t/day Hydro elec. 1.25 MW installed capac
Diesel 1 0.9 MW standby

IIA Diesel only 500 t/day

II B Diesel only 300 T/day

P6/7 Estimated Requirements for Power + Heating

	500 tons/day	300 tons/day
Power	1.5 MW	0.9 MW
Heating	0.6 MW	.36
	2.1 MW	1.26 MW

5.4 COST SUMMARY

Table II below summarizes the capital costs, annual costs and unit energy costs for the four alternatives described previously. The annual cost of capital was calculated assuming capital write-off over a ten year period and an annual interest rate of 10%.

TABLE II

ANNUAL COST COMPARISON

	$(millions)/year		Annual Unit Energy Cost ($/kWh)	
	Capital	Annual	Electricity Only	Electricity and Heat
COMBINED HYDRO/DIESEL				
IA-500 t/d Mine				
Capital Cost	4.30	0.70		
O & M Cost		1.08		
Total Annual Cost		1.78	0.136	0.097
IB-300 t/d Mine				
Capital Cost	2.79	0.46		
O & M Cost		0.17		
Total Annual Cost		0.63	0.080	0.058
DIESEL ONLY				
IIA-500 t/d Mine				
Capital Cost	1.66	0.27		
O & M Cost		1.71		
Total Annual Cost		1.98	0.151	0.108
IIB-300 t/d Mine				
Capital Cost	1.08	0.18		
O & M Cost		1.07		
Total Annual Cost		1.25	0.159	0.114

6. CONCLUSIONS AND FURTHER WORK REQUIRED

Table II indicates the potential annual cost advantages of using a combined hydro/diesel power scheme for the Surf Inlet site, especially if the 300 t/day mine is developed and a firm hydroelectric installed capacity of about 1250 kW can be realized.

The cost estimates presented in this report are approximate only, but we feel they represent the correct order of magnitude for the four alternatives studied. As noted earlier in the report a contingency of 25% has been applied to the capital costs of the hydroelectric components. The major unknown at the present time is the state of the existing reinforced concrete dam. During the next phase of study a detailed site inspection of this structure must be carried out by a suitably qualified engineer so as to assess its present structural integrity, the spillway capacity, the state of the intake works, the nature and conditions of the foundation and abutment materials, and the costs which may be necessary to repair or even completely rebuild the dam, spillway works, and the penstock intake works for installation of a new hydro scheme.

Other work necessary to prepare a detailed feasibility study on the project, including more accurate capital and operating cost estimates, would include:

a) inspection of the existing powerhouse structure and site, and detailed surveys of the site if reconstruction is necessary.

b) water level surveys to confirm potential gross head available.

c) inspection and survey of the old transmission line route and penstock route and any alternate routes.

d) detailed surveys in the area proposed for the diesel generator units powerhouse.

e) detailed assessment of storage availability in Cougar/Bear Lake.

f) detailed hydrological review to establish the maximum firm installed hydropower capacity, the degree of regulating water storage required, and the design flood for the control structure.

g) preparation of detailed power demand requirements once the gold extraction process and daily mine throughput have been established.

h) further economic analyses to assess the effect of potential mine life and annual interest rate on annual costs and unit energy costs.

KLOHN LEONOFF LTD.

Peter S. McCreath, P.Eng.
Project Manager

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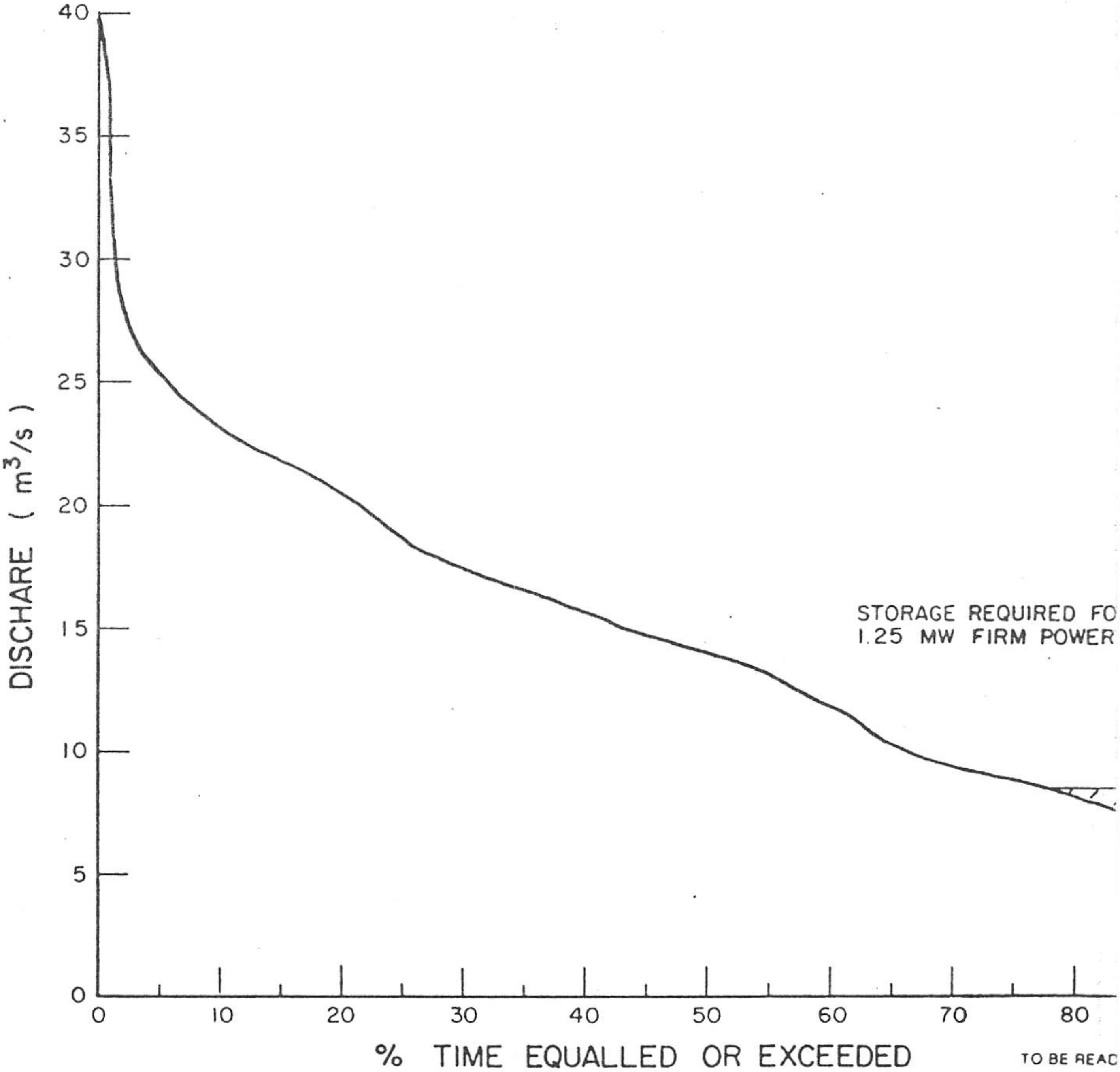

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