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STEAM CYCLE OPTIMIZATION STUDY FOR LARGE SODIUM GRAPHITE NUCLEAR POWER GENERATING STATIONS

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ABSTRACT

This report presents steam cycle optimization studies for large sodium graphite nuclear power generating stations. The general trend that is apparent from these optimization studies for SGR nuclear power plants are as follows:

1) For plant ratings up to approximately 350 Mwe, 2400-psig steam pressure would be the most economical operating condition.

2) For plant ratings above 350 Mwe, 3500-psig steam pressure is the economic selection.

3) The highest justifiable steam temperature for reheat cycles at 1150°F reactor outlet temperature is 1000/1000°F, the final selection being either 950/950°F or 1000/1000°F.

4) For all plant ratings studied, the best range for the value of the sodium temperature difference across the reactor is from 350 to 375°F.

5) The best range for the value of the temperature approach of the intermediate heat exchanger for the 2400-psig steam cycle is 65 to 80°F; while for the 3500-psig steam cycle, the range is 85 to 95°F. Decisions on the actual plant design steam conditions should be based on studies for a specific plant site and on specific utility company ground rules, not on generalized steam studies.

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I. INTRODUCTION

This energy generated in sodium-cooled nuclear reactor plants of the thermal or fast breeder type, is transferred from the core to the steam generator equipment by means of high temperature sodium (1150 to 1200°F). The properties of sodium offer the capability of generating steam at the high temperature (1000 to 1100°F) conditions of existing fossil fired plants. In addition to this advantage, sodium also enables exceptionally low reactor system operating pressures (less than 100 psi).

Since the reactor, primary loop, intermediate heat exchanger, and secondary piping loop contain only sodium, they are relatively independent of the operating steam pressure in the steam generators. Thus, the steam portion of the plant may be studied separately.

The main purpose of the steam cycle optimization study is to establish steam conditions and the sodium heat transfer system parameters for large sodium graphite nuclear power plants. This study was made in three phases as defined in Section III of this report.

II. SUMMARY

The results of the steam cycle study for sodium graphite nuclear power plants establishes 3500 or 2400-psig steam as optimum depending on the capital charge rate. The pertinent results based on 20¢/10^6 Btu fuel cycle cost and a reactor sodium outlet temperature of 1150°F for a 400-Mwe size plant, are as follows:

	7% Capital Charge Rate	14% Capital Charge Rate 1st Choice	14% Capital Charge Rate 2nd Choice
Steam throttle pressure (psig)	3500	3500	2400
Initial and reheat steam temperature (°F)	1000	950	950
Type steam cycle	Double reheat	Double reheat	Single reheat
Type steam turbine	CCDF-30"	TC4F-30"	TC4F-30"
Net station heat rate (Btu/nkwh)	7665	7870	8300
Fuel cycle cost at 20c//10^6 Btu (mill/nkwh)	1.53	1.57	1.66
Reactor sodium ΔT (°F)	350	350	350
Intermediate heat exchanger LMTD (°F)	95	95	75

The excellent net station heat rates available with sodium graphite reactors, as illustrated above, combined with the nuclear fuel costs result in low fuel cycle costs. With further improvements in fuel technology and fabrication, it is reasonable to expect future reduction in fuel costs.

The steam conditions shown are equivalent to those presently being selected by utilities with fossil fired power expansion programs. The influence of fuel costs, plant factors, capital charge rates, and pertinent system ground rules for sodium graphite nuclear power stations were evaluated in a manner similar to that used in conventional fossil fired plant study.

The final selection of steam conditions and turbine type for a sodium graphite nuclear power station should be based on a specific plant site and specific ground rules as related to a specific utility. The tabulated results shown in the summary are based on the phase three section of this steam study.

III. GENERAL APPROACH

The major components of the sodium graphite nuclear power generating system considered in this steam cycle study are shown schematically in Figure 1. In addition, typical sodium-steam side operating temperatures and pressures are shown.

The economics pertaining to the steam cycle portion of a sodium graphite reactor are quite different from those pertaining to a conventional fossil fired power plant. Generally, with $20¢/10^6$ Btu fossil fuel, one does not consider the more efficient high pressure steam cycles because as the steam pressure and temperature increase, the cost of the fossil fired boiler increases and offsets the capitalized fuel cost savings. However, for the case of sodium graphite reactor plants (refer to Figure 1), the cost of the reactor, primary-secondary loops, and intermediate heat exchanger (excluding steam generator) are virtually independent of the steam pressure. The major component in the sodium portion of the plant that is affected by the steam pressure is the steam generator.

