University of Minnesota
St. Anthony Falls Hydraulic Laboratory

Project Report No. 212

HYDROPOWER FEASIBILITY

AT THE

RUM RIVER DAM IN ANOKA, MINNESOTA

by

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and

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Prepared for

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ACKNOWLEDGEMENTS

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I. INTRODUCTION

The Rum River Dam MN 00549 is located on the Rum River in Anoka, Minnesota. The existing dam, completed in 1970, replaced a log timber dam operated by Pillsbury-Washburn Milling Company until 1935, when the title was trasferred to the City of Anoka. The mill was located on the left bank of the river adjacent to the dam, and its five turbines had a combined capacity of 450 HP. The purpose of this study is to assess the feasibility of developing hydropower production facilities at the Rum River Dam.

The Rum River Dam was included in a grant agreement dated September 22, 1980, between the Minnesota Department of Natural Resources and the St. Anthony Falls Hydraulic Laboratory for hydroelectric power feasibility studies on seven municipally owned dam sites in the State of Minnesota. The Minnesota Department of Natural Resources and the City of Anoka subsequently made a cost-sharing agreement for the feasibility study. Authorization to begin the Rum River Dam feasibility study was given on May 21, 1981.

This study begins with a hydraulic and hydrologic analysis of the site to determine the available power. The value of the power and marketing options are then determined. The core of the study is proposed development alternatives which include preliminary designs, project cost estimates, and the estimated power production of each alternative. Finally, the benefit and costs of each development alternative are compared and the environmental impact of the proposed development is evaluated.

II. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

The Rum River Dam located at Anoka, Minnesota, is owned and operated by the City of Anoka. The Rum River Dam consists of an Amberson-type spillway 11.4 ft high and 236 ft long. The spillway is abuted on the east by an Ogee-type tainter gate spillway. The tainter gate spillway is 20 ft wide, 15 ft high, with a spillway basin 88 ft in length. To the west of the spillway is a retaining wall set on pile footings which serves mainly for erosion control along the bank. The top of the abutment is 9 feet above the spillway crest and extends 84 feet along the west end of the fixed crest spillway and spilling basin. The dam is equipped with 2.9 ft high flashboards which are in good condition. There are presently no hydropower generating facilities at the Rum River Dam.

The average annual discharge at the site is 697 cfs, and the drainage area is 1590 mi^2. The design net head is approximately 12.3 ft. The maximum discharge over the period of record was 11,800 cfs, occurring in 1965. The minimum discharge recorded was 34 cfs occurring in 1934.

All of the energy produced at the proposed hydropower facilities will be used to offset energy purchases from Northern States Power Company (NSP). The value of the hydroelectric energy, therefore, is equal to the rate at which the Anoka utility purchases energy from NSP. Operation of hydropower facilities will also reduce the monthly demand charge paid by the Anoka utility to NSP. An estimate of the average reduction in demand charge which may be expected in each month of the year is given in Section V. Operating the hydropower facility in a peak mode will transfer some energy production from off-peak hours and reduce the demand charge.

The present contract between Anoka and NSP utilizes three separate rates: the energy charge, a fuel adjustment charge which is tied in with NSP fuel costs, and the demand charge. In January of 1982 the Federal Energy Regulatory Commission approved a rate increase on the energy and demand charges. This rate increase is effective as of January 1982 and sets the energy charge at 2.128 cents/kWH, leaving the fuel adjustment charge near zero. The demand charge is based upon the greatest 15 minute average demand of each month. The present demand charge is $4.60/kW/month.

All calculations in this study are based upon January 1982 dollars. The January 1982 value of energy (2.128 cents/kWH) is assumed to be applicable to energy plus the fuel adjustment charge. The energy value of 2.128/kWH and a demand charge of $4.60/kW/month will be used in the economic analysis in Section VIII.

Three development alternatives were considered. A summary of design capacity, total initial cost, total average annual benefits, and 35-year project life benefit-cost ratio for all three development alternatives are given below (1982 base year):

Alternative	Design Capacity (kW)	Total Initial Cost ($)	Total Average Annual Benefits ($)	35-Year Project Life Benefit-Cost Ratio
A	565	1,965,000	68,600	0.72
B	552	2,087,000	71,100	0.72
C	603	1,113,000	75,600	0.75

Of the three development alternatives considered, Alternative C has the best economic feasibility. The cost and benefit streams illustrated in Tables 3, 4, and 5 of Section VIII indicate that all three of the proposed development alternatives will not be feasible given the economic assumptions made herein.

An economic sensitivity analysis indicates that variation in project parameters and economic assumptions will not alter the negative feasibility of the proposed development. Variations in demand charge credit; project cost; value of energy; operation, maintenance, and replacement costs; and discount and escalation rates were considered.

The potential environmental impacts of the proposed development are minor since no new impoundment will be constructed. The greatest potential impact would occur during construction of the powerplant when dredging and other activities may impair water quality or interfere with fish spawning.

RECOMMENDATION:

Based upon the economic analysis of Section VIII, it is not recommended that hydropower facilities be constructed at the Rum River Dam.

III. SITE CHARACTERISTICS AND EXISTING FACILITIES

A. Site Description and Location

The Rum River Dam MN 00549 is located on the Rum River in the City of Anoka, approximately 0.75 miles upstream from the Mississippi River. The dam abuts land described as Lot 2 - Pillsbury-Watson Subdivision, and Lot 6 - Pillsbury Subdivision, City of Anoka, further described as SE1/4 of Section 1, Township 32 North, Range 25 West of the 4 P.M., Anoka County, Minnesota. The location of the Anoka Dam is shown in Fig. 1.

The Rum River Dam consists of an Amberson-type spillway 11.4 ft high and 236 ft long. The spillway is abuted on the east by an Ogee-type tainter gate spillway. The tainter gate spillway is 20 ft wide, 15 ft high, with a spilling basin 88 ft in length. A plan view of the project area is given in Fig. 2. Cross sections of the fixed crest spillway and the tainer gate spillway are given in Figs. 3 and 4. A view looking upstream towards the dam is given in Fig. 5. Photographs of the project are given in Figs. 6 through 11.

To the west of the spillway is a retaining wall set on pile footings which serves mainly for erosion control along the bank. The top of the abutment is 9 feet above the spillway crest and extends 84 feet along the west end of the fixed crest spillway and spilling basin. The west abutment and tainter gate spillway both allow public access and use of the facilities.

There are two rows of steel sheeting under the dam, both serving as seepage cutoffs. The front row is new sheeting placed upstream of the dam, and a second row 19 feet downstream of the new sheeting, which is part of the old structure. To monitor the effectiveness of these seepage cutoffs a piezometric system was installed under the foundation slabs. Piesometric readings are taken at least once each year and when there is maximum differential head, as outlined in Ref. [1][1].

The dam is equipped with 2.9 ft high flashboards which are in good condition. Through a system of cables the flashboards are automatically tripped at headwater elevation 848.5, if they are not removed manually at headwater elevation of 847, as advised in the operations and maintenance manual [1].

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[1]Number in brackets indicate references on page 60.

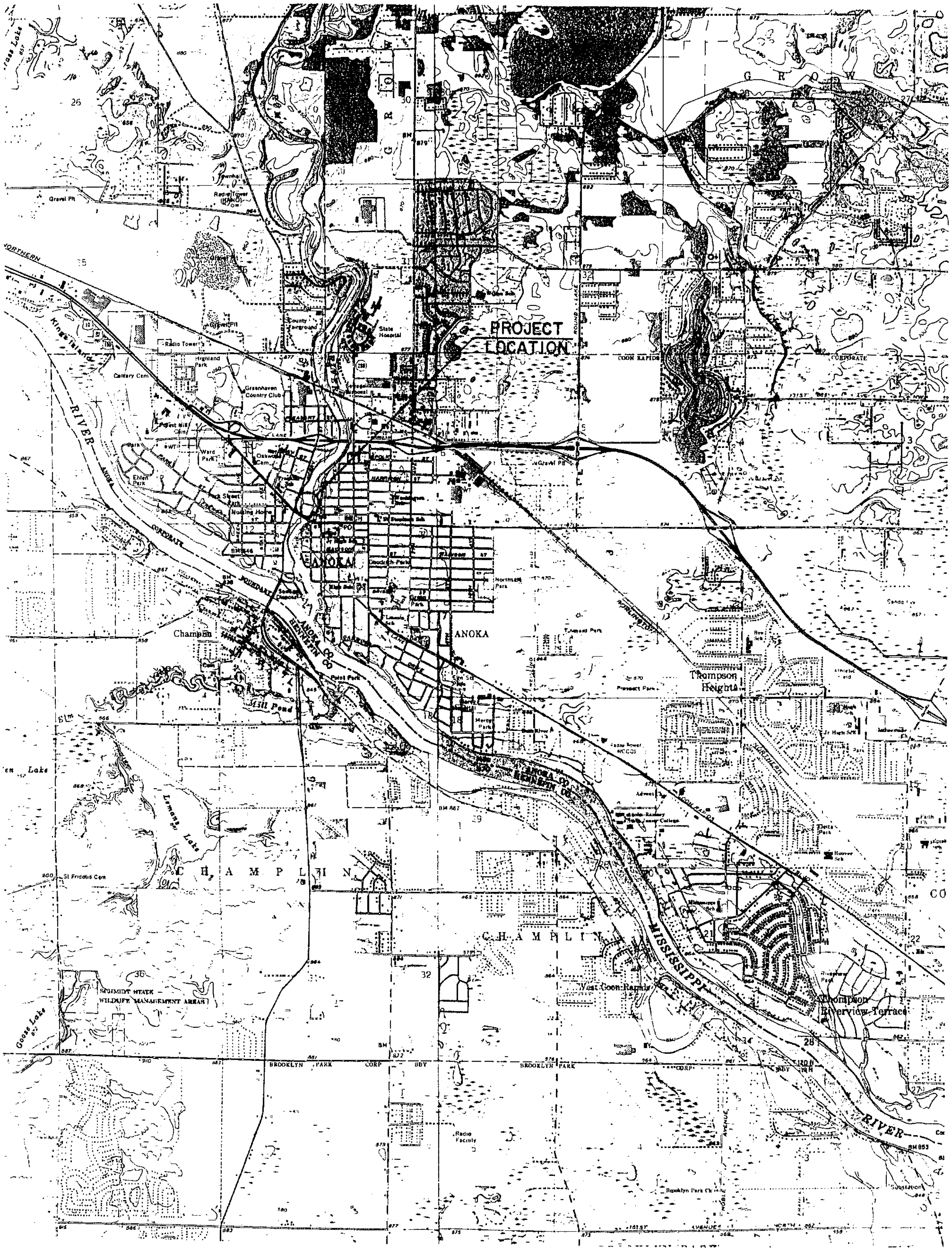

Fig. 1. Project location of the Anoka Dam on the Rum River.

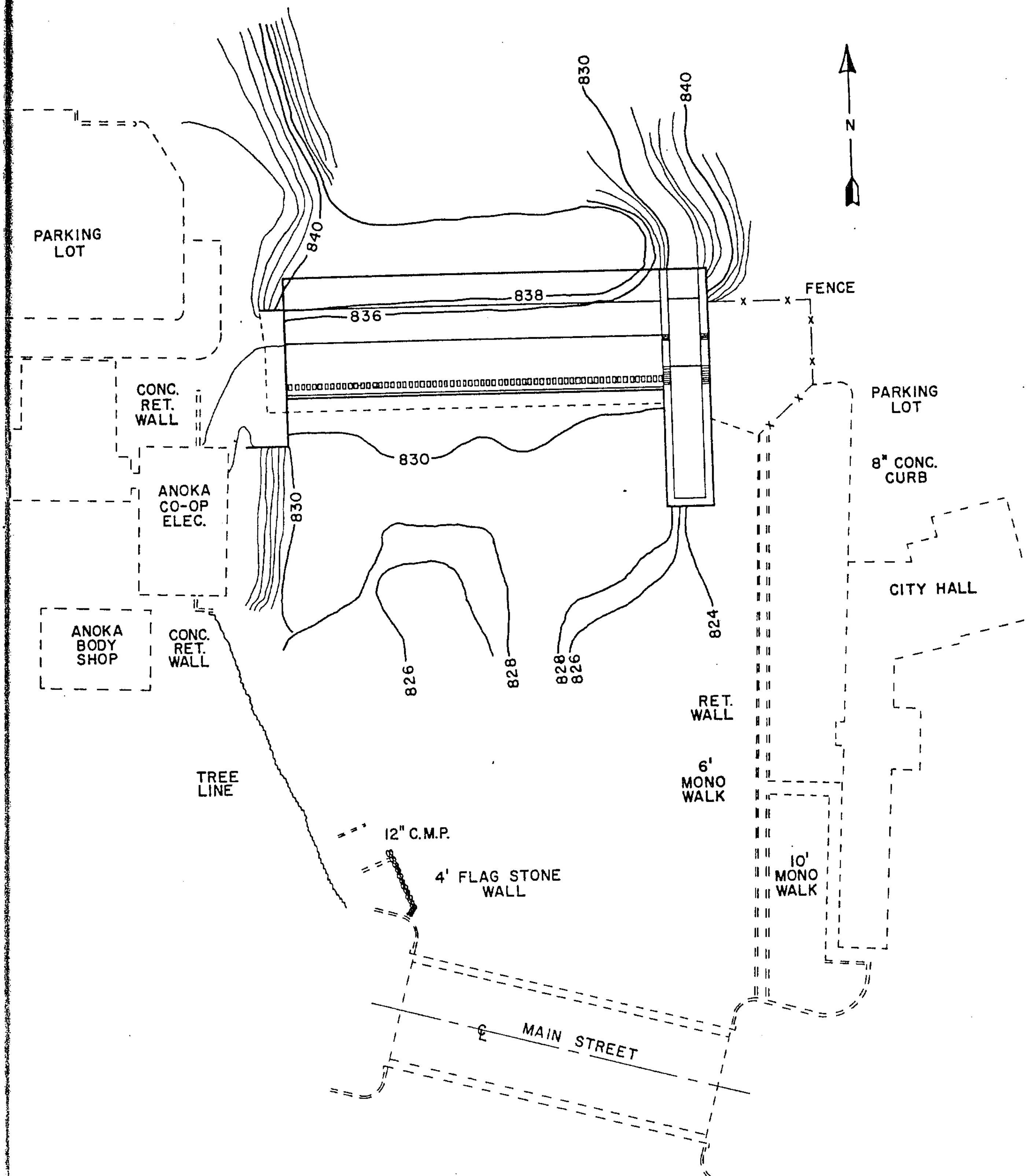

Fig. 2. Plan view of the Rum River Dam at Anoka.

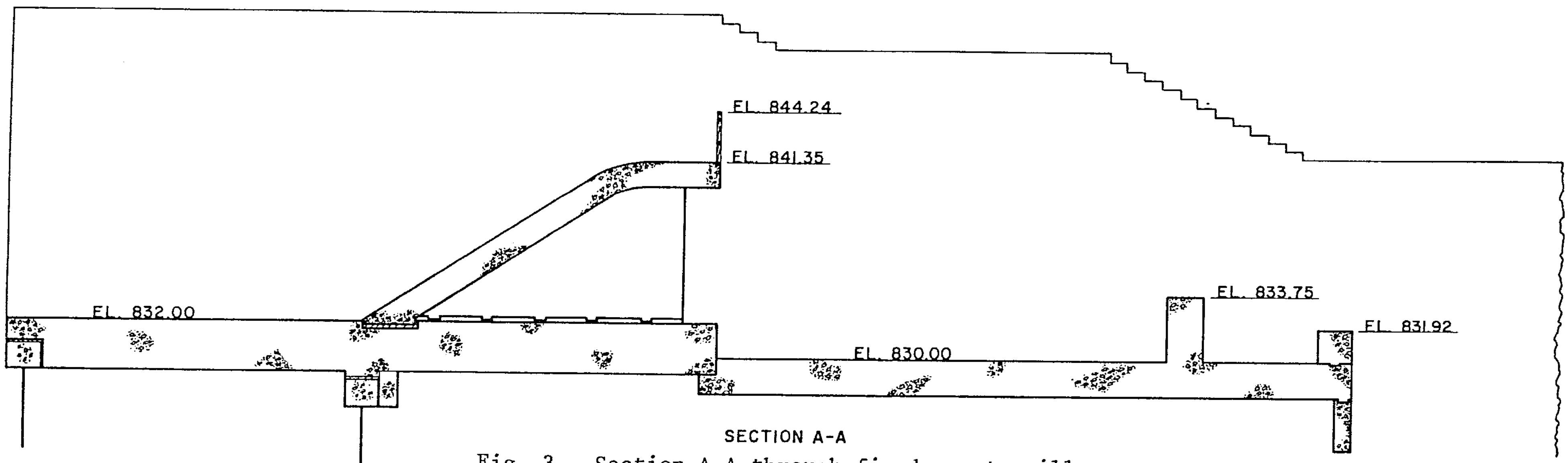

Fig. 3. Section A-A through fixed crest spillway.

