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MASTER

MONTHLY TECHNICAL PROGRESS REPORT

SAN/ET-78-C-03-2233-TPE-6

FOR THE MONTH OF MARCH 1979

SOLAR CENTRAL RECEIVER
HYBRID POWER SYSTEM

ISSUE DATE: APRIL 1979

ROCKWELL INTERNATIONAL
ENERGY SYSTEMS GROUP
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CANOGA PARK, CALIFORNIA 91304

MONTHLY TECHNICAL PROGRESS REPORT
FOR MARCH, 1979

EXECUTIVE SUMMARY

ENERGY SYSTEMS GROUP

Contract ET-78-C-03-2233

The preliminary market assessment for the sodium-cooled, solar, central receiver hybrid plant has been completed. It is estimated that between the years 1990 and 2001, there will exist a need for 49.8 GWe and 44.2 GWe of base-load and intermediate-load electrical power for the states of Arizona, California, Colorado, Kansas, Louisiana, Nevada, New Mexico, Texas and Utah.

Projected,levelized, busbar energy costs (BBEC) for coal-fired hybrid and pure coal-fired plants were calculated using a revised economic model and two assumed prices for coal ($1.00/MBTU and $1.40/MBTU). At a capacity factor of 0.7, a fuel escalation of 10%, and a fuel cost of $1.00/MBTU, the BBEC was found to be 74 mills/kwhr for the hybrid plant and 87 mills/kwhr for the pure coal plant. Slightly higher BBEC values were calculated on the basis of a coal cost of $1.40/MBTU. It was also found that for a fuel cost of $1.40/MBTU that significant storage became economically attractive for fuel escalations exceeding about 9%. This escalation would be 1% above general escalation.

The economic merit in alternate fuels such as coal gas, coal liquids, and shale oil were investigated. Despite the disadvantages encountered in the direct burning of coal, it would seem that synthetic fuel alternatives are so expensive that they are not likely to be useful in advancing the coal hybrid concept. If the coal storage problem is severe, it could be avoided in part by use of silo storage and/or by location of the coal storage downwind of the plant, a nominal distance from the heliostat field. A trench or tunnel could be used for transporting coal to the combustion unit, and a short-term storage silo could be incorporated into the central operating complex.

Additional studies of the optimum size for the collector field, tower, and receiver were carried out. Single point and two-point aims were investigated. Currently our selected receiver concept is based upon a single aim and a 13.5 meters high by 10.4 meters diameter system.

Work was initiated on a "back of the envelope" estimate of the relative cost of a water/steam hybrid concept that matches as nearly as possible the total energy produced by the sodium-cooled system on an annual basis.

A preliminary design of a combustion gas exhaust stack that uses the central tower for structural support was completed. Also a preliminary design of the sodium heater was completed to the point at which more detailed costing could be started.

TASK 1 - REVIEW AND ANALYSIS OF REQUIREMENTS DEFINITION

Complete.

TASK 2 - MARKET ANALYSIS

FORCAST DEMAND

In considering the market potential of the hybrid solar system, SRI assumes that the system will not be available until 1990 or later. In this case, the utility will have purchased and put on-line alternate generating units between now and 1989-1990. Thus, we assume that by 1986 utilities in California will have long-term contracts for purchase or installed capacity additions beyond those that have already been announced, and the effective base load capacity in California in 1986 will be 26.1 GW. Similarly, in 1989 and 2001, the effective base load capacities will be 29.5 and 44.2 GW, respectively. Thus, in the period from 1990 to 2001, we would expect the increase to be 44.2 minus 29.5 or 14.7 GW capacity. However, the utilities have announced plans to install units of 1.4 GW capacity in the period. We deducted this from the market available to arrive at the 13.3 GW shown in Table I (last column). The 1986-1989 base load potential market of 0.4 GW for California and the 1.7 GW for Texas were included to show the small market to be gained if the hybrid solar system were available earlier.

The estimates set forth in Table I are based on the assumption that each state would act independently and that deficits in generating capacity in 1986 and 1989 are not carried over. We have re-estimated demand as if the states considered operated in two power pools with membership as follows:

Pool 1	Pool 2
Arizona	Colorado
California	Kansas
Nevada	Louisiana
New Mexico	Texas
Utah	

TABLE I

PROJECTED CAPACITY AND REQUIREMENTS, SUM OF MAJOR UTILITIES, SELECTED STATES, GWe

1	2	3	4	5	6	7	8	9	10	11	12†	13†
											Additional Capacity Required Total Potential Market	
		Capacity Needed			Capacity Available* (Present Plans)			Col. 3 Minus	Col. 4 Minus	Col. 5 Minus		
State	Current Capacity	1986	1989	2001	1896	1989	2001	Col. 6	Col. 7	Col. 8	1987-1989	1990-2001
Arizona												
Base	3.5	4.2	4.7	7.2	6.7	7.9	8.9	-2.5	-3.2	-1.7	None	None
Intermediate	1.1	2.6	3.0	4.5	3.1	3.0	2.0	-0.5	0.0	2.5	None	2.5
Peak	2.2	1.6	1.8	2.8	1.8	1.9	2.1	-0.2	-0.1	0.7	None	0.7
California												
Base	16.7	26.1	29.5	44.2	20.0	23.0	24.4	6.1	6.5	19.8	0.4	13.3
Intermediate	8.4	16.5	18.4	27.8	13.3	11.8	5.9	3.2	6.6	21.9	3.4	15.3
Peak	6.9	10.1	11.4	17.2	15.6	15.7	15.6	-5.5	-4.3	1.6	None	1.6
Colorado												
Base	1.2	1.8	2.2	3.8	2.8	3.2	3.2	-1.0	-1.0	0.6	None	0.6
Intermediate	0.8	1.2	1.4	2.4	1.6	1.5	1.3	-0.4	-0.1	1.1	None	1.1
Peak	0.6	0.7	0.8	1.4	0.5	0.5	0.5	0.2	0.3	0.9	0.1	0.6
Kansas												
Base	0.8	1.6	1.7	1.9	1.7	1.7	1.7	-0.1	0.0	0.2	None	0.2
Intermediate	0.4	1.0	1.0	1.2	0.7	0.7	0.4	0.3	0.3	0.8	None	0.5
Peak	0.5	0.6	0.7	0.6	0.7	0.6	0.5	-0.1	0.1	0.1	0.1	None
Louisiana												
Base	5.7	8.3	9.7	15.5	10.3	10.3	8.7	-2.0	-0.6	6.8	None	6.8
Intermediate	2.6	5.3	6.2	9.9	3.1	2.7	1.4	2.2	3.5	8.5	1.3	5.0
Peak	1.3	3.3	3.7	5.8	0.7	0.4	0.1	2.6	3.3	5.7	0.7	2.4

TABLE I

PROJECTED CAPACITY AND REQUIREMENTS, SUM OF MAJOR UTILITIES, SELECTED STATES, GWe
(Sheet 1 of 2)

1	2	3	4	5	6	7	8	9	10	11	12†	13‡
											Additional Capacity Required	
		Capacity Needed			Capacity Available* (Present Plans)			Col. 3 Minus Col. 6	Col. 4 Minus Col. 7	Col. 5 Minus Col. 8	Total Potential Market	
State	Current Capacity	1986	1989	2001	1896	1989	2001				1987-1989	1990-2001
Nevada												
Base	1.2	1.0	1.2	1.6	1.1	1.4	1.4	-0.1	-0.2	0.2	None	0.2
Intermediate	0.4	0.7	0.7	0.1	1.2	1.1	0.3	-0.5	-0.4	0.7	None	0.7
Peak	0.4	0.4	0.4	0.6	1.1	1.1	1.2	-0.7	0.7	-0.6	None	None
New Mexico												
Base	0.6	0.5	0.6	0.8	1.7	2.1	2.7	-1.2	-1.5	-1.9	None	None
Intermediate	0.2	0.3	0.4	0.5	-	-	-	-	-	-	0.1	0.1
Peak	0.1	0.2	0.2	0.2	0.2	0.2	-	0.0	0.0	-	None	0.2
Texas												
Base	24.1	39.2	44.2	63.9	39.9	42.5	36.2	-0.7	1.7	27.7	1.7	26.0
Intermediate	11.6	24.4	28.1	40.1	11.7	11.5	5.9	12.7	16.6	34.2	3.9	17.6
Peak	6.3	15.1	17.1	24.7	6.7	4.6	2.0	8.4	12.5	22.7	4.1	10.2
Utah												
Base	1.4	1.6	1.7	2.5	3.0	4.3	4.3	-1.4	-2.6	-1.8	None	None
Intermediate	0.6	1.0	1.1	1.6	0.8	0.7	0.3	0.2	0.4	1.3	0.2	0.9
Peak	0.3	0.6	0.6	0.9	0.2	0.2	0.2	0.4	0.4	0.7	None	0.3

*Present Announced Situation - No allowance for further additions.

†Column 10 minus Column 9 - Negative numbers (surplus) are disregarded (i.e., considered to be zero)

‡Column 11 minus Column 10- Negative numbers (surplus) are disregarded (i.e., considered to be zero)

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The effect of pooling is the use of surplus generating capacity in certain states to supply electric demand and reduce deficits in others. Because this is particularly successful in early years, new capacity additions are deferred so that the potential markets for hybrid solar systems are increased in later years. This perhaps unexpected result is shown in the totals in Table II (labeled corrected). However, the differences in the two sets of estimates are quite small.

TABLE II

POTENTIAL MARKET FOR SOLAR ADDITIONS - GWE

(Corrected)

	1987-1989	1990-2001
Arizona		
Base	0	0
Intermediate	0	2.5
California		
Base	0.4	13.3
Intermediate	3.4	15.3
Colorado		
Base	0	0.6
Intermediate	0	1.1
Kansas		
Base	0	0.2
Intermediate	0	0.5
Louisiana		
Base	0	6.8
Intermediate	0	5.0
Nevada		
Base	0	0.2
Intermediate	0	0.7
New Mexico		
Base	0	0
Intermediate	0.1	0.1

Texas		
Base	1.7	26.0
Intermediate	3.1	17.6
Utah		
Base	0	0
Intermediate	0.2	0.9
TOTAL		
Base	2.1	47.1
Intermediate	8.9	43.7
TOTAL CORRECTED*		
Base	0.1	49.8
Intermediate	9.8	44.2

*If area treated as two pools with surplus being fed to California from Arizona, Nevada, New Mexico, and Utah, and to Texas from Colorado, Kansas, and Louisiana.

A word of caution is necessary. These projections are of potential, not actual markets. The capacity needed before 1995 or perhaps later will be ordered by 1990. Utilities are not likely to order a hybrid system until it is a demonstrated and proven technology. Orders placed before demonstration would be conditional and subject to cancellation. Utility caution will influence ordering patterns and rates of market penetration. This topic will be addressed at a later stage of our project.

COSTS OF POWER FROM COAL AND COAL-SOLAR HYBRID UNITS

Calculations of the levelized bus bar costs of electric power produced by coal and coal-solar hybrid units have been updated. The results obtained were favorable to the hybrid concept.

The economic and financial assumptions used are those given in Table III. SRI believes that the coal price used as base may be high. Therefore, SRI has used both $1.00 and $1.40 per million Btu as 1979 base prices for coal.

The results are displayed in graphical form in Figures 1-6.* Figures 1-4 compare the levelized bus bar cost of solar hybrids with solar multiples of 0.8 and 1.5 to coal only. They show the effect of coal cost, and escalation and capacity factors. Figure 1 illustrates first plant costs for an initial coal cost of $1.40 per million Btu. We see both hybrids are competitive at a 10 percent fuel escalation rate, at capacity factors of 50 percent and above. Figure 2 shows the first plants are not competitive at $1.00 per million Btu at any capacity factor if the fuel escalation is 10 percent or less. Figure 3 shows the Nth solar hybrid plants to be competitive with coal for fuel escalation rates above 8 percent when the initial coal cost is $1.40 per million Btu. Figure 4 shows only the solar multiple of 1.5 linked with fuel escalation of 8 percent and initial coal cost of $1.00 per million Btu is uneconomic. Another trend to be noted is the decreasing differential between first and Nth plant at larger capacity factor.

Figures 5 and 6 directly compare the hybrid solar options (solar multiple of 0.8 and 1.5) as a function of capacity factor and fuel escalation (for Nth plant). A cross-over in economics seems to occur at moderate fuel escalation rates. Consequently, Figures 7 and 8 show the bus bar cost as an explicit function of fuel escalation at stated capacity factors. For the range of capacity factors used (0.5-0.9), the economics of each solar option intersect in ranges of a 10.2 to 10.6 percent rate of fuel escalation for $1.00 per million Btu and an 8.8 to 9.0 percent for $1.40 per million Btu. Plots 9 and 10 illustrate the 4-7 mills/kWh cost advantage of these solar options relative to coal at fuel escalation rates of 10.5 and 9.0 for initial coal costs of $1.00 and $1.40 per million Btu over the range of 0.5 to 0.9 capacity factor.

*For these curves, "The Annual Insurance & Other Taxes" was taken as 0.0; and a "Fixed Charge Rate" of 15.7% was used (see Table III).

