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MONTHLY TECHNICAL PROGRESS REPORT

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FOR THE MONTH OF DECMEBER 1978

SOLAR CENTRAL RECEIVER HYBRID POWER SYSTEM

MASTER

ISSUE DATE: JANUARY 17, 1979

SEE LETTER DTD IN reply to 79ESG-393

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MONTHLY TECHNICAL PROGRESS REPORT
FOR DECEMBER 1978

EXECUTIVE SUMMARY

Task 1: Complete.

Task 2: Levelized busbar energy costs for the sodium-cooled hybrid central receiver concept using both oil and coal as a fuel were developed as a function of the plant capacity factor and as a function of the solar multiple. The values varied from 109 mill/kWh down to 46.9 mill/kWh as the capacity factor varied from 27 to 90%, respectively, for a fuel escalation of 8% for coal. The fuel escalation question was reviewed in detail during this reporting period on the basis of past historical data, and it was concluded that the lower escalation numbers that are provided in the requirements definition document appear to be more likely to represent the real situation.

Task 3: Subsystem-level trade studies were continued during this reporting period. A detailed investigation of the series/parallel arrangement of the sodium heater and solar receiver was conducted. The various performance, lifetime, and cost factors were determined for each arrangement for the receiver and nonsolar subsystems, respectively.

Collector subsystem studies were continued. Revised cost algorithms that include levelized O&M costs for the heliostats were generated in order that they can be used in the field optimization. By including the O&M, which is a more realistic approach, one can change, to some extent, the optimization point between collector field size, receiver size, tower height, and other factors. The revised heliostat cost, including the O&M factor, is $\$71.96M^2$, $\$11.84/M^2$ of this amount being that related to O&M.

Task 4: On the basis of the subsystem studies and the economic assessment work, a reference configuration was tentatively derived. This configuration does not require storage and uses a parallel arrangement of the receiver and the heater. At this time, a coal-fired heater seems to have a potential economic advantage under realistic assumptions for the escalation of coal relative to oil over the next decade or so.

I. CONTRACT OBJECTIVES

The overall, long-term objective of the program is to identify, characterize, and ultimately demonstrate the viability and cost effectiveness of a solar/fossil, steam Rankine cycle, hybrid power system that (1) consists of a combined solar central receiver energy source and a non-solar energy source at a single, common site, (2) operates in the intermediate capacity mode, (3) produces the rated output independent of variations in solar insolation, (4) provides a significant savings (50% or more) in fuel consumption, and (5) produces power at the minimum possible cost in mills/kWh. It is essential that this hybrid concept be technically feasible and economically competitive with other system in the near- to mid-term time period (1985-1900) on a commercial scale.

The program objective for Phase I is to identify and conceptually characterize a solar/fossil steam Rankine cycle, commercial-scale, power plant system that appears to be economically viable and technically feasible. In order to realize this goal, parametric analyses will be performed, a market analysis will be conducted, a preferred commercial configuration will be selected, a conceptual design, including drawings and cost estimate, will be prepared, and an assessment (in terms of economics, safety, environmental effect, market potential, etc.) of the hybrid concept will be carried out.

II. CONTRACT TASKS

This report is for the month of December 1978. The progress is presented by tasks.

TASK 1 - REVIEW AND ANALYSIS OF REQUIREMENTS DEFINITION

Complete.

TASK 2 - MARKET ANALYSIS

Work has continued on estimation of market size. As preliminarily reported last month, California, and particularly Texas, forms the largest potential market for new power plants. Texas markets suffer from the fact that the areas with the greatest demand have somewhat poorer direct solar insolation conditions. If the solar hybrid is considered an intermediate plant, then the costs of transmission of solar electricity from high solar to low solar areas will be quite high. However, if the solar hybrid is run as a base-loaded plant, then the transmission could be justified. (The base load mode of operation has more favorable economics as shown below.)

Fuel Prices

The economics of hybrid solar central station power plants are significantly influenced by fossil fuel prices. Even though basic assumptions regarding these fossil fuel prices were furnished for baseline comparison, it is of interest to examine them in order to provide a basis for future projections.

Past Prices

Past average fossil fuel prices (1967-1977) to electric utilities in selected western states are set forth in Table I. Average annual rates of escalation in current and constant 1977 dollars (calculated by using implicit GNP inflator/deflator factors) are set forth in Table II. The annual growth rates are set out for the periods 1967-1973 and 1973-1977 separately, so that the market influence of the increase in world oil price observed in 1973-1974 would be demonstrated.

For coal, average annual increases of delivered fuel prices in constant dollar terms of 3.5 to 36% were recorded over the 1973 to 1977 period. Increases for oil and gas ranged from 14 to 33% and 17.8 to 36%, respectively, for the states investigated.

The prices shown on Table I for the 1975-1977 period were recorded on an "as purchased basis." Previously, they were in an "as burned" basis. The former are expected to be lower than the latter prices by $0.01 to $0.05 per million Btu on the average.

Future Prices

In a detailed examination of prices by region, estimated prices of fuels for electricity production by region have been made.* The analysis produced the estimates shown in Table III.

Direct comparison between prices quoted from this forecast and the purchase records of Table I is difficult because of differences in exact location, transportation cost, etc. Also, the delivered prices of Table I represent a mix of very old to new contracts, while the projected

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*"Fuels and Energy Price Forecasts." EPRI-433. Electric Power Research Institute, Palo Alto, California, 1977

Table I

PRICES OF FUELS FOR ELECTRIC UTILITIES
(Cents per Million Btu)

	Current Dollars											Constant 1977 Dollars										
	1967	1963	1969	1970	1971	1972	1973	1974	1975	1976	1977	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977
Arizona																						
Coal	24	25	26	27	29	32	31	22	21	22	47	43	43	42	42	43	45	41	27	23	23	47
Gas	29	29	32	34	37	39	42	53	73	97	108	52	50	52	53	54	55	56	64	81	102	108
Oil/No. 2 +6	59	28	84	56	74	86	100	163	211	228	231	106	48	137	87	109	121	133	198	234	241	231
California																						
Coal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Gas	31	31	31	32	35	38	42	58	104	156	210	55	53	50	50	52	54	56	71	116	165	210
Oil/No. 2 + 6	31	32	35	37	55	74	88	170	250	234	237	55	55	57	57	81	105	117	207	278	247	237
Colorado																						
Coal	22	22	24	24	26	28	29	39	48	49	61	39	38	39	37	38	40	39	47	53	52	61
Gas	22	22	23	24	26	28	35	42	59	82	106	39	38	37	37	38	40	47	51	66	87	106
Oil/No. 2 + 6	39	66	51	39	59	54	89	190	198	166	194	70	113	83	60	87	76	119	231	220	175	194
Kansas																						
Coal	25	25	23	28	29	32	33	39	67	74	75	45	43	37	43	43	45	44	47	74	78	75
Gas	23	23	27	24	26	26	29	35	48	71	101	41	39	44	37	38	37	39	43	53	75	101
Oil/No. 2 + 6	44	44	74	49	61	58	79	123	165	168	210	79	75	121	76	90	82	105	150	183	177	210
New Mexico																						
Coal	14	15	14	14	15	15	17	20	23	26	29	25	26	23	22	22	21	23	24	26	27	29
Gas	22	22	23	24	25	29	34	48	69	95	145	39	38	37	37	37	41	45	58	77	100	145
Oil/No. 2 + 6	32	36	36	41	57	67	86	171	225	262	249	57	62	59	63	84	95	115	208	250	277	249
Utah																						
Coal	22	19	21	23	29	29	34	36	48	64	74	39	33	34	36	43	41	45	44	53	68	74
Gas	27	27	27	27	28	31	32	41	62	94	109	48	46	44	42	41	44	43	50	69	99	109
Oil/No. 2 + 6	25	25	25	25	25	26	50	138	204	201	212	45	43	41	39	37	37	67	168	227	212	212
Texas																						
Coal	--	--	--	--	na	21	13	17	23	30	58	--	--	--	--	na	30	17	21	26	32	58
Gas	20	20	21	21	22	23	27	44	77	102	123	36	34	34	33	32	32	36	54	86	108	123
Oil/No. 2 + 6	48	64	38	53	58	68	92	154	194	188	210	86	110	62	82	85	96	123	187	216	199	210

Source: National Coal Association, Steam Electric Plant Factors, 1968-78 eds. (T-2 "Cost as burned," 1967-74)
Deflated by GNP factors. (T-2 "Cost as received," (Avg.), 1975-77)

Table II

ESCALATION RATES FOR FUEL PRICES TO ELECTRIC UTILITIES

	Average Annual Growth Rates* (%)		Average Annual Growth Rates† (%)	
	1967/73	1973/77	1967/73	1973/77
Arizona				
Coal	4.4	11.0	(0.8)	3.5
Gas	6.4	27.0	1.2	17.8
Oil/No. 2 + 6	9.2	23.0	3.8	14.8
California				
Coal	----	----	----	----
Gas	5.2	50	0.3	39
Oil/No. 2 + 6	19.0	28.0	13.4	19.3
Colorado				
Coal	4.7	20.0	-0-	11.8
Gas	8.1	32	3.2	23.0
Oil/No. 2 + 6	14.7	21.0	9.2	13.0
Kansas				
Coal	4.7	23.0	(0.4)	14.3
Gas	3.9	36	(0.8)	27.0
Oil/No. 2 + 6	10.2	28.0	0.6	18.9
New Mexico				
Coal	3.3	14.3	(1.4)	6.0
Gas	7.5	44	2.4	34
Oil/No. 2 + 6	17.9	30	12.4	22.0
Utah				
Coal	7.5	21.0	2.4	13.2
Gas	2.9	36	(1.8)	26.0
Oil/No. 2 + 6	12.2	44	6.9	33
Texas				
Coal	----	45	----	36
Gas	2.4	46	-0-	36
Oil/No. 2 + 6	11.4	23.0	6.2	14.3

*Current dollar basis.

†Constant dollar basis.

Source: National Coal Association, Steam Electric Plant Factors, 1968-78 eds. (T-2 "Cost as burned," 1967-74) (T-2 "Cost as received," (Avg.), 1975077). Deflated by GNP factors.

Table III

PROJECTED GROWTH RATES OF FUEL PRICES
(Dollars per Million Btu)[1]

Region	1980	1986	1992	2001	Average Annual Revenue (Percent) 1980-2001
West South Central					
Coal HS	.92	.99	1.02	0.97	0.26
Coal LS	1.15	1.15	1.15	1.20	0.20
Oil[2]	2.45	2.75	3.07	3.38	1.60
Gas[3]	2.22	2.66	3.12	3.57	2.3
Rocky Mountain					
Coal LS	.86	.88	.88	.85	--.1
Oil[2]	2.49	2.76	3.04	3.22	1.2
Gas[3]	2.19	2.36	2.51	2.67	0.96
Pacific					
Coal LS	1.24	1.28	1.28	1.28	0.15
Oil[2]	2.43	2.67	2.94	3.25	1.4
Gas[3]	2.53	2.74	2.89	3.01	0.89

1. Region gate marginal prices, 1975 dollars.

2. Low sulfur resid.

3. Deregulated

prices of Table III are marginal or new production prices. Oil prices (in constant dollars) are forecast to rise at 1.2 to 1.6% per year for the solar significant regions of the U.S. This compares very well with a predicted general world oil price rise of 2% to be discussed below. For coal, regional prices are estimated to remain level or grow at very low (to 0.26% per year) annual rates.

With a new equilibrium reached after the abrupt changes on world energy markets imposed by OPEC in 1973-1974, price increases are likely to be moderate. In a recently completed analysis of worldwide supply, demand, and price relationships, it is forecast that world oil prices (constant dollars) will remain relatively constant between 1975 to 1980 and then rise at approximately 2% per year until 2000 and beyond. The mine mouth price of high sulfur eastern coal is forecast to remain relatively constant. Natural gas is expected to rise to a price (on a per-Btu basis) slightly above that for distillate. The rationale behind this prediction, arrived at through detailed modeling of world and regional energy trade, is explained below.

It is believed that the increased prices of fossil fuels will have a marked effect on demand for fuels and energy. Already the effects of conservation can be seen in lower Energy/GDP* ratios. In industrial countries, energy demand in the residential/commercial sector grew 50 to 70% faster than GDP/capita in the 1960's. It is projected to grow at 10 to 20% slower than GDP/capita in the period 1975-2000. Industrial energy efficiency in the U.S. is expected to improve 30 to 40% over the same period. Also in the U.S., mandated automobile fleet standards will result in at least one-third less consumption for each automobile after 1985. Thus, it is expected that gasoline demand will drop after 1985.

Increased prices will also increase supply. There are ample supplies of fossil fuels on a worldwide basis until sometime in the next century.

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*GDP - Gross Domestic Product

While discovery of major fields like those of Saudi Arabia is unlikely,* higher prices should result in further exploration and development of small fields and further exploitation of existing fields (secondary and tertiary recovery). The U.S. has ample (several centuries at current consumption) coal reserves.

Declining growth in demand and increasing supply have already resulted in a decline in the constant dollar price of oil. Continuation of these trends in supply and demand will produce the low growth in constant dollar prices forecast here.

The 2% rise in constant dollar oil prices forecast to 2000 and the zero growth of Western coal prices suggests that the lower inflation rates provided by DOE are the most appropriate for economic comparisons. If the general U.S. inflation rate is assumed to range from 6 to 8% in the period beyond 1990, then oil inflation rates of 8 to 10% would be expected. Coal prices should escalate at a slower rate, in the range of 6 to 8% on a current dollar basis.

Solar Electricity Prices

The influence of time of operation, capacity factor and fossil fuel price escalation on the costs of electricity produced by hybrid solar central station power plants has been investigated. The purposes of the investigation were twofold.

- To establish approximate prices as guidance to market analysis.

- To provide economic comparison between hybrid systems using coal, gas, and oil. This comparison plays an important role in the selection of the design basis fuel and related plant systems.

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*It should be noted, however, that Mexico's oil and gas reserves may equal or even exceed those of Saudia Arabia.

The cost of electricity was calculated on a 30-year levelized cost basis using EUTBEC, an SRI computer code based on the methods described by J. S. Doane, et al.* This code is similar to BUCKS, but does not require allocation of capital costs by plant segment.

The economic parameters used for the calculations are given in Table IV. Basic fuel costs (1978) and escalation rates were taken from the requirements definition document.** They are in reasonable agreement with the data presented above.

The results of the calculations are given in Table V. As indicated in the table, the plants were assumed to be producing power for periods ranging from 110 to 329 days per year (30 to 90% of calendar days). All plants were assumed to be online or on hot standby 90% of the calendar days. The plant was assumed to operate over these times at average power outputs ranging from 44 to 100% of rated capacity. A wide range of costs was obtained with the lower production costs, as expected, arising with heavy plant usage--longest available times and highest power usage. The lowest estimated cost was $0.047 per kWh achieved by a coal-fired hybrid operating at 100% of rated power for 90% of the calendar days, (6% average annual increase in the cost of fuel).

Inspection of Table V suggests coal will be more economic than oil as a hybrid fuel under many conditions. Gas, while included in Table V, was not seriously considered in the comparisons because of likely long-term prohibitions against its use as a utility fuel. Tables VI and VII set forth some of these conditions. Table VI deals with the case of equal escalation in all fuel prices. Table VII allows for a difference of 2% in the escalation rates of oil and coal with coal being the lower.

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*"The Cost of Energy from Utility-Owned Solar Electric Systems. A Required Methodology for ERDA/EPRI Evaluations." Jet Propulsion Laboratory, 1976.

** T. H. Springer to Subcontractors, "Solar Central Receiver Hybrid Power Systems Requirements Definition, " ESG Letter Number 78ESG-10379 dated November 21, 1978.