The steam cycle study was divided into the following phases:

a) Phase One: Survey the range of potential steam pressures and temperatures used in fossil fuel fired power plants, since the sodium-cooled reactor system can match any present day operating condition. Select the two best pressure conditions based on a comparison of the major component and operating costs for a 350-Mwe plant.

b) Phase Two: Select one pressure condition from phase one for a 350-Mwe size plant to study the effect of variations in:

   1) Steam temperature

   2) Feedwater temperature

   3) Reactor sodium temperature differential

   4) Intermediate heat exchanger LMTD

   5) Type of steam turbine generator

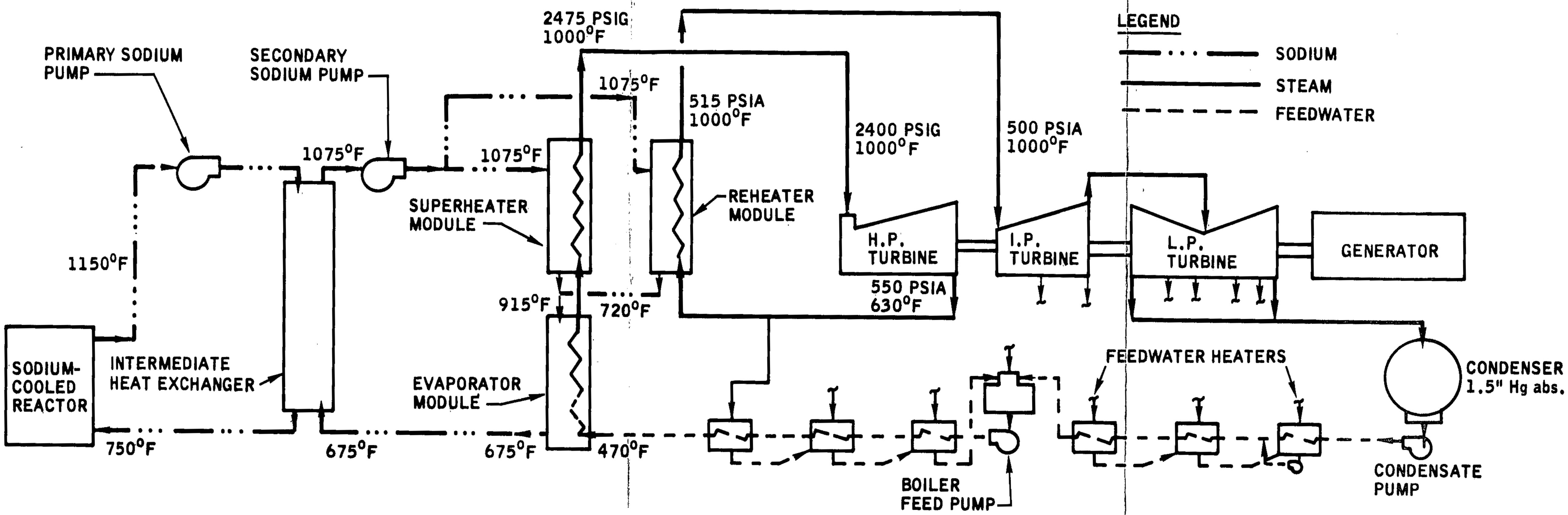

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Figure 1. Typical Schematic of Sodium Graphite Nuclear Power Generating System

c) Phase Three: Compare the two best steam pressure conditions in greater detail, based on Phase Two results for a 400-Mwe size plant. A change was made at this point from a 350-Mwe plant basis to a 400-Mwe plant basis, as the 400-Mwe plant is better suited to current objectives of the study. The study was an extended effort over the period July 1962 to September 1963. Minor changes in approach were made as the study progressed.

A. PHASE ONE

1. Purpose

The initial study efforts were based on an economic analysis of four standard steam pressure conditions common to the power industry. These pressures were 1450, 1800, 2400 and 3500 psig.

The purpose of the phase one study was to reduce to two, the number of steam pressure conditions to be studied in detail.

2. Basis of Comparison

The basis of comparison used was total evaluated cost, consisting of major equipment first costs, and capitalized energy costs, all in terms of differentials.

The following major equipment costs were included in the analysis for a 350-Mwe plant:

a) Main steam turbine generator

b) Steam generator, reheater, and intermediate heat exchanger

c) Reactor

d) Feedwater heater and treatment system; steam, condensate, and feedwater piping

e) Main steam condenser.

