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Fixed Mirror Line Focus Central Power System Cost and Performance Objectives

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FOREWORD

This report is written as a partial account of work performed for the Department of Energy, on the Advanced Central Power Project, under Letter Contract Number EY-76-C-03-1101 (PA 14).

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1.0 INTRODUCTION

The Department of Energy's (DOE) Division of Solar Energy is engaged in an effort to develop the technology for economic conversion of sunlight to electricity. DOE made an early decision to emphasize the development of point focus systems (PFS). DOE's first generation PFS plant includes a large collector field of two-axis driven heliostats providing power to a tower mounted water boiler receiver which, in turn, provides steam to a conventional nonreheat Rankine conversion system. Second generation plants would incorporate a separate primary loop which provides energy to a more efficient reheat Rankine Conversion cycle.

DOE is currently funding a study to determine if recent advances in line focus technology provide this solar concept with an economic potential comparable to the first generation Point Focus central receiver system for generation of electricity. This report was prepared in support of this effort and has the following specific objectives:

1. Determine the Fixed Mirror Solar Concentrator (FMSC) cost goals required for the system to be economically competitive with first generation PFS.
2. Determine FMSC sensitivities to equipment capital costs.
3. Identify FMSC plant physical and operational characteristics.

A simplified analytical model was developed to determine the annual electrical energy generating capabilities and the plant capacity factor while accounting for both the daily and annual variation in solar position. The PFS performance data was based on recent DOE studies, while the FMSC performance was obtained from sources at General Atomics. The performance models were combined with the standard DOE economic model to generate the annual cost of electricity in terms of mills/kw-hr.

Both the PFS and FMSC were analyzed with this model using identical performance, operational and economic groundrules. The performance and cost characteristics of both systems were determined and judgments made on their comparative merits.

2.0 ANALYTICAL PROCEDURES

This section describes the Line Focus System design, performance and cost models, and the analytical procedures used for solar electrical power plant cost-of-service calculation.

2.1 Line Focus Concept Overview

The General Atomic Company (GA) distributed collector concept is a stationary cylindrical concentrator which uses a sun tracking receiver. An artist's concept of a large collector field array is shown in Figure 1-a. A scale working module has been built for testing the design (Figure 1-b). A module contains many fixed mirror segments, each having a different surface angle. GA states in Reference 1 that the segments are positioned so that they produce a sharp line focus of the sunlight, regardless of the position of the sun. The receiver tube is continuously moved so that it always lies along the line of focus, and coolant within the tube is heated by the concentrated sunlight.

A key feature of the GA module concept is the use of a fixed concentrator which is to be permanently mounted in an east-west orientation in a shallow trough at ground level, canted 15° to the south. Contractor analyses indicate that the focal point of the mirror segments can be made to lie along the surface of the reference cylinder (Figure 1-c) for all positions of the sun. Figure 1-c is for illustrative purposes and does not show either the cant angle to the south or the angular differences in the mirror segments. Thus, a simple support mechanism pivoted at the axis of the reference cylinder can conceivably properly position the receiver as the sun moves across the sky. According to GA, this approach to the design of the support and tracking equipment may significantly reduce the construction and installation costs per module. Another feature of the system is the receiver which consists of the coolant tube held in place with straps, insulated from the rear and covered with a single glass plate. A Winston secondary concentrator is incorporated to increase the solar concentration.

The 100 MWe design would incorporate many mirrors distributed over an area greater than 1 mi^2 to produce 100 MWe of converted solar power. The net collected heat energy would be directed to a turbine-generator.

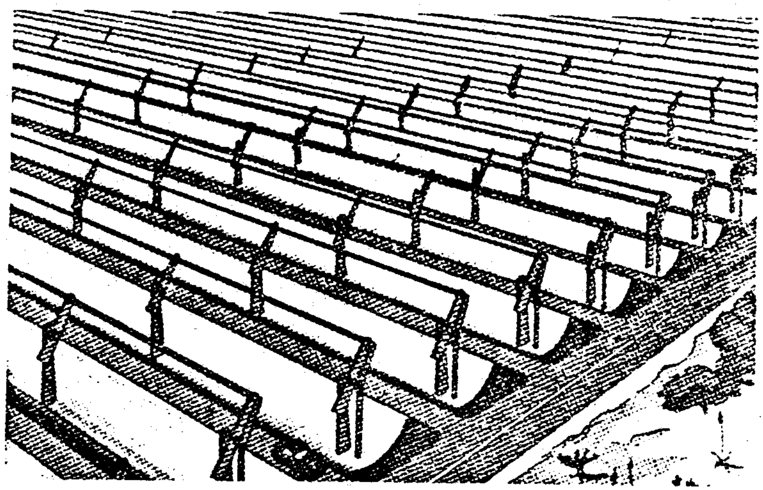


Figure 1-a. General Atomic Distributed Collector Deployment Concept

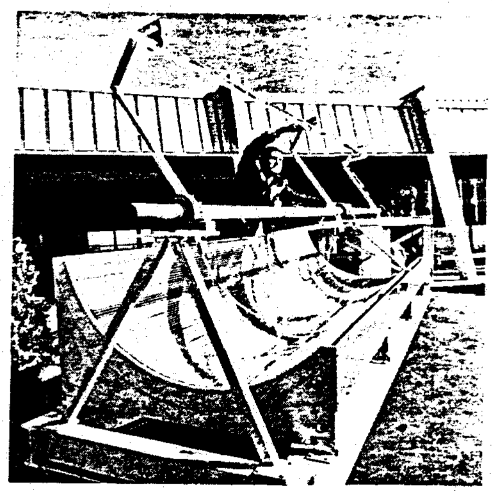


Figure 1-b. FMSC Scale Test Model

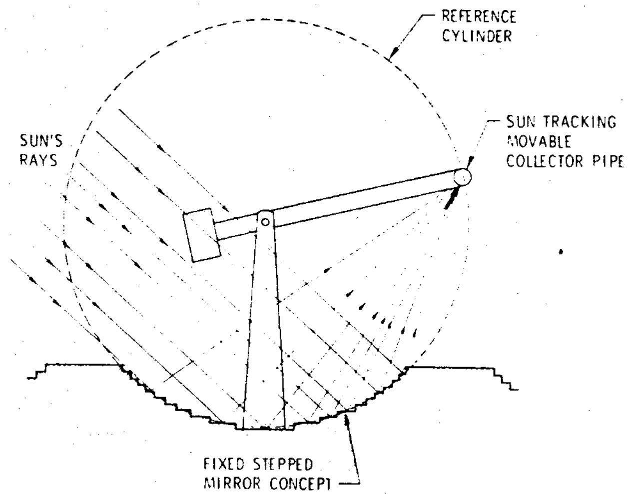


Figure 1-c. GA Distributed Collector Concept

2.2 Analytical Procedures

The analytical procedures used in this study are summarized in Figure 2. The analysis is designed to calculate the annual electrical energy generation including the effects of variation in the sun position throughout the day and the year.

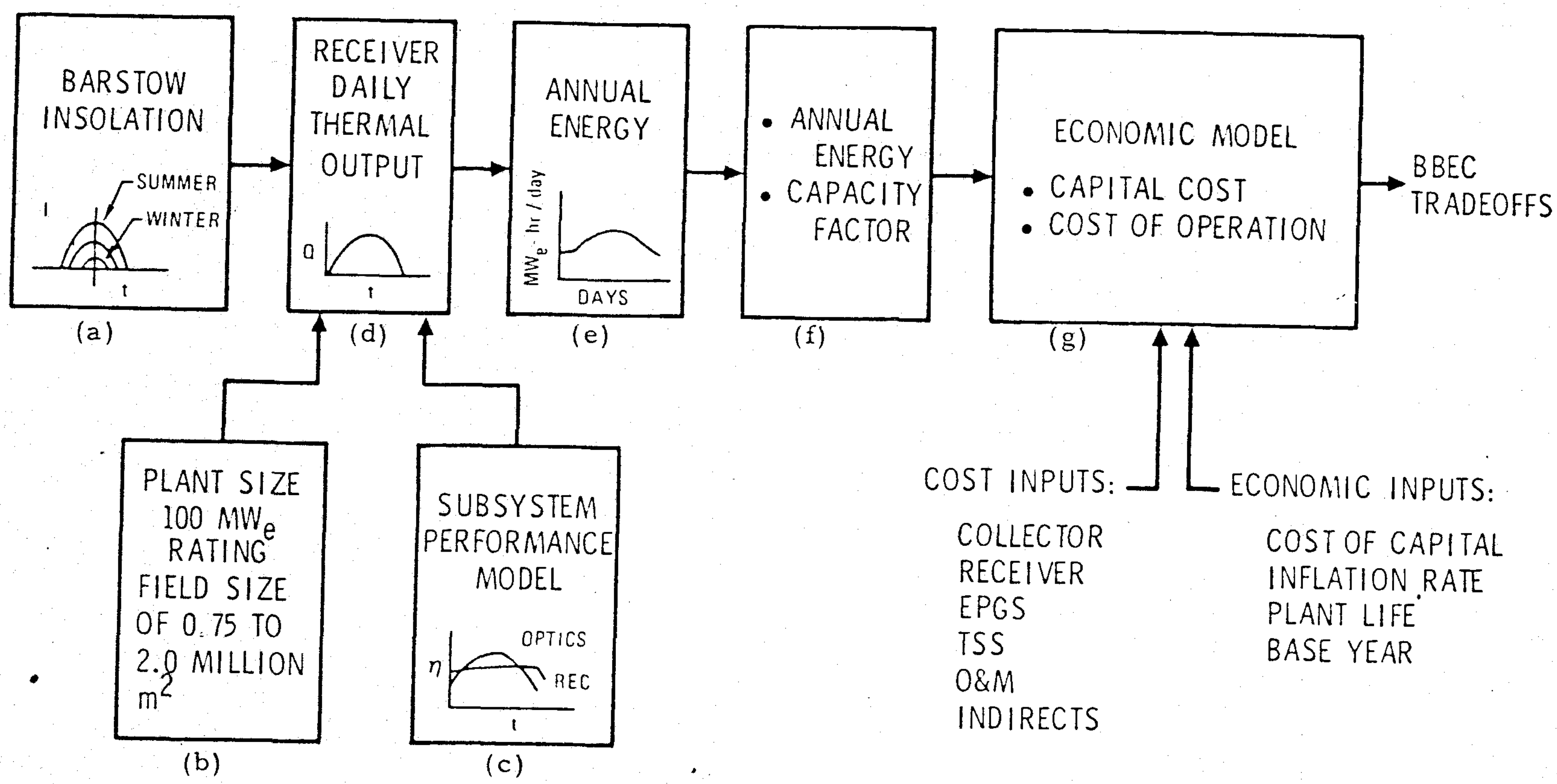
The analysis is based on clear day Barstow, California insolation data. Power generation characterizations are based on three days of the year, summer and winter solstice and spring equinox (Figure 2a). Due to the symetry of the sun position, only one-half of the year need be calculated since output characteristics would be identical for both halves. The symetry of sun positions about noon is also used to simplify daily energy calculations. The calculated energy generation for the three days are then extended to other days, in proportion to the known daily insolation levels throughout the year.

The calculation is performed for a 100 MWe rated plant in which the collector field glass area is varied from 0.75 to 2.0 million square meters (Figure 2b). Excess glass area is used to increase energy storage and therefore plant capacity. The plant subsystem performance models used to convert insolation into electrical power to the utility grid is based on the models identified in Section 2.3 and shown schematically in Figure 2a to 2e.

The analysis begins by calculating the power absorbed into steam in the receiver for three key days of the year, accounting for the collector field and receiver thermal losses (Figure 2d). The thermal energy absorbed in the steam is converted into electrical energy using the following technique: when the power absorbed by the receiver in transforming water into steam is equal to or greater than 270 MWt, corresponding to the energy required for the turbine-generator set to provide 100 MWe net to the utility grid, 270 MWt is delivered to the turbine to generate the 100 MWe; any absorbed power above 270 MWt is diverted to the Thermal Storage Subsystem for subsequent production of electrical power to the utility grid; absorbed power below 270 MWt is also used to charge the Thermal Storage Subsystems.

The electrical energy generated each day is plotted on an annual basis (Figure 2e) based on the three key days and the insolation symetry. This curve is integrated to yield the total annual energy generation and the plant capacity factor (Figure 2f). The plant capital and operating costs are based on the economic models described in Section 2-4 (Figure 2g) with the key assumptions that the indirect and operational and maintenance costs are proportional

Figure 2. Flow Diagram for Analysis



to capital costs.

The performance and cost models are then combined to yield the plant operating costs for the range of conditions of interest.

2.3 Performance Assumptions

Performance assumptions are based primarily on data available in the literature. Central receiver point focus data are based on the McDonnell Douglas final report (Reference 2). The central receiver line focus data are less defined and are based primarily on data reported by GA (Reference 1). The FMSC data will come under further scrutiny in the current 100 MWe LFS studies.

The solar insolation data were obtained from The Southern California Edison Company and processed by The Aerospace Corporation. (Reference 3 and 4). The data are based on clear-day Barstow, Ca. measurements for the best insolation day (24 June 1976, representative of summer solstice), worst solar insolation day (21 December 1976) and spring equinox (21 March 1976). See Figure 3.

2.3.1 Optical Performance

Optical performance assumptions and sources are summarized in Table 1. The line focus data were based on work by GA (Reference 6). The point focus data were based on McDonnell-Douglas results for time invariant properties, and on Aerospace work for data dependent on sun angle (Reference 5).

A comparison of point focus and line focus optical performance is shown in Figure 5. The FMSC collector modules are arranged in long east-west rows to minimize optical end losses. The east-west arrangement optimizes the optical efficiency at the spring and fall equinox due to the more promising cosine factor. The FMSC optical efficiency is superior at noon but drops rapidly in the early morning and late afternoon, while the point focus efficiency is more uniform throughout the day.

It is assumed that none of the solar energy is useful for sun elevations below 15^{o} since there is no sun tracking requirement on the collector field below that angle. It was also assumed that linear scaling of the energy collected by the collector fields as a function of the size of the heliostat glass area is valid.