Table IV

FINANCIAL ASSUMPTIONS

Base Year for Costs	1978
Year of First Investment	1985
Year of Commercial Operation	1990
System Lifetime	30 Years
Rated Output	100 MW
Depreciation Option	Sum-of-the-Years' Digits
Depreciation Lifetime	22 Years
Debt/Equity Ratio	50/50
Corporate Debt Interest Rate	8 %
Rate of Return	12 %
Federal and State Taxes	50 %
Other Taxes, Investment Tax Credit, and Insurance	0 %
Capital Expenditure Escalation Rate	10 % per year
O&M Cost Escalation Rate	8 % per year
Fuel Cost Escalation Rate	6, 8, 10, 15 % per year
Base Capital Cost (in 1978 dollars)	
Coal	$ 128 million
Oil	$ 116 million
Gas	$ 113 million
Deflator used in converting 1990 levelized electricity costs to 1978 dollars	8 % per year

Table V

EFFECTS OF FUEL PRICE INFLATION ON LEVELIZED BUSBAR COSTS FOR ELECTRICITY PRODUCTION, HYBRID SOLAR POWER PLANTS

Costs in Mills/kWh

1978 Dollars

Case	At Power (%)	CF (%)	Power Level Ave. %	Fuel Escalation Rate (%/Yr.)	Cost: Oil	Coal	Gas (at $2.10)	Gas (at $2.75)
1	30	30	100	6	101.4	110.1	99.5	103.6
				8	109.0	115.8	107.5	113.9
				10	121.7	125.4	120.8	131.4
				15	208.7	190.7	211.7	250.5
2	50	40	80	6	82.4	86.0	81.2	86.1
				8	91.5	91.6	90.8	98.6
				10	106.9	100.9	106.8	119.7
				15	211.7	164.4	216.4	263.1
3	50	50	100	6	72.1	72.7	71.5	77.2
				8	82.9	78.8	82.7	91.9
				10	100.9	89.1	101.6	116.7
				15	224.3	159.2	230.7	285.7
4	75	40	53	6	80.6	84.3	79.4	83.7
				8	88.7	88.8	87.8	94.7
				10	102.3	96.3	102.0	113.3
				15	194.8	147.6	198.6	239.8
5	75	60	80	6	64.0	62.6	63.7	69.6
				8	75.2	68.4	75.4	84.8
				10	93.9	78.2	94.9	110.4
				15	221.4	144.8	228.3	285.2
6	75	75	100	6	57.4	53.9	57.4	64.0
				8	69.8	60.2	70.3	80.9
				10	90.6	70.9	92.0	109.3
				15	232.1	143.6	240.1	303.2
7	90	40	44	6	79.6	83.2	78.3	82.2
				8	87.0	87.1	86.0	92.4
				10	99.4	93.6	99.1	109.4
				15	184.5	137.6	187.9	225.8

Table V
(Concluded)

Case	At Power (%)	CF (%)	Power Level Ave. %	Fuel Escalation Rate (%/Yr.)	Cost: Oil	Cost: Coal	Cost: Gas (at $2.10)	Cost: Gas (at $2.75)
8	90	60	67	6	63.4	61.9	63.0	68.6
				8	74.1	67.3	74.1	83.3
				10	92.0	76.3	92.9	107.9
				15	214.7	138.0	221.1	275.8
9	90	75	83	6	56.9	53.3	56.8	63.2
				8	68.9	59.3	69.3	79.6
				10	89.1	69.4	90.4	107.2
				15	226.9	138.2	234.3	295.6
10	90	90	100	6	52.6	47.7	52.7	59.6
				8	65.5	54.0	66.2	77.2
				10	87.1	64.8	88.8	106.9
				15	234.8	138.2	243.3	309.1

Table VI

ESCALATION RATES * FAVORING COAL USE
IN HYBRID SOLAR PLANTS

Case Number°	Fuel Escalation Rate
1	15
2	8 ⁄
3	8
4	8 ⁄
5	6
6	6 **
7	8 ⁄
8	6
9	6 **
10	6 **

* = Equivalent escalation oil and coal

o = See Table V for case conditions

⁄ = Break even slightly above quoted rate

** = Marked advantage, >5%

Table VII

COAL ESCALATION RATES* FAVORING COAL USE
IN HYBRID SOLAR PLANTS

Case Number°	Coal Escalation Rate
1	8
2	6 ≁
3	6 ≁
4	6 ≁
5	6 **
6	6 **
7	6 ≁
8	6 **
9	6 **
10	6 **

* = Oil escalation 2% age points greater than coal

o = See Table V for case conditions

≁ = Marked advantage, >5%

** = Very marked advantage, >10%

With equal escalation rates for coal and oil (Table VI), coal is generally the preferred fuel where escalation rates are 6 to 8% or higher. Oil would be the preferred fuel at lower escalation rates. Estimates at very high usage factors (Cases 6, 9, and 10) indicate that fuel escalation rates above 4% would favor coal.

If oil is assumed to escalate at a rate that is 2% average points above coal, oil 8%, and coal 6%, then coal is even more highly favored. Coal has advantages over oil at modest inflation rates and lower plant use factors.

TASK 3 - PARAMETRIC ANALYSIS

Fuel Selection

The studies of fuel options vs plant capacity factor, fuel escalation rates, and solar multiple have been extended and completed. The guiding conclusions from the studies are:

(1) At fuel escalation rates greater than 6% and plant capacity factors above 55%, coal is the preferred fuel. At lower values of these variables, oil is more cost effective. The fuel choice at this time for the 100-MWe Hybrid Central Receiver Power Plant is, therefore, coal.

(2) Utilizing coal as the selected fuel, the optimum solar multiple is 0.8. The completed trade study is given in Appendix A.

Turbine Parametric Study

The screening study reported on last month was extended and completed. The results are given in Table VIII. In addition to the baseline turbine

Table VIII

SOLAR CENTRAL RECEIVER HYBRID POWER SYSTEM (PHASE I)

ESTIMATED TURBINE-GENERATOR PERFORMANCE AND COST

$100MW_e$ COMMERCIAL PLANT

1-3-79

C-21725

ITEM	CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	Turbine Type - LSB		TC2F-23	TC2F-23	TC2F-23	TC2F-23	TC2F-23	TC2F-23	TC2F-23 (HARP)	TC2F-23 (HARP)	TC2F-23 (HARP)	TC2F-23 (HARP)	TC2F-23 (HARP)	TC2F-23 (HARP)	TC2F-23 (2RH)	TC2F-23 (2RH)	TC2F-23 (2RH)	TC2F-23 (SC-2RH)	TC2F-23 (SC-2RH)
2	Gross Generation	kW	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000
3	Gross Cycle Heat Rate	$\frac{BTU}{kW\,h}$	7,795	7,783	7,769	7,713	7,696	7,588	7,843	7,830	7,731	7,718	7,641	7,533	7,720	7,541	7,430	7,523	7,412
4	Gross Cycle Efficiency	%	43.2	43.8	43.9	44.2	44.3	45.0	43.5	43.6	44.1	44.2	44.6	45.3	44.2	45.2	45.9	45.4	46.0
5	Throttle Pressure	PSIA	1,815	1,815	1,815	2,415	2,415	2,415	1,815	1,815	1,815	1,815	2,415	2,415	1,815	2,415	2,415	3.515	3,515
6	Throttle Temperature	^oF	1,000	1,050	1,050	1,000	1,000	1,050	1,000	1,000	1,050	1,050	1,000	1,050	1,000	1,000	1,050	1,000	1,050
7	Throttle Flow	lb/hr	729,200	699,500	658,800	740,900	738,100	706,800	735,500	737,500	704,800	706,500	752,000	718,900	649,900	657,200	628,850	732,700	698,700
8	First Reheat Pressure	PSIA	407	407	407	542	542	542	297	328	298	328	433	433	407	542	542	906	906
9	First Reheat Temperature	^oF	1,000	1,050	1,050	1,000	1,000	1,050	1,000	1,000	1,050	1,050	1,000	1,050	1,000	1,000	1,050	1,000	1,050
10	First Reheat Flow	lb/hr	653,000	627,500	631,500	656,700	661,400	634,600	606,500	620,500	583,100	596,400	620,400	595,700	587,700	598,000	564,700	650,400	622,100
11	Second Reheat Pressure	PSIA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	136	178	178	330	330
12	Second Reheat Temperature	^oF													1,000	1,000	1,050	1,000	1,050
13	Second Reheat Flow	lb/hr													558,150	553,750	532,100	605,900	581,000
14	Condenser Pressure	In. HgA	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
15	Condenser Flow	lb/hr	518,500	500,400	498,600	507,700	505,600	487,500	504,500	505,400	486,600	487,500	493,700	476,000	469,300	458,100	441,400	473,100	455,300
16	Condenser Heat Rejection	$10^6\ \frac{BTU}{hr}$	502	489	488	484	482	470	496	495	484	482	476	464	482	464	451	470	456
17	Final Feedwater Temperature	^oF	453.6	453.6	453.6	483.0	483.0	483.0	483.5	483.5	483.5	483.5	514.8	514.8	453.6	483.0	483.0	547.0	547.0
18	Number of Feedwater Heaters	--	6	6	7	6	7	7	6	7	6	7	7	7	7	7	7	8	8
	ESTIMATED INSTALLED COST (JAN. 1979)																		
19	Turbine-Generator & Accessories	$	12,340,000	13,255,000	13,255,000	12,745,000	12,745,000	13,660,000	12,340,000	12,340,000	13,255,000	13,255,000	12,745,000	13,660,000	14,490,000	14,895,000	16,345,000	15,296,000	16,747,000
20	Incremental Heater Cost Over Base (Base = 6 Heaters, 1800 PSIG)	$	Base	0	100,000	50,000	150,000	150,000	50,000	150,000	50,000	150,000	200,000	200,000	150,000	200,000	200,000	400,000	400,000
21	Incremental Main Steam, Reheat & Feedwater Piping Cost Over Base (Base = 1800 PSIG, 1000/1000^oF)	$	Base	245,000	245,000	150,000	150,000	425,000	0	0	245,000	245,000	150,000	425,000	250,000	400,000	775,000	725,000	1,325,000
22	TOTAL ESTIMATED COST	$	12,340,000	13,500,000	13,600,000	12,945,000	13,045,000	14,235,000	12,390,000	12,490,000	13,550,000	13,650,000	13,095,000	14,285,000	14,890,000	15,495,000	17,320,000	16,421,000	18,472,000
23	Total Cost per kW Net	$/kW net	123	135	136	129	130	142	124	125	136	137	131	143	149	155	173	164	185

NOTES:

1) Cost and performance data are approximate for relative comparison of alternate cycles

conditions, i.e., 1800 psig - $1000^{o}/1000^{o}F$, we have considered 2400 psig and 3500 psig with single and double reheats at $1000^{o}F$ and $1050^{o}F$. HARP (heater above reheat point) cycles at 1800 psig and 2400 psig were also analyzed.

The turbine-generator cost includes the turbine, generator, accessories and installation labor. The turbine accessories would include the excitation system, lube system, inlet valves, steam seal system, electrohydraulic speed governing system, insulation and lagging, and generator H_2 and CO_2 manifolds, etc. Not included is the turbine-generator foundation, extraction piping, drain systems, condenser, heat rejection equipment, pumps, condensate piping, electrical work, etc., which is considered a standoff for the alternates considered. Feedwater heater cost is included as an incremental cost over the base 1800 psig, $1000^{o}/1000^{o}F$, 6-heater cycle. Likewise the main steam, reheat, and feedwater piping costs for the various cases are shown as an incremental cost over the base cycle.

Buffering and Storage

The conceptual assessment of the transient response of the fossil fuel-fired sodium heater has been completed and is given in the following section.

Introduction and Summary

The transient response capability of the oil- or coal-fired sodium heater in the Hybrid Advanced Central Receiver (Hybrid ACR) determines the lower limit of the amount of thermal storage or buffering required for system operation. A brief review of sodium heater design and operation was made to determine the factors that would limit the transient response of such heaters. It was found that only the tube wall temperature thermal transients were intrinsic limits. It was, therefore, concluded that a heater could be designed with sufficient response to make the use of storage unnecessary in the hybrid central receiver design.

Factors That Limit Heater Response

Six factors that tend to limit heater response rates were identified. These include:

(1) Combustion air supply rate
(2) Fuel supply rate
(3) Heat transfer tube temperature response
(4) Tube - header thermal stress
(5) Thermal shock sensitivity of refractory linings
(6) System stability

Discussion of Limiting Factors

Combustion air supply rate response is a function of fan type, drive motor configuration, and duct size. It is apparent that by using larger motors and/or multiple blower assemblies a great deal of latitude in air supply rate response can be designed into a system. As an extreme example, the blowers can be operated at full-power continuously and the air flow rate could be controlled by diversion. This condition would result in practically instantaneous response in the air supply rate. Variable pitch propellers and variable diffusers can also be used to obtain rapid air flow rate response.

Power plant fuels often require a significant amount of preparation before being used in a combustor. In the case of oil-fired plants, this condition most often consists of preheating of heavy crude stocks. In the case of a coal-fired plant, a grinding or sizing operation is often required. Current practice has been to design the conditioning systems for the proper output, but little attention has been paid to accelerating and decelerating the processes. There does not, however, appear to be any intrinsic limits on these supply rates, if the supply systems are properly sized (larger motors, for example) and sufficient prepared fuel accumulation is provided for.

The only intrinsic limit to sodium heater thermal response appears to be the rate at which the heater tubes reach thermal equilibrium. This rate was calculated for the existing ETEC sodium heaters by use of an 11-node Thermal Analyzer Program (TAP) model of the heater tube wall. Tube thermal response was calculated for an initial uniform temperature of 1100^{o}F and step input heat rates of 50,000 and 175,000 Btu/hr-ft^2. These rates are typical of run-in, coal-fired burners and of new oil-fired burners, respectively. In every case, it was found that it took less than 2.0 sec for the tube wall temperature gradient to become fully established.

Header - Tube thermal stress and refractory thermal shock are two problems that will be severely aggravated by rapid furnace heatup cycles. However, both conditions can be alleviated by operating the heater at a constant temperature. This is accomplished by operating at a reduced fuel/air rate and a reduced sodium coolant rate. Power ramping is then accomplished by simultaneously increasing the fuel/air rate and the sodium coolant flow rate.

The controls on a sodium heater with rapid power ramping must be such as to avoid system instabilities. System instabilities can be generated by the combustion process, by fuel/air feed system oscillations, or by unstable operation of the control system. Due to operation at low pressures, short combustion delay times and relatively large combustion chambers, the occurrence of combustion driven instabilities appears unlikely. In general, feed system oscillations can be minimized by careful design. However, the possibility of their existence may require an experimental development program to insure that there is no effect on the operation of the heater. Control system oscillations can also be eliminated by careful design; however, the design also requires experimental verification.

Receiver Subsystem

The trade study comparing series vs parallel receiver heater process arrangements has been completed. Three alternate configurations for connecting the solar receiver and fossil-fired sodium heater into the sodium process system were compared in order to select an optimum configuration for the solar hybrid 100-MWe conceptual design study. Options considered were one parallel arrangements: one of the series arrangements consisted of a receiver piped ahead of the heater, and the other with the heater piped ahead of the receiver.

Results show that the parallel configuration is the preferred choice. It is easier to control such a configuration because the sodium inlet and outlet temperatures are fixed and the power level is controlled by varying the sodium flow; carbon steel can be utilized for sodium riser and inlet piping to receiver; thermal cycling is minimized; and it is the most cost-effective arrangement.

Current conclusions are to adopt the parallel configuration for the ongoing hybrid plant conceptual design.

The complete study is given in Appendix B.