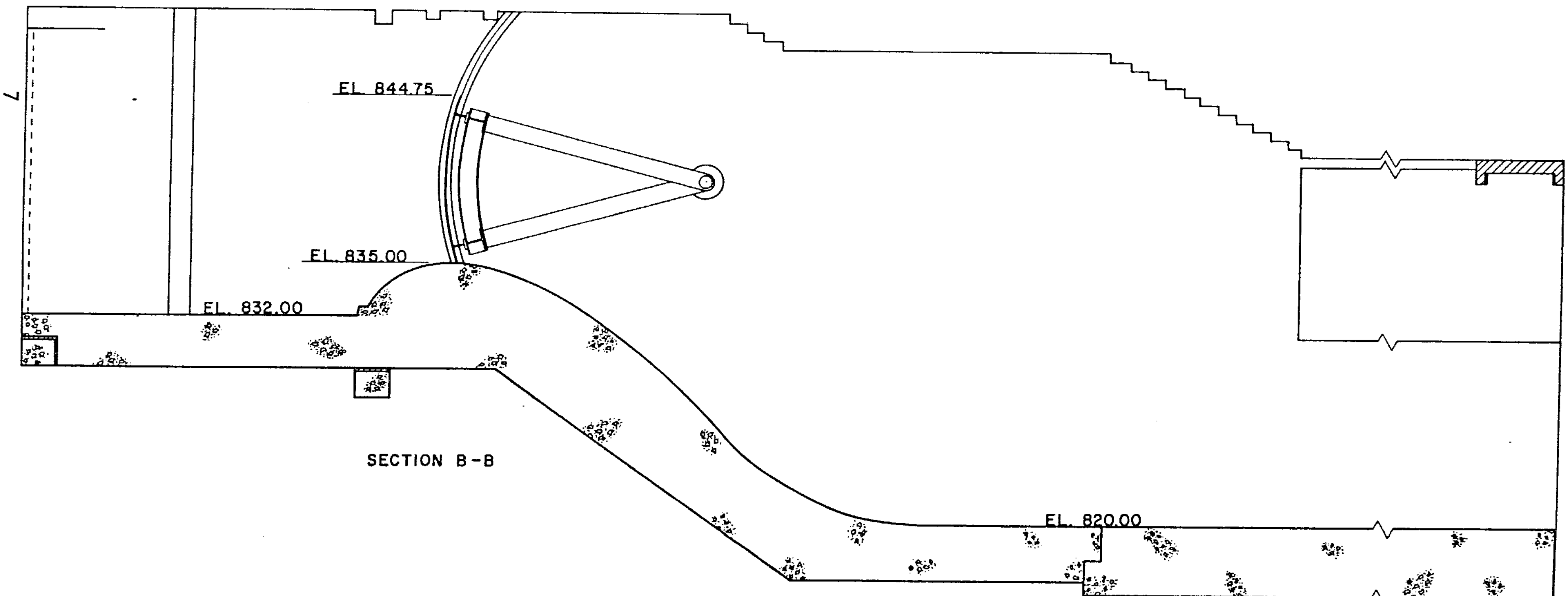

Fig. 4. Section B-B through tainter gate spillway.

Fig. 4. Section B-B through tainter gate spillway.

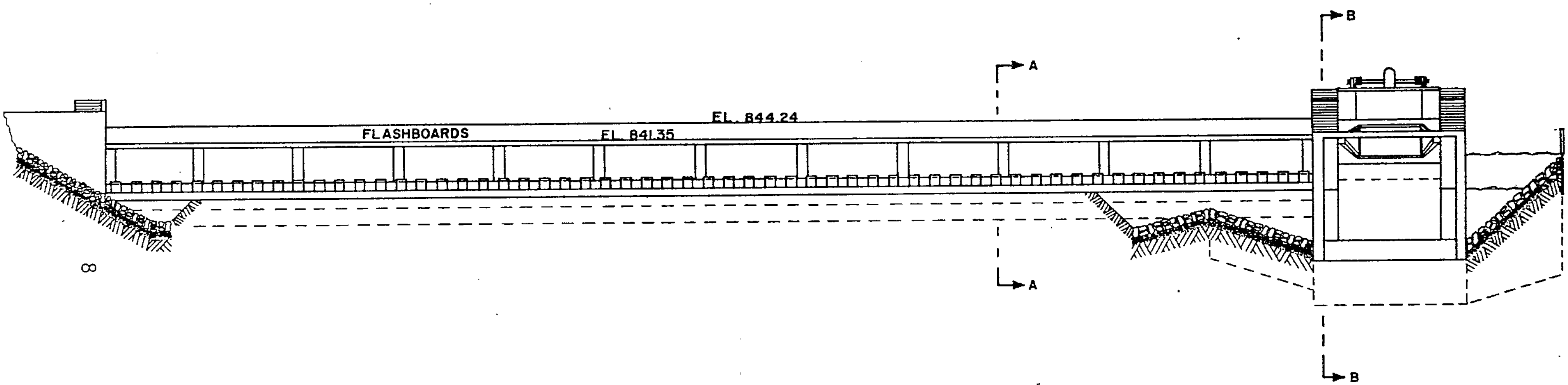

Fig. 5. Elevation view of the Rum River Dam.

Fig. 6. View upstream at Rum River Dam from Main Street bridge.

Fig. 7. View from right abutment showing Amberson-Type spillway with flashboards and west retaining wall of the tainter gate spillway.

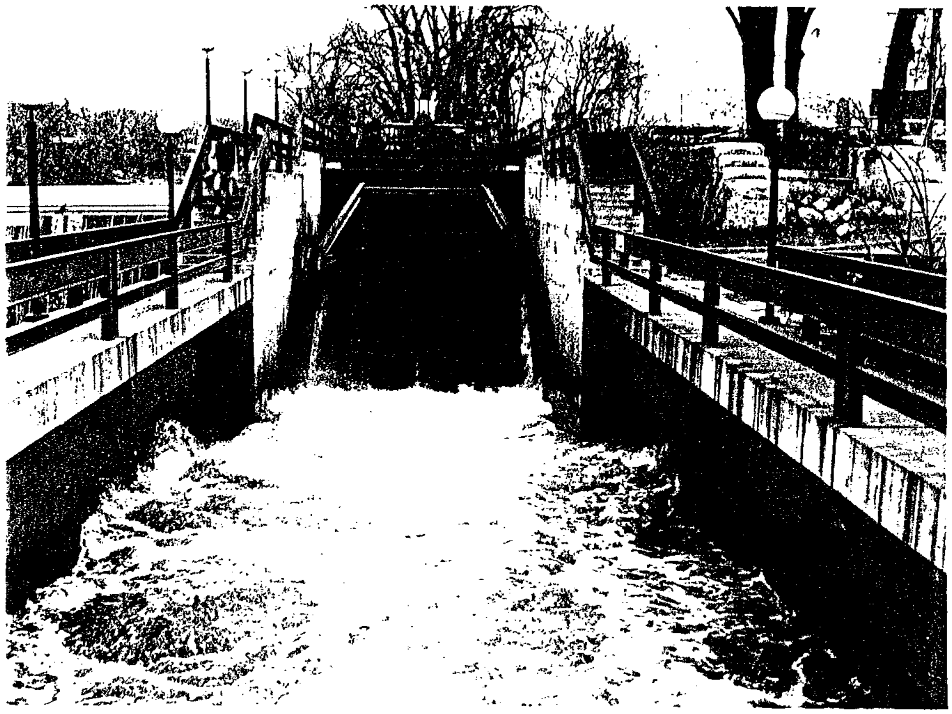

Fig. 8. Upstream view of the tainter gate spillway. Note old foundation and proposed powerhouse area to the right of tainter gate spillway.

Fig. 9. View of the tainter gate spillway and the proposed powerhouse intake.

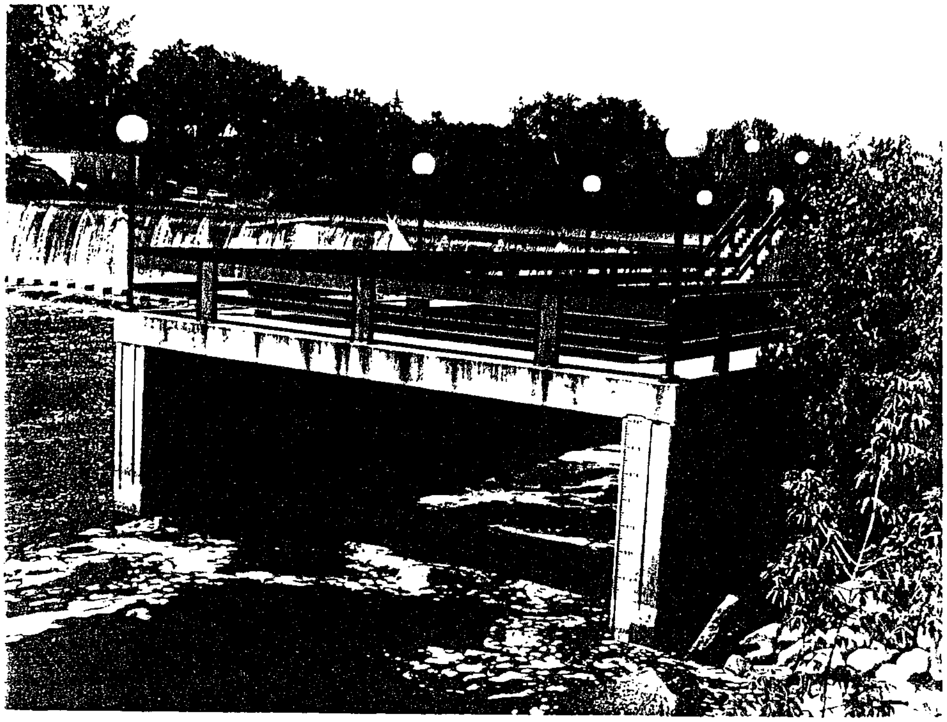

Fig. 10. View of the tainter gate spillway outlet. The location of the proposed tailrace is to the right of the spillway.

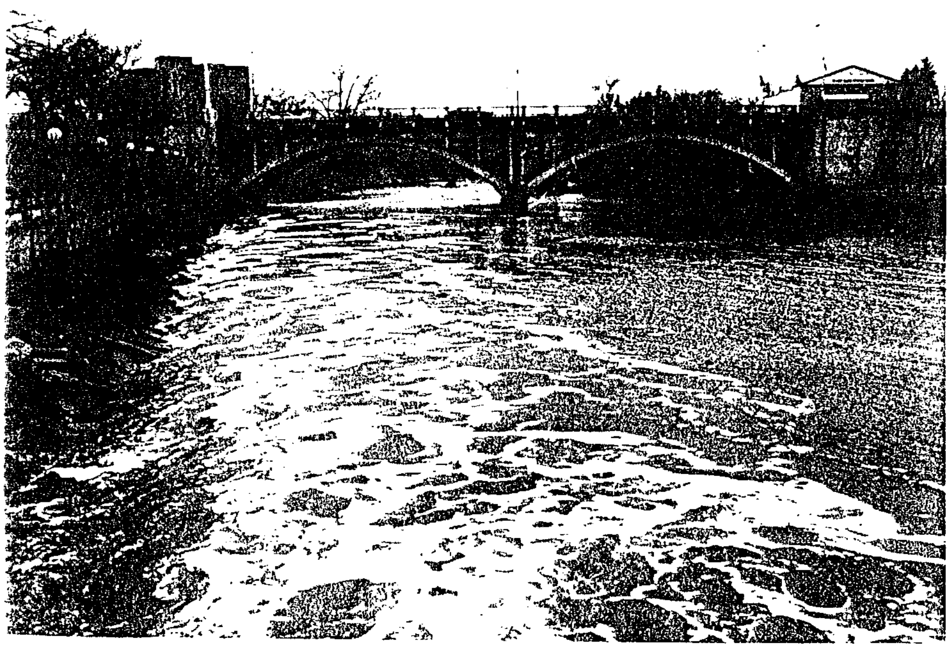

Fig. 11. Downstream view from the tainter gate spillway outlet. Note Main Street bridge.

B. Historical Background

The first dam on the Rum River at Anoka was built with logs cut near Round Lake and floated downstream to the dam site for a sawmill built on the site. The original dam structure was destroyed several times before 1856. A new structure was built which lasted until the late 1890's when a fire burned it to the waterline. At that time, the structure was again rebuilt to provide power for the Lincoln Mill Flour Company. The 12 foot timber dam backed up the water for a distance of 5.7 miles. The mill was located on the left bank of the river adjacent to the dam and its turbines had a combined capacity of 450 HP.

In the early 1900's the dam was obtained by the Pillsbury-Washburn Milling Company (forerunner of Pillsbury Mills, Inc.) and they maintained the dam until 1935 when the title was transferred to the City of Anoka. At Anoka the Pillsbury Mining Company of Minneapolis operated the Lincoln Mill by water power. The mill was later torn down and now only the foundation remains as an historical landmark. The flumes through which water formerly was conducted from the dam to the waterwheels are also gone and the openings in its upper end have been blocked by concrete bulkheads.

IV. HYDRAULICS AND HYDROLOGY

A. Description of the Drainage Area

The Rum River is a tributary of the Mississippi River and therefore part of the Upper Mississippi River drainage basin.

The area drained by the Rum River is in East-Central Minnesota, chiefly in Mille Lacs, Isanti and Anoka Counties. The Rum River originates in Lake Mille Lacs, and for 16 miles flows through three lakes bordered by flat, marshy shores; the entire fall over this range is less than 2 feet. Below the lake the river winds southward as far as Princeton, where it is joined by the West Branch. Below Princeton it flows eastward in a still more winding course until it reaches Cambridge, where it turns to the south and enters the Mississippi at Anoka.

The principal tributaries are West Branch, Tibbetts, and Bogus Brooks, and Upper and Lower Stanchfield and Cedar Creeks. With the exception of the West Branch of the Rum River the streams are small.

The dam at Anoka is 0.75 miles above the confluence of the Rum and Mississippi Rivers. The drainage area at the dam site is 1590 miles squared.

B. Flow Duration

The flow duration curve for the Rum River Dam of Anoka was developed by the use of a drainage area relationship between the nearest U.S.G.S Gage and the dam site. The nearest U.S.G.S. Gage is located 20 miles upstream of the dam at Saint Francis. The drainage area at Saint Francis is given by the U.S.G.S. as 1360 miles. The following linear relationship was used:

$$Q_i \text{ (at the dam site)} = \left[\frac{\text{Drainage Area at Anoka}}{\text{Drainage Area at St. Francis}}\right] Q_i \text{(USGS Gage at St. Francis}$$

or

$$Q_i = 1.17\ Q_i \text{(USGS Gage at St. Francis)}$$

The resulting flow duration curve is given in Fig. 12. The Average annual flow at the Rum River Dam was similarly established to be 697 cfs.

Flow duration curves were also computed for each month over the period of record and are shown in Fig. 13. The driest and wettest years of record

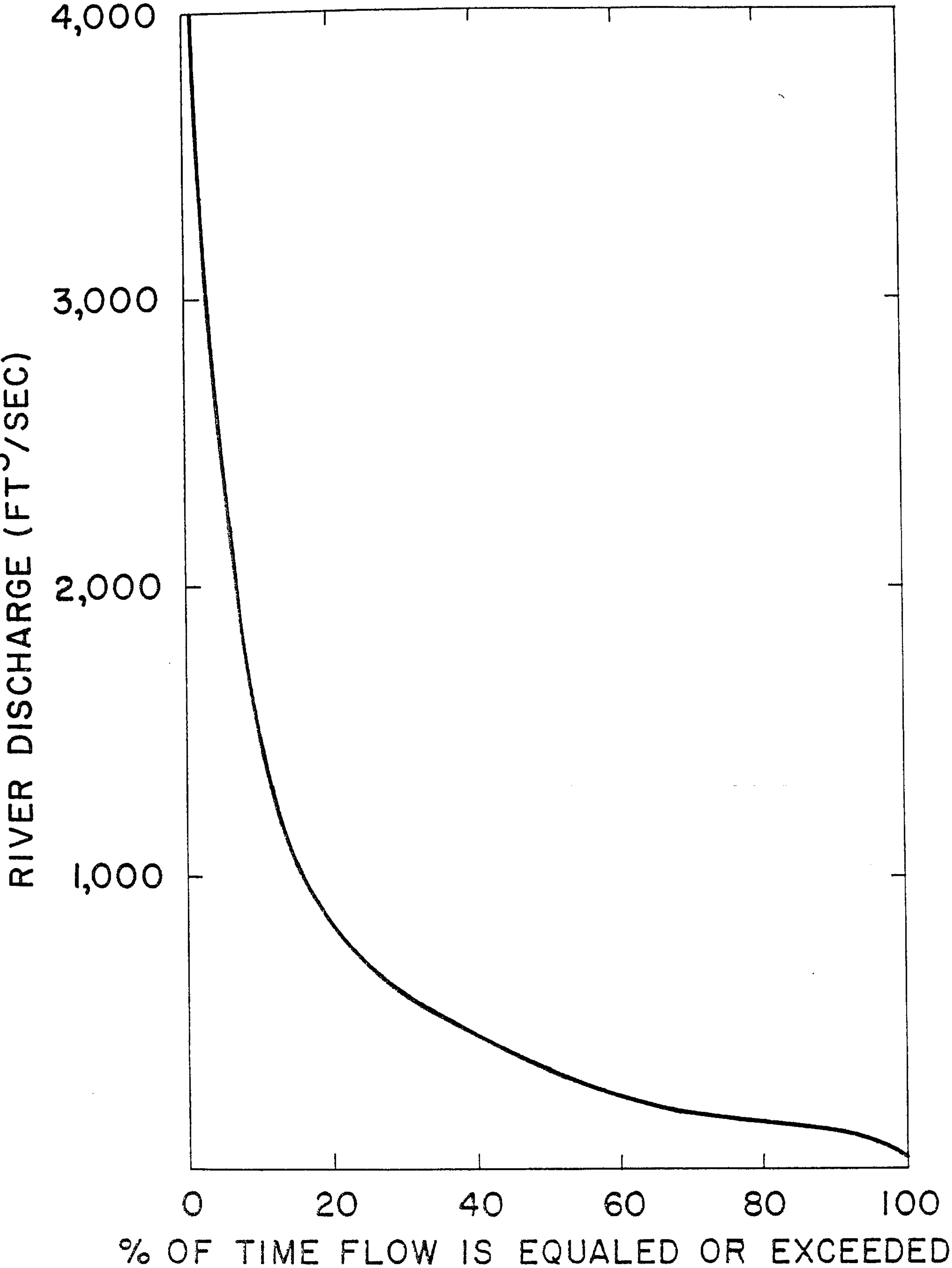

Fig. 12. Flow duration curve for the Rum River Dam.