The following tabulation outlines the particular steam cycle conditions studied for a 350-Mwe plant:

TABLE 1

STEAM CYCLE CONDITIONS STUDIED

Type Cycle	Steam Temperature (° F)	Steam Throttle Pressure (psig)			
		1450	1800	2400	3500
Nonreheat	950	X	-	-	-
	1000	X	-	-	-
Single-reheat	830/830	X	-	-	-
	900/900	X	-	-	-
	950/950	X	X	X	X
	1000/1000	X	X	X	X
	1050/1050	-	X	X	X
Double-reheat	950/950/950	-	-	-	X
	1000/1000/1000	-	-	-	X
	1050/1050/1050	-	-	-	X

The minimum throttle pressure was set at 3500 psig, when considering the use of double reheat cycles in this study. This is based on the fact that, for a double reheat cycle at 2400-psig throttle pressure, the second reheat pressure has a detrimental effect on the heat rate. For a double reheat cycle at throttle pressures of 3500-psig or above, the effect of the second reheat pressure is a gain in heat rate.[1]

The feedwater temperatures that were used with the steam conditions in Table 1 were obtained from previous steam studies.[2] These were chosen at higher temperatures than used in conventional practice. It was intended[2] to illustrate the minimum cycle heat rates which could be obtained in sodium-cooled nuclear power plants. The feedwater temperatures are as follows:

Feedwater Temperature (° F)	Steam Throttle Pressure (psig)	Number of Feed-Water Heaters
600	3500	9
550	2400	8
530	1800	7
500	1450	7

The type turbine evaluated for the steam conditions listed in Table 1 is a cross compound double flow 43 in. lsb unit operating at 3600/1800 rpm. For the 1450-psig nonreheat cycle, a tandem compound double flow 43 in. lsb unit operating at 1800 rpm was used. Steam cycle data available from previous studies[2] were calculated based on the foregoing more efficient type of turbines to obtain consistent results. The turbine prices were obtained from manufacturer handbook listings.[3]

The design of the steam generator is based on the "once through" type vertical modular concept being developed for the Atomic Energy Commission by Atomics International.[4] The steam generator is divided into two sections; the low temperature section that admits feedwater and produces slightly superheated steam, and the high temperature module that superheats to the final steam temperature. (See Figure 1.) Each module section consists of 37 5/8-in.-diameter tubes contained within a 6-in.-diameter shell. The tubes in the low temperature module are "5 chrome-1/2 moly;" the tubes in the high temperature module are Type 321 SS. The reheater steam module consists of 102, 1-in. tubes of Type 304 SS. The sodium side of the reheater is connected in parallel with the sodium side of the superheater (see Figure 1).

The intermediate heat exchanger shell and tubing are fabricated of Type 304 SS, the tube diameter is 5/8-in. The intermediate heat exchanger transfer heat energy from the reactor primary sodium system to the steam generators located in the secondary sodium system.

The estimated incremental cost of heat exchanger surface available in July 1962 was as follows:

Exchanger	Surface Cost ($/ft^2) Steam Throttle Pressure (psig)			
	1450	1800	2400	3500
Superheater, high temperature module (HTM)	45	50	55	60
Evaporator, low temperature (LTM)	40	45	50	50
Reheater, reheater module (RHT)	35	35	35	40
Intermediate heat exchanger module (IHX)	35	35	35	35

The costs for the feedwater heater, supply, and treatment system, plus the steam, condensate, and feedwater piping were extrapolated from published reports for similar steam conditions.[5,6,7]

The basis for evaluating the main steam condenser was $4.50/ft^2 of surface,[3] and 7/8-in. tubing at 7.5 ft/sec circulating water velocity, and inlet/outlet temperatures of 57/85°F, respectively.

In order to account for variations in reactor thermal rating because of variations in cycle efficiencies, a reactor differential cost of $50,000 was applied for each 1% change in reactor rating from a reference size reactor.

For Phase One study, the equilibrium nuclear fuel cycle costs were based on 20¢/10^6 Btu and the following standard factors:

a) 4.75% annual uranium lease charge

b) 80% plant factor

c) Uranium value based on the AEC price schedule effective July 1, 1962

d) Spent fuel shipping, $10.00/kg U

e) Conversion of uranium nitrate to UF_6, $5.60/kg U

f) Value of Pu as nitrate, $8/gm

g) Fuel fabrication costs, $110/kg

h) Equilibrium fuel burnup, 25,000 Mwd/T

To calculate the capitalized energy cost, an 80% annual plant factor was applied with capital charge rates of 14 and 7%.

The capitalized energy cost as used in this study was based on calculating the annual capitalized value of the incremental heat rate as follows:

$$\frac{\text{Fuel Cost} \times \text{Gross Turbine Generation} \times \text{Total Hours Per Year} \times \text{Annual Plant Factor}}{\text{Capital Charge Rate}} = \text{Capitalized Energy Cost} \Big/ \text{Heat Rate Differential}$$

By using the foregoing values for a 350-Mwe size plant, the capitalized energy cost or fuel value per heat rate differential was:

$$\frac{\$0.20/10^6 \text{ Btu} \times 350{,}000 \text{ kw} \times 8760 \text{ hr} \times 80\%}{14\%} = \$3500/\text{Btu-kwh}$$

Basedon the foregoing ground rules, the comparative costs were calculated for 1450, 1800, 2400, and 3500-psig steam conditions.