TABLE 1

PERFORMANCE ASSUMPTIONS

	Point Focus		Line Focus	
	Value	Reference	Value	Reference
Collector Efficiencies				
Cosine	Variable (Fig. 4)	Reference 5	Variable (Fig. 5)	Reference 6
Reflectivity	.91	Reference 2	Variable (Fig. 5)	Reference 6
Blocking	Variable (Table 2)	Reference 5	Variable (Fig. 5)	Reference 6
Shading	Variable (Table 2)	Reference 5	Variable (Fig. 5)	Reference 6
Atm. Atten.	0.953	Reference 2		Reference 6
Rec. Intercept Factor	0.958	Reference 2	Figure 5	Reference 6
Receiver Efficiency			0.69	Reference 1
Rec. Absorption	0.95	Reference 2		
Rec. Radiation & Conv.	0.952	Reference 2		
Heat Transport				
Thermal Loss	.994	Reference 2	.95	Estimated
EPGS				
Direct				
Gross Cycle Efficiency	0.337	Reference 2	0.403	Reference 1
Parasitic Power	0.89	Reference 2	0.89	Reference 2
From Thermal Storage				
Gross Cycle Efficiency	0.268	Reference 2	.37	Reference 1
Parasitic Power	0.92	Reference 2	0.92	Reference 2

TABLE 2

ADDITIONAL HELIOSTAT FIELD VARIABLE POWER LOSS FACTORS

Day	Time		% Spillage (mirror waviness, tracking errors)	% Shading	% Blocking
21 December	Noon,		1.68	1.87	0.09
	11:00 A.M.	1:00 P.M.	1.77	2.52	0.17
	10:00 A.M.	2:00 P.M.	1.83	5.25	0.09
	9:00 A.M.	3:00 P.M.	2.10	15.05	0.06
	8:00 A.M.	4:00 P.M.	2.38	34.22	0.11
21 March	Noon,		1.71	0	0.05
	11:00 A.M.	1:00 P.M.	1.77	0.01	0.11
	10:00 A.M.	2:00 P.M.	1.77	0.04	0.09
	9:00 A.M.	3:00 P.M.	1.85	0.94	0.11
	8:00 A.M.	4:00 P.M.	1.86	6.66	0.09
	7:00 A.M.	5:00 P.M.	2.31	25.41	0.07
24 June	Noon,		1.65	0	0.01
	11:00 A.M.	1:00 P.M.	1.61	0	0.06
	10:00 A.M.	2:00 P.M.	1.71	0	0.17
	9:00 A.M.	3:00 P.M.	1.98	0.04	0.07
	8:00 A.M.	4:00 P.M.	1.91	0.81	0.08
	7:00 A.M.	5:00 P.M.	2.06	6.08	0.12
	6:00 P.M.	6:00 P.M.	2.59	23.75	0.10

2.3.2 Receiver Performance

The source of receiver efficiency data is also identified in Table 1. The FMSC efficiency is much poorer due to the high receiver tube area and the high average tube temperature. This loss is assumed uniform throughout the day.

2.3.3 Heat Transport Subsystem Performance

The heat transport losses shown in Table 1 are considered speculative at this time. The FMSC losses, however, should be substantially larger than those of the point focus systems due to the distributed nature of the multiple receivers.

2.3.4 Electrical Power Generation System (EPGS) Performance

The steam cycle used with the point focus design is a non-reheat unit. The GA unit features a high pressure reheat cycle. The performance of the non-reheat cycle is based on the steam conditions (temperature/pressure) used by MDAC in their preliminary design report (Reference 2) while the reheat cycle data is based on Reference 1. The EPGS efficiencies noted in Table 1 are based on the following conditions:

Point Focus System

(a) Rated receiver steam (950°F and 1465 psia) at the turbine stop valve.
   1. feedwater inlet conditions - 2600 psia, 425°F and enthalpy of 405 BTU/lb.
   2. receiver exit conditions - 1465 psia, 950°F, and an enthalpy of 1461 BTU/lb.
   3. steam flow rate - 960,415 lb/hr.

(b) Thermal storage steam.
   1. feedwater inlet conditions - 2600 psia, 250°F, and enthalpy of 219 BTU/lb.
   2. steam generator exit conditions at the turbine admission port--385 psia, 525°F, and enthalpy of 1263 BTU/lb.
   3. steam flow rate - 905,593 lb/hr.
   4. generator output - 76.1 MWe

Figure 3: DIRECT SOLAR INSOLATION

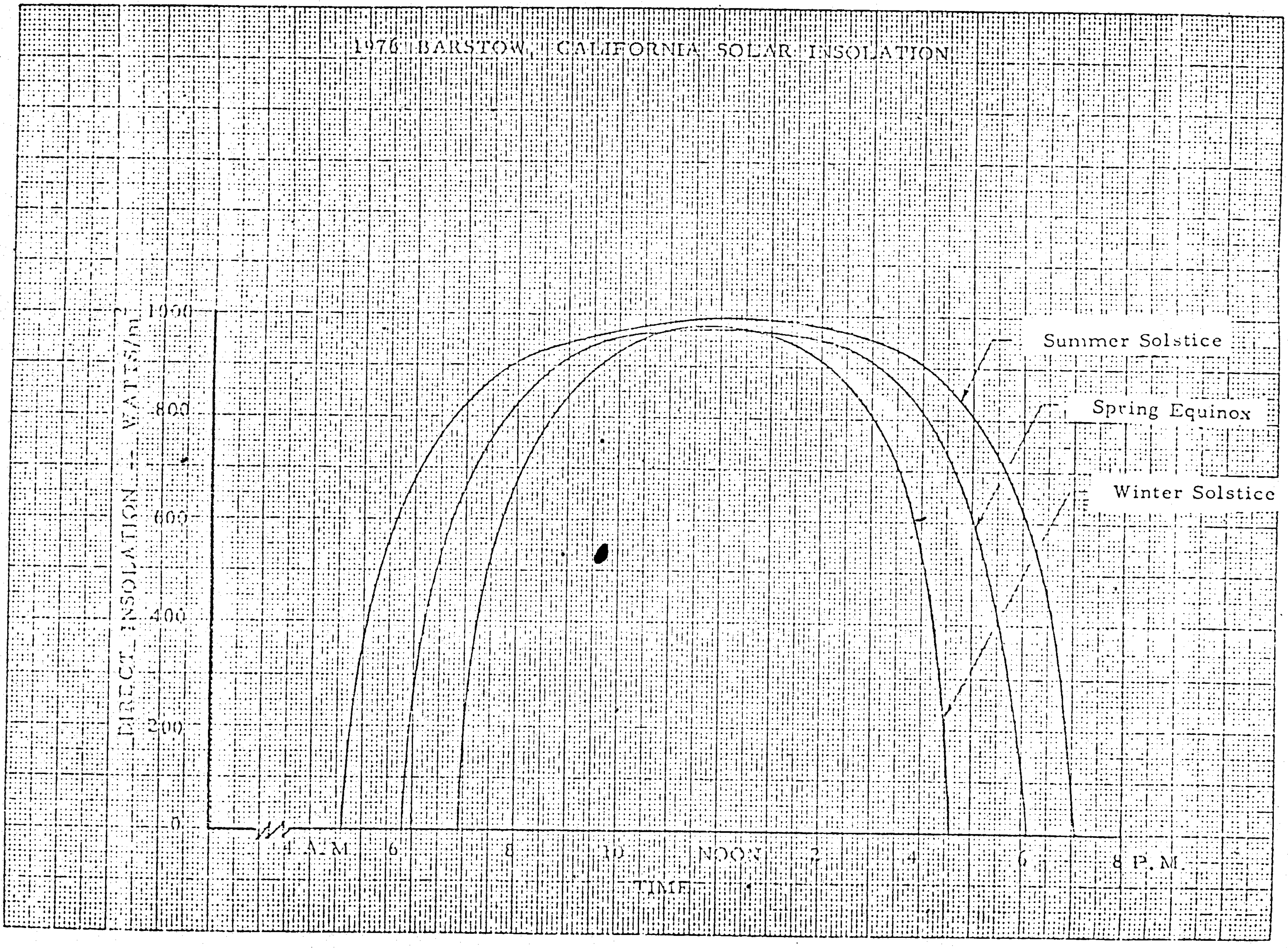


Figure 4.

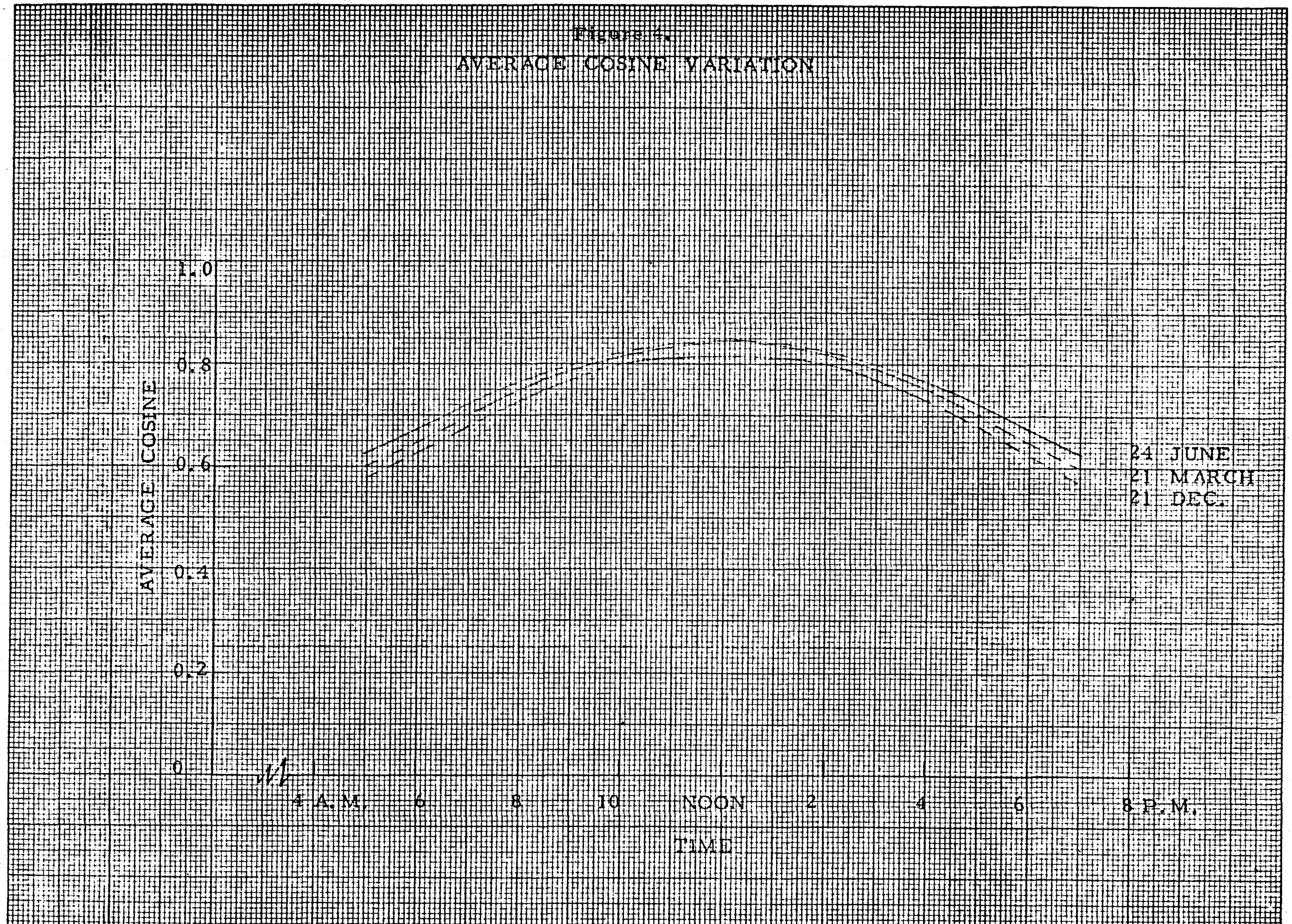
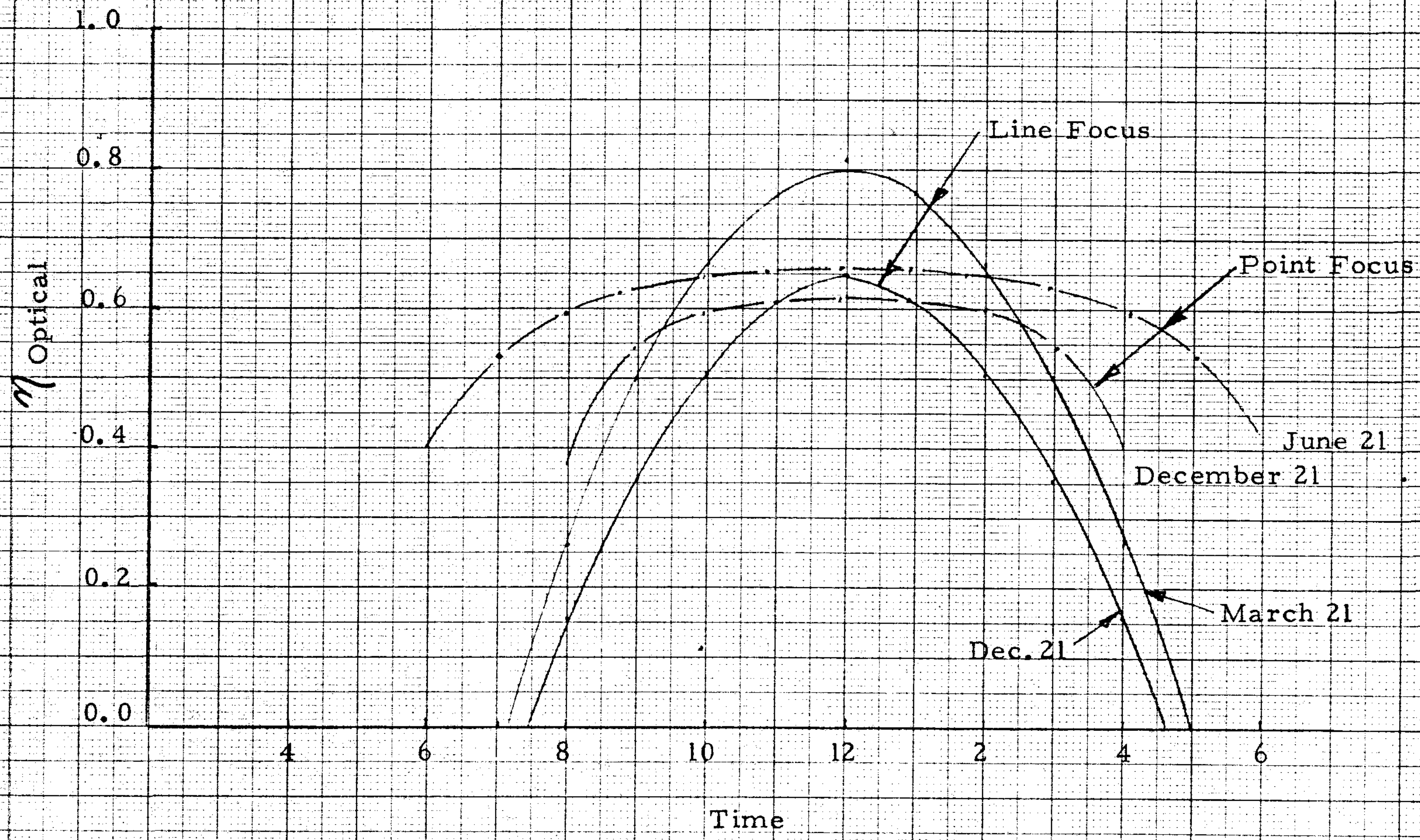

AVERAGE COSINE VARIATION
AVERAGE COSINE
1.0
0.8
0.6
0.4
0.2
0
4 A.M.
6
8
10
NOON
2
4
6
8 P.M.
TIME
24 JUNE
21 MARCH
21 DEC.

