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EVALUATION PROCEDURES FOR INDUSTRIAL COGENERATION UTILIZING ALTERNATE STEAM SOURCES

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DISCLAIMER

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EVALUATION PROCEDURES FOR INDUSTRIAL 1.14
COGENERATION UTILIZING ALTERNATE STEAM SOURCES 1.15

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ABSTRACT 1.23

This paper reports the results of a cogeneration feasibility 1.24
study, funded by the Department of Energy, utilizing 1.25
alternate steam sources. The study considered sites which 1.27
could serve four to six industrial complexes in the Gulf
States Utilities service area. The sources of steam 1.29
considered were conventional steam generators using oil or

coal and advanced technologies such as: high-temperature 2.1
gas-cooled nuclear reactor (HTGR), consolidated nuclear
steam supply (CNSS) using a light water reactor, 2.2
fluidized-bed coal combustion, and coal gasification using 2.3
conventional steam generators, combined cycles, and fuel
cells. The scope of the study included selecting two 2.4
preferred sites for cogeneration plants, developing and 2.5
optimizing heat cycles, writing plant and equipment
descriptions, determining capital and operating costs, 2.6
evaluating alternatives, and drawing conclusions based on
technical and economic factors.

INTRODUCTION 3.9

The potential benefits of cogeneration to the nation's 3.10
economy are well established; the institutional barriers to 3.11
cogeneration are surmountable. The thermodynamic advantages 3.13
of cogeneration are well known: fuel chargeable to the
power produced by noncondensing turbines supplying steam for 3.14
process use and feedwater heating is on the order of 4,500 3.[illegible]
Btu/kWh (4,748 kJ/kWh) which is about half that required in
the best condensing steam power plants. None of these facts 3.17
will lead to the construction of cogeneration plants in the
absence of an acceptable rate of return on the owner's 3.18
investment or an overriding government mandate.

The purpose of this paper is to present evaluation 3.19
procedures and techniques for cogeneration plants. It 3.20
summarizes the results of a study of cogeneration in the
Gulf States Utilities (GSU) service area funded by the 3.21
Department of Energy. Specific objectives of this study 3.22
are:

- Determine the technical and economic feasibility of 3.24
cogeneration alternatives using coal and nuclear 3.25
fuels in the GSU service area.

- Develop technical and economic data on cogeneration 3.26
plants generally useful in the United States. 3.27

- Develop plans and schedules for possible 3.28
implementation of preferred alternatives.

SITE SELECTION 3.31

Exclusionary and evaluative criteria were developed to 3.32
screen potential cogeneration plant sites in four 3.33
geographical regions in the GSU service area. Based on 3.35
assigned scores, sites at Orange, Texas and Geismar,
Louisiana were selected as best suited for both coal and 3.36

nuclear cogeneration plants. There were suitable sites in 3.37
the other two regions but they did not score as high as
those chosen. There are four potential industrial consumers 3.38
in Orange with a total current peak electrical requirement 3.39
of about 200 MW. Four potential consumers in Geismar 3.40
require about 350 MW. The projected 1985 steam requirements 3.41
for both sites are shown in Table 1.

STEAM CYCLE OPTIMIZATION 3.43

There are three principal areas to be optimized in a steam 3.44
power cycle: throttle conditions, feedwater heating cycle, 3.45
and condensing pressure. Condensing capability was ruled 3.47
out initially for the cogeneration plants studied, with the
expected deficiency in power generation to be supplied from 3.48
the GSU grid. This ground rule was later relaxed for one of 3.49
the nuclear alternatives. With this exception, the 3.50
optimization involved determining the throttle steam
conditions and feedwater heater arrangement. 3.51

Industrially owned cogeneration plants have historically 3.52
operated with steam turbine inlet pressures up to 1,450 psig 3.53
(9,997 kPa). This compares with 2,400 psig (16,547 kPa) or 3.54
3,800 psig (24,821 kPa) used for large turbines in plants 3.55

owned by electric utilities. Figure 1 shows the theoretical 3.56
relationship between throttle pressure, exhaust pressure, 3.57
and kWh per 1,000 pounds of steam at a throttle temperature
of 1,000°F (538°C). At an exhaust pressure of 600 psig 3.58
(4,137 kPa) the power generation can be increased about
20 percent by raising the throttle pressure from 1,450 psig 4.1
(9,997 kPa) to 1,800 psig (12,411 kPa). An additional 4.3
20 percent can be gained by going to 2,400 psig (16,547
kPa). It is evident that throttle pressures higher than 4.4
current industrial practice should be considered for large 4.5
cogeneration plants, regardless of who owns or operates
them. Turbine throttle conditions of 1,800 psig (12,411 4.6
kPa), 950°F (510°C), and 2,400 psig (16,547 kPa), 1,000°F 4.7
(538°C) were selected for comparison for the fossil-fired 4.8
cogeneration plants at Orange and Geismar. The basic 4.9
feedwater heating cycle included a deaerator operating at 30
psig (207 kPa), and one stage of closed feedwater heating 4.10
supplied with steam at 275 psig (1,896 kPa). Budgetary 4.12
capital and operating costs were estimated for each plant.
At both Orange and Geismar, the 2,400 psig (16,547 kPa) 4.13
plant costs about 5 percent more and was capable of 4.14
generating about 20 percent more power.

A comparison of the fixed charges and levelized operating 4.15
costs was made assuming initial operation in 1985. Both 4.17
plants supply the same quantity of process steam, and
recoverable heat from this steam is nearly the same. The 4.18
levelized cost of power to large industrial consumers in the
GSU service area over a 30-year period beginning in 1985 is 4.19
estimated to be about $0.076 per kWh. The break-even power 4.20
cost which would justify increasing the design throttle
pressure from 1,800 psig to 2,400 psig is less than half of 4.21
this levelized cost. Supercritical throttle pressures were 4.22
not considered, since the trend is away from these in 4.23
central station practice. Throttle conditions of 2,400 psig 4.24
(16,547 kPa) and 1,000°F (538°C) were selected for the
fossil-fired plants at both Orange and Geismar. A cycle 4.26
study performed by the General Atomic Company led to the
same steam conditions at the turbine throttle for the HTGR 4.27
cogeneration plants.

The steam leaving the Consolidated Nuclear Steam System 4.28
(CNSS) is saturated at a pressure of 920 psig (6,343 kPa). 4.29
A reboiler is necessary to reduce the possibility of sending 4.30
radioactive steam to the industrial customers. The 4.31
reboilers and oil-fired superheaters supply steam at 625
psig (4,309 kPa) and 700°F (371°C) at Orange and 675 psig 4.32

(4,654 kPa) and 750°F (399°C) at Geismar. Part of this steam is sent out for process use and the rest is expanded through a turbine to supply lower pressure steam for process and feedwater heating. 4 4

There are two primary parameters to be determined in optimizing the feedwater heating cycle: the final feedwater temperature and the number of stages of heating. The steam used for feedwater heating produces work over and above that produced by the process steam. For given initial and final feedwater temperatures, the maximum work would be obtained with an infinite number of stages of heating. Figure 2 shows this theoretical work in kWh per 1,000 pounds of condensate and makeup at 68°F (20°C) for the turbine conditions listed. 4 4 4 0 .1

The fossil power cycles at Orange and Geismar do not include closed heaters before the deaerator. Although these would increase the fraction of the theoretical work that would be obtained, they increase the capital cost and pose problems of venting and draining in a plant that does not have a condenser. A minimum exhaust flow must be maintained to prevent overheating the low pressure section of the turbine. .2 4.43 4.44 4.45 4.46

The base case includes a deaerator operating at 30 psig (207 4.47
kPa) and one stage of closed heaters at 275 psig (1,896 4.48
kPa). An additional stage of closed heaters operating at 4.49
625 psig (4,309 kPa) at Orange and 675 psig (4,654 kPa) at
Geismar were found to be economically justified. This 4.51
feedwater heating cycle produces about 70 percent of the
potential with an infinite number of heaters. 4.52

The HTGR feedwater heating cycle selected by the General 4.53
Atomic Company has two stages of closed feedwater heating 4.54
before the deaerator which operates at 85 psig (586 kPa) and 4.55
one after it. Final feedwater temperature is 435°F (240°C). 4.56
This cycle produces about 80 percent of the infinite heater 4.57
potential. The deaerator should be designed to operate with 4.58
the low pressure heaters out of service, so the entire cost 5.1
of these heaters must be justified by the additional power
produced.

Table 2 provides a general comparison of the plant 5.2
arrangements considered. Figures 3, 4, and 5 are the 5.3
fundamental flow diagrams and heat balances for the fossil 5.4
plants, CNSS, and HTGR at Geismar. Above a certain size, 5.5
multiple backpressure turbines are more advantageous than

automatic extraction turbines because of their higher 5.5/1
efficiency. This also improves the plant availability. 5.5/2

ECONOMIC ANALYSIS 5.8/1

The Minimum Revenue Requirements (MRR) method and the 5.8/2
Discounted Cash Flow (DCF) method were both used in the 5.8/4
economic analysis of the alternatives considered. The basic 5.8/5
economic factors employed in the study are shown in Table 3.
Sample calculations showing the method used to determine the 5.8/6
capital and operating costs using the MRR method are 5.8/7
contained in Tables 4 and 5. These costs for all 5.8/8
alternatives considered at Orange and Geismar are shown in 5.8/9
Tables 6, 7, and 8. For comparison, fuel plus operation and 5.8/10
maintenance costs only are shown for the users' facilities
assuming that they would burn No. 2 fuel oil. The uniform 5.8/12
annual costs in Tables 6, 7, and 8 are the minimum revenue
requirements necessary for the plant owners to realize a 5.8/13
rate of return of 10 percent, representative of utility 5.8/14
practice. The fixed charges are the components of the 5.8/15
revenue requirements which are a function of the invested 5.8/16
capital and include debt service, taxes, and insurance. The 5.8/17
levelized fuel and operating and maintenance charges are the
uniform annual costs which have the same present value in 5.8/18

the first year of operation as the predicted costs including 5.27
escalation.

The total of the costs represents revenue which must be 5.28
obtained from the users. However, for this they receive 5.30
electric power which is shown as a credit based on the
levelized utility rate. The net annual cost represents the 5.32
user's levelized before-income-tax cash flow chargeable to 5.33
process steam. The net-of-taxes cash flow would be reduced 5.34
by the users' effective income tax rate, which is 5.35
46.0 percent at Orange and 48.4 percent at Geismar.

The bottom line shows the levelized cost per thousand pounds 5.36
of process steam based on the design load factor of 5.37
90 percent. Figure 6 shows the effect of changes in load 5.38
factor on some of the alternates.

A reliability analysis has been made based on equipment 5.39
availability data in Reference 1. The base case included 5.40
two half-capacity boilers for the fossil plants, one HTGR
and one CNSS at Orange, and three reactors for the HTGR 5.41
plant and two reactors for the CNSS plant at Geismar.
Levelized steam costs including backup fuel costs at the 5.41/1
users' plants for 100-percent load factor are shown in

Table 9. These costs are up to about 20 percent more than 5.41/3
those in Tables 6, 7, and 8 except for the HTGR in Orange 5.41/4
which is 90 percent higher. A third half-capacity boiler 5.41/5
can be economically justified at Geismar. A thorough 5.41/6
economic analysis is needed to determine the number and size
of boilers and reactors to balance reliability and capital 5.41/7
cost.

DISCOUNTED CASH FLOW ANALYSIS 6.10

The economic comparisons were based on the revenue 6.12/1
requirements which must be realized from the sale of steam 6.12/2
in order to produce the minimum acceptable rate of return, 6.12/4
taken as 10 percent. An "expense center" analysis has also 6.12/5
been made to determine, for each fossil-fired and nuclear 6.12/6
alternative, the net present value of the cash flow both
during the construction period and for 30 years of 6.12/7
operation. For simplicity, the start of construction for 6.12/8
the fossil-fired alternatives has been delayed so that all 6.12/9
alternatives have the same year of initial operation, 1986.

Tabulations of the net present value for four different fuel 6.12/10
costs and three discount rates are shown on Table 10 for 6.12/11

existing plants (fuel and operation and maintenance only),
eastern coal, western coal, No. 6 fuel oil, the HTGR, and 6.12/12
the CNSS at both Orange and Geismar. These results are 6.12/13
compared graphically on Figures 7 through 14. Annual fuel 6.12/14
costs were taken as 90, 100, 150, and 200 percent of the
1986 costs used in the minimum revenue requirements study. 6.12/15
The net present worth has been determined for each fuel cost 6.12/16
at discount rates of 10, 15, and 20 percent. 6.12/17

Table 11 shows levelized steam costs (LSC) calculated from 6.12/18
the following equation.

$$LSC = \frac{(1+i)^7 \ (NPV)}{\frac{1}{i}\left[1 - \left(\frac{1}{1+i}\right)^{30}\right](S)}$$

Where LSC = steam cost levelized over the 30 years of oper- 6.12/21
ation, $\$/10^3$ lb 6.12/22
i = discount rate 6.12/23
NPV = net present value, 1979 dollars from DCF analysis 6.12/24
S = annual process steam sendout, 10^3 lb 6.12/25

These levelized steam costs are after taxes. The break-even 6.12/29
price of purchased steam to give the same levelized after-
tax costs are shown in Table 12. These prices are not 6.12/31
exactly comparable to the levelized steam costs in Tables 6
and 7 since the fossil-fired plants tabulated there begin 6.12/32
operation earlier, and the nuclear plant costs are levelized 6.12/33
over 35 years.