3. Results and Conclusions

Table 2 summarizes the best steam/sodium temperature conditions resulting from the Phase One study for each steam cycle pressure condition listed in Table 1, coupled with the corresponding evaluated cost data. In Table 2, the evaluated costs for the 3500-psig steam pressure condition with single reheat was arbitarily selected as the base for the purpose of a comparison across the steam throttle pressure range on a differential basis.

To illustrate how the best condition was chosen, a typical steam pressure of 2400 psig is selected. The lowest combined cost, as shown in Figure 2, at a 7% capital charge rate is for: (a) reactor outlet temperature of 1150°F, (b) sodium inlet temperature to steam generator of 1050°F, and (c) a steam temperature of 1000°F. These values were then shown in Table 2, in a similar manner, the best steam — sodium temperature conditions for each steam cycle pressure condition were selected based on the lowest combined cost. The results of the Phase One study are as follows:

a) The steam pressure condition with the lowest differential comparative cost at a 14% capital charge rate is 2400 psig; the next best pressure is 3500 psig.

b) At a 7% capital charge rate, the steam pressure condition with the lowest differential comparative cost is 3500 psig, followed by the 2400-psig pressure condition.

c) At 14% capital charge rate, the best steam temperature condition is 950°F; at 7% capital charge rate either 950 or 1000°F results in the best temperature condition.

The detailed cost breakdown of the various items calculated for the 1450, 1800, 2400, and 3500-psig steam conditions are given in Tables 6 through 10, located in Appendix A. Graphical representations of the differential cost of the items in these tables are shown in Figures 13 through 24 in Appendix A.

Steam/Sodium System Data									Evaluation Cost Data						
									1	2	3	4	5	6	7
Capital Charge Rate (%)	Throttle Steam Press (psig)	Throttle Steam Temp. (°F)	1st Reheat Steam Temp. (°F)	2nd Reheat Steam Temp. (°F)	Reactor Outlet Temp. (°F)	Sodium Temp. to Steam Gen (°F)	Net Turbine Cycle Heat Rate (Btu/kw-hr)	Diff. Heat Rate (Btu/kw-hr)	Value of Diff. Annual Capital, Fuel Cost ($)	Differ. Heat Exchanger Costs (HTM + LTM + RHT + IHX) ($)	Differ. Turbine-Generator Cost ($)	Differ. Reactor Cost ($)	Differ. Feedwater/Condensate Syst. Cost ($)	Differ. Main Condenser Cost ($)	Differential Comparative Cost of Items 1 thru 6 ($)
14	3,500	950	950	-	1,150	1,050	7,754	Base	Base	Base	Base	Base	Base	Base	Base
	3,500	950	950	950	1,150	1,050	7,519	-235	-847,000	+139,000	+500,000	-151,000	+213,000	-39,000	-185,000
	2,400	950	950	-	1,150	1,050	7,885	+131	+469,000	-33,000	-203,000	+85,000	-759,000	+20,000	-421,000
	1,800	950	950	-	1,150	1,050	8,081	+327	+1,179,000	-45,000	-135,000	+210,000	-1,300,000	+53,000	-38,000
	1,450	950	950	-	1,100	1,000	8,208	+454	+1,636,000	+443,000	+5,000	+293,000	-1,671,000	+77,000	+783,000
	1,450	950	-	-	1,100	1,000	8,260	+506	+1,824,000	-55,000	+75,000	+325,000	-1,751,000	+99,000	+517,000
7	3,500	1,000	1,000	-	1,150	1,050	7,640	Base	Base	Base	Base	Base	Base	Base	Base
	3,500	950	950	950	1,150	1,050	7,519	-121	-872,000	-181,000	+307,000	-78,000	+19,000	-18,000	-824,000
	2,400	1,000	1,000	-	1,150	1,050	7,746	+106	+764,000	-51,000	-203,000	+69,000	-761,000	+19,000	-163,000
	1,800	1,000	1,000	-	1,150	1,050	7,968	+328	+2,365,000	-42,000	-136,000	+212,000	-1,322,000	+53,000	+1,130,000
	1,450	950	950	-	1,100	1,000	8,208	+568	+4,094,000	+30,000	-188,000	+367,000	-1,772,000	+98,000	+2,629,000
	1,450	950	-	-	1,100	1,000	8,260	+620	+4,469,000	-468,000	-118,000	+399,000	-1,853,000	+120,000	+2,549,000