An effort was begun on the solar system optimization. System figure of merits (cost of solar system per MWt at base of tower) are being determined as a function of power level over a range of power levels from 100 to 1200 MWt. The cost used as input for the optimization codes is shown in Table IX. The bases for these costs were the final optimization costs used in the Advanced Central Receiver (ACR) Study Phase I. The costs were reviewed in light of recent work on other studies, and those costs marked with an asterisk were changed or added, as was the cost of location-dependent heliostat operations and maintenance (O&M). Recent analyses showed that the previous value used for heliostat

Table IX

COST MODELS (INCLUDING PRESENT VALUE HELIOSTAT O&M)

		(NOTE)
FIXED*	\$4.80 M	CONSTANT BASED ON WATER/STEAM STUDY
HELIOSTAT*	\$71.96/m^2	EXCLUDING LAND AND WIRING INCLUDING NONHELIOSTAT LOCATION DEPENDAND O&M
LAND*	\$1.45/m^2	\$5,871/ACRE - INCLUDING ROUGH SITE PREP.
WIRING	.0412 R	COST PER HELIOSTAT
TRENCHING	.04237 ΔR	R = DISTANCE FROM TOWER TO COMPUTATIONAL CELL
ELECT. DIST.	4.72 Δaz	ΔR = RADIAL SPACING IN CELL
LOC. DEP* O&M	8.525 Δaz	Δaz = AZIMUTHAL SPACING IN CELL (DISTANCES IN M)
SODIUM PUMP	40.7 P (H + 66m)	COST OF APPROXIMATELY \$1000/HP H = RECEIVER CENTERLINE ELEVATION (M) P = ABSORBED POWER (MW)
RECEIVER	\$8.3M $(L\ D/260.8m^2)^{.8}$	MODEL DEVELOPED LATE IN ACR STUDY. L = RECEIVER LENGTH (m) D = RECEIVER DIAMETER (m)

*CHANGED OR ADDED SINCE ADVANCED CENTRAL RECEIVER (ACR) STUDY cost in the ACR study ($65.67/m^2) could be reduced to $60.12/m^2. This value excludes the cost of wiring, trenching, and electrical distribution which is accounted for elsewhere. The previous cost also did not include heliostat O&M present values. This amounts to $11.84/m^2 as discussed in the last (November) progress report. This value does not include heliostat location-dependent O&M costs accounted for elsewhere. This cost is primarily associated with the labor involved in cleaning the heliostat, a cost that is directly related to the time to wash the heliostats and to move from heliostat to heliostat. The total distance travelled is related to the distance between heliostats, which is represented by the following:

Total distance = Σazimuthal spacing + the distance from the tower to the farthest heliostat.

The first term is much larger than the second and, therefore, the cost per heliostat was defined as

Location-Dependent (Loc. Dep.) O&M Cost/Heliostat = 8.525ΔAz

Where ΔAz is the azimuthal spacing between heliostats. The constant was derived by dividing the Loc. Dep. O&M cost/heliostat ($131) by the average azimuthal spacing. The average spacing was determined by averaging the azimuthal spacing in the 100-MWe ACR field. This value was found to be 15.37 meters.

The following discussion presents the rationale for the revised fixed and land costs.

The costs shown in Table X were estimated from like areas of other programs with a few exceptions. The table shows a comparison of costs used in the Advanced Central Receiver Phase I with those being used in the Hybrid Study.

TABLE X
COST DERIVATION

Fixed Costs

	ACR	Hyb	
Calib. Eq.	.10	.17	BCS evaluated
Design & Support Engr.	1.74	1.84	OK (Inflat. 1.06)
Master Control	1.78	.75	This system does not include the interface controllers for valves and motors, etc., as did the PDR.
Ind. A&E	1.35	1.43	OK (Inflat. 1.06)
	4.97M	4.19M	
	(5.25M if inflated by 6%)		

Yardwork

Central (Bldgs., Tower)	= $.046603 M/acre x 8 acres	= $ 372,823
Field	= $.000871 M/acre x 732 acres	= $ 637,572
		$1,010,278
	Contingencies	200,000
	Total Yardwork	$1,200,000

Land $500-5,000/acre

Low - inaccessible with little to no amenities
High - closer to metropolitan area

Costs used as input to optimization

Fixed Costs

$4.19	
.37	Yardwork (8 acres central)
.04	Land (8 acres)
$4.60 M	
.20	Yardwork Contingencies
$4.80 M	

Variable Costs

$ 817	Yardwork (field)
5,000	Land
$5,871/acre	

Table X (Continued)

COST MODELS (INCLUDING PRESENT VALUE HELIOSTAT O&M)

TOWER	COST = \$109 (FL – 22m)$^{2.1}$	
	FL = REC EQUATOR ELEV – 4m	BASED ON WATER/STEAM STUDY
PIPING NETWORK		
PIPING	55 · D (in)	\$/FT (STAINLESS STEEL)
	30 · D (in)	\$/FT (CARBON STEEL)
VALVES	\$2,000 · D (in)	6" – 17" VALVES
	\$3,000 · D (in)	17" – 24" VALVES
EXPANSION AND BENDS	X (1.5)	ADJUSTMENT TO PIPE LENGTH
VERTICAL FACTOR		5% INCREASE PER 60 FEET

Calibration equipment was originally an educated guess, later updated using a bottoms-up estimate of a newly defined Beam Characterization Subsystem.

Design and Support Engineering costs were originally based on the allocation of engineering costs from the PDR and were inflated six percent to bring them up to date.

Master Control costs decreased considerably from the PDR (commercial) due to the fact that one of the ground rules for the Advanced Central Receiver is that interface controllers for valves, motors, etc., are to be costed by the subsystem and not included in our master control costs. Software costs were estimated by sizing against the PDR. Some learning was assumed.

Indirect A&E Services were originally estimated at 10 percent over the PDR Pilot Plant and inflated six percent to bring them up to date.

An earlier estimate for yardwork has been reduced from $1.5M to $1.2M. (It included a double counting in the area of fences and gates.) Yardwork costs were broken down into those associated with the central portion of the field (buildings, tower, etc.) and the rest of the field. (Costs used were based on those from the Commercial PDR.) The size of the Advanced Central Receiver (740 acres) is approximately one half the size of the Commercial PDR (1450 acres) field. Therefore, one half the cost for grading was used for the field, 70 percent of the cost of fencing was used. It is assumed that the grading will be ten times as concentrated per acre for the area under the tower and buildings. The overall projected cost for yardwork of $1.5M was not adhered to because the original estimate for the program was based on the 100 MW PDR (Commercial), which is double the size.

Land costs are estimated by the Systems Cost Analysis Department. Desert land is selling for $500-5,000/acre. The low side is for land that is inaccessible with no power lines, sewer drainage, etc. The higher priced land is improved, more easily accessible (roads already in), has utilities in close proximity, and is usually located fairly close to a populous area (i.e., Barstow).

Costs were broken down into fixed and variable. The fixed costs are those which do not vary with the size of the field, such as those associated with the central part of the field, i.e., the tower, buildings, etc. Fixed yardwork is decreased by $.3M to $.37M, thereby decreasing the total fixed cost from $5.1M to $4.8M since the earlier estimate. Variable costs include land and yardwork associated with the rest of the field, which depend directly upon size.

714-F.73/clh

APPENDIX A

Selection of Fuel and Solar Multiple

CONTENTS

FIGURES

TABLES

I. INTRODUCTION

Two of the primary baseline selection decisions to be made during the conceptual design of the 100 MWe Solar Central Receiver/Fossil Hybrid Power System are: (1) which fossil fuel to use to fire the sodium heater, and (2) what is the optimum solar multiple for the selected fuel. A diagram of the general configuration of the hybrid power system is shown in Figure 1.

The turndown ratio of the sodium heater (rated power/minimum operating power) is determined primarily by the fuel being fired. When the heater is at minimum power, the difference between the steam generator power and heater power is the required receiver power.

Once the fuel is known and the turndown specified, the economic effects of varying solar multiple can be determined and an optimum solar multiple selected. (For a parallel heater/receiver configuration, 1-1/turndown ratio is the point of departure for solar multiple selection trade studies.) Selection of the solar multiple in conjunction with the steam generator power determines the size of the receiver and receiver sodium components in terms of required power and indicates the size of the thermal storage subsystem.

The purpose of these trade studies is to select a fossil fuel and receiver size (power) for the 100 MWe conceptual design of the Solar Central Receiver Hybrid Power System. These parameters form the basis of other ongoing trade studies.

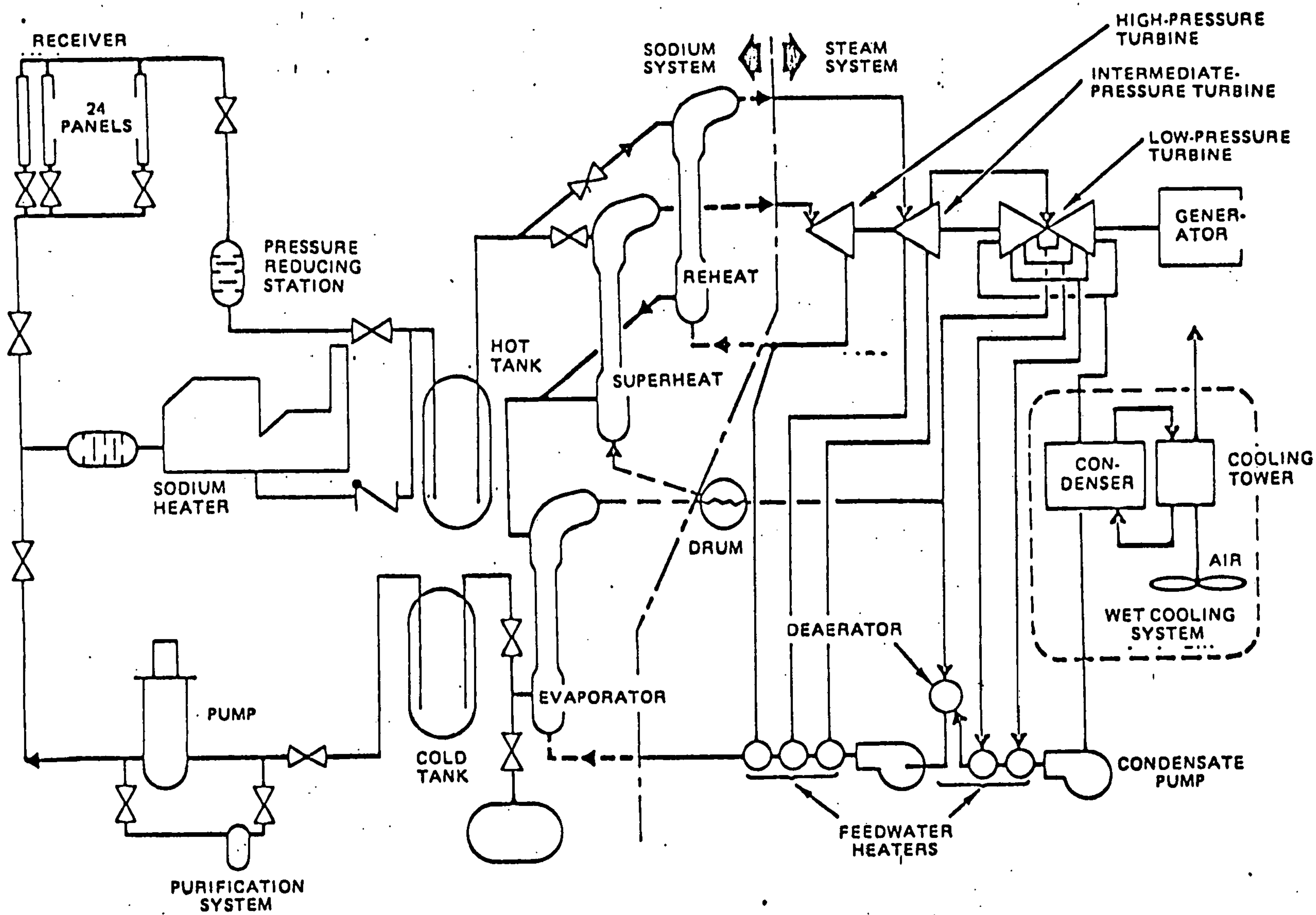


FIGURE 1. BASELINE SOLAR CENTRAL RECEIVER HYBRID POWER SYSTEM

42400-1096D

II. DESIGN BASIS FOR COMPARISON STUDY

The parallel receiver/heater configuration has been selected as baseline for the hybrid system.(1) In this configuration, the heater is required to be at temperature during sunlight hours in order to be capable of rapidly supplementing meteorological induced shortfalls in receiver power. This requirement means that either the receiver power be large enough such that the heater can be kept warm by solar heated sodium or that fuel be burned to keep the heater at temperature. Only the latter case is considered in this study. Depending on the fuel selected, the minimum heater power required to maintain combustion stability and sodium temperatures concurrently, ranges from 10 to 20% of full power. Full heater power is currently set at the steam generator power level of 260 MWt.

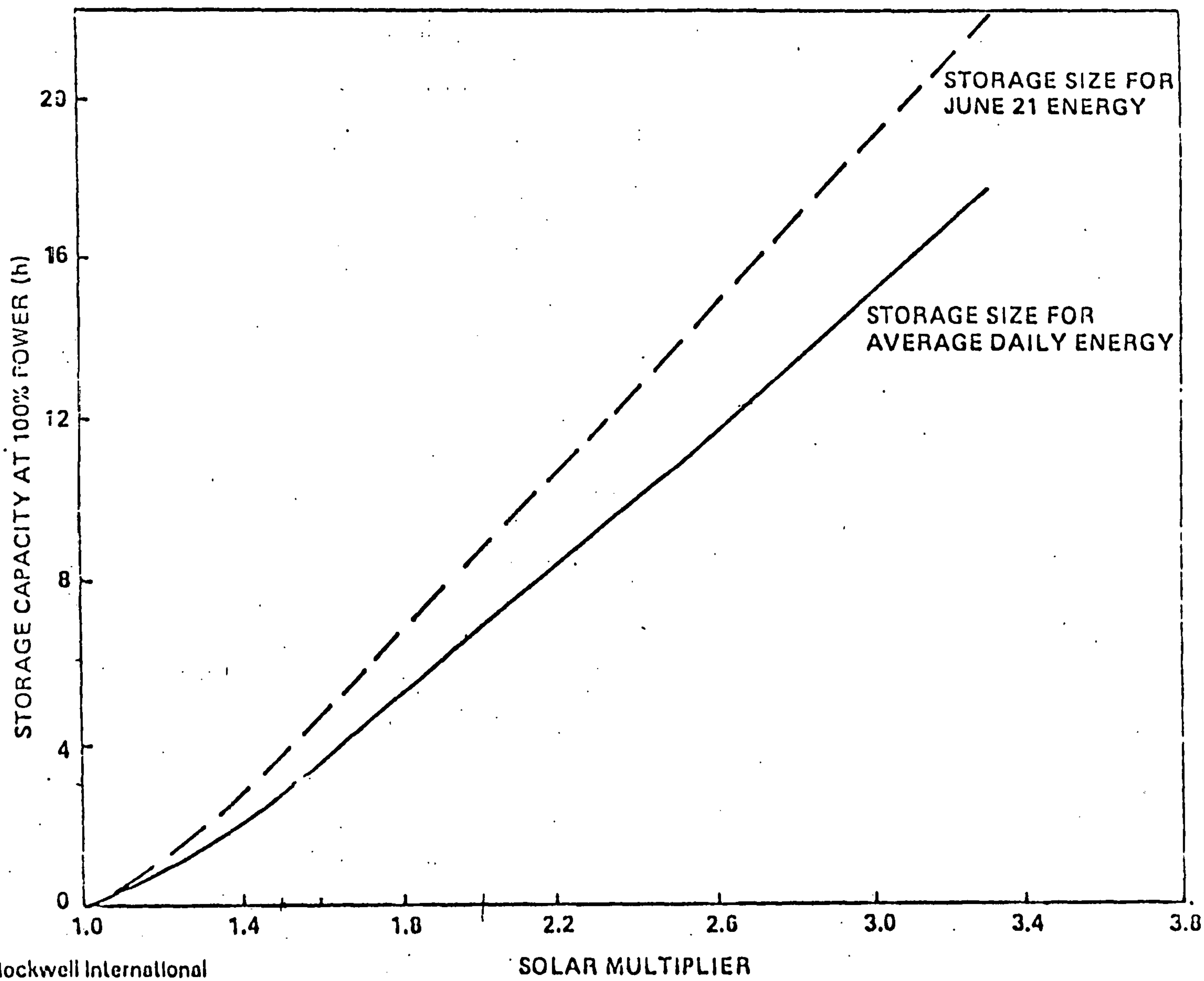
The sodium inlet temperature to the steam generator is currently fixed at 1100°F and the temperature drop (ΔT) across the steam generator is maintained constant at 550°F which establishes the steam generator outlet temperature at 550°F. The sodium heater and receiver outlet temperature of 1100°F and the ΔT of 550°F were established as the optimum design points as a result of previous solar design studies.(2) Based on the foregoing, the receiver and heater, connected in parallel, are designed to furnish the required thermal energy with a constant sodium inlet and outlet temperature of 550°F and 1100°F, respectively.