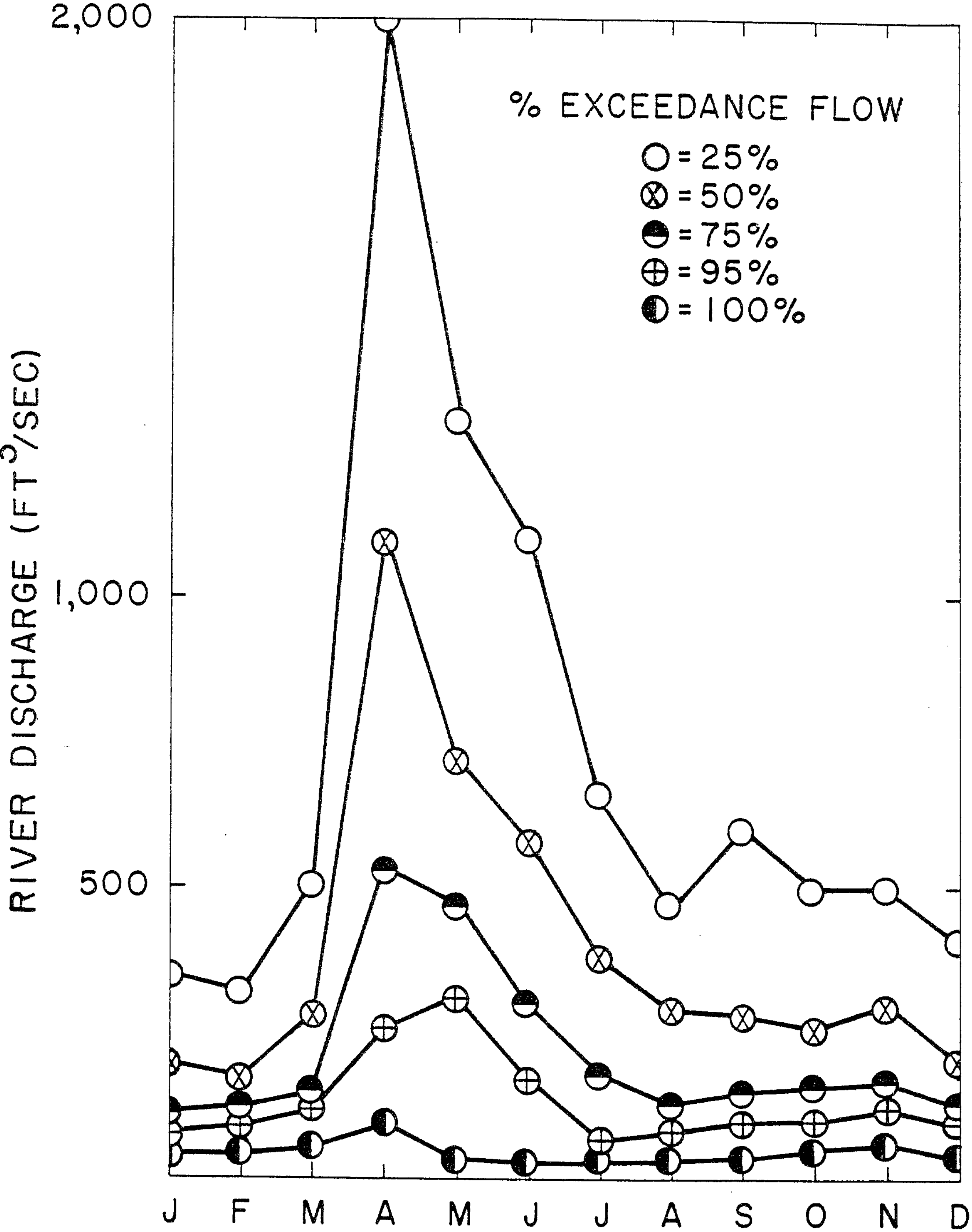

Fig. 13. Monthly flow duration curves for the Rum River Dam.

are water years (October through September) 1934 and 1972, respectively. The flow duration curves for these years are shown in Figs. 14 and 15.

The Rum River Dam at Anoka is classified as a run-of-river since it has no seasonal peaking capabilities. There is, however, a small amount of storage which may be used for a limited amount of daily peaking. Daily peaking allows operation of the facilities during periods of low flow and peak demand.

The Rum River Dam at Anoka creates a reservoir extending about 6.0 miles upstream of the dam, with a surface area of approximately 210 acres. Drawing the reservoir down 0.8 feet over 5 hours will add 407 cfs to the turbine discharge.

C. Headwater and Tailwater Elevations

The headwater and tailwater elevation curves have been established by Barr Engineering during the design of the dam. During a field test the tailwater curve was discovered to deviate from the original curve established by Barr Engineering at the lower flows. Low flow tailwater elevations were therefore adjusted and incorporated into the corrected Tailwater curve given in Fig. 16. The Headwater curve is given in Fig. 17.

Since the dam at Anoka is a short distance (0.75 miles) from the Rum River's confluence with the Mississippi River, the minimum tailwater elevation at Anoka will be established by the stage at the Mississippi River.

D. Flood Frequency and Spillway Design Flood

The discharge of the Rum River has been gaged near St. Francis for a period of 32 years. Utilizing the record of flow at St. Francis and a drainage area relationship between St. Francis and Anoka, a discharge frequency curve has been developed for Anoka by Barr Engineering as shown in Fig. 18. The curve indicates the probable flood discharge which could be expected for various recurrence intervals. For instance, the curve indicates that a flood flow of 16,000 cfs can be expected to occur on the average of once in 150 years. The greatest flood in the period of record was 11,800 cfs, occurring in 1965.

The dam is designed to handle all flood flows up to 16,000 cfs. Because of the tailwater conditions prevailing, the critical discharge for various parts of the dam are frequently at relatively low flood flows. Because the tailwater rises rather rapidly at high discharges, it is probable that flood flows even greater than 16,000 cfs can be passed without damage to the dam. [1]

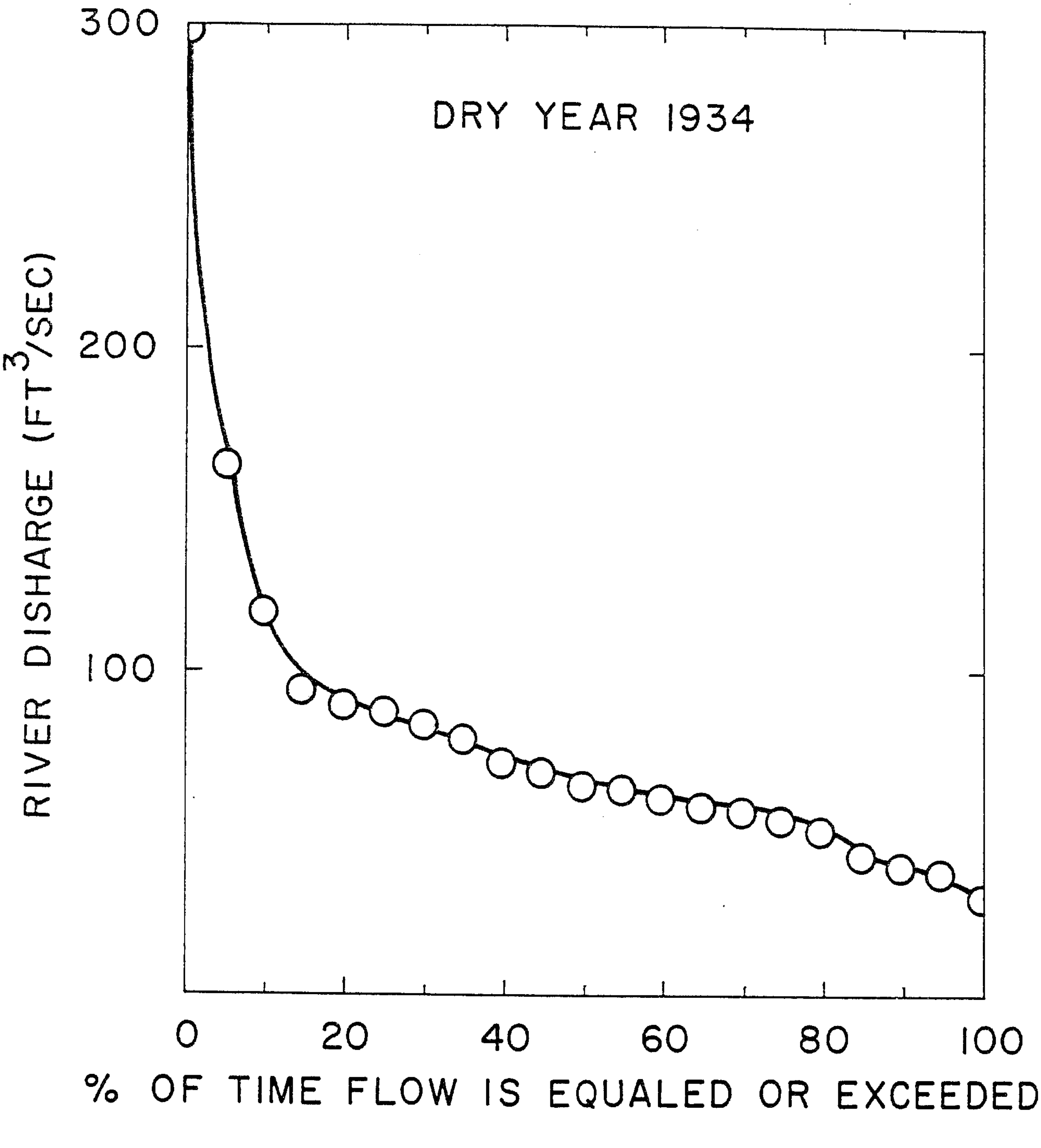

Fig. 14. Dry year flow duration curve for the Rum River Dam, occurring in 1934.

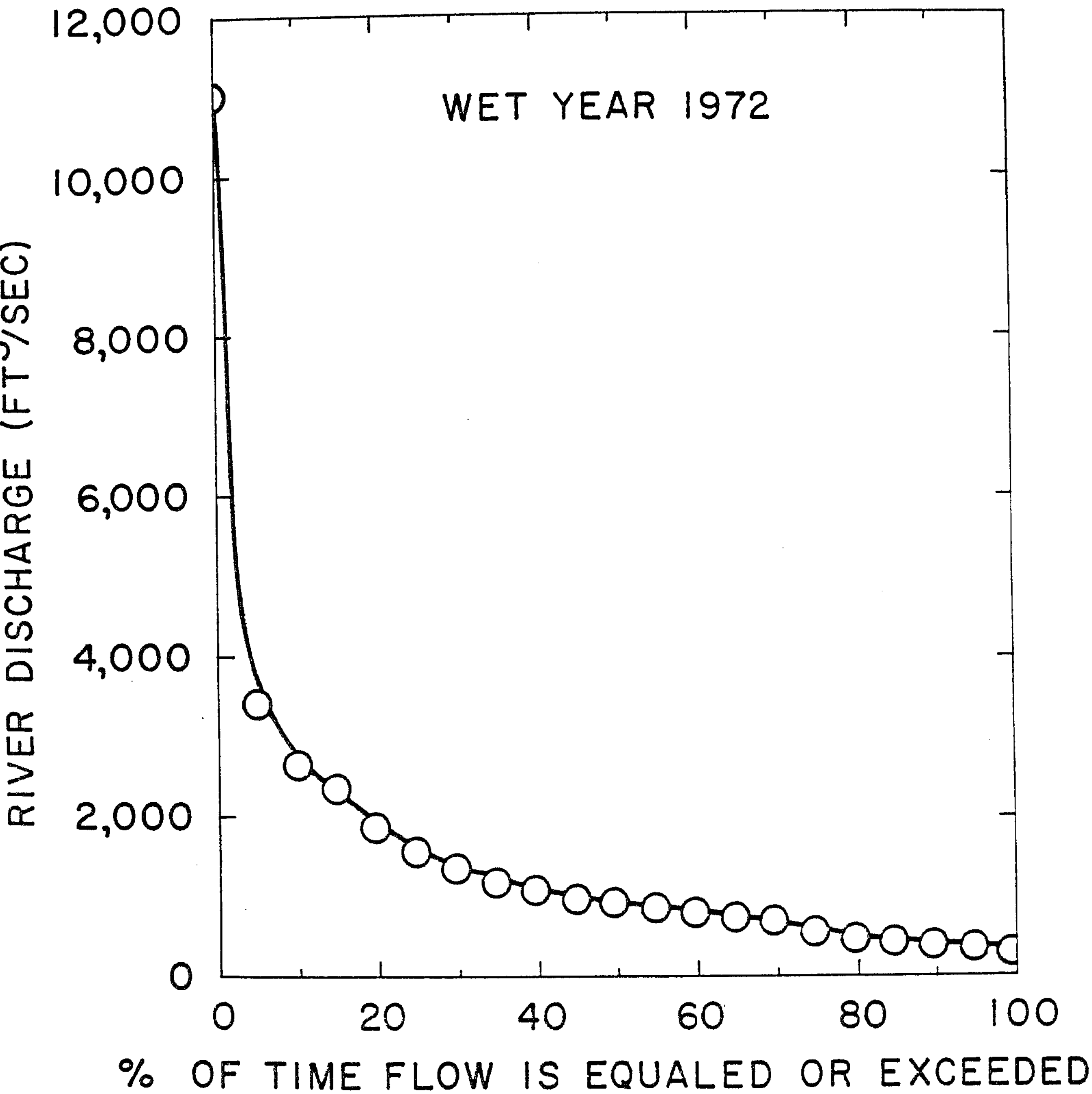

Fig. 15. Wet year flow duration curve for the Rum River Dam, occurring in 1972.

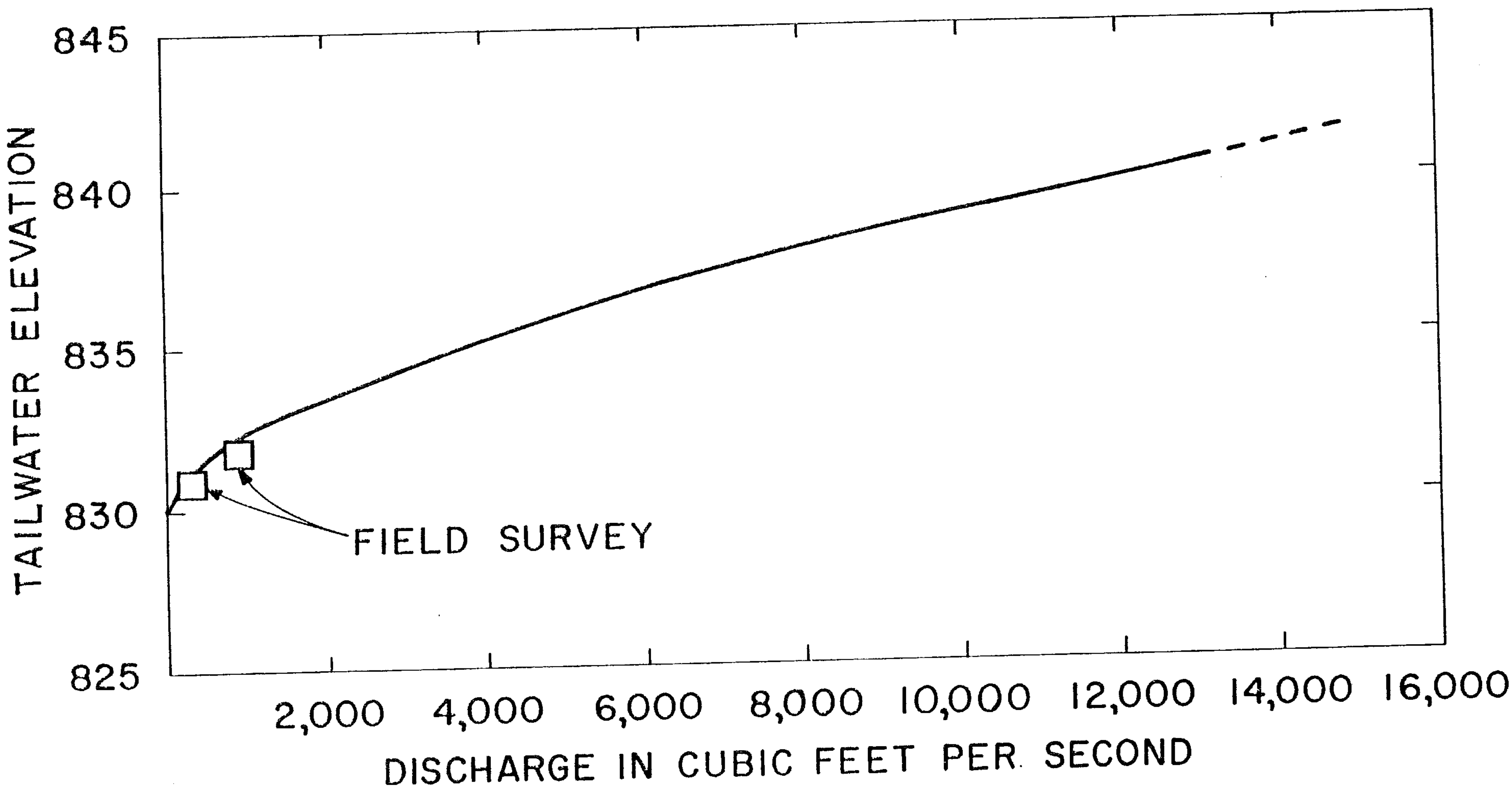

Fig. 16. Tailwater elevation curve for the Rum River Dam.