TABLE III

ECONOMIC PARAMETERS

Item		
Year of Commercial Operation		1990
Construction Period, Years		
Hybrids		5
Coal		4.2
Interest During Construction		20% of Total Capital
System Lifetime, Years		30
Debt Fraction		0.5
Return on Debt		0.10
Stock Fraction		0.5
Return on Stock		0.15
Cost of Capital, %, After Tax		10.0
Income Tax Rate		0.5
Annual Insurance/Other Taxes		0.0225
Depreciation Method		SOYD
Depreciation Life, Years		22
Fixed Charge Rate, %		18
Rate of General Inflation, %		8
Capital Escalation Rate, %		10
O&M Escalation Rate, %		8
Reference Year		1978
Capital Cost, $/kWe (1978 $)		
First Hybrid (solar multiple = 0.8)		1,283
Nth Hybrid (solar multiple = 0.8)		1,060
First Hybrid (solar multiple = 1.5)		1,863
Nth Hybrid (solar multiple = 1.5)		1,464
Coal		970
Annual O&M Cost, $/kWe (1978 $)		
Hybrid	Fixed +	Variable
	1% capital cost	30% of reference year fuel cost
Coal	0.75% capital cost +	30% of reference year fuel cost
Heat Rate Btu/kWhe		
Coal		10,200
Fuel Cost, $/MBtu (1978 $)		
Coal		1.00, 1.40
Fuel Escalation, %		
Coal		6, 8, 10, 12

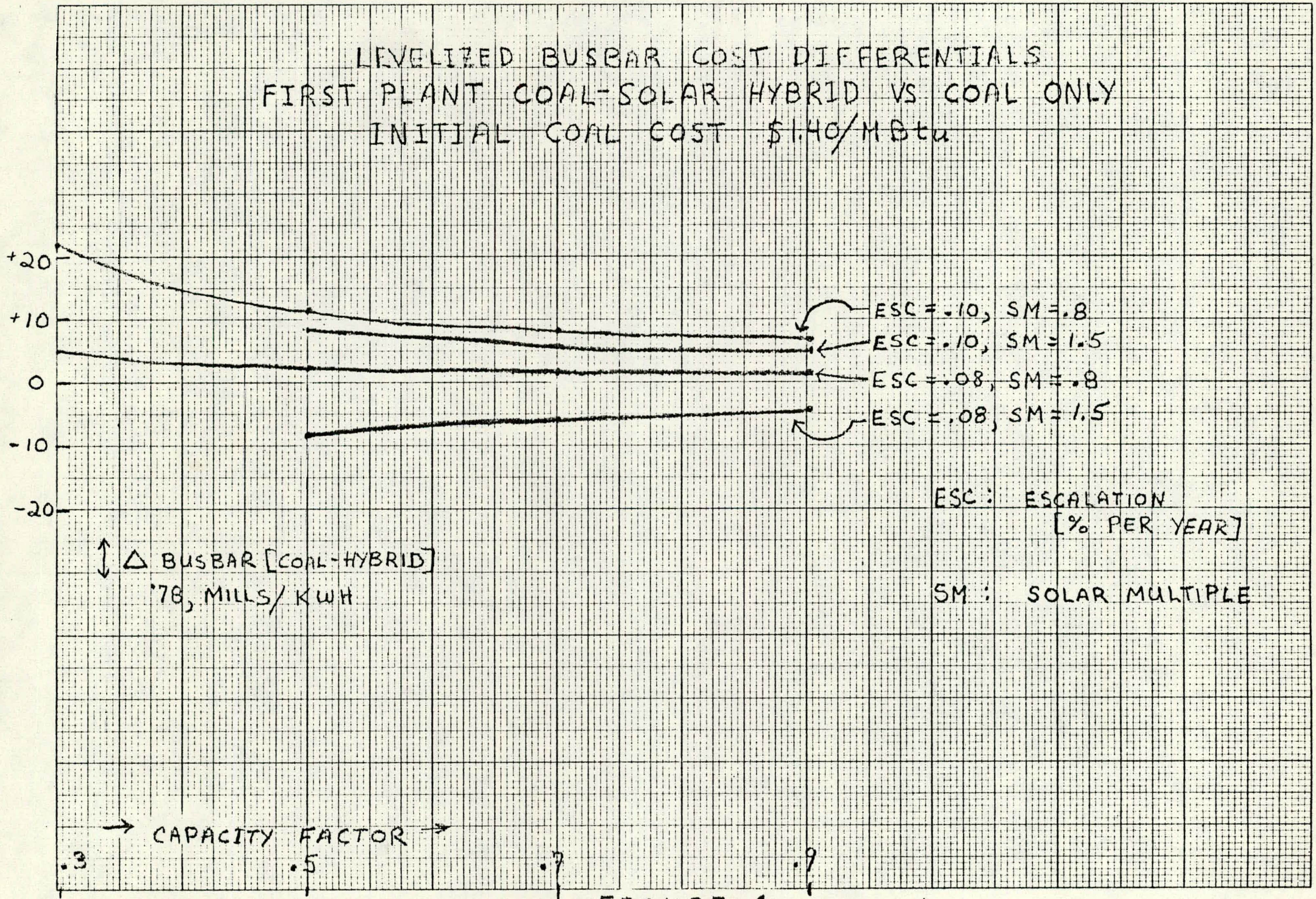
LEVELIZED BUSBAR COST DIFFERENTIALS
FIRST PLANT COAL-SOLAR HYBRID VS COAL ONLY
INITIAL COAL COST $1.40/MBtu
+20
+10
0
-10
-20
ESC = .10, SM = .8
ESC = .10, SM = 1.5
ESC = .08, SM = .8
ESC = .08, SM = 1.5
ESC: ESCALATION [% PER YEAR]
SM: SOLAR MULTIPLE
Δ BUSBAR [COAL-HYBRID]
'78, MILLS/KWH
CAPACITY FACTOR
.3
.5
.7
.9

FIGURE 1

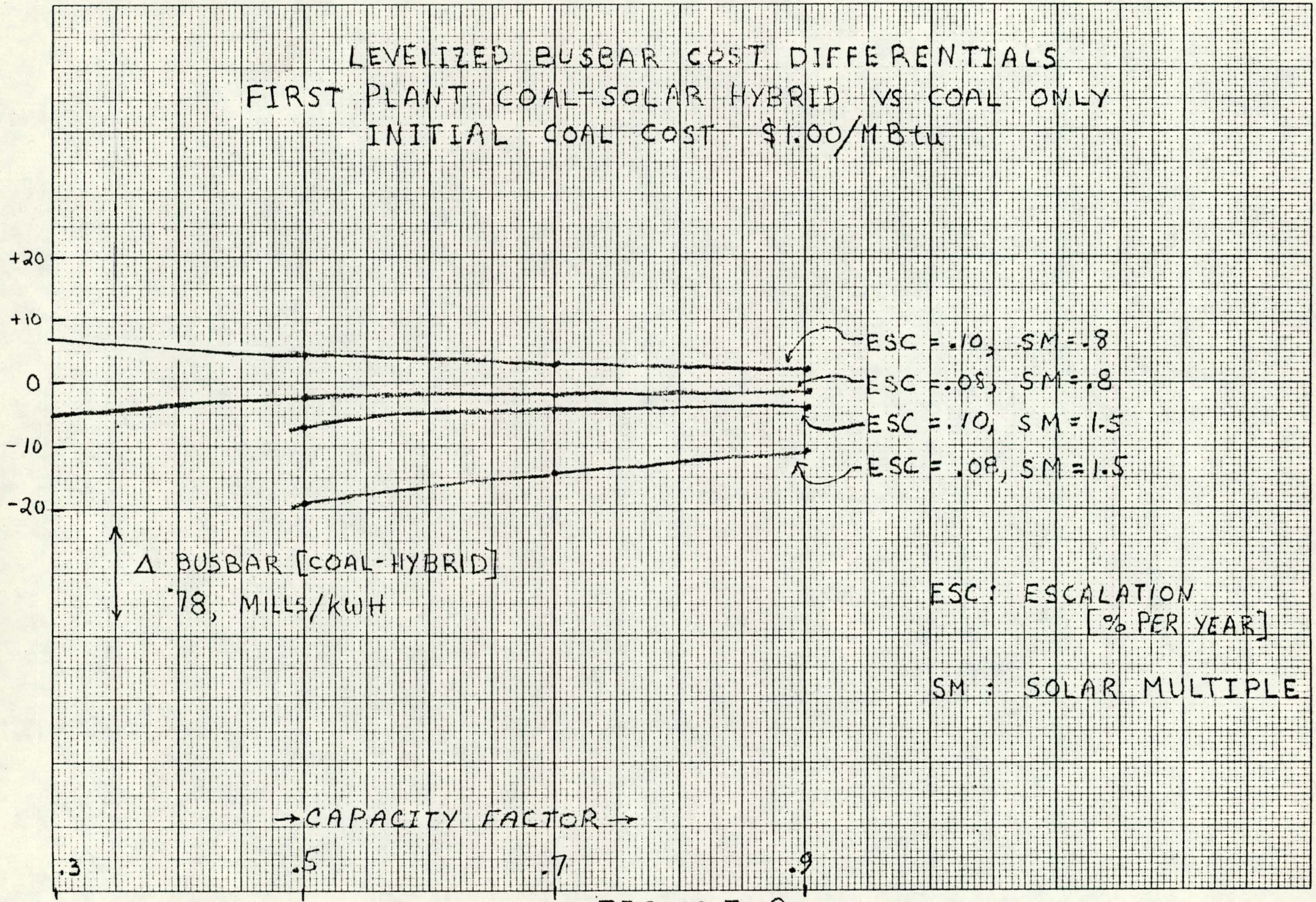
LEVELIZED BUSBAR COST DIFFERENTIALS
FIRST PLANT COAL-SOLAR HYBRID VS COAL ONLY
INITIAL COAL COST $1.00/MBtu
+20
+10
0
-10
-20
ESC = .10, SM = .8
ESC = .08, SM = .8
ESC = .10, SM = 1.5
ESC = .08, SM = 1.5
Δ BUSBAR [COAL-HYBRID]
'78, MILLS/KWH
ESC : ESCALATION
[% PER YEAR]
SM : SOLAR MULTIPLE
→CAPACITY FACTOR→
.3
.5
.7
.9

FIGURE 2

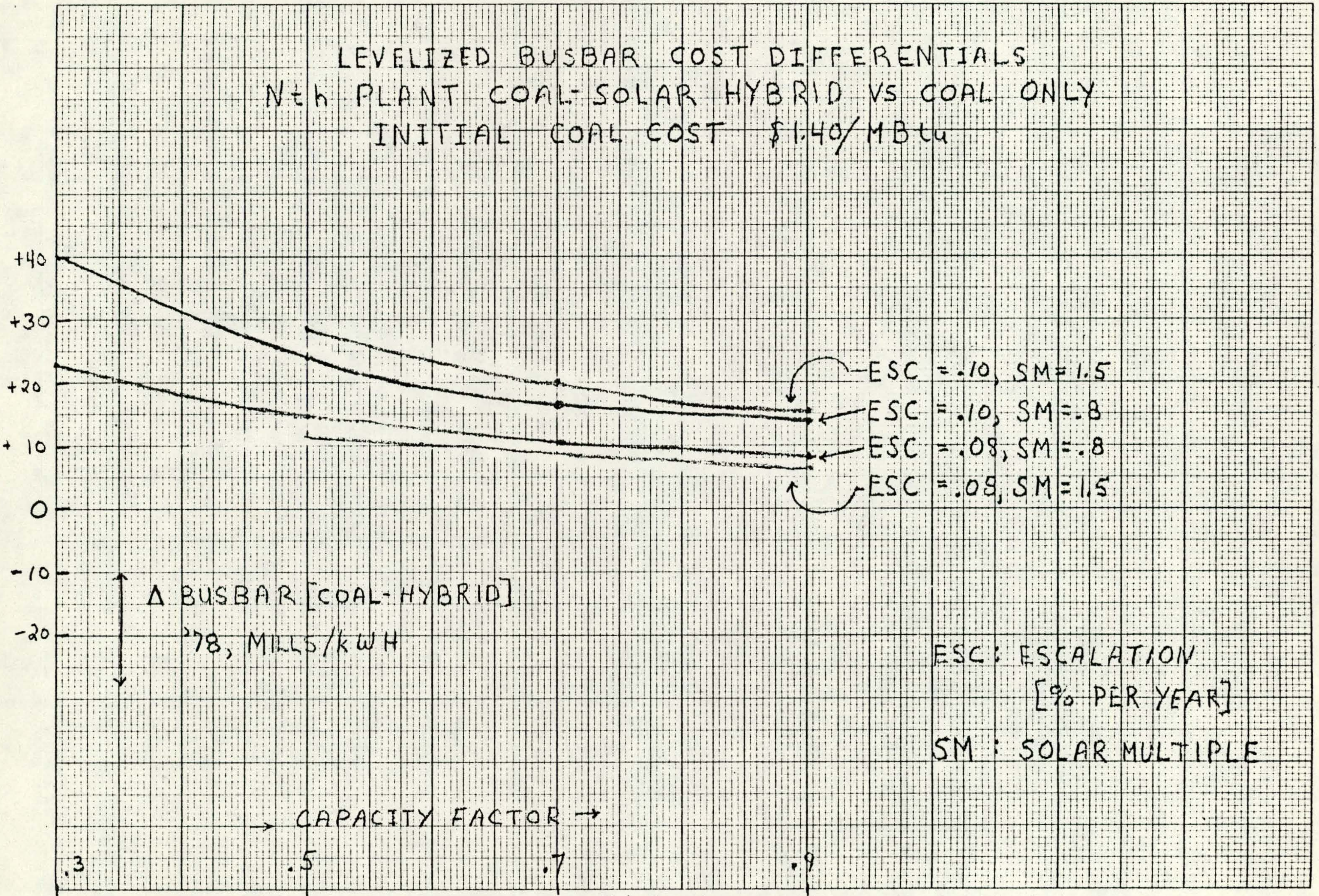
LEVELIZED BUSBAR COST DIFFERENTIALS
Nth PLANT COAL-SOLAR HYBRID VS COAL ONLY
INITIAL COAL COST $1.40/MBtu
+40
+30
+20
+10
0
-10
-20
ESC = .10, SM = 1.5
ESC = .10, SM = .8
ESC = .08, SM = .8
ESC = .08, SM = 1.5
Δ BUSBAR [COAL-HYBRID]
'78, MILLS/kWH
ESC: ESCALATION
[% PER YEAR]
SM : SOLAR MULTIPLE
CAPACITY FACTOR
.3
.5
.7
.9