Figure 5. Comparison of Collector Field Optical Efficiency

Efficiency Includes:
Shading & Blocking
Cosine
Reflectivity
Atmospheric Attenuation
Receiver Intercept Factor
End Losses



FMSC System

(a) Rated steam (900°F and 2000 psia) at the turbine stop valve.
   1. Superheater exit conditions -2020 psia, 902°F.
   2. Reheater exit conditions -550 psia, 950°F
   3. Steam flow rate - 860,000 lb/hr.

(b) Thermal storage steam
   1. Superheater exit conditions - 2000 psia, 900°F
   2. Reheater exit conditions - 550 psia, 950°F
   3. Steam flow rate - 92,900 lb/hr

2.3.5 Thermal Storage Subsystem (TSS) Performance

Point Focus System

The TSS performance assumptions are summarized below:

(a) thermal storage media - Caloria HT-43 + rock
(b) storage conditions - 232° to 316°F
    (450° to 600°F)
    charge: 950°F/1450 psig (480°F condensate out)
    discharge: 525°F/385 psia (250°F feedwater in)
(c) warm turbine startup (daily) requires 100 MWt-hr. extraction from TSS
(d) turbine seal steam (daily) requires 5.04 MWt-hr. extraction from TSS.
(e) thermal storage subsystem daily convection energy losses equal 2% of maximum TSS capacity.

FMSC System

(a) thermal storage media - Draw salt + rock
(b) storage conditions - 550°F to 1014°F
    charge: 1014°F/draw salt
    discharge: 1010°F/draw salt
(c) warm turbine startup (daily) requires 120 MWt-hr extraction from TSS
(d) turbine seal steam requires (daily) 6.0 MWt-hr. extraction from turbine
(e) thermal storage subsystem daily corrective energy losses equal to 2% of maximum TSS capacity.

The capacity of the Thermal Storage Subsystem is a free parameter, and the assumption is made that any receiver steam bypassing the turbine can be accommodated by the Thermal Storage Subsystem at any charging rate. The physical sizes (and, hence, cost of equipment, such as charging heat exchangers, steam generators, pumps, piping, and Thermal Storage Unit - Caloria Storage Tank), are expected to be affected by this assumption, but it should not lead to insurmountable design problems.

2.3.6 Performance Assumptions Summary

All of the estimates used in this analysis should be considered approximate, even though they are based on the latest available information. Also, effects caused by detailed component characteristics (such as startup/shutdown limitations and turndown ratios) on the operating modes used in this analysis were ignored. The data will be updated by the FMSC integrating contractor in the design definition phase of the program.

2.4 Solar Power Plant Economic Model

The following procedures and cost data are used to generate capital cost and operating costs for both the line and point focus power plant concepts.

2.4.1 Baseline Capital Costs

Table 3 displays the capital costs for all the subsystems of the point focus and line focus plants for both the first plant and the 80th plant. The cost groundrules are identified in the Table and are applied equally for both plants.

The line focus collector/receiver/heattransport costs are varied parametrically to determine the operating cost sensitivity to this key variable. Of special note for this analysis is that both the indirect costs identified in Table 3 and the operations and maintenance costs are assumed proportional to capital cost.

TABLE 3

BASELINE CAPITAL COSTS

Item	Capital Costs $/kwe			
	Strawman Point Focus		Line Focus Plant	
	1st Plant	80th Plant	1st Plant	80th Plant
Land, Yardwork [2]	5.	6.	Variable [2]	Variable [10]
Structures & Improvements	51.	39. [3]	51	39 [3]
Turbine Plant	242.	187. [3]	290	224 [3]
Electric Plant	88.	68. [3]	88	68 [3]
Collectors	695. [4]	504. [3]	Variable	Variable [3]
Receiver	185.	108. [5]	Variable	Variable [3]
Tower	124.	124.	N/A	N/A
Thermal Storage	215.	156. [3]	Variable	Variable [11]
Distributables [9]	86.	36. [6]	86	36 [16]
BOP	53.	38. [3]	53	38 [3]
Direct Cost	1744.	1262.	TBD	TBD
Indirect Cost [8]	348. [7]	136. [6]	TBD [7]	TBD [6]
Total	2092.	1398.	TBD	TBD

(1) Taken from Reference 5, increased by 6% from 1977 dollars. Costs include burden, contingency and fee.

(2) Based on 900 acres @ $500/acre.

(3) 0.95 Learning curve.

(4) Based on $\$80/m^2$

(5) 0.90 Learning Curve

(6) 69% Reduction from 1 unit due to larger cost base for 80 units, Reference 5, p. 169.

(7) 20% of Direct Costs.

(8) Indirect Costs include A&E services, construction management, solar integrator, and plant startup.

(9) Distributables include contractor field office, insurance (project and equipment) construction equipment, spares, taxes.

(10) 20% cost growth from 1978 dollars.

(11) Set equal to 80th plant Point Focus specific costs of $9.28/kwt-hr.

2.4.2 Cost of Service Calculation

The cost of service calculation determines the specific cost of electricity (mills/kw-hr) using normal private utility estimating procedures. The following are data input for the cost of service calculation:

1. Planning Factors

   Plant = 80th unit

   System Lifetime, (N) = 30 years

   First Year of Operations (y_{co}) = 1990

   Site = Barstow, Ca.

   Type of Ownership = Investor Owned

2. Operation and Maintenance Cost

   Assume Operations and Maintenance (X_o) = 1% of CI_t

3. Utility Descriptive Data

   Annual "Other Taxes" as a fraction of CI_{pv}, (β_1) - 0.02

   Annual insurance premiums as a fraction of CI_{pv}, (β_2) = 0.0025

   Income tax rate, (τ_1) = 0.50

   Ratio of debt to total capitalization, (D/V) = 0.55

   Ratio of common stock to total capitalization, (C/V) = 0.27

   Ratio of preferred stock to total capitalization (P/V) = 0.18

   Debt interest rate, (k_d) = 0.09

   Annual rate of return on common stock, (k_c) = 0.15

   Annual rate of return on preferred stock, (k_p) = 0.11

   Investment tax credit, (α) = 0.10

   Depreciation ($DPF_{m,k,n}$) = Straight Line ($DPF_{SL_{k,n}}$)

4. General Economic Conditions

   Rate of general inflation, (g) -0.050

   Escalation plus inflation rate for capital costs, (g_c) - 0.65

   Escalation plus inflation rate for operating costs, (g_o) - 0.065

   Escalation plus inflation rate for maintenance cost, (g_m) - 0.065

   Base year for constant dollars, (y_b) - 1978

The following equations are used for the cost of service calculation for all the power systems. The analysis is based on a JPL model and is the current standard for the DOE/SAN funded solar thermal central power system cost of energy calculation. (Reference 7). All values are in 1978 dollars.

Cost of Capital (k)

$$k = (1 - \tau)\, k_d \frac{D}{V} + k_c \frac{C}{V} = k_p \frac{P}{V}$$

Capital Recovery Factor ($CRF_{k,N}$)

$$CRF_{k,N} = \frac{k}{1 - (1+k)^{-N}}$$

Annualized Fixed Charge Rate ($\overline{FCR}$)

$$\overline{FCR} = CRF_{k,N} \left(\frac{1 - (\tau)(n\;\; CRF_{k,N})^{-1} - a}{1 - \tau} \right) + \beta_1 + \beta_2$$

Present Value of Capital Investment (CI_{pv})

$$CI_{pv} = (1+g_c)^{y_{co} - y_p} \sum_t CI_t \left(\frac{1 + g_c}{1 + k} \right) y_t - y_{co} + 1$$

Present Value of Recurrent Costs (X_{pv})

$$X_{pv} = (1+g_x)^{y_{co} - y_p} (X_o) \left(\frac{1+g_x}{k - g_x} \right) \left[1 - \left(\frac{1+g_x}{1+k} \right)^N \right]$$

Annualized System - Resultant Cost ($\overline{AC}$)

$$\overline{AC} = (1+g)^{-y_{co} + y_b} \left[\overline{(FCR)}(CI_{pv}) + (CRF_{k,N})(X_{pv}) \right]$$

Levelized Bus Bar Energy Cost ($\overline{BBEC}$)

$$\overline{BBEC} = \frac{AC}{MW_e h} = \frac{AC}{(MW_e)(PCF)(8760)}$$

3.0 ANALYTICAL RESULTS

This section details the analytical techniques and results used in the process of developing the LFS plant performance. comparison to point focus plants.

3.1 Power Absorbed into Steam

The analysis begins by applying the collector field and receiver loss factors identified in Section 2 to the Barstow, California measured insolation data to determine the steam thermal power rate of the receiver. The plant rating was fixed at 100 MWe, but the collector field glass area was varied parametrically from a range of 0.75 to 2.0 million square meters. The significant power loss factors for both the collectors and the receiver were varied with the time of day.

Figure 6a-e show the power absorbed into steam in the receiver for the 100 MWe point focus system after accounting for the aforementioned losses for the summer solstice (June 24), Equinox (March 21) and winter solstice (December 21) days. The shaded area in the curves of Figure 6 correspond to the unused solar insolation for sun elevations less than 15% above the horizon. Figure 7a-e show the similar data for the line focus system using GA performance representative data.

Figure 8 shows the comparative absorbed power for the two concepts for equal glass area. The point focus power level is flatter due to its uniform efficiency throughout the day. The line focus system power peaks around the noon characteristic high collector efficiency and high insolation point. This high peak power level will lead to higher TSS and Receiver ratings requirements for the FMSC systems. On a full day basis, June 21, the point focus system can produce 242% more thermal energy per glass area than the FMSC and on December 21 the point focus plant outproduces the LFS by 50%. Even on its best days, the spring/fall equinox, the point focus plant outproduces the FMSC by 40%.

3.2 Daily Electrical Output

Figures 9a-e show the daily electrical power generating capability for the two conceptual plants, for each of the candidate field sizes, under the groundrules previously discussed. The FMSC system generates peak near the

Figure 6a. Net Power Absorbed into Steam
Point Focus Plant of $0.75 \times 10^6 M^2$ Collector Area
(Barstow Insolation Data)

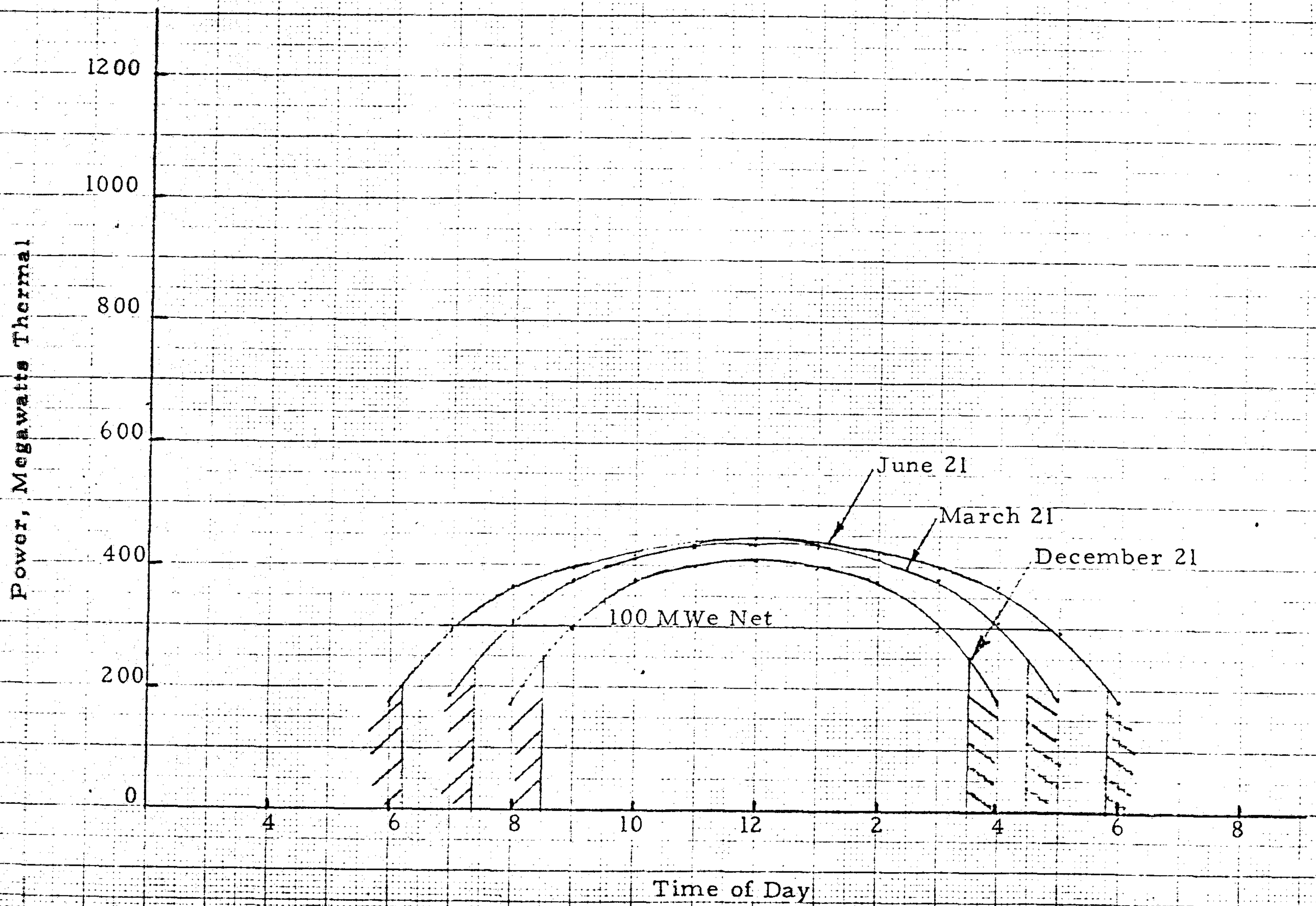


Figure 6b. Net Power Absorbed into Steam
Point Focus Plant of $0.87 \times 10^6 M^2$ Collector Area
(Barstow Insolation Data)