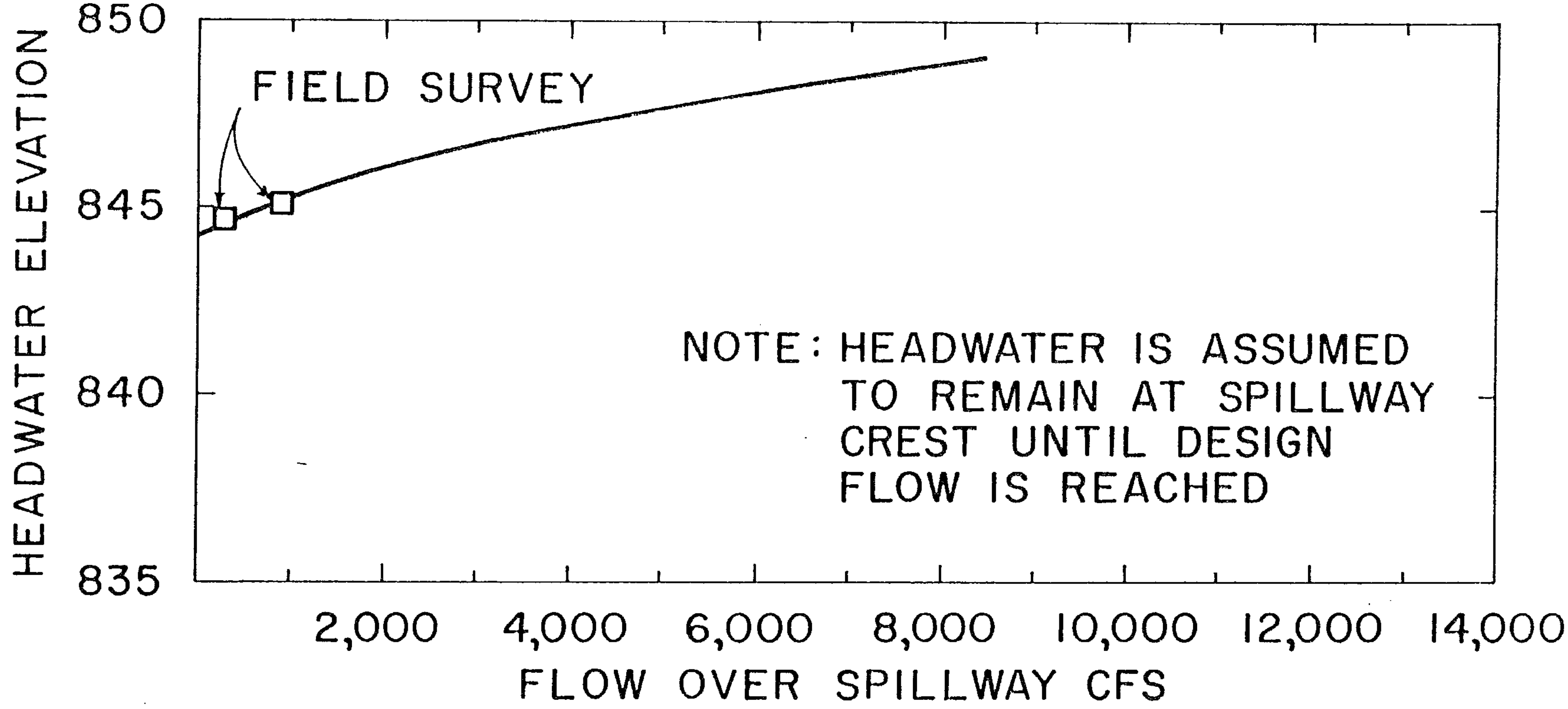

Fig. 17. Headwater curve for the Rum River Dam.

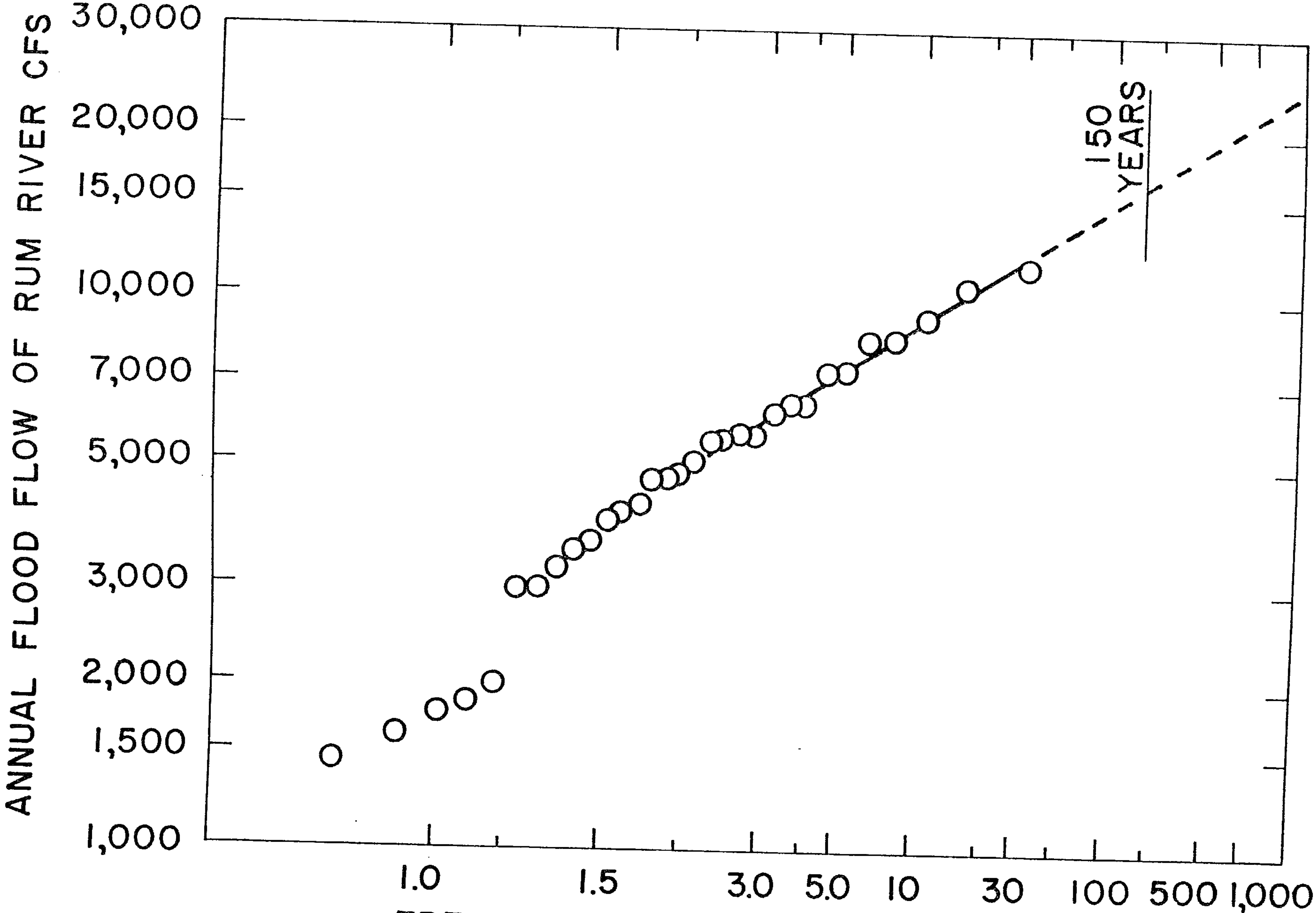

Fig. 18. Flood frequency of recurrence for the Rum River Dam [1].

V. CURRENT DEMAND AND VALUE OF ENERGY

A. Current Demand & Energy Usage

The City of Anoka is a municipal utility with its own distribution system. All power generated from the hydropower facilities will therefore be used to offset power purchases from Northern States Power Company (NSP) by the Anoka Municipal Utility.

A typical daily demand distribution shown in Fig. 19 indicates that the demand is relatively constant throughout the daytime period (8 a.m. through 8 p.m.), with the peak demand usually occurring between 3 p.m. and 8 p.m.. The monthly demand and energy usage for 1980 are given in Table 1.

TABLE 1. Monthly Demand and Energy Usage for the Municipality of Anoka During 1980

Month	Energy (GWH)	Demand (MW)
January	126.00	25.198
February	115.75	23.542
March	119.44	22.279
April	105.00	21.972
May	112.56	26.384
June	109.36	29.129
July	130.00	31.800
August	126.84	28.116
September	99.96	28.811
October	108.69	21.357
November	112.00	22.657
December	119.00	23.897

B. Value of Energy and Power

All of the energy produced at the Anoka hydropower facilities would be used to offset energy purchases from NSP. The value of the hydroelectric energy is therefore equal to the rate at which Anoka purchases energy from NSP.

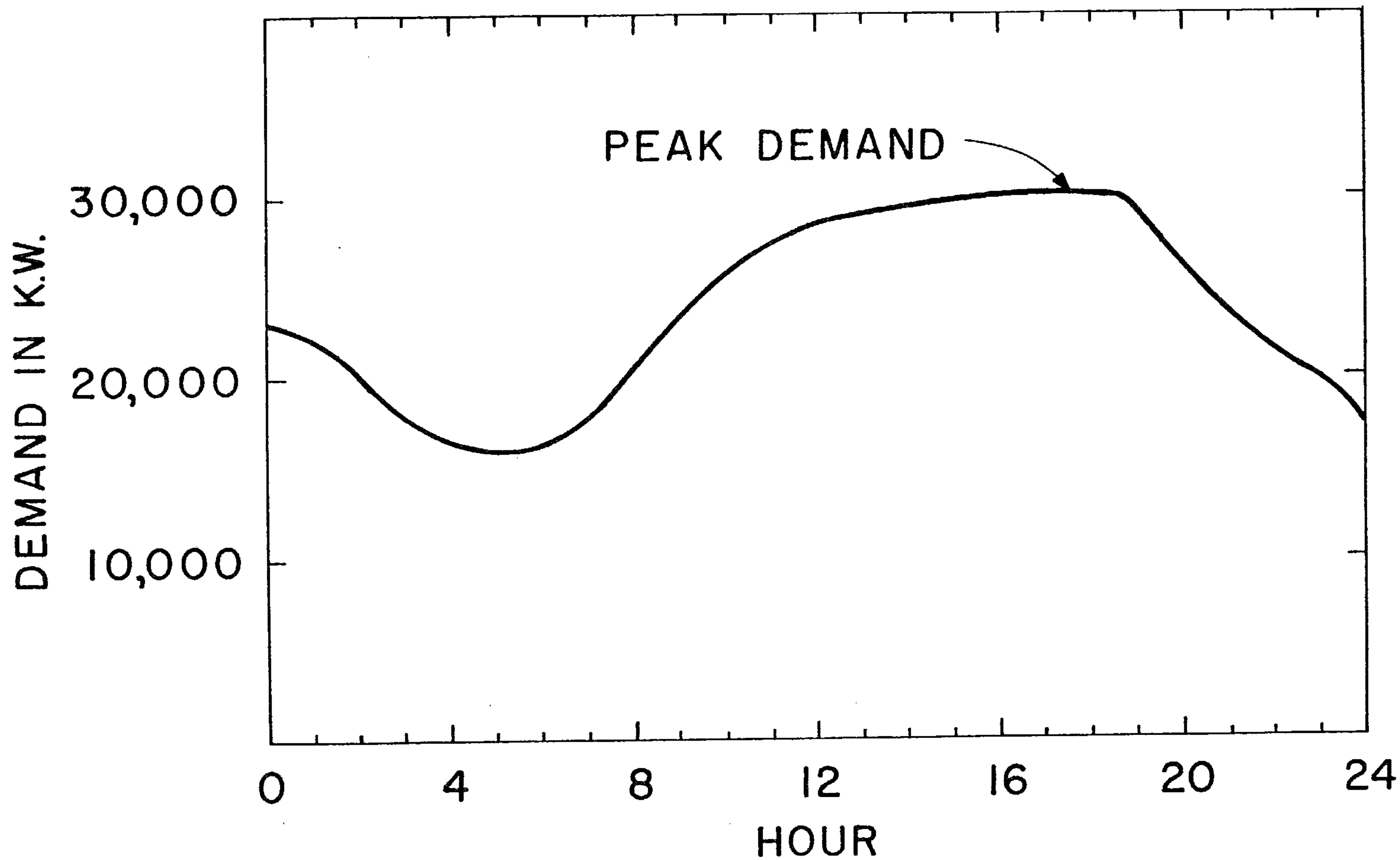

Fig. 19. Electricity demand curve for the City of Anoka on a typical day (July 15, 1980).

The terms of the present contract between Anoka and NSP has three separate charges: the energy charge, a fuel adjustment charge which is tied in with NSP fuel costs, and the demand charge. In January of 1982 the Federal Energy Regulatory Commission approved a rate increase on the energy and demand charges. This rate increase is effective as of January 1982 and set the energy charge at 2.128 cents/kWH, leaving the fuel adjustment charge near zero. The demand charge is based upon the greatest 15 minute average demand of each month. The present demand charge is $4.60/kW/month.

All calculations in this study are based upon January, 1982, dollars. The January, 1982, value of energy (2.128 cents/kWH) is assumed to be applicable to energy plus the fuel adjustment charge. The energy value of 2.128/kWH and a demand charge of $4.60/kW/month will be used in the economic analysis in Section VIII.

Operation of the hydropower facilities during the peak period will reduce the monthly demand charge. The annual reduction in demand charge is herein referred to as capacity credit. Determination of the average reduction in demand charge which may be expected in each month of the year was determined as follows.

1. The minimum expected power output over the peak demand period was determined for each month over 20 years of record. The minimum power output was assumed to occur at the minimum flow conditions of each month.

2. The minimum power output was averaged over the 20 year period to give dependable power output.

3. The value of dependable power was then determined, by applying the present demand charge to the dependable power output.

4. It is estimated that the actual peak demand will occur within the selected peaking period of 3 p.m. to 8 p.m, approximately 80 percent of the time. Therefore 80 percent of the capacity credit of part #3 was used in the economic analysis in Section VIII.

VI. FACILITY OPERATION

The amount of energy generated by a hydropower facility such as the Rum River Dam at Anoka will depend somewhat on the operational plan. Due to the terms of the contract between Anoka's municipal electric utility and Northern States Power Company, it is most desirable to operate the hydroturbines during the peak usage hours to offset the demand charge. (See Section V.B.)

All hydroturbines have a minimum flow below which they cannot operate. At low flows, therefore, the water must be stored, and then released during the peak hours to operate the turbines. However, while the reservoir is recharging, a base flow of 100 cfs must pass through the impoundment to insure an adequate supply of fresh water to the downstream habitat.

The operational plan for the proposed hydropower facilities should place top priority on operating at greatest possible output during the peak period. The river's discharge during off peak hours that is not used for storage should be used to produce off peak energy. The operation of the hydropower facility should also be consistent with the operational scheme for the dam as outlined in Ref. [1].

The operational plan used to determine the energy output given in Section VIII is as follows. The facilities operate at maximum possible output during the peak hours (3 p.m. to 8 p.m.). The discharge on the off peak hours (8 p.m. to 3 p.m.) which is not used for storage is used to produce off-peak energy. While the reservoir recharges, a minimum discharge of 100 cfs is passed through the impoundment. The limit of reservoir drawdown during peaking operation is one foot below flashboard elevation.

VII. PROJECT DEVELOPMENT ALTERNATIVES

In this section, the costs and expected annual energy production of three development alternatives for the Anoka hydropower facilities are considered. Project development alternatives were formulated in the following manner:

- Once the hydraulic and hydrologic analysis was performed, the first step in choosing development alternatives was to determine which types of hydroturbines are most applicable to the site. Turbine and generator manufacturers were then contacted to obtain cost estimates of specific turbine/generator units, since they are the major equipment item in a hydropower facility. Turbine performance curves were also obtained.

- The expected annual energy production was computed for each of the three alternatives using flow duration, headwater and tailwater information, and turbine performance curves.

- The income generated by displacing energy to be bought from NSP and reducing the monthly demand charge was computed by the method described in Section V.B.

- Construction costs were estimated on the basis of unit costs applied to preliminary layout drawings. Construction cost estimates include facilities' structural costs as well as diversion, removal, and excavation costs. A 25 per cent contingency allowance was added to cover smaller items and possible omissions. A 10 percent profit factor was also included in the total cost.

- When electrical equipment costs were not included in the turbine/generator cost estimates, these costs were estimated based upon information obtained from a well known generator/switchgear/controls manufacturer. Electrical equipment costs include switchgear, transformer, control switchboard, wire and cable system, conduit, grouping, and lighting.

- Freight and installation estimates for turbines and generators were based on the manufacturer's recommendation.

- Miscellaneous powerplant equipment costs were estimated according to guidelines in Ref. [2]. Equipment for ventilation, fire protection, communication, and turbine/generator bearing cooling water is included in this category. The cost estimates include 15 percent for freight and installation. The July 1978 cost base was escalated to January, 1982, according to the Consumer Price Index.

- A multiplier of 20 percent was applied to the final project cost for engineering, construction management, and other costs [2]. These costs include expenditures for license and permit application, preliminary and final design, construction management, and administration.

- Annual operation, maintenance and replacement costs were computed using the technique described in Ref. [2] and escalated to January, 1982.

The plan view of the proposed powerhouse for the three development alternatives is shown in Fig. 20.

A. Alternative A: One 2000 mm Adjustable Blade Horizontal Tube Unit

Alternative A consists of an Allis-Chalmer standard Tube unit, with a maximum discharge of 637 and a rated generator output of 565 kW at 12.3 ft net head.

The advantage to an adjustable-blade turbine is that the turbine may be operated over a range of flows, rather than at one specific design discharge. The disadvantage is that the adjustable blade capability adds cost to the unit.