Table 13 shows the figures from Tables 6 and 7 adjusted to a 6.12/34
starting date of 1986 and 30 years of operation. For 6.12/36
comparison, the break-even purchased steam prices are shown
for 100-percent fuel cost and 10-percent discount factor. 6.12/37
The numbers are very close, showing that if industrial 6.12/38
owners were willing to accept a 10-percent rate of return, 6.12/39
it would make little difference economically whether they
owned the cogeneration plant or bought steam from a plant 6.12/40
owned by others. The fixed charge rate of 15 percent is a 6.12/41
typical value for a utility with roughly equal debt and
equity financing, a minimum acceptable rate of return of 6.12/42
10 percent, and a 30-year plant operating life. The 6.12/43
site-specific fixed charge rate would be on the order of
1-percent higher at Orange than at Geismar because of the 6.12/44
effect of taxes. This would account for the slightly 6.12/45
different ratios at the two sites.

If the hurdle rate of return were 15 or 20 percent, there 6.12/46
would be a definite economic advantage to purchasing steam 6.12/47
from an entity whose rate of return was limited by
regulation. If this is not possible, the economic choice at 6.12/48
a hurdle rate of return of 15 percent is between the HTGR 6.12/49
and the coal-fired plants. Eastern coal produces the lowest 6.12/50
cost steam at a fuel cost of 90 percent, but the HTGR has
the advantage at fuel costs of 150 and 200 percent. At a 6.12/52
fuel cost of 100 percent, the two are competitive. The CNSS 6.12/53
with a fuel cost of 90 percent would become competitive with
eastern coal plants having a fuel cost at about 150 percent. 6.12/54

At a hurdle rate of return of 20 percent, the HTGR is not 6.12/55
competitive with coal-fired plants except at a fuel cost of 6.12/56
200 percent. The CNSS with a fuel cost of 90 percent 6.12/57
becomes competitive with coal plants with fuel costs of
about 200 percent. Fuel and operating and maintenance costs 6.12/58
for existing plants are below the coal-fired plant costs at
fuel costs of 90 and 100 percent. Replacement costs for 6.12/60
existing boilers will affect this comparison, and it is
questionable whether the use of oil for the next 37 years is 6.12/61
a viable option.

PRESENT VALUE STEAM COST 10.20

Steam costs levelized over a 30-year period beginning in 10.21
1986 are good for comparison of alternatives, but are 10.22
difficult to compare with present steam costs. A present 10.24
value steam cost (PVSC) may be calculated from the net
present value (NPV) using the following equation: 10.25

$$PVSC = \frac{(1+i)^7 \quad (NPV)}{(i+e)^7 \left\{ \frac{1}{i-e} \left[1 - \frac{1+e}{1+i}^{30} \right] \right\} (S)}$$

Where PVSC = present value steam cost, $\$/10^3$ lb 13.17
NPV = net present value in 1979 $ 13.18
i = rate of return 13.19
e = rate of steam cost escalation 13.20
S = process steam sendout, 10^3 lb. 13.21

The PVSC calculated from this equation is the cost which, if 13.23/1
escalated year-by-year for 37 years, would yield the given 13.23/2
NPV for steam use during the 30-year period beginning in 13.23/3
1986. The curves in Figure 15 show the ratio of levelized 13.23/4

steam cost to net PVSC for discount rates from 10 to 13.23/5
20 percent and escalation rates from 5 to 9 percent. The 13.23/6
PVSC is quite sensitive to the assumed rate of escalation.
Table 14 shows the PVSC for the five alternative plants at 14.0/1
Orange and Geismar for 100-percent fuel cost, 6- and 14.0/2
7-percent escalation, and discount rates of 10, 15, and 14.0/3
20 percent. For comparison, fuel and operation and 14.0/4
maintenance costs only are shown for the existing plants net 14.0/5
of taxes. At discount rates of 10 and 15 percent, the coal- 14.0/6
fired plants and the HTGR show a clearcut economic advantage 14.0/7
over continued operation of existing plants with No. 2 fuel
oil.

CONCLUSIONS 14.9

Large coal-fired cogeneration plants are economically 14.10
attractive at rates of return of 15 percent or less. 14.11
Nuclear plant steam costs are based on nth-of-a-kind plant 14.13
costs. It does not appear that development of these plants 14.14
for cogeneration use only is justified. The HTGR has an 14.15
advantage over coal only for rates of return less than
15 percent. The CNSS would require fossil fuel escalation 14.16
rates nearly twice those projected in order to be 14.17
attractive.

Of the other alternatives studied, only the atmospheric fluidized-bed plants are competitive with coal.

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1. Edison Electric Institute, Report on Equipment Availability for the Ten-Year Period 1966–1975, EEI Publication No. 76–85, New York, December 1976.

TABLE 1

PROJECTED 1985 STEAM DEMANDS

	Process Steam Flows (lb/hr x 1,000)				
	970 psia	690 psia	640 psia	290 psia	Total
Geismar	370	5,020	-	450	5,840
Orange	-	-	1,450	745	2,195

TABLE 2 1.9

COMPARISON OF VARIOUS PLANT ARRANGEMENTS 1.11

ORANGE	Operating Pressure (psia)	Heat Input (MWt)	Net Electric Power (MWe)	3.39 3.40 3.41
Eastern & Western				3.43
Coals	2415	989.360	148.6	3.44
No. 6 Fuel Oil	2415	989.360	155.2	3.46
HTGR	2415	1007.363	164.6	3.48
CNSS without Condensing	640	871.083	23.8	3.50
CNSS with Condensing	640	1315.560	152.3	3.50/2
GEISMAR				3.56
Eastern & Western				3.58
Coals	2415	2630.958	352.2	3.59
No. 6 Fuel Oil	2415	2630.958	369.7	4.2
HTGR	2415	2684.883	400	4.4
CNSS without Condensing	690	2371.290	38.4	4.4/2
CNSS with Condensing	690	2872.295	183.2	4.4/4
Foster-Wheeler AFB	2415	2630.958	344.3	4.6
Babcock & Wilcox AFB	2415	2630.958	339.9	4.8
Coal Gasification with				4.10
Conventional Boiler				4.11
(Air-Blown)	2415	4791.7	474.7	4.12
Conventional Boiler				4.14
(Oxygen-Blown)	2415	4867.6	476.7	4.15
Combined Cycle				4.17
(Unlimited Elec.)	*	8161.1	1854	4.18
Combined Cycle				4.20
(Limited Elec.)	*	4629.7	352	4.21
Fuel Cell				4.23
(Unlimited Elec.)	*	10,989.0	2701.3	4.24
Fuel Cell				4.26
(Limited Elec.)	*	4487.3	352	4.27

4.29

*970/690/290 psia 4.30

[redacted]

TABLE 3

ASSUMPTIONS USED IN ECONOMIC ANALYSES

	Fuel Oil No. 6	Fuel Oil No. 2	Coal Eastern	Coal Western	CNSS	HTGR	Coal Gasification	AFB	Fuel Cells	Comb. Cycle	
1. Construction period (yrs)	5	-	6	6	7	7	6	6	6	6	1.16 1.17
2. Operating date	1984	-	1985	1985	1986	1986	1985	1985	1985	1985	1.29
3. Basis for capital costs	1/78	-	1/78	1/78	1/78	1/78	1/78	1/78	1/78	1/78	1.32 1.33
4. Escalation of capital costs (% per year) [1]	7	-	7	7	7[6]	7	7	7	7	7	1.36 1.37
5. Interest during construction (% per year) [2]	9	9	9	9	9	9	9	9	9	9	1.40 1.41
6. Operating life of unit (yrs)	30	-	30[5]	30[5]	35[7]	35	30	30	30	30	1.44 1.45
7. Rate of return (%)	10	-	10[5]	10[5]	10[5]	10	10	10	10	10	1.48
8. Annual fixed charge rate (%) [16]	15	-	15[5]	15[5]	16	16	15	15	15	15	1.51 1.52
9. Load factor (%)	90	90	90	90	90	90	90	90	90	90	1.55
10. Fuel cost (1977 $ per 10^6 Btu)	1.98[3]	2.55[3]	1.11	1.22[4]	0.72[8]	0.63	1.11	1.11[12]	1.11	1.11	1.58 1.59
11. Escalation of fuel cost (% per year)	7[4]	7	6	6	[10]	[10]	6	6	6	6	2.3 2.4
12. Limestone cost (1977 $ per ton)	13	-	13	13	-	-	-	13	-	-	2.7 2.8

[redacted] [redacted] [redacted]

TABLE 3 (Cont)

	Fuel Oil No. 6	Fuel Oil No. 2	Coal Eastern	Coal Western	CNSS	HTGR	Coal Gasification	AFB	Fuel Cells	Comb. Cycle	
13. Escalation of limestone (% per year)	6	-	6	6	-	-	-	6	-	-	2.12 2.13
14. O&M costs (1977 $ per 10^6 Btu)[10]	0.23	0.14	0.29	0.27	0.18	0.16	(13)	0.26	(14)	(15)	2.16 2.17
15. Escalation for O&M costs (% per year)	6	6	6[9]	6[9]	6[9]	6	6	6	6	6	2.20 2.21
16. GSU electric power rates (1977 mills/kWh)	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	2.24 2.25
17. Escalation for electric power (% per year):											2.28 2.29
To 1985	11	11	11	11	11	11	11	11	11	11	2.30
Beyond 1985	7	7	7	7	7	7	7	7	7	7	2.31
18. Sulfur ($ per ton)	-	-	-	-	-	-	20	-	20	20	2.35
19. Escalation for sulfur (% per year)	-	-	-	-	-	-	6	-	6	6	2.37 2.38
20. Aqueous ammonia ($ per ton)	-	-	-	-	-	-	24	-	24	24	2.42
21. Escalation for aqueous ammonia, (% per year)	-	-	-	-	-	-	6	-	6	6	2.44 2.45
22. Anhydrous ammonia ($ per ton)	-	-	-	-	-	-	120	-	120	120	2.49
23. Escalation for anhydrous ammonia (% per year)	-	-	-	-	-	-	6	-	6	6	2.51 2.52

[redacted] [redacted] [redacted]

TABLE 3 (Cont)

NOTES 3.1

Unless noted otherwise, economic factors are best estimates by Stone & Webster Engineering Corporation. 3.3

(1) Escalation compounded through 60% of the construction period. 3.4/1
(2) Simple interest (not compounded) during last 40% of construction period. 3.4/2
(3) From Reference (c) for No. 6 and No. 2 fuel oil. 3.4/3
(4) From Reference (c). 3.4/4
(5) From Reference (a) Section 5.9.. 3.4/5
(6) From Reference (b) page 4-18. 3.4/6
(7) From Reference (b) page 4-15, assuming same life of CNSG and CNSS. 3.4/7
(8) From Reference (d) page B-4 excluding plutonium credit and escalated one year. 3.4/8
(9) From Reference (e) page 28. 3.4/9
(10) Yellowcake escalation (1/3) is estimated at 6% per year. Conversion, enrichment, shipping, and fabrication 3.4/1
escalation (2/3) is estimated at 4% per year. 3.15
(11) Scrubbers included for fossil units except for No. 2 oil. 3.15/
(12) Comparison made on basis of eastern coal. 3.15/
(13) 0.52 for air-blown O&M, 0.54 for oxygen-blown. 3.15/
(14) 0.61 for unlimited power, 0.54 for limited power. 3.15/
(15) 0.63 for unlimited power, 0.57 for limited power. 3.15/
(16) Includes taxes, insurance, and debt service. 3.15/

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(c) R. G. Chapman, Gulf States Utilities Company, to R. B. Steiner, 3.29
Stone & Webster Engineering Corporation, communication dated July 22, 1977. 3.30
(d) 400-MWe Consolidated Nuclear Steam System (CNSS) - 1200 MWe/Conceptual Design, 3.31
prepared by Babcock & Wilcox Company for Oak Ridge National Laboratory, ORNL/Sub-4390/4 (June 1977). 3.32
(e) Evaluation of Geismar Steam - Electric Project, prepared for Gulf States Utilities Company 3.33
by Arthur D. Little, Inc. (December 12, 1975). 3.34

TABLE 4

SAMPLE CALCULATIONS FOR ECONOMIC COMPARISON - CAPITAL COSTS

	Capital Costs ($ x 1,000)
Example is for Geismar coal-fired plant using eastern coal:	
6-Year Construction Period 1985 Service Date	
Estimated capital cost (in January 1978 dollars).	713,491
Escalation based on 7% per year compounded through 60% of construction period.	
$(1.07)^{1+(0.6 \times 6)} - 1 = 0.3651$ x capital cost	260,496
SUBTOTAL (Escalated Capital Cost)	$ 973,987
Interest during construction at 9% per year simple interest during last 40% of construction period.	
$(0.09) \times (6 \text{ yrs} \times 0.4) = 0.216$ x escalated capital cost	210,381
TOTAL CAPITAL COSTS	$1,184,368

TABLE 5

SAMPLE CALCULATIONS FOR ECONOMIC COMPARISON - OPERATION COSTS

	Annual Operating Costs ($ x 1,000)
Example is for Geismar coal-fired plant using eastern coal:	
Assumptions	
30-Year Operating Life Rate of Return - 10% Boiler Efficiency - 86% Availability - 90%	
1. Fixed charges at 15% of total capital cost for insurance, taxes, and debt service.	$177,655
2. Fuel costs ($1.11/10⁶ Btu) escalated at 6% and levelized.	
$\$1.11 \times 1.59385 \times \frac{16.771225}{9.426914} = \$3.15/10^6$ Btu	
$\frac{2630.958 \text{ MWt} \times 3413(10)^3}{0.86 \times 10^6} \times 3.15 \times 7{,}884$ hr/yr	$259,304
3. O&M costs ($0.29/10⁶) Btu escalated at 6% and levelized.	
$\$0.29 \times 1.59385 \times \frac{16.771225}{9.426914} = \$0.82/10^6$ Btu	
$\frac{2630.958 \text{ MWt} \times 3413(10)^3}{0.86 \times 10^6} \times 0.82 \times 7{,}884$ hr/yr	$ 67,501
SUBTOTAL (Annual Operating Cost)	$504,460
4. Credit for power (16.5 mills/kWh) escalated at 11% to 1985 and 7% thereafter and levelized.	
$16.5 \times 2.30454 \times \frac{18.79176}{9.426914} = 75.7$ mills/kWh	
$352.2 \text{ MWe} \times 7{,}884 \text{ hrs} \times 0.0757(10)^3$	$210,200
NET ANNUAL OPERATING COST	$294,260
5. Steam cost/1000 lb process steam	
$\frac{\$294{,}260\ (10)^3}{5{,}840 \text{ lb} \times 10^3/\text{hr} \times 7{,}884 \text{ hr/yr}}$	$ 6.39