FIGURE 3

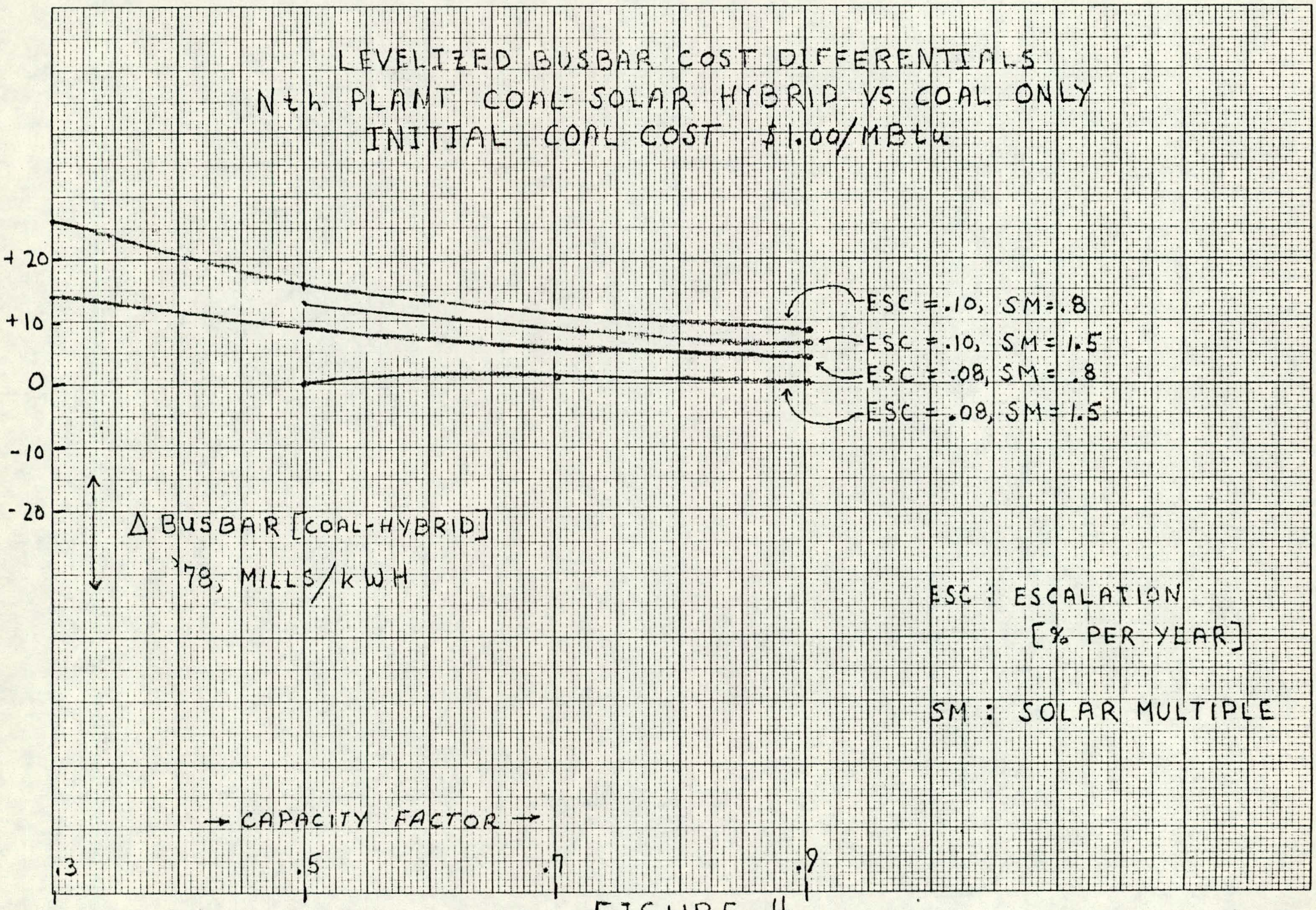
LEVELIZED BUSBAR COST DIFFERENTIALS
Nth PLANT COAL-SOLAR HYBRID VS COAL ONLY
INITIAL COAL COST $1.00/MBtu
+20
+10
0
-10
-20
ESC = .10, SM = .8
ESC = .10, SM = 1.5
ESC = .08, SM = .8
ESC = .08, SM = 1.5
Δ BUSBAR [COAL-HYBRID]
78, MILLS/kWH
ESC : ESCALATION [% PER YEAR]
SM : SOLAR MULTIPLE
→ CAPACITY FACTOR →
.3
.5
.7
.9

FIGURE 4

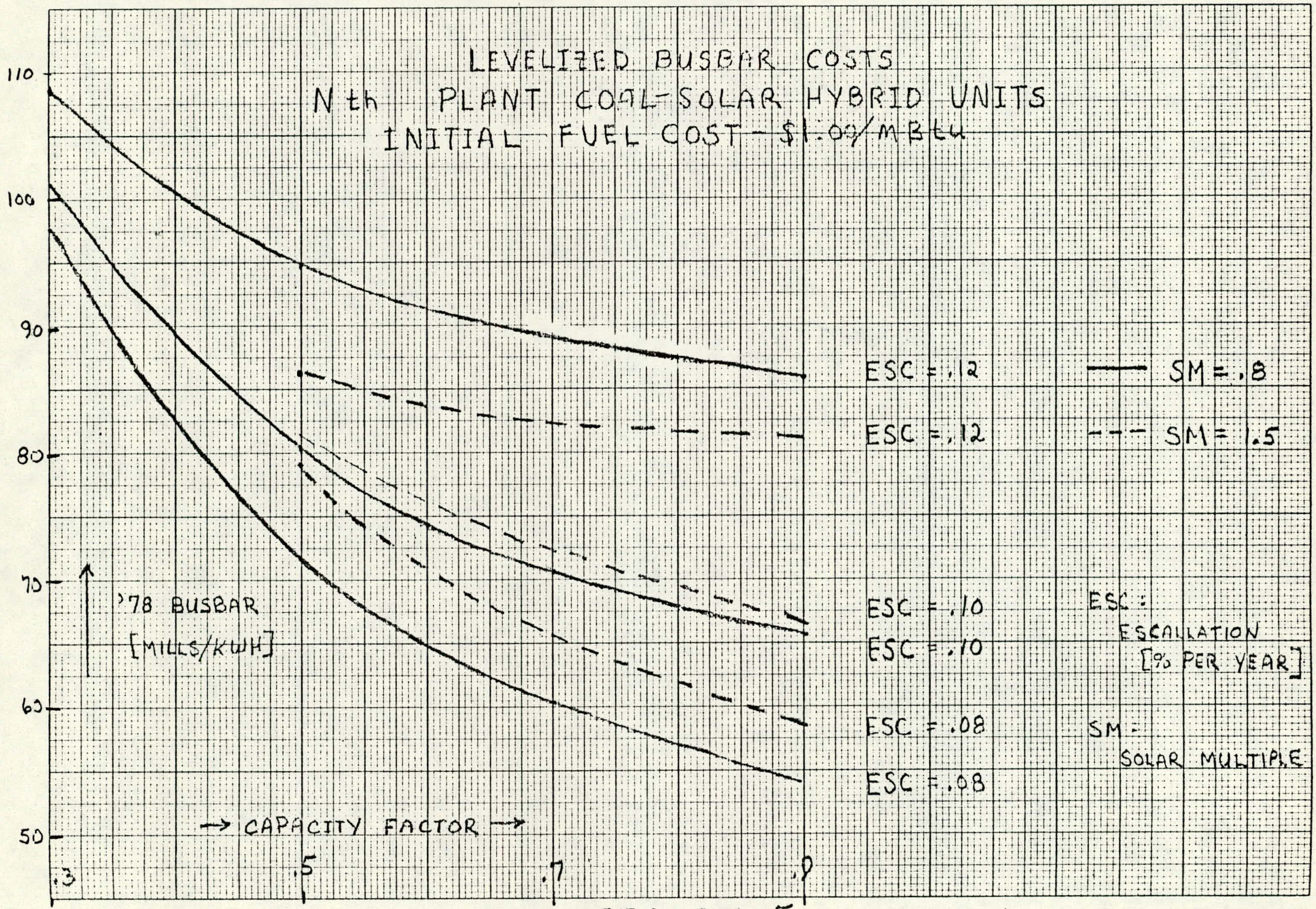
LEVELIZED BUSBAR COSTS
Nth PLANT COAL-SOLAR HYBRID UNITS
INITIAL FUEL COST - $1.00/MBtu
110
100
90
80
70
60
50
'78 BUSBAR
[MILLS/KWH]
→ CAPACITY FACTOR →
.3
.5
.7
.9
ESC = .12
ESC = .12
ESC = .10
ESC = .10
ESC = .08
ESC = .08
SM = .8
SM = 1.5
ESC:
ESCALATION
[% PER YEAR]
SM:
SOLAR MULTIPLE

FIGURE 5

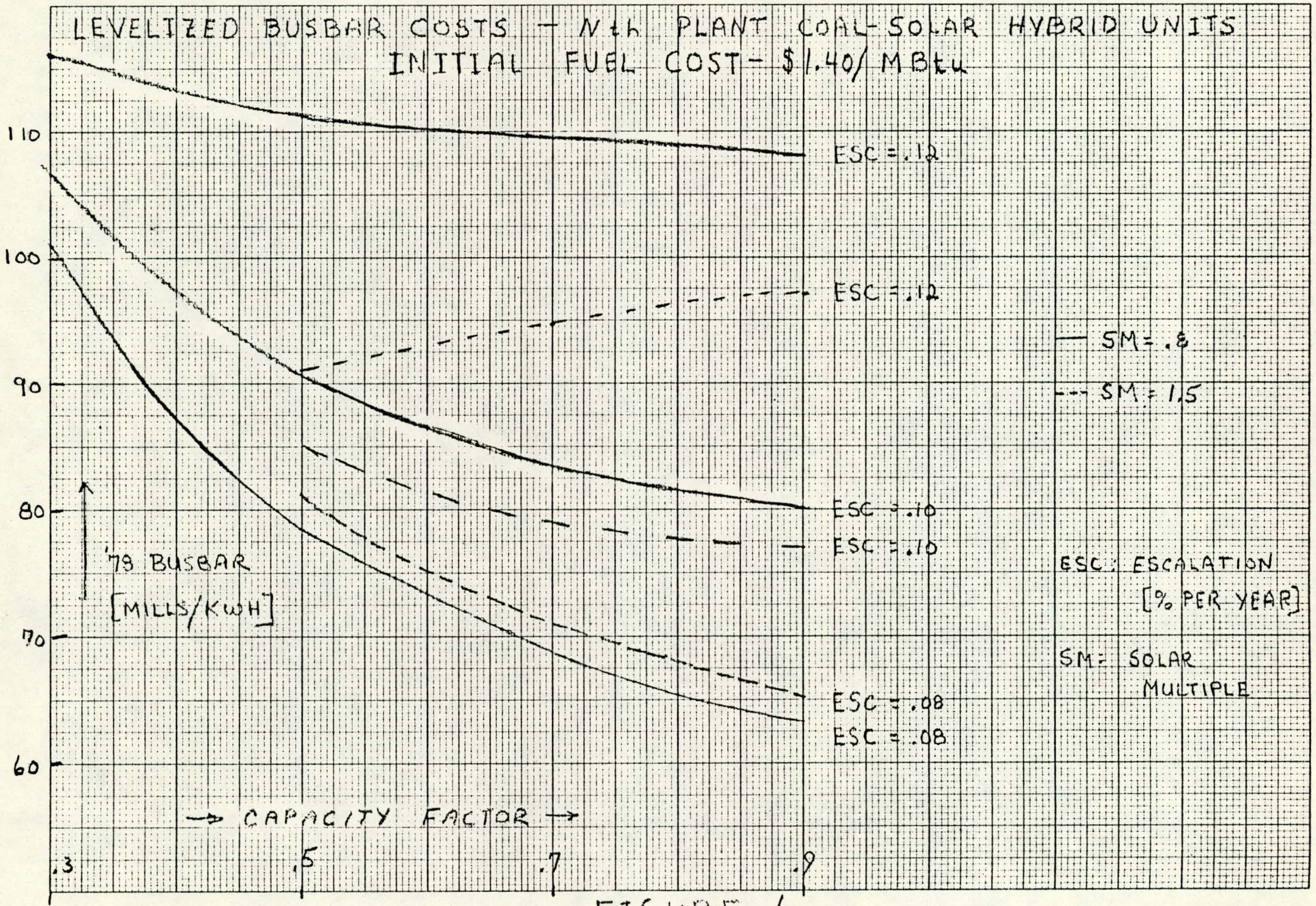
LEVELIZED BUSBAR COSTS - Nth PLANT COAL-SOLAR HYBRID UNITS
INITIAL FUEL COST - $1.40/MBtu
110
100
90
80
70
60
'79 BUSBAR
[MILLS/KWH]
ESC = .12
ESC = .12
ESC = .10
ESC = .10
ESC = .08
ESC = .08
SM = .8
SM = 1.5
ESC: ESCALATION
[% PER YEAR]
SM = SOLAR
MULTIPLE
CAPACITY FACTOR
.3
.5
.7
.9

FIGURE 6

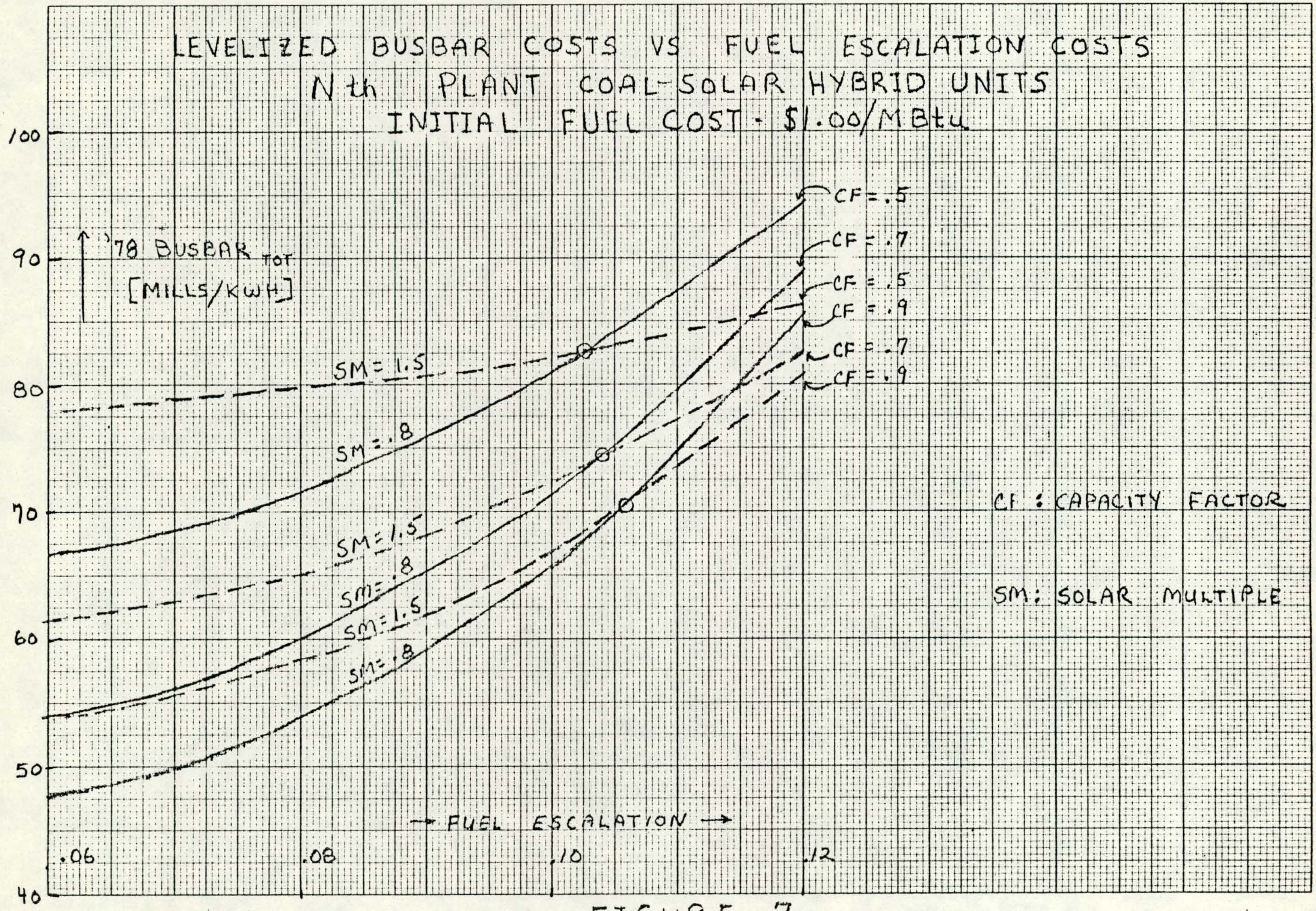
LEVELIZED BUSBAR COSTS VS FUEL ESCALATION COSTS
Nth PLANT COAL-SOLAR HYBRID UNITS
INITIAL FUEL COST - $1.00/MBtu
'78 BUSBAR TOT [MILLS/KWH]
100
90
80
70
60
50
40
CF = .5
CF = .7
CF = .5
CF = .9
CF = .7
CF = .9
SM = 1.5
SM = .8
SM = 1.5
SM = .8
SM = 1.5
SM = .8
CF : CAPACITY FACTOR
SM: SOLAR MULTIPLE
→ FUEL ESCALATION →
.06
.08
.10
.12