Variations in the solar receiver thermal energy output, because of the diurnal variation in absorbed thermal power, will be made up by the fossil-fired sodium heater to provide a constant net electrical plant output of 100 MW. As the receiver output drops, the heater output is increased. Load changes are made by varying the sodium flow through the components. Changes in the seasons, time of day, and weather patterns all affect the solar heat input which will require adjustment in the fossil-fired sodium heater thermal input to maintain a fixed plant output. At some specified minimum load in the solar receiver, the receiver will be shut down and all the power will be generated by the sodium heater.

If oil or either of the cadadate gases are used as fossil fuels in the hybrid plant, the projected minimum heater power is 10% of full power. The projected minimum power of a coal-fired sodium furnace is 20%.[3] This means that as a point of departure, the power provided by the receiver at peak design conditions would be 90% for an oil or gas system, and 80% for a coal system.

There is no technical restriction on the amount of total power the receiver can contribute to the system. Consequently, the receiver can contribute more or less than the foregoing percentages of total required steam generator power. As a minimum, however, a fossil fuel displacement of at least 50% at design operating conditions should be utilized for the plant to be considered a true hybrid. This sets the minimum receiver power rating at 50% of the steam generator rating. As a maximum, the design receiver power has been limited to 266% of the required steam generator power. This would effectively supply the steam generator 100% power all day and night if storage facilities were available. Thus, it can be seen that for receiver powers equal to or less than the point of departure, no storage is required. For higher powers, storage is required. A convenient single factor which describes the receiver power capability relative to the turbine requirements at name plate rating and simultaneously indicates the relative magnitude of storage is the Solar Multiple. Selecting a Solar Multiple defines the peak design solar/fossil spit of the plant and indicates the magnitude of storage. Figure 2 shows the relation between Solar Multiple and hours of storage.

STORAGE CAPACITY VS. SOLAR MULTIPLIER



Rockwell International
Energy Systems Group

FIGURE 2

It is also possible to increase the total solar contribution to the plant by increasing the size of the heliostat field without adding storage. This will increase the collector field to receiver power ratio (FRPR) for a given receiver power. An investigation of this parameter is currently being conducted as part of the field optimization study and is, therefore, excluded from the scope of this study.

III. TRADE STUDY ASSUMPTIONS

The technical trade study assumptions and brief justifications are shown in Table 1. The economic assumptions used in this trade study are shown in Table 2.

The heater standby turndown requirements shown in Table 2 are based on two operating philosophies. The first philosophy dicates that the heater be at temperature in order for the plant to be "available." The second philosophy does not require the heater to be at temperature in order to be available. This philosophy results in lower fuel costs and lower overall busbar costs and is supported by the utilities who do not like to start a plant up unless it will produce electricity.[4] (In either case, the results of this trade study were unchanged.)

It was also assumed that there were no significant variations in technical reliability with fuel or solar multiple.

TABLE 1

TECHNICAL ASSUMPTIONS

		Notes
1.	Net Plant Rating = 100 MWe	See Reference 5
2.	Heater/Receiver Configuration = Parallel	See Reference 1
3.	Plant Availability = 90% including solar variation	See Reference 5
4.	Heater Standby Turndown Rating oil = 10% and 0% coal = 20% and 0%	See Preceding Discussion
5.	Plant Performance Requirements	As per Reference 5
6.	Plant Capacity Factor Range = 5-95%	
7.	Oil and Gas Base Turndown = 10 to 1	See Reference 3
8.	Coal Turndown = 5 to 1	See Reference 3
9.	Standby Turndown Heat Source = fuel	
10.	Number of cloudy days per year = 35	See Reference 6

TABLE 2

ECONOMIC ASSUMPTIONS*

Discount Rate = 10%

Economic Life = 30 years

Fixed Charge Rate = 18%

Annual Capital Escalation Rate = 10%

Startup Year = 1990

Annual Fuel Escalation Rates = 6, 8, 10, and 15%

Oil Cost = $2.00/MMBTU (1978 $)

Coal Cost = $1.00/MMBTU (1978 $)

Natural Gas Cost = $2.10/MMBTU (1978 $)
(See Reference 7)

Syngas Cost = $3.75/MMBTU (1978 $)
(See Reference 7)

*All assumptions as per Reference 5 except as noted.

IV. FOSSIL FUEL SELECTION

A. NONECONOMIC CONSIDERATIONS

The noneconomic advantages and disadvantages of each fuel alternative are shown in Table 3. The most abundant of the alternatives is coal. This fact is reflected in its low fuel cost. Coal is also the most available fuel. While it is recognized that its availability is subject to labor negotiations, last winter's coal strike did not seem to seriously impact the operation of western coal-fired plants in the major solar market areas. Oil availability is subject to the decisions of foreign suppliers. Natural gas is expected to be unavailable to new power plants as a result of fuel management regulations. "Syngas" is and will continue to be unavailable so long as natural gas prices remain regulated at low levels.

Coal and syngas are the only fuel alternatives expected to remain or become available with reasonable certainty. A number of utilities expect that oil would not be used in new power plants.[4] The use of natural gas in new power plants is currently prohibited in many western states.

Oil and natural gas are the easiest fuels to handle of the two alternatives. Coal is the most difficult. The handling problems of syngas depend upon whether the gas is manufactured onsite. If it is manufactured onsite from coal, then the handling difficulties would be the same as those for coal. If, however, syngas is purchased from an outside supplier, the handling difficulties would be similar to those of natural gas.

Both coal and oil are expected to require flue gas scrubbers and electrostatic precipitators or equivalent SO_2 removal and particulate

TABLE 3

FUEL SELECTION NONECONOMIC CONSIDERATIONS

	Coal	Oil	Natural Gas	Syngas
Abundance	+	-	-	+
Availability	+	-	-	-
Convertability	+	-	-	-
Freedom from Usage Restrictions	+	-	-	+
Ease of Handling	-	+	+	0
Lack of Flue Gas Cleanup	-	-	+	0
Mirror Fly Ash Precipitation	-	0	+	0
Plant Location Flexibility	-	+	+	0

+ Advantage

- Disadvantage

0 No significant effect

control equipment. This problem is critical in that it impacts heliostat fly ash deposition rates. Stearns-Roger has indicated that with properly operating precipitators and correct fuel selection, the deposition rate should be manageable. It is not known whether fly ash deposition will be a serious problem with oil firing at this time. Firing natural gas eliminates the scrubber and precipitator requirements as well as the fly ash problem. The precipitator and scrubber requirements as well as fly ash deposition resulting from syngas firing depend upon syngas plant design and location.

Another noneconomic fuel selection criteria is plant site flexibility. Coal is the least flexible alternative as reflected in increasing transportation costs as a function of distance from mine mouth. Oil and natural gas have the most flexibility with regard to site location. The site location flexibility of syngas will depend upon the syngas plant location.

It is probable that gas may be unavailable at any price as a result of fuel management decisions. Syngas is, at this time, high enough in cost to be ruled out from an economic consideration. Since oil is more abundant than natural gas, the final economic choice is between oil and coal.

A final noneconomic consideration is the capability of fuel conversion. A coal heater is the only heater that, once selected, can be converted to other fuels.

B. ECONOMIC CONSIDERATIONS

The economic comparisons of oil and coal for various fuel escalation rates in the range of 6 to 15% were made, in terms of busbar energy costs vs capacity factor, using the JPL methodology.[8] The economic assumptions used are listed in Table 2. The methodology was programmed into a computer code for use on a Hewlett Packard 9845 desk top computer. The program generates fuel, O&M plus fuel, and total busbar energy costs as a function of capacity factor and fuel escalation if given the capital cost, standby turndown heater power requirement, solar multiple, and number of cloudy days per year. A sample output of the code is shown in Figure 3.

The technical and economic parameters of each case are followed by the busbar costs arranged in rows of ascending capacity factor, from left to right, and columns of ascending fuel escalation from top to bottom. A fuel algorithm based on a standby turndown rate, fuel cost, and solar multiple is also shown in 1978 dollars.

The results of the fuel selection trade study were plotted by the same computer and are shown in Figures 4 through 9. Figures 4 and 5 show the busbar energy cost breakdowns vs capacity factor for coal and oil-fired system, respectively. Figures 6 through 9 show the total busbar energy costs for full escalation of 6, 8, 10, and 15%, respectively.

The capital costs, solar multiples, and fuel escalation rates shown in Figures 4 and 5 were considered points of departure for the fuel selection and solar multiple trade study.

As shown in Figures 6 through 9, coal is a more cost effective fuel, at any fuel escalation rate, above capacity factors of 55-60%. Furthermore, at an escalation rate equal to the historical rate of the last five years, 10%, coal is superior to oil at capacity factors of 42% or higher.

As a result of the lower fuel costs of coal, the incremental fuel cost of electricity from a coal plant will also be less than that of an oil plant, as shown in Figures 4 and 5. Consequently, a dispatcher

```
[illegible] COAL          TURNDOWN = 0.0 %

[illegible] LIFE = [illegible]0.0 YEARS
INITIAL YEAR OF OPERATION = 19[illegible]0.0
CAPITAL COST = 128.8 MILLION
INITIAL ANNUAL O&M COST = 1.3 MILLION
FIXED CHARGE RATE = 18.0 %
ANNUAL CAPITAL ESCALATION RATE = 10.0 %
ANNUAL O&M ESCALATION RATE = 8%
DISCOUNT RATE = 10.0 %
FUEL = 9.1 CF- 2.4 MILLION/YEAR (1978 $)
FUEL COST = 1.0 $/MMBTU (1978 $)
FUEL ANNUAL ESCALATION = 6,8,10 AND 15%

SOLAR MULTIPLE = .80
 35.00 CLOUDY DAYS/YEAR
CF= .2677
CF= .3723
CF= .4769
CF= .5815
CF= .6862
CF= .7908
CF= .8954
BUSBAR ENERGY COSTS, (MILS/KWH, 1978 $)
FUEL
 0.0  3.5  5.5  6.8  7.7  8.3  8.8

 0.0  5.7  8.9  11.0  12.4  13.4  14.2

 0.0  9.3  14.6  17.9  20.3  22.0  23.3

 0.0  34.1  53.2  65.5  74.0  80.3  85.1


FUEL+O&M
 10.6  11.2  11.5  11.7  11.9  12.0  12.0

 10.6  13.4  14.9  15.9  16.5  17.0  17.4

 10.6  17.0  20.6  22.8  24.4  25.6  26.5

 10.6  41.7  59.2  70.4  78.2  83.9  88.2


TOTAL BUSBAR ENERGY COSTS
 109.1  82.0  66.8  57.0  50.3  45.3  41.5

 109.1  84.2  70.2  61.2  55.0  50.4  46.9

 109.1  87.8  75.8  68.2  62.8  58.9  55.9

 109.1  112.6  114.5  115.7  116.6  117.2  117.7
```