+Indicates additional cost over base
-Indicates savings in cost over base

TABLE 2

SUMMARY OF PHASE ONE STUDY, STEAM/SODIUM SYSTEM DATA AND EVALUATED COST DATA

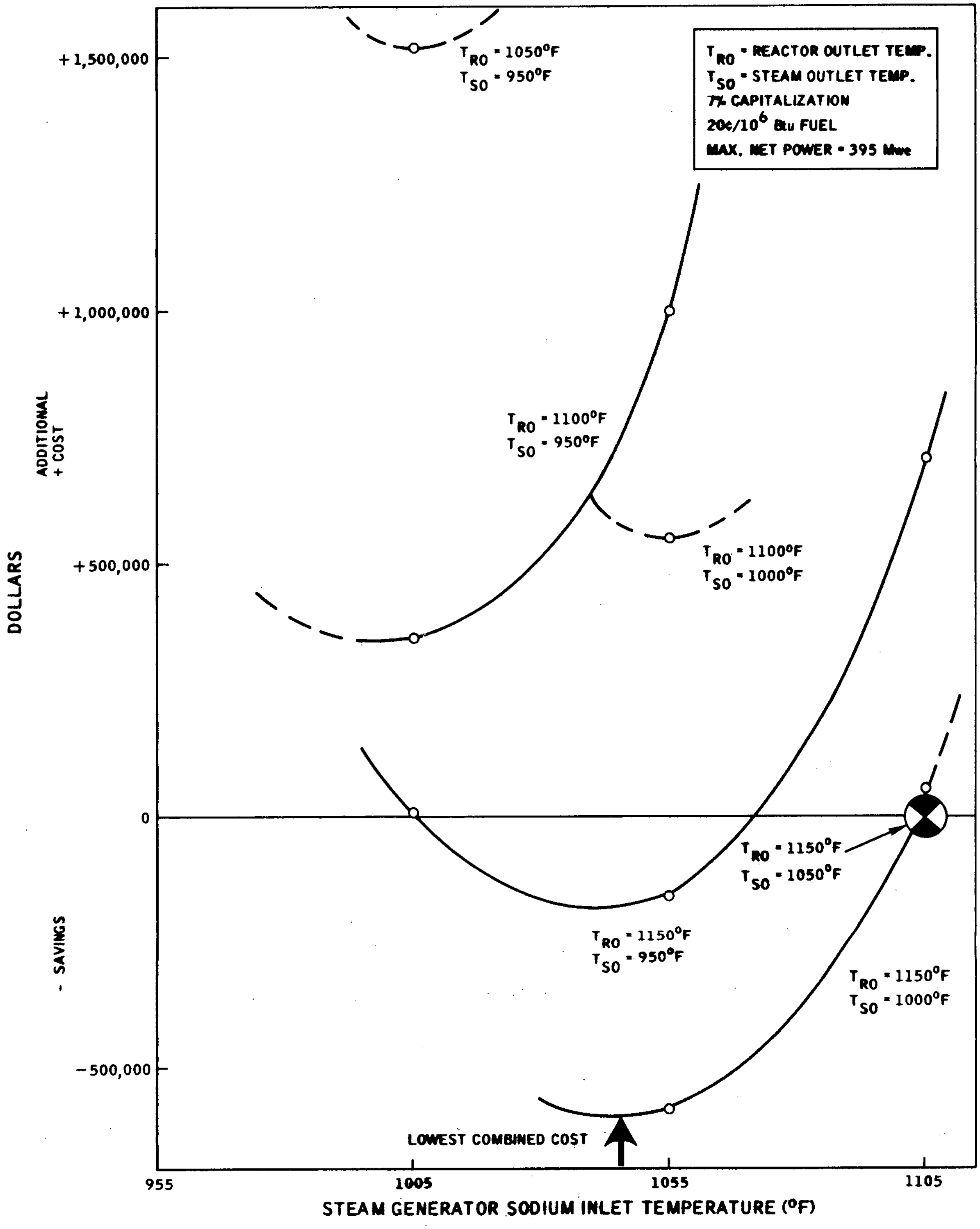

Figure 2. Differential Costs for 2400 psig Single Reheat Steam Cycle for 7 Percent Capital Charge Rate

B. PHASE TWO

1. Purpose

From the results of the Phase One study, one steam pressure 2400 psig was arbitarily selected for the purpose of determining and justifying the most reasonable steam-. odium system parameters for a 350-Mwe plant.

