HYDROPOWER

IDO-1699-2

IDAHO FALLS HYDROELECTRIC PROJECT

Selection of Unit Size

MASTER

October 1978

Work Performed Under Contract No. ET-78-F-07-1699

International Engineering Company, Incorporated
San Francisco, California

U. S. DEPARTMENT OF ENERGY

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OCTOBER 1978

CITY OF IDAHO FALLS
IDAHO FALLS, IDAHO

INTERNATIONAL ENGINEERING COMPANY, INC.
A MORRISON-KNUDSEN COMPANY

CONSULTING
ENGINEERS

INTERNATIONAL ENGINEERING COMPANY, INC.
A MORRISON-KNUDSEN COMPANY

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8009-810

12 October 1978

Mr. G. S. Harrison, Manager
Electric Light Division
City of Idaho Falls
P.O. Box 220
Idaho Falls, ID 83401

Dear Steve:

We are pleased to present this report, which describes the studies we have made to select the unit size for the Idaho Falls Hydroelectric Project. In determining the unit size we have considered the following factors: water availability; estimated costs (provided by manufacturers) for furnishing and installing the units; the value of the power benefits established for the project; unit efficiencies (determined from typical model performance curves); and estimated construction costs.

Selection of the optimum unit size is very sensitive to both project costs and the value assigned to the energy benefits. Figure 1 shows the relationship between annual net benefits (at 30 mills per kWh for the energy benefits) and average annual energy generation for the three plants operating as a system. Although the curve is very flat, it does show that maximum net benefits will be obtained at an average annual energy generation of 170 GWh (million kilowatt-hours). This generation level corresponds to a unit size of 8.0 MW (6000 cfs discharge capacity), which is the optimum unit size. With units of this size, the total estimated capital investment required for the project will be $39.9 million, and the energy cost will be 21 mills per kWh.

After establishing 8.0 MW as the optimum unit size, we considered a slightly larger unit size of 8.4 MW, at an incremental energy cost of 30 mills per kWh for the additional energy produced by these units. With 8.4-MW units, the three plants, operating as a system, would generate an additional 2 GWh of energy a year at an additional cost of 30 mills per kWh. The total estimated capital investment required for the project with units of this size is $40.6 million.

As shown on Figure 1, if average annual energy is increased beyond 170 GWh, each dollar of costs will return less than a dollar of benefits. The reason for this is that the substantially higher costs associated with larger units, to obtain increasingly smaller increments of additional energy, are not justified on the basis of net benefits. Thus, the additional capital investment required for 8.4-MW units (172 GWh average annual energy) would be justified only if alternative source energy would be displaced early in the life of the project. However, alternative source energy will probably not be required at Idaho Falls for at least 10 to 15 years after the completion of project construction. Therefore, we recommend the optimum unit size of 8.0 MW for the Idaho Falls Hydroelectric Project. With units of this size, the project can be constructed within the funds available from both the authorized revenue bonds and the Department of Energy, provided delays during construction do not exceed about 1 year. (Normally, 2 to 3 years' contingency is recommended).

We will be pleased to discuss any aspect of this report with you at your convenience.

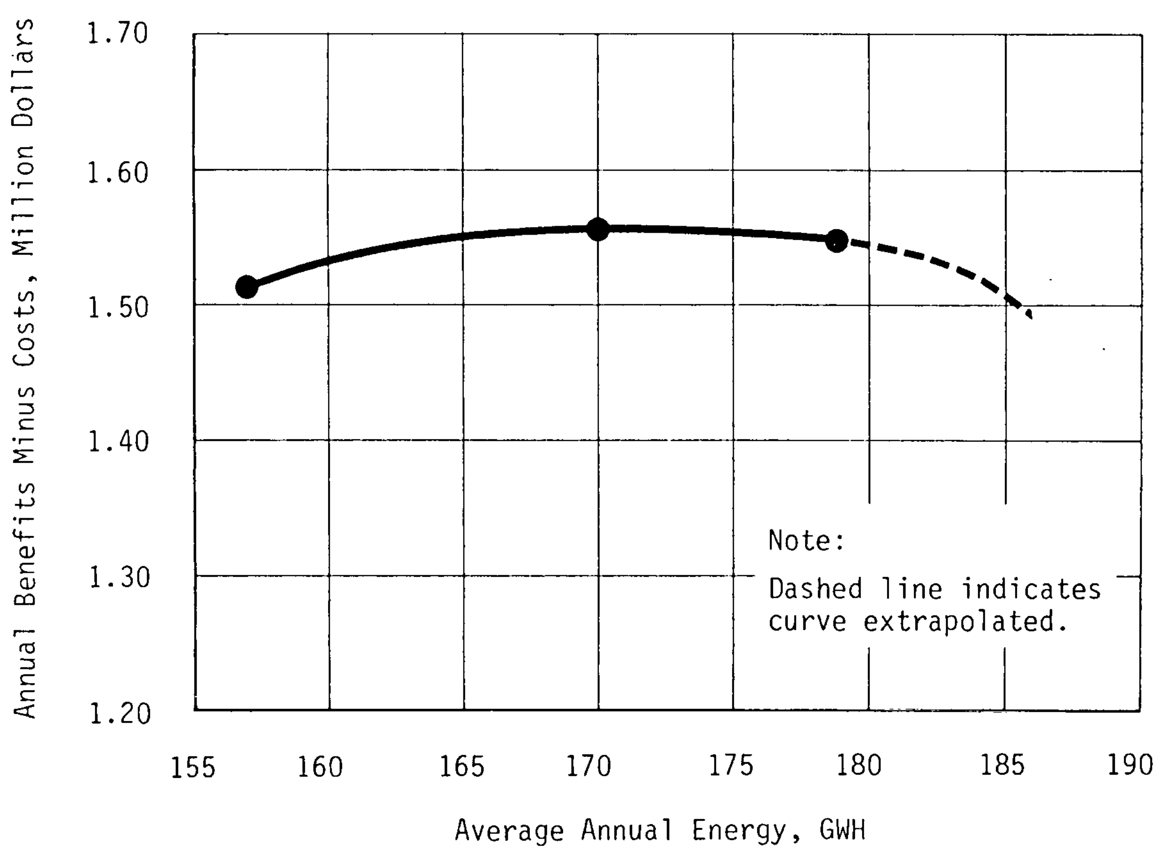
Very truly yours,

Pablo Chavez

Pablo Chavez
Project Manager

PC:abm

Annual Benefits Minus Costs



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IDAHO FALLS HYDROELECTRIC PROJECT
SELECTION OF UNIT SIZE

I. GENERAL

This report describes the studies performed by International Engineering Company, Inc. (IECO) to select the unit size for the Idaho Falls Hydroelectric Project. The project comprises three separate power plants: the Upper, City, and Lower Plants. The plant forebays will have no storage; power operation will be on a run-of-river basis utilizing Snake River flows.

The new generating units will be three identical horizontal-axis bulb turbine-generators, one at each plant. At the Lower Plant, the existing generating units will remain in service on a standby basis. At the Upper and City Plants, the existing equipment will be removed.

II. BASIC INPUT DATA

A. Hydrologic Data

Monthly streamflow data for the Snake River at Idaho Falls adjusted to present (1975) flow conditions (Upper Snake Study No. 22), previously obtained from the Idaho Department of Water Resources, were used in these studies. These streamflow data are presented in Table B-1, and the flow-duration curve for this condition is presented on Figure B-1.

B. Tailwater Rating Curves

Representative river cross sections were made available by the Idaho Falls Electric Division for use in backwater and tailwater computations. A computer program developed by the U.S. Army Corps of Engineers' Hydrologic Engineering Center was used in making the backwater computations.

Tailwater rating curves were derived for the Upper, City, and Lower Plants for use in determining the hydraulic head available for power generation. These tailwater rating curves are shown on Figures B-2, B-3, and B-4.

III. METHODOLOGY

Four sizes of units were selected by judgment as probably covering the range within which the optimum size would fall, namely units with flow capacities of 5000, 6000, 7000, and 8000 cfs, respectively. The flow-duration curve (Figure B-1) and the following table show the availability of these flows at each of the three Idaho Falls plants:

Flow (cfs)	Percent of Time Flow is Equaled or Exceeded
5000	45
6000	30
7000	21
8000	17

This means, for example, that if a unit capable of passing only 5000 cubic feet per second were installed, it would utilize for power generation all water passing down the river 55% of the time; for 45% of the time the flow would exceed the unit capacity, and the excess would pass over the spillway, wasted as far as energy is concerned.

For a substantially larger investment, a unit capable of passing 8000 cfs could be installed, reducing the period of wastage over the spillway to 17% of the time.

The aim of this report is to study the tradeoff between increasing capital investment and decreasing spillage (energy waste) to determine the economic installation.

Operation studies were performed for plants with 5000, 6000, 7000, and 8000 cfs installations, respectively, to determine their average annual energy generation in kilowatt-hours. The value of this generation was established by applying the cost of purchasing the same energy from an alternative source. The result is the annual benefit of the project.

Cost estimates were developed for plants with these installations. All costs were then reduced to the annual cost of ownership and operation.

Comparison of the annual benefits and annual costs permitted selection of the economic installation--that is, the one that will maximize the net benefits (excess of annual benefits over annual costs).

IV. OPERATION STUDIES

Power operation studies were performed for each plant. In making these studies, the following criteria were observed:

- The plants will operate as run-of-river plants and will utilize water only as it comes to them from upstream lakes and reservoirs.

- The plants will operate continuously to carry a portion of the baseload. Minor downtime for maintenance was not considered a factor.

- The generator output will not be exceeded under any operating conditions.

- The unit output is based on efficiency curves determined from a typical model performance curve. The efficiency curves were scaled up to the prototype turbine performance and then derated for the generator efficiency.

- The operation study is on a monthly basis, based on average monthly streamflow data.

- At the Upper Plant, during periods of flow below the turbine design discharge, fish water requirements were assumed to be 100 cfs. Streamflows available for power generation were reduced accordingly.

- The minimum net head for power generation is 13 feet.

- The minimum river discharge for power generation is 1600 cfs.

The results of the operation studies for present flow conditions are summarized in Table 1.

In the power operation studies, evaporation losses were assumed to be nil, since the three plants will utilize the Snake River flows on a run-of-river basis. Head losses for the three plants were estimated as intake, entrance, gate slot, transition, and outlet losses. Head losses through the bulb turbine-generator, the impeller, and the draft tube are excluded because they are accounted for as part of the turbine efficiency. The overall head losses for each of the three power plant units are estimated to be about 1.4 feet at turbine design discharge.

TABLE 1

SUMMARY OF OPERATION STUDIES

5000 CFS UNITS	Upper Plant	City Plant	Lower Plant	Total
Average Annual Energy (GWh)	53.654	51.656	51.589	156.899
Minimum-Year Energy (GWh)*	43.362	42.521	43.913	129.796
Maximum-Year Energy (GWh)	58.902	56.521	57.281	172.704
Average Output/ Unit Capacity	86%	83%	83%	

6000 CFS UNITS	Upper Plant	City Plant	Lower Plant	Total
Average Annual Energy (GWh)	57.409	56.444	56.172	170.025
Minimum-Year Energy (GWh)	45.972	44.605	45.937	136.614
Maximum-Year Energy (GWh)	65.866	64.788	65.253	195.907
Average Output/ Unit Capacity	82%	80%	80%	

7000 CFS UNITS	Upper Plant	City Plant	Lower Plant	Total
Average Annual Energy (GWh)	59.818	59.771	59.273	178.862
Minimum-Year Energy (GWh)	45.700	46.997	48.267	190.964
Maximum-Year Energy (GWh)	65.866	64.788	65.253	195.907
Average Output/ Unit Capacity	75%	75%	74%	

8000 CFS UNITS	Upper Plant	City Plant	Lower Plant	Total
Average Annual Energy, GWh	62.746	62.178	61.522	186.446
Minimum Year Energy, GWh	47.707	47.882	49.152	144.741
Maximum Year Energy, GWh	80.443	78.586	74.784	233.813
Average Output/ Unit Capacity	73%	72%	72%	

* GWh equals million kWh.

V. OVERALL ENGINEERING AND ECONOMIC CONSIDERATIONS

The following factors were considered in selecting the economic unit size for the three identical bulb turbine-generators for the Idaho Falls installations: streamflows; topographic conditions of the sites and system operation; the turbine-generator outputs and efficiencies; the accuracy of the equipment prices received from the manufacturers; the high equipment cost relative to the total cost; escalation of construction costs; future value of the dollar; and future value of energy. These factors are discussed below and in Section VIII.