FIGURE 7

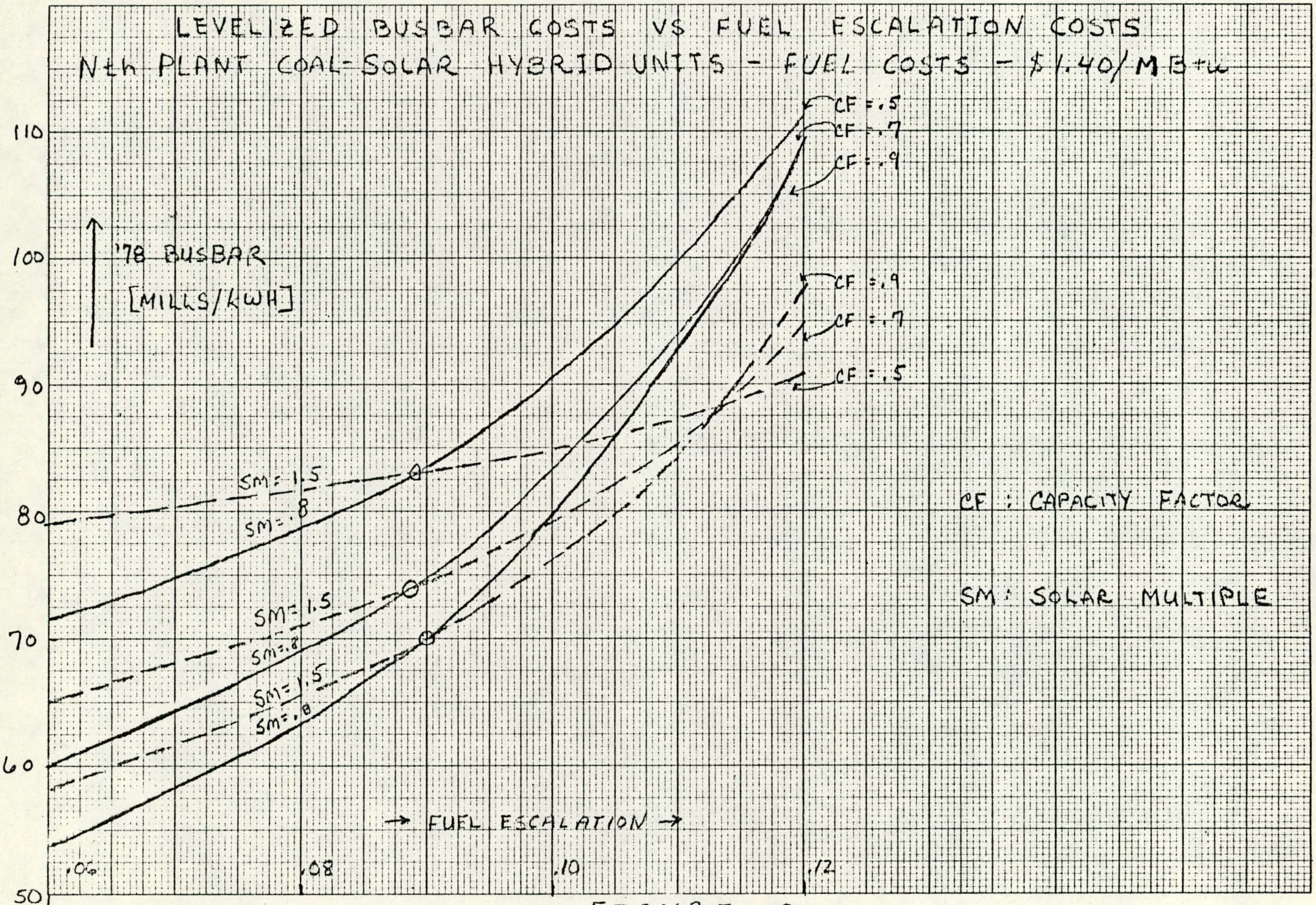
LEVELIZED BUSBAR COSTS VS FUEL ESCALATION COSTS
Nth PLANT COAL-SOLAR HYBRID UNITS - FUEL COSTS - $1.40/MBtu
'78 BUSBAR [MILLS/KWH]
CF = .5
CF = .7
CF = .9
CF = .9
CF = .7
CF = .5
SM = 1.5
SM = .8
SM = 1.5
SM = .8
SM = 1.5
SM = .8
CF : CAPACITY FACTOR
SM : SOLAR MULTIPLE
→ FUEL ESCALATION →
110
100
90
80
70
60
50
.06
.08
.10
.12

FIGURE 8

NO. 340R-20 DIETZGEN GRAPH PAPER
20 X 20 PER INCH

DIETZGEN CORPORATION
MADE IN U.S.A.

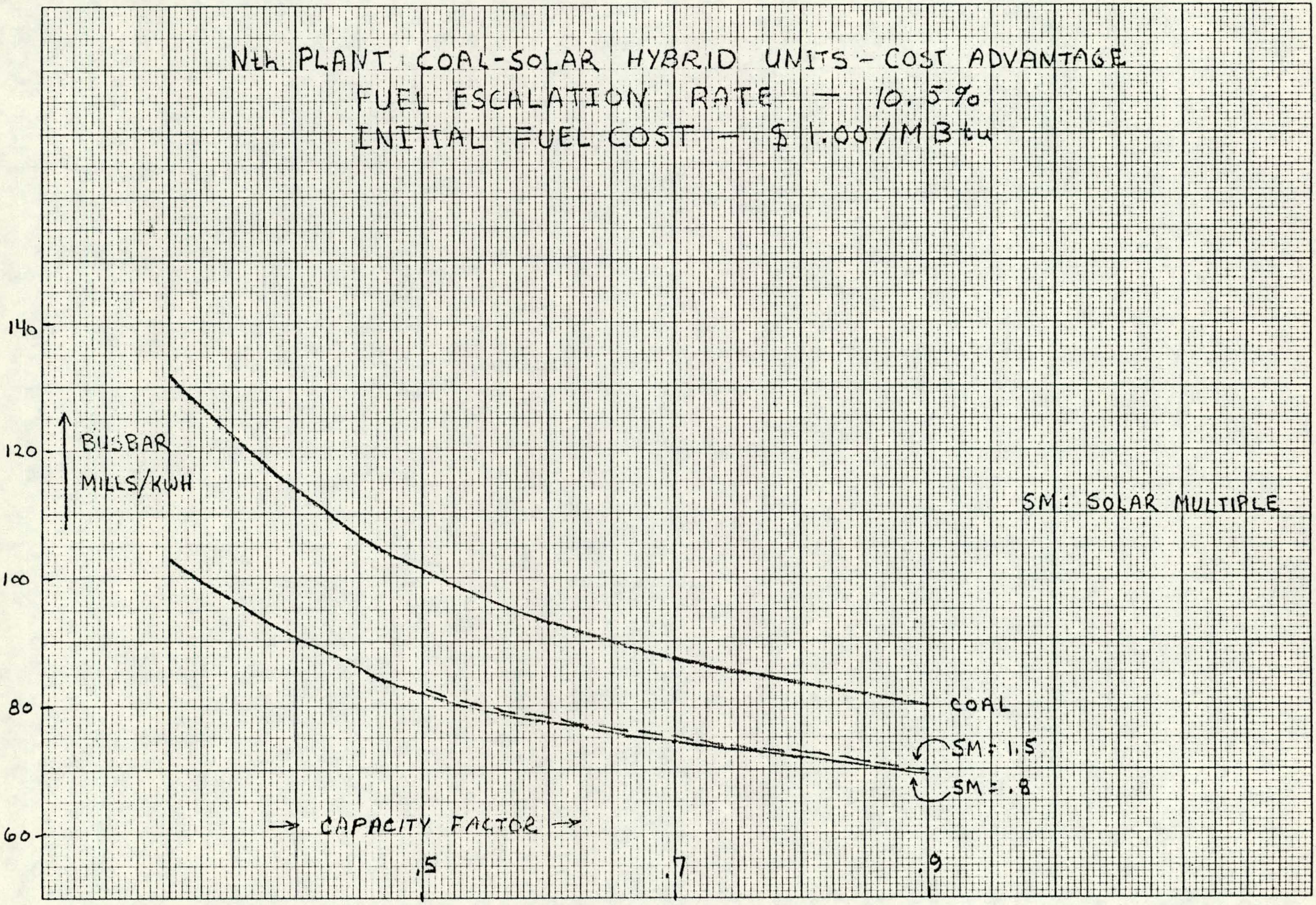

FIGURE 9

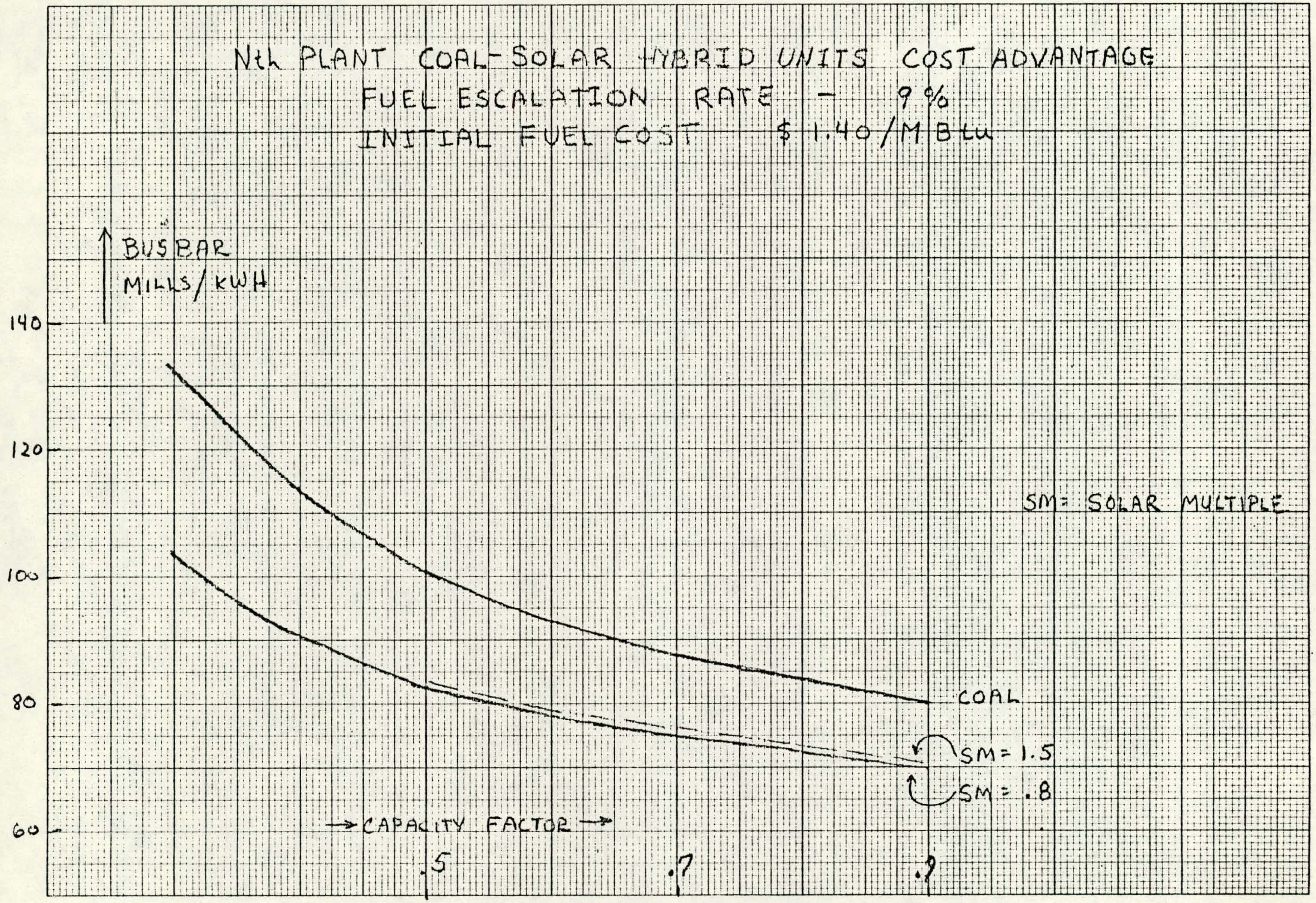
Nth PLANT COAL-SOLAR HYBRID UNITS COST ADVANTAGE
FUEL ESCALATION RATE - 9%
INITIAL FUEL COST $1.40/M Btu
BUSBAR
MILLS/KWH
140
120
100
80
60
SM= SOLAR MULTIPLE
COAL
SM= 1.5
SM= .8
CAPACITY FACTOR
.5
.7
.9

FIGURE 10

ALTERNATES TO DIRECT BURNING OF COAL

Introduction

While the use of coal is encouraged by U.S. policy and coal is more abundant and less likely to escalate in price, there are certain drawbacks to its use in hybrid solar power plants. The dusts arising from coal handling and storage operations and the particulates produced in combustion could reduce mirror efficiency and require additional maintenance. Transport of coal from storage at, or near, the edge of the heliostat field to the centrally located boiler can also pose operations and maintenance difficulties.

Technology exists for the conversion of coal to more easily transportable forms--gases or liquids. These fuels could be made in plants far enough removed to minimize or eliminate the impacts of coal handling on heliostat performance. The use of coal gases and liquids could also remove the particulate problem. Finally, these materials would permit the use of lower capital cost utility plant and better turndown ratios in the heater unit, approximately 10/1 instead of 5/1. Thus, more of the plant's output could come from solar energy.

Coal Gases

Coal gasification is an old art. Town gas, producer gas, and water gas were some of the coal gas products used for heating and lighting in the United States in the late 19th and early 20th century. These and similar products are still in limited use today in other parts of the world. Most have heating values of 180 Btu per standard cubic foot (scf) or below and are, consequently, referred to as low-Btu gases (LBG). More modern technologies now are used to produce these and higher heating value gases (intermediate-Btu gas (IBG) at 300 to 500 Btu per scf and synthetic natural gas (SNG) at approximately 1,000 Btu per scf).