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TABLE 6

ECONOMIC COMPARISON - ORANGE SITE

	Existing No. 2 Oil-Fired Plants Compared With Plants That Are: Coal	Oil	Nuclear	Proposed Plants: Fossil-Fired: Alabama Coal	Wyoming Coal	No. 6 Fuel Oil	Nuclear: HTGR (1-1200 MWt)	CNSS* (1-1200 MWt) without condensing	CNSS* (1-1200 MWt) with condensing
Initial Steam Press (psia)				2,415	2,415	2,415	2,415	640	640
Initial Steam Temp. (F)				1,000	1,000	1,000	1,000	700	700
Steam Flow (lb/hr)				3,441,382	3,441,382	3,441,382	3,239,239	2,695,872	4,298,788
Service Date	1985	1984	1986	1985	1985	1984	1986	1986	1986
Gross Generation (MWe)				185.3	185.3	185.3	188.2	42.86	183.06
Aux. Power & FW Pump (MWe)				36.7	36.7	30.1	23.6	19.06	30.76
Net Generation (MWe)				148.6	148.6	155.2	164.6	23.6	152.3
Heat Input (MWt)				989.360	989.360	989.360	1007.363	871.083	1315.560
Heat Output (MWt)				816.162	816.162	816.162	815.775	830.114	1136.545
<u>Capital Cost ($ x 1,000)</u>									
(1/78) Cost				292,620	294,993	247,286	410,000	380,800	424,200
Escalation				106,836	107,702	76,659	172,897	160,583	178,885
Total				399,456	402,695	323,945	582,897	541,383	603,085
Int. During Construction				86,282	86,982	58,310	146,890	136,429	151,977
Total				485,738	489,677	382,255	729,787	677,812	755,062
<u>Annual Cost ($ x 1,000)</u>									
Fixed Charges				72,861	73,452	57,338	116,766	108,450	120,810
Fuel Charges	247,989	231,797	285,485	97,510	107,106	196,258	42,286	64,389	85,678
O&M Charges	11,306	10,652	12,641	25,384	23,836	19,192	13,824	14,227	21,044
Total				195,755	204,394	272,788	172,876	187,066	227,532
Credit for Power				(88,687)	(88,687)	(86,508)	(113,160)	(16,362)	(104,704)
Net Annual Operating Cost				107,068	115,707	186,280	59,716	170,704	122,828
Process Steam Cost ($/1,000 lb - 7,884 hr/yr @ 2,195,000 lb/hr)	14.98**	14.01**	17.23**	6.19	6.69	10.76	3.45	9.86	7.10

*Plus oil-fired superheater.
**Process steam cost based on operating costs only. No allowance for capital cost (fixed charges).

[redacted]

TABLE 7

ECONOMIC COMPARISON - GEISMAR SITE

	Existing No. 2 Oil-Fired Plants Compared With Plants That Are:			Proposed Plants: Fossil-Fired			Proposed Plants: Nuclear		
	Coal	Oil	Nuclear	Alabama Coal	Wyoming Coal	No. 6 Fuel Oil	HTGR (3-1200 MWt)	CNSS* (2-1200 MWt) without condensing	CNSS* (2-1200 MWt) with condensing
Initial Steam Press (psia)				2,415	2,415	2,415	2,415	690	690
Initial Steam Temp. (F)				1,000	1,000	1,000	1,000	750	750
Steam Flow (lb/hr)				9,237,178	9,237,178	9,237,178	8,633,414	6,784,539	8,591,312
Service Date	1985	1984	1986	1985	1985	1984	1986	1986	1986
Gross Generation (MWe)				448.8	448.8	448.8	462.1	90.8	248.8
Aux. Power & FW Pump (MWe)				96.6	96.6	79.1	62.1	52.4	65.6
Net Generation (MWe)				352.2	352.2	369.7	400	38.4	183.2
Heat Input (MWt)				2630.958	2630.958	2630.958	2684.883	2371.290	2872.295
Heat Output (MWt)				2214.604	2214.604	2214.604	2213.709	2286.277	2631.678
<u>Capital Cost ($ x 1,000)</u>									
(1/78) Cost				713,491	717,514	636,172	1,127,000	844,700	888,900
Escalation				260,496	261,964	197,213	475,256	356,210	374,849
Total				973,987	979,478	833,385	1,602,256	1,200,910	1,263,749
Int. During Construction				210,381	211,567	150,009	403,769	302,629	318,465
Total				1,184,368	1,191,045	983,394	2,006,025	1,503,539	1,582,214
<u>Annual Cost ($ x 1,000)</u>									
Fixed Charges				177,655	178,657	147,509	320,964	240,566	253,154
Fuel Charges	685,749	640,975	789,436	259,304	284,823	521,900	112,702	206,219	230,215
O&M Charges	31,263	29,456	34,955	67,501	63,385	51,038	36,845	39,914	47,598
Total				504,460	526,865	720,447	470,511	486,699	530,967
Credit for Power				(210,200)	(210,200)	(206,070)	(274,994)	(26,399)	(125,947)
Net Annual Operating Cost				294,260	316,665	514,377	195,517	460,300	405,020
Process Steam Cost ($/1,000 lb - 7,884 hr/yr @ 5,840,000 lb/hr)	15.57**	14.56**	17.90**	6.39	6.88	11.17	4.25	10.00	8.80

*Plus oil-fired boiler and superheater.
**Process steam cost based on operating costs only.
Nothing included for capital costs (fixed charges).

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TABLE 8

ECONOMIC COMPARISON - ADVANCED TECHNOLOGY (FUTURE DEVELOPMENT) - GEISMAR SITE

	Atmospheric Fluidized-Bed		Coal Gasification						
			With Conventional Boiler		Air-Blown Gasification With				
					Combined Cycle Power		Fuel Cell Power		
	Foster-Wheeler	Babcock & Wilcox	Air-Blown	Oxygen-Blown	Unlimited	Limited	Unlimited	Limited	
Initial Steam Pressure (psia)	2,415	2,415	2,415	2,415	970/690/ 290	970/690/ 290	970/690/ 290	970/690/ 290	5.25 5.26
Initial Steam Temp. (F)	1,000	1,000	1,000	1,000	850/684/ 509	850/684/ 509	850/684/ 509	850/684/ 509	5.28 5.29
Steam Flow (lb/hr)	9,237,178	9,237,178	9,237,178	9,237,178	8,316,158				5.31
Service Date	1985	1985	1985	1985	1985	1985	1985	1985	5.33
Gross Generation (MWe)	448.832	448.832	-	-	2206.7	552	-	-	5.35
Aux. Power (MWe)	104.532	108.932	-	-	352.7	200	-	-	5.37
Net Generation (MWe)	344.3	339.9	474.7(1)	476.7(1)	1854	352	2701.3	352	5.39
Heat Input (MWt)	2630.958	2630.958	4791.713	4867.592	8161.096	4629.752	10989.0	4487.3	5.41
Heat Output (MWt)	2214.604	2214.604	2214.604	2214.604	2214.604	2214.604	2214.604	2214.604	5.43
Capital Cost ($ x 1,000)									5.45
1/78 Cost	626,202	751,828	1,297,086	1,473,439	2,976,000	1,600,000	2,797,230	1,179,100	5.47
Escalation	228,626	274,492	473,566	537,953	1,086,538	584,160	1,021,269	430,489	5.48
Total	854,828	1,026,320	1,770,652	2,011,392	4,062,538	2,184,160	3,818,499	1,609,589	5.49
Int. During Const.	184,643	221,685	382,461	434,461	877,508	471,779	824,796	347,671	5.50
Total	1,039,471	1,248,005	2,153,113	2,445,853	4,940,046	2,655,939	4,643,295	1,957,260	5.52
Annual Costs ($ x 1,000)									6.8
Fixed Charges	155,921	187,201	322,967	366,878	741,007	398,391	696,494	293,589	6.10
Fuel Charges	258,163	259,787	406,148	412,579	691,739	392,420	931,431	380,346	6.11
O&M Charges	60,402	60,782	189,536	200,396	397,475	208,045	511,548	184,739	6.12
Total	474,486	507,770	918,651	979,853	1,830,221	998,856	2,139,473	858,674	6.13
Credit									6.15
Power	(205,485)	(202,859)	(283,310)	(284,504)	(1,106,502)	(210,080)	(1,612,187)	(210,080)	6.15
Sulfur	-	-	(8,942)	(9,072)	(15,354)	(8,711)	(20,507)	(8,374)	6.15
Ammonia	-	-	(22,003)	(22,450)	(37,810)	(21,450)	(50,460)	(20,605)	6.15
Net Operating Cost	269,001	304,911	604,396	663,827	670,555	758,615	456,319	619,615	6.21
Process Steam Cost ($/1,000 lb - 7,884 hr/yr @ 5,840,000 lb/hr)	5.84	6.62	13.13	14.42	14.56	16.48	9.91	13.46	6.23 6.24 6.25 6.25/

(1)Sum of fossil plant and gasification plant outputs. 6.25/

TABLE 9

LEVELIZED PROCESS STEAM COSTS

Levelized process steam costs in $/1,000 lb including back-up fuel costs in users' plants.

Fuel	Orange	Geismar
Western Coal	7.24	8.06
Eastern Coal	6.78	7.63
No. 6 Oil	10.96	11.70
HTGR	6.56	5.10
CNSS	11.99	11.50

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TABLE 10

PRESENT VALUE OF NET CASH OUTFLOW

(1979$ x 10^3)

Site	Fuel Cost (%)	Discount Rate (%)	Existing Plants	Eastern Coal	Western Coal	No. 6 Fuel Oil	HTGR	CNSS	
Orange	90	10	675,068	276,386	297,952	513,997	160,794	414,206	1.20
	90	15	296,124	199,534	209,852	290,062	201,241	289,093	1.21
	90	20	150,455	151,510	157,246	189,525	194,847	220,155	1.22
	100	10	744,412	303,356	327,592	572,676	171,451	430,185	1.25
	100	15	326,035	211,487	222,991	315,369	206,102	296,213	1.26
	100	20	165,398	157,600	163,949	202,164	197,377	223,303	1.27
	150	10	1,091,144	438,205	475,769	866,051	224,739	510,072	1.31
	150	15	475,574	271,257	288,668	441,895	230,418	231,813	1.32
	150	20	24,011	188,082	197,436	265,385	210,044	242,026	1.33
	200	10	1,437,868	573,052	623,947	1,159,423	278,027	589,974	1.37
	200	15	625,109	331,033	354,348	568,425	254,727	367,414	1.38
	200	20	314,826	218,563	230,927	328,601	222,704	260,252	1.39
Geismar	90	10	1,786,205	690,414	743,527	1,326,839	429,173	1,011,118	1.43
	90	15	784,100	481,969	506,926	736,940	523,303	666,772	1.44
	90	20	398,675	361,008	374,604	477,065	507,040	493,246	1.45
	100	10	1,969,440	758,953	818,332	1,475,937	456,317	1,059,805	1.49
	100	15	863,126	512,351	540,309	801,246	535,690	688,321	1.50
	100	20	438,158	376,501	391,625	509,194	513,488	504,222	1.51
	150	10	2,885,617	1,101,670	1,195,362	2,221,418	592,029	1,303,206	1.55
	150	15	1,253,261	664,259	707,205	1,122,758	597,612	796,033	1.56
	150	20	635,581	453,960	476,730	669,835	545,739	559,097	1.57
	200	10	3,801,788	1,444,390	1,571,892	2,966,903	727,736	1,546,619	2.2/1
	200	15	1,653,393	816,175	874,100	1,444,276	659,536	903,755	2.4
	200	20	832,997	531,424	561,333	830,472	577,989	613,975	2.5

1 of 1

TABLE 11

LEVELIZED STEAM COST AFTER TAXES

BASED ON THE DCF ANALYSIS

($/1000 lb)