2. Basis of Comparison

The areas studied in detail to establish system criteria which in effect would delineate those items where potential savings exist are as follows:

a) Compare 2400-psig/950 to 950°F versus 2400-psig/1000 to 1000°F.

b) Vary the feedwater temperature from 550°F (used in the Phase One study) to 475 and 425°F.

c) Vary the cost of heat exchanger equipment by using a low, medium, and high set of cost figures as follows in dollars/ft^2:

	Set 1	Set 2	Set 3
High temperature module (HTM, superheater)	50	75	110
Low temperature module (LTM, evaporator)	45	55	90
Reheater module (RHT, reheater)	35	40	40
Intermediate heat exchanger (IHX)	35	40	35

The purpose of applying a wide variation of surface costs for the steam generators was to determine whether distinct trends in the steam and sodium parameters would result.

d) Vary the sodium temperature differential across the reactor at 350, 400, and 450°F.

e) Vary the intermediate heat exchanger LMTD at 45, 65, 80, 95, and 125°F.

f) Compare the different type turbines[3] such as:

1) Cross compound double flow, 43 in. lsb

2) Cross compound double flow, 38 in. lsb

3) Tandem compound four flow, 29 in. lsb

4) Tandem compound four flow, 26 in. lsb

g) Use 11.55% capital charge rate, an 80% plant factor, and 20¢/10^6 Btu fuel cost. The 11.55% capital charge rate was applied during the September-October 1962 period for a specific design application.

h) Include capitalized sodium pumping power and boiler feedwater pumping power costs.

i) Include main steam condenser, feedwater heater, and associated piping costs.

j) Vary the fuel cost from 20¢ to 25¢/10^6 Btu.

k) Vary the annual plant load factor from 80 to 60%.

l) Fix the reactor sodium outlet temperature at 1150°F.

m) Fix the turbine exhaust pressure at 1.5 in. Hg abs.

To illustrate the effect of varying the sodium temperature differential across the reactor as mentioned in d) of the basis of comparison, a typical example is shown in a temperature-enthalpy pinchpoint diagram see Figure 3-A, 3-B.

The ground rules for this illustration are as follows:

a) For the steam side, select the 2400-psig/1000 to 1000°F condition with 470°F feedwater temperature for both Figure 3-A and Figure 3-B.

b) Fix the reactor outlet sodium temperature at 1150°F and the intermediate heat exchanger LMTD at 75°F for Figure 3-A and Figure 3-B.

c) Fix the reactor sodium ΔT at 400°F in Figure 3-A as shown, and 350°F in Figure 3-B.