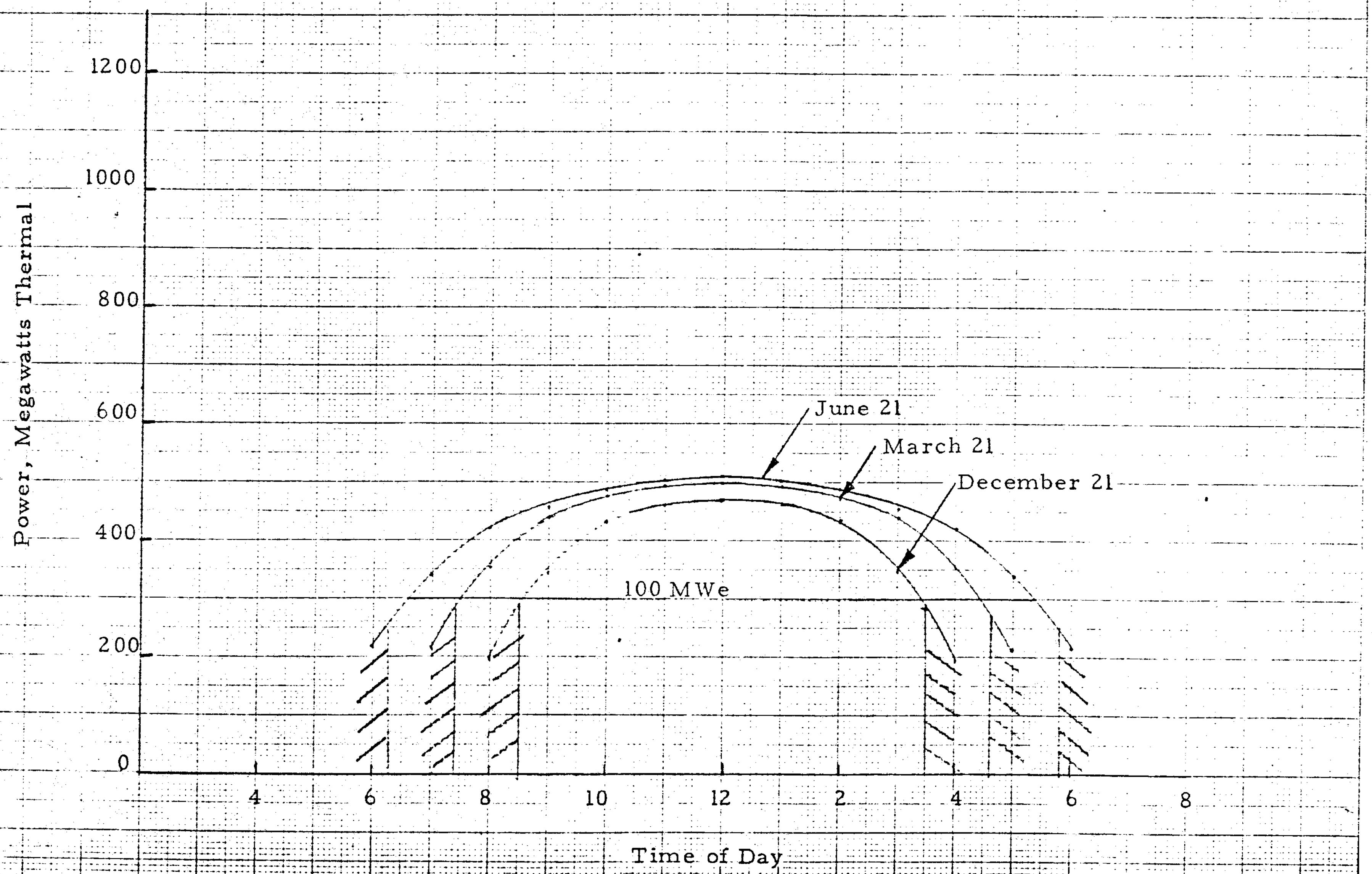


Figure 6c. Net Power Absorbed into Steam
Point Focus Plant of 1.0 x 10^6 M^2 Collector Area
(Barstow Insolation Data)

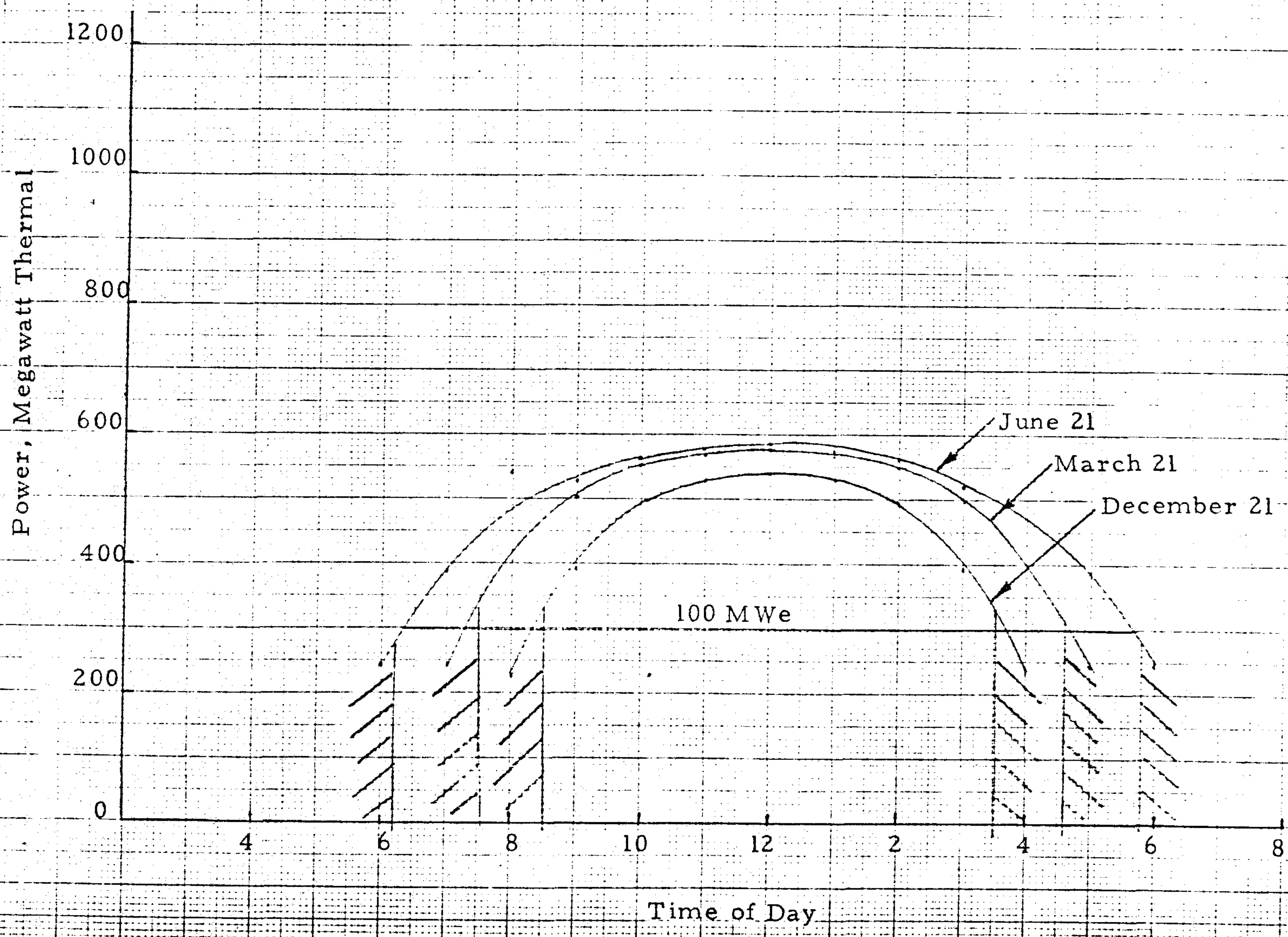


Figure 6d. Net Absorbed Power into Steam
Point Focus Plant of $1.5 \times 10^6 M^2$ Collector Area
(Barstow Insolation Data)

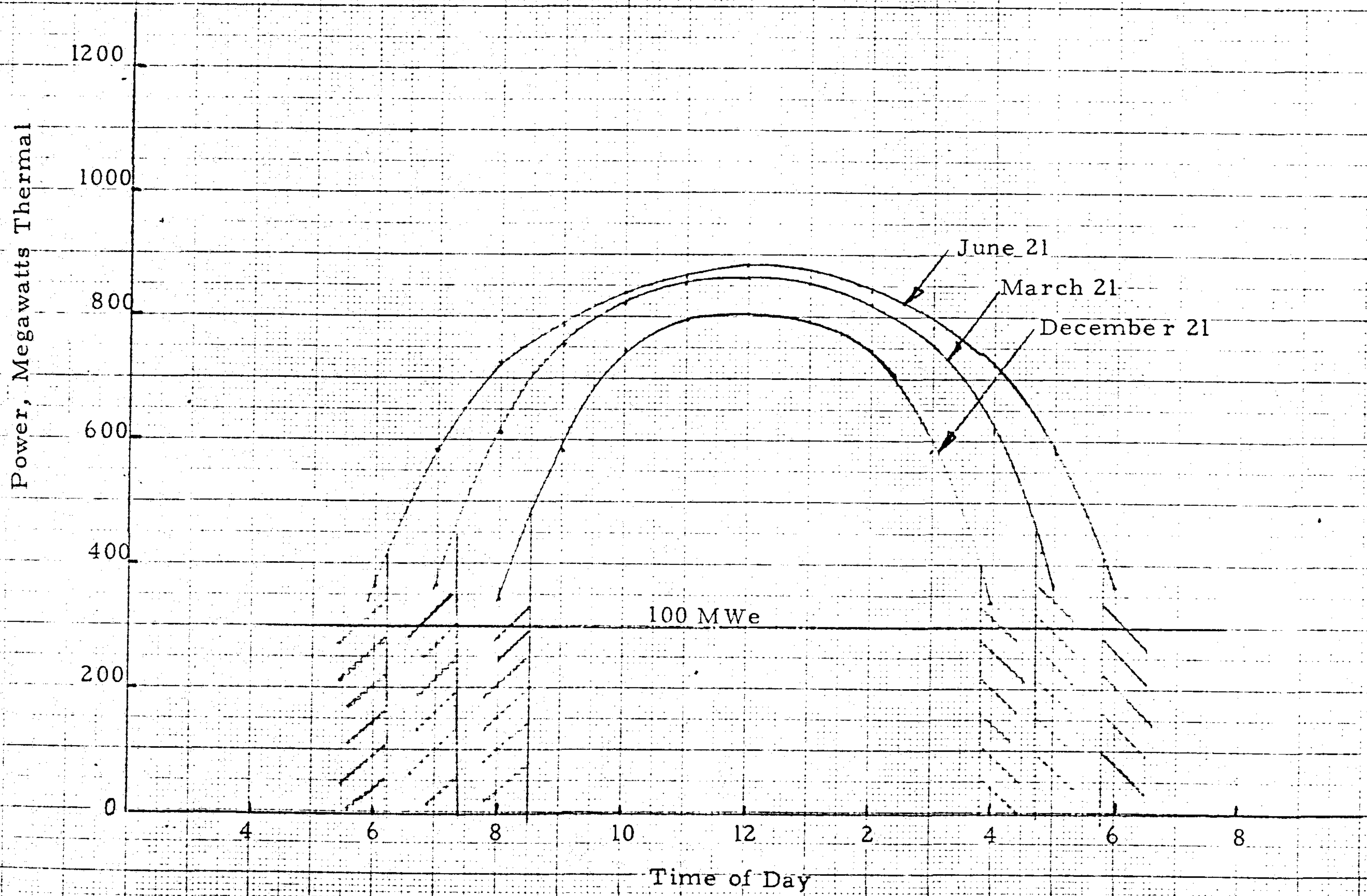


Figure 6e. Net Absorbed Power into Steam
Point Focus Plant of $2.0 \times 10^6 M^2$ Collector Area
(Barstow Insolation Data)

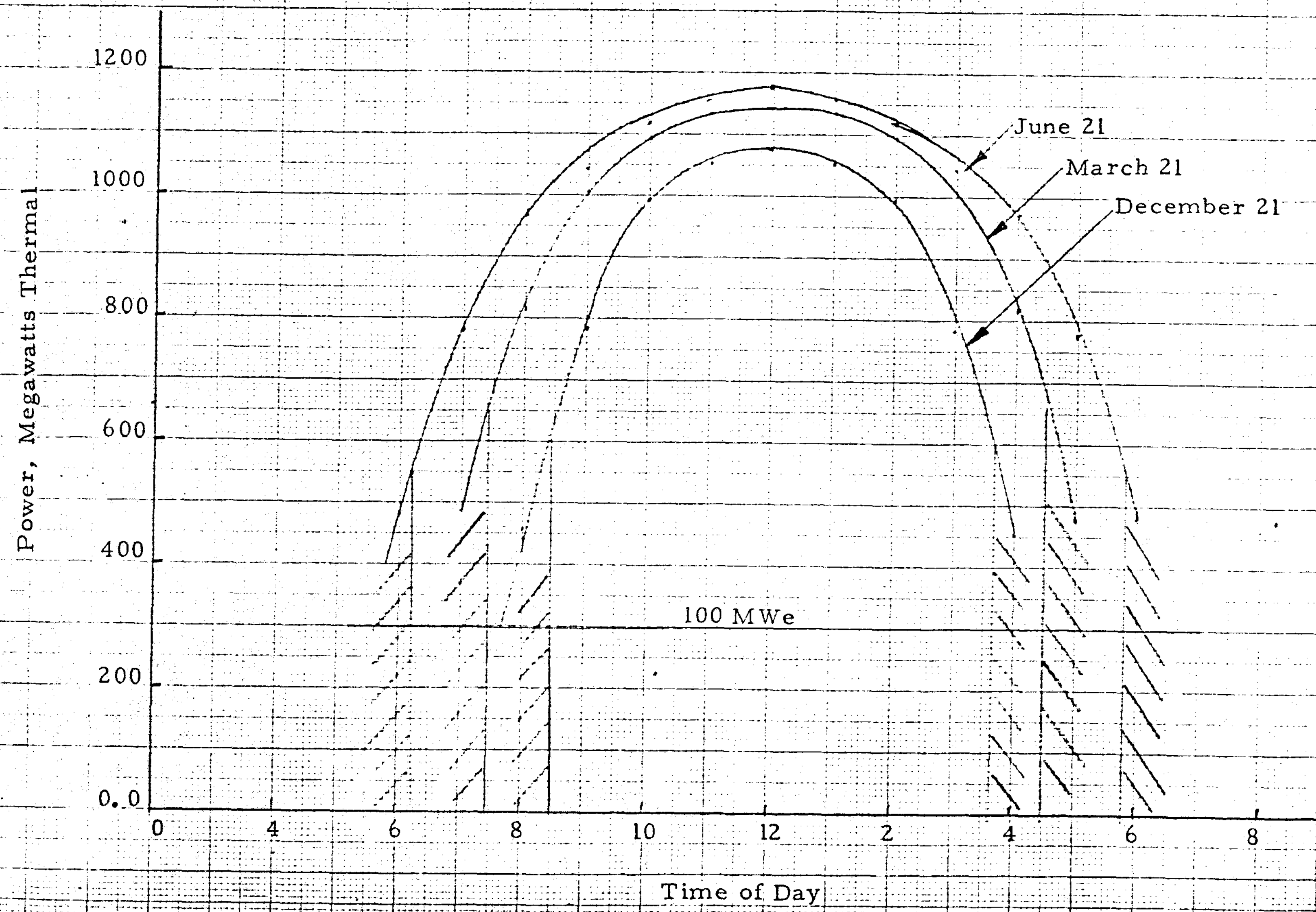


Figure 7a. Net Power Absorbed into Steam
Line Focus Plant of 0.75 x 10^6 M^2 Collector Area
GA Data Base
Barstow Insolation Data