LBG is produced by partial combustion and/or pyrolysis in air. The principal combustible ingredients in the product are carbon monoxide and hydrogen. Intermediate heating value IBG is produced using oxygen instead of air for the combustion/pyrolysis step, thus avoiding dilution of the product with nitrogen. SNG is produced by altering the CO/H_2 ratio of IBG by a water shift reaction to obtain a CO/H_2 ratio of 1/3 and then reacting the mixture, after removal of H_2S and CO_2, to produce methane.

It is generally considered uneconomic to transport LBG for more than 1 to 2 miles. This links the gasifier to a single power station and to those industrial consumers located in the immediate vicinity. It also does not significantly alter potential problems with coal dust. On the other hand, IBG can be transported economically up to 100 miles, with the distance determined by gas quality (heating value), market size, and pipeline requirements. SNG can be transported economically even greater distances. For these gases, the coal-related problems do not influence heliostat operations, and the gasification plant can be sized and operated in a manner that reflects a larger market.

The efficiency of conversion (heat content fuel out/heat content fuel in) and most developed gasification processes ranges from 60 to 70 percent (advanced processes may reach 75 to 80 percent). Thus, even without the substantial capital and operating charges associated with the gasification facility, the fuel cost to the power plant is 25 to 65 percent higher for gasified coal fuels.

The true cost of the fuel must include O&M costs and properly apportioned capital charges. The capital charges are dependent upon plant use factors. For example, a dedicated gasification facility operated in conjunction with a solar hybrid plant would run at 10 percent of capacity for a few hours around the solar peak, at 50 percent capacity at intermediate times, and at 100 percent of capacity during the night-time hours. The capacity factor overall might range from 40 to 50 percent. The dedicated plant output without means to level the load would range from 10^8 to 10^9 Btu per hour, a turndown ratio of 1/10. Such a turndown is not feasible for single gasification units. Both capacity factor and turndown ratio are unfavorable.

However, gasification units embodying entrained beds, e.g., Koppers-Totzek can have individual turndowns to 70 percent of complete load. A three-train system with rapid start-up and shut-down features could provide gas at rates ranging from 20 to 100 percent of full output.

To obtain full advantage of the turndown ratio, some storage would be required. This should amount to, at a minimum, 10 percent of full output for the 8 to 10 hours that the solar plant is making its full contribution to electricity generation. Such storage would be, perhaps, 3×10^6 scf. A 60-inch inside diameter pipe 1-mile long and a 60-foot outside diameter sphere both represent about 10^5 cubic feet. Unreasonably high pressures would be required for compact storage. (If LBG were used, the requirement for volume (or pressure) would nominally be 2-1/2 to 3 times as great).

If a 10-mile transmission line were required, then high-pressure pipe storage might be feasible. Also, if the gas requirements could be spread among properly selected customers, ones with compatible duty cycles, the storage requirement could be lessened further or eliminated. The multiple-customer approach would also increase the gasification unit use with reductions in gas cost, but would limit plant location and market penetration.

SRI has recently made an analysis on the cost of IBG production by several near-commercial technologies. These costs are approximately \$3.45 to \$4.25 per 10^6 Btu (1979 dollars) when calculated on the usual gas utility average price basis, assuming a 90 percent capacity factor.*

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*Plant producing 5×10^9 Btu per hour with a coal feedstock cost of \$1.00 per MMBtu. With coal at \$1.40 per MMBtu, the costs would range from \$3.95 to \$4.80 per MMBtu.

With a smaller, dedicated plant and its lower capacity factors, the costs are estimated to range from at least $4.10 to as much as $6.50 per million Btu.

Other financial assumptions and use of levelized rather than average costs would change these results. However, the changes are likely to be small in comparison to the fuel cost differences between synthetic gas and coal.

Coal Liquids

Liquids from coal are indigenous resources not subject to supply interruption or excessive cost caused by cartel actions. These fuels are readily delivered and stored. A recent SRI estimate of the cost of coal syncrude produced from Illinois No. 6 coal ($1.02 per million Btu) was $6.77 per million Btu (1979 dollars) for a plant producing 50,000 barrels per day of product suitable for boiler fuel. This cost assumes normal commercial development and rates of return on investment. A commercial plant might be in operation as soon as the late 1980's. Additional plants built in the 1990's would have technological improvements that could overcome part of the costs of inflation.

Methanol produced from $1.02 per million Btu coal is estimated at $7.60 per million Btu.

Shale Oil

An indigenous fossil fuel that is an alternate to coal is oil shale. The oil contained in shale in the United States is much more abundant than our residual petroleum reserves but not nearly as abundant as coal. Including mining costs, the price of a synthetic boiler fuel at plant gate could range from $3.15 to $5.10, with a likely price of $4.00 per million Btu (1979 dollars). These prices/costs will be reached only after substantial shakedown. Syncrude could be available by 1990, but costs would not be as low as $4.00 (1979 dollars) in that year.

Conclusions

Despite the disadvantages encountered in the direct burning of coal, it would seem that synthetic fuel alternatives are so expensive that they are not likely to be useful in advancing the coal hybrid concept. If the coal storage problem is severe, it could be avoided in part by use of silo storage and/or by location of the coal storage downwind of the plant, a nominal distance from the heliostat field. A trench or tunnel could be used for transporting coal to the combustion unit, and a short-term storage silo could be incorporated into the central operating complex.

TASK 3 - PARAMETRIC ANALYSIS

SOLAR ENERGY SYSTEM OPTIMIZATION

Further optimizations have been made for the solar system with the 120 m tower. These involved analyzing larger elongated receivers. The sizes included 12.0 m length by 10.4 m diameter, 13.5 m length by 10.4 m diameter, and 15.0 m length by 10.4 m diameter receivers. Two different aim strategies were investigated (single point equatorial aim and a high-low two-point aim). This was done to determine the effect on the peak flux incident on the receiver. Single point aim resulted in peak fluxes on the order of 1.9 MW/m^2, with the high-low two-point aim showing a marked reduction in peak flux to less than 1.4 MW/m^2. The two-point aim was only practical on the 13.5 and 15.0 m long receivers.

The results of the optimizations can be compared on Figures 11 and 12. Also shown for reference on Figure 11 is the previously analyzed 10.4 m x 10.4 m receiver. The input figure of merit (FMI) was increased from 65 to 72, and this variation can be compared directly for the 12.0 m long by 10.4 m diameter receiver. The FMI affects field density in an inverse fashion. Increasing the FMI tends to increase the optimum power level for a given receiver size due to a change in the allowable field density. The receiver/tower combination with the lowest figure of merit at the required power level (228.9 MWt) (208 MWt required with a field/receiver power ratio of 1.1) that operates at the acceptable reduced peak flux, is the 13.5 m x 10.4 m receiver shown on Curve Z of Figure 12.

Figure 13 shows the distribution of incident power on the selected 13.5 m x 10.4 m receiver at equinox noon. Only the east one-half of the receiver is shown because of the symmetry at noon. During the next reporting period, annualized performance data will be generated for the selected tower/receiver combination. Slight adjustments in field layout will be made in order to more evenly distribute the incident power from north to south on the receiver.

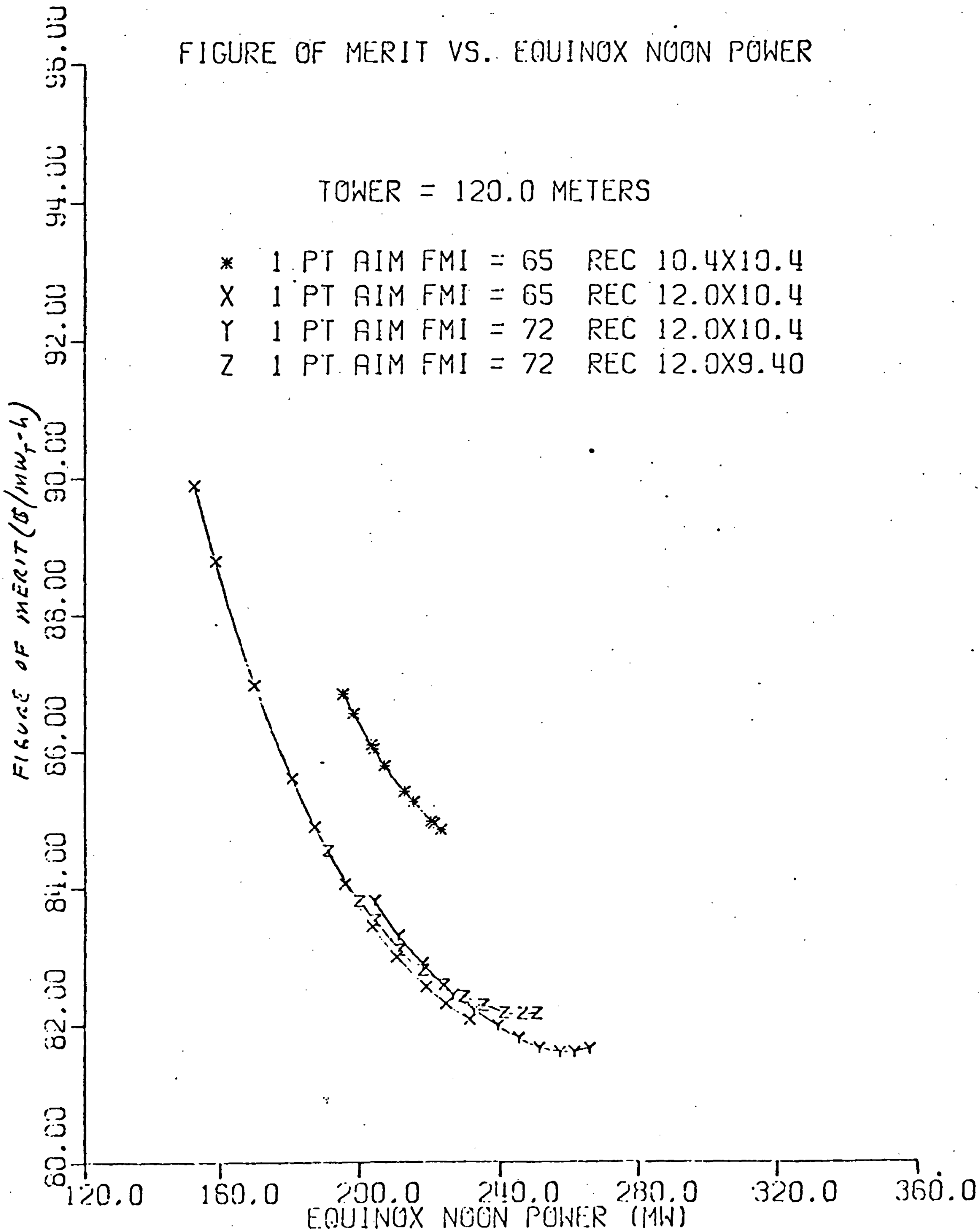


FIGURE OF MERIT VS. EQUINOX NOON POWER
TOWER = 120.0 METERS
* 1 PT AIM FMI = 65 REC 10.4X10.4
X 1 PT AIM FMI = 65 REC 12.0X10.4
Y 1 PT AIM FMI = 72 REC 12.0X10.4
Z 1 PT AIM FMI = 72 REC 12.0X9.40
FIGURE OF MERIT ($/MW_T-h)
EQUINOX NOON POWER (MW)
120.0
160.0
200.0
240.0
280.0
320.0
360.0

Figure 11.

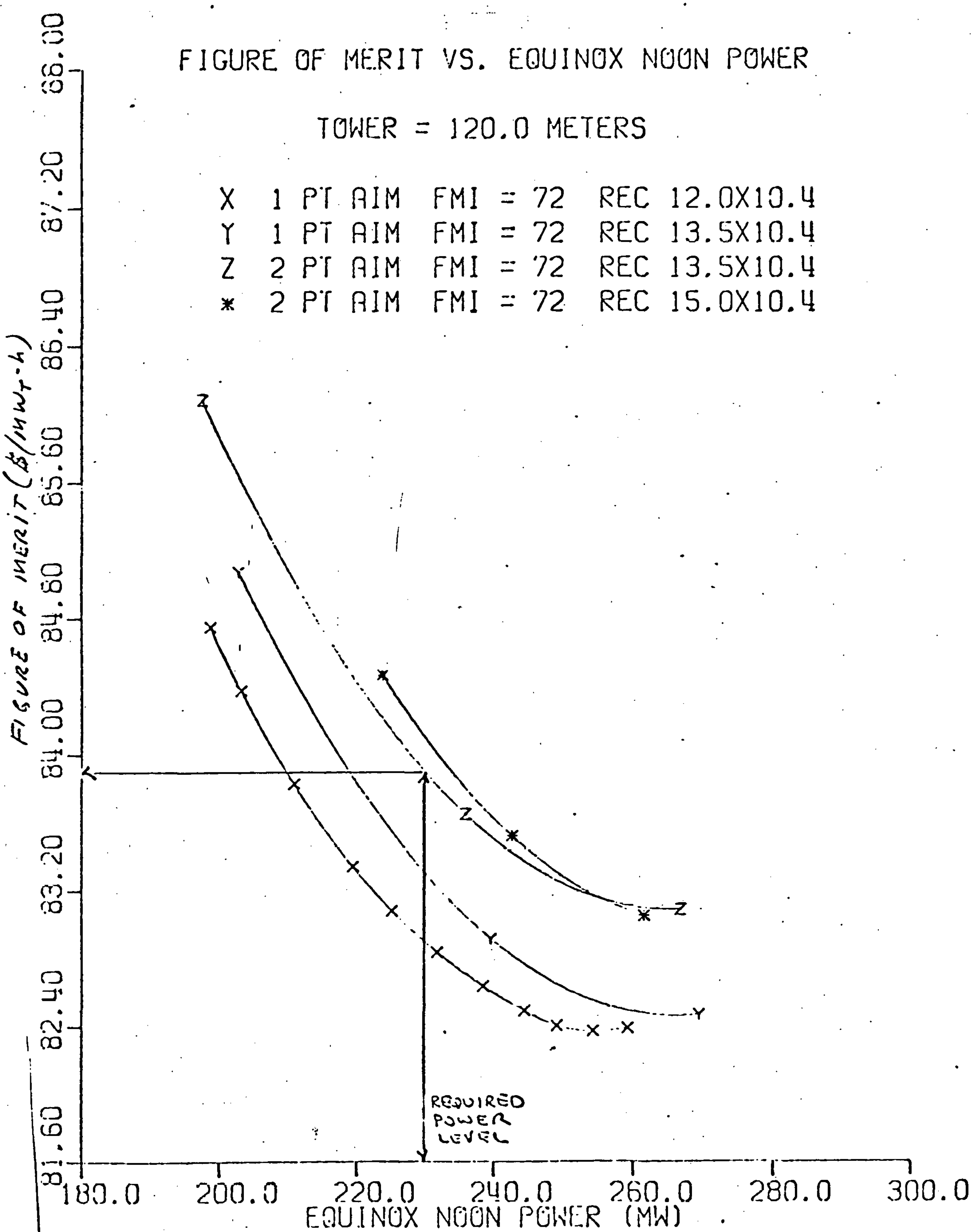


FIGURE OF MERIT VS. EQUINOX NOON POWER
TOWER = 120.0 METERS
X 1 PT AIM FMI = 72 REC 12.0X10.4
Y 1 PT AIM FMI = 72 REC 13.5X10.4
Z 2 PT AIM FMI = 72 REC 13.5X10.4
* 2 PT AIM FMI = 72 REC 15.0X10.4
FIGURE OF MERIT ($/MWT-h)
88.00
87.20
86.40
85.60
84.80
84.00
83.20
82.40
81.60
REQUIRED POWER LEVEL
180.0
200.0
220.0
240.0
260.0
280.0
300.0
EQUINOX NOON POWER (MW)

Figure 12.