A. Streamflows

The power estimates were derived from a simulated study based on monthly streamflows for 45 years of record, from water year 1928 through water year 1972, adjusted to 1975 upstream development conditions. These flows can be considered representative of long-term conditions since both wet and dry periods are included. The average annual energy estimated in this manner reflects what can be expected, but not guaranteed, in the future. Furthermore, the three Idaho Falls plants will operate on a run-of-river basis, using streamflows only as they are available, since the forebays will have no significant storage.

B. Site Interrelationships and System Operation

The flows at the three plants are essentially equal most of the year. One irrigation diversion structure is located between the City Plant and the Upper Plant. This structure diverts water into the Porter Canal for delivery to farmlands southwest of the City.

The head developed at each site and the storage available is dictated by existing topographic conditions. In each case, low diversion dams will divert flows to the power plants and maintain the desired water levels upstream from the plants.

The proposed headwater at the Lower Plant will affect the tailwater of the City Plant, approximately 2 miles upstream. However, the upper pool of the City Plant will not affect the tailwater of the Upper Plant, 5 miles upstream from the City Plant. Pertinent data for each plant are given in Table 2.

TABLE 2

HEADWATER AND TAILWATER ELEVATIONS AND GROSS HEAD FOR THE THREE PLANTS

Item	Upper Plant	City Plant	Lower Plant
Average headwater elevation (ft)	4734.0	4694.25	4674.0
Average tailwater elevation (ft) (Q = 4700 cfs)	4713.5	4674.10	4653.6
Gross head (ft)	20.5	20.1	20.4

C. Turbine-Generator Efficiency

Overall turbine-generator efficiency curves were prepared as input for a computer program used to determine the total annual energy that could be generated by three different sizes of bulb turbine-generator units at nominal flows of 5000, 6000, and 7000 cfs (see Figures C-1, C-2, and C-3).* These flows correspond to the nominal unit sizes quoted upon by eight bulb turbine-generator manufacturers in their prequalification proposals, and the three efficiency curves are based on data furnished by the manufacturers. Each curve is a composite of efficiencies based on three conditions: 1) The model efficiencies quoted by the manufacturers were the baseline of acceptable values. 2) These model efficiencies were uprated or increased in value according to the Hutton formula for scale-up from model to prototype,

* An efficiency curve for an 8000-cfs unit was estimated from the data for the 7000-cfs unit efficiency curve and is not included in this report.

as defined by the International Electrical-Technical Commission Code 193. Some averaging of the manufacturers' speeds and diameters was necessary in these calculations. 3) A generator efficiency of 96.5% average, in accordance with the manufacturers' data, was then used to derate the efficiencies giving the overall efficiency curves presented.

The variation in the efficiency curves among the three plants for each size unit was found to be less than half a percent; therefore, an average efficiency curve could be (and was) used to represent the operating conditions at the three power plants for each size unit, without compromising the performance evaluation with regard to total annual energy output. The methods used provide a minimum acceptable unit efficiency, which is a conservative estimate for determining total energy output.

D. Equipment Costs

The equipment costs for the Idaho Falls installations, as with any low-head hydroelectric project, will be a high percentage of the total project cost. The estimated prices received from five manufacturers (in April 1978) were adjusted for rate of exchange, transportation to the jobsite, customs duty, and installation. To minimize possible inaccuracies, the prices were averaged.

E. Escalation

To ensure that the total investment required for the project is consistent with the funds available for the project, escalation throughout the planned construction period and the effects of possible delays were considered. The amount of revenue bonds authorized is $48 million. When the Department of Energy's (DOE's) contribution of $7.3 million is added, this financing covers an estimated $38.2 million capital cost in 1978 dollars plus 10% escalation per year thereafter and a contingency of a 2-year delay in the start of construction.

F. Value of the Dollar

Bids for the equipment are expected from manufacturers located in Europe, Japan, and the United States. Therefore, the future value of the dollar in foreign exchange will be a factor in the bidding. No special provisions for this contingency have been made in the studies. The prices used are based on the rate of exchange existing in April 1978, when they were received. Bids will be received in U.S. dollars.

VI. ALTERNATIVE UNIT SIZES

Studies were performed to determine the economic generating potential of the Idaho Falls sites. Costs, annual energy, and benefits were estimated for units with discharge capacities of 5000, 6000, 7000 and 8000 cfs, respectively, to determine the most economical combination of turbine-generator size and civil works. Pertinent data for the alternative sizes investigated are presented in Table 3, and criteria for the studies are summarized on the following pages.

TABLE 3

PHYSICAL DATA FOR ALTERNATIVE UNIT SIZES

	Alternatives			
Item	A	B	C	D
Unit Discharge Capacity (cfs)	5000	6000	7000	8000
Rated Head (ft)	19.15	18.1	17.66	16.62
Runner Diameter (ft)	15.0	16.40	17.7	18.5*
Number of Units	3	3	3	3
Overall Efficiency (%)	87.8	87.3	87	87
Rated Output (MW)	7.12	8.0	9.11	9.8
Average Annual Energy (GWh)	156.899	170.025	178.862	186.000

* Extrapolated value.

Figures A-1, A-2, and A-3 show, respectively, turbine design discharge versus average annual energy, rated output versus average annual energy, and runner diameter versus rated output.

A. Capital Costs

Capital costs for the project were estimated as described below:

- Quantity and Cost Estimates - Quantity estimates for Alternatives A, B, and C are based, in general, on takeoffs from the Federal Energy Regulatory Commission (FERC) application drawings and from study layouts. The estimated cost of the equipment was based on data received from manufacturers in April 1978. Costs of the other machinery and electrical items were estimated on the basis of experience. The costs for Alternative D were obtained by extrapolating the curves shown on Figures A-4, A-5, and A-6.

- Unit Costs - The unit costs applied in the estimates are based on information gathered in the feasibility studies for similar construction projects, adjusted to the Idaho Falls area. They are considered current, complete, and adequate for the studies. No price escalation was added to the unit prices.

- Contingencies - A contingency factor of 15% was added to the estimates to obtain the direct costs.

- Engineering and Administration - Costs for engineering and administration, including construction supervision, were estimated by applying a factor of 15% to the estimated direct costs. Final figures were rounded.

- Interest during Construction - Interest during construction was estimated by assuming an annual interest rate of 7% and a 36-month construction period.

B. Equivalent Annual Costs

Annual costs comprise the following items:

- Capital Recovery - Capital recovery costs are based on a 50-year period of analysis, assuming an annual interest rate of 7-3/4%, resulting in a capital recovery factor of 0.0794.

- Operation and Maintenance - Operation and maintenance costs were estimated on the basis of FERC experience records for power plants.

- Interim Replacements - Interim replacement costs were estimated on the basis of FERC (formerly FPC) guidelines* for hydroelectric power evaluation, assuming an annual rate of 0.65% of the initial investment for the items to be replaced during the economic life of the project.

- Insurance - Costs for fire, storm, vandalism, equipment, public liability, and property damage insurance were estimated at 0.1% of the capital investment.

- General Expenses - Administrative and general expenses were estimated at 39% of the total annual operation and maintenance costs, based on FERC guidelines.

C. Unit Cost of Energy

The unit cost of energy was estimated based on the estimated average annual energy generation at each plant.

* Hydroelectric Power Evaluation, Federal Power Commission, March 1968 and Supplement No. 1, November 1969.

D. Benefits

Energy benefits are based on the cost of providing equivalent energy by the most economical alternative means. A value of 30 mills per kWh was used. This value was furnished by the Idaho Falls Electric Division.

VII. COMPARISON OF ALTERNATIVES

The estimated project costs, energy, and benefits for the four alternatives investigated to determine the most economic installed capacity are summarized in Table 4. Figures A-4 through A-9 show the relationships of costs, benefits, and costs-minus-benefits to average annual energy. The criteria selected for the comparison are summarized below:

- Any benefits that may be derived from the existing units at the Lower Plant are not included in the economic analysis.
- The economic analysis is based on annual benefits and annual costs for the three plants operating as one system.
- The economic installed capacity is the one that will give the maximum benefits-minus-costs.
- The benefit-to-cost ratio shall be greater than one.
- The total investment shall be consistent with the amount of revenue bonds authorized by the voters and DOE's contribution, considering the possible escalation due to delays.

Table 5 summarizes the benefits, costs, benefits-minus-costs, and benefit-to-cost ratios for the four alternatives investigated. Table 6 and Figure A-8 show the effect of 1- and 2-year delays in the start of construction on the cost to the owner.

TABLE 4

COMPARISON OF ALTERNATIVES

Item	Alternative A Upper Plant	Alternative A City Plant	Alternative A Lower Plant	Alternative A Total	Alternative B Upper Plant	Alternative B City Plant	Alternative B Lower Plant	Alternative B Total	Alternative C Upper Plant	Alternative C City Plant	Alternative C Lower Plant	Alternative C Total	Alternative D*** Total
AVERAGE ANNUAL ENERGY (kWh)*	53,654,000	51,656,000	51,589,000	156,899,000	57,409,000	56,444,000	56,172,000	170,025,000	59,818,000	59,771,000	59,273,000	178,862,000	186,000,000
COSTS													
Capital Cost (thousand $)													
Total Direct Cost (including contingencies)	9,894	10,754	7,720	28,368	11,016	11,923	8,688	31,827	11,838	12,816	9,617	34,271	36,553
Engineering and Administration	1,484	1,613	1,158	4,255	1,652	1,789	1,333	4,774	1,776	1,922	1,443	5,141	5,483
Total Construction Cost	11,378	12,367	8,878	32,623	12,668	13,712	10,221	36,601	13,614	14,738	11,060	39,412	42,036
Interest During Construction	1,024	1,113	799	2,936	1,140	1,234	920	3,294	1,225	1,326	996	3,547	3,783
Total Capital Cost	12,402	13,480	9,677	35,559	13,808	14,946	11,141	39,895	14,839	16,064	12,056	42,959	45,819
Equivalent Annual Cost (thousand $/yr)													
Capital Recovery (assuming 50-yr repayment period at 7 3/4% interest)	985	1,070	768	2,823	1,096	1,187	885	3,168	1,178	1,276	957	3,411	3,638
Operation and Maintenance, interim replacements and insurance	128	124	118	370	133	124	122	379	142	136	131	409	454
Total Equivalent Annual Cost	1,113	1,194	886	3,193	1,229	1,311	1,007	3,547	1,320	1,412	1,088	3,820	4,092
Energy Cost ($/kWh)	0.02074	0.02311	0.01717	0.02035	0.02141	0.02323	0.01793	0.02086	0.02207	0.02362	0.01836	0.02136	.02195
BENEFITS													
Total Annual Benefits ($/yr)**	1,609,620	1,549,680	1,547,670	4,706,970	1,722,270	1,693,320	1,685,160	5,100,750	1,794,540	1,793,130	1,778,190	5,365,860	5,582,000
Benefit to Cost Ratio	1.446	1.298	1.747	1.474	1.401	1.292	1.673	1.438	1.360	1.270	1.634	1.405	1.364
Benefits Minus Costs ($/yr)	496,620	355,680	661,670	1,513,970	493,270	382,320	678,160	1,553,750	474,540	381,130	690,190	1,545,860	1,488,000

* Under present (1975) conditions.

** Power benefits are based on the cost of providing equivalent energy by the most economical alternative means. A value of $0.030/kWh was used. This value was furnished by the Idaho Falls Electric Division.

*** Total costs for Alternative D were obtained by extrapolating the curves shown on Figures A-4, A-5 and A-6.

Note: Alternative A = 5000 cfs (7.12 MW)
Alternative B = 6000 cfs (8.0 MW)
Alternative C = 7000 cfs (9.11 MW)
Alternative D = 8000 cfs (9.8 MW)

TABLE 5

ECONOMIC ANALYSIS OF ALTERNATIVES

ANALYSIS BASED ON TOTAL ANNUAL BENEFITS AND TOTAL ANNUAL COSTS

Alternative	Total Annual Benefits ($)	Total Annual Costs ($)	Total Benefits Minus Total Costs ($)	Benefit-to-Cost Ratio
A (5000 cfs)	4,706,970	3,193,000	1,513,970	1.474
B (6000 cfs)	5,100,750	3,547,000	1,553,750	1.438
C (7000 cfs)	5,365,860	3,820,000	1,545,860	1.405
D (8000 cfs)	5,582,000	4,092,000	1,488,000	1.364

TABLE 6

COST TO THE OWNER (in Dollars)

	Alternative A	Alternative B	Alternative C
Capital Cost	35,558,000	39,895,000	42,959,000
Escalated Cost (Factor = 1.2)	42,670,000	47,874,000	51,551,000
DOE Contribution	7,300,000	7,300,000	7,300,000
Cost to Owner	35,370,000	40,574,000	44,251,000
One-Year Delay			
Escalated Cost (Factor = 1.32)	46,937,000	52,661,000	56,706,000
DOE Contribution	7,300,000	7,300,000	7,300,000
Cost to Owner	39,637,000	45,361,000	49,406,000
Two-Year Delay			
Escalated Cost (Factor = 1.45)	51,559,000	57,848,000	62,291,000
DOE Contribution	7,300,000	7,300,000	7,300,000
Cost to Owner	44,259,000	50,548,000	54,991,000

Note: Alternative A = 5000 cfs (7.12 MW)
Alternative B = 6000 cfs (8.0 MW)
Alternative C = 7000 cfs (9.11 MW)

Values for Alternative D (8000 cfs, 9.8 MW) were extrapolated from values for Alternatives A, B, and C, as shown on Figure A-8.