FIGURE 3. SAMPLE OUTPUT

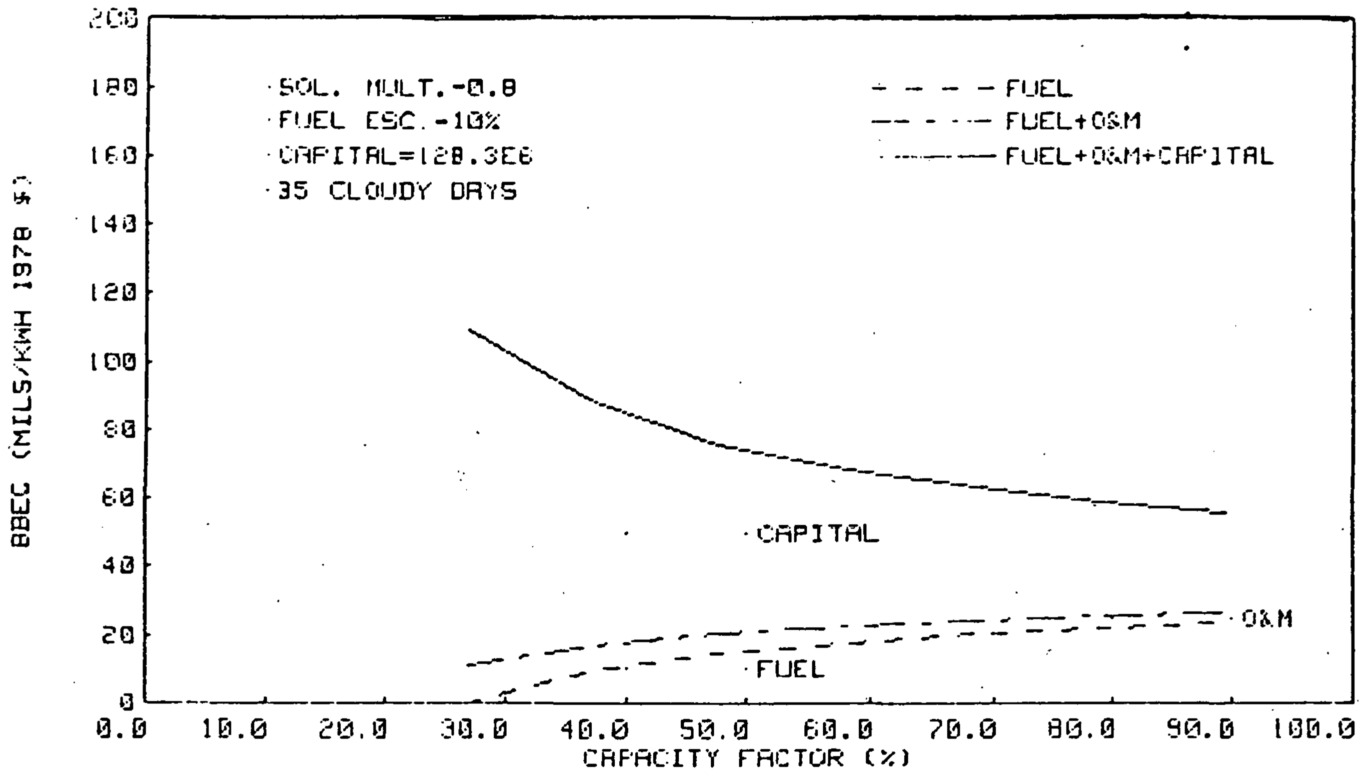


FIGURE 4 COAL FIRED HYBRID BASELINE ENERGY COSTS

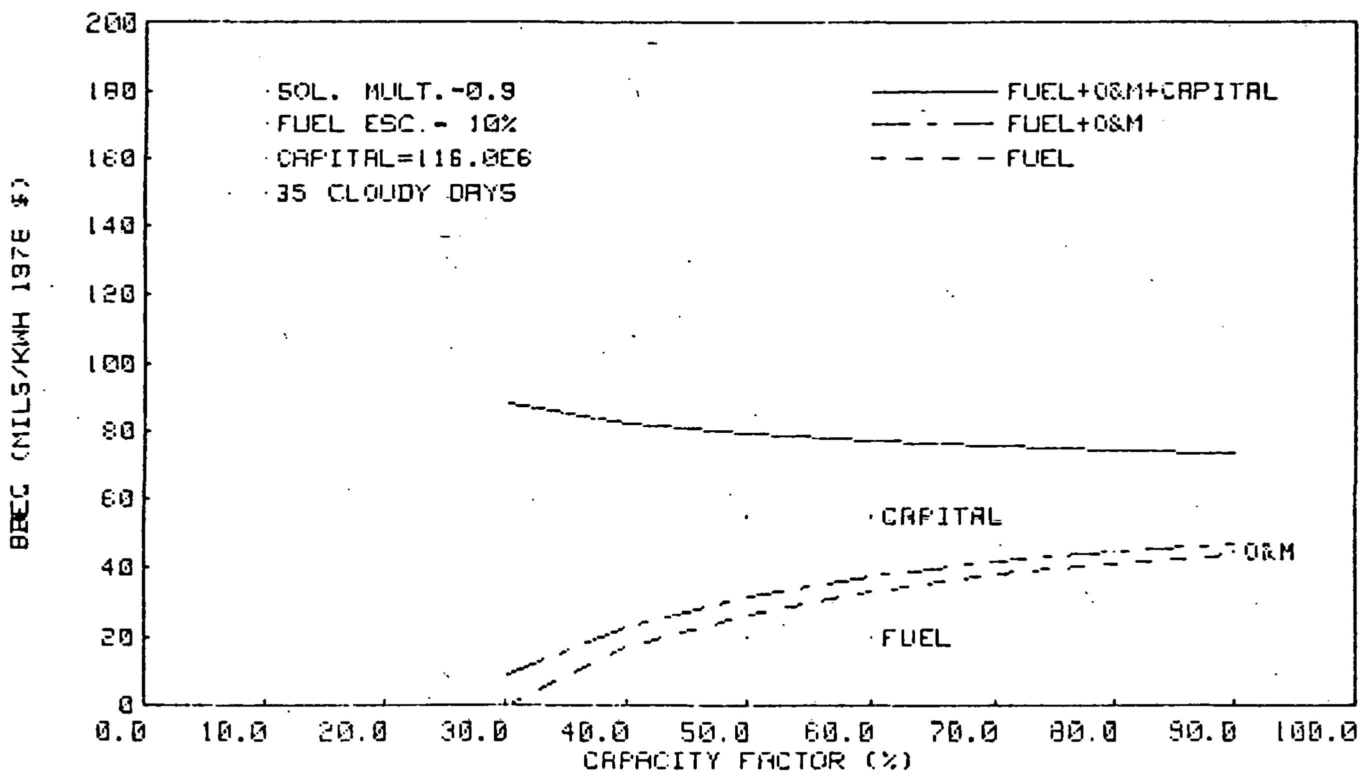


FIGURE 5 OIL FIRED HYBRID BASELINE ENERGY COSTS

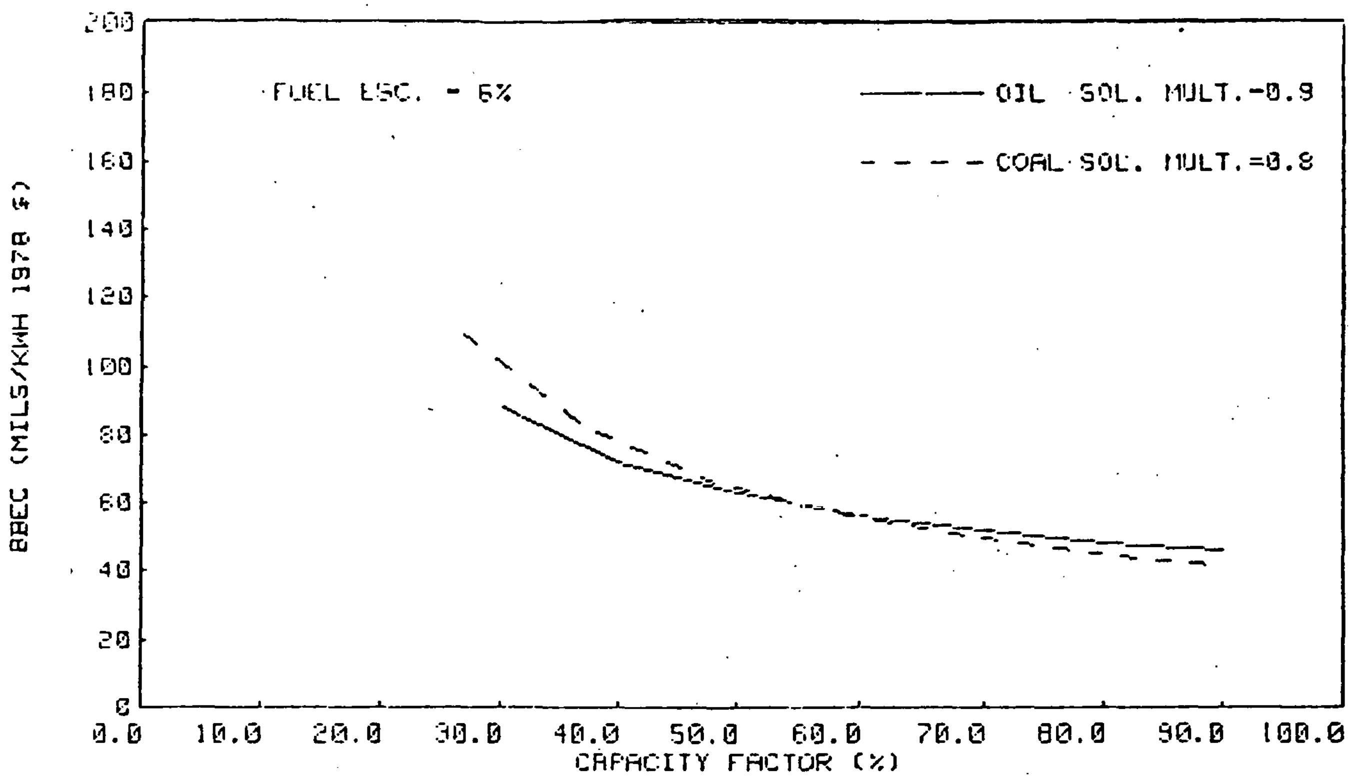


FIGURE 6 OIL AND COAL HYBRID BUSBAR ENERGY COSTS

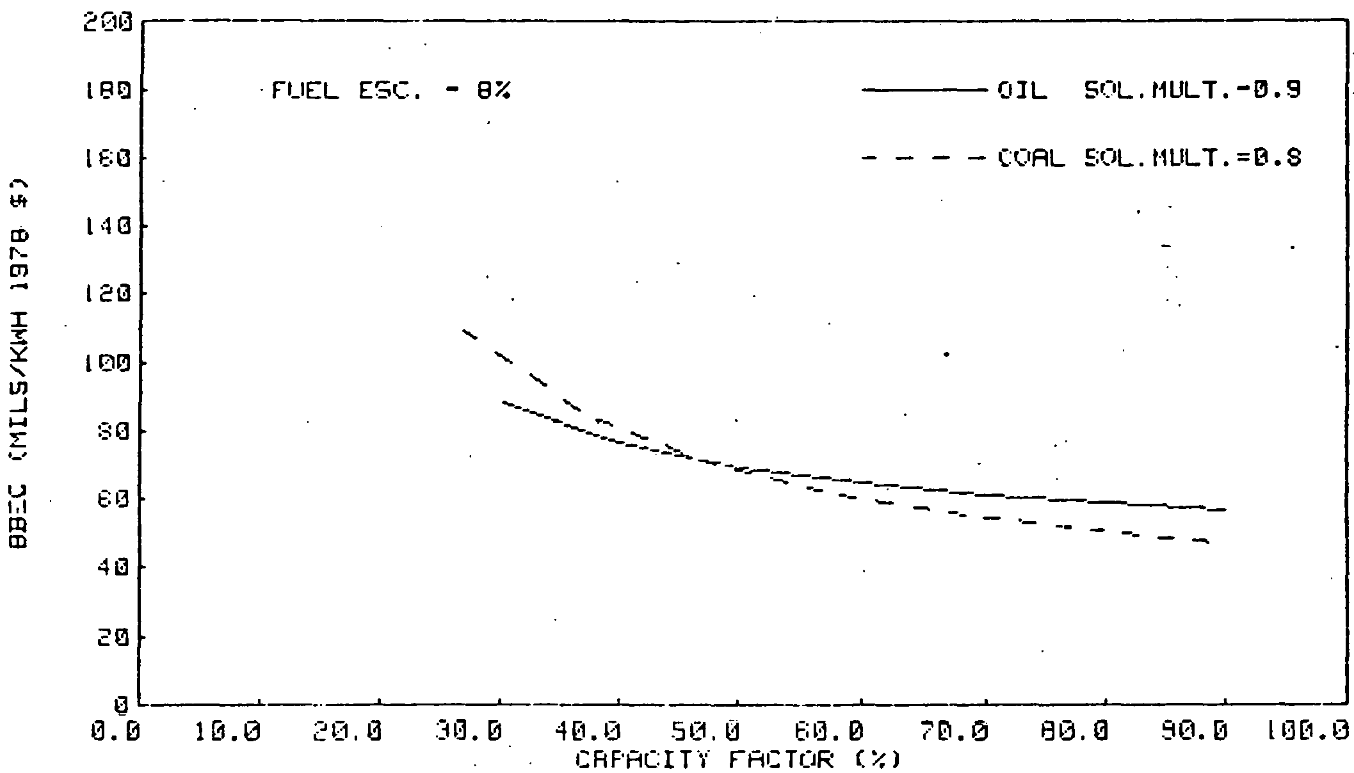


FIGURE 7 OIL AND COAL HYBRID BUSBAR ENERGY COSTS (cont.)

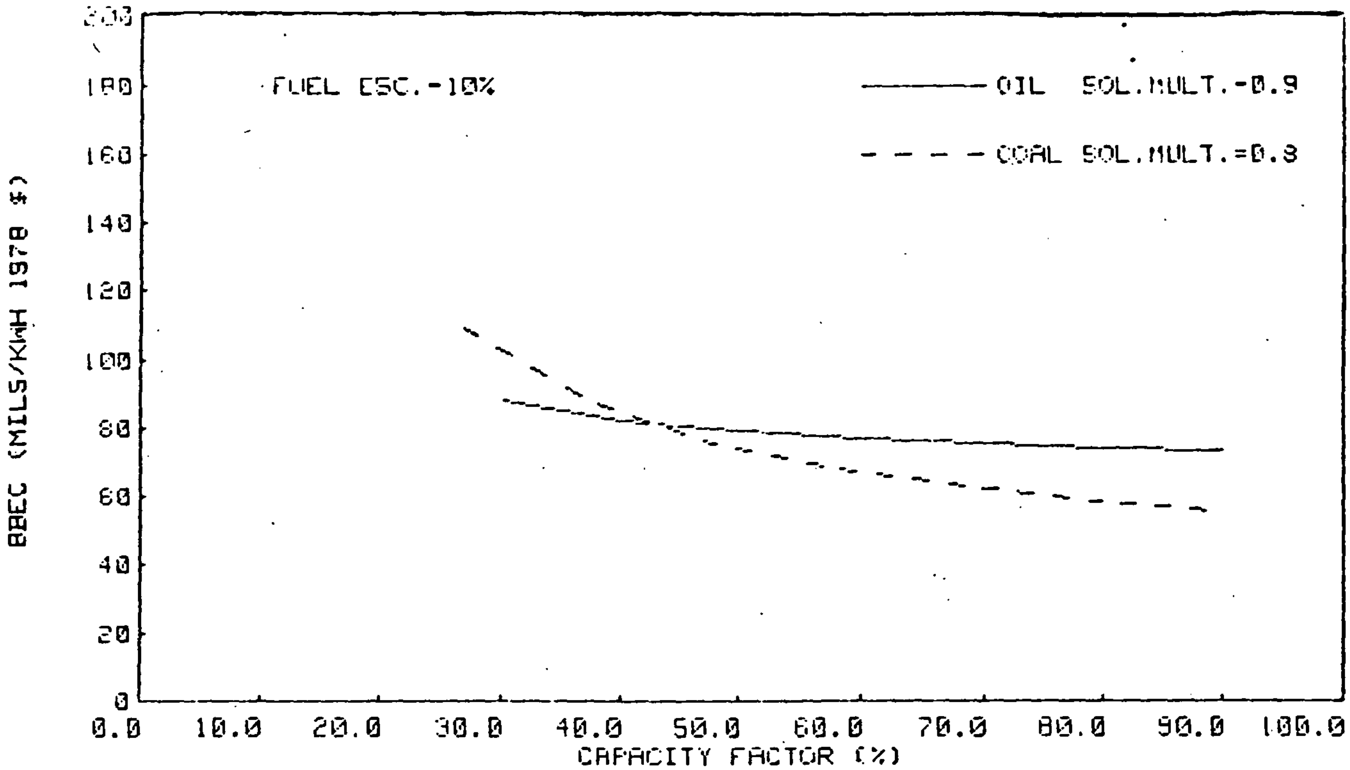


FIGURE 8 OIL AND COAL HYBRID BUSBAR ENERGY COSTS (cont.)

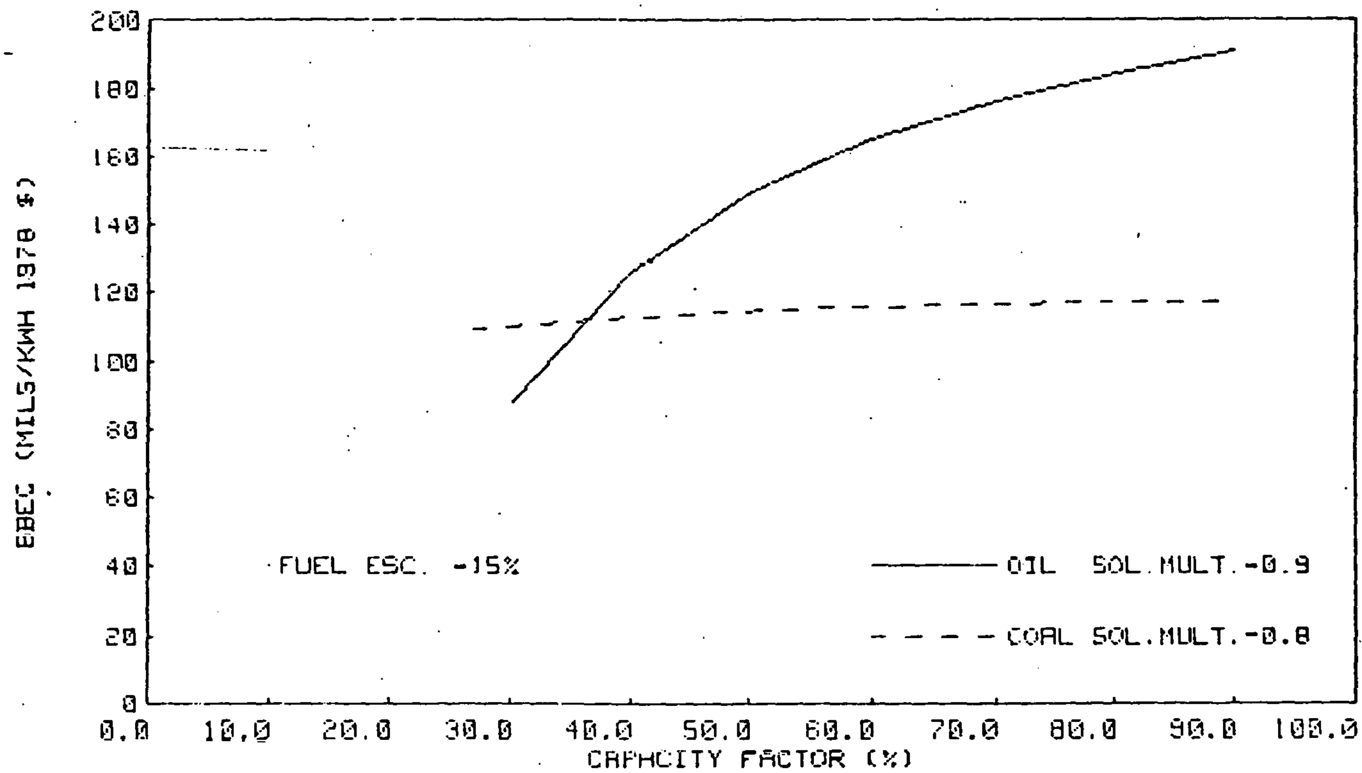


FIGURE 9 OIL AND COAL HYBRID BUSBAR ENERGY COSTS (cont.)

would be reasonably expected to select a coal hybrid over an oil hybrid if two otherwise equivalent plants existed. This would result in the coal hybrid attaining a relatively higher capacity factor. It can be concluded, therefore, that from an economic standpoint, coal should be the baseline fuel for the hybrid system.