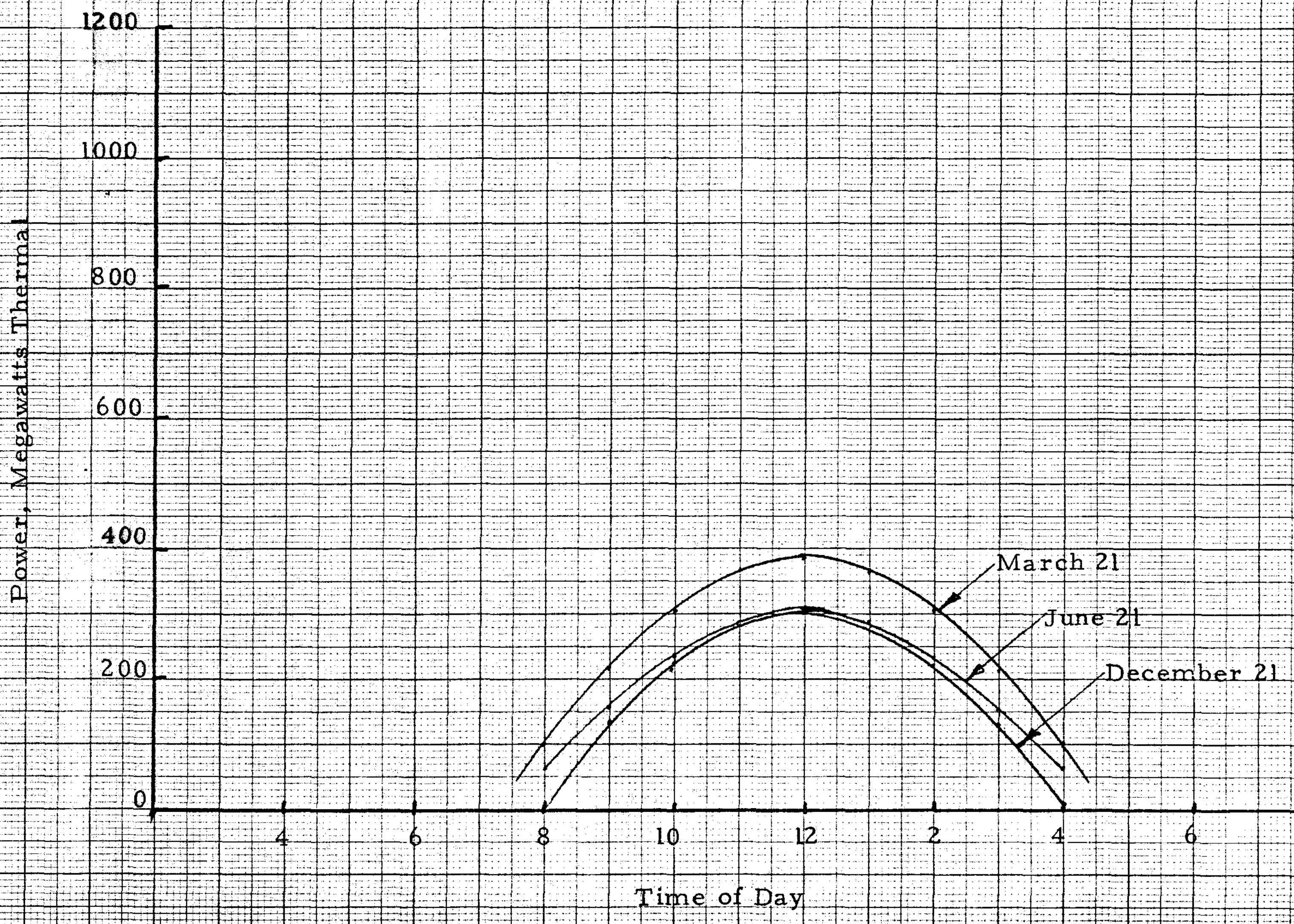


Figure 7b. Net Power Absorbed into Steam
Line Focus Plant of $0.87 \times 10^6 M^2$ Collector Area
GA Data Base
Barstow Insolation Data

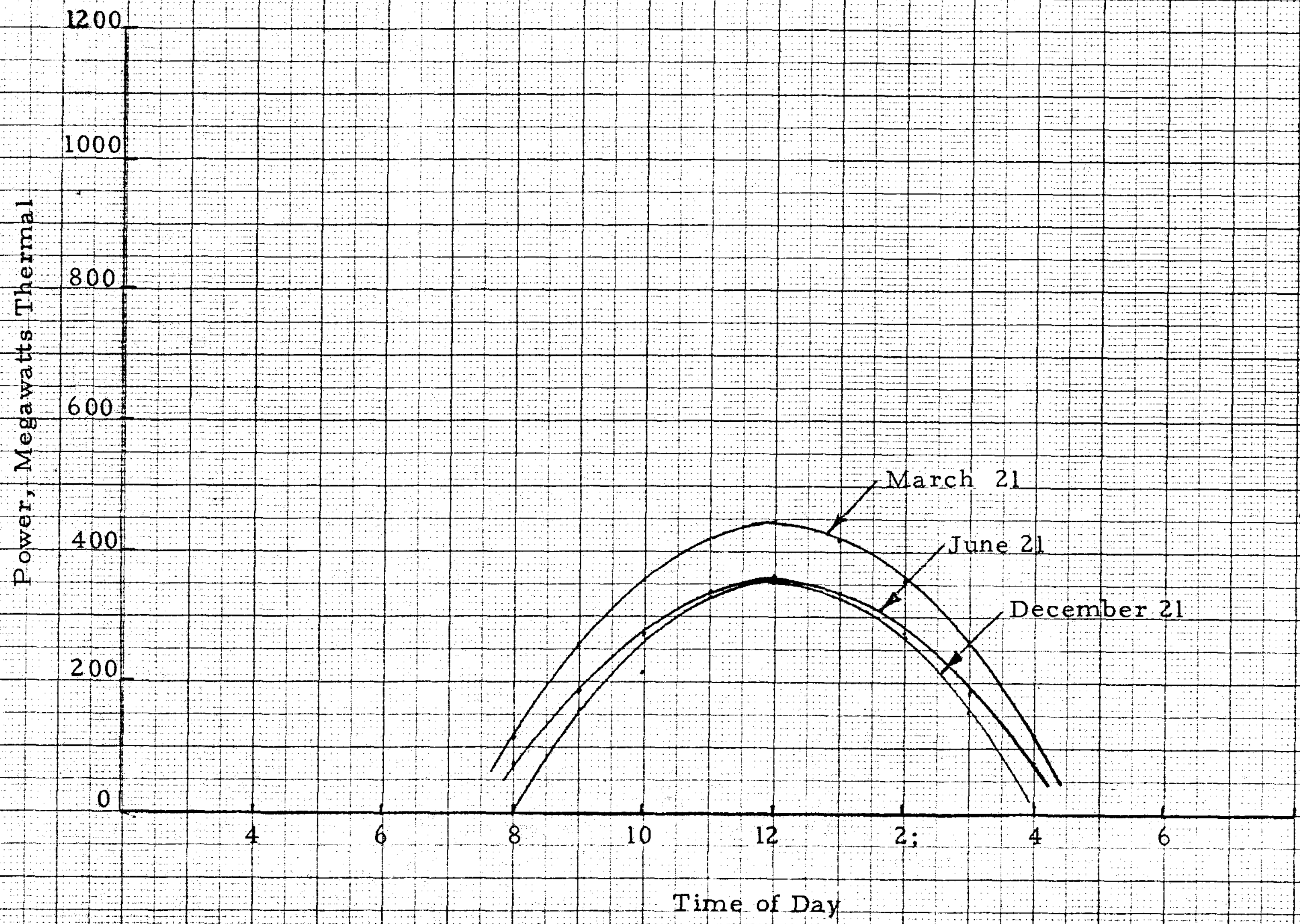
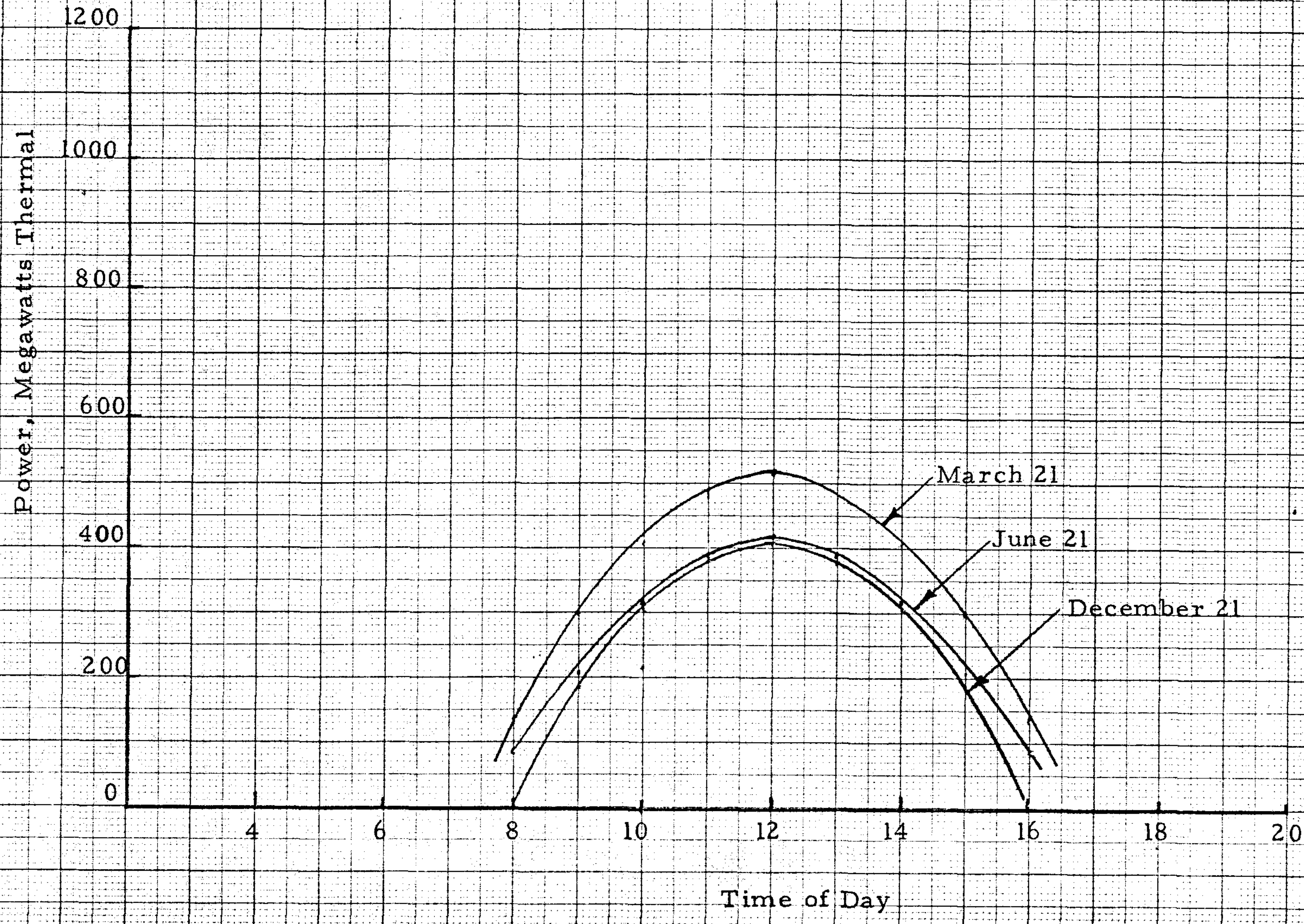


Figure 7c. Net Power Absorbed into Steam
Line Focus Plant of 1.0 x 10^6 m^2 Collector Area
GA Data Base
Barstow Insolation Data



GA

Figure 7d. Net Power Absorbed into Steam
Line Focus Plant of 1.5 x 10^6 m^2 Collector Area
GA Data Base
Barstow Insolation Data