For Alternatives A and B, turbine/generator package and electrical equipment were obtained as one cost estimate. The turbine/generator package for these alternatives includes:

- Turbine
- Gear speed increaser
- Induction generator
- Coupling
- Blade positioner (for adjustable-blade units)
- Hydraulic power unit to operate valve and blade positioner
- Indoor generator protection and control panel
- Outdoor switchgear
- Outdoor step-up transformer
- Outdoor disconnect switch
- Fixed wheel intake gate

A plan and section view of a preliminary layout for Alternative A are given in Figs. 21 and 22. The cost estimates for Alternative A are as follows:

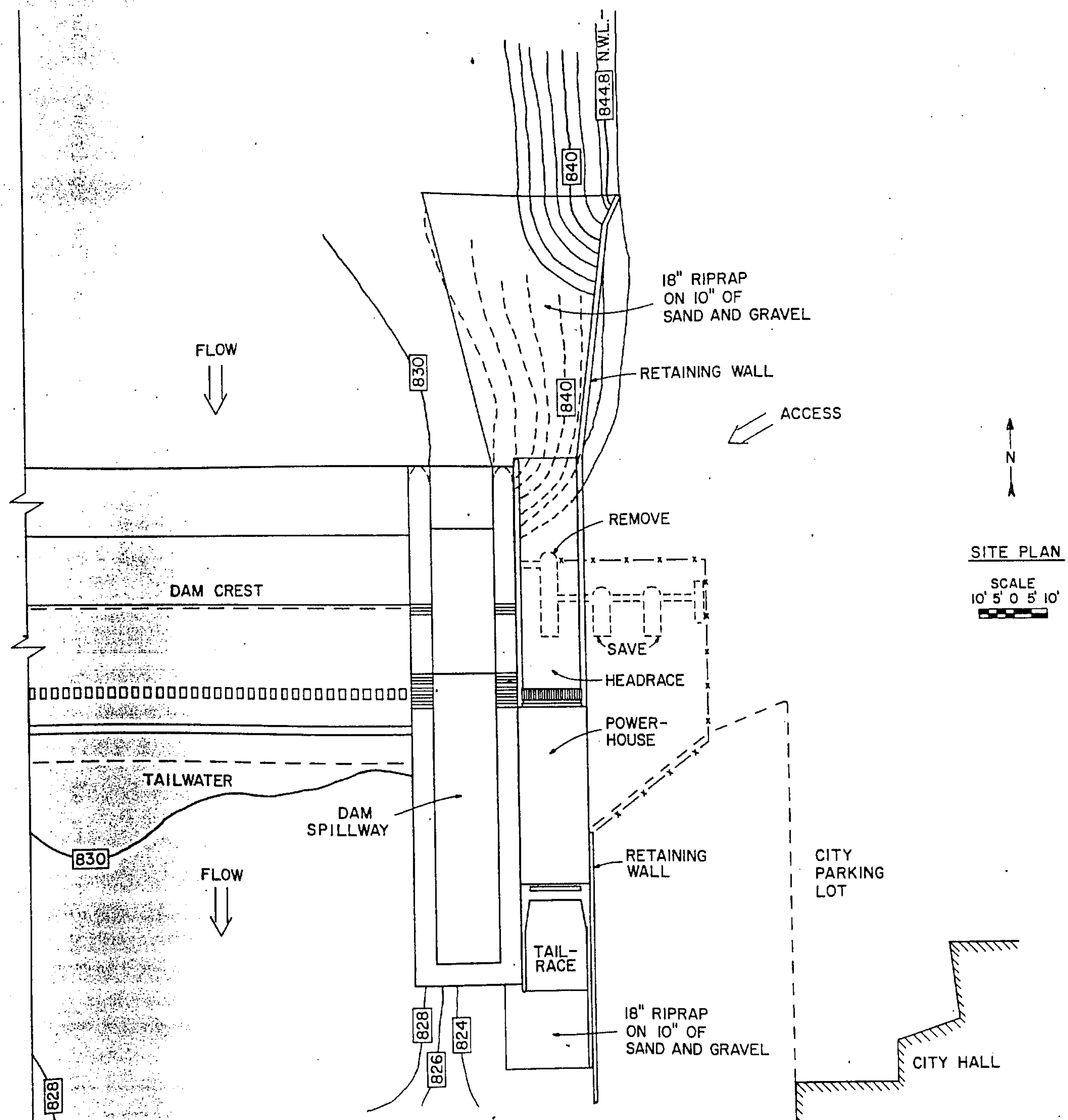

Fig. 20. Plan view showing powerhouse location.

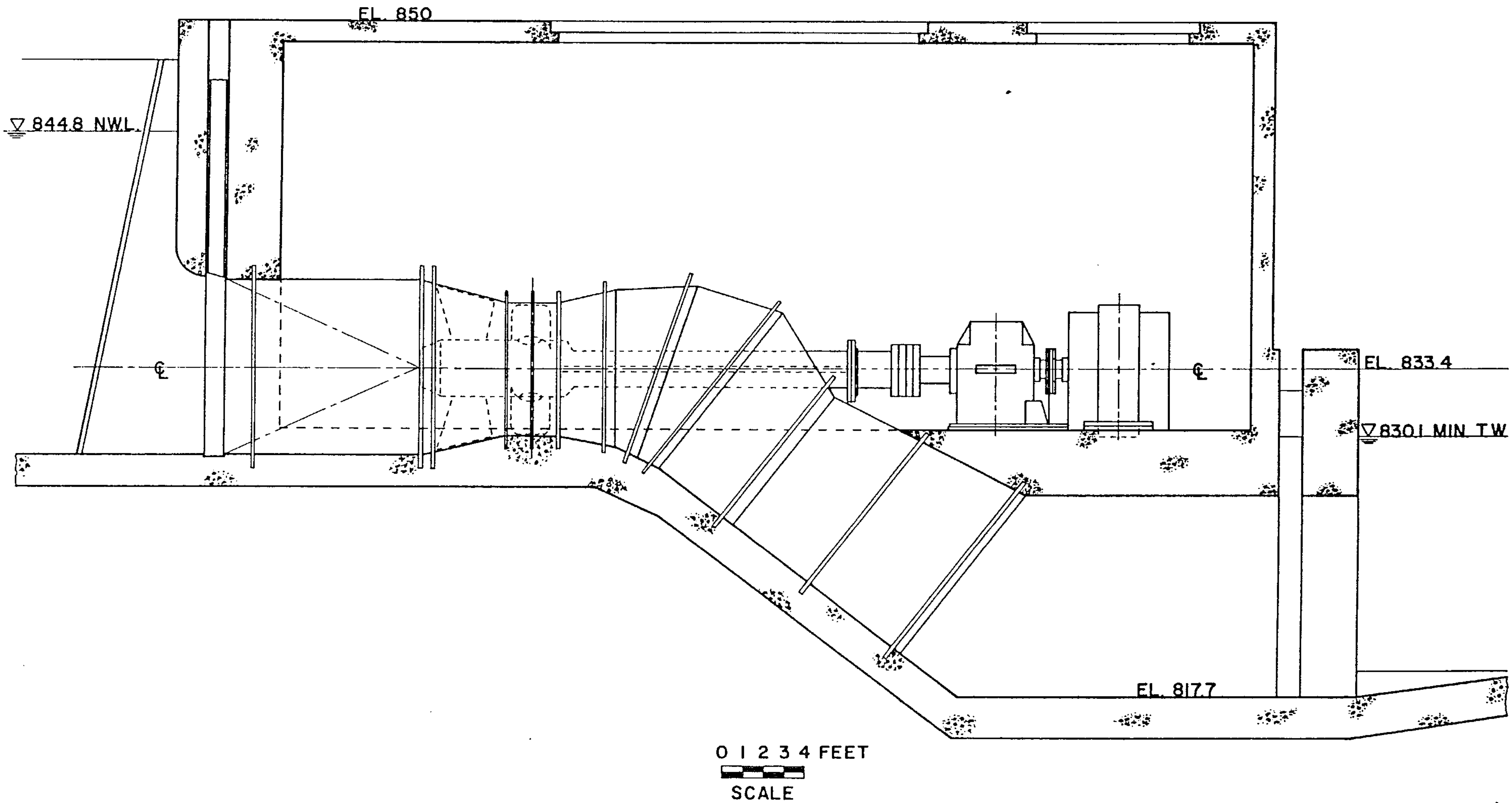

Fig. 21. Section view of Alternative A: One 2000 mm adjustable blade horizontal Tube turbine.

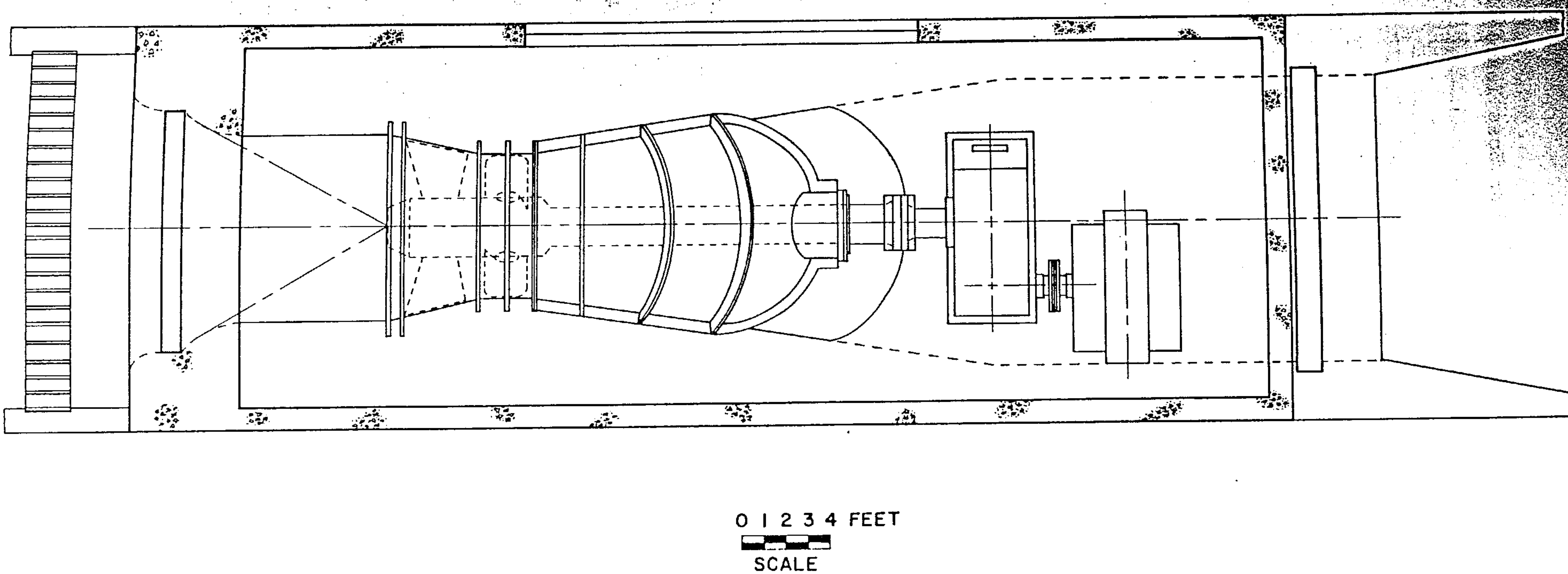

Fig. 22. Plan view of Alternative A.

Alternative A Cost Estimates (1982 Base Year)

Civil works costs	$667,000
Turbine, generator, gates and electrical equipment	727,000
Turbine, freight and installation	109,000
Automatic controls	80,000
Miscellaneous plant equipment	55,000
Engineering, construction, management, etc.	327,000
Total Initial Cost	$1,965,000

The annual energy production and benefits are (1982 base year):

Average Annual Energy Production	2.32 GWH
Average Annual Energy Benefits	$49,400
Average Annual Demand Charge Credit	$19,200
Annual Gross Income	$68,600

The annual operation, maintenance and replacement costs for Alternative A are estimated to be $19,300 (1982 base year).

B. Alternative B: A Combination of a 72 in. and a 48 in. Fixed Blade Inclined Mini Tube Units

Alternative B consists of two Allis Chalmers inclined Mini-Tube units with a combined design discharge of 675 cfs and a generator output of 552 kW at 12.3 ft of net head.

Plans and section views of the preliminary layout for Alternative B are given in Figs. 23 through 25.

The cost estimates for Alternative B are as follows:

Alternative B Cost Estimates (1982 base year)

Civil works	$ 835,000
Turbine, generator, gates and electrical equipment	641,000
Turbine freight and installation	128,000
Automatic controls	80,000
Miscellaneous plant equipment	54,000
Engineering, construction management, etc.	348,000
Total Initial Cost	$2,086,000

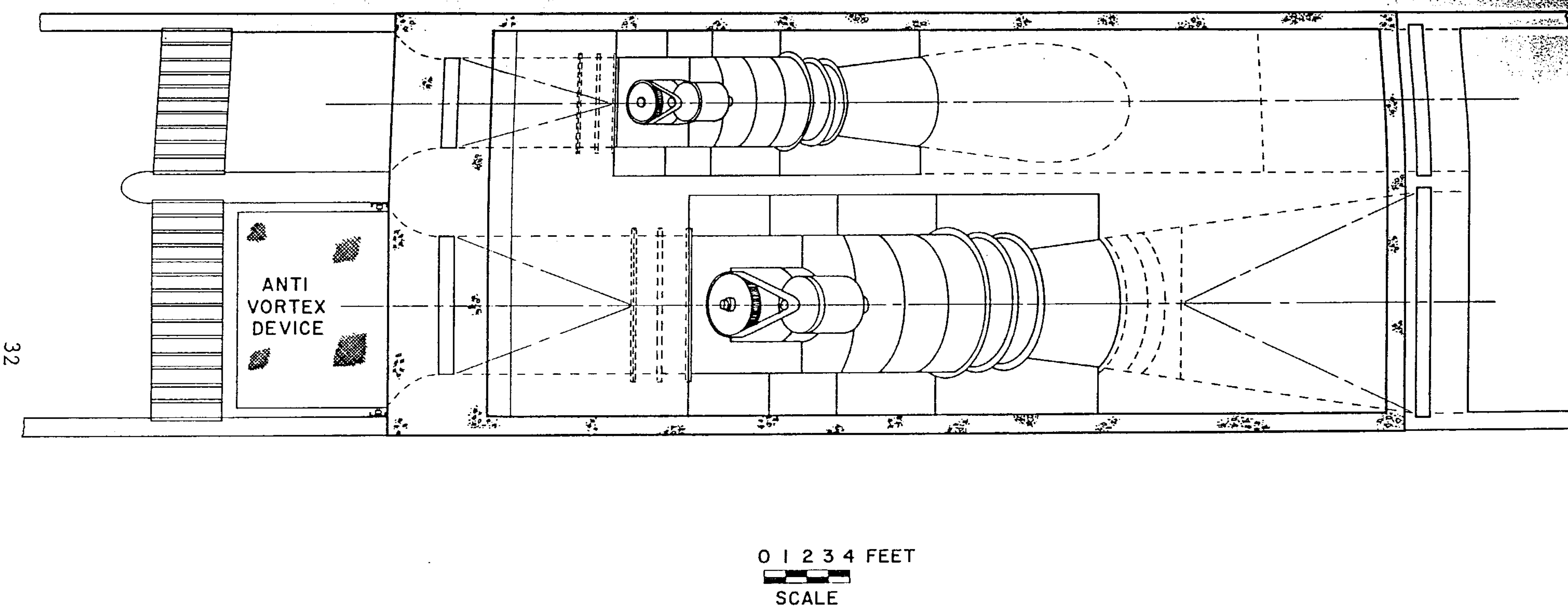

Fig. 23. Plan view of Alternative B: One 72 in. and one 48 in. fixed blade inclined Mini-Tube unit.

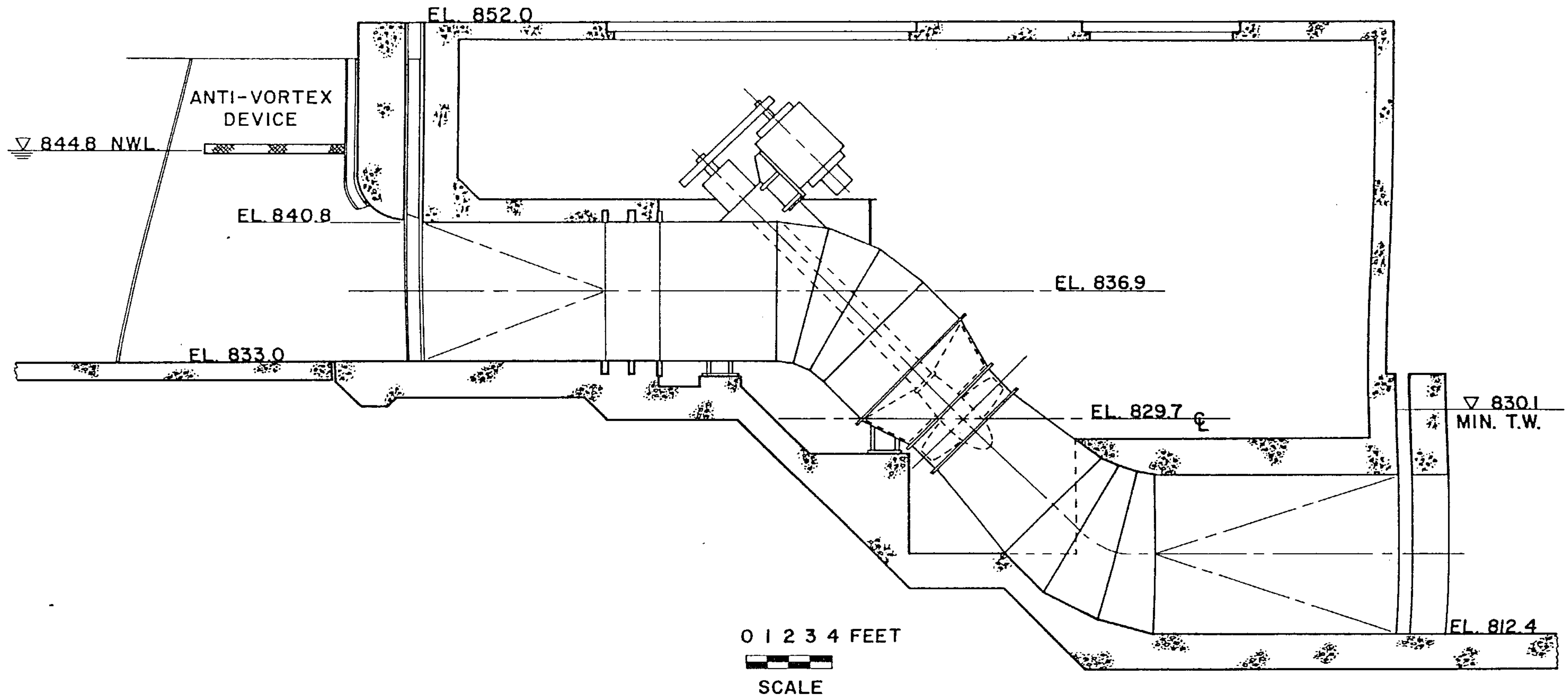

Fig. 24. Section view of 72 in. runner diameter unit for Alternative B with generator output is 375 kW at 460 cfs discharge and 12.3 feet net head.