V. SOLAR MULTIPLE TRADE STUDY

Using the same computer program, the busbar energy costs of coal and oil fired hybrid plants as functions of capacity factor and fuel escalation rates were generated for solar multiples in the range of 0.5 to 2.15. The results are shown for coal with solar multiples of 0.5, 0.8, and 1.5 in Figures 10, 11, and 12 for fuel escalation rates of 6, 10, and 15%, respectively. Also shown are the capital costs of each plant in millions (1978 dollars). All plant capital costs were generated by estimates of heater costs provided by Babcock and Wilcox and balance of plant component costs determined by scaling the costs from previous solar studies.

For coal with low fuel escalation rates, Figure 10 shows that a low solar multiple is cost effective due to the relatively low cost of fuel. Increasing the fuel escalation rate to a more reasonable rate of 10% decreases the cost effectiveness of the low solar multiple. In fact, it can be shown that the difference in incremental fuel costs would cause a plant with a solar multiple of 0.8 to be used at a higher capacity than a plant with a solar multiple of 0.5. Consequently, the total busbar energy costs of the 0.8 solar multiple plant would be less than those of the 0.5 solar multiple plant. At a 10% fuel escalation rate, the 1.5 solar multiple is still not competitive.

At very high fuel escalation rates (15%), the high solar multiple plant is clearly most cost effective as shown in Figure 12.

On the basis of the foregoing trade study, the optimum solar multiple appears to be 0.8 for coal.

A similar trade study for oil showed that the optimum solar multiple at a fuel escalation rate of 10% was greater than 1.5 due to the high

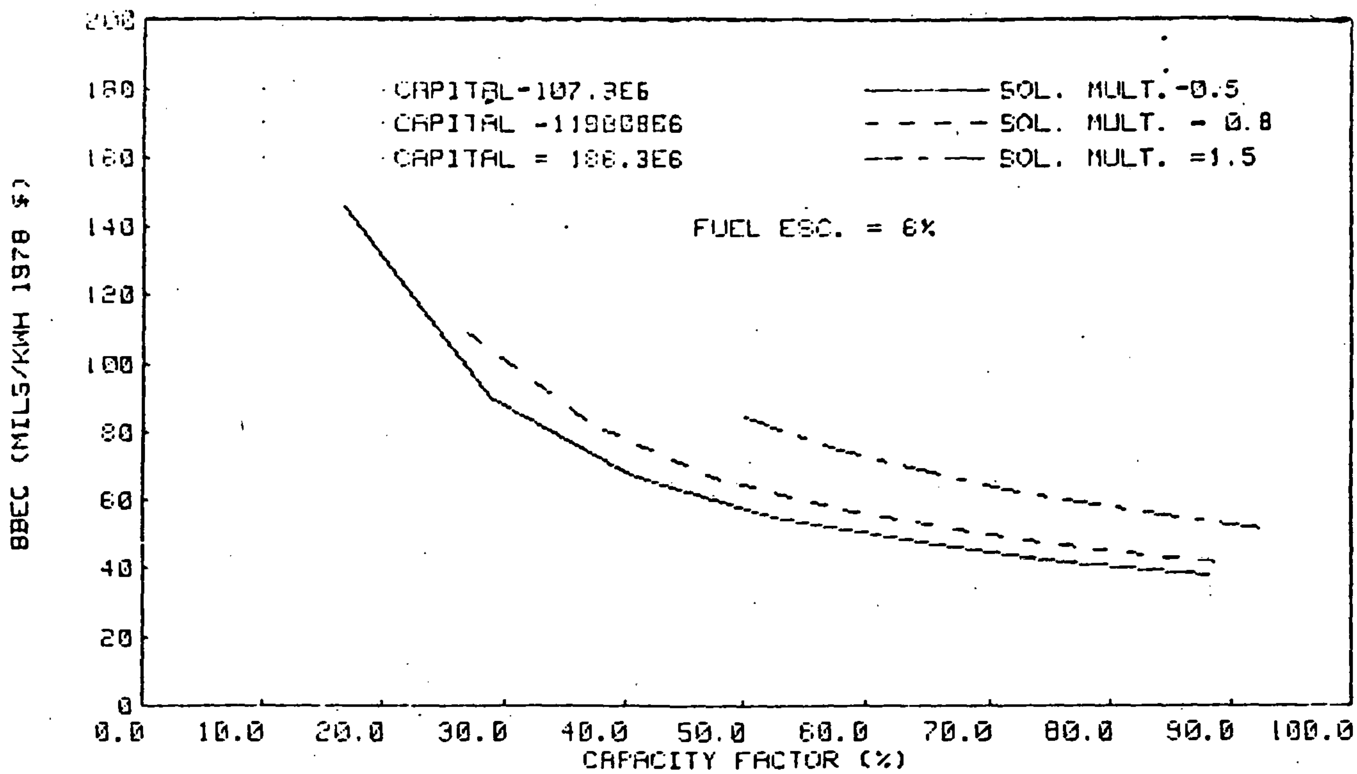


FIGURE 10 COAL SOLAR MULTIPLE TRADE STUDY

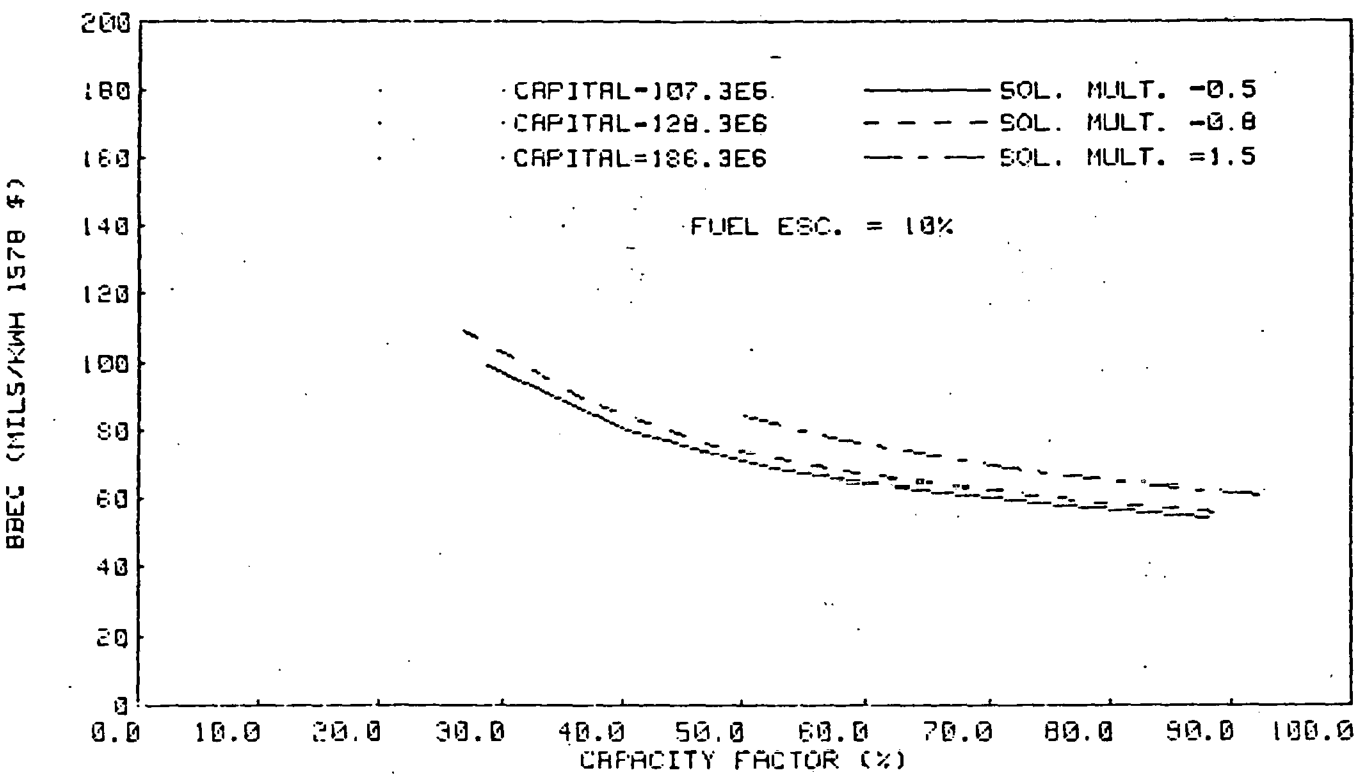


FIGURE 11 COAL SOLAR MULTIPLE TRADE STUDY (cont.)

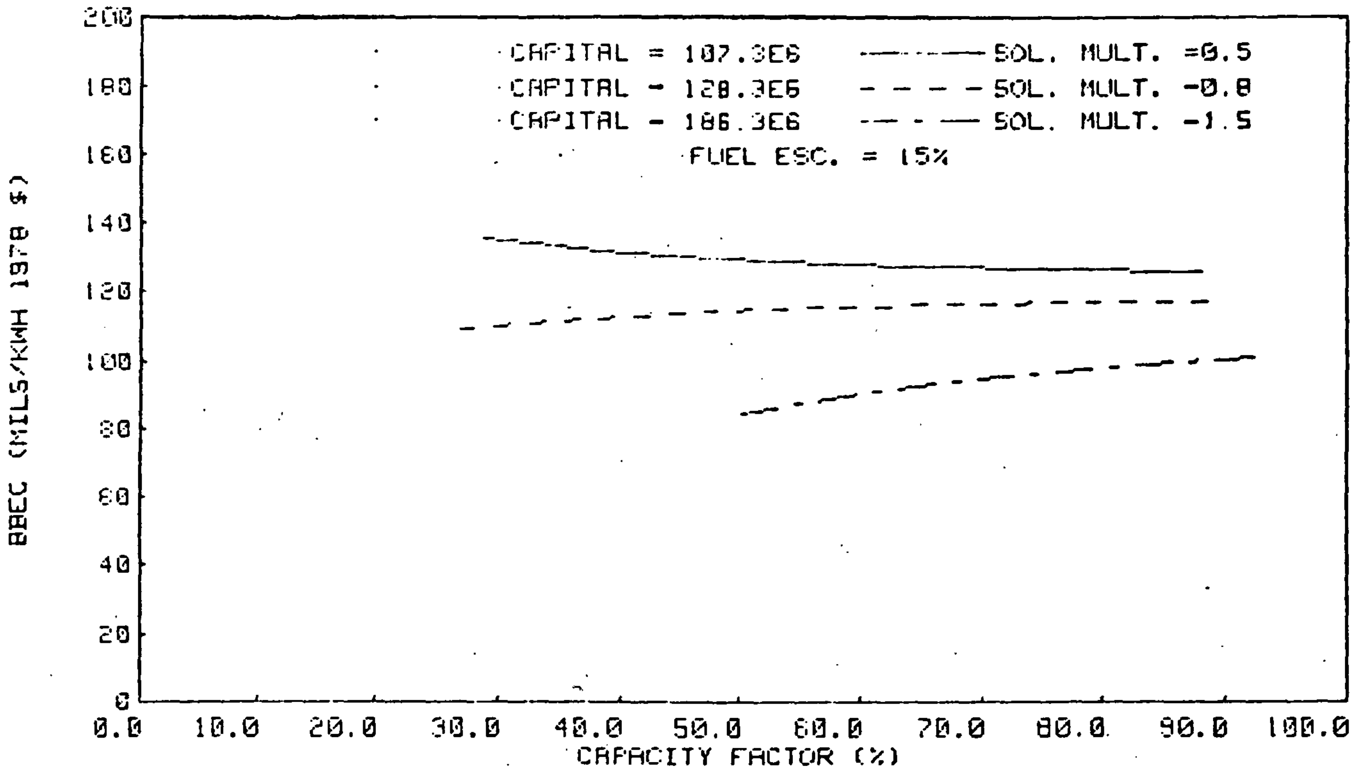


FIGURE 12 COAL SOLAR MULTIPLE TRADE STUDY (cont.)

cost of fuel. In this case, the margin of superiority of the 1.5 solar multiple was not large. However, the incremental fuel cost drives the solar multiple up. The results of this study are shown in Figure 13 for a fuel escalation rate of 10%.

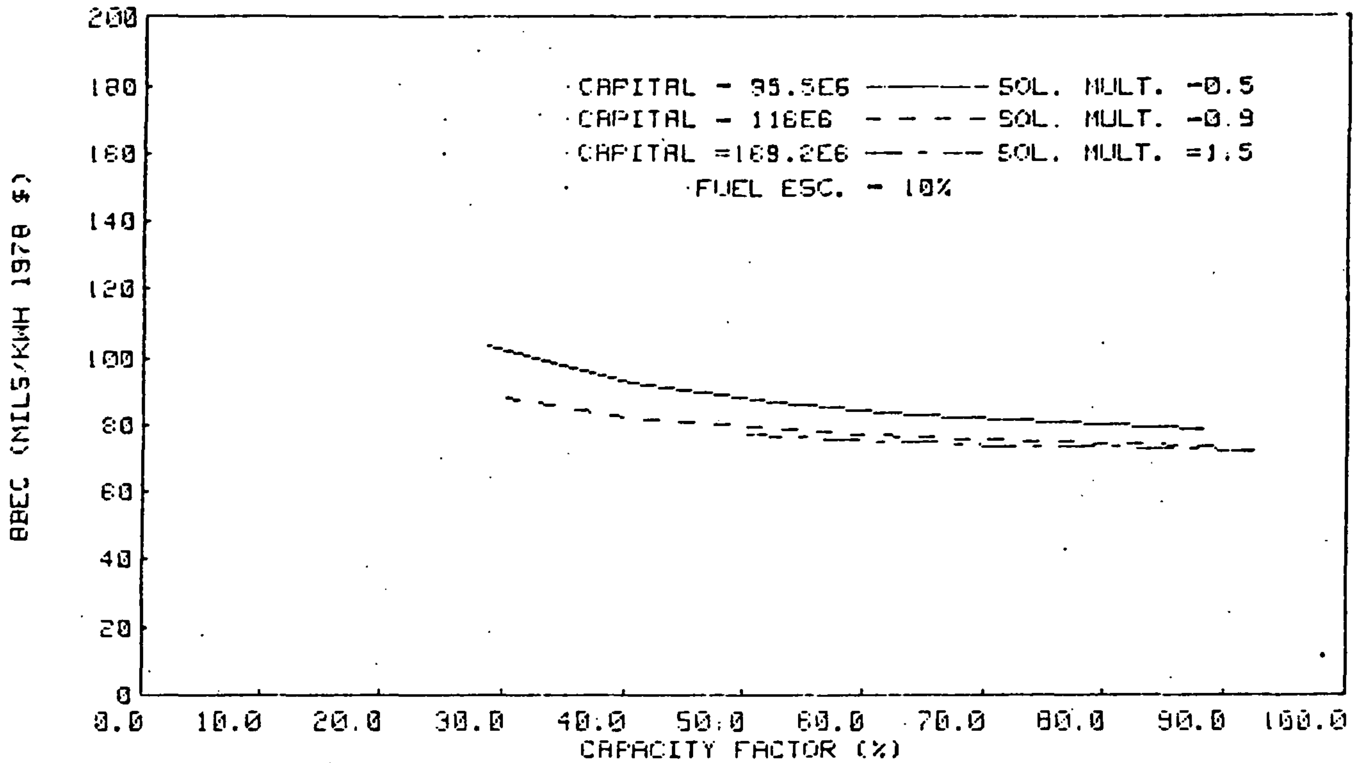


FIGURE 13 OIL SOLAR MULTIPLE TRADE STUDY

VI. SUMMARY AND CONCLUSIONS

Based on economic and noneconomic considerations, coal has been shown to be the superior fossil fuel candidate. It is, therefore, recommended that coal be selected as the baseline fuel for the solar central receiver hybrid power system. The option of heater conversion to oil or gas operation should, however, be left open to mitigate the effects of the uncertainty of the study.