Site	Fuel Cost (%)	Discount Rate (%)	Existing Plants	Eastern Coal	Western Coal	No. 6 Fuel Oil	HTGR	CNSS	
Orange	90	10	7.48	3.30	3.56	6.14	1.92	4.95	1.20
	90	15	6.43	4.67	4.91	6.79	4.71	6.77	1.21
	90	20	5.80	6.30	6.54	7.88	8.10	9.16	1.22
	100	10	8.25	3.62	3.91	6.84	2.05	5.14	1.25
	100	15	7.08	4.95	5.22	7.38	4.82	6.93	1.26
	100	20	6.38	6.55	6.82	8.41	8.21	9.31	1.27
	150	10	12.09	5.23	5.68	10.35	2.68	6.09	1.31
	150	15	10.33	6.35	6.76	10.34	5.39	7.77	1.32
	150	20	9.26	7.82	8.21	11.04	8.73	10.06	1.33
	200	10	15.93	6.85	7.45	13.85	3.32	7.05	1.37
	200	15	13.57	7.75	8.30	13.31	5.96	8.60	1.38
	200	20	12.14	9.09	9.60	13.67	9.26	10.82	1.39
Geismar	90	10	6.09	3.10	3.34	5.96	1.93	4.54	1.43
	90	15	5.24	4.24	4.46	6.48	4.60	5.87	1.44
	90	20	4.73	5.64	5.86	7.46	7.93	7.71	1.45
	100	10	6.72	3.41	3.68	6.63	2.05	4.76	1.49
	100	15	5.77	4.51	4.75	7.05	4.71	6.06	1.50
	100	20	5.20	5.88	6.12	7.96	8.03	7.88	1.51
	150	10	9.84	4.95	5.37	9.97	2.66	5.85	1.55
	150	15	8.41	5.84	6.22	9.88	5.26	7.00	1.56
	150	20	7.55	7.10	7.45	10.47	8.53	8.74	1.57
	200	10	12.97	6.48	7.06	13.32	3.27	6.94	2.3
	200	15	11.05	7.18	7.69	12.71	5.80	7.95	2.4
	200	20	9.89	8.31	8.78	12.98	9.03	9.60	2.5

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TABLE 12

BREAK-EVEN PURCHASED STEAM PRICE

(1986$/1000 lb)

Site	Fuel Cost (%)	Discount Rate (%)	Existing Plants	Eastern Coal	Western Coal	No. 6 Fuel Oil	HTGR	CNSS	
Orange	90	10	13.85	6.11	6.59	11.37	3.56	9.17	1.20
	90	15	11.91	8.65	9.09	12.57	8.72	12.54	1.21
	90	20	10.74	11.67	12.11	14.59	15.00	16.96	1.22
	100	10	15.28	6.70	7.24	12.67	3.80	9.51	1.25
	100	15	13.11	9.17	9.67	13.67	8.93	12.82	1.26
	100	20	11.81	12.13	12.63	15.57	15.20	17.24	1.27
	150	10	22.39	9.69	10.52	19.17	4.96	11.28	1.31
	150	15	19.13	11.76	12.52	19.15	9.98	14.39	1.32
	150	20	17.15	14.48	15.20	20.44	16.17	18.63	1.33
	200	10	29.50	12.69	13.80	25.65	6.15	13.06	1.37
	200	15	25.13	14.35	15.37	24.65	11.04	15.93	1.38
	200	20	22.48	16.83	17.78	25.31	17.15	20.04	1.39
Geismar	90	10	11.71	5.96	6.42	11.46	3.71	8.73	1.43
	90	15	10.08	8.15	8.58	12.46	8.85	11.29	1.43/
	90	20	9.10	10.85	11.27	14.35	15.25	14.83	1.45
	100	10	12.92	6.56	7.08	12.75	3.94	9.15	1.48
	100	15	11.10	8.67	9.13	13.56	9.06	11.66	1.49
	100	20	10.00	11.31	11.77	15.31	15.44	15.13	1.50
	150	10	18.92	9.52	10.33	19.17	5.12	11.25	1.54
	150	15	16.17	11.23	11.96	19.00	10.12	13.46	1.55
	150	20	13.52	13.65	14.33	20.13	16.40	16.81	1.56
	200	10	24.94	12.46	13.58	25.62	6.29	13.35	2.2
	200	15	21.25	13.81	14.79	24.44	11.15	15.29	2.3
	200	20	19.02	15.98	16.88	24.96	17.37	18.46	2.4

TABLE 13

COMPARISON OF MRR STEAM COSTS

Comparison of Minimum Revenue Requirements (MRR) steam cost for 10% rate of return and 15% fixed charge rate with Discounted Cash Flow (DCF) break-even purchased steam price for 10% discount factor.

Orange Site	MRR Steam Cost ($\$/10^3$ lb)	DCF Break-Even Price ($\$/10^3$ lb)	Ratio MRR/DCF
Eastern coal	6.55	6.70	0.978
Western coal	7.06	7.24	0.975
No. 6 fuel oil	12.28	12.67	0.969
HTGR	3.33	3.80	0.876
CNSS	9.29	9.51	0.977
Geismar Site			
Eastern coal	6.76	6.56	1.030
Western coal	7.27	7.08	1.027
No. 6 fuel oil	12.75	12.75	1.000
HTGR	4.07	3.94	1.033
CNSS	9.40	9.15	1.027

NOTE: All figures are levelized over a 30-year period for plants beginning operation in 1986.

TABLE 14

PRESENT VALUE STEAM COSTS NET OF TAXES

(1979$/1000 lb)

Site	Escalation Rate (%)	Discount Rate (%)	Existing Plants[1]	Eastern Coal	Western Coal	No. 6 Fuel Oil	HTGR	CNSS
Orange	6	10	2.73	1.35	1.46	2.56	0.77	1.92
	6	15	2.73	2.13	2.25	3.18	2.08	2.98
	6	20	2.73	3.11	3.24	3.99	3.90	4.42
	7	10	2.73	1.13	1.22	2.14	0.64	1.61
	7	15	2.73	1.83	1.93	2.73	1.78	2.56
	7	20	2.73	2.73	2.84	3.50	3.42	3.88
Geismar	6	10	2.73	1.27	1.37	2.48	0.77	1.78
	6	15	2.73	1.94	2.05	3.03	2.03	2.61
	6	20	2.73	2.80	2.91	3.78	3.81	3.74
	7	10	2.73	1.06	1.15	2.07	0.64	1.49
	7	15	2.73	1.67	1.76	2.61	1.74	2.24
	7	20	2.73	2.45	2.55	3.31	3.34	3.28

[1] 1979 Fuel, Operation and Maintenance Costs Only, Net of Taxes

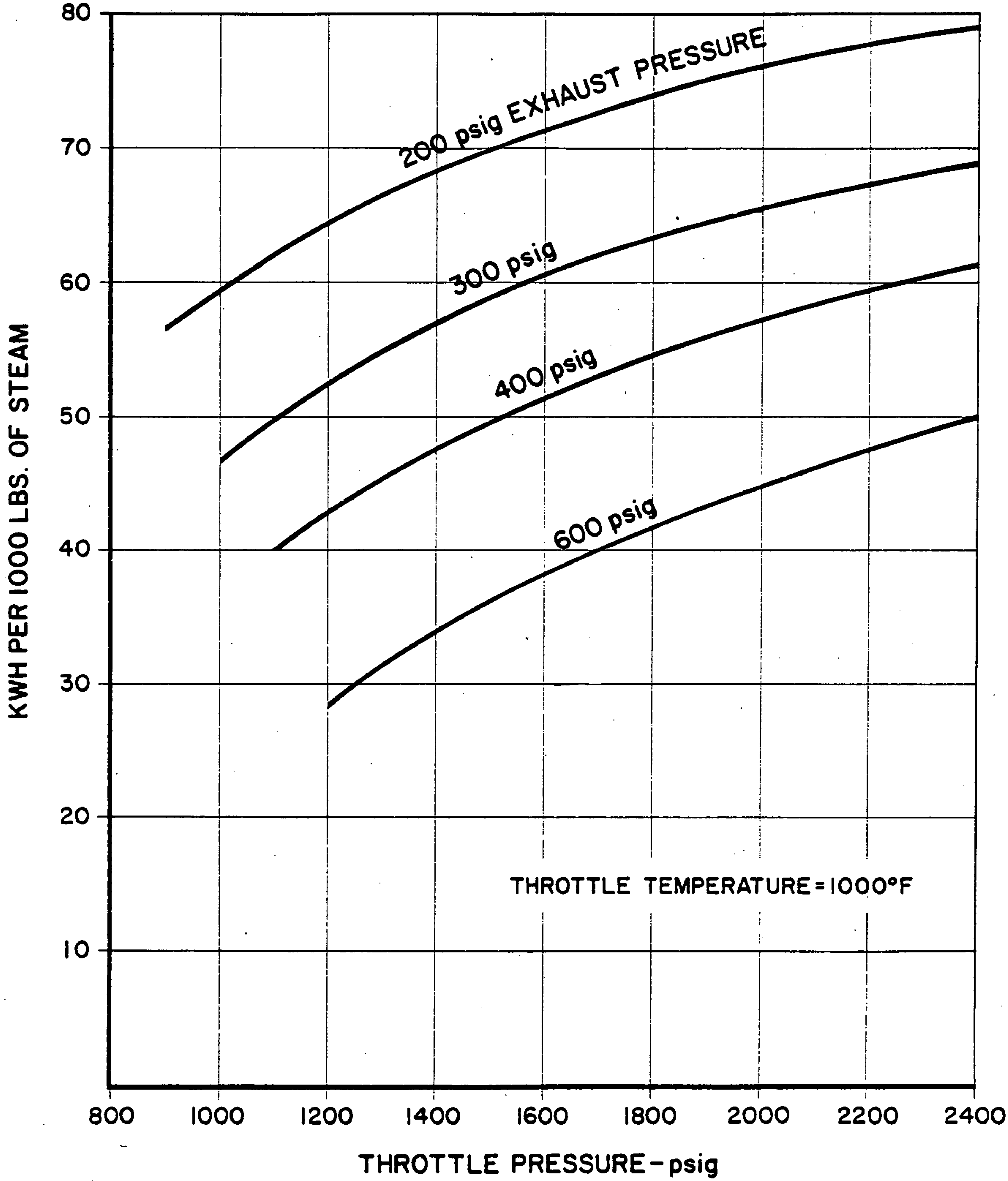


FIGURE 1 RELATIONSHIP AMONG THROTTLE PRESSURE, EXHAUST PRESSURE, & kWh/1,000 LB STEAM

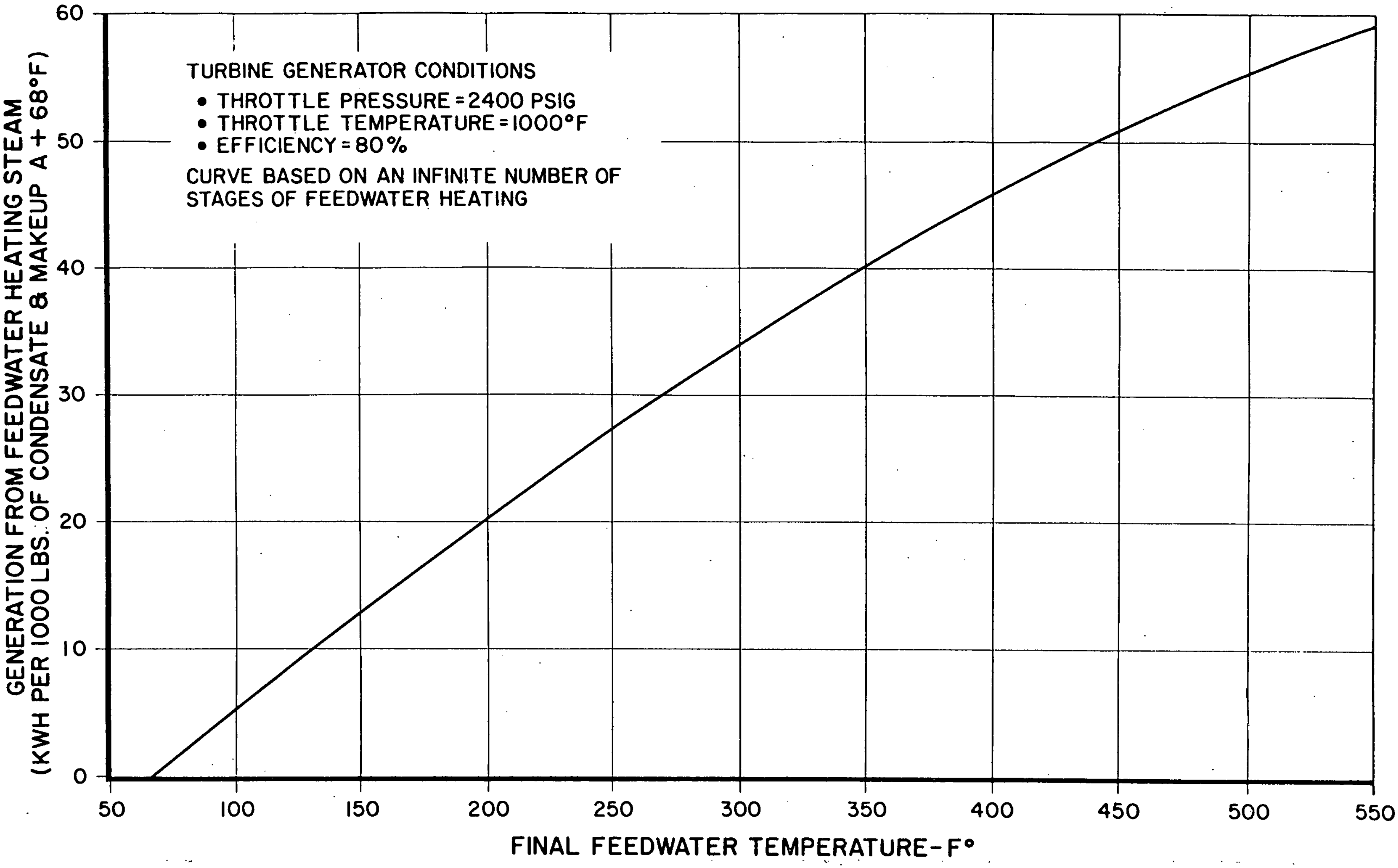
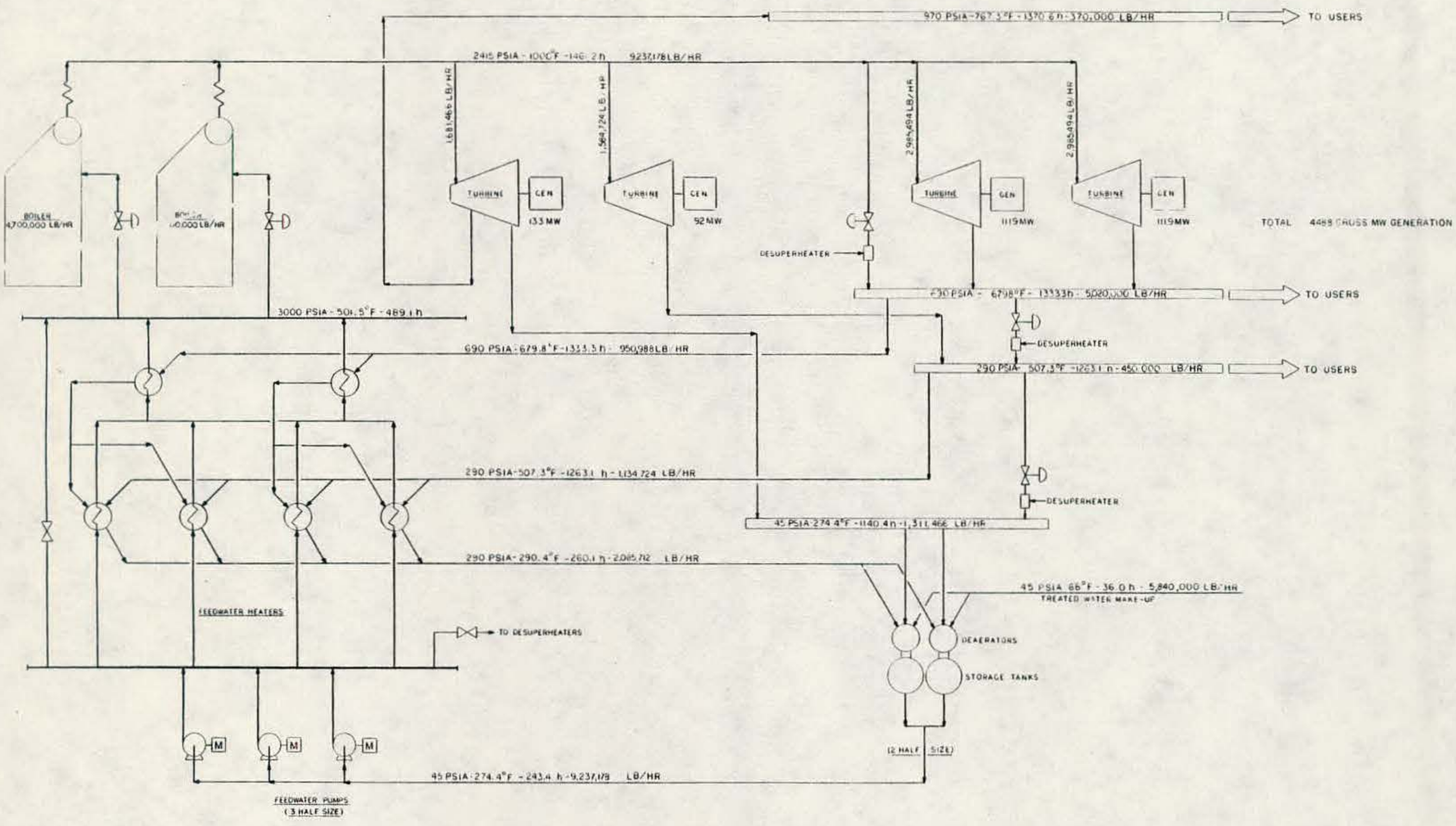