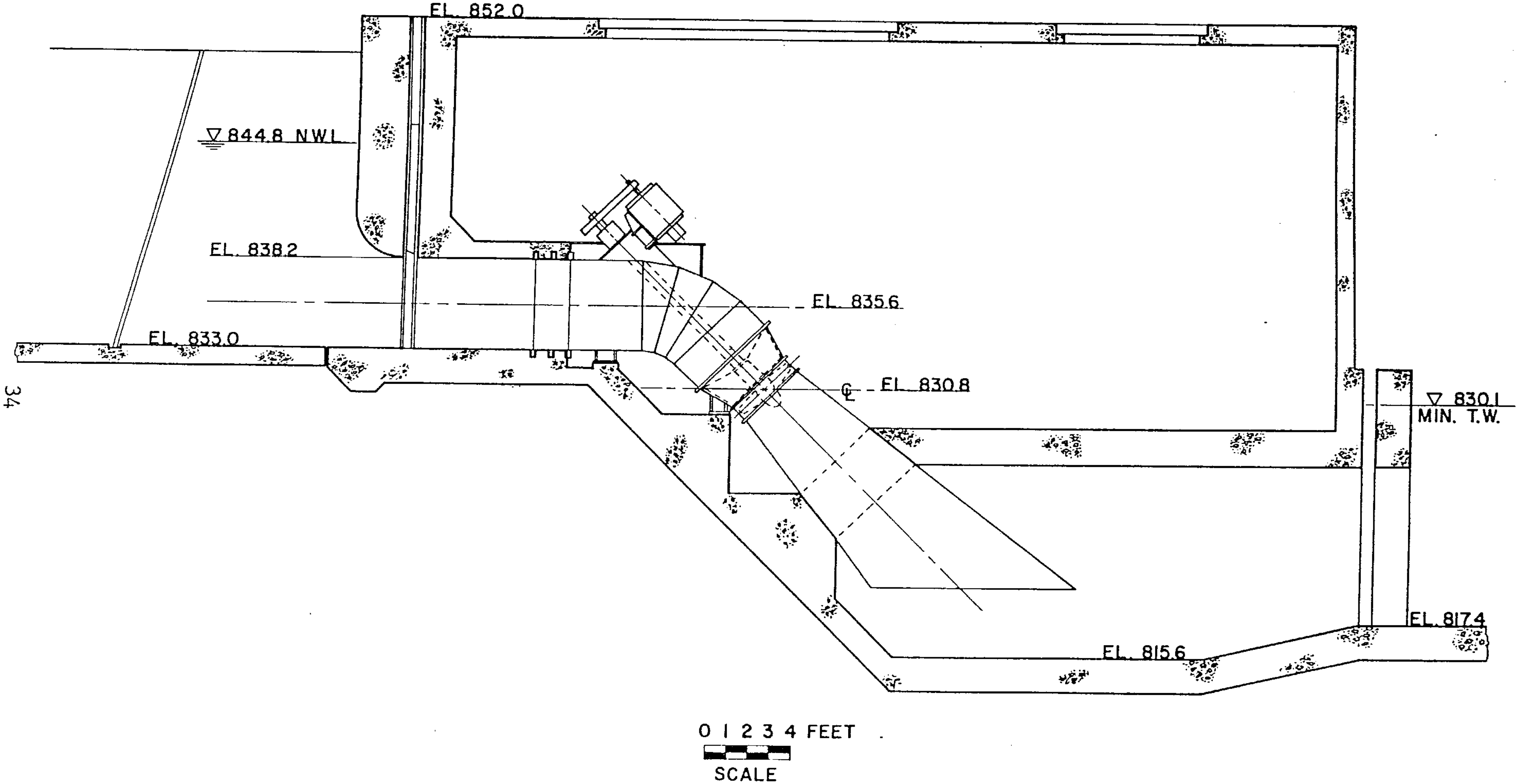

Fig. 25. Section view of 48 in. runner diameter unit for Alternative B with generator output of 177 kW at 215 cfs discharge and 12.3 feet net head.

The annual energy production and benefits for Alternative B are (1982 base year):

Average Annual Energy Production	2.44 GWH
Average Annual Energy Benefits	$51,900
Average Annual Demand Charge Credit	$19,200
Annual Gross Income	$71,100

The annual operation, maintenance and replacement costs for Alternative B are estimated at $19,200 (1982 base year).

C. Alternative C: One 2150 mm Horizontal Full Kaplan Unit

Alternative C is one horizontal full Kaplan turbine manufactured by The James Leffel & Company. The 2150 mm turbine has a design discharge of 650 cfs and a rated output of 603 kW at 12.3 ft of net head.

Leffel's preliminary cost estimate for the turbine, synchronous generator, governor, and gear drive system was $717,000. Section and plan views of the preliminary layout for Alternative C are given in Figs. 26 and 27.

The cost estimates for this development alternative are as follows:

Alternative C Cost Estimates (1982 base year)

Civil works costs	$ 657,000
Turbine and generator	717,000
Electrical equipment	143,000
Turbine freight and installation	108,000
Automatic controls	80,000
Miscellaneous plant equipment	56,000
Engineering, construction management, etc.	352,000
Total Initial Cost	$2,113,000

The annual energy production and benefits for Alternative C are (1982 base year)

Average Annual Energy Production	2.57 GWH
Average Annual Energy Benefits	$54,700
Average Annual Demand Charge Credit	$20,900
Annual Gross Income	$75,600

The annual operation, maintenance, and replacement costs for Alternative C are estimated at $19,800 (1982 base year).

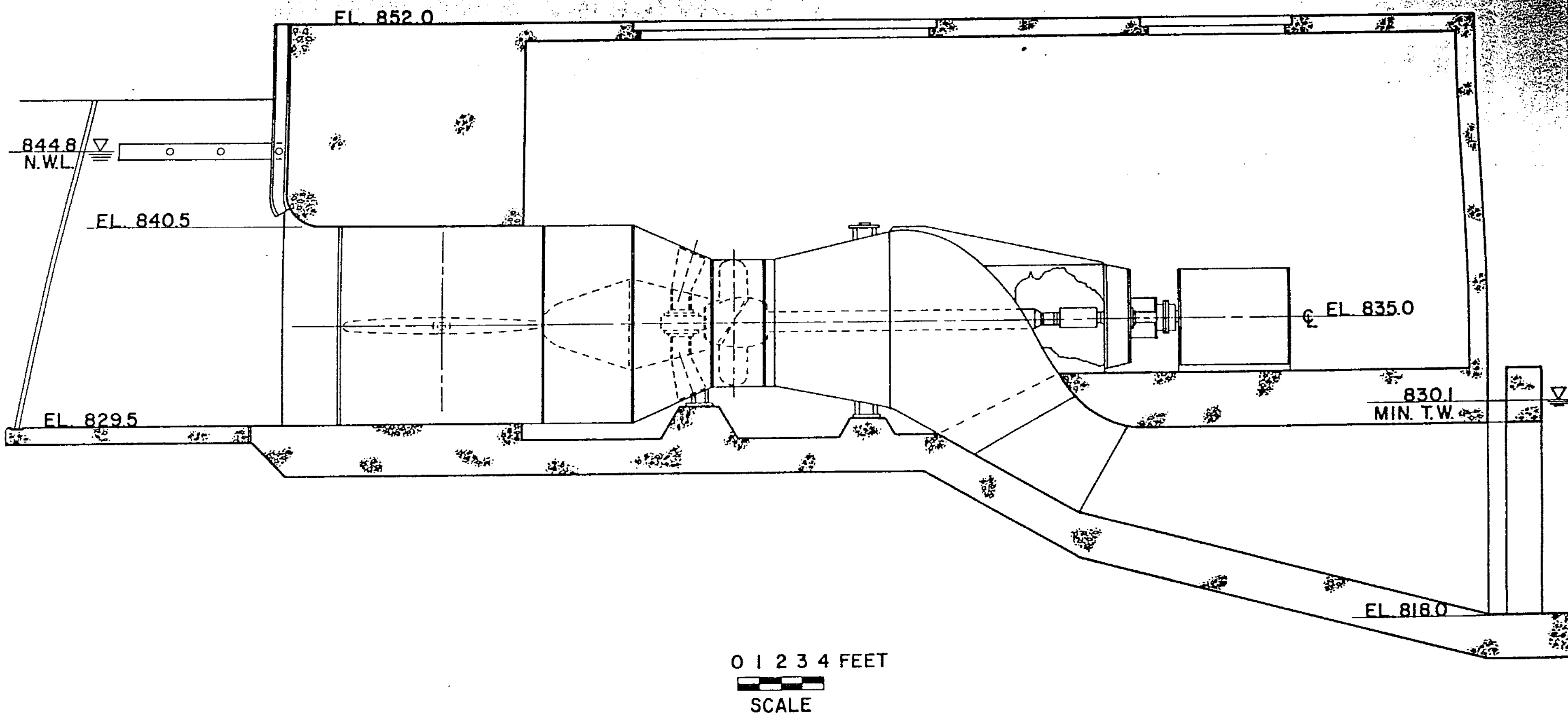

Fig. 26. Section view of Alternative C: One 2150 mm horizontal full Kaplan unit.

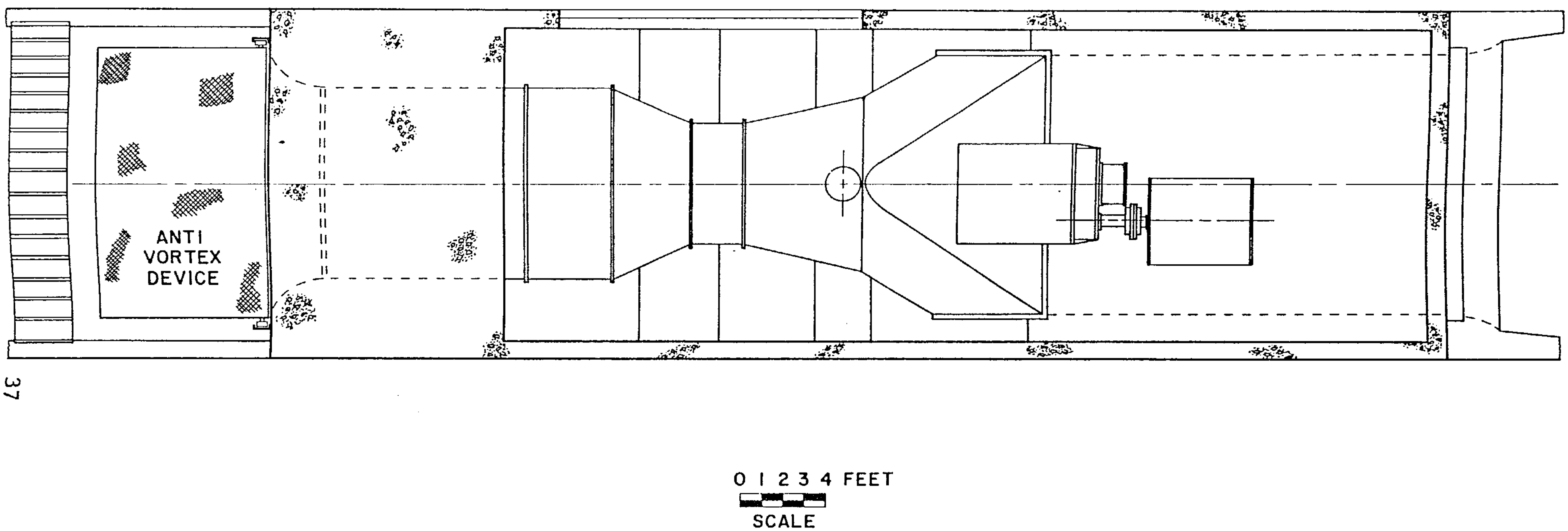

Fig. 27. Plan view of Alternative C.

D. Other Development Alternatives

There are other turbine manufacturers marketing turbines in the United States which are applicable to the Rum River Dam. Axel-Johnson, Inc. (KMW unit), Kvaerner-Moss (Sorumsand-Verksted unit), Dominion Bridge-Sulzer, Voest-Alpine, and Nissho-Iwa are all marketing tubular units with standardized designs which are comparable to Alternatives A, B, and C. The Neyrpic right-angle drive units manufactured in the United States by Hydro Energy Systems, Inc., are a fixed-blade propeller turbine designed to fulfill the same market as the Allis-Chalmers Mini-Tube Units given in Alternative B. These manufacturers should be contacted during later stages of project development.

A number of generator manufacturers also responded to requests for bids on hydroelectric projects. In this case, the generator manufacturer would submit a bid in conjunction with one of the turbine manufacturers mentioned herein. Three generator manufacturers who have made bids for low-head hydroelectric developments are General Electric, Brown-Boveri, and Westinghouse.

E. Summary of Project Development Alternatives

There is not a great deal of difference in project cost and energy production between the project development alternatives. Alternative C appears to be most favorable because of the ability to generate more energy without a substantial increase in the project cost. All efforts should be made in the final design stages to increase the annual energy production and peaking capacity without substantially increasing the initial project cost.

VIII. ECONOMIC ANALYSIS

A. Background and Assumptions

This section of the report will compare the benefits and costs of hydropower development at the Rum River Dam. Certain basic assumptions which are required in benefit/cost analysis will be outlined before describing the results of the economic analysis. The sensitivity of the benefit/cost comparisons to these basic assumptions is investigated in Section VIII.E.

1. Economic Feasibility Indicators

A number of economic feasibility indicators will be given herein to provide interested parties with information to base future economic decisions and to outline the economic advantages and disadvantages of each option. These indicators are:

- The first year cost of power is the cost of debt service, operation and maintenance, and other costs divided by the average annual energy production.

- The benefit-cost ratio is the present worth of the project benefits divided by the present worth of the initial project costs and annual costs

$$B/C = \frac{\sum_{i=0}^{n} B_i/(1+d)^i}{C_i + \sum_{i=0}^{n} OM_i/(1+d)^i} \qquad (1)$$

where B/C = benefit cost ratio for a project economic life of n years,

B_i = benefits in year i,

C_i = initial project cost,

OM_i = operation, maintenance and replacement costs in year i,

d = discount rate, and

n = project economic life.

- The net present value is the present worth of project benefits minus the present worth of project costs:

$$NPV = \sum_{i=0}^{n} NB_i/(1+d)^i \qquad (2)$$

where NPV = net present value for a project economic life of n years, and

NB_i = net present benefits in year i (benefits minus costs).

- The internal rate of return is the discount rate which would give zero net present value at the end of the project economic life.

- Payback period is the number of years generating power required to reach a zero net present value.

2. Assumptions

The following assumptions are incorporated into the economic analysis:

- The economic life of the project is assumed to be 50 years.

- The initial project cost will be amortized over the typical period used in public works, 20 years.

- Eleven percent interest and discount rate. Historically, A-rated tax- exempt bonds have been near the rate of inflation. The recent tax cuts, however, have reduced the attractiveness of tax-exempt bonds. Many economic analysts believe the difference between long-term rates for tax-exempt bonds and nontax-exempt financing rates will decrease by approximately 1.5 percent.[2] For this reason, a 2 percent spread between interest rate and escalation rate will be used.

- Nine percent annual escalation in the value of energy and power. Power producing utilities in the State of Minnesota have projected that the value of electricity will increase at or near the rate of inflation over the next 20 years.[3] The annual increase in the

[2]Donald Porter. First Boston Corporation, New York, N. Y.

[3]Minnesota Energy Agency.

consumer price index between 1977 and 1981 has averaged 9.9 percent. The CPI is currently moderating; however, most economic forecasters are still predicting inflation rates near 9 percent over the next five to ten years.[4]

- Annual operation, maintenance, and replacement costs in 1981 dollars were determined from Ref. [2].

- Nine percent annual escalation in operation, maintenance, and replacement costs. This rate was chosen to coincide with the predicted inflation rate.

- A two-year construction period [2].

- A linear expenditure of capital during project construction.

The sensitivity of the benefit/cost analysis to discount rate and escalation rates will be described in Section VIII.E.

B. Comparison of Project Development Alternatives

The first year cost of power, benefit-cost ratio, net present value, and internal rate of return of each development alternative is given in Table 2. A 35-year and 50-year project economic life were used. The useful life of a hydropower facility is anywhere from 50 to 100 years. The 50-year project economic life is used herein because it corresponds most closely to the useful life of any proposed facility.

Net present value is an estimate of the net income or profit over an assumed project life in 1982 dollars. Of the indicators given herein, net present value is generally considered as the most appropriate means of comparing development alternatives.

All of the development alternatives have a payback period greater than 50 years. The economic indicators of Alternative C are slightly better than those of Alternatives A and B; all of the alternatives have poor feasibility indicators with the assumptions listed above. With these results hydropower development of the Rum River Dam would not be recommended unless 8 percent financing could be obtained.