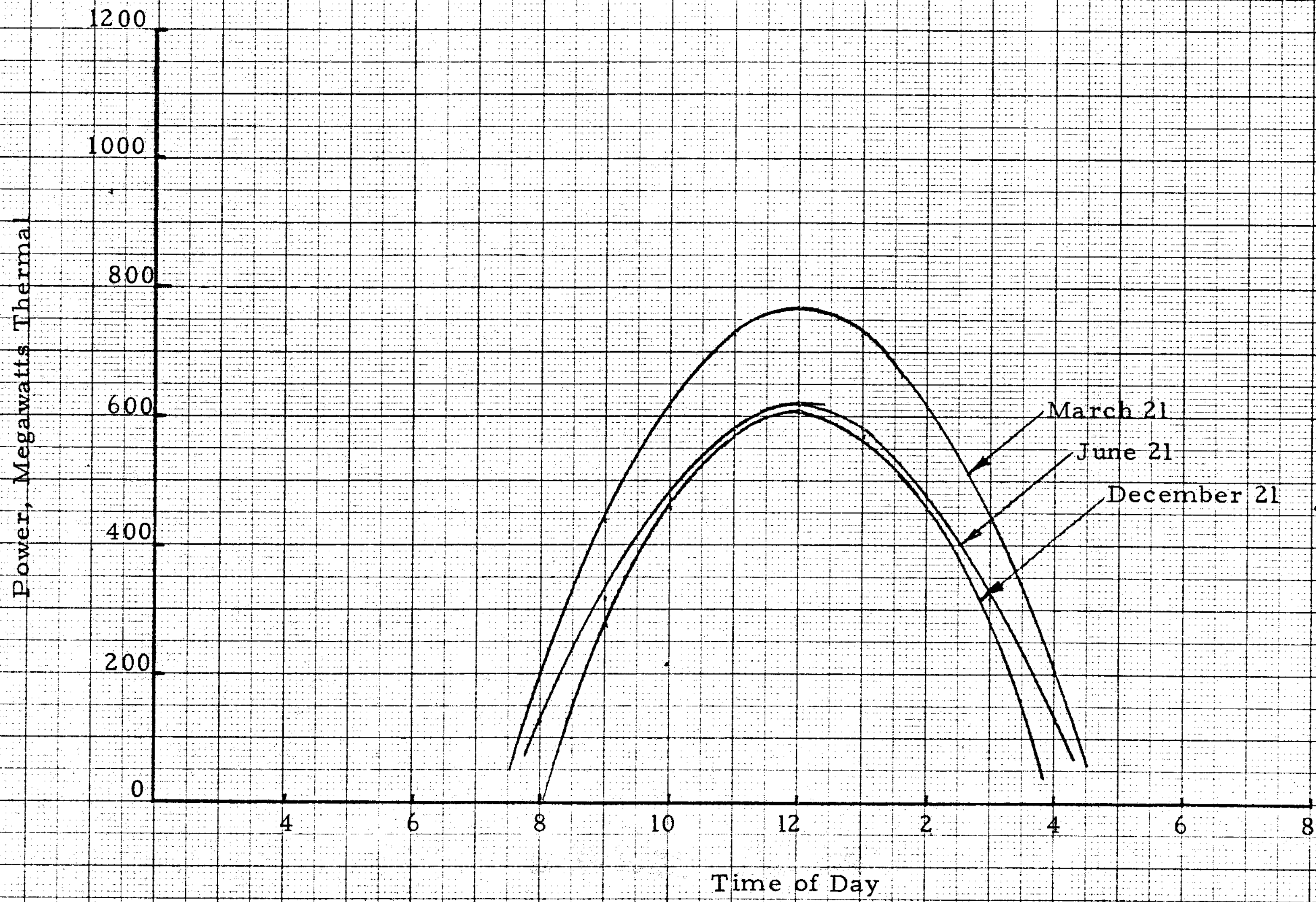


Figure 7e. Net Power Absorbed into Steam
Line Focus Plant of $2.0 \times 10^6 m^2$ Collector Area
GA Data Base
Barstow Insolation Data

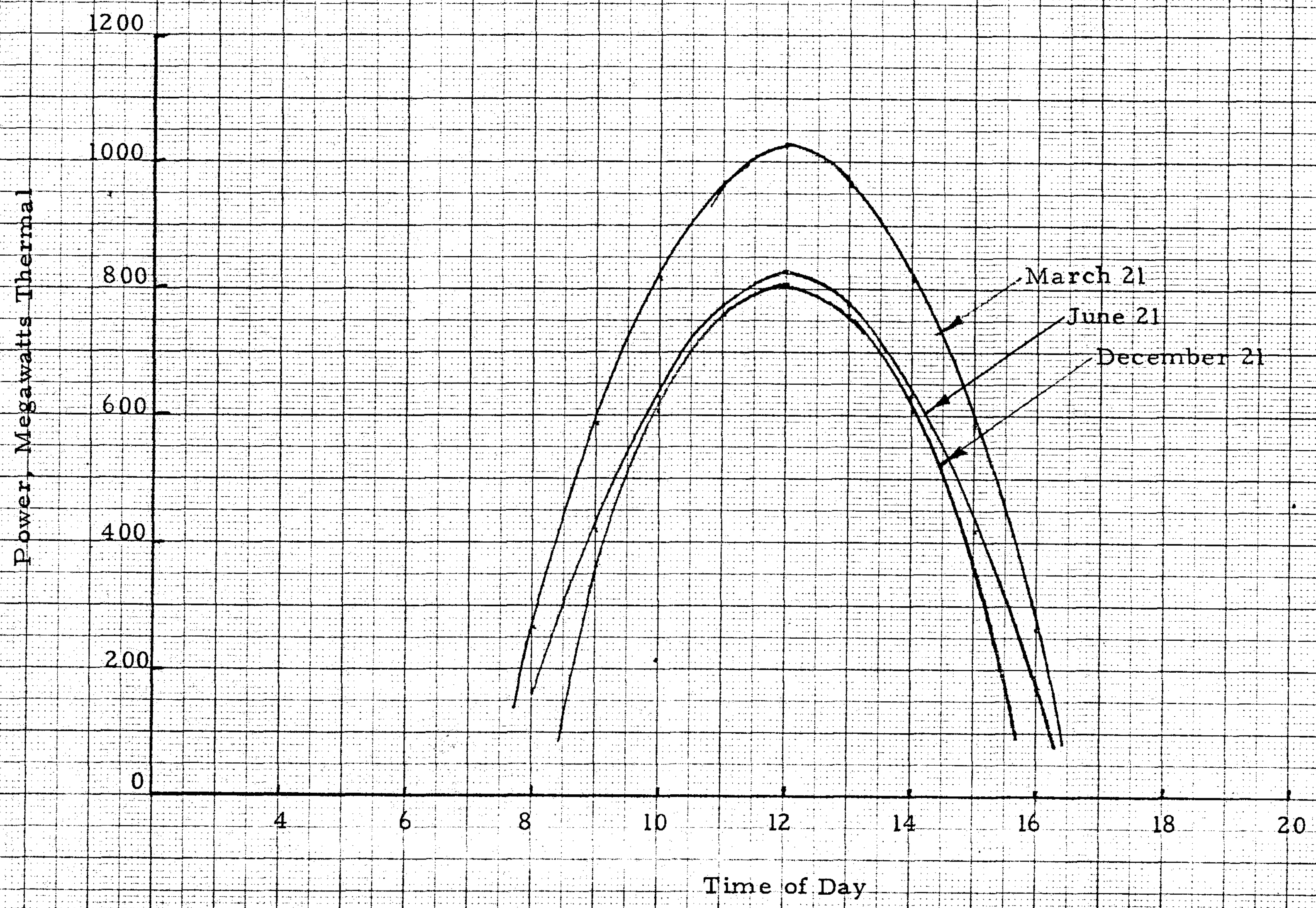


Figure 8. Thermal Power Available From Receiver
($0.87 \times 10^6 m^2$ Collector Field Glass Area)

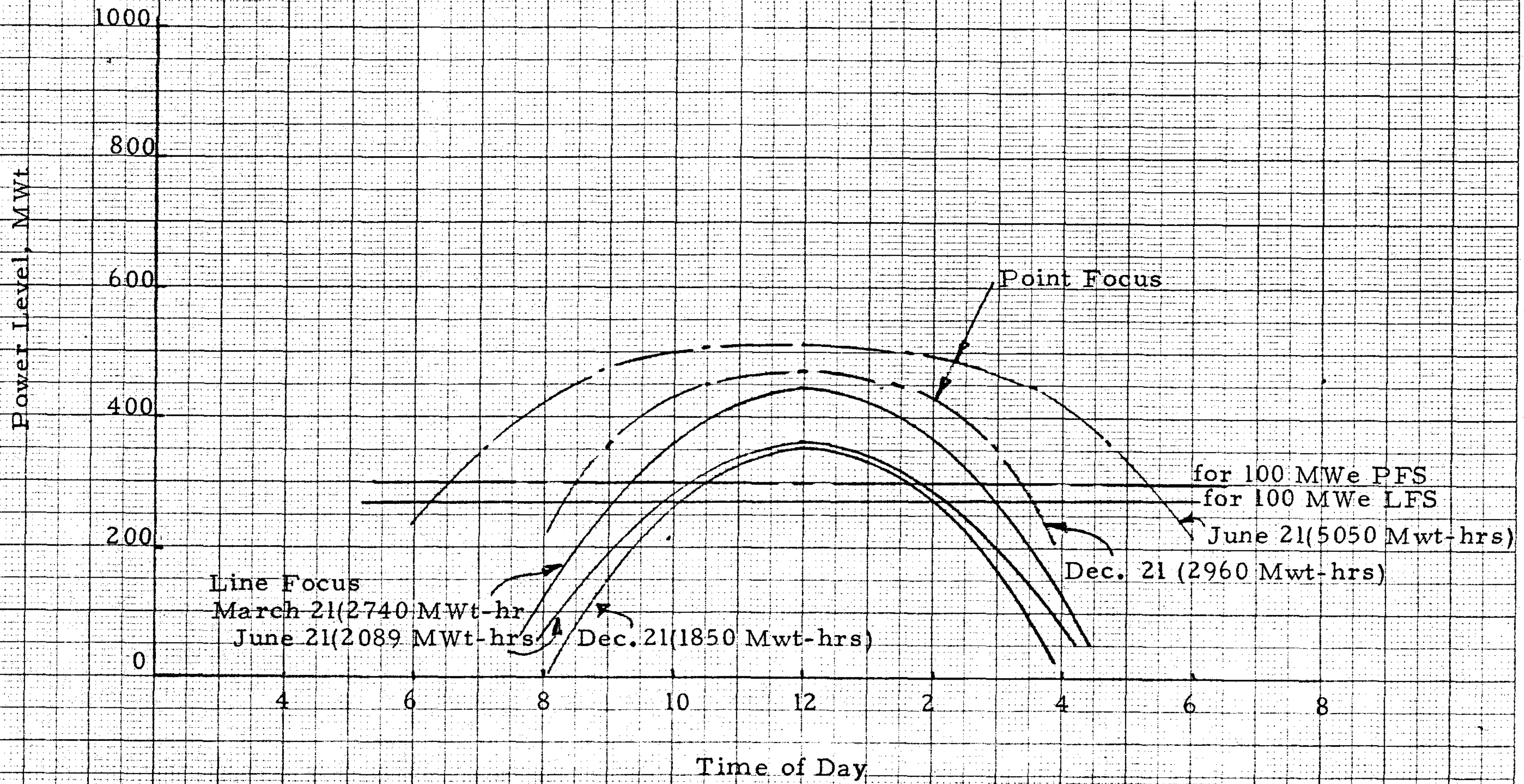


Figure 9a. Daily Electrical Energy Generation Capability
($0.75 \times 10^6 m^2$ Collector Glass Area)

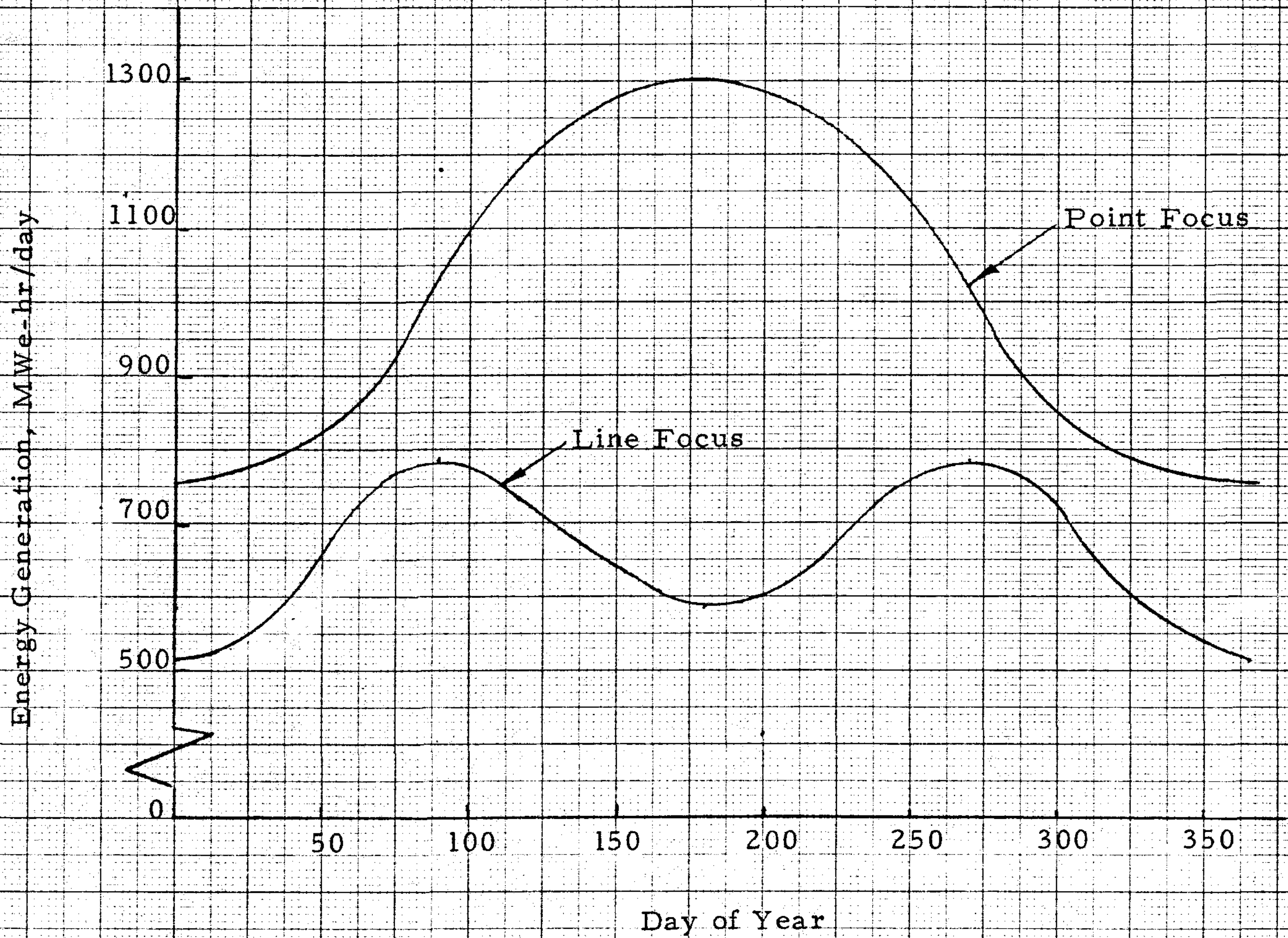


Figure 9b. Daily Electrical Energy Generation Capability
(0.87×10^6 m^2 Collector Glass Area)