An effort is underway to define and cost a water steam hybrid system, which has performance similar to the sodium system, to be used as a benchmark for comparative purposes. The basic configuration will be a variation (in power level and storage capability) of the 100 MWe commercial system defined during the MDAC Central Receiver Solar Thermal Power System Phase I study. The system is shown schematically in Figure 14 with the addition of a parallel fossil boiler.

FIELD RECEIVER POWER RATIO

The field receiver power ratio (FRPR) is defined here as the ratio of the power that could be accepted by an idealized receiver compared to the power the actual receiver of the same geometry can accommodate at the design point. In effect, this determines how many additional heliostats can be profitably added to the collector field and which are used only during off-peak insolation periods. The curves of the differential bus bar energy cost versus the FRPR for the 100 MWe plant are shown in Figure 15. The top curve is based on standard economic assumptions for the project. The bottom curve is based on the assumption that the additional heliostats can be purchased at the bulk rate but that their procurement would be at the end of the construction period and would be treated as a post-construction option. Utilizing the bottom curve, the optimum occurs at an FRPR of 1.1 which is the value selected for the hybrid design.

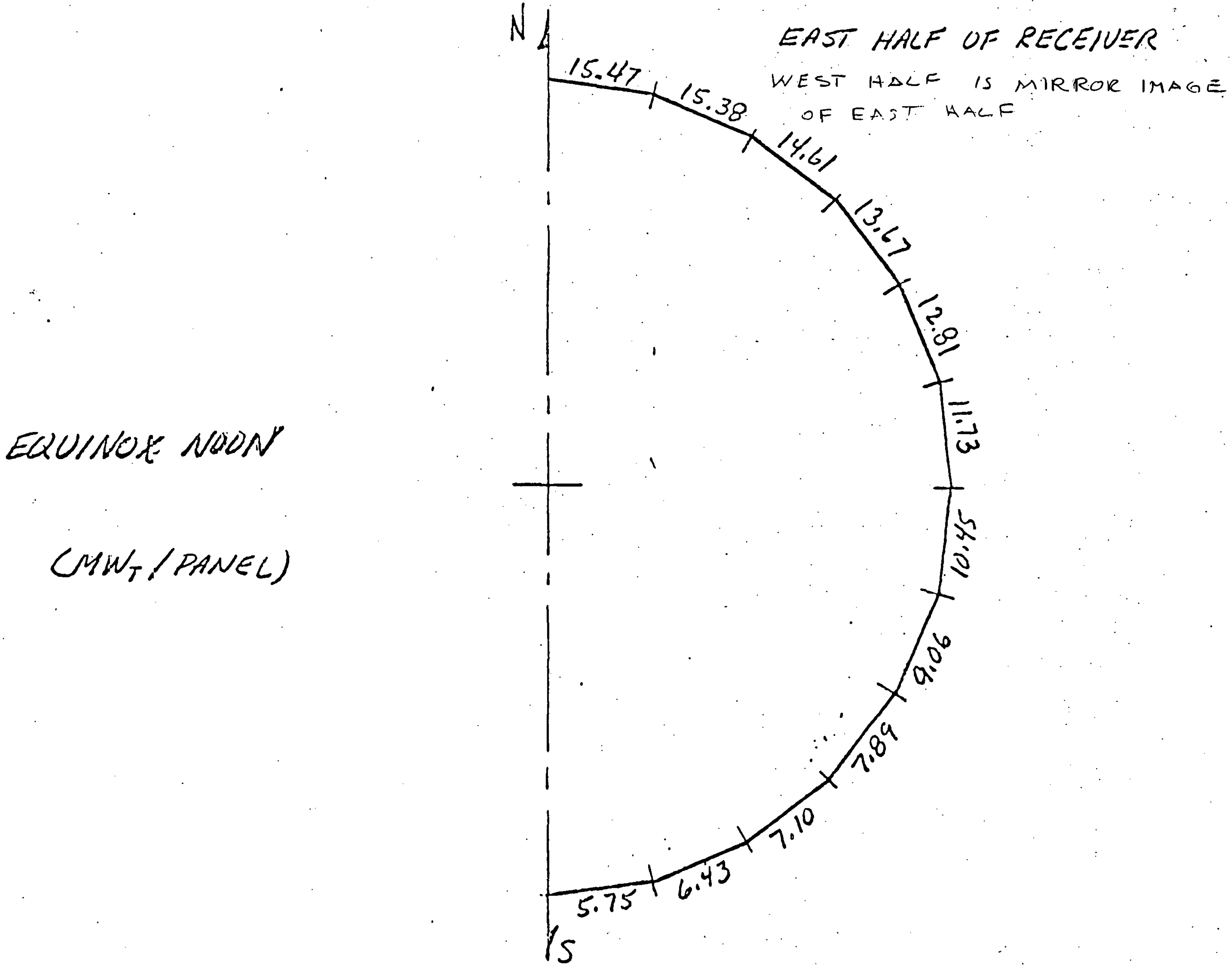
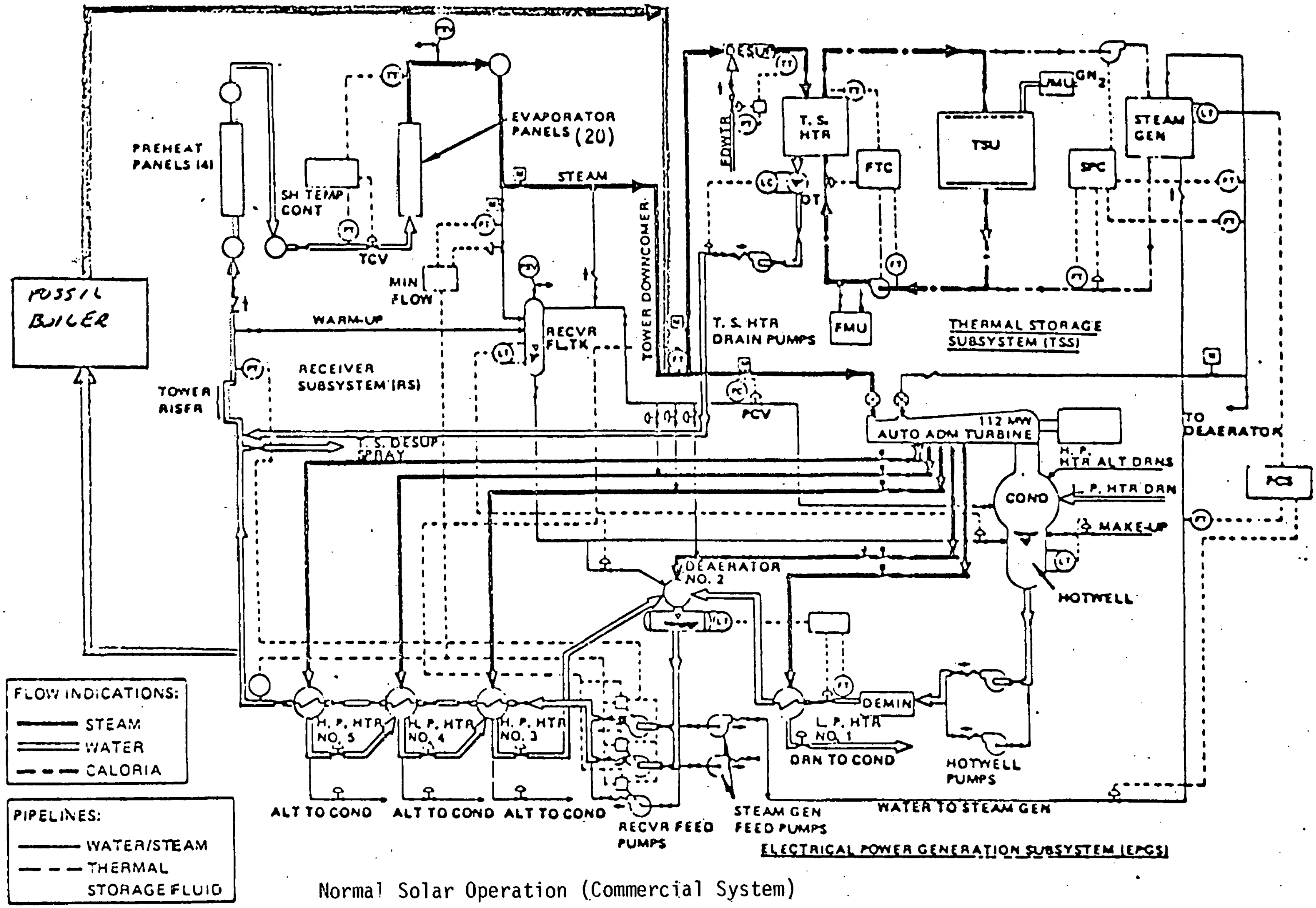
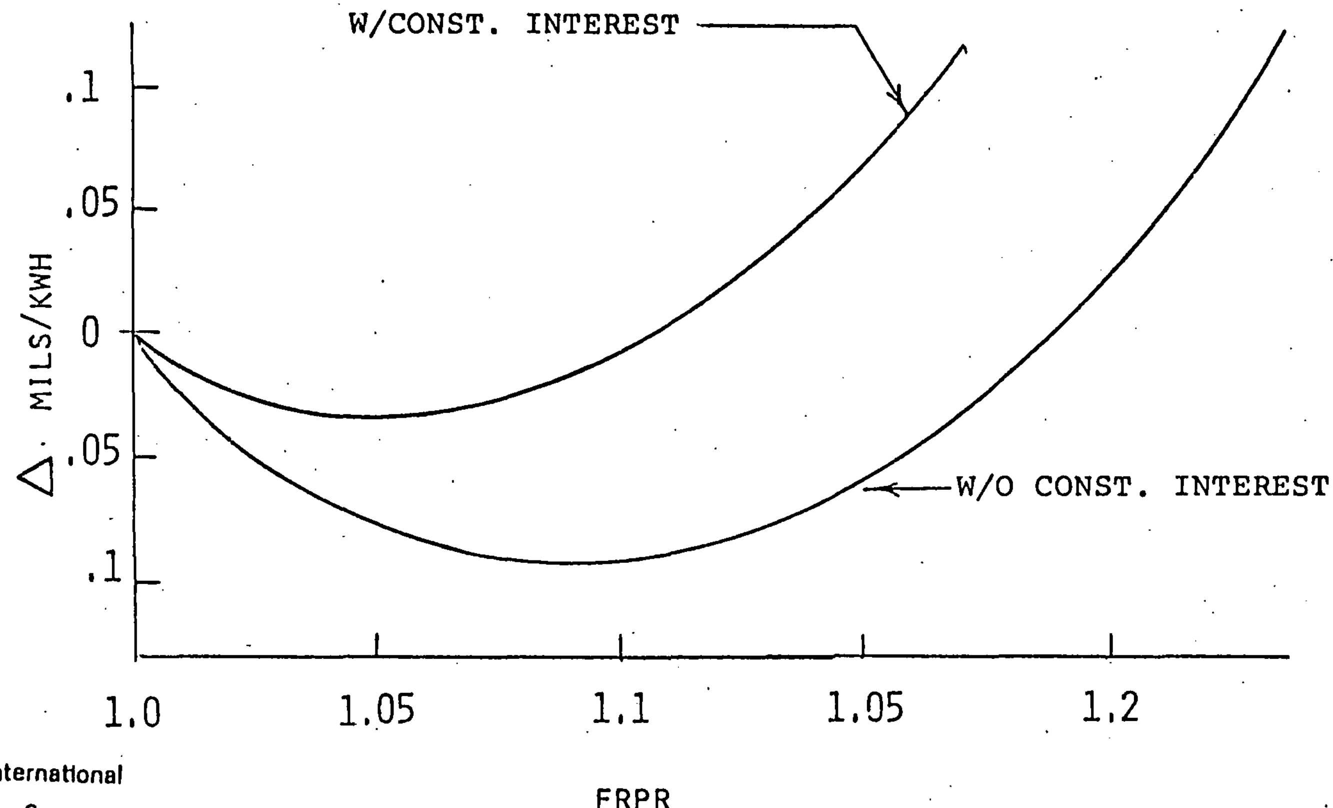


Figure 13. Incident Flux By Panel



Normal Solar Operation (Commercial System)

Figure 14



Rockwell International
Energy Systems Group

Busbar Energy Cost vs Field/Receiver Power Ratio

Figure 15

FOSSIL FIRED HEATER STACK STUDY

The results of the stack flow study are given in Figure 16 which shows the stack flow loss, exit gas velocity, and incremental ID fan power vs stack diameter. The stack diameter refers to that portion extending through the receiver. The stack diameter from grade elevation to the transition at the top of the tower was held constant at 12 ft 0 in. ID. Figure 17 shows the stack arrangement at the tower/receiver interface for an assumed inner stack diameter of 8 ft 0 in. ID. We have a 12-ft 0-in. ID RFP* stack liner from grade elevation to the transition piece at the top of the tower. The transition piece and remainder of inner stack is 316L stainless steel due to temperature, strength, and corrosion/erosion consideration, and is insulated on its outer surface. A stack outer shell is provided above the tower for temperature protection and is independent from the liner and is designed to take all wind loads.

The actual diameter of the upper stack will depend on the receiver configuration and clearance requirements for sodium piping, tanks, maintenance, access, etc., and the economic trade-off between stack diameter (fan power) and receiver cost. The stack height of 450 ft 0 in., called out on the drawing, is considered to be a minimum. There is a possibility that in order to minimize stack plume effects due to wet flue gas, stack gas reheating may be necessary. This could be accomplished by the addition of sodium heating coils at the base of the chimney.