C. Cost and Benefit Streams

The cost and benefit streams for Alternatives A, B, and C are given in Tables 3, 4, and 5. The negative net present value over the 50-year period for all of the proposed development alternatives indicates the poor economic feasibility. Alternative C gives the best (least poor) return of all the proposed development alternatives.

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[4]Data Resources, Inc.

TABLE 2. First Year Cost of Power, Benefit Cost Ratio, Net Present Value and Internal Rate of Return for Alternatives A, B, and C

	Development Alternatives		
	A	B	C
First Year Cost of Power ($/kWH)	0.115	0.115	0.111
35-Year Project Life			
Benefit-Cost Ratio	0.72	0.72	0.75
Net Present Value (Millions $, 1982 Base Year)	-0.65	-0.70	-0.63
Internal Rate of Return	8.2	8.1	8.4
50-Year Project Life			
Benefit Cost Ratio	0.87	0.86	0.90
Net Present Value (Millions $, 1982 Base Year)	-0.32	-0.35	-0.26
Internal Rate of Return	9.8	9.8	10.0

TABLE 3. Cost and Benefit Streams for Development Alternative A of the Rum River Dam. Base Year for Present Worth is 1982. Two-Year Construction Period. 11 Percent Discount Rate and 9 Percent Escalation Rate. All Figures in Dollars.

Year	Debt Service	OM & R Costs	Gross Income	Present Worth: Benefits	Present Worth: Costs	Present Worth: Cash Flow	Net Present Value
1	123378	0	0	0	111151	-111151	-111151
2	246756	0	0	0	200373	-200273	-311424
3	246756	24994	88800	64930	198701	-133772	-445196
4	246756	27244	96792	63760	180492	-116732	-561929
5	246756	29695	105503	62611	164061	-101450	-663378
6	246756	32368	114998	61483	149231	-87749	-751127
7	246756	35281	125348	60375	135846	-75471	-826598
8	246756	38456	136629	59287	123761	-64474	-891072
9	246756	41918	148926	58219	112850	-54631	-945703
10	246756	45690	162329	57170	102995	-45825	-991528
11	246756	49802	176939	56140	94093	-37953	-1029481
12	246756	54284	192863	55128	86050	-30921	-1060403
13	246756	59170	210221	54135	78780	-24645	-1085048
14	246756	64495	229141	53159	72209	-19049	-1104097
15	246756	70300	249764	52202	66266	-14064	-1118162
16	246756	76627	272242	51261	60891	-9639	-1127791
17	246756	83523	296744	50337	56026	-5689	-1133480
18	246756	91040	323451	49430	51623	-2192	-1135672
19	246756	99234	352562	48540	47635	905	-1134767
20	246756	108165	384292	47665	44022	3643	-1131124
21	123378	117900	418879	46806	26961	19845	-1111279
22	0	128511	456578	45963	12937	33026	-1078253
23	0	140077	497670	45135	12704	32431	-1045822
24	0	152684	542460	44322	12475	31847	-1013975
25	0	166425	591281	43523	12250	31273	-982702
26	0	181404	644496	42739	12030	30709	-951993
27	0	197730	702501	41969	11813	30156	-921837
28	0	215526	765726	41214	11600	29613	-892224
29	0	234923	834642	40470	11391	29079	-863145
30	0	256066	909759	39741	11186	28555	-834590
31	0	279112	991638	39025	10984	28041	-806550
32	0	304232	1080885	38322	10786	27535	-779014
33	0	331613	1178165	37631	10592	27039	-751975
34	0	361458	1284200	36953	10401	26552	-725423
35	0	393990	1499778	36287	10214	26074	-699349
36	0	429449	1525758	35633	10030	25604	-673745
37	0	468099	1663076	34991	9849	25143	-648603
38	0	520228	1812753	34361	9671	24690	-623913
39	0	556148	1975900	33742	9497	24245	-599668
40	0	606202	2153731	33134	9326	23808	-575861
41	0	660760	2347567	32537	9158	23379	-552482
42	0	720228	2558848	31951	8993	22958	-529524
43	0	785049	2789145	31375	8831	22544	-506980
44	0	855703	3040168	30810	8672	22138	-484842
45	0	932717	3313783	30254	8516	21739	-463104
46	0	1016661	3612023	29709	8362	21347	-441756
47	0	1108161	3937105	29174	8212	20963	-420794
48	0	1207895	4291445	28648	8064	20585	-400209
49	0	1316606	4677675	28132	7918	20214	-379995
50	0	1435100	5098665	27625	7776	19850	-360145
51	0	1564259	5557545	27128	7635	19492	-340653
52	0	1705042	6056624	26639	7498	19141	-321512

Economic Analysis for a Project Life of 35 Years
Present Net Value = $ -648603
Benefit Cost Ratio = .72
Internal Rate of Return = 8.2 percent

Economic Analysis for a Project Life of 50 Years
Present Net Value = $ -321512
Benefit Cost Ratio = .87
Internal Rate of Return = 9.8 percent

TABLE 4. Cost and Benefit Streams for Development Alternative B of the Rum River Dam. Base Year for Present Worth is 1982. Two-Year Construction Period. 11 Percent Discount Rate and 9 Percent Escalation Rate. All Figures in Dollars.

Year	Debt Service	OM & R Costs	Gross Income	Present Worth: Benefits	Present Worth: Costs	Present Worth: Cash Flow	Net Present Value
1	131038	0	0	0	118052	-118052	-118052
2	262076	0	0	0	212707	-212707	-330759
3	262076	24865	92107	67348	209809	-142461	-473221
4	262076	27102	100396	66134	190491	-124357	-597578
5	262076	29542	109432	64942	173061	-108119	-705696
6	262076	32200	119281	63772	157332	-93560	-799256
7	262076	35098	130016	62623	143137	-80513	-879769
8	262076	38257	141717	61495	130323	-68828	-948597
9	262076	41700	154472	60387	118754	-58367	-1006964
10	262076	45453	168374	59299	108307	-49008	-1055972
11	262076	49544	183528	58230	98872	-40642	-1096614
12	262076	54003	200046	57181	90348	-33167	-1129781
13	262076	58863	218050	56151	82647	-26496	-1156277
14	262076	64161	237674	55139	75685	-20546	-1176823
15	262076	69936	259065	54146	69392	-15246	-1192069
16	262076	76230	282381	53170	63700	-10530	-1202600
17	262076	83091	307795	52212	58552	-6339	-1208939
18	262076	90569	335497	51271	53892	-2621	-1211460
19	262076	98720	365691	50348	49674	674	-1210886
20	262076	107605	398604	49440	45853	3587	-1207298
21	131038	117289	434478	48550	27749	20801	-1186497
22	0	127845	473581	47675	12870	34805	-1151693
23	0	139351	516203	46816	12638	34178	-1117515
24	0	151893	562662	45972	12410	33562	-1083953
25	0	165563	613301	45144	12187	32957	-1050996
26	0	180464	668498	44331	11967	32363	-1018633
27	0	196706	728663	43532	11752	31780	-986853
28	0	214409	794243	42747	11540	31208	-955645
29	0	233706	865725	41977	11332	30645	-925000
30	0	254739	943640	41221	11128	30093	-894907
31	0	277666	1028567	40478	10927	29551	-865356
32	0	302656	1121138	39749	10730	29018	-836337
33	0	329895	1222041	39033	10537	28496	-807842
34	0	359585	1332025	38329	10347	27982	-779860
35	0	391948	1451907	37639	10161	27478	-752382
36	0	427224	1582578	36961	9978	26983	-725399
37	0	465674	1725010	36295	9798	26497	-698902
38	0	507584	1880261	35641	9621	26019	-672883
39	0	553267	2049485	34998	9448	25550	-647332
40	0	603061	2233938	34368	9278	25090	-622242
41	0	657336	2434993	33749	9111	24638	-597604
42	0	716497	2654142	33141	8946	24194	-573410
43	0	780981	2893015	32543	8785	23758	-549652
44	0	851270	3153386	31957	8627	23330	-526322
45	0	927884	3437191	31381	8471	22910	-503412
46	0	1011393	3746538	30816	8319	22497	-480915
47	0	1102419	4083727	30261	8169	22092	-458824
48	0	1201637	4451262	29715	8022	21694	-437130
49	0	1309784	4851876	29180	7877	21303	-415827
50	0	1427664	5288545	28654	7735	20919	-394909
51	0	1556154	5764514	28138	7596	20542	-374367
52	0	1696208	6283320	27631	7459	20172	-354195

Economic Analysis for a Project Life of 35 Years
Present Net Value = $ -698902
Benefit Cost Ratio = .72
Internal Rate of Return = 8.1 percent

Economic Analysis for a Project Life of 50 Years
Present Net Value = $ -354195
Benefit Cost Ratio = .86
Internal Rate of Return = 9.8 percent

TABLE 5. Cost and Benefit Streams for Development Alternative C of the Rum River Dam. Base Year for Present Worth is 1982. Two-Year Construction Period. 11 Percent Discount Rate and 9 Percent Escalation Rate. All Figures in Dollars.

Year	Debt Service	OM & R Costs	Gross Income	Present Worth Benefits	Present Worth Costs	Present Worth Cash Flow	Net Present Value
1	132671	0	0	0	119523	-119523	-119523
2	265341	0	0	0	215357	-215357	-334880
3	265341	25642	97891	71577	232764	-141187	-476067
4	265341	27949	106701	70287	193200	-122912	-598980
5	265341	30465	116304	69021	175547	-106526	-705506
6	265341	33207	126771	67777	159616	-91839	-797344
7	265341	36195	138181	66556	145238	-78682	-876026
8	265341	39453	150617	65357	132258	-66902	-942928
9	265341	43003	164173	64179	120540	-56361	-999288
10	265341	46874	178948	63023	109957	-46935	-1046223
11	265341	51092	195053	61887	100399	-38512	-1084735
12	265341	55691	212608	60772	91764	-30992	-1115727
13	265341	60703	231743	59677	83961	-24284	-1140011
14	265341	66166	252600	58602	76908	-18306	-1158317
15	265341	72121	275334	57546	70531	-12985	-1171302
16	265341	78612	300114	56509	64764	-8255	-1179557
17	265341	85687	327124	55491	59546	-4055	-1183611
18	265341	93399	356565	54491	54823	-332	-1183944
19	265341	101805	388656	53509	50548	2961	-1180982
20	265341	110967	423635	52545	46675	5870	-1175112
21	132671	120954	461762	52598	28341	23258	-1151855
22	0	131840	503321	50669	13272	37396	-1114458
23	0	143706	548620	49756	14033	36723	-1077735
24	0	156639	597996	48859	12798	36061	-1041674
25	0	170737	651815	47979	12568	35411	-1006263
26	0	186103	710479	47114	12341	34773	-971490
27	0	202853	774422	46265	12119	34147	-937343
28	0	221109	844120	45432	11900	33541	-903812
29	0	241009	920090	44613	11686	32927	-870885
30	0	262700	1002899	43809	11475	32334	-838551
31	0	286343	1093159	43020	11269	31751	-806799
32	0	312114	1191544	42245	11066	31179	-775620
33	0	340204	1298783	41484	10866	30617	-745003
34	0	370823	1515673	40736	10671	30066	-714937
35	0	404197	1543084	40002	10478	29524	-685413
36	0	440574	1681961	39282	10289	28992	-656432
37	0	480226	1833338	38574	10104	28470	-627951
38	0	523446	1998338	37879	9922	27957	-599994
39	0	570556	2178189	37196	9743	27453	-572541
40	0	621907	2374225	36526	9568	26958	-545583
41	0	677878	2587906	35868	9395	26473	-519110
42	0	738887	2820817	35222	9226	25996	-493114
43	0	805387	3074691	34587	9060	25527	-467587
44	0	877872	3351413	33964	8897	25067	-442520
45	0	956880	3653040	33352	8736	24616	-417904
46	0	1042999	3981814	32751	8579	24172	-393732
47	0	1136869	4340177	32161	8424	23737	-369995
48	0	1236869	4730793	31581	8272	23309	-346686
49	0	1350715	5156564	31012	8123	22889	-323798
50	0	1472279	5620655	30454	7977	22477	-301321
51	0	1604784	6126514	29905	7833	22072	-279249
52	0	1749215	6677900	29366	7692	21674	-257576

Economic Analysis for a Project Life of 35 Years
Present Net Value = $ -627951
Benefit Cost Ratio = .75
Internal Rate of Return = 8.4 percent

Economic Analysis for a Project Life of 50 Years
Present Net Value = $ -257576
Benefit Cost Ratio = .90
Internal Rate of Return = 10.0 percent

D. Private Financing Example

The City of Anoka may wish to consider leasing the Rum River Dam to a private concern for hydropower development. For this reason a typical example of the retdurn which may be expected by a private developer is included. Recent state legislation enables the City of Anoka to waive property taxes for the development in lieu of the lease arrangement.

There are many additional tax considerations to be incorporated into a economic analysis of private development. The tax bracket is individual to each developer so a 50 percent tax bracket is chosen herein as "typical" although the incremental tax bracket may be significantly higher. In addition, the following assumptions were made.

- An initial equity of 25 percent.
- A 13 and 15 percent discount rate.
- A 21 percent energy tax credit on the initial project investment.
- 15 year depreciation of equipment and structure.
- 15 year amortization period for loan.
- 15 year project economic life.
- Salvage value at 70 percent of original project cost in 1982 dollars, escalated to the year of sale. This corresponds to a linear decrease in present worth salvage value over a 50-year period.

The benefit and cost streams which would result from these private finance assumptions for Alternative C at discount rates of 15 and 13 percent are given in Tables 6 and 7, respectively. Although the net present value is positive for a 13 percent discount rate, it is not of the magnitude expected to attract private investment to the project. Thus, the feasibility of hydropower development at the Rum River Dam with private investment is also poor.

TABLE 6. Cost and Benefit Streams for Development Alternative C using Private Financing at the Rum River Dam. Base Year for Present Worth is 1982. Two-Year Construction Period. 13 Percent Discount Rate and 9 Percent Escalation Rate. All Figures in Dollars.

Year	Initial Equity & Debt Service	OM & R Costs	Tax Benefits & Gross Income	Present Worth Benefits	Present Worth Costs	Present Worth Cash Flow	Net Present Value
1	650864	0	51504	45579	575985	-530406	-530406
2	245227	0	103009	80671	192049	-111378	-641784
3	245227	25642	678938	470538	187726	282814	-358971
4	245227	27949	238219	146104	167544	-21440	-380412
5	245227	30465	241398	131021	149634	-18613	-399025
6	245227	33207	244748	117557	133737	-16180	-415205
7	245227	36195	248270	105530	119622	-14092	-429297
8	245227	39453	251961	94778	107085	-12307	-441604
9	245227	43003	255819	85158	95948	-10789	-452393
10	245227	46874	259836	76545	86050	-9505	-461898
11	245227	51092	264002	68825	77250	-8425	-470324
12	245227	55691	268303	61899	69424	-7524	-477848
13	245227	60703	272720	55680	62460	-6780	-484628
14	245227	66166	277229	50089	56261	-6173	-490801
15	245227	72121	281797	45057	50741	-4684	-496485
16	122614	78612	286385	40522	28473	12050	-484436
17	0	85687	5411747	677648	10730	666918	182483

Economic Analysis for a Project Life of 15 Years
Present Net Value = $182,483
Benefit Cost Ratio = 1.08
Internal Rate of Return = 14.1 percent

TABLE 7. Cost and Benefit Streams for Development Alternative C using Private Financing at the Rum River Dam. Base Year for Present Worth is 1982. Two-Year Construction Period. 15 Percent Discount Rate and 9 Percent Escalation Rate. All Figures in Dollars.

Year	Initial Equity & Debt Service	OM & R Costs	Tax Benefits & Gross Income	Present Worth Benefits	Present Worth Costs	Present Worth Cash Flow	Net Present Value
1	663760	0	59428	51677	577182	-525506	-525506
2	271019	0	118856	89872	204930	-115057	-640563
3	271019	25642	694786	456833	195059	260774	-378789
4	271019	27949	254117	145292	170936	-25644	-404433
5	271019	30465	257303	127925	149891	-21966	-426399
6	271019	33207	260604	112666	131525	-18859	-445258
7	271019	36195	264004	99249	115493	-16244	-461502
8	271019	39453	267482	87440	101949	-14054	-475556
9	271019	43003	271011	77038	89265	-12227	-487783
10	271019	46874	274556	67866	78578	-10712	-498495
11	271019	51092	278073	59770	69236	-9466	-507961
12	271019	55691	281508	52616	61064	-8449	-516409
13	271019	60703	284794	46287	53914	-7627	-524037
14	271019	66166	287848	40681	47654	-6973	-531009
15	271019	72121	290571	35710	42170	-6461	-537470
16	135510	78612	292841	31294	22882	8412	-529058
17	0	85687	5415316	503223	7963	495261	-33797

Economic Analysis for a Project Life of 15 Years
Present Net Value = $-33,797
Benefit Cost Ratio = .98
Internal Rate of Return = 14.1 percent

E. Sensitivity Analysis

Sensitivity analysis investigates the impact of variations in project parameters and economic assumptions on the feasibility indicators. The economic indicators of Alternative C are slightly better than those of Alternatives A and B. Therefore, Alternative C will be used in the sensitivity analysis.

1. Demand Charge Credit

A significant amount of projected income is the demand charge credit. It is unlikely that a complete loss of demand charge credit will occur, although future rate hikes may change the value of the demand charge credit. The impact of a 20 percent increase and decrease from the original value of the demand charge credit is given in Table 8. The variation in demand charge credit has only a minor effect upon project feasibility.

2. Variation of Project Cost

Cost estimates in a feasibility study are not as detailed as in the final design stage of a project. Feasibility cost estimates, therefore, have a limited degree of accuracy. In addition, unforeseen future events can alter a project. The economic feasibility indicators for a project cost 30 percent greater and 30 percent less than the original project cost estimate for Alternative C are given in Table 9. A decrease of 30 percent in project costs below that estimated herein would give the project marginal feasibility.