VIII. SELECTION OF UNIT SIZE

Selection of the optimum unit size for the Idaho Falls installations is extremely sensitive, as shown on Figure A-9, to the value assigned to alternative source energy and other factors.

Figure A-9 reflects the relationship of benefits-minus-costs for various assumed values of benefits to the average annual energy and unit size. For benefits of 25 mills per kWh, an optimum unit size of 7 MW is indicated, whereas at 40 mills per kWh a unit size of 10 MW would probably be selected. As noted above, the value of power benefits used in this study is 30 mills per kWh. This value, furnished by the Idaho Falls Electric Division, represents the present cost of alternative source energy. Figure A-7 shows the relationship between annual net benefits (at 30 mills per kWh for the energy benefits) and average annual energy generation for the three plants operating as a system. Although the curve is very flat, it does show that maximum net benefits will be obtained at an average annual energy generation of 170 million kWh (Alternative B). As shown on Figures A-1 and A-2, this generation level corresponds to a unit size of 8.0 MW (6000 cfs discharge capacity), which is the optimum unit size. With units of this size, the total estimated capital investment required for the project will be $39.9 million, and the energy cost will be 21 mills per kWh.

Consideration was then given to a slightly larger installed capacity (8.4 MW), at an incremental energy cost of 30 mills per kWh for the additional energy produced by the larger units. With 8.4-MW units, the three plants, operating as a system, would generate 2 million kWh of additional energy at an additional cost of 30 mills per kWh. The total estimated capital investment required for the project with units of this size is $40.6 million.

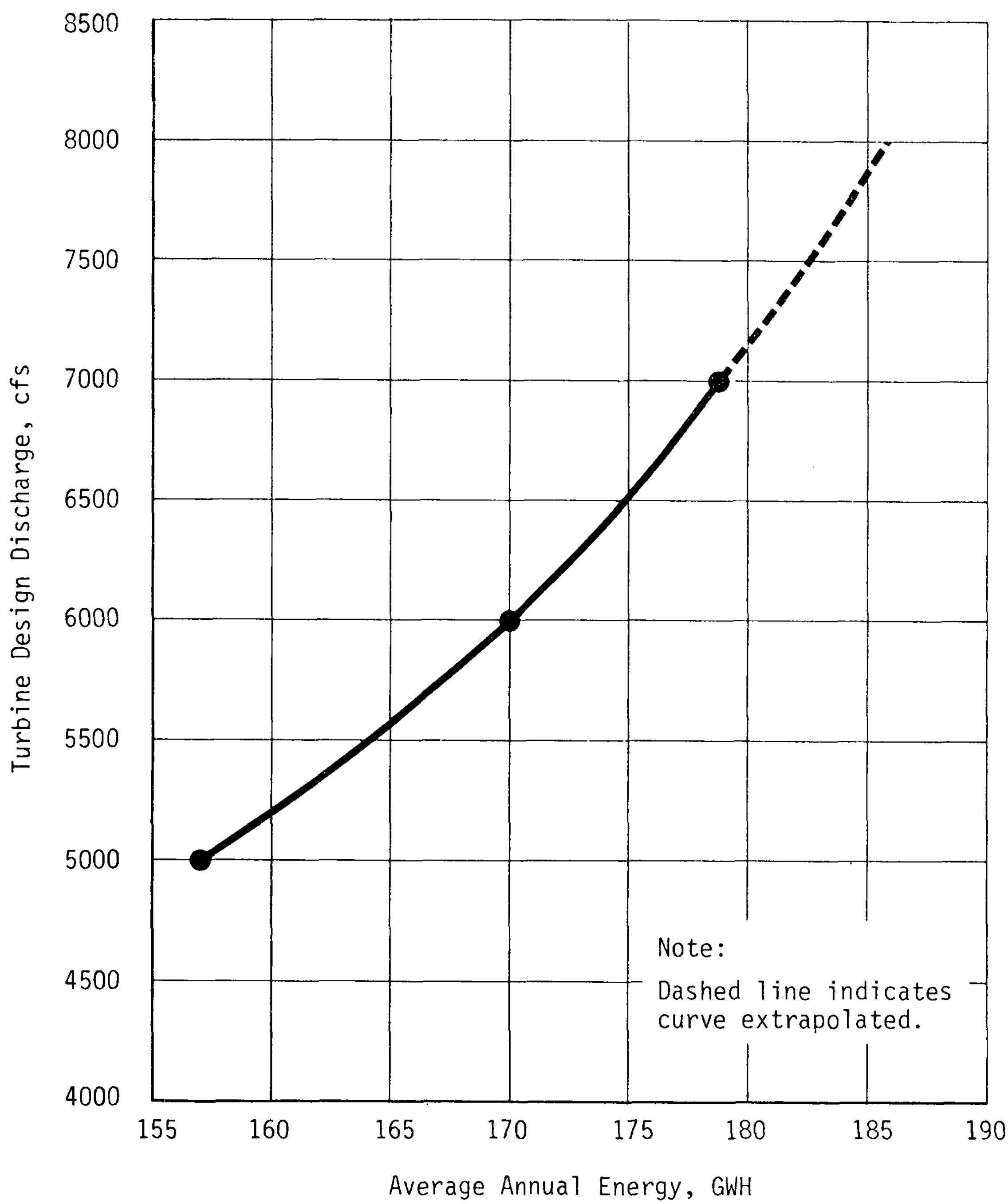
As shown on Figure A-7, if average annual energy is increased beyond 170 million kWh, each dollar of costs will return less than a dollar of benefits. The reason for this is that the substantially higher costs associated with larger units, to obtain increasingly smaller increments of additional energy, are not justified on the basis of net benefits. For example, increasing the average annual energy from 170 million kWh (Alternative B) to 179 million kWh (Alternative C) would result in additional costs of $273,000 per year and provide additional benefits of only $265,000 per year. This would clearly be an uneconomical situation.

Comparing the 8.0- and 8.4-MW units, the additional capital investment required for the 8.4-MW units would be justified only if alternative source energy would be displaced early in the life of the project. However, alternative source energy is not expected to be required at Idaho Falls for at least 10 to 15 years after the completion of project construction. Therefore, 8.0 MW is selected as the recommended size.

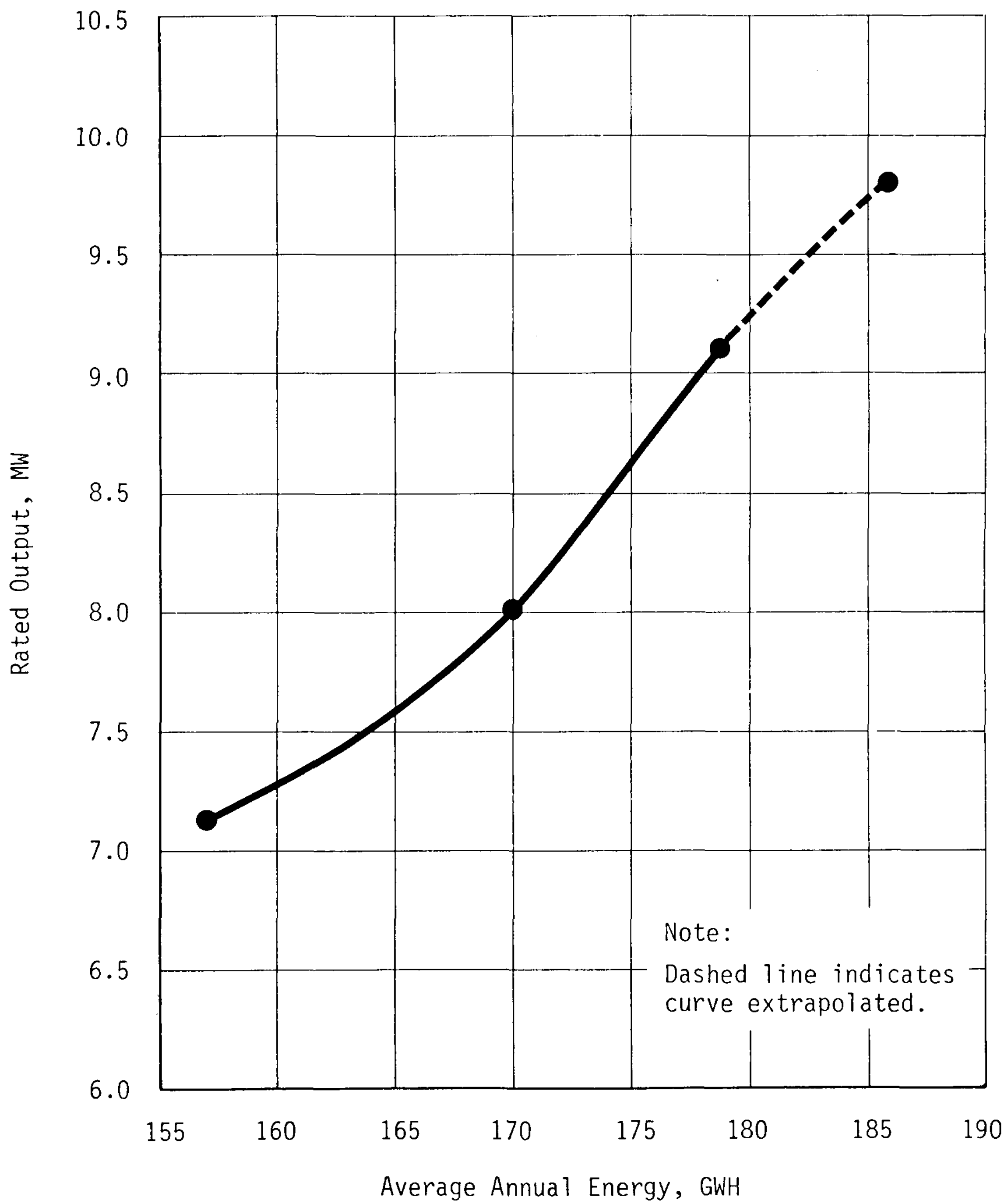
With 8.0-MW units the project can be constructed within the funds available from both the authorized revenue bonds and the DOE, provided delays during construction do not exceed about 1 year. It should be noted that allowances for this contingency are normally 2 to 3 years.