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*RFP - Reinforced Fiberglass Plastic

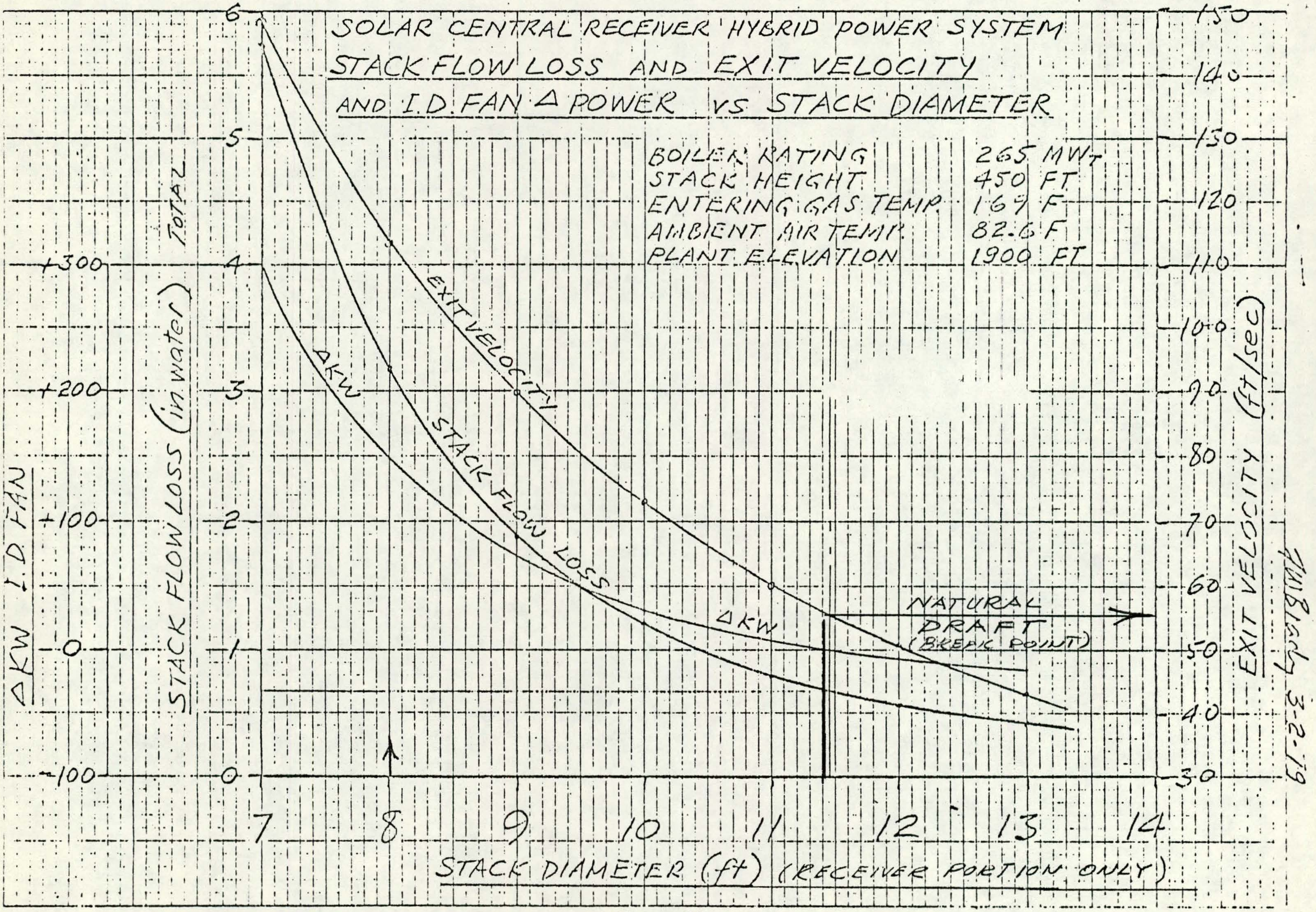
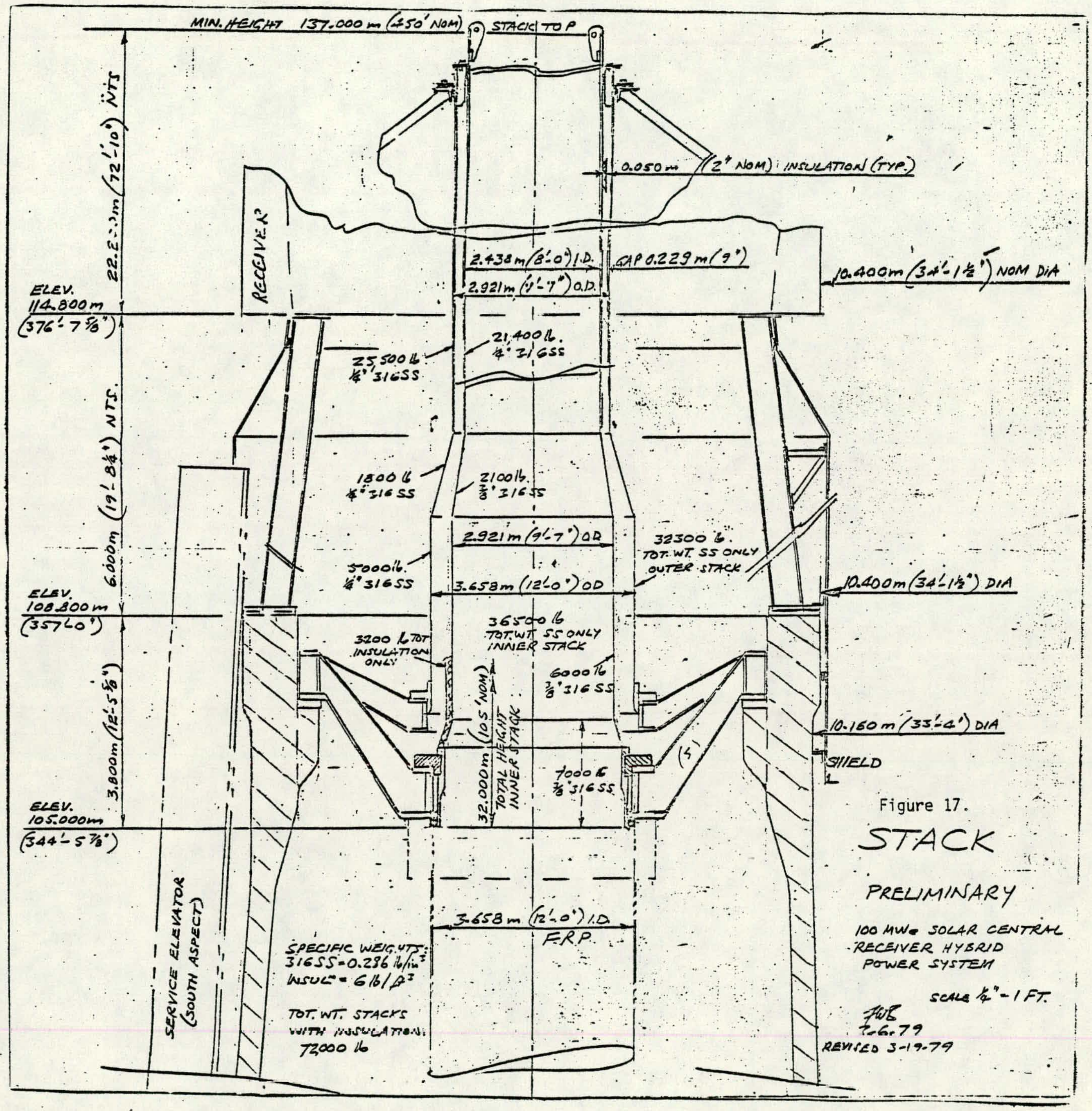

SOLAR CENTRAL RECEIVER HYBRID POWER SYSTEM
STACK FLOW LOSS AND EXIT VELOCITY
AND I.D. FAN Δ POWER VS STACK DIAMETER
BOILER RATING 265 MWT
STACK HEIGHT 450 FT
ENTERING GAS TEMP 169 F
AMBIENT AIR TEMP 82.6 F
PLANT ELEVATION 1900 FT
EXIT VELOCITY
STACK FLOW LOSS
ΔKW
NATURAL DRAFT (BREAK POINT)
ΔKW I.D FAN
TOTAL
STACK FLOW LOSS (in water)
EXIT VELOCITY (ft/sec)
STACK DIAMETER (ft) (RECEIVER PORTION ONLY)
+300
+200
+100
0
-100
6
5
4
3
2
1
0
150
140
130
120
110
100
90
80
70
60
50
40
30
7
8
9
10
11
12
13
14
3-2-79

Figure 16.


MIN. HEIGHT 137.000 m (450' NOM)
STACK TOP
0.050 m (2" NOM) INSULATION (TYP.)
RECEIVER
2.438 m (8'-0") I.D.
GAP 0.229 m (9")
2.921 m (9'-7") O.D.
10.400 m (34'-1½") NOM DIA
ELEV. 114.800 m (376'-7⅝")
21,400 lb. ¼" 316SS
25,500 lb ¼" 316SS
1800 lb ¼" 316 SS
2100 lb. ⅜" 316SS
2.921 m (9'-7") OD
32300 lb. TOT. WT. SS ONLY OUTER STACK
5000 lb. ¼" 316SS
3.658 m (12'-0") OD
10.400 m (34'-1½") DIA
ELEV. 108.800 m (357'-0")
36500 lb TOT. WT. SS ONLY INNER STACK
3200 lb TOT INSULATION ONLY
6000 lb ⅜" 316 SS
32.000 m (105' NOM) TOTAL HEIGHT INNER STACK
10.160 m (33'-4") DIA
SHIELD
7000 lb ⅜" 316SS
ELEV. 105.000 m (344'-5⅜")
6.000 m (19'-8¼") NTS
3.800 m (12'-5⅝")
3.658 m (12'-0") I.D.
F.R.P.
SERVICE ELEVATOR (SOUTH ASPECT)
SPECIFIC WEIGHTS: 316SS = 0.286 lb/in³ INSUL = 6 lb/ft³
TOT. WT. STACKS WITH INSULATION: 72000 lb
STACK
PRELIMINARY
100 MWe SOLAR CENTRAL RECEIVER HYBRID POWER SYSTEM
SCALE ½" = 1 FT.
FWB 2-6-79
REVISED 3-19-79
Figure 17.

FOSSIL FIRED SODIUM HEATER STUDY

The design of the heater has been completed in sufficient detail to permit preparing a cost estimate to be started. Other areas investigated during this report period were materials for the heater and the operation of the heater with respect to load change response.

A description of the heater design developed during the past month is attached. This design incorporates the "design basis coal" provided by Salt River Project. (The composition of this coal is given in Appendix A.) This change had a negligible effect on the design; however, the calculations were updated to be consistent with the design basis coal. A scope of supply for cost estimating purposes is provided in Appendix B.

An investigation of the materials for the heater was completed. The primary decisions involve materials that will come in contact with sodium (i.e., tubing, piping, heaters, and downcomers). Other materials are those typical for fossil units. It appears that tube metal thicknesses will be determined by fabrication requirements rather than by pressure requirements. Thus, the selection of tubing materials is limited by corrosion considerations.

There are two major limitations imposed by corrosion which are both temperature dependent. One is the oxidation of the material while the other is decarburization of ferritic materials in contact with sodium. A third corrosion consideration that is addressed in the design of the unit (i.e., gas temperatures in contact with peak metal temperatures) is coal ash corrosion.

Tubing in the low-temperature convection section of the heater can be fabricated from carbon steel. As sodium flows to the furnace, tube metal temperatures rise, oxidation limits of carbon steel are exceeded, and another material for the furnace tubes is required. Here the choice is 2-1/4 Cr - 1 Mo steel. The membrane panels can be fabricated from this material, and tube metal temperatures may go as high as 1000°F.

Another alloy is required for the high-temperature convection section due to the rate of decarburization of 2-1/4 Cr - 1 Mo above 1000^{o}F. (The practical oxidation limit has not been reached. The decarburization of this alloy results in a reduction in mechanical properties.) Two choices are possible, Type 304 stainless steel and 9 Cr - 1 Mo steel. Type 304 is preferred since total costs appear to be the same due to additional fabrication costs associated with using 9 Cr - 1 Mo.

The major material question related to the design and operation of the heater is limiting the tube metal temperature in the furnace. It may be difficult and will be costly to make furnace walls from higher alloys than 2-1/4 Cr - 1 Mo. At full load using an intermediate furnace mix, tube metal temperatures should be acceptable. At low loads, more of the total absorption takes place in the furnace resulting in higher sodium and tube metal temperatures. This can be controlled by gas recirculation, higher excess air, and firing with only the top row of burners in service. The first two reduce the gas temperature in the burner zone while the third effectively reduces the size of the furnace. With these controls, it is believed that tube metal temperatures can be held to acceptable values.

The final area to be covered is the load change response of the heater as it relates to the operation of the system. Two possibilities exist for the heater operating at minimum turndown waiting to go up in load. The first is that the unit is operating with one burner row in service. To ramp to full load would require firing of additional burners and would take an estimated 3-5 min to complete the ramp. The use of a "bin system" for storage of pulverized coal or pulverizer type (B&W type EL vs tube mill) would have little impact on this time.

The other situation is that the unit is operating with all burners in service by operation of oil ignitors to achieve the minimum turntown. In this case, the fuel being consumed is No. 2 oil or gas. This is an expensive mode of operation; however, with a "bin system" or a tube mill as a stored supply for pulverized coal, the unit can ramp to full load in about 1-1/2 min. The "bin system" adds an estimated $1M to the capital costs, whereas, tube mills offer the advantage of usable coal storage at the expense of higher operating costs at low loads (i.e., power requirements are essentially independent of load) and the inability to handle "wet" coals. Another point is that there is a hazard involved with operating over a period of time with oil ignitors in service. Oil and oily soot can accumulate on low-temperature convection and air heater surfaces and can easily be ignited resulting in a fire that is difficult to extinguish. Finally, operating with all burners in service at low loads makes it more difficult to control furnace absorption and tube metal temperatures.

Based upon these considerations, it is recommended that a conventional burner-pulverizer arrangement be used. This would require startup of burner-pulverizer sets to ramp to full load. However, this arrangement would result in the lowest capital and operating expense and would minimize hazards of operation.

Sketches of the heater arrangement, furnace heat load apportionment diagram, and a list of design comments and notes are contained in Appendix C.