FIGURE 2 GENERATION FROM FEEDWATER HEATING SYSTEM



COGENERATION FEASIBILITY STUDY
GEISMAR AREA - GSU/ERDA
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE
FOR FOSSIL FUEL PLANTS

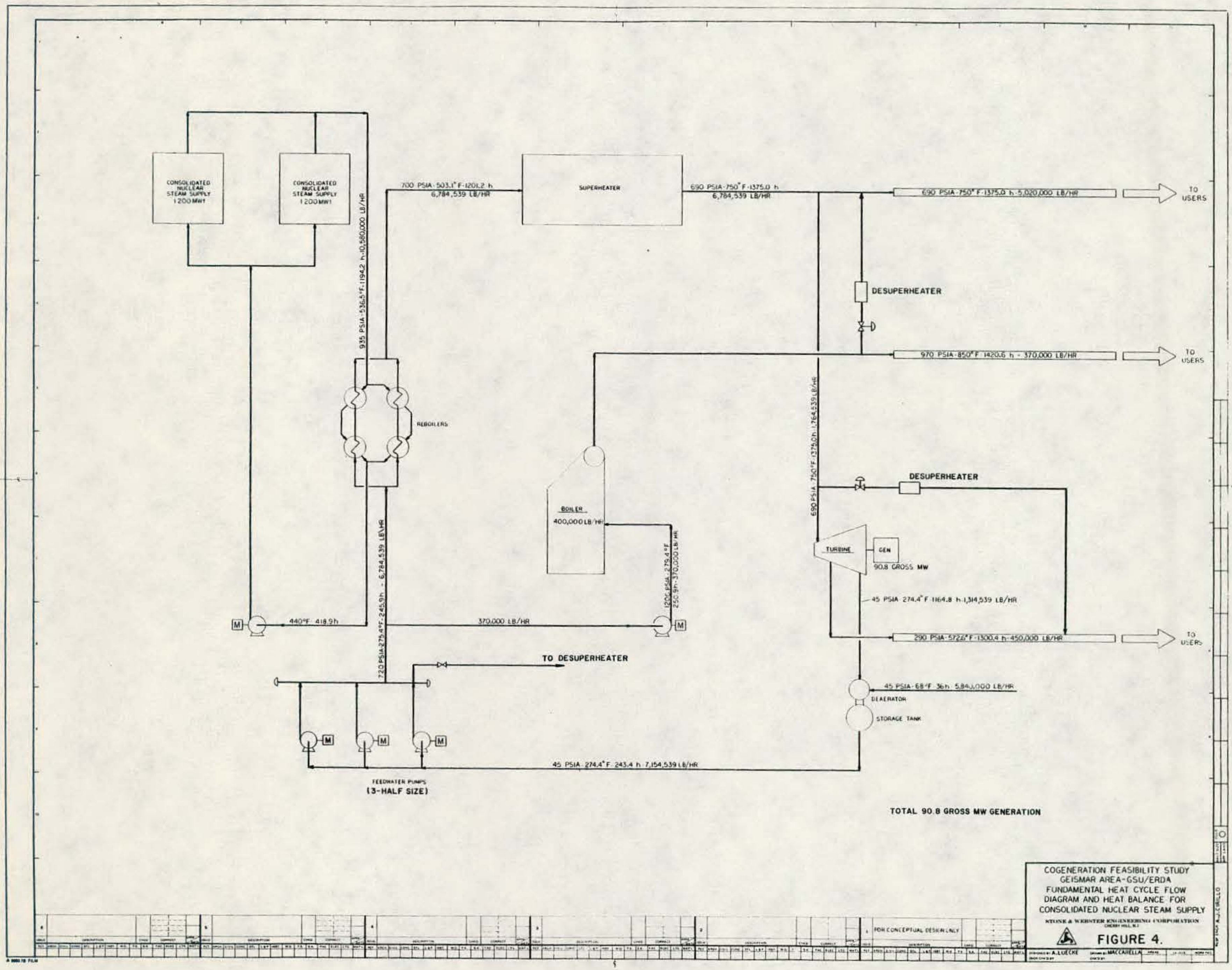
STONE & WEBSTER ENGINEERING CORPORATION

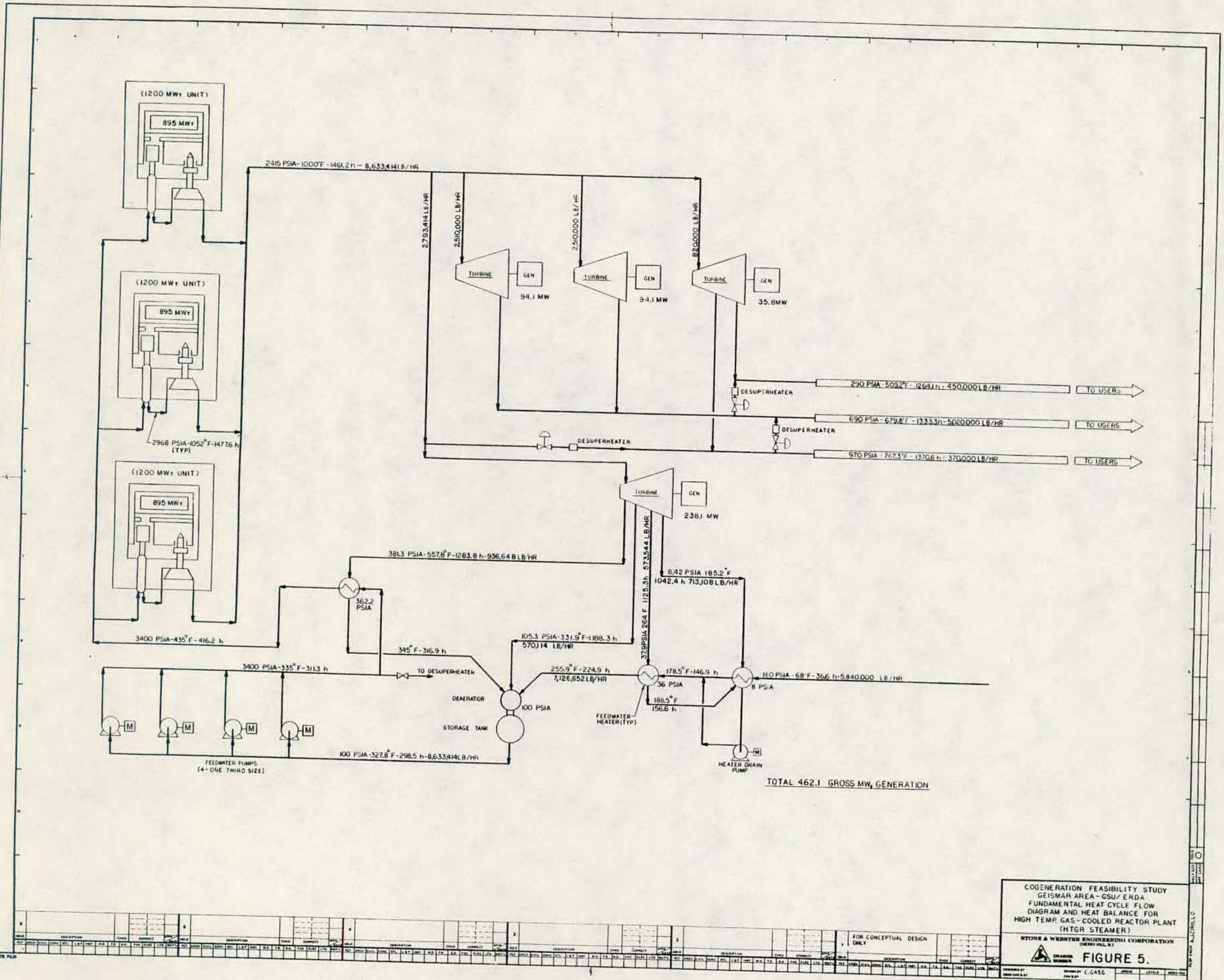
FIGURE 3.

FOR CONCEPTUAL DESIGN ONLY

F. PERSIA MACCARELLA

A. J. CIRILLO C. NIECKOSKI


CONSOLIDATED NUCLEAR STEAM SUPPLY 1200 MWt
CONSOLIDATED NUCLEAR STEAM SUPPLY 1200 MWt
935 PSIA-536.5°F-1194.2 h-10,580,000 LB/HR
700 PSIA-503.1°F-1201.2 h
6,784,539 LB/HR
SUPERHEATER
690 PSIA-750°F-1375.0 h
6,784,539 LB/HR
690 PSIA-750°F-1375.0 h-5,020,000 LB/HR
TO USERS
DESUPERHEATER
970 PSIA-850°F-1420.6 h - 370,000 LB/HR
TO USERS
REBOILERS
690 PSIA-750°F-1375.0 h-1,764,539 LB/HR
DESUPERHEATER
BOILER
400,000 LB/HR
1200 PSIA-279.4°F
250.9h-370,000 LB/HR
TURBINE
GEN
90.8 GROSS MW
45 PSIA-274.4°F-1164.8 h-1,314,539 LB/HR
290 PSIA-572.6°F-1300.4 h-450,000 LB/HR
TO USERS
440°F-418.9h
720 PSIA-275.4°F-245.9h - 6,784,539 LB/HR
370,000 LB/HR
TO DESUPERHEATER
45 PSIA-68°F-36h-5,840,000 LB/HR
DEAERATOR
STORAGE TANK
45 PSIA-274.4°F-243.4 h-7,154,539 LB/HR
FEEDWATER PUMPS
(3-HALF SIZE)
TOTAL 90.8 GROSS MW GENERATION
FOR CONCEPTUAL DESIGN ONLY
COGENERATION FEASIBILITY STUDY
GEISMAR AREA-GSU/ERDA
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE FOR
CONSOLIDATED NUCLEAR STEAM SUPPLY
STONE & WEBSTER ENGINEERING CORPORATION
FIGURE 4.
A.LUECKE
MACCARELLA