Figure A-1

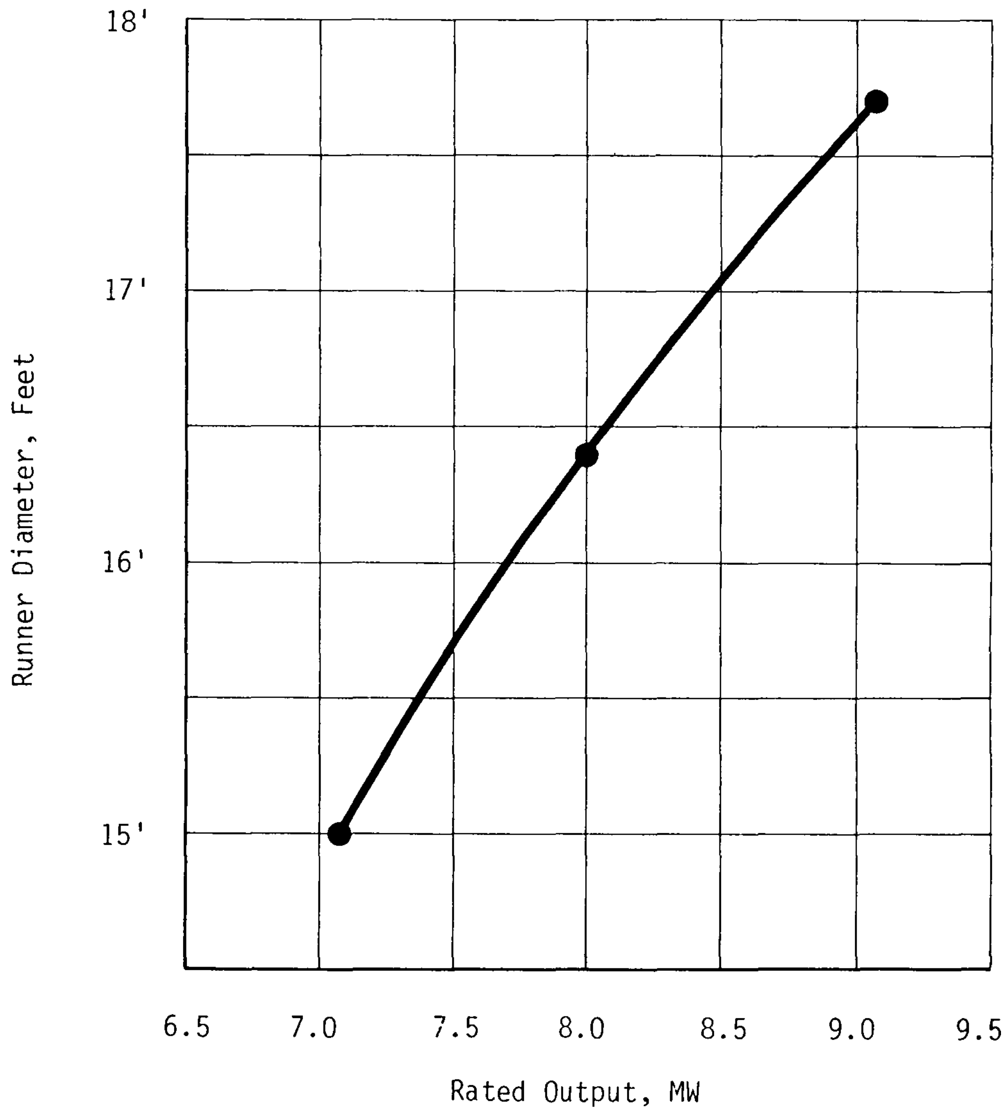
Turbine Discharge, CFS



Average Annual Energy



Runner Diameter, Feet



Capital Cost

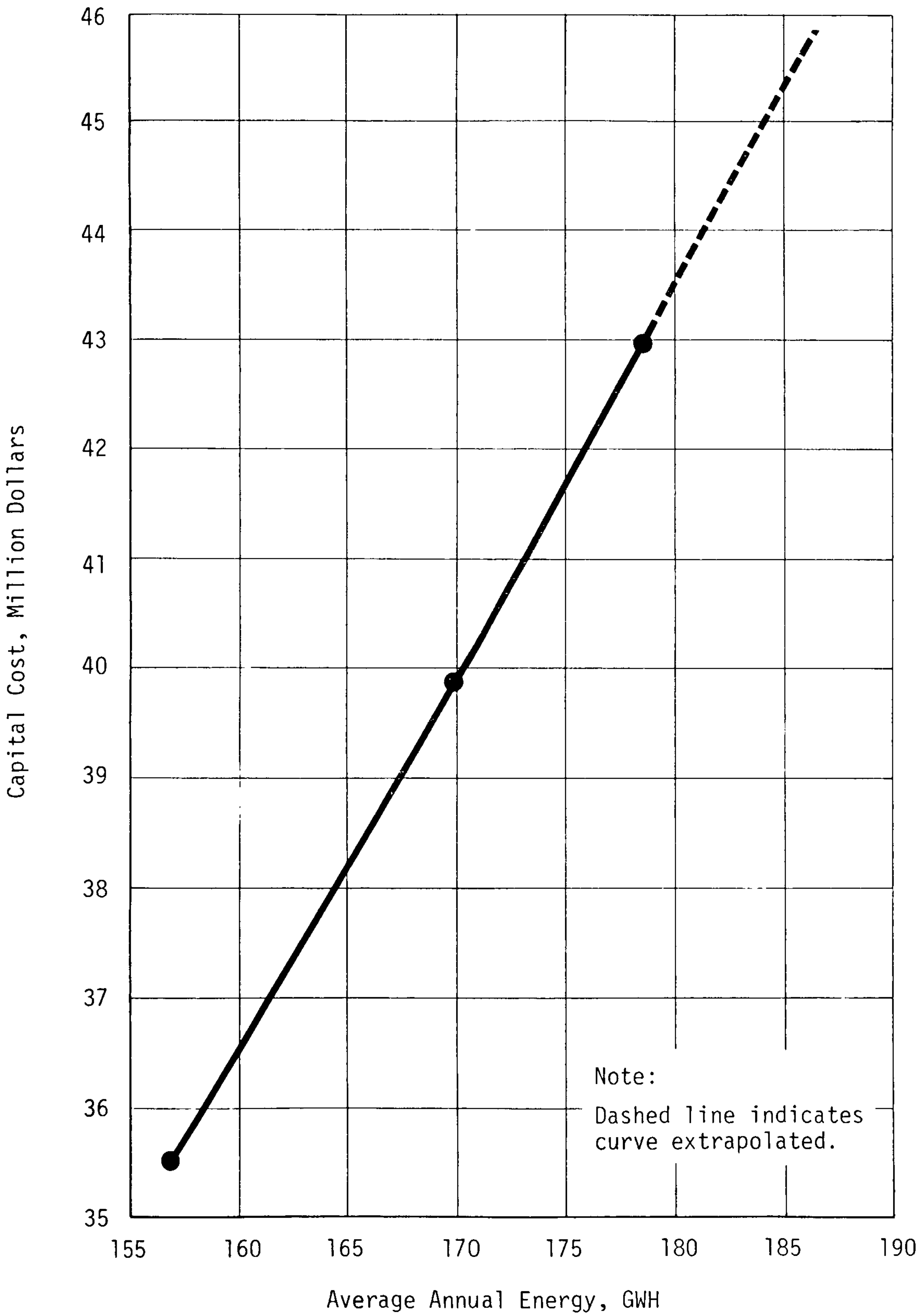
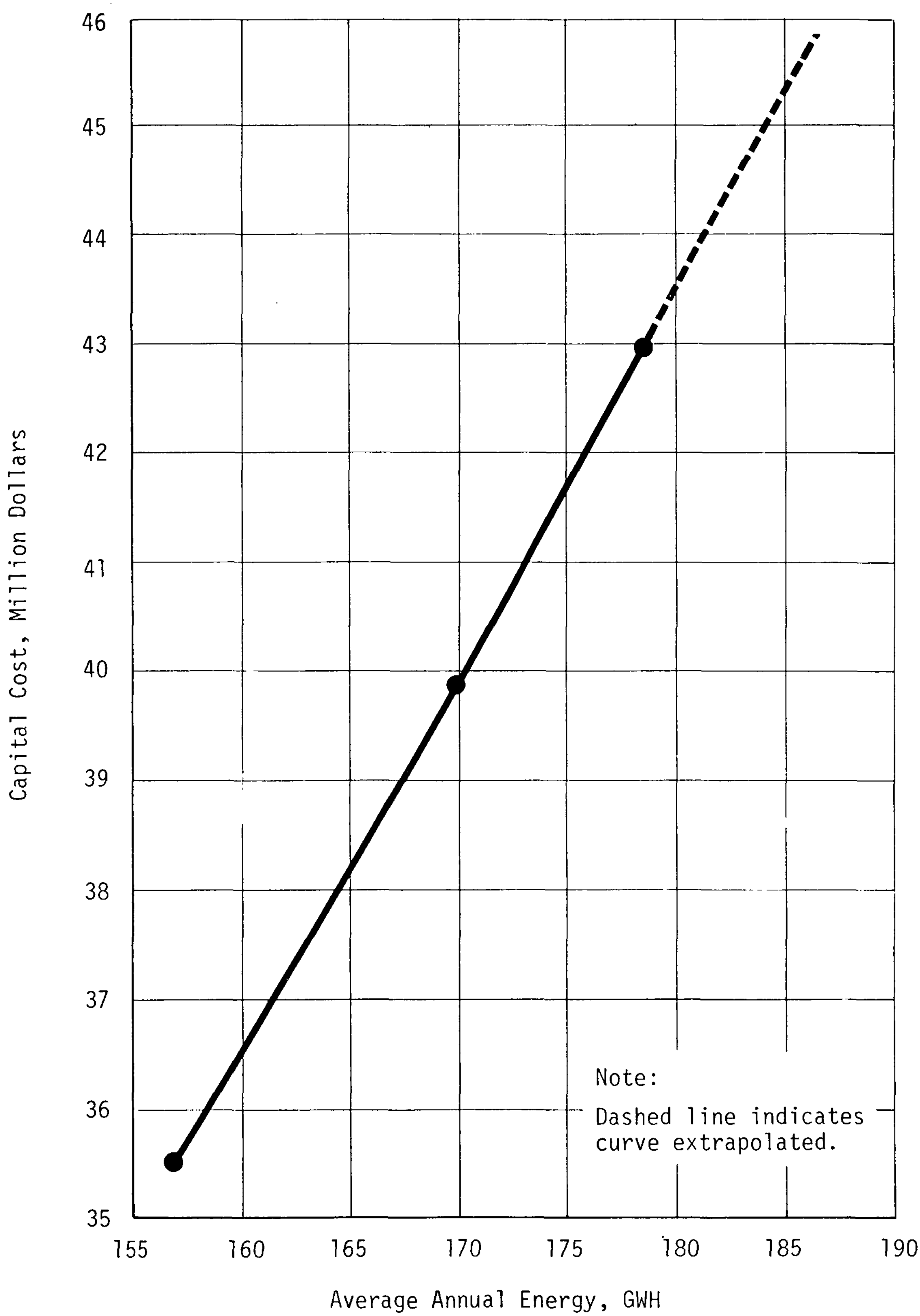
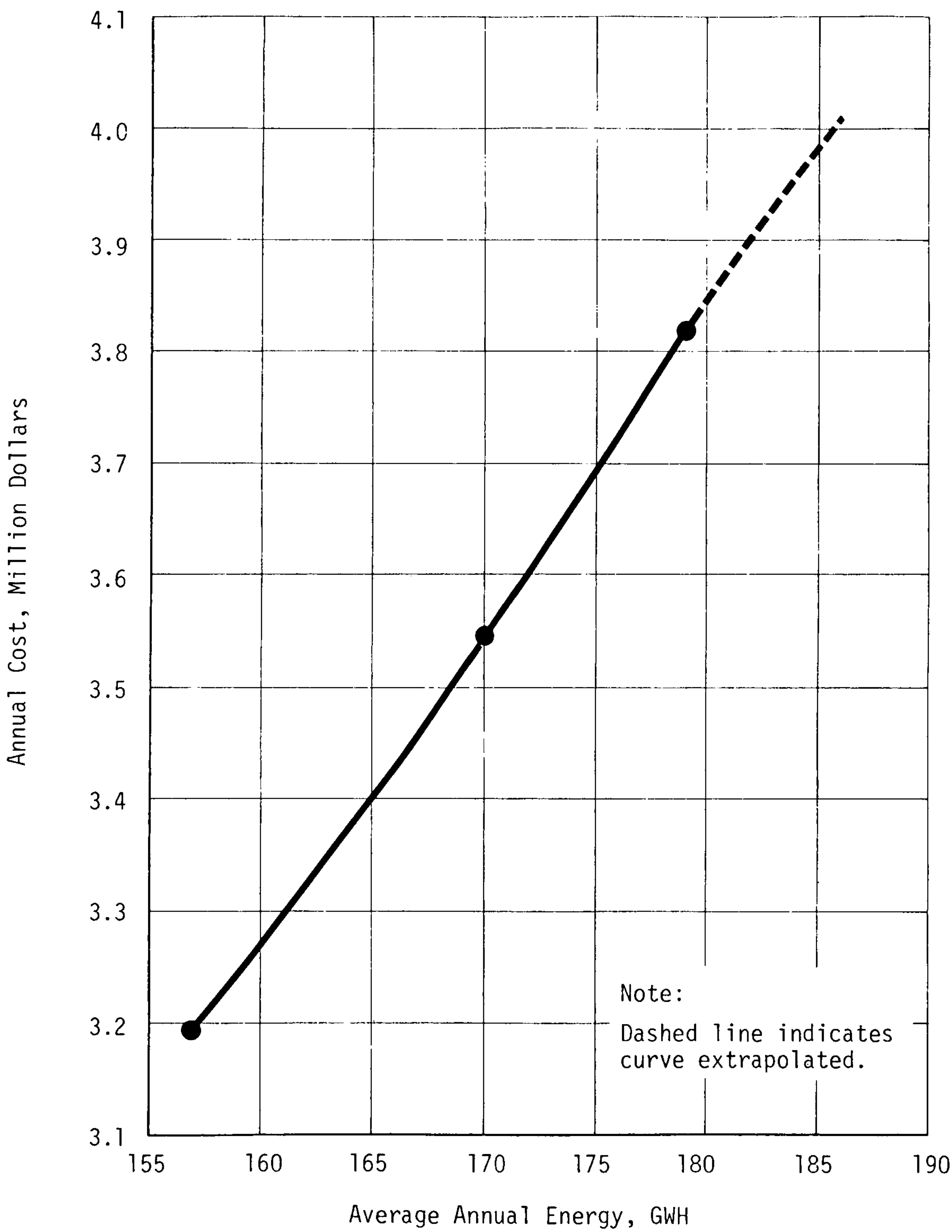