APPENDIX A

DESIGN BASIS COAL

		Average	Range
1. Proximate Analysis			
Moisture		14.5	9.5 - 18.0
Volatile Matter		36.3	34.0 - 38.0
Fixed Carbon		36.7	32.0 - 41.5
Ash		12.5	9.0 - 18.0
BTU		10,000	9,000 - 10,800
2. Ultimate Analysis			
Moisture		14.5	9.5 - 18.0
Carbon		55.8	50.5 - 60.5
Hydrogen		4.2	3.9 - 4.8
Oxygen		11.5	10.0 - 13.5
Nitrogen		0.9	0.7 - 1.0
Sulfur		0.6	0.4 - 1.0
Ash		12.5	9.0 - 18.0
Chlorine		0.03	0.01 - 0.04
3. Ash Analysis			
Phosphorous Pentoxide	P_2O_5	0.08	0.05 - 0.12
Silica	SiO_2	57.78	47.50 - 63.00
Ferric Oxide	Fe_2O_3	6.21	3.90 - 7.90
Alumina	Al_2O_3	21.64	19.00 - 24.30
Titania	TiO_2	1.19	0.70 - 1.30
Lime	CaO	4.99	4.10 - 8.10
Magnesia	MgO	1.14	1.00 - 1.60
Sulfur Trioxide	SO_3	4.33	3.90 - 7.20
Potassium Oxide	K_2O	0.52	0.30 - 0.60
Sodium Oxide	Na_2O	1.78	0.40 - 2.10
Undetermined		0.34	
4. Grindability			
		50	43 - 55

DESIGN BASIS COAL
(Continued)

	Average	Range
5. Ash Fusion Temperature		
a) Reducing Atmosphere		
Initial Deformation	2190^{o}	2100 - 2750+
Ash Softening (H = W)	2320^{o}	2140 - 2750+
Ash Softening (H = 1/2W)	2340^{o}	2150 - 2750+
Fluid	2520^{o}	2300 - 2750+
b) Oxidizing Atmosphere		
Initial Deformation	2300^{o}	2200 - 2750+
Ash Softening (H = W)	2400^{o}	2260 - 2750+
Ash Softening (H = 1/2)	2420^{o}	2270 - 2750+
Fluid	2600^{o}	2450 - 2750+
6. Sulfur Forms		
Pyritic	0.2	0.1 - 0.7
Sulfate	0.0	0.0 - 0.2
Organic	0.4	0.2 - 0.8
7. Water Soluble Alkalies		
Na_2O_4	0.036	0.016 - 0.079
K_2O	0.003	0.000 - 0.007
8. Silica Value	82.4	74.0 - 92.4

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APPENDIX B

FOSSIL FIRED SODIUM HEATER

SCOPE OF SUPPLY

Coal feeders

Pulverizers

Pulverized coal conveying system

Primary air fan

Burners

FD and ID fans

Gas recirculation fan

Furnace and convection surface

Sodium piping and downcomers

Structural steel (Zone 3)

Enclosures

Insulation

Soot blowers (air)

Air heater

Burner and combustion controls

Particulate removal equipment

SO_2 removal equipment (FPGD-APC)

Erection

Items such as foundations, ash handling system, coal storage and chimney will be provided by Stearns-Roger.

731-D.256/jmh/sjh

APPENDIX C

FOSSIL FIRED SODIUM HEATER DESIGN

	Item	Notes
1.	Heater Rating = 265 MW_t - heats 5.4×10^6 lb/hr sodium from 550° to 1100°F.	
2.	Fuel - Pulverized coal (Western).	See "Design Basis Coal".
3.	Fuel Handling Equipment	
	Heat input from fuel = 1.04×10^9 Btu/hr.	Combustion calculations (heater) efficiency = 87%).
	Fuel feed rate = 52 T/hr.	
	Three Type EL-76 (ball and race) pulverizers are specified on the basis of load change response and capacity range.	
	Fuel feed system - direct feed from pulverizers with one pulverizer per burner row (compartmented windbox).	To meet NO_x requirements (0.5 lb NO per million Btu's). Expected EPA requirements.
4.	Combustion Equipment	
	Total air = 115% @ full load.	NO_x requirements.
	Nine dual register burners are specified with a heat input per burner of 116×10^6 Btu/hr.	NO_x requirements (min. secondary air temperature @ full load = 500°F).
	This gives three burner rows with three burners per row (opposed wall firing: two rows front wall, one row rear wall). Each burner row and its associated pulverizer act as a set with a net turndown of 2.5:1 (approximately). Limiting factors are the flow of primary air and the ratio of primary air to fuel.	Maximum unit turndown is 5:1 achieved with one burner row in service (one of the top rows to cut furnace absorption at low loads).

FOSSIL FIRED SODIUM HEATER DESIGN
(Continued)

Item	Notes
5. Furnace Plan Area - 36 ft x 30 ft based upon burner clearances. With furnace tubes 1-1/4 in. OD (0.148 in. wall) on 1-3/4 in. centers (membrance panels), the plan area allows for approximately 900 tubes. The sodium velocity inside tubes is just under 7 ft/sec.	See attached figure.
6. Radiant Surface - This is determined by a balance between the dimensions required for the fuel type and burner arrangement and the furnace exit gas temperature limit ($2250^{o}F$). The liberation rate is under 18,000 Btu/ft^3-hr.	See attached figure for dimensions. For this arrangement, the furnace exit gas temperature is under $2200^{o}F$ at full load. Surfaces cleaned by wall soot blowers (compressed air).
7. Heater Arrangement - The following serve as a basis for the design:	
a. Upflow for fluid being heated	External downcomers
b. Drainable surface	
c. Slagging	Furnace dimensions
d. Fouling and erosion	Convection tube spacing
8. Heat Balance - See attached figure for temperature profiles.	
9. Convection Surface Arrangement	
High Temperature Convection (2-1/2 in. OD Tubes	Soot blowers on both sides of banks (except the last bank - one side blowing with gas flow).
Cavity dimensions 14 ft x 30 ft.	
First bank - 24-in. side spacing, 24 rows high, feed 8 tubes high x 13 wide (sodium velocity = 10 ft/sec). Gas velocity entering bank is less than 50 ft/sec.	Tube spacing in direction of gas flow - 3.125 in. C_L to C_L.

FOSSIL FIRED SODIUM HEATER DESIGN
(Continued)

Item	Notes
9. Continued	
Second bank - 12 in. side spacing, 24 rows high. Gas velocity entering bank is under 50 ft/sec.	
Third bank - same as second bank.	
Fourth bank - 6-in. side spacing, 16 rows high. Gas velocity entering bank is approximately 50 ft/sec.	
Fifth bank - 6-in. side spacing, 12 rows high.	
Total surface - 27,800 ft^2.	Exceeds requirements based upon heat transfer calculations.
<u>Screen</u> - (between high and low temperature convection sections). Gas velocity is under 50 ft/sec with a 10-ft high cavity.	Tubes with 18-in. side spacing.
<u>Low Temperature Convection (2-1/2 in. OD Tubes</u>	
Four-in. side spacing, cavity - 22 ft. x 30 ft. Gas velocity entering section is under 50 ft/sec. Sodium feed 2 tubes high x 88 wide, velocity = 6 ft/sec.	Area for downcomer flow - 3 ft^2. Soot blowers on both sides of banks.
Three banks, each 16 rows high.	
Total surface = 60,800 ft^2.	Exceeds requirements based upon heat transfer calculations.
10. <u>Materials</u> (Tubing)	
Low temperature convection - carbon steel. Furnace tubes - 2-1/4 Cr - 1 Mo. High temperature convection - TP 304	Alternate is 9 Cr - 1 Mo.

FOSSIL FIRED SODIUM HEATER DESIGN
(Continued)

Item	Notes
11. Air Heater - regenerative type - design conditions.	(Adequate for load change response.) Stationary surface - rotating ducts.

	Temp(F)	Flow(lb/hr)
Air(in)	80	0.9×10^6
Air(out)	500	0.9×10^6
Gas(in)	700	1×10^6
Gas(out)	300	1×10^6

12. Auxiliary Equipment - see Appendix B.

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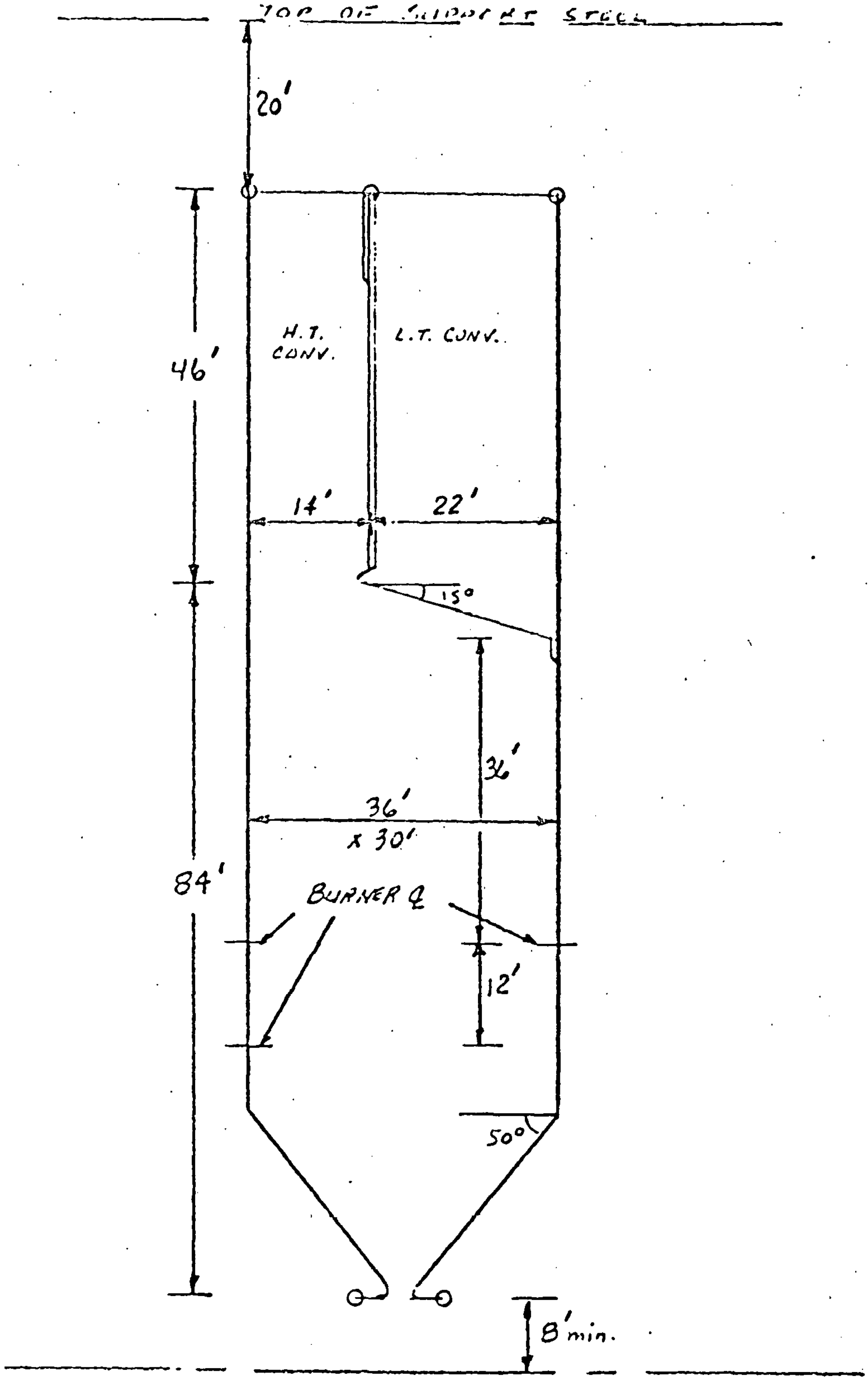

FOSSIL FIRED SODIUM HEATER (265 MWt)

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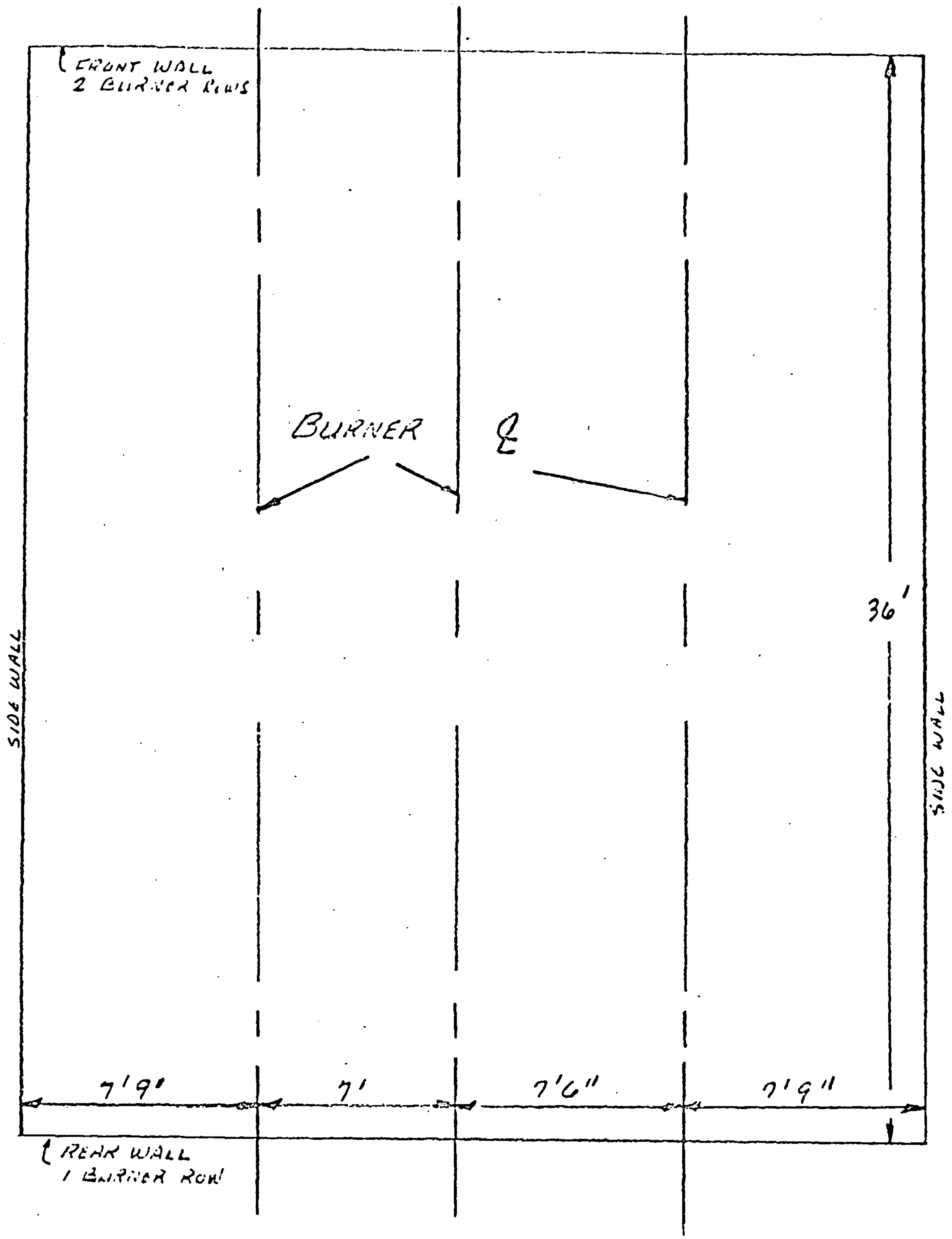

FOSSIL FIRED SODIUM HEATER

FURNACE PLAN AREA

K&E 10 X 10 TO 1/2 INCH 46 1320
7 X 10 INCHES MADE IN U.S.A.
KEUFFEL & ESSER CO.