(1200 MWt UNIT)
895 MWt
(1200 MWt UNIT)
895 MWt
(1200 MWt UNIT)
895 MWt
2968 PSIA-1052°F-1477.6 h (TYP)
2415 PSIA-1000°F-1461.2 h - 8,633,414 LB/HR
2,793,414 LB/HR
2,510,000 LB/HR
2,510,000 LB/HR
820,000 LB/HR
TURBINE
GEN
94.1 MW
TURBINE
GEN
94.1 MW
TURBINE
GEN
35.8 MW
DESUPERHEATER
290 PSIA - 509.2°F - 1264.1 h - 450,000 LB/HR
TO USERS
DESUPERHEATER
690 PSIA - 679.8°F - 1333.3 h - 5,020,000 LB/HR
TO USERS
DESUPERHEATER
970 PSIA - 767.3°F - 1370.6 h - 370,000 LB/HR
TO USERS
TURBINE
GEN
238.1 MW
381.3 PSIA-557.8°F-1283.8 h-936,648 LB/HR
362.2 PSIA
37.9 PSIA 264 F 1125.3 h 573,544 LB/HR
8.42 PSIA 185.2°F
1042.4 h 713,108 LB/HR
3400 PSIA-435°F-416.2 h
345°F-316.9 h
105.3 PSIA-331.9°F-1188.3 h
570,114 LB/HR
3400 PSIA-335°F-311.3 h
TO DESUPERHEATER
255.9°F-224.9 h
7,126,652 LB/HR
178.5°F-146.9 h
36 PSIA
160 PSIA - 68°F - 36.6 h-5,840,000 LB/HR
8 PSIA
188.5°F
156.6 h
DEAERATOR
100 PSIA
STORAGE TANK
FEEDWATER HEATER (TYP)
M
M
M
M
M
100 PSIA-327.8°F-298.5 h-8,633,414 LB/HR
FEEDWATER PUMPS
(4-ONE THIRD SIZE)
HEATER DRAIN PUMP
TOTAL 462.1 GROSS MW, GENERATION
FOR CONCEPTUAL DESIGN ONLY
COGENERATION FEASIBILITY STUDY
GEISMAR AREA - GSU/ERDA
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE FOR
HIGH TEMP. GAS-COOLED REACTOR PLANT
(HTGR STEAMER)
STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.
FIGURE 5.
C. GASS