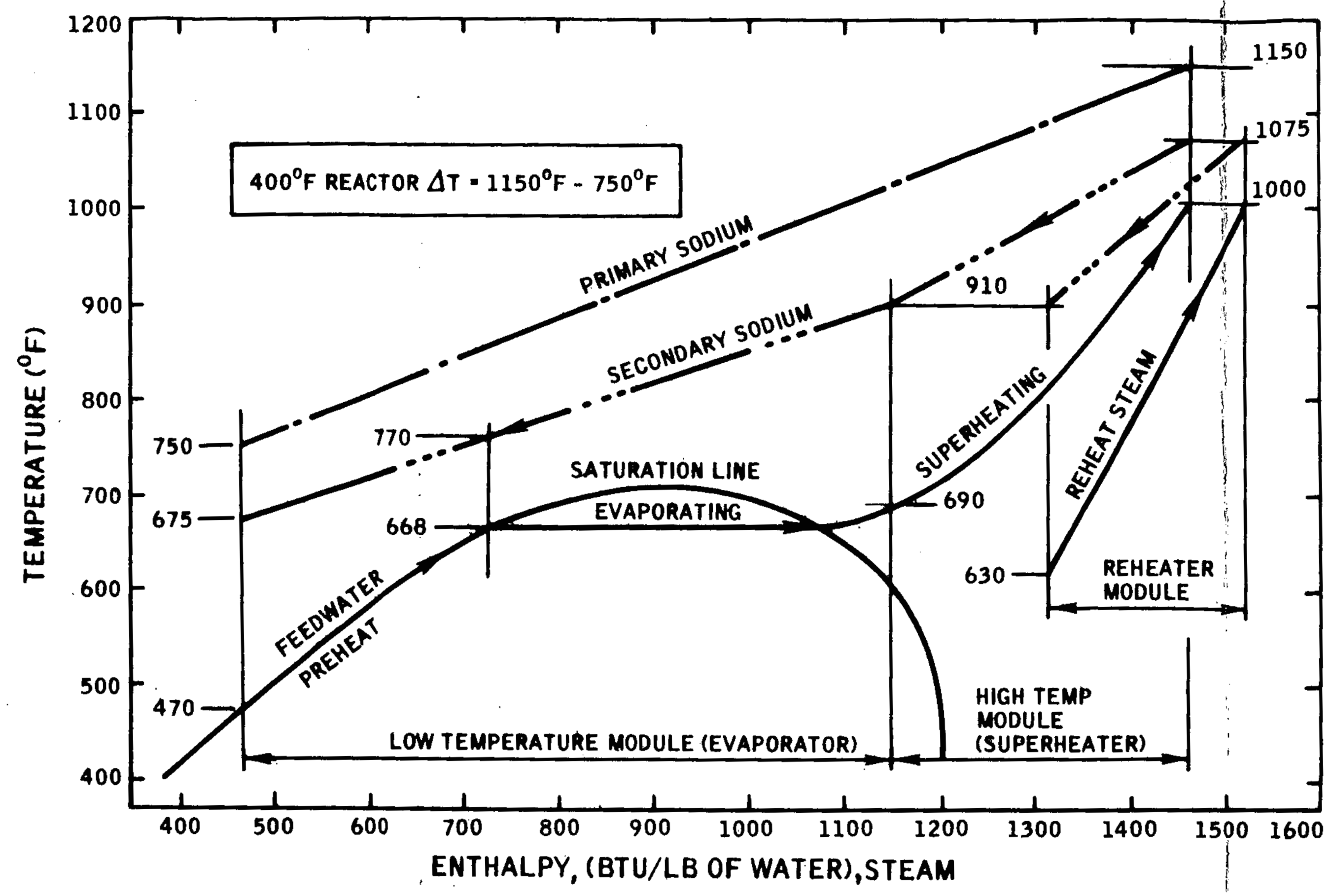

Figure 3A

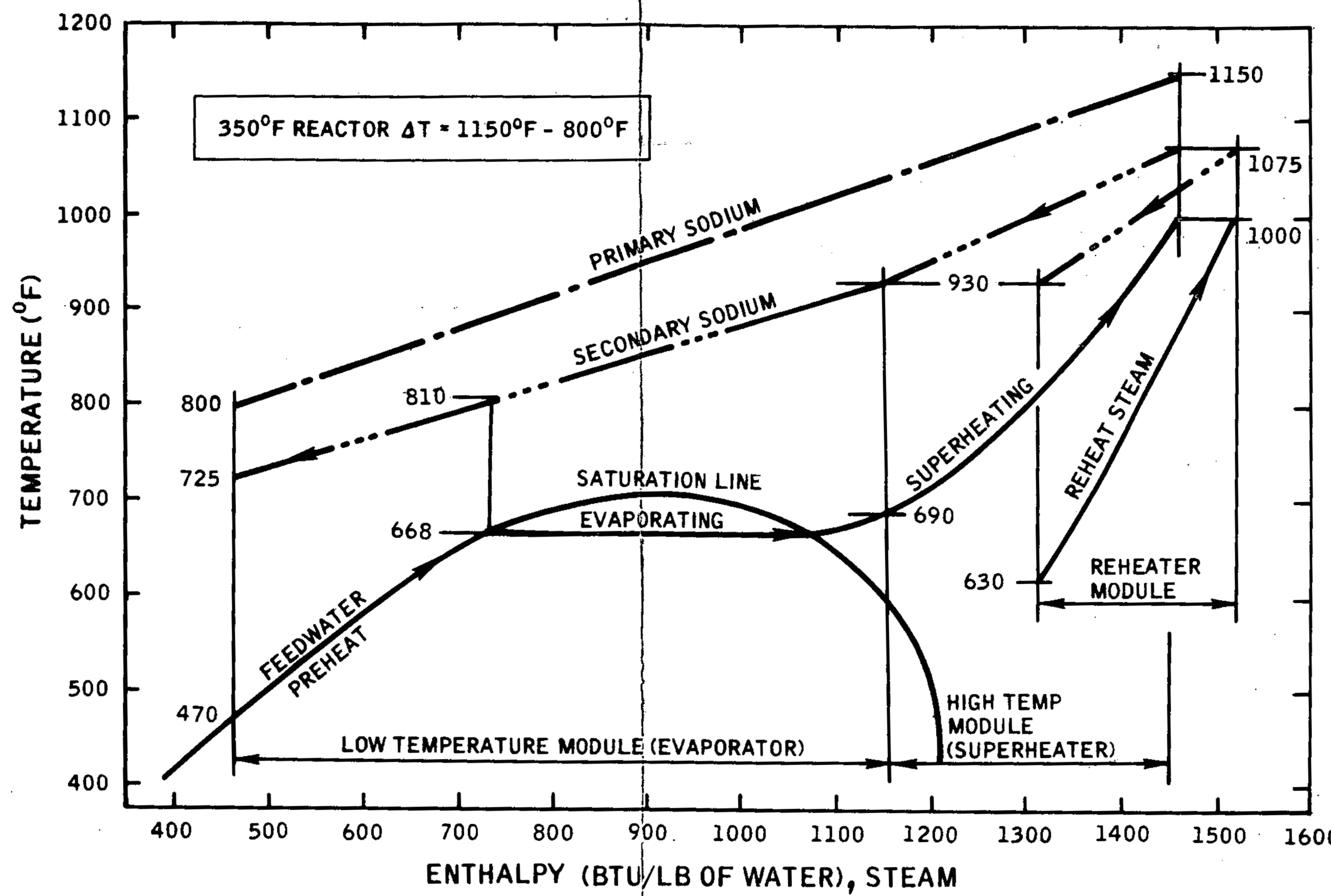

Figure 3B

PART 1. Effect on Heat Exchanger Surface Requirements for Fixed Steam-Flow and Steam Temperature Conditions

$A = \dfrac{Q}{U \times LMTD}$ where A = surface, ft^2 ...; Q = duty, Btu/hr ...; U = transfer coefficient, Btu/hr-ft^2-°F; and LMTD = log mean temp diff, °F.

a) in Figure 3–A, the LMTD of the feedwater preheat section of the low temperature evaporator module is $\begin{array}{cc} 675 & 770 \\ -470 & -668 \\ \hline 205 & 102 \end{array}$ $= \dfrac{205 - 102}{\log_e \dfrac{205}{102}} = 148°F$ ... for Figure 3–B the LMTD for the feedwater preheat section is $\begin{array}{cc} 725 & 810 \\ -470 & -668 \\ \hline 255 & 142 \end{array}$ $= \dfrac{255 - 142}{\log_e \dfrac{255}{142}} = 194°F$

b) with Q and U being constant, the feedwater preheat section surface requirements of Figure 3–A are $\dfrac{194}{148} = 1.30$ times greater than for Figure 3–B. In a similar approach, because of higher log mean temperatures of the remaining heat exchanger sections such as the evaporating, superheating, and reheating of Figure 3–B over Figure 3–A, the total exchanger surface requirements of Figure 3–B will be less than Figure 3–A.

PART 2. Effect on Main Sodium Pump Size and Sodium Pumping Power of Primary Sodium Side

a) Since $Q_{Fig\ 3\text{–}A} = Q_{Fig\ 3\text{–}B} = W_{Fig\ 3\text{–}A}\,c_p\,(1150°F - 750°F) = W_{Fig\ 3\text{–}B}\,c_p\,(1150°F - 800°F)$, $\dfrac{W_{Fig\ 3\text{–}B}}{W_{Fig\ 3\text{–}A}} = \dfrac{400}{350} = 1.14.$

b) The main primary sodium pump power required and sodium pumping power cost of Figure 3–B will then be $(1.14)^3 \times$ Figure 3–A since the pump power varies as the cube of the flow ratio.