Figure A-4

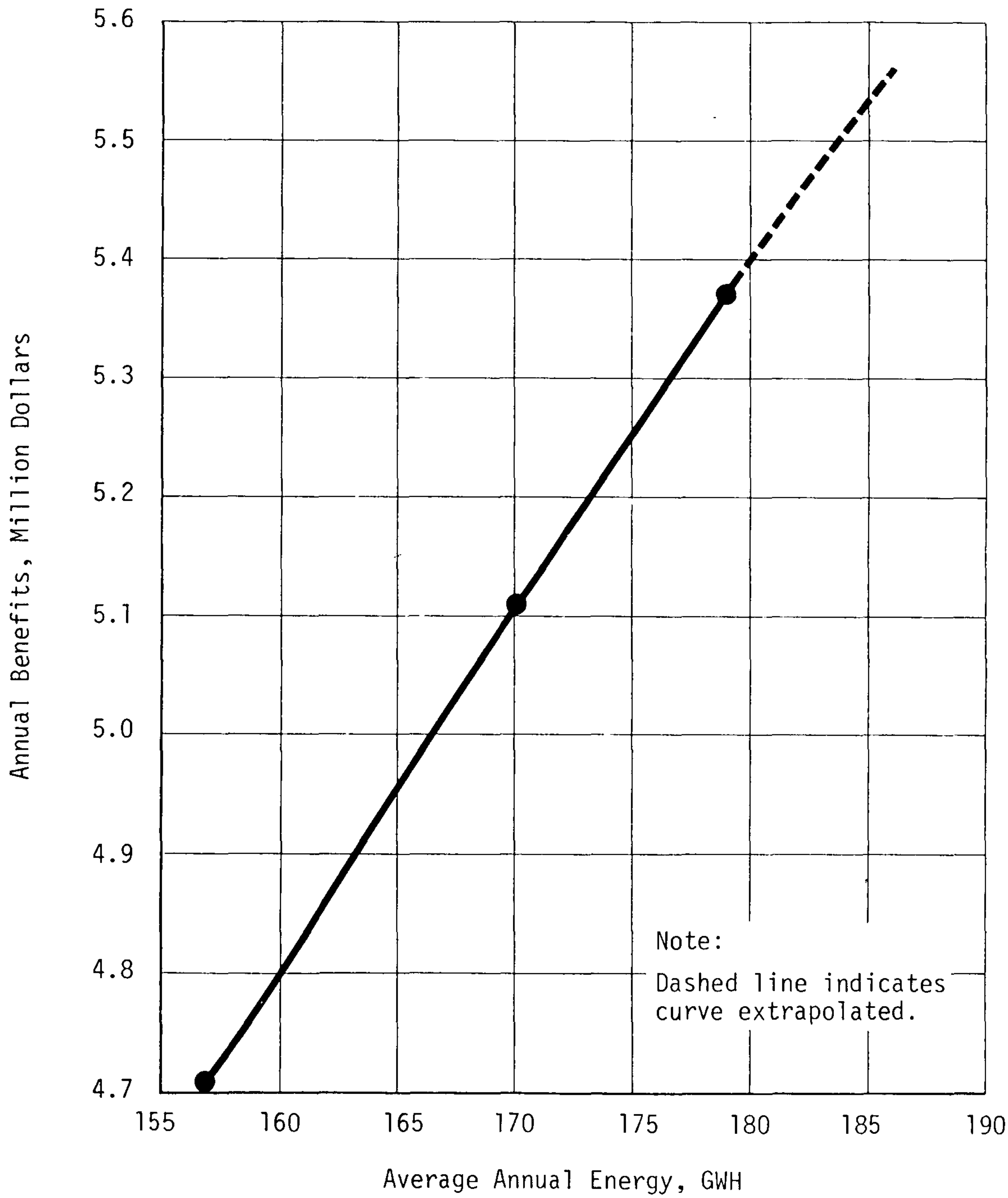
Capital Cost



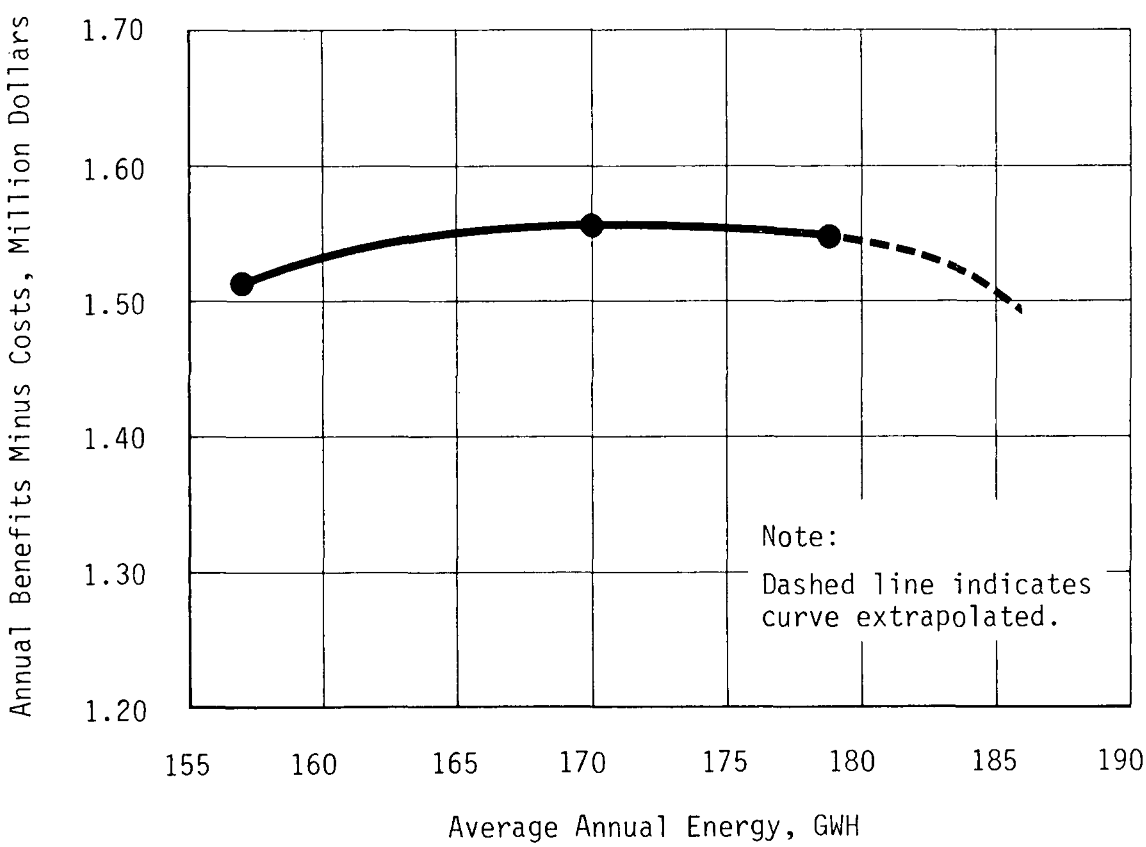
Annual Cost


4.1
4.0
3.9
3.8
3.7
3.6
3.5
3.4
3.3
3.2
3.1
Annual Cost, Million Dollars
155
160
165
170
175
180
185
190
Average Annual Energy, GWH
Note:
Dashed line indicates curve extrapolated.