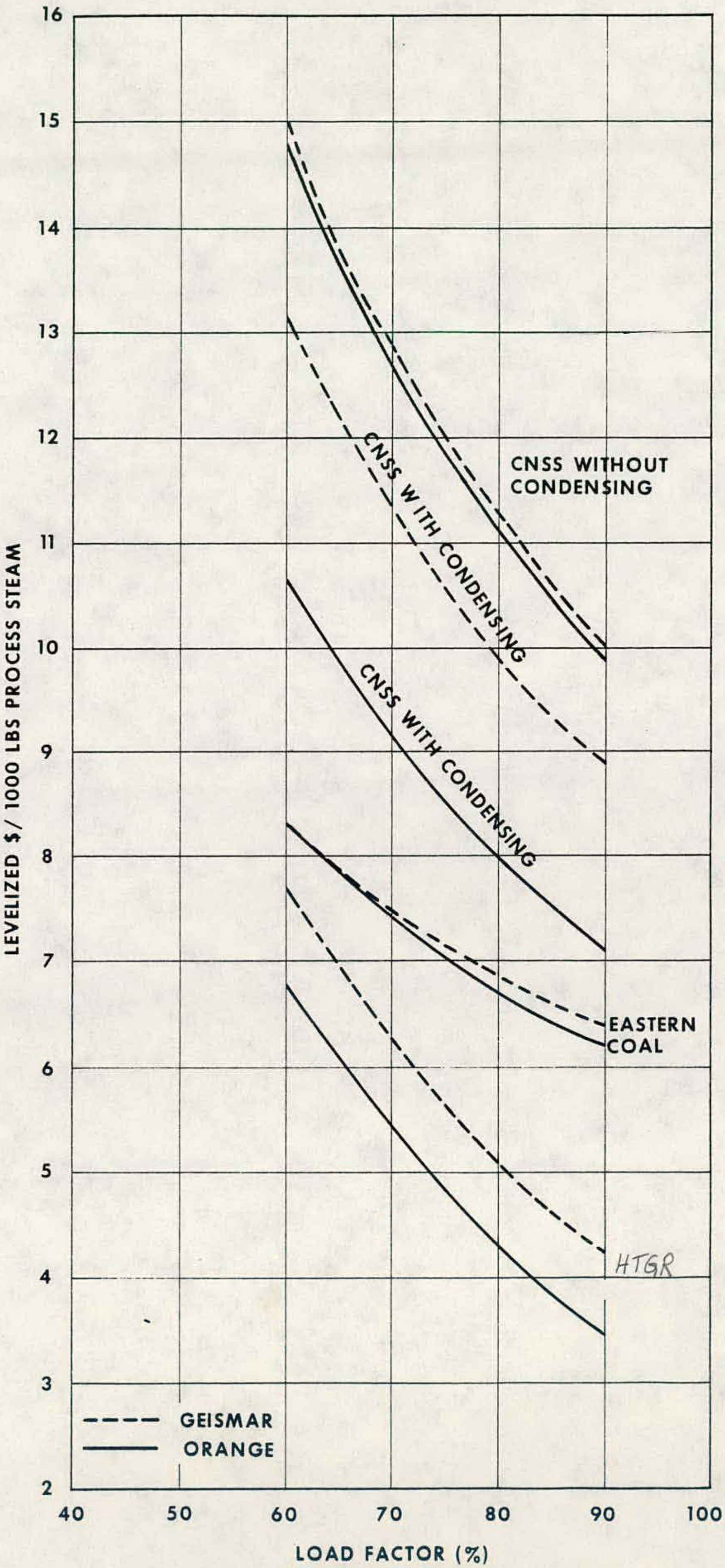


FIGURE 6 EFFECT OF CHANGES IN LOAD FACTORS AT ORANGE AND GEISMAR SITES

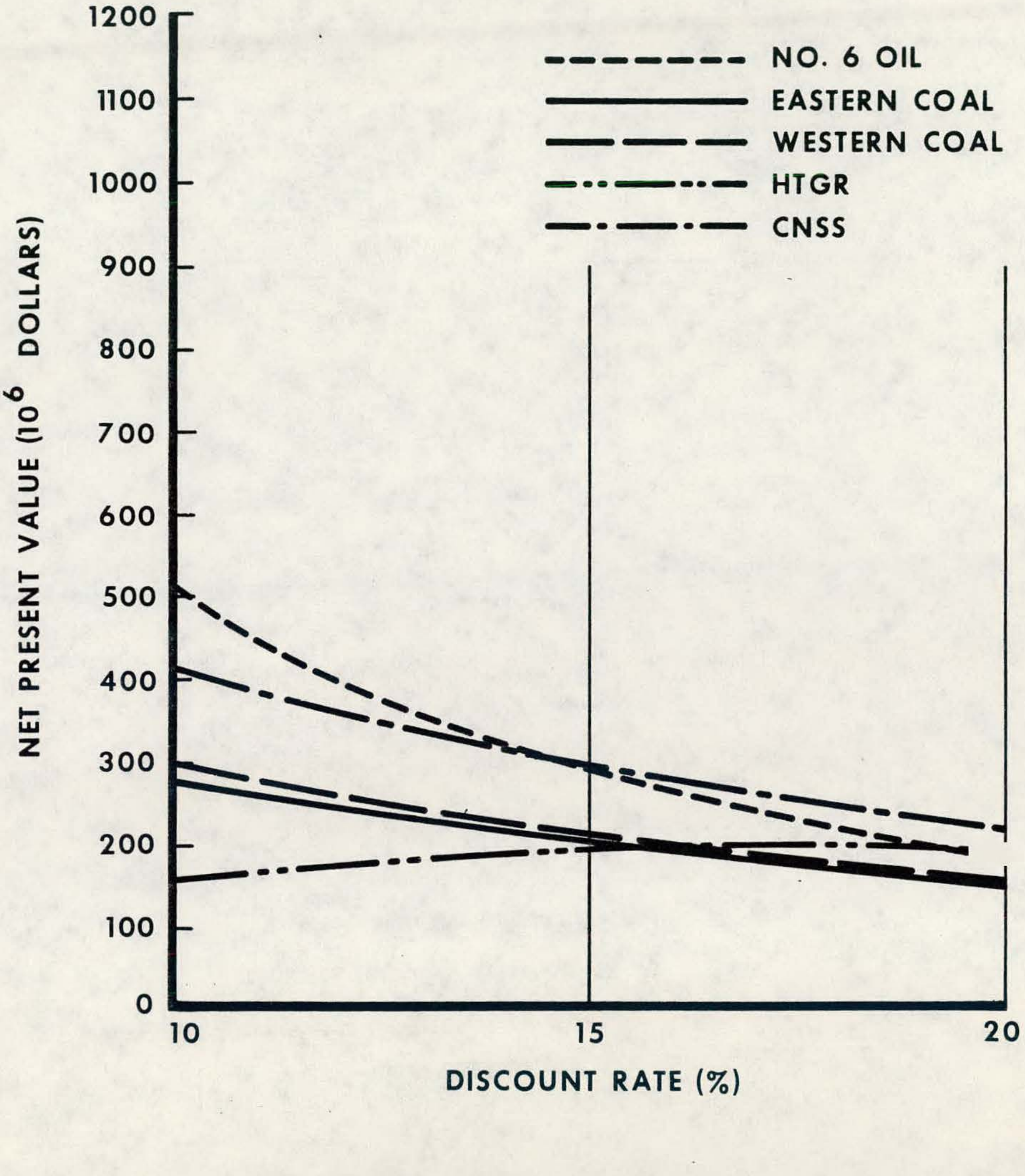


FIGURE 7 NET PRESENT VALUE VS DISCOUNT RATE AT ORANGE WITH 90-PERCENT FUEL COST

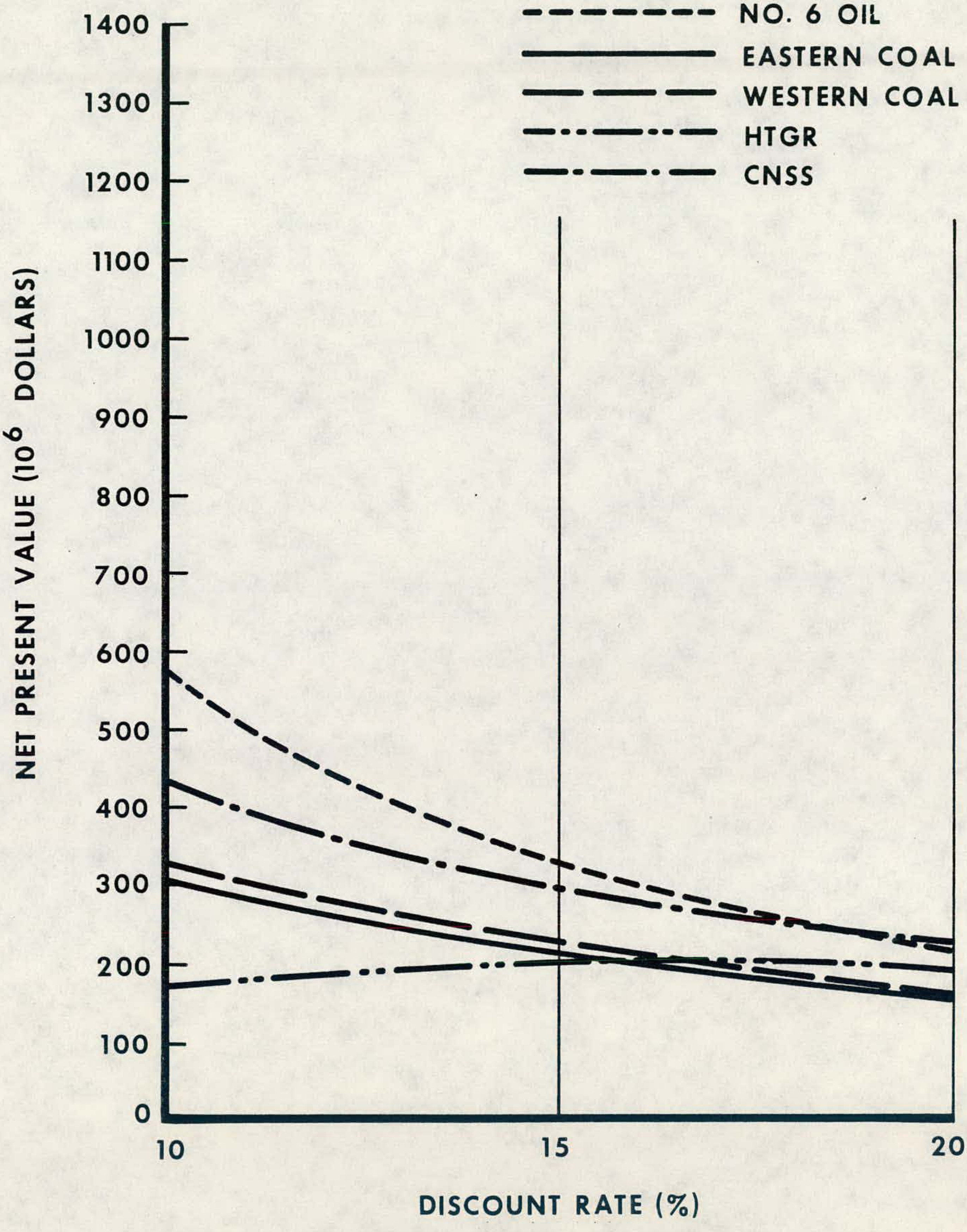


FIGURE 8 NET PRESENT VALUE VS DISCOUNT RATE AT ORANGE WITH 100-PERCENT FUEL COST

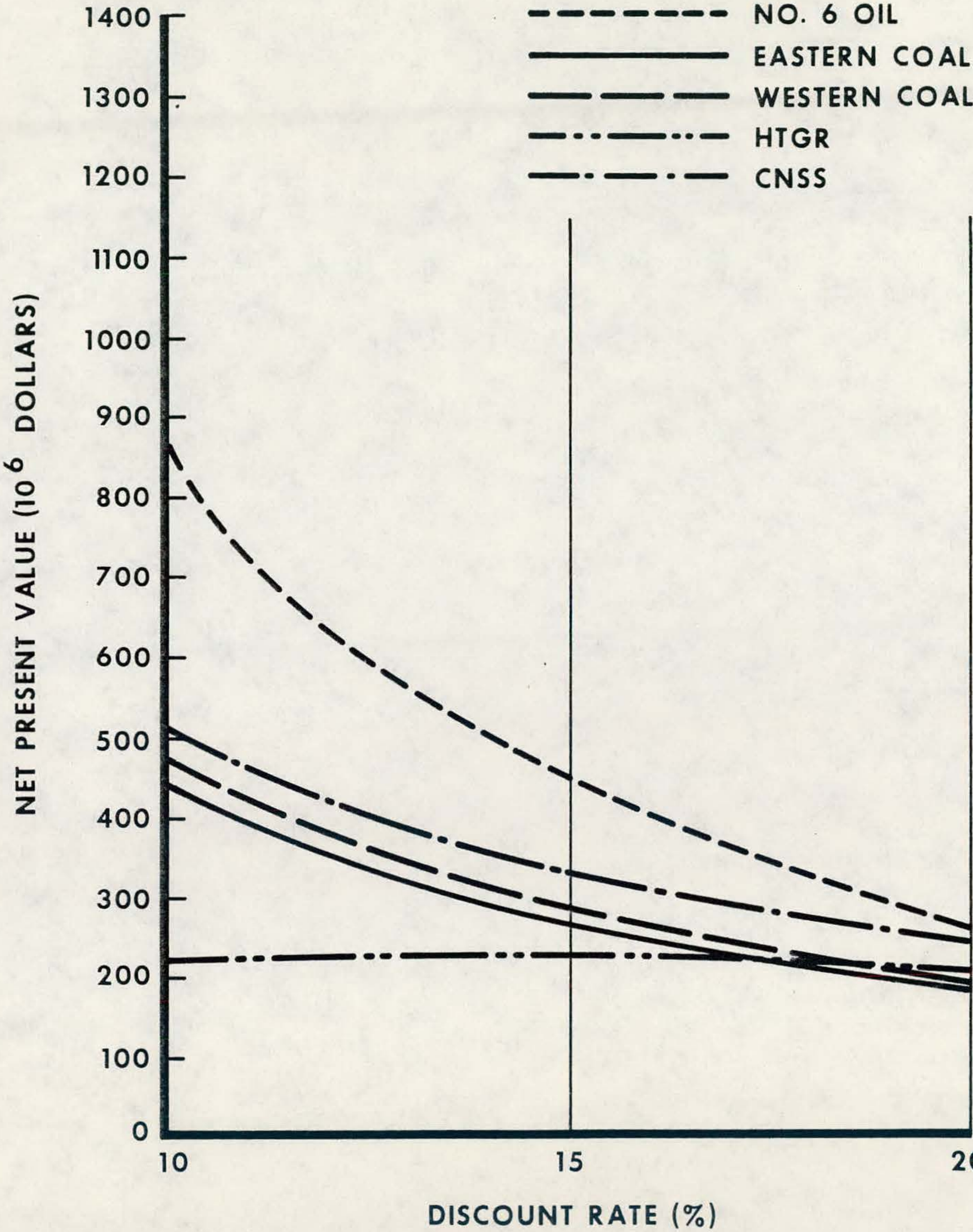


FIGURE 9 NET PRESENT VALUE VS DISCOUNT RATE AT ORANGE WITH 150-PERCENT FUEL COST

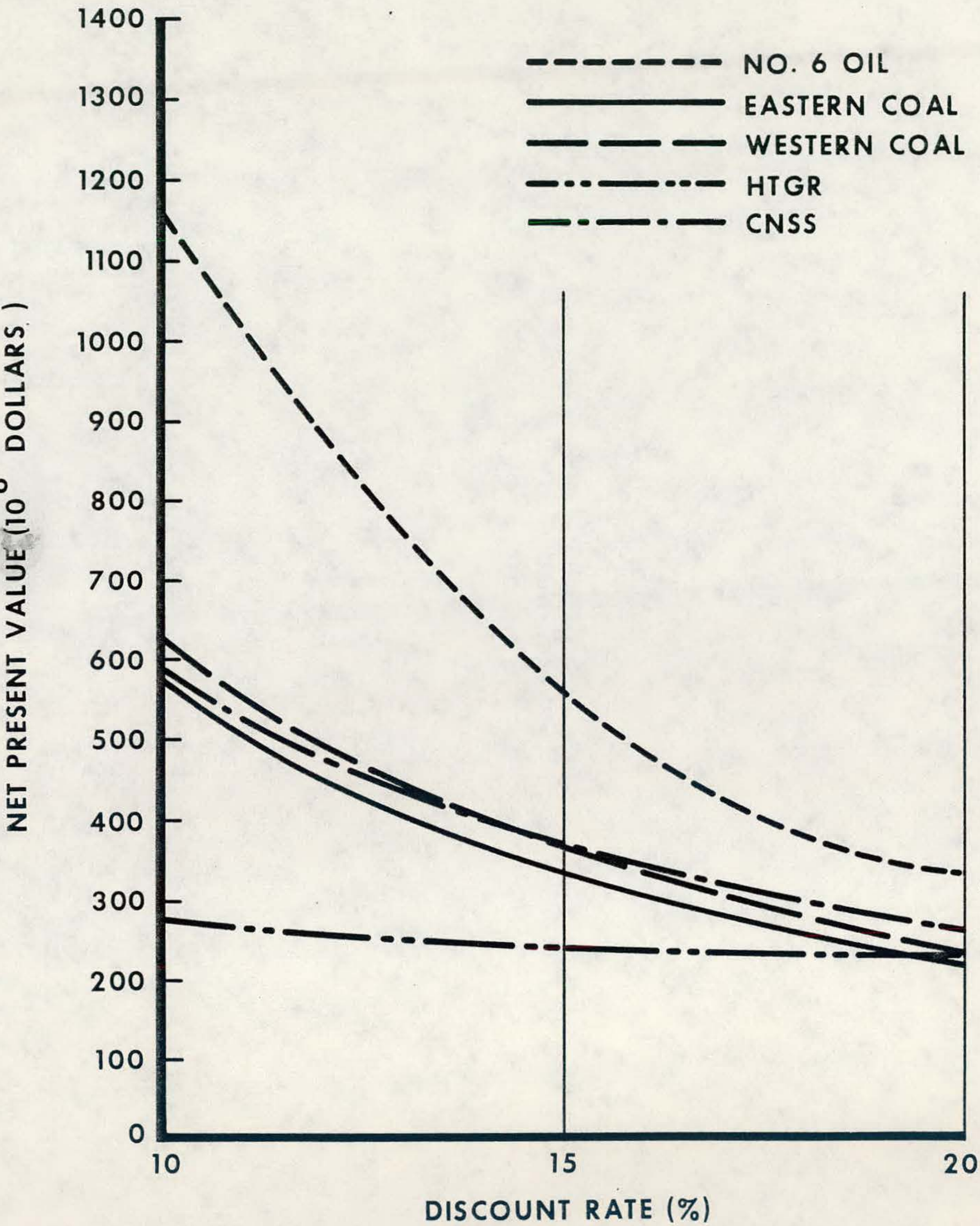


FIGURE 10 NET PRESENT VALUE VS DISCOUNT RATE AT ORANGE WITH 200-PERCENT FUEL COST

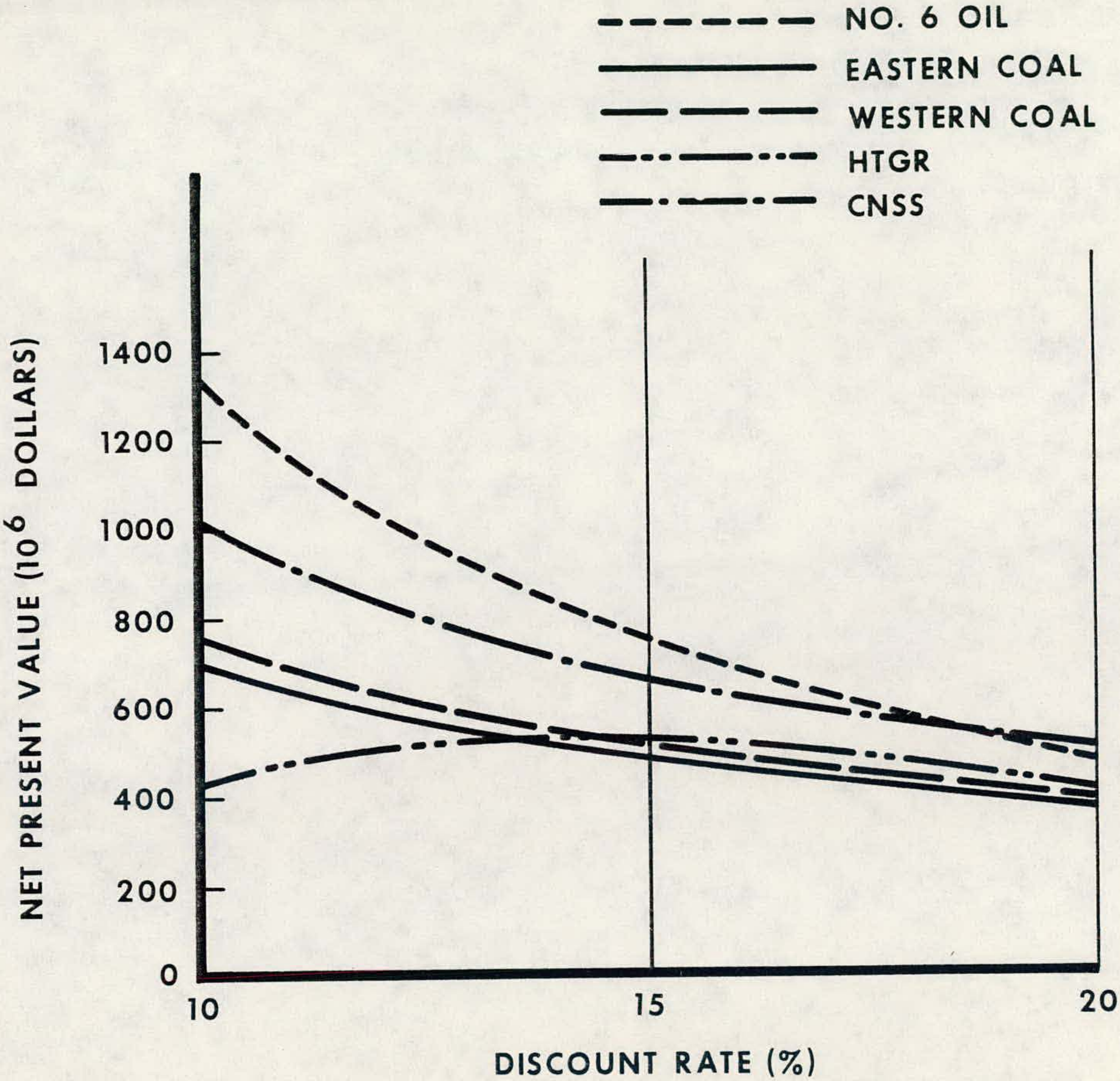