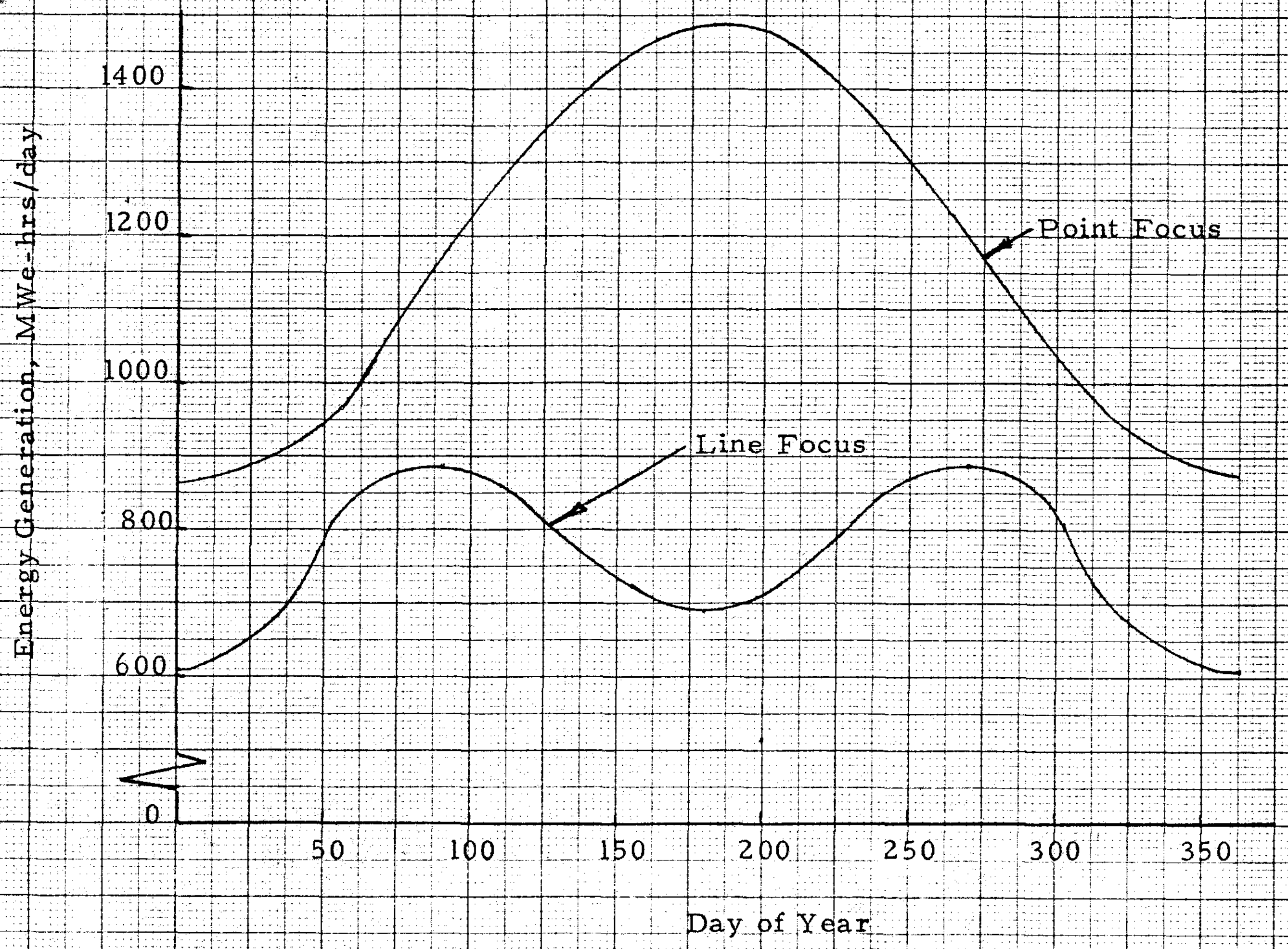


Figure 9c. Daily Electrical Energy Generation Capability
($1.0 \times 10^6 m^2$ Collector Area)

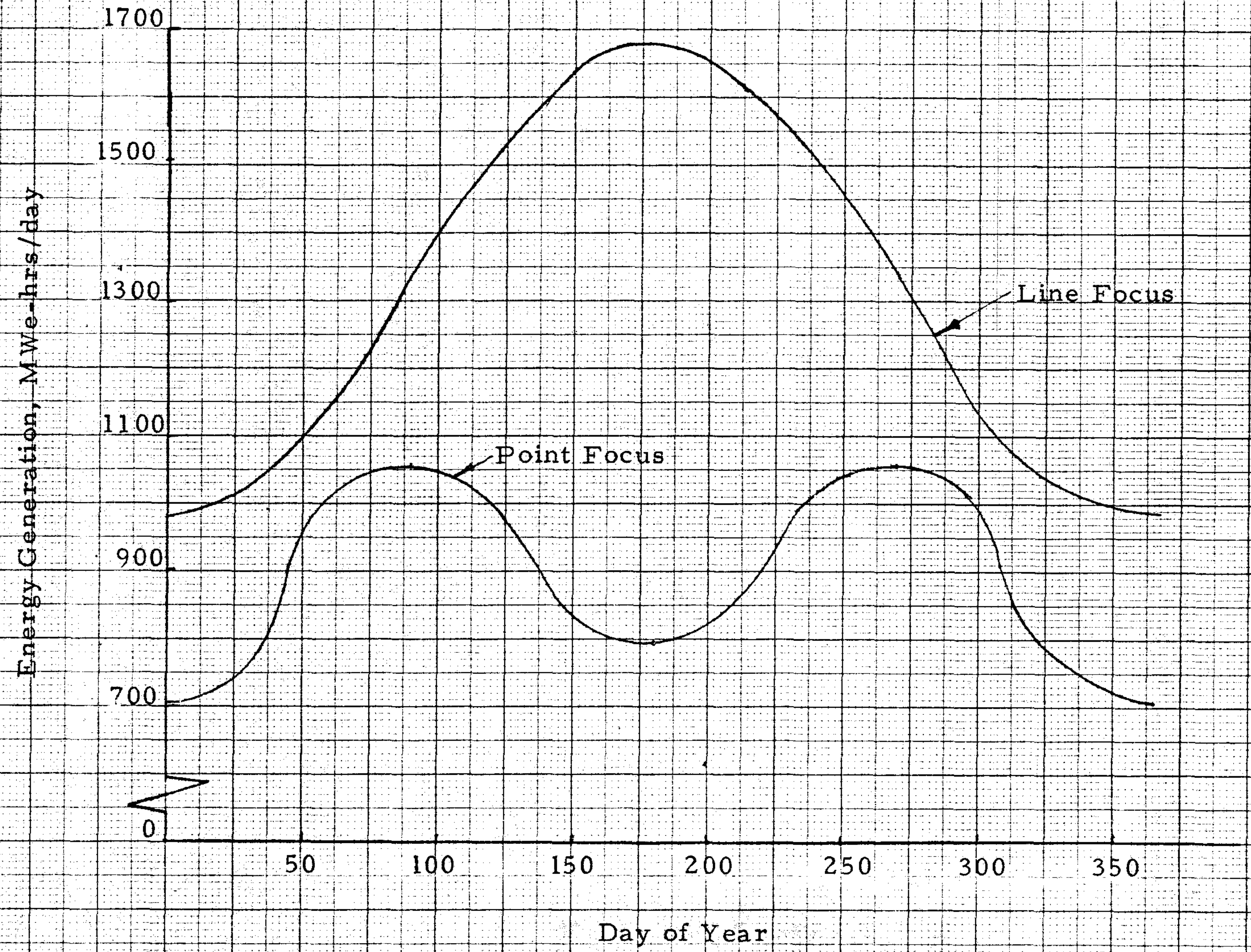


Figure 9d. Daily Electrical Energy Generation Capability
($1.5 \times 10^6 m^2$ Collector Glass Area)

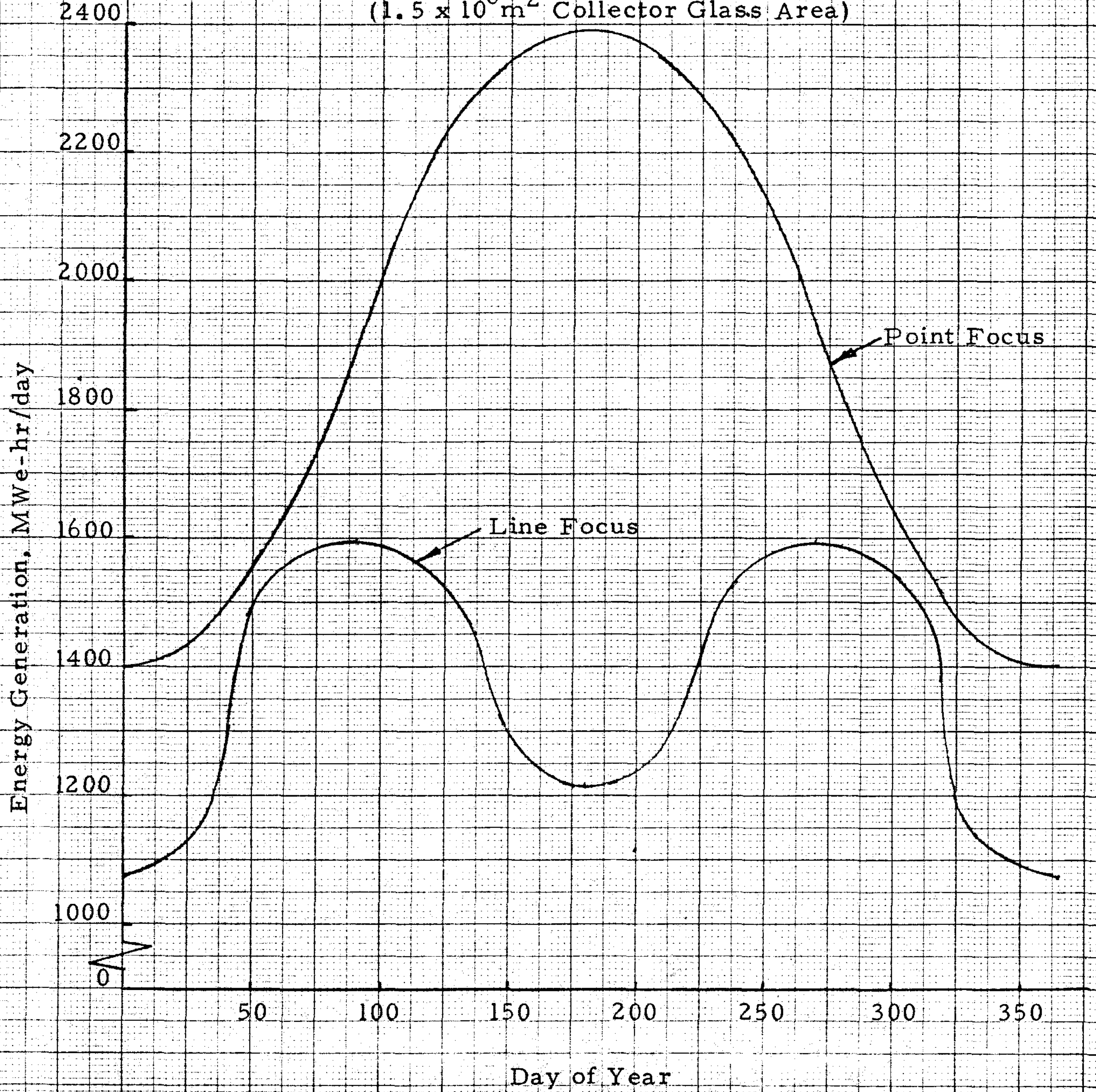
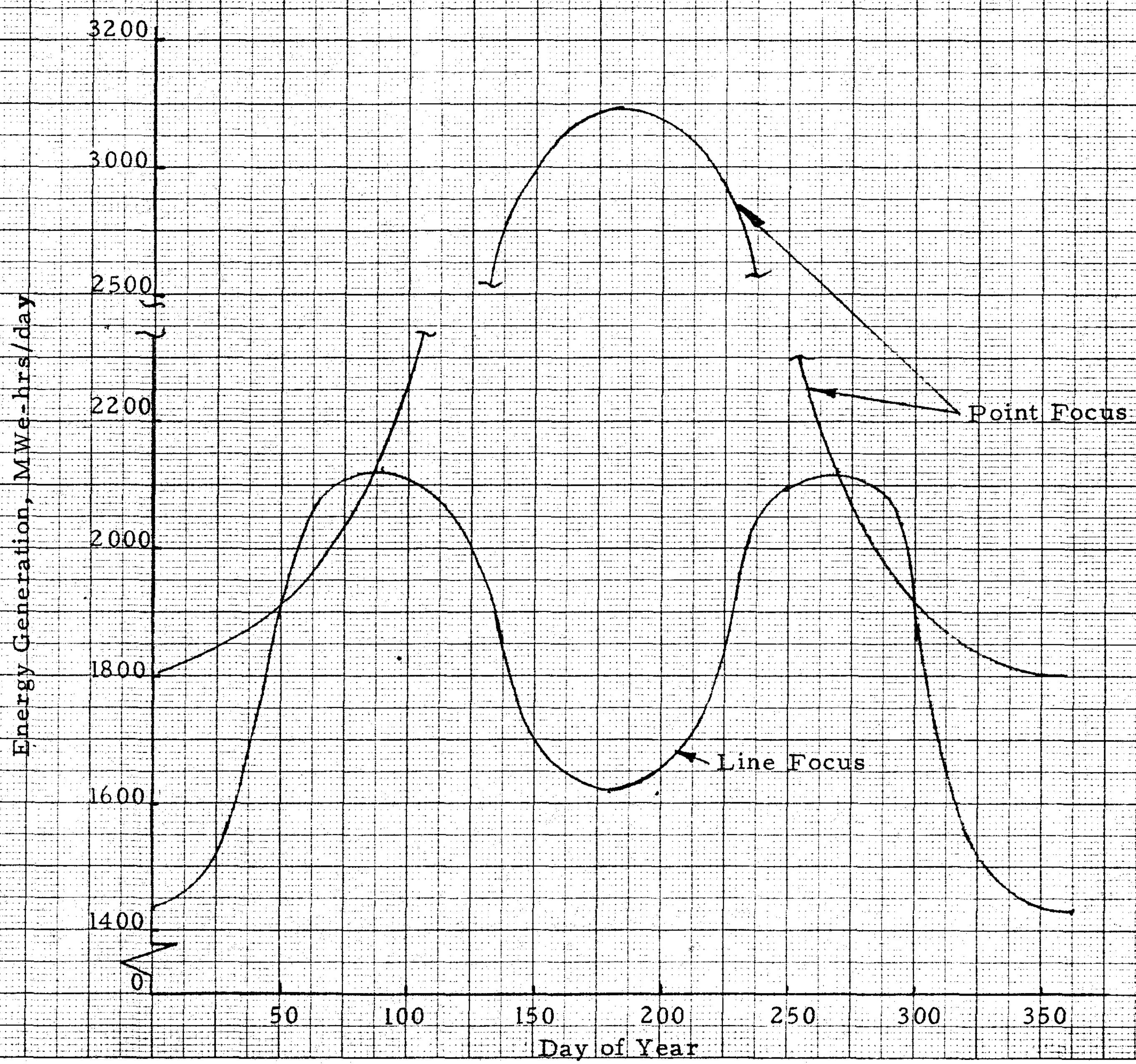


Figure 9e. Daily Electrical Energy Generation Capability
($2.0 \times 10^6 m^2$ Collector Glass Area)



equinoxes while the point focus power levels peak heavily in the summer months.