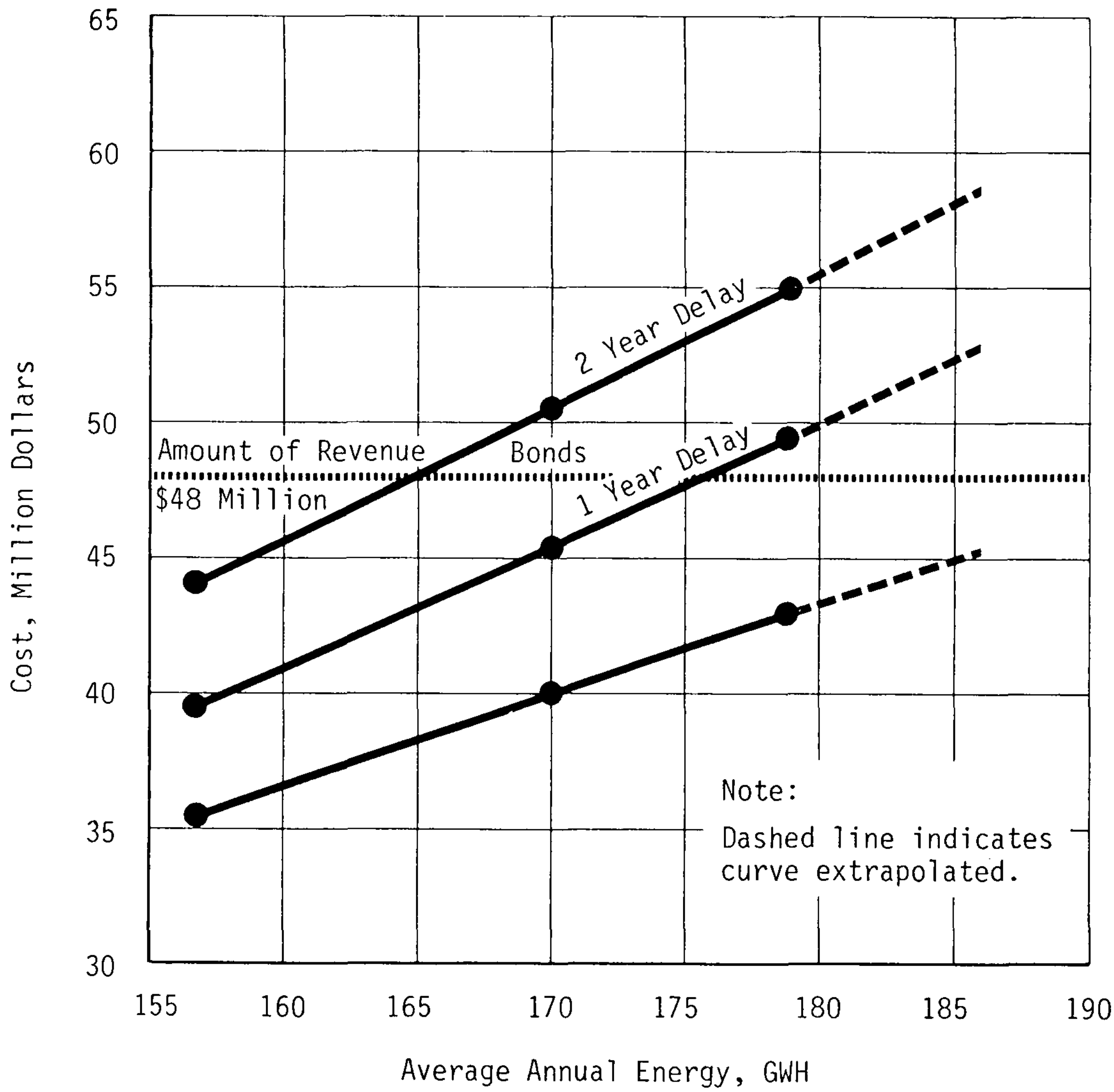
Annual Benefits



Annual Benefits Minus Costs



Cost to the Owner



Benefits Minus Costs, Million Dollars

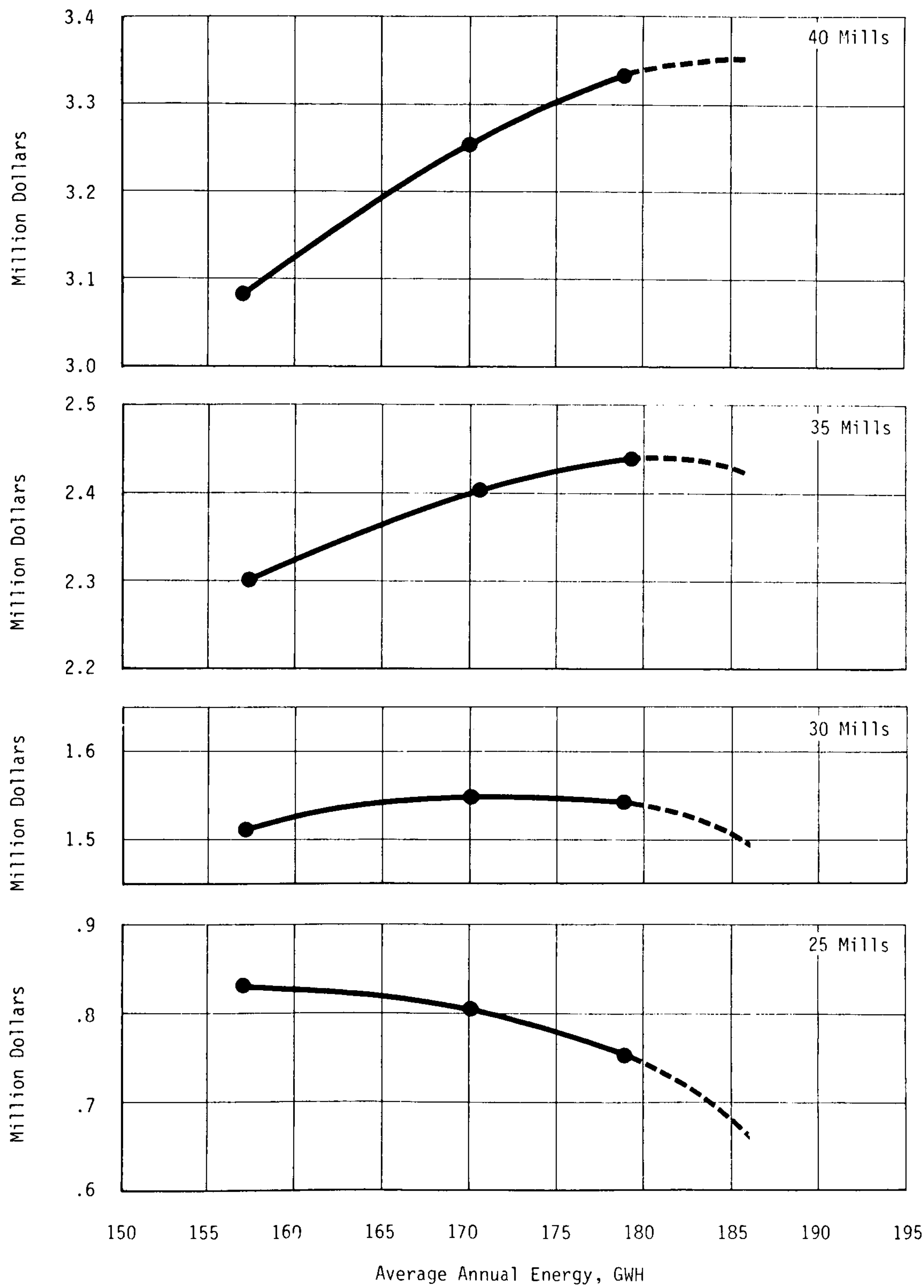


TABLE B-1

DISCHARGE - SNAKE RIVER NEAR IDAHO FALLS (in CFS)
PRESENT (1975) FLOW CONDITIONS

Water Year	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sept.	Total
1928	3,943	3,882	4,545	6,733	6,302	5,329	17,794	18,638	12,006	6,303	6,888	3,753	96,116
1929	3,234	3,533	4,729	5,001	4,256	3,342	4,096	7,456	12,537	5,291	4,969	3,728	62,171
1930	3,047	3,462	4,578	3,927	3,119	3,531	4,533	7,003	7,933	5,699	4,722	3,784	55,337
1931	2,524	4,463	4,356	3,424	3,109	3,306	3,462	5,649	5,722	6,069	4,555	3,470	50,109
1932	2,423	2,984	3,385	3,602	3,851	3,536	3,120	6,133	5,196	5,929	7,086	5,916	53,160
1933	4,103	4,285	3,926	3,317	3,973	3,501	4,004	8,843	6,228	5,674	5,579	5,955	59,387
1934	4,429	4,322	.3,330	3,008	3,377	3,571	3,369	5,618	5,321	5,371	1,945	1,403	43,064
1935	1,329	1,652	2,907	3,297	3,121	3,207	3,403	5,597	6,199	8,112	9,996	2,609	51,428
1936	2,031	1,932	3,466	3,412	3,761	3,173	3,785	12,031	5,303	5,458	7,616	4,408	56,376
1937	4,351	4,174	3,238	3,704	3,543	3,292	3,456	7,115	5,704	5,435	5,480	3,913	53,406
1938	3,707	4,233	3,303	3,421	3,379	3,705	3,878	9,018	8,133	7,044	4,945	3,507	58,273
1939	3,116	3,554	4,498	4,832	4,178	3,952	6,912	9,810	7,178	6,119	4,784	3,075	62,008
1940	3,027	4,531	3,807	3,466	3,533	3,557	4,618	6,233	5,948	5,634	5,522	3,630	53,507
1941	2,413	4,010	3,498	3,470	3,532	3,505	3,174	6,194	5,916	5,732	4,426	3,539	49,408
1942	2,718	3,036	3,283	3,659	3,873	3,360	3,333	8,037	5,745	5,738	4,413	3,005	50,201
1943	3,376	3,883	3,374	3,267	3,774	3,833	20,297	12,951	8,548	11,443	4,941	4,322	84,008
1944	3,595	4,631	5,965	5,318	5,251	3,420	4,236	7,504	10,001	5,602	4,569	3,356	63,447
1945	3,302	3,136	4,185	4,579	3,191	3,573	4,158	9,867	11,522	8,204	6,043	3,551	65,311
1946	3,610	4,452	5,927	5,207	6,068	5,957	13,216	11,737	13,275	5,744	4,676	3,385	83,254
1947	3,496	3,551	4,643	5,055	3,892	4,889	8,667	15,807	8,279	5,898	6,351	3,675	74,203
1948	3,419	3,590	4,670	5,033	4,944	3,755	5,339	16,472	15,789	5,255	4,088	3,479	76,553
1949	2,752	3,484	4,513	4,493	3,788	7,643	5,837	17,408	8,309	5,590	4,727	3,373	71,917
1950	2,679	3,493	4,461	4,614	3,608	4,683	18,165	10,786	13,187	12,168	4,923	3,621	86,390
1951	5,023	6,223	6,422	5,485	8,770	11,307	14,618	17,626	5,654	8,601	9,454	3,918	103,102
1952	3,661	4,497	6,110	6,236	6,633	5,750	14,010	19,698	13,978	5,262	4,848	3,502	94,185
1953	3,350	3,543	4,914	5,360	4,303	4,695	4,520	6,811	15,940	5,567	5,032	3,532	67,566
1954	3,024	3,401	4,592	4,277	3,915	4,011	13,348	15,247	5,514	6,976	4,978	3,454	72,738
1955	2,856	3,324	4,523	3,778	3,880	3,569	4,363	7,950	8,423	6,495	4,691	3,699	57,551
1956	2,885	3,748	4,763	4,595	7,644	10,038	17,178	17,040	13,542	5,807	7,662	4,154	99,057
1957	3,322	3,673	4,910	5,147	4,913	5,286	11,989	19,858	12,613	7,305	6,617	3,885	89,517
1958	3,339	3,433	4,753	5,179	4,650	4,092	4,188	15,524	8,625	5,419	4,892	3,494	67,588
1959	3,442	3,275	3,583	3,449	3,599	3,572	3,752	5,613	10,280	6,667	5,621	3,409	56,263
1960	2,867	3,979	4,590	3,738	3,540	3,470	4,912	6,366	6,528	6,311	8,505	5,435	60,242
1961	2,469	3,773	3,462	3,800	3,378	3,379	3,404	6,499	6,594	6,486	5,054	3,693	51,991
1962	2,018	2,964	3,449	3,812	3,732	3,483	7,016	12,480	7,347	7,591	5,006	4,166	63,064
1963	3,219	4,342	4,526	4,094	3,732	3,326	3,750	9,356	17,566	6,620	4,796	3,234	68,561
1964	4,069	3,267	3,405	3,499	3,884	3,742	6,230	15,422	15,292	7,745	6,370	3,663	76,589
1965	3,352	3,479	5,163	7,783	7,033	9,175	17,201	12,949	11,536	11,478	5,860	5,268	100,276
1966	5,178	5,959	6,502	5,752	5,481	3,746	5,679	9,865	7,090	6,108	5,243	4,195	70,797
1967	3,368	3,006	3,640	3,437	3,622	3,716	3,415	11,101	16,257	9,562	5,407	3,954	70,484
1968	3,718	3,759	5,106	6,286	4,684	4,746	5,015	8,567	15,622	6,248	4,745	3,565	72,060
1969	4,138	5,488	6,106	6,887	11,006	8,587	7,113	14,363	6,961	5,830	4,932	3,346	84,757
1970	2,895	3,794	4,974	3,806	3,854	3,845	4,656	16,393	17,740	6,727	5,216	2,723	76,623
1971	3,442	4,965	6,208	9,233	9,292	10,314	15,641	20,255	19,954	14,368	5,990	6,020	125,681
1972	6,687	7,383	7,524	10,764	10,296	14,660	13,991	15,264	14,655	6,117	5,260	4,458	117,059
Avg.	3,354	3,901	4,529	4,716	4,739	4,892	7,530	11,337	10,038	6,818	5,559	3,805	71,217
Max.	6,687	7,383	7,524	10,764	11,006	14,660	20,297	20,255	19,954	14,368	9,996	6,020	125,681
Min.	1,329	1,652	2,907	3,008	3,109	3,173	3,120	5,597	5,196	3,371	1,945	1,403	43,064

Source: Idaho Department of Water Resources.