FIGURE 11 NET PRESENT VALUE VS DISCOUNT RATE AT GEISMAR WITH 90-PERCENT FUEL COST

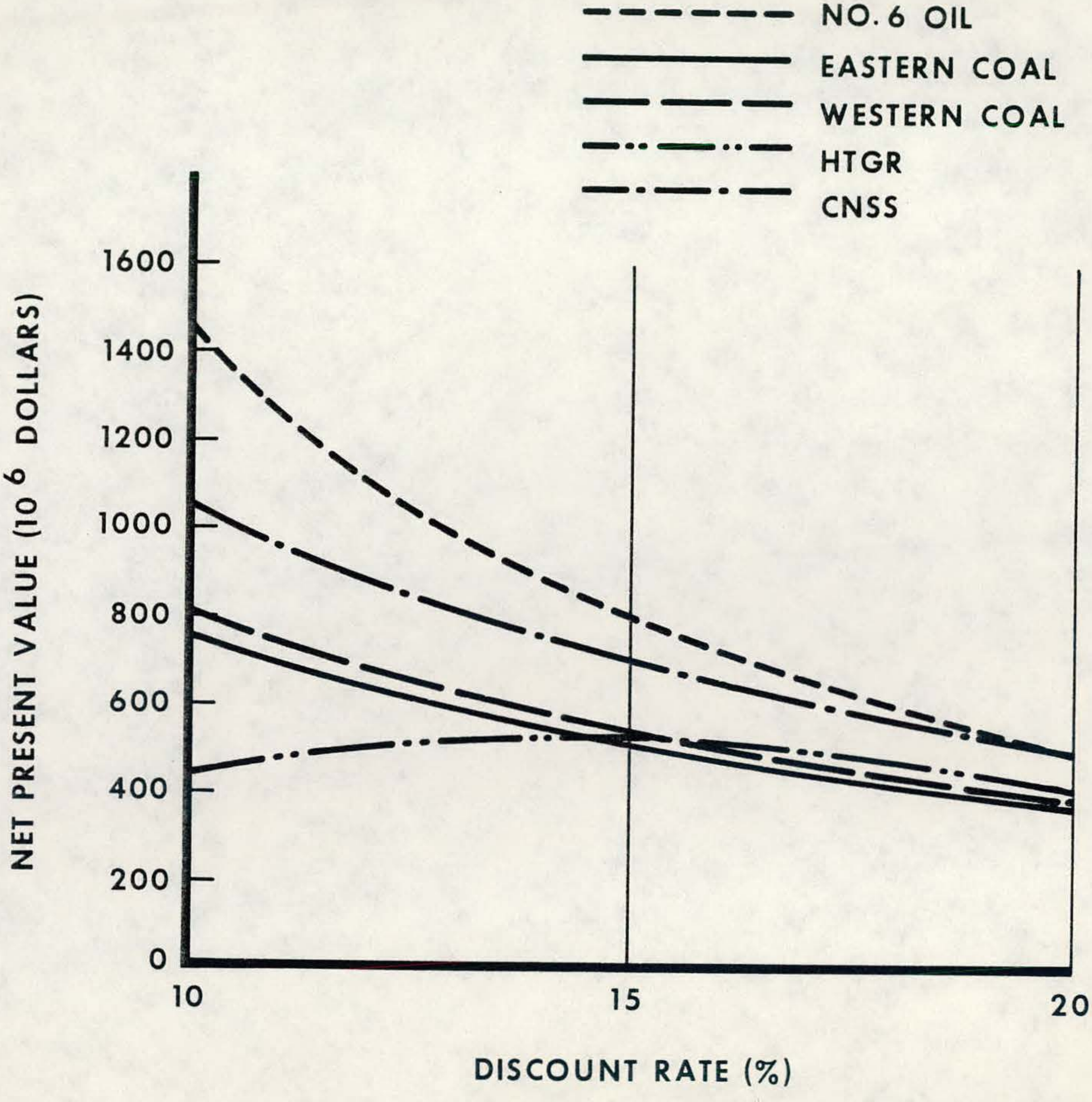


FIGURE 12 NET PRESENT VALUE VS DISCOUNT RATE AT GEISMAR WITH 100-PERCENT FUEL COST

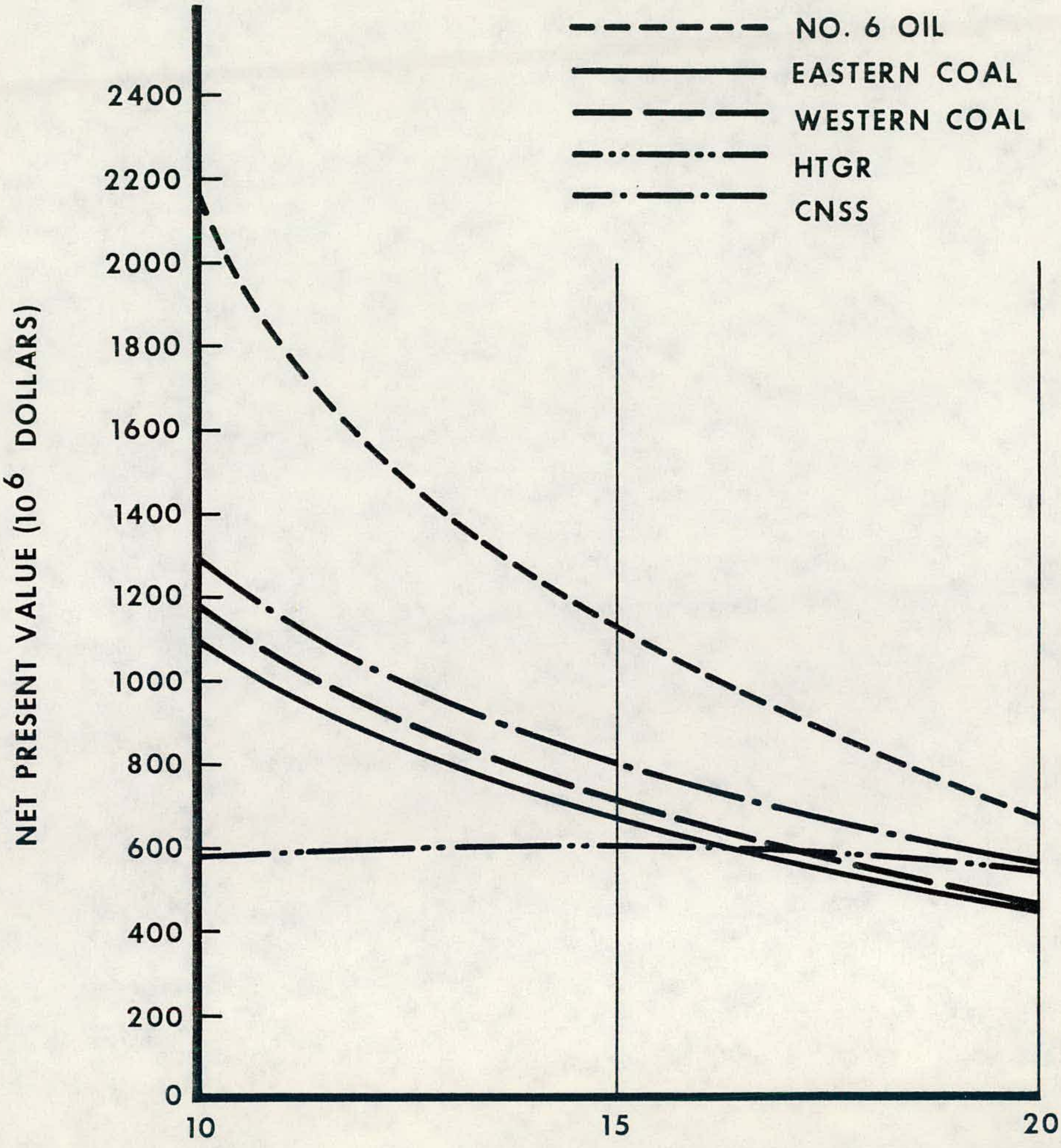


FIGURE 13 NET PRESENT VALUE VS DISCOUNT RATE AT GEISMAR WITH 150-PERCENT FUEL COST

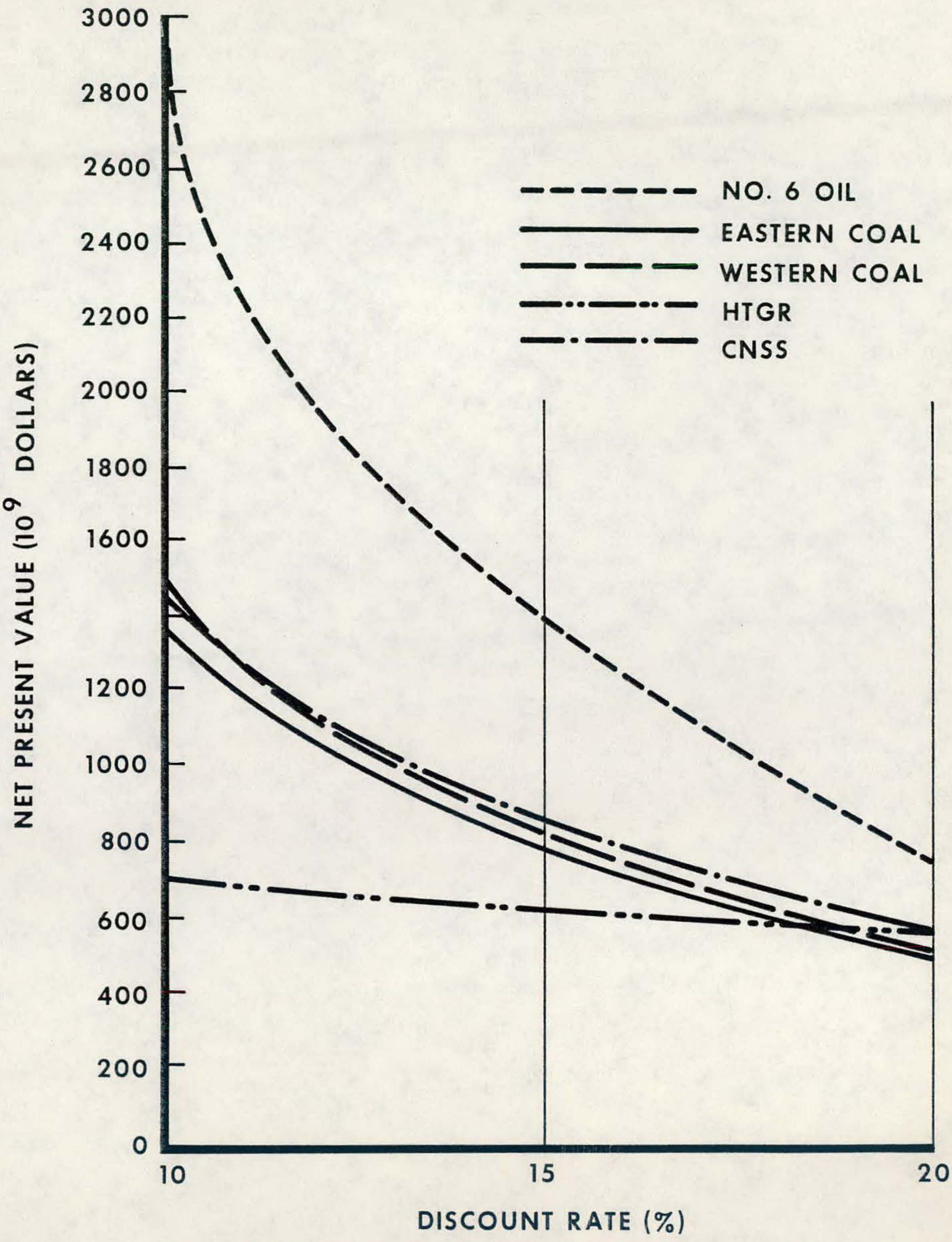


FIGURE 14 NET PRESENT VALUE VS DISCOUNT RATE AT GEISMAR WITH 200-PERCENT FUEL COST

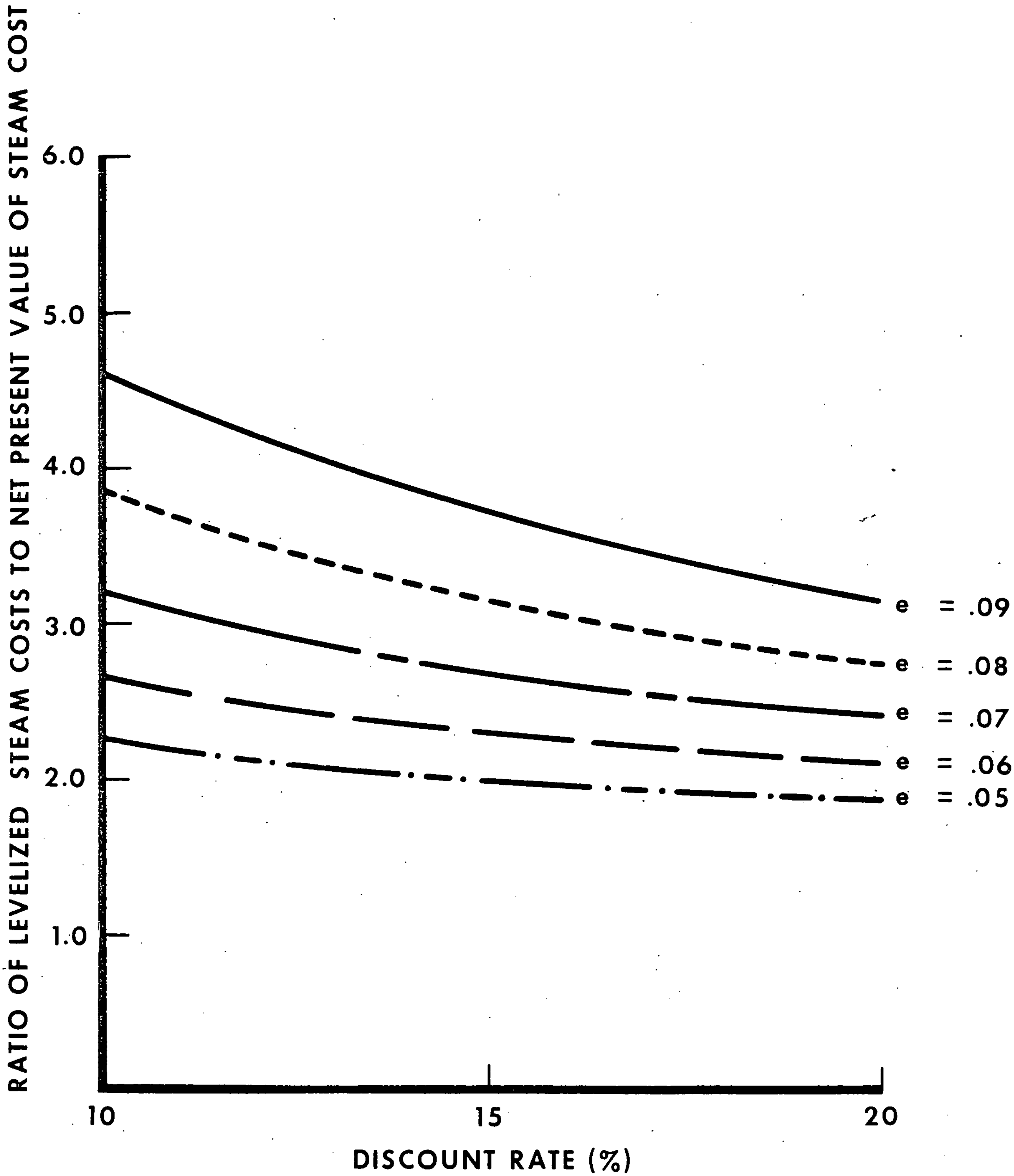


FIGURE 15 RATIO OF LEVELIZED STEAM COSTS TO NET PRESENT VALUE OF STEAM VS DISCOUNT RATE FOR VARIOUS ESCALATION RATES