Based on the results of the solar multiple trade study, the fossil to solar power ratio at plant design conditions should be 80/20. The solar multiple associated with this ratio is 0.8 and the required receiver power is 208 MWt at current design conditions. Unless required by transient considerations, storage of solar energy has not been shown cost effective. It is, therefore, recommended that thermal storage facilities not be included in the baseline conceptual design.

VII. REFERENCES

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APPENDIX B

Selection of Parallel vs Series Configuration

CONTENTS

FIGURES

TABLES

I. INTRODUCTION

Several alternatives exist for piping the solar receiver and fossil-fired sodium heater into the sodium process system for the solar central receiver hybrid power system conceptual design study. These two components can be connected either in parallel or series. Two options also exist for the series connection. The solar receiver can be connected in series either upstream or downstream of the heater.

A study was made to compare the relative merits of these alternatives in order to make a selection to be used as the baseline design for the ongoing study work. The following is a discussion of this study whereby advantages and disadvantages are presented for comparison among the various options.

II. DESIGN BASIS FOR COMPARISON STUDY

At full power, both the solar receiver and fossil-fired sodium heater are designed to furnish 260 MW of thermal energy to the steam generator. Steam, which is generated at 1000^{O}F in the steam generator, passes through the turbine generator to develop the 100 MWe net plant output.

The sodium inlet temperature to the steam generator is fixed at 1100^{O}F and the temperature drop (ΔT) across the steam generator is maintained constant at 550^{O}F, which establishes the steam generator outlet temperature at 550^{O}F. The sodium outlet temperature of 1100^{O}F and the ΔT of 550^{O}F were established as the optimum design points as a result of previous solar design studies. Based on the foregoing, the receiver and heater, connected either in series or parallel, are designed to furnish the required thermal energy with a constant sodium inlet and outlet temperature of 550^{O}F and 1100^{O}F, respectively. In the series configuration, the sodium enters the downstream component at 550^{O}F and leaves the upstream component at 1100^{O}F.

Variations in the solar receiver thermal energy output, because of the diurnal variation in absorbed thermal power, will be made up by the fossil-fired sodium heater to provide a constant net electrical plant output of 100 MW. As the receiver output drops, the heater output is increased. In the series arrangement, load changes are adjusted by varying the temperature rise across the components. Conversely, with the parallel arrangement, load changes are made by varying the sodium flow through the components. Changes in the seasons, time of day, and weather patterns all affect the solar heat input, which will require adjustment in the fossil-fired sodium heater thermal input to maintain a fixed plant output. At some specified minimum load in the solar receiver, the receiver will be shut down and all the power will be generated by the sodium heater. For the baseline reference design, the receiver is sized to develop full power at noon during the summer solstice.

III. SERIES CONFIGURATION

The two options that exist for designing the plant with a series configuration for the heater and receiver are shown in Figures 1 and 2. In Figure 1, the receiver is piped upstream of the heater, whereas in Figure 2 the receiver is connected downstream. In either case, for full-load operation, the sodium flow rate through the two components is maintained constant at 5.4×10^6 lb/h and the temperature rise across each component is varied in direct proportion to its load. This is illustrated in Tables 1 and 2.

As an example, Table 1 shows that with the receiver operating at 75% power the $\Delta T = 413^{\circ}F$ and the heater operates at 25% power with a $\Delta T = 137^{\circ}F$. The total ΔT across the two series connected components is $550^{\circ}F$ with a flow rate of 5.4×10^6 lb/h at full load. Either component may be required to operate at full power by itself and, therefore, both components must be designed for the full $550^{\circ}F$ temperature rise which is the same temperature design conditions for these components when they are connected in parallel.

The life of sodium systems is determined by the number and magnitude of the thermal and mechanical stress cycles they receive. For a very good approximation the design life is simply the number of thermal cycles. The integral of the damage factor is very uncertain which leads to large design margins. For this reason, sodium systems are generally designed to minimize the number of thermal cycles, unless there is a compelling economic or technical reason to do otherwise.

With the series arrangement, components are subjected to more thermal cycling than with the parallel arrangement, since the sodium flow is fixed and the temperatures are varied with the load. In addition, more severe temperature transients are generated in the heater and receiver when connected in series.

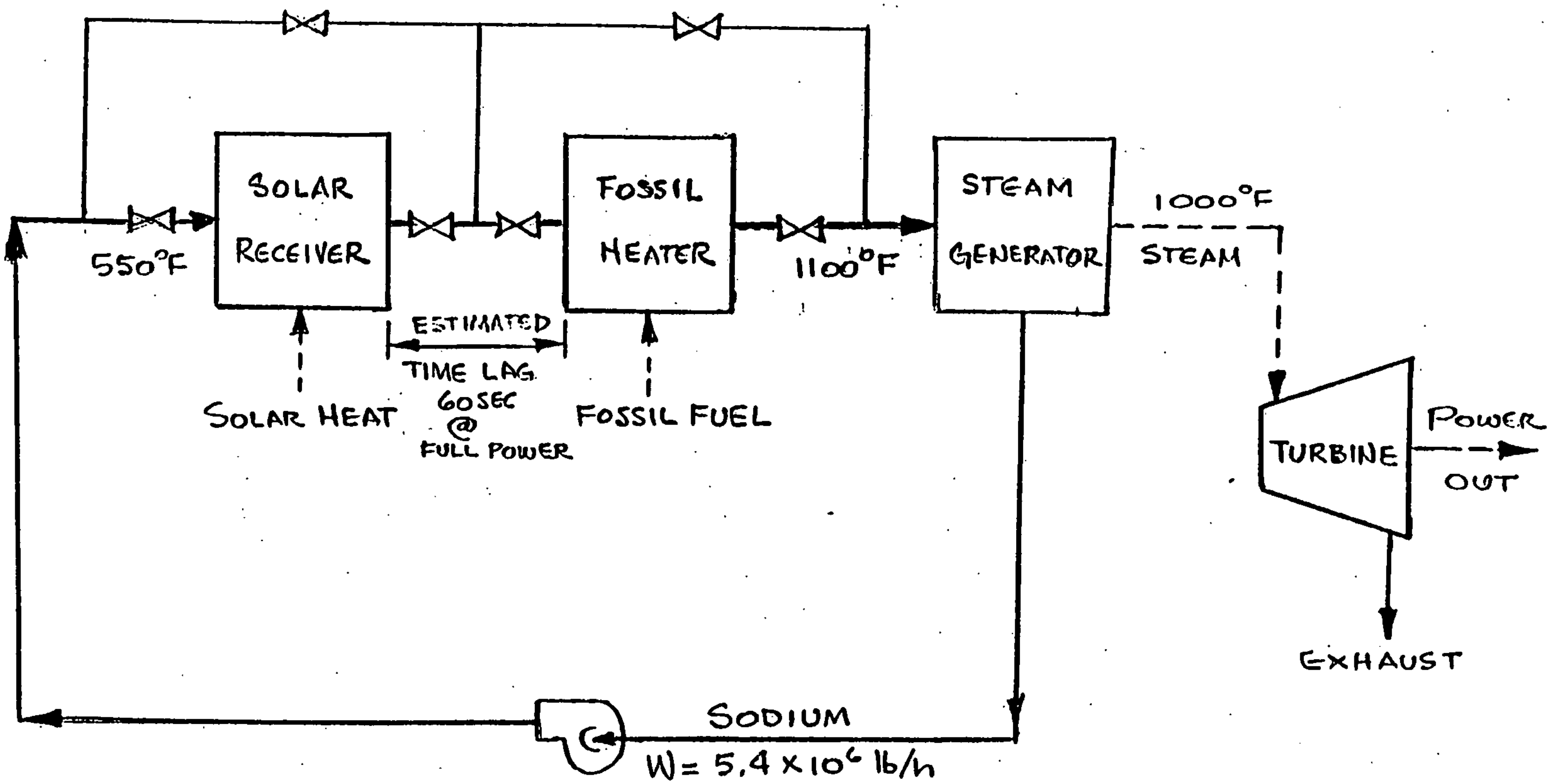

Figure 1. Simplified Diagram — Solar Hybrid Plant Series Configuration
Solar Receiver Followed By Fossil Heater

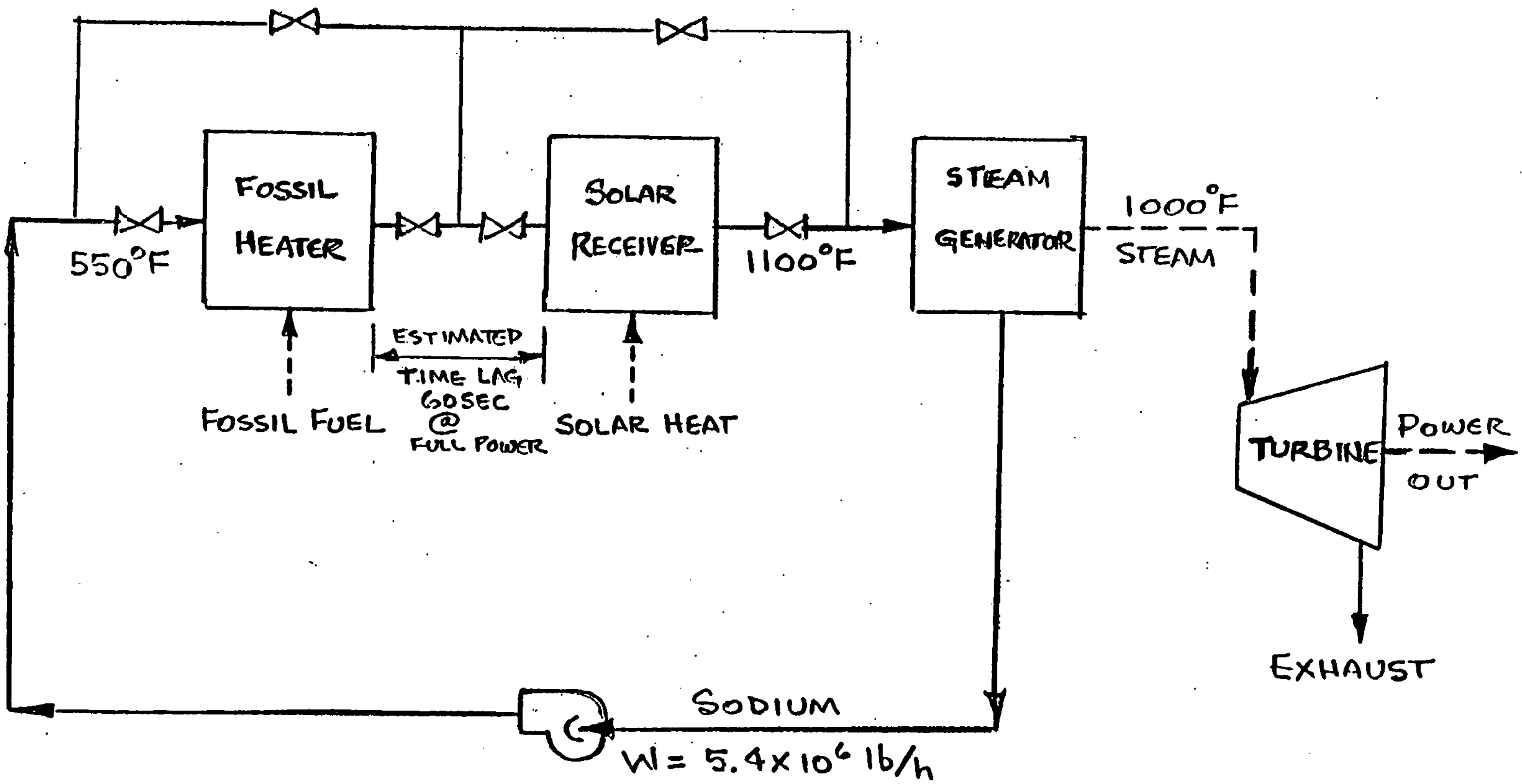

Figure 2. Simplified Diagram — Solar Hybrid Plant Series Configuration
Fossil Heater Followed By Solar Receiver

TABLE 1

SODIUM TEMPERATURE RISE VS % LOAD FOR SERIES CONFIGURATION
SOLAR RECEIVER FOLLOWED BY FOSSIL HEATER
CONSTANT FLOW OF 5.4 x 10^6 lb/h

Solar Receiver			Fossil Fired Heater		
	Temperature Rise			Temperature Rise	
% Load	T_{IN} - T_{OUT} °F	ΔT °F	% Load	T_{IN} - T_{OUT} °F	ΔT °F
100	550 - 1100	550	0	0	0
75	550 - 963	413	25	963 - 1100	137
50	550 - 825	275	50	825 - 1100	275
25	550 - 687	137	75	687 - 1100	413
0	0	0	100	550 - 1100	550

TABLE 2

SODIUM TEMPERATURE RISE VS % LOAD FOR SERIES CONFIGURATION
FOSSIL HEATER FOLLOWED BY SOLAR RECEIVER
CONSTANT FLOW OF 5.4 x 10^6 lb/h

Fossil Fired Heater			Solar Receiver		
	Temperature Rise			Temperature Rise	
% Load	T_{IN} - T_{OUT} °F	ΔT °F	% Load	T_{IN} - T_{OUT} °F	ΔT °F
100	550 - 1100	550	0	0	0
75	550 - 963	413	25	963 - 1100	137
50	550 - 825	275	50	825 - 1100	275
25	550 - 687	137	75	687 - 1100	413
0	0	0	100	550 - 1100	550

For example, if the receiver power output drops due to cloud cover, the temperature collapse in the receiver creates severe temperature shocks to the series connected components. Thus, it will require more extensive design analysis and possibly the installation of thermal liners to mitigate the thermal shock and extend the life of the components when they are connected in series rather than in parallel. The reliability of the components is severely affected by the number of thermal cycles. When the receiver is connected downstream of the heater, the temperature collapse due to cloud cover will create a severe thermal shock in the hot storage tank which may be carried over to the steam generators.

One scheme evaluated for reducing the receiver cost was to consider lowering the receiver design outlet temperature to 800^{o}F, thereby permitting the use of carbon or 2-1/4 Cr - 1 Mo low alloy steel instead of stainless steel which is required for the 1100^{o}F operation. In order to limit the receiver temperature to 800^{o}F for the series arrangement, the receiver must be piped ahead of the heater and be limited to approximately 50% of the total plant output. Use of carbon or 2-1/4 Cr - 1 Mo steel results in lower tube wall stresses in the receiver because of the lower coefficient of thermal expansion for these steels. However, this stress reduction is offset by the reduction in allowable stress for the lower grade steels. Thus, it was determined that the receiver size could not be reduced by lowering the design temperatures and using lower grade materials. Material cost plus the added heat treatment cost for the 2-1/4 Cr - 1 Mo were equivalent to the stainless steel costs. Carbon steel was not considered cost effective because of the significantly lower allowable stress at 800^{o}F than stainless steel at 1100^{o}F.