3. Value of Energy

Hydropower feasibility is naturally dependent upon the price at which the generated electricity is sold. Table 10 presents the economic indicators over a range of energy values for Alternative C. An energy value of 3¢/kWH would be required to give the project marginal feasibility.

4. Variation in Operation, Maintenance, and Replacement Costs

Operation, maintenance, and replacement costs cannot be precisely determined until the facility is in operation. The effects of a 25 percent addition and reduction from the original operation, maintenance, and replacement costs on the economic indicators for Alternative C are given in Table 11.

5. Discount and Escalation Rate

Economic feasibility is extremely sensitive to the difference between discount and escalation rates. The economic feasibility indicators for various magnitudes at spread between the discount and escalation rates for Alternative C are given in Table 12. Table 11 indicates that an extremely favorable relationship of discount and escalation rates would be required to given the project favorable feasibility.

TABLE 8. Benefit-Cost Ratio, Net Present Value and Internal Rate of Return with a Twenty Percent Increase and Reduction in Demand Charge Credit for Alternative C

Demand Charge Credit ($, 1982 base year)	25,080 (+20%)	16,720 (-20%)
35-Year Project Life		
Benefit-Cost Ratio	0.79	0.71
Net Present Value (Million $, 1982 Base Year)	-0.52	-0.73
Internal Rate of Return	8.8	8.0
50-Year Project Life		
Benefit-Cost Ratio	0.95	0.85
Net Persent Value (Million $, 1982 Base Year)	-0.13	-0.39
Internal Rate of Return	10.4	9.7

TABLE 9. Benefit-Cost Ratio, Net Present Value and Internal Rate of Return with a Thirty Percent Increase and Reduction in Demand Charge Credit for Alternative C

Initial Project Cost (million $, 1982 base year)	2.75 (+30%)	1.48 (-30%)
35-Year Project Life		
Benefit-Cost Ratio	0.60	0.99
Net Present Value (Million $, 1982 Base Year)	-1.23	-0.03
Internal Rate of Return	7.1	10.5
50-Year Project Life		
Benefit-Cost Ratio	0.73	1.17
Net Persent Value (Million $, 1982 Base Year)	-0.86	-0.35
Internal Rate of Return	8.9	11.7

TABLE 10. Benefit Cost Ratio, Net Present Value and Internal Rate of Return at Various Values of Energy for Alternative C

	Value of Energy ($/kWH)				
	.010	.015	.020	.025	.030
35-Year Project Life					
Benefit-Cost Ratio	0.46	0.59	0.72	0.84	0.97
Net Present Value (Million $, 1982 base year)	-1.35	-1.03	-0.71	-0.39	-0.07
Internal Rate of Return	4.9	6.7	8.1	9.3	10.4
50-Year Project Life					
Benefit-Cost Ratio	0.56	0.71	0.86	1.02	1.17
Net Present Value (Million $, 1982 base year)	-1.17	-0.76	-0.36	-0.04	0.45
Internal Rate of Return	7.2	8.6	9.8	10.8	11.6

TABLE 11. Benefit-Cost Ratio, Net Present Value and Internal Rate of Return at a Twenty-Five Percent Addition and Reduction from the Original Operation, Maintenance, and Replacement Cost for Alternative C

Operation, Maintenance, and Replacement Costs ($, 1982 base year)	24,800 (+25%)	14,850 (-25%)
35-Year Project Life		
Benefit-Cost Ratio	0.71	0.79
Net Present Value (Million $, 1982 Base Year)	-0.75	-0.51
Internal Rate of Return	8.0	8.9
50-Year Project Life		
Benefit-Cost Ratio	0.85	0.96
Net Persent Value (Million $, 1982 Base Year)	-0.41	-0.10
Internal Rate of Return	9.6	10.4

TABLE 12. Benefit-Cost Ratio, Net Present Value and Internal Rate of Return at Four Combinations of Discount and Escalation Rate for Alternative C

Discount Rate (%)	7	9	11	13
Energy Escalation Rate (%)	9	9	9	9
Escalastion Rate for O & M (%)	9	9	9	9
35-Year Project Life				
Benefit-Cost Ratio	1.27	0.97	0.75	0.58
Net Present Value (million $, 1982 base year)	0.83	-0.07	-0.63	-0.98
Internal Rate of Return (%)	8.4	8.4	8.4	8.4
50-Year Project Life				
Benefit Cost Ratio	1.74	1.25	0.90	0.66
Net Present Value (million $, 1982 base year)	2.77	0.76	-0.26	-0.81
Internal Rate of Return (%)	10.0	10.0	10.0	10.0

IX. ENVIRONMENTAL IMPACT OF PROPOSED DEVELOPMENT

A. Background

Because small-scale hydropower facilities are generally developed at existing dam sites, the environmental impact is usually limited; there is no land inundated due to new dam construction and the character of the stream is not greatly altered. The environmental impact of small-scale hydropower facilities should not be entirely discounted, however. There are likely to be a few cases where a fishery may be harmed, public health may be threatened due to dredge spoils, or a historic structure may be destroyed. The scope of this section is to identify the potential environmental impacts of hydropower development at the Rum River Dam. If hydropower development is more seriously contemplated, this section will provide information which is helpful in the preparation of license and permit applications.

B. FERC Requirements

The Federal Energy Regulatory Commission (FERC) in its application procedure for a hydropower license requires an environmental report to be filed. The environmental report should be consistent with the scope of the project and environmental impacts of the proposed action [3].

The report must be prepared in consultation with local, state, and federal agencies with expertise in environmental matters. The names and addresses of these agencies may be obtained from the Director, Division of Licensed Projects. All contact with the local, state, and federal agencies should be made well in advance of the final design phase of the project. The application for licensing should be filed during the final design phase.

The environmental report should include the following section [3]:

1. General description of the project locale.

2. A report on the current consumptive water use and the impact of the project on water quality.

3. A report on fish, wildlife, and botanical resources in the vicinity of the project and the impact of the project on those resources. Special attention should be given to endangered plant and animal species, critical habitats, and sites on Wild and Scenic Rivers.

4. A report on historical and archeological resources, with emphasis on sites eligible for or included on the National Register of Historic Places.

5. A report on recreational resources which considers the existing and proposed recreational facilities and recreational opportunities of the project.

6. A report on land management and aesthetics which includes the management of wetlands, flood plains and other lands within the project boundary and the protection of the recreational and scenic values of the project.

C. Water Level Fluctuation and In-Stream Flows

The proposed operational plan used herein has a one-foot maximum reservoir drawdown during on-peak power generation. This limit is well below that which naturally occurs in the reservoir and will have a small or negligible impact on wildlife, shoreline erosion, and reservoir aesthetic qualities.

The stream reach downstream from the dam is only 0.7 miles long, before its confluence with the Mississippi River. Thus, the stream reach affected by reduced in-stream flows during on-peak power generation will be small. For this reason, a minimum stream flow of 100 cfs was selected at the 93 percent exceedance level on the flow duration curve as that which will protect the stream reach from any excessive degredation due to stranding of fish, etc.

D. Water Quality

The Minnesota Pollution Control Agency (PCA) classifies state lakes and rivers according to their water quality. The Rum River has been classified as a 2B river, which is defined as follows:

> The quality of this class of the intrastate waters of the state shall be such as to permit the propagation and maintenance of cool or warm water sport or commercial fishing and be suitable for aquatic recreation of all kinds, including bathing, for which the water may be usable.

There are two permanent water quality testing sites on the Rum River that are monitored by the PCA. One is at river mile 34 in Isanti. The other is in Anoka at river mile 0.6.[4]

Reading from these testing sites indicates that water quality near the headwaters of the river is excellent. Near St. Francis, however, water quality occasionally exceeds the standards for a 2B classification because of the presence of fecal coliforms.

The Rum River Dam reservoir has a low storage capacity and corresponding small hydraulic residence time. At the normal storage capacity of 9.3 million cubic feet and the average annual stream discharge (697 cfs), the hydraulic residence time at the reservoir is about four hours.

At the base flow of 100 cfs, the reservoir hydraulic residence time is still only about one day. With the short hydraulic residence time and shallow reservoir depth at the Anoka Dam, a strong thermal stratification is unlikely during operating periods. It is therefore unlikely that the dissolved oxygen concentrations of the reservoir will be depleted during operation of the proposed facilities. Therefore the water quality problems associated with dissolved oxygen depletion, such as high nutrient levels, heavy metal and toxics released from reservoir sediments, and high biochemical oxygen demand, will not occur. In addition, the facility intake will take water from the complete water column. This will eliminate the possibility of selective withdrawal of cold hypolimnetic water. Therefore, the facilities will not significantly alter the natural downstream temperature regime.

E. Construction Impacts

The temporary impacts due to construction activities at the Anoka Dam could potentially have adverse impacts on the environment. The most significant problem which may occur during construction concerns dredging and other activities affecting water quality. All necessary precautions should be taken so that no excessively turbid water is released to the streams. All necessary state and federal permits must be obtained in addition to consultation with these agencies well in advance.

Care should be taken so that construction activities will not interfere with the natural spawning activities of fish. Species and diversity taken above and below the Rum River Dam are shown in Tables 13 and 14. The dates for the spawning season of each species are also shown in these tables.

Many construction activities involve excavation and dredging. Cofferdams around the construction area will minimize the impact of these construction activities. Turbid water should not be released during fish spawning season.

Testing and/or sampling of the sediment should be taken to determine its physical, chemical, and biological characteristics to make a proper determination of adverse effects caused by sediment resuspension. A suitable disposal site for the dredge material should also be chosen.

F. Historic Preservation

In the course of FERC's licensing procedure, the Advisory Council on Historic Preservation and the State Historic Preservation Officer must be consulted to assure that no historic or cultural sites will be adversely affected. Novak [5] observes that, "Many older hydropower sites, while not of national significance, have played an important role in the local history of an area and thus important enough to stimulate local concerns. Additions and other needed alterations of the exterior of a structure should be designed in keeping with the historic and aesthetic value of an area, especially if other historic structures are in close proximity" [5].

TABLE 13. Percent Composition and Spawning Season of Fish Population Upstream of the Rum River Dam [4]

Species*	Percent Composition	Spawning Season
Northern Redhorse	51.1	Late May - Early June
White Sucker	17.6	Mid-May
Silver Redhorse	13.8	Late May - Early June
Carp	8.8	Mid-May
Smallmouth Bass	8.2	May-July
Rock Bass	0.5	May-Early June

*Minnows and other small fish species identified in the survey are not included.

TABLE 14. Percent Composition and Spawning Season of Fish Population Downstream of the Rum River Dam [4]

Species	Percent Composition	Spawning Season
Black Bullhead	35.4	May-June
Carp	32.7	Mid-May
Northern Redhorse	9.7	Late May-Early June
White Sucker	7.1	Mid-May
Smallmouth Bass	6.2	May-July
Walleye	4.4	Spring shortly after thaw
Silver Redhorse	1.8	Late May-Early June
Northern Pike	1.8	April-Early May
White Crappie	0.9	May-June

Sites on the National Register of Historic Places are given special protection by federal law. It is therefore important to review each site for potential archeological, cultural, and historic significance.

To date, the Minnesota Historical Society has no information of historical significance at the Rum River Dam.

The old powerhouse foundation to the east of the Rum River Dam, however, has attracted enough interest so that local officials have erected a historical marker that states the significance of the existing foundation. It is the author's recommendation that the Minnesota Historical Society and any concerned local officials should have an opportunity to assess the historical significance well in advance of any development. These agencies and the developers should then work together to preserve and present the historical significance of the existing foundation.

G. Endangered Species

At this time, the Minnesota Natural Heritage Program (Minnesota Department of Natural Resources) has no records of priority animal elements at the Anoka site. There is a 1954 record of a Blandings Turtle (Emydoidea blandingi) collected at Anoka. This uncommon turtle has been classified by the Natural Heritage Program as a Species of Special Concern. In Minnesota its distribution is confined primarily to the Anoka sand plain and the sand dunes along the Mississippi River south of the Twin Cities. Although it is likely that the turtle may still be found in the vicinity of Anoka, the proposed construction work should not pose any problems.

The Minnesota Natural Heritage Program performed a survey of the site area and found no recorded occurrence of rare or endangered plant species at the Anoka site.

H. Recreation

Rum River Central Regional Park, Rum River South, and various Anoka city parks border the Rum River in the vicinity of the Rum River Dam. The natural beauty, fish, and wildlife and the historical legacy of the Rum River valley all contribute to the river's importance as a recreational resource. In fact, the river attracts many canoeists, fishermen, hunters and other people who enjoy the outdoors. It is in light of these recreational virtues, that the Rum River is classified a Wild and Scenic River under the Minnesota State Wild and Scenic River Act.

All of the project development alternatives proposed herein will have a minor (if any) impact upon recreational resources near the Rum River Dam.

I. Agency Contacts/Correspondence

Close coordination with public agencies is essential early in the developmental phases of the project to assure that regulatory requirements and acceptable policies become known. "Both beneficial and adverse effects of small hydropower development will be a function of project design and operation as well as the nature of the existing environment that will be altered. Successful mitigation of adverse effects associated with such development will depend upon (1) accurate prediction of the magnitude of adverse impacts and (2) early awareness of potentially significant environment issues. Ecologists and environmental scientists must be consulted during the preliminary design phase of project development. By defining the relevant environmental issues at this stage, meaningful discussions can be held with all responsible and interested agencies and groups" [6].

It should be noted that mitigation of impacts at existing dam sites should be viewed in the context of an already perturbed environment [7]. Feasibility studies completed to date have validated this assumption: "The experience of our firm in conducting feasibility studies at three hydroelectric sites indicates that identifiable adverse environmental impacts associated with restoration of the three facilities are relatively minor" [8].

The various stage contact agencies are included on the following pages [9]:

STATE AGENCIES TO BE CONTACTED
FOR SMALL HYDROPOWER DEVELOPMENT

1. MINNESOTA DEPARTMENT OF NATURAL RESOURCES - Division of Waters

   a. Inquiries to the Director, Attn: Development Section

   b. EAW (Environmental Assessment Worksheet). Even if not mandatory, we strongly suggest that one be prepared by mutual cooperation within DNR. Purposes:

      - to give early and preliminary thought to any and all problems and benefits which may occur, and

      - to bring the project before the public early in development and avoid delays later in project.

   c. One permit may be issued to cover the concerns of:

      - work in public waters,
      - water appropriation,
      - dam safety - modification of dam,
      - water regulation & usage,
      - fish and wildlife habitat (including rare species),
      - recreation, and
      - water quality.

      The decision to issue a single permit is made on a site specific basis.

d. Generally DNR requires permits for raising or lowering of spillway level, fluctuating water level, and discharges which are different than historical records, dam modification, dredging and disposal of dredged material (spoil), shore protection, riprap, shoreline excavation, partial or complete drainage, water level control structure, stream or channel enlargement, or relocation.

2. MINNESOTA POLLUTION CONTROL AGENCY

a. Inquiries to the Director, Attn: Permit Section - Water Quality

b. The 1977 Clean Water Act gives authority to the MPCA to certify hydropower projects. This MPCA Certification is a prerequisite for permitting by FERC, DOE, Coast Guard or any other Federal Agency issuing permits of this type.

c. The MPCA has authority to become the primary agency issuing NPDES (National Pollutant Discharge Elimination Systems) permits, replacing FERC, Corps, etc., but has not exercised this authority. They may possibly do so in the future.

d. Primarily concerned with water quality during construction and operation. These concerns include but are not limited to: maintaining minimum and constant flows, reaeration, thermal stratification dredging and downstream water supply.

e. The MPCA must also review all secondary consideration, such as downstream flooding, effects of fish and wildlife, etc., before issuing certification according to Minnesota Statutes, Part 116B,09, Subd. 2.

3. STATE PLANNING AGENCY (including Environmental Quality Board-EQB)

a. Power Plant Siting

- Certificate of site compatibility N/A to sites less than 50 MW
- Construction permit for transmission lines if:
  - greater than 200 kV
  - greater than 50 miles

b. Environmental Planning

Current Rules

<u>Actions Requiring Environmental Assessment Worksheet with Local Government as Responsible Agency:</u>

- An action that will eliminate or significantly alter a wetland of Type 3, 4, or 5 (as defined in U.S. Department of

Interior, Fish and Wildlife Service, Circular 39, "Wetlands of the U.S.," 1956) of five or more acres in the seven-county metropolitan area, or of 50 or more acres outside the seven-county metropolitan area, either singly or in a complex of two or more wetlands.

Actions Requiring Environmental Assessment Worksheet with State Agency as Responsible Agency:

- Any new or additional impoundment of water creating a water surface in excess of 200 acres. (DNR)

- Construction of electric generating plants at a single site designed for, or capable of, operation at a capacity of 200 or more megawatts (electrical). (PCA)

- Construction of electric transmission lines and associated facilities designed for, or capable of, operation at a nominal voltage of 200 kilovolts AC or more, or operation at a nominal voltage of ± 200 kilovolts DC or more and of 50 miles or more in length. (EQB)

Proposed Rules - (possibly effective in Oct. - not yet approved)

- Impoundment of 160 acres or more

- Generating capacity 10-200 megawatts - require an EAW

- Generating capacity 200 or more megawatts - required an EIS.

c. EQB could also serve as staff agency and oversee the analysis of EAW and EIS if required.

4. WATERSHED DISTRICTS

   a. Each concerned district should be contacted.

   b. Permit may be required.

5. COUNTY

   Individual county may have zoning or shoreline management requirements.

6. MINNESOTA ENERGY AGENCY

   Certificate of Need - for sites greater than 50 MW.

7. MINNESOTA HERITAGE PROGRAM

   a. Concerned with rare species.

   b. Part of DNR Environmental Review Process.

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9. Regalia, C. (1981). Personal Communication. Division of Waters, Minnesota Department of Natural Resources, St. Paul, Minnesota.