SNAKE RIVER NEAR IDAHO FALLS
FLOW-DURATION CURVE
PRESENT (1975) FLOW CONDITIONS, MONTHLY DATA 1928-1972

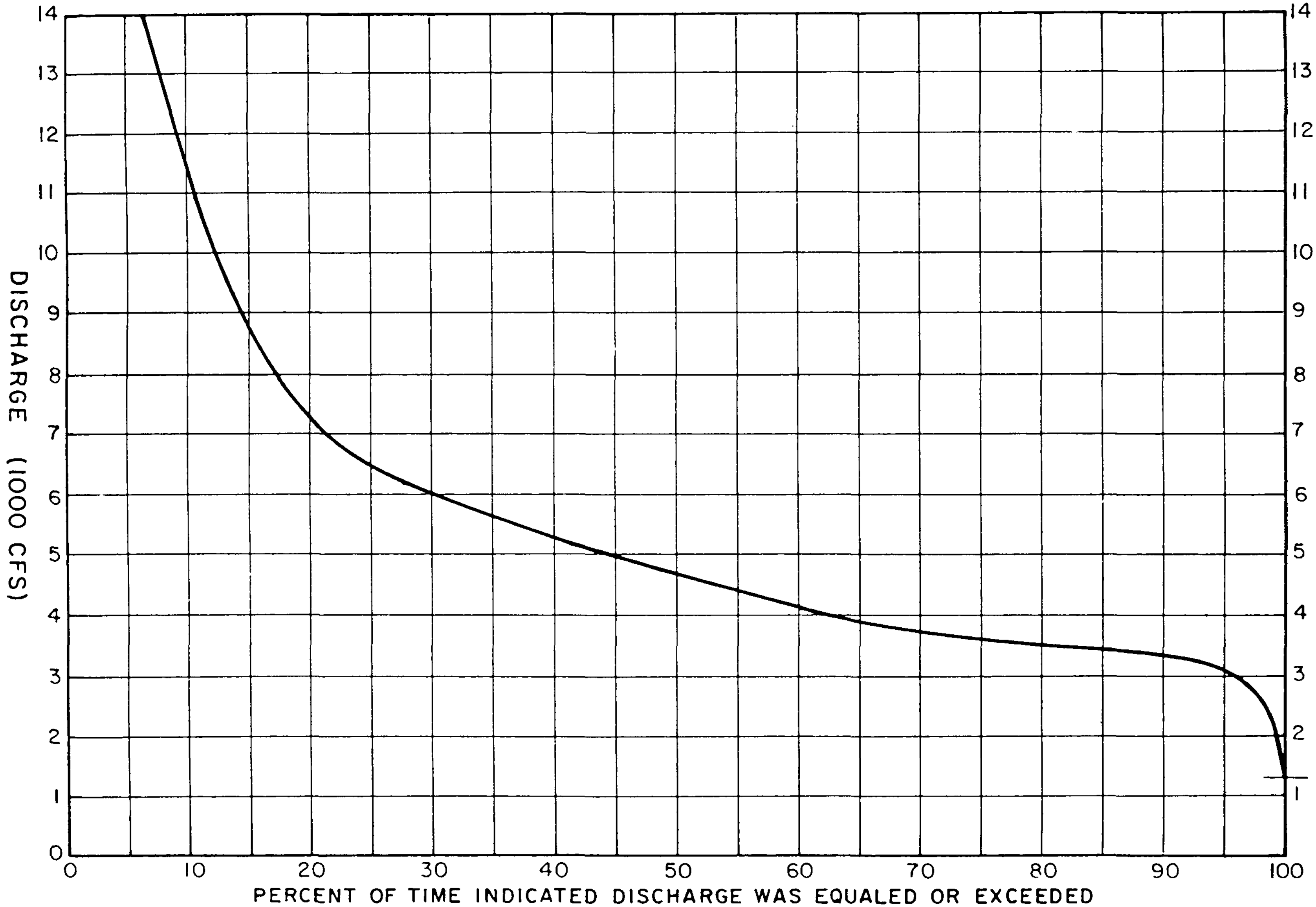
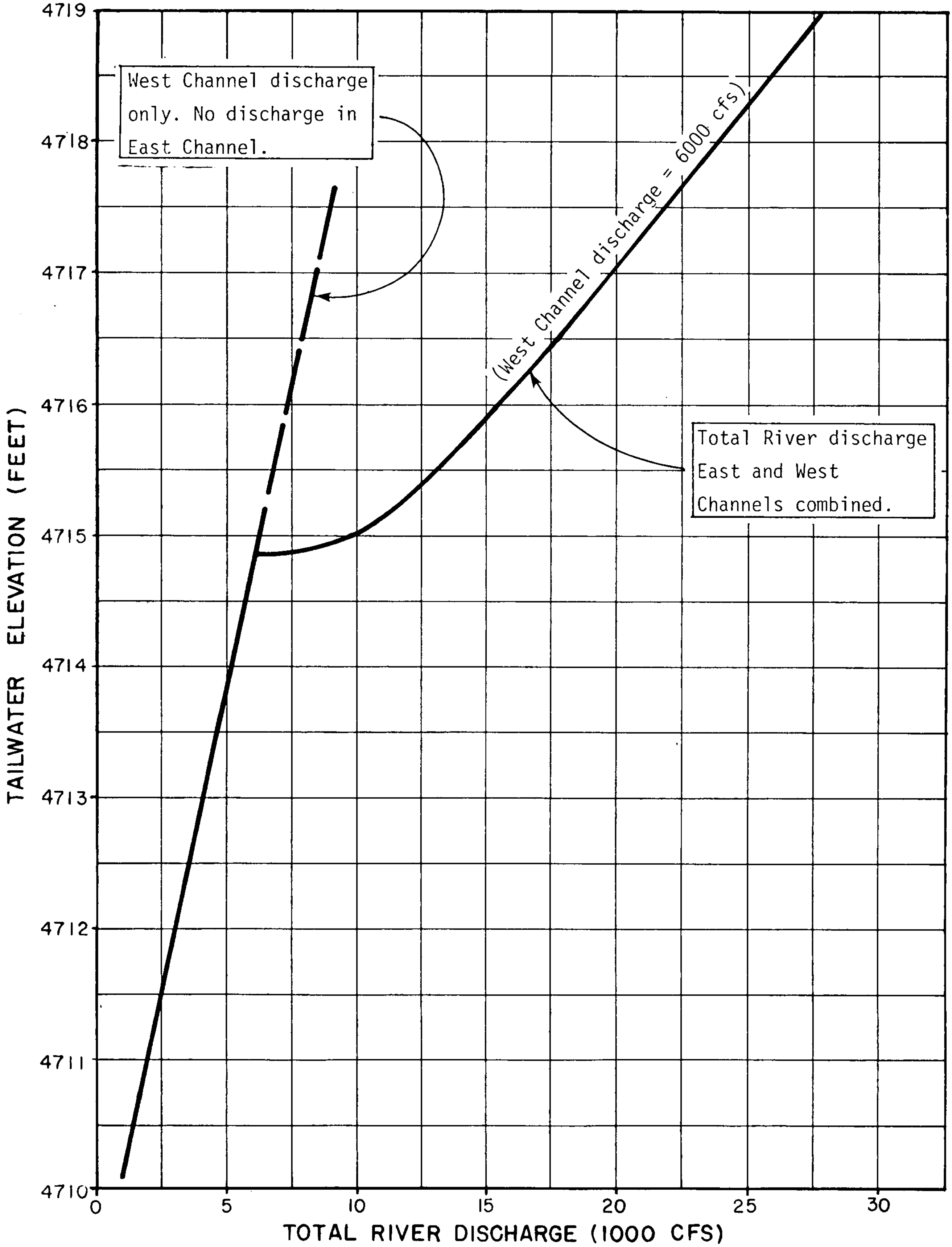
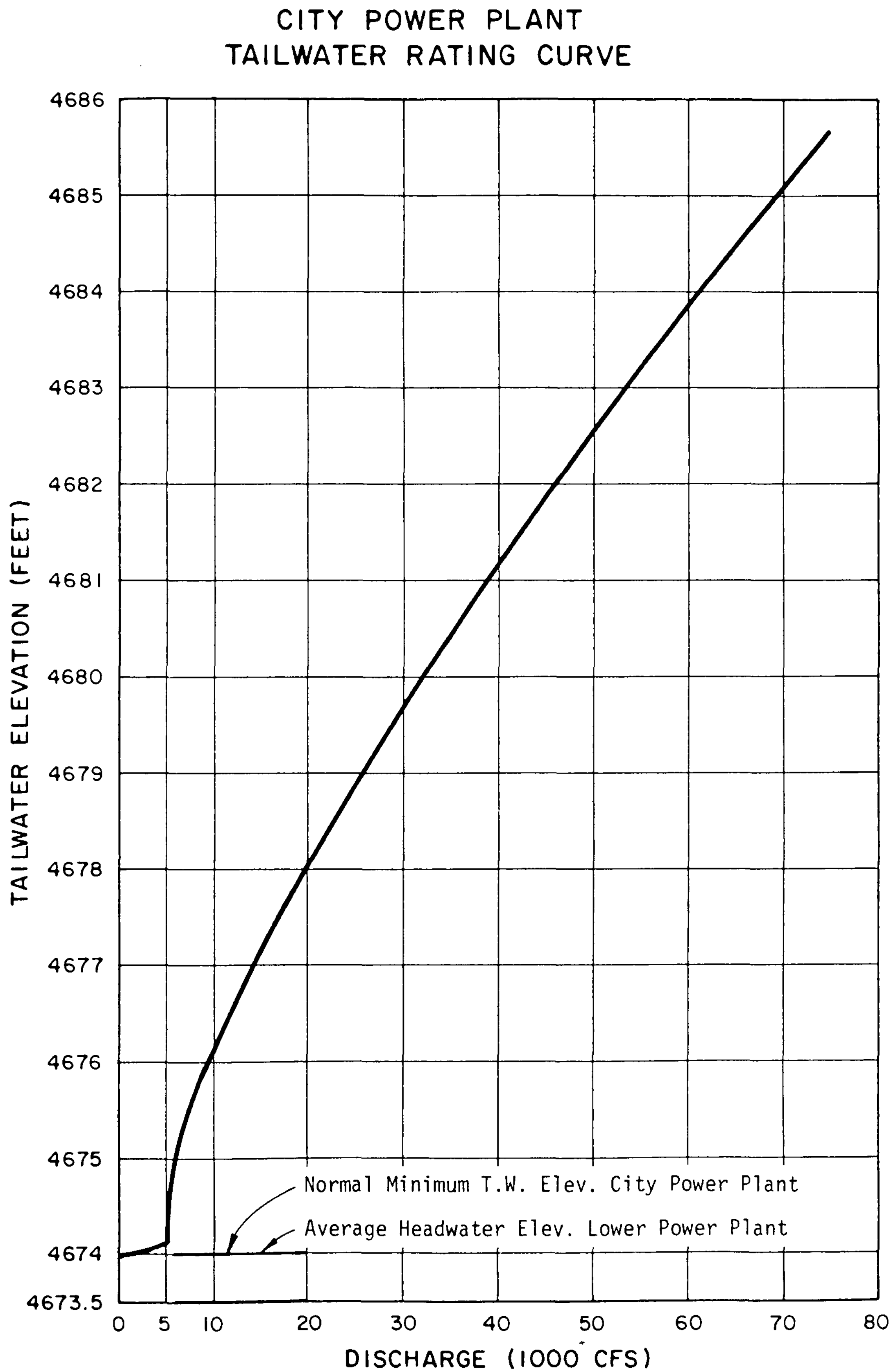