3.3 Annual Energy Delivered

Figure 10 shows the annual energy delivered to the grid, and the plant capacity factor as a function of collector glass area. The plant capacity factor is defined as the ratio of annual energy output to the rated power (100 MWe) multiplied by the 8760 hours of the year.

3.4 FMSC Operating Costs

The LFS operating costs as a function of collector field/receiver/tower specific costs are shown in Figure 11 for three values of capacity factor. The data indicates that the LFS operating costs are relatively insensitive to capacity factor, or TSS size. This phenomena is the result of the low specific cost of thermal storage used in the study. As capacity factor increases the collector field contribution to the cost of electricity remains relatively constant since it generates approximately constant kilowatts thermal per glass area. The plant EPGS size, however, remains constant at 100 MWe and therefor as it's used more with greater capacity factors, its contribution to the specific cost of electricity drops. If the TSS cost per stored energy is low, its contribution to the specific cost of electricity as more TSS capacity is used increases but this increase is balanced by the lower EPGS specific cost, and the total cost remains relatively constant until higher capacities are reached.

This result was further investigated by varying the TSS specific cost ($/kwt-hr). See Figure 12. At higher than the baseline TSS capital cost, the TSS cost contribution to total cost increases more rapidly and the system optimum cost is biased towards less storage.

Under the ideal insolation conditions assumed, the first generation point focus data yields an operating cost of 83 mills/kw-hr. using a collector/receiver/tower cost of $\$85/m^2$, of which $\$56/m^2$ represents the collector system. For the FMSC to be competitive its cost must be $\$65/m^2$ for a plant capacity factor of 0.4. If the plant capacity factor is increased to 0.5 the cost goal is $\$70/m^2$, and at 0.6 capacity factor the cost goal is $\$74/m^2$. If the cost goals are extrapolated back to the first plant, the cost goals become $\$94/m^2$ at the 0.4 capacity factor.

Figure 10. Comparison of Energy Generation Capability

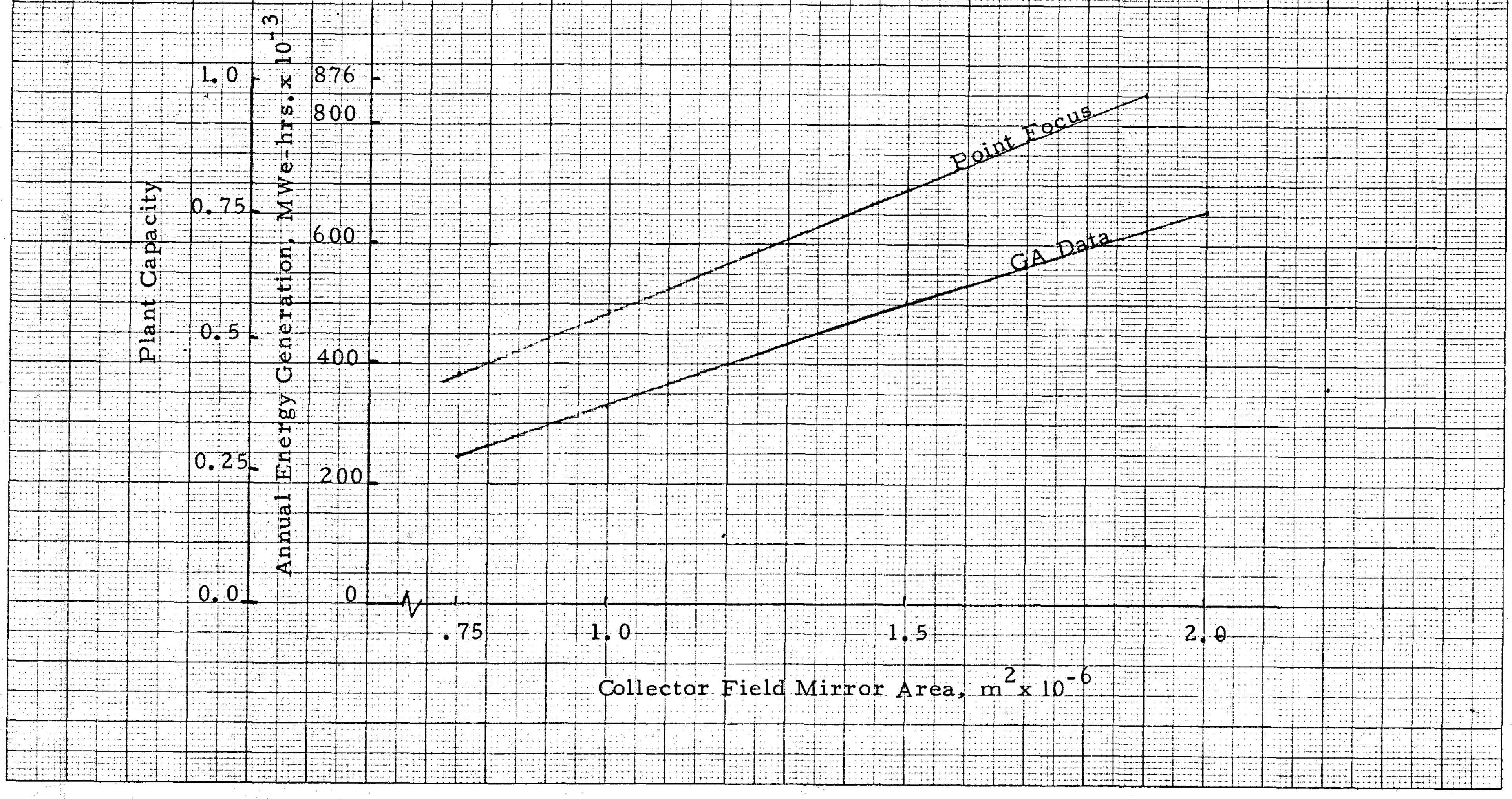


Figure 11. LFS Operating Costs as a Function of Operating Cost and Collector/Receiver/Tower Specific Costs

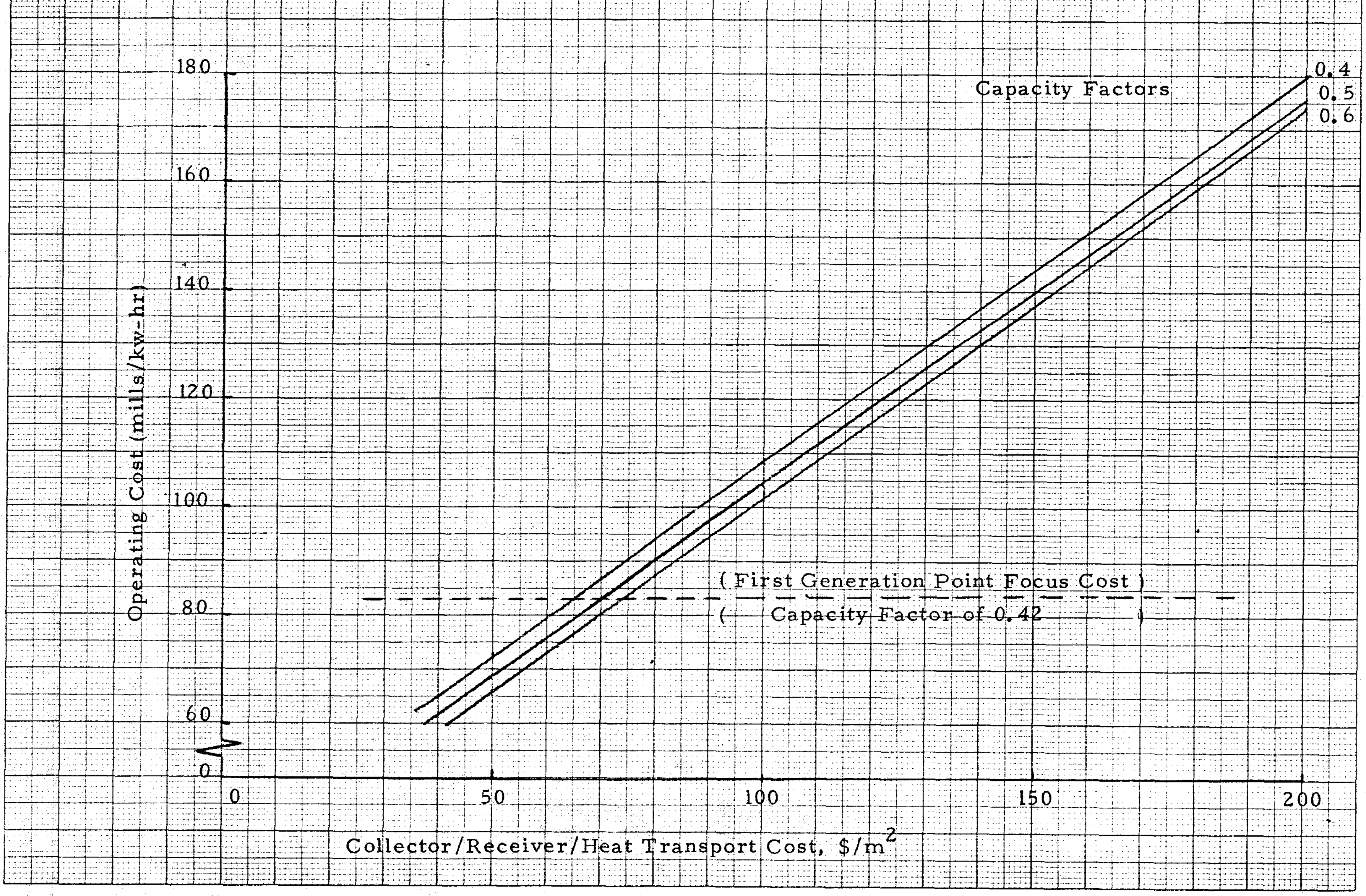
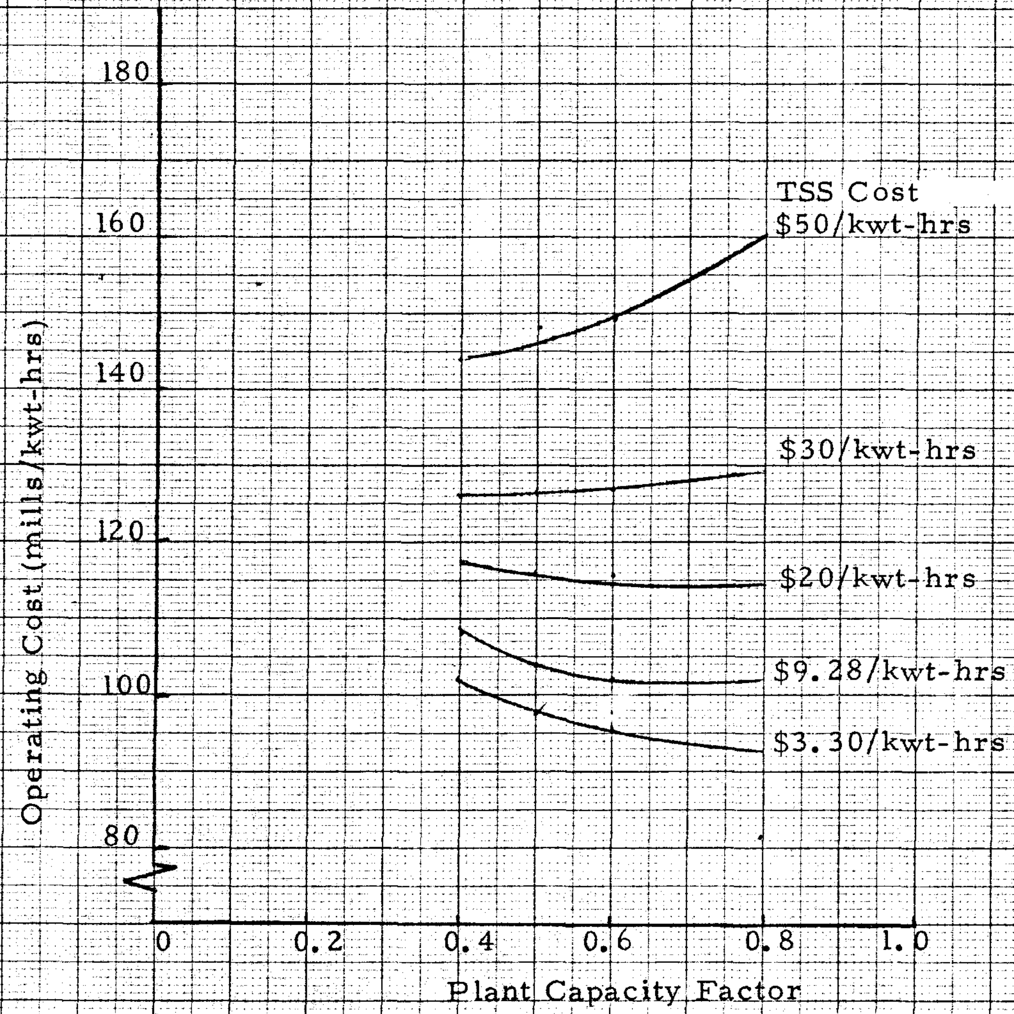


Figure 12. Sensitivity of Plant Operating Costs to TSS Cost
(Collector/Receiver/HTS Capital Cost of $100/m^2$)



4.0 CONCLUSIONS

Based on this preliminary analysis, the following conclusions can be reached on the LFS system economic viability in comparison to the first generation point focus power plant.

- The General Atomics LFS can be cost competitive with PFS when its collector/receiver/heat transport costs are below $\$65/m^2$ based on 80th plant learning curves.
- The GA LFS of same capacity can operate approximately 4.5 hours directly from solar insolation as compared to 7 to 10 hours for PFS.
- The GA LFS is strongly dependent on TSS operation to improve plant capacity factor.
- TSS cost must be low in order for LFS to be cost competitive.
- LFS receiver and TSS charging equipment ratings must be larger than those of PFS.
- The GA LFS performance data used in this analysis is considered optimistic.

These conclusions are strongly dependent of the assumptions used in this study. Most basic of these assumptions are the assumptions of the proportionality of the O&M and indirect costs to capital costs. The LFS studies currently underway will serve to verify these and other assumptions used in this study.

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