For this scheme, the efficiency of the receiver is improved by about 2% because of the lower average operating temperature. However, whatever cost savings this results in is more than offset by the additional cost for a thermal buffering system required to effect rapid load changes from receiver to heater. It was estimated that approximately 1/4 hour of thermal storage is required for this temperature buffering. It was concluded that this scheme of low-temperature receiver operation in series is not cost effective when compared to the parallel operation.

Following are the advantages and disadvantages of the two series configurations whcn compared to the parallel configuration.

A. ADVANTAGES - Receiver followed by Heater (Figure 1)

1) Good sodium distribution at all loads because of constant flow rate
2) High solar receiver efficiency at part loads because of low average temperature
3) High-temperature flue gas available for air preheating

B. DISADVANTAGES - Receiver followed by Heater (Figure 1)

1) Large thermal fatigue effects because of ΔT variations with load resulting in lower component reliability
2) High exit gas temperature at low heater loads
3) Bypass piping and valves required for single component operation
4) Lag in thermal equilibrium may lead to instability for fast load changes in heater
5) Heat loss always present on the idle unit unless it is bypassed
6) Heater inlet must be designed for approximately 1000°F
7) Stainless steel piping and valves required between receiver and heater, whereas carbon steel can be used for parallel configuration
8) System more difficult to control than parallel arrangement
9) Requires thermal storage to offset load changes

C. ADVANTAGES - Heater followed by Receiver (Figure 2)

1) Good sodium distribution at all loads because of constant flow rate
2) Favorable heater efficiency at all loads

D. DISADVANTAGES - Heater followed by Receiver (Figure 2)

1) Large thermal fatigue effects because of ΔT variations with load resulting in lower component reliability
2) Lower solar receiver efficiency at lower loads because of higher average temperatures
3) Bypass piping and valves required for single component operation
4) Lag in thermal equilibrium may lead to instability for fast load changes in heater
5) Heat loss always present on the idle unit unless it is bypassed
6) Receiver inlet must be designed for approximately $1000^{\circ}F$
7) Stainless steel riser piping and valves required between heater and receiver, whereas carbon steel can be used for parallel configuration
8) Average heat losses greater than when receiver is followed by heater
9) More difficult to control than parallel arrangement
10) Requires thermal storage to offset load changes

IV. PARALLEL CONFIGURATION

Figure 3 shows a simplified diagram of the hybrid plant with the solar receiver and fossil-fired heater connected for parallel operation. In this configuration, either component may be operated by itself up to 100% full load, or else the total plant load may be split between the two heat sources.

For the parallel mode of operation, the sodium flow must be proportioned between the receiver and heater in order to maintain the temperature rise across the units constant at 550^{o}F with a fixed outlet temperature of 1100^{o}F. For example, in order to provide a total of 260 MWt power to the steam generator the sodium flow rate is fixed at 5.4 x 10^6 lb/h for a temperature rise (ΔT) of 550^{o}F. Sodium enters the receiver and heater at 550^{o}F and is heated to 1100^{o}F. If the receiver is operating at 75% of full load, the flow is adjusted to approximately 4.1 x 10^6 lb/h. The balance of the sodium flow (i.e., 1.3 x 10^6 lb/h) is circulated to the heater to provide the 25% balance of the load.

Following are the advantages of the parallel configuration.

A. ADVANTAGES - Parallel configuration

1) System is able to respond more rapidly to load changes than series arrangement
2) Components experience small thermal fatigue effects since the axial ΔT remains approximately fixed at all loads
3) Easier to control than series arrangement
4) Thermal buffering is not required

In comparing the parallel arrangement with the series arrangement, no disadvantages of the parallel arrangement were identified.

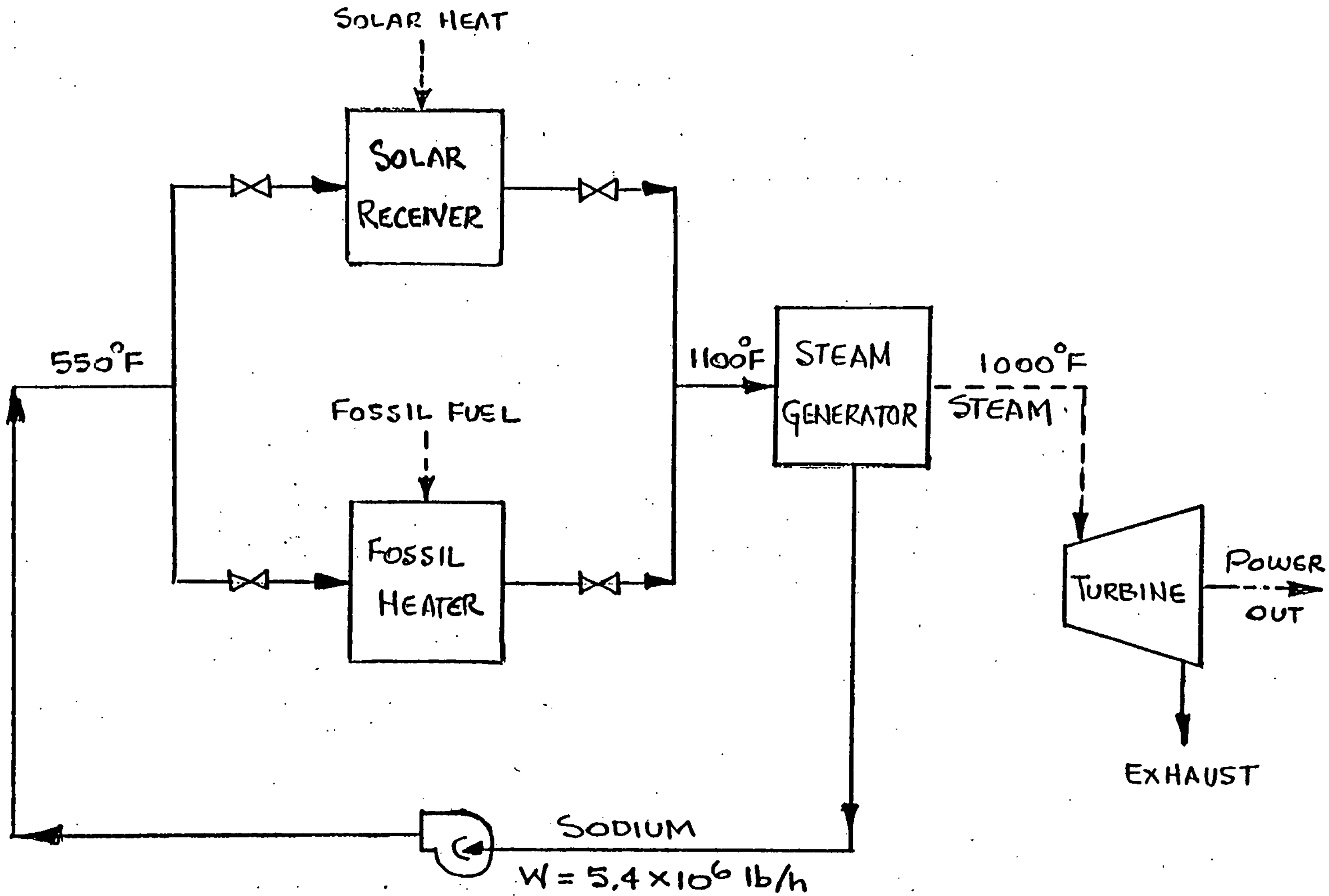

Figure 3. Simplified Diagram — Solar Hybrid Plant Parallel Configuration

V. SODIUM HEATER TEMPERATURES

To illustrate how the flue gas outlet temperature varies, estimates of temperature variation in the sodium heater with power level were made for the parallel and series configurations. Test data from the ETEC 35 MWt SCTI sodium heater (H-1) were used as the basis for estimating the temperature conditions for the solar hybrid plant sodium heater. Flue gas outlet temperatures, assuming no air preheating, were estimated for 100% full power, 75% part load, and 50% part load. These are shown in Figure 4. Calculations were based on assuming a constant UA and a fixed flue gas inlet temperature of $3400^{\circ}F$. The LMTD was assumed to vary directly with power level. The flue gas outlet temperatures were calculated from the LMTD. As shown, the highest flue gas outlet temperatures occur with the sodium heater installed in series downstream from the receiver.

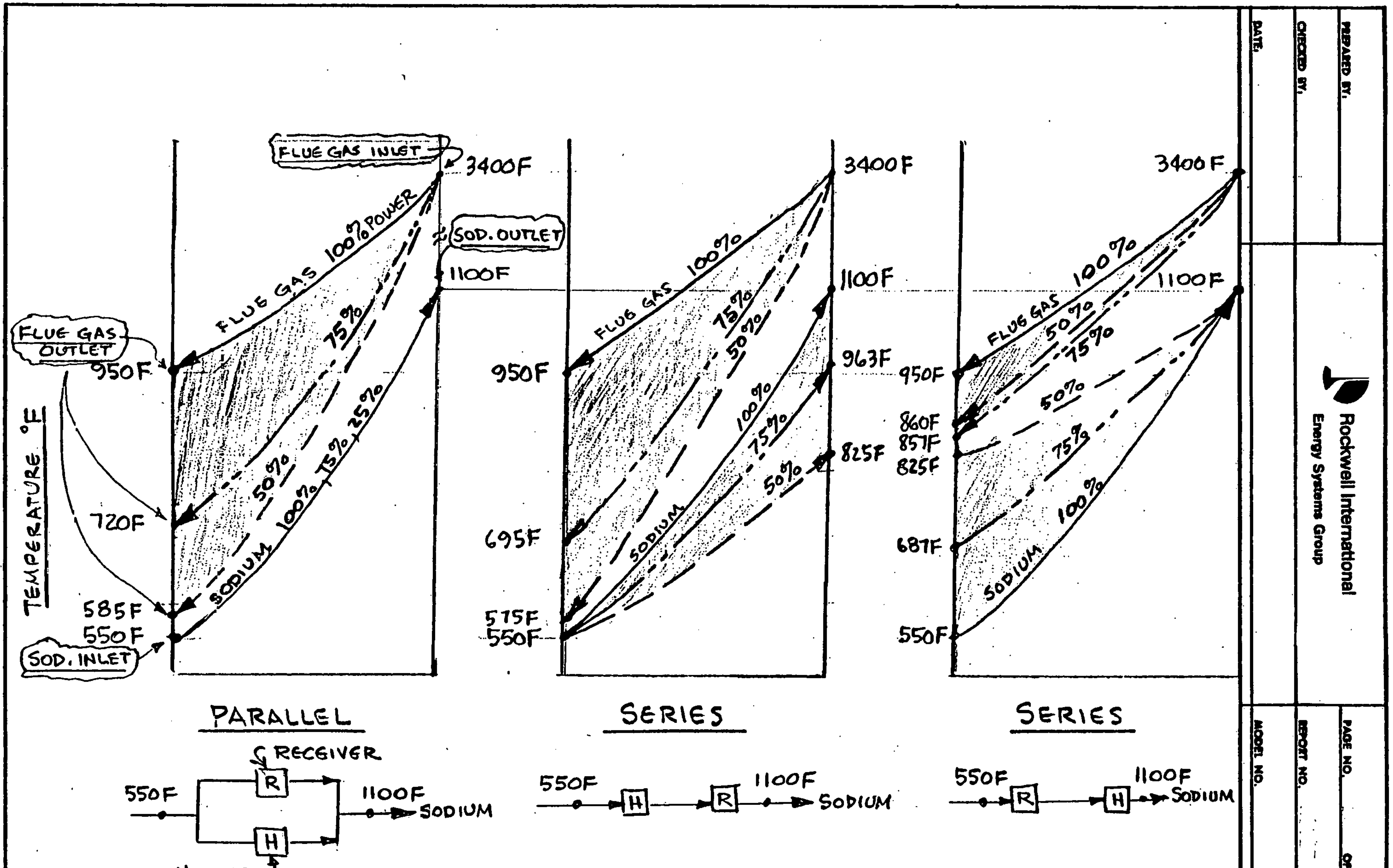

FIGURE 4 SODIUM HEATER TEMPERATURES

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VI. ECONOMIC CONSIDERATIONS

An assessment of the economic factors which influence the choice between the series and parallel configurations was made. The economics favor the parallel arrangement for the following reasons:

1. Stainless steel piping will be required for the piping connecting the receiver to the heater when connected in series. In the case where the receiver is downstream of the heater (Figure 2), this piping is the riser piping in the solar receiver tower.

   Replacing the carbon steel piping and valves, which can be used for parallel operation, with stainless steel piping and valves is estimated to cost an additional $160,000 in 1978 dollars.

2. Stainless steel piping and valves are also required for the bypass piping for the series arrangement.

   It is estimated that this additional piping and valving will cost an additional $700,000 in 1978 dollars.

3. Average heat losses for the series configuration are greater than for the parallel configuration when the receiver is installed downstream of the heater. The higher average receiver-operating temperature results in the larger heat losses which are made up by increasing the power output of the heater.

   It is estimated that heat losses equal to about 2 MW of thermal energy must be provided by the heater. Assuming a coal-fired heater, additional annual fuel costs of $47,000 per year are estimated based on a fuel escalation rate of 10%. This is equivalent to a present worth of $450,000 in 1978 dollars.

4. Rapid load changes between the receiver and heater when connected in series will require thermal storage. This is because the receiver can change load at 1% per second, whereas the heater is limited to a temperature change of 10^{o}F per minute, which is equivalent to a load change of 1.8% per minute. Storage of about 1/4 hr will be required in this case to provide the necessary thermal power to maintain constant output during the transfer of the load from the receiver to the heater.

   It is estimated that 1/4 hr of thermal storage is equivalent to approximately $1.6M in 1978 dollars.

5. Larger number of thermal cycles will require more expensive design analyses and design requirements to mitigate thermal stresses for the series connected components.

   It is estimated that the engineering design and analysis costs for the series connected components could result in increased costs of up to 30%. The life and reliability of these components will be severely impaired by the continuous thermal cycling with load changes. This is a one-time nonrecurring cost for the hybrid plant.

Table 3 presents a summary of the estimated additional capital price required for the series configuration and indicates that an additional price of 2.9 million dollars would be required for the series configuration when compared to the parallel configuration. In addition, $900,000 of nonrecurring capital price would be required for the design and analyses associated with the thermal cycling problem.

TABLE 3

ESTIMATED ADDITIONAL CAPITAL PRICE
REQUIRED FOR SERIES CONFIGURATION

	Item	Capital Price $1000 (1978)
1.	Replace carbon steel piping and valves with stainless steel	160
2.	Install stainless steel piping and valves for bypass	700
3.	Make up for heat losses using coal-fired sodium heater	450
4.	Provide 1/4 hr of thermal storage for rapid load changes	1,600
	Subtotal	2,910
5.	Additional design and analyses for thermal cycling*	900
	TOTAL	3,810

*Nonrecurring price

VIII. SUMMARY AND CONCLUSIONS

Based on the foregoing, it was concluded that the parallel configuration for the solar receiver and the fossil-fired sodium heater is the preferred arrangement for the baseline hybrid plant. This configuration offers the following major technical advantages over the series arrangements:

1. Thermal cycling of components is minimized, because load changes are effected by variation in flow rate and not temperature rise, since outlet temperature from heater and receiver is maintained constant at all loads
2. Sodium system is easier to control by varying flow rate
3. Carbon steel can be utilized for sodium riser and inlet piping to receiver
4. Thermal storage may not be a requirement for this mode of operation

Based on the economic factors previously discussed, the parallel configuration is also the most cost effective and, therefore, is the recommended choice for the reference solar central receiver hybrid plant conceptual design.