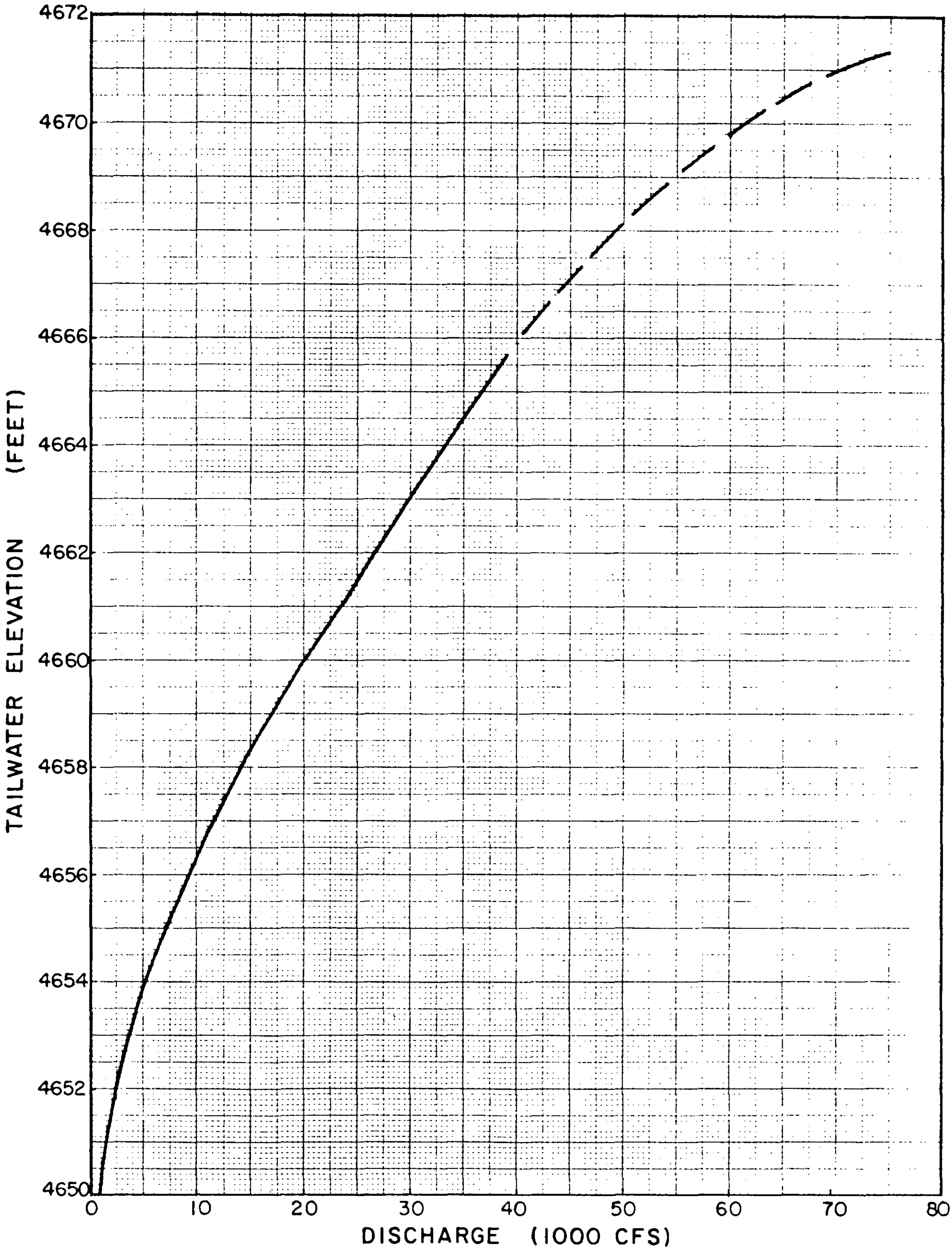
Figure B-1

UPPER POWER PLANT TAILWATER RATING CURVE

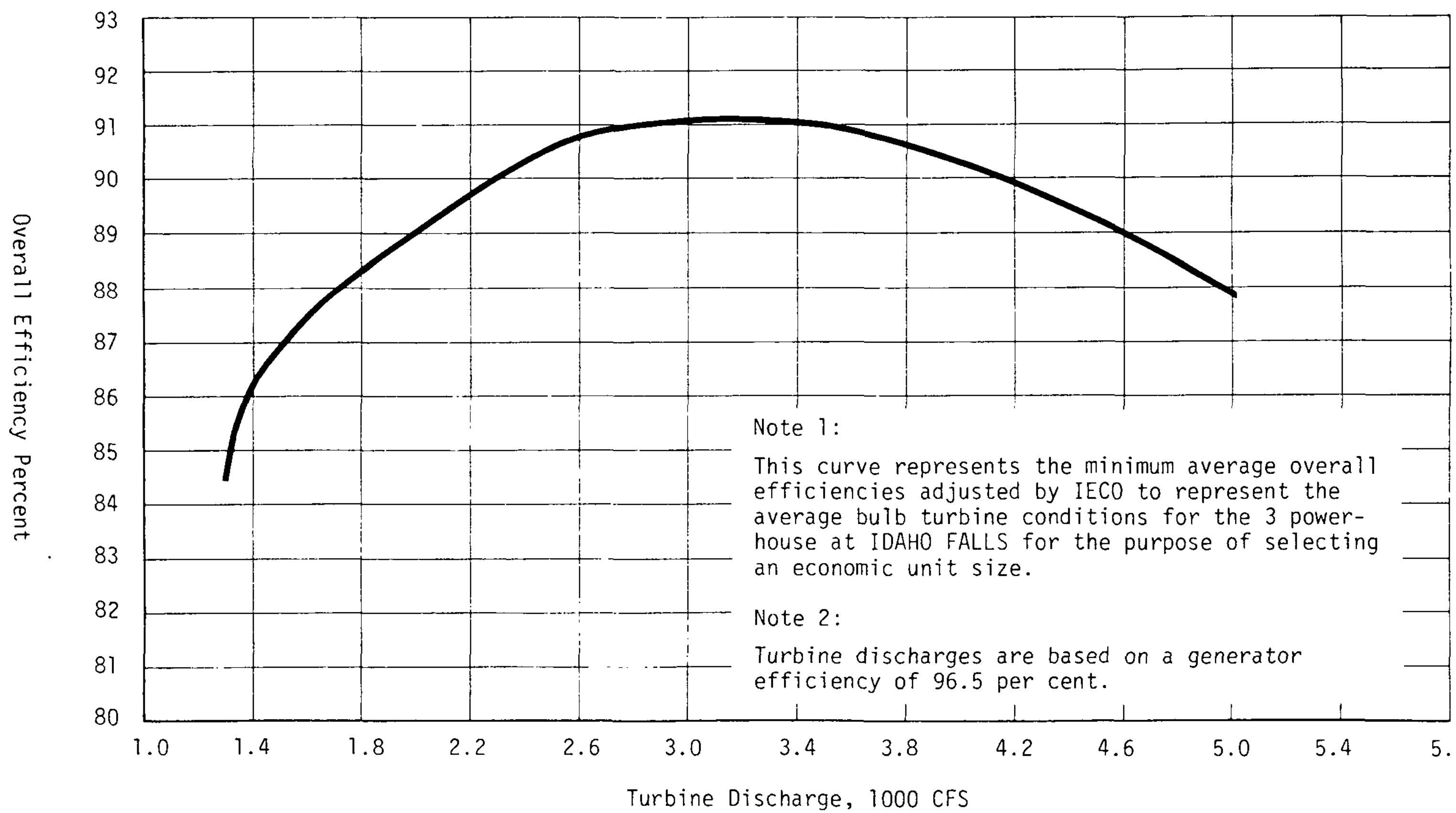



CITY POWER PLANT
TAILWATER RATING CURVE
TAILWATER ELEVATION (FEET)
4686
4685
4684
4683
4682
4681
4680
4679
4678
4677
4676
4675
4674
4673.5
0
5
10
20
30
40
50
60
70
80
DISCHARGE (1000 CFS)
Normal Minimum T.W. Elev. City Power Plant
Average Headwater Elev. Lower Power Plant

LOWER POWER PLANT
TAILWATER RATING CURVE



Overall Turbine-Generator Efficiency in Percent vs. Turbine Discharge in CFS (Head Varies) Nominal 5000 CFS Units



APPENDIX C
TURBINE-GENERATOR EFFICIENCY
Figure C-1

Overall Turbine-Generator Efficiency in Percent vs. Turbine Discharge in CFS (Head Varies) Nominal 6000 CFS Units

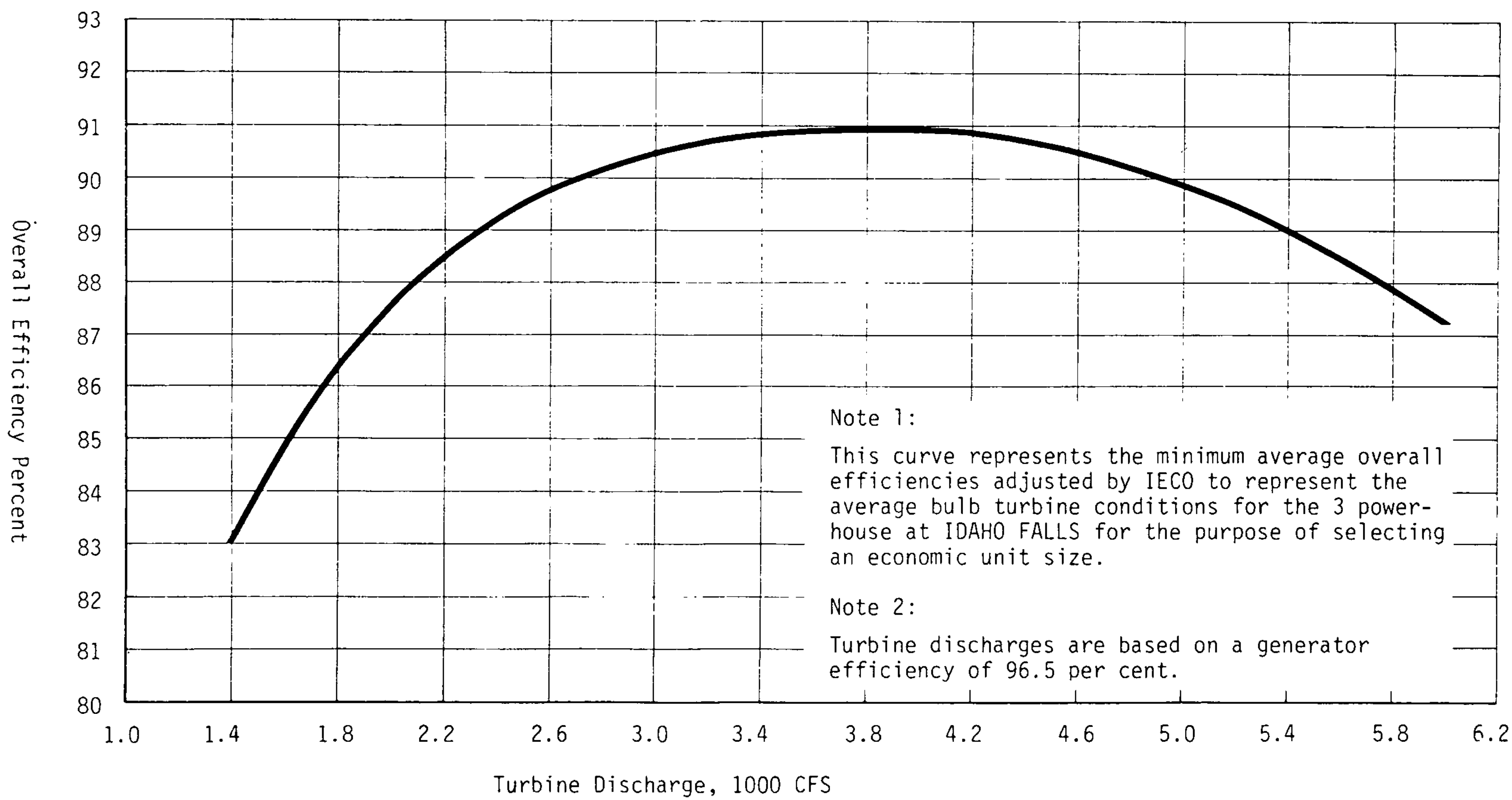


Figure C-2

Overall Turbine-Generator Efficiency in Percent vs. Turbine Discharge in CFS (Head Varies) Nominal 7000 CFS Units

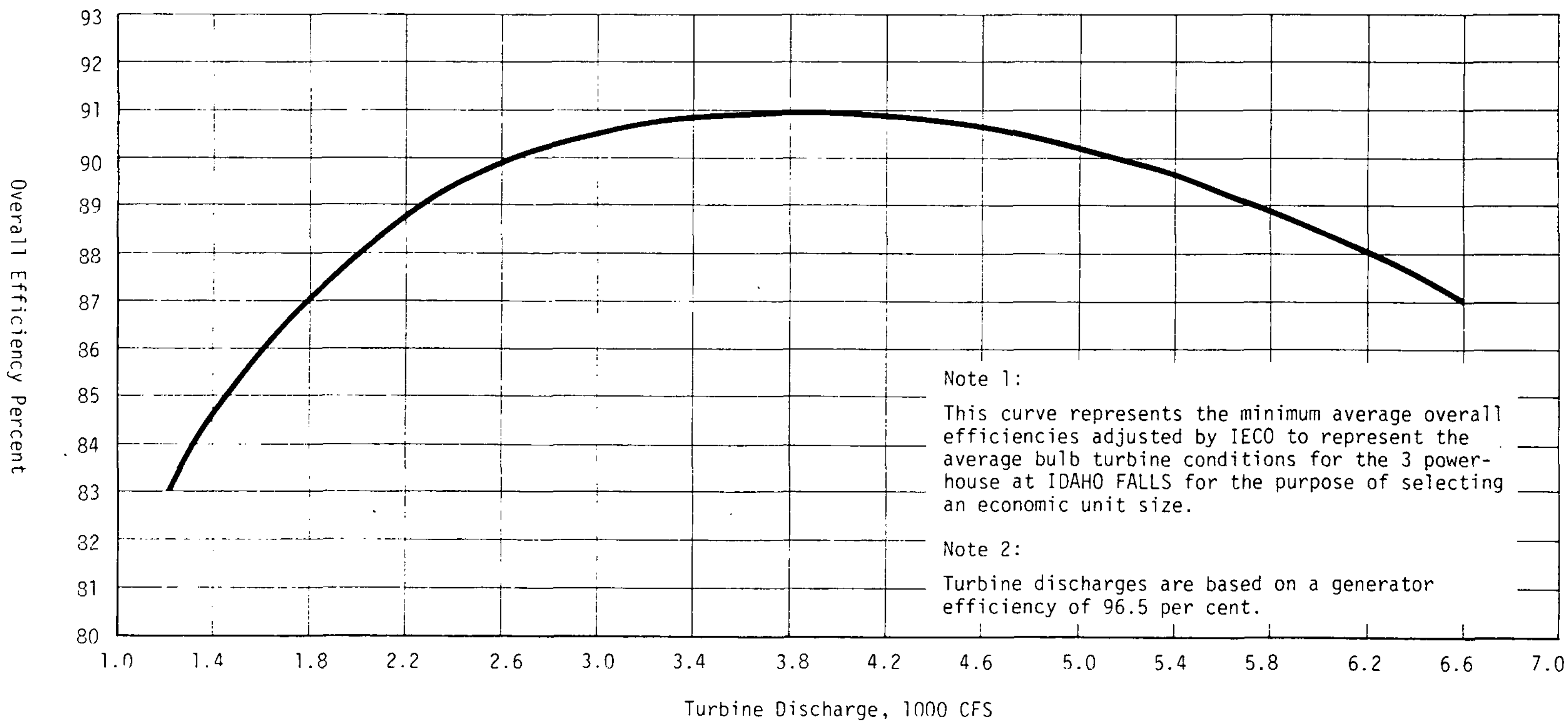


Figure C-3