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Figure 3A and B. Example Illustrating Effect of Varying Reactor Sodium Temperature Differential

As outlined in Part 1 of Figure 3, the effect of a 400°F-reactor ΔT (Figure 3A) versus a 350°F reactor ΔT (Figure 3B) is to require 1.30 times more surface in the feedwater preheat section of the steam generator for the larger ΔT. This is due to a smaller temperature drive across the feedwater preheat section in the 400°F reactor ΔT case (LMTD = 148°F) versus the larger temperature drive across the feedwater preheat section in the 350°F reactor ΔT case (LMTD = 194°F).

With a similar approach for the evaporating, superheating, and reheating exchanger sections, it can be shown that the temperature drives (LMTD's) of individual sections will be greater for the 350°F reactor ΔT condition than the 400°F reactor ΔT. This results in less total surface required for a 350°F reactor ΔT than a 400°F reactor ΔT. Less surface results in lower exchanger costs, exchanger space requirements, and inherently lower exchanger system pressure drops.

The main disadvantage associated with a 350°F reactor ΔT is that it requires about 1.50 times more sodium pumping power than the 400°F reactor ΔT case. As outlined in Part 2 of Figure 3, the corresponding increase in flow factor is 1.14 for the smaller reactor ΔT. Another disadvantage is the large temperature difference across the tube sheet on the cold end of the evaporator (LTM) module. The higher capital cost of the larger pumping equipment has been considered.

For each variation in: (a) sodium temperature differential across the reactor, (b) intermediate heat exchanger LMTD, and (c) feedwater temperature, the effect on equipment costs and operating costs (as illustrated in Figure 3) was incorporated in the evaluation of each steam pressure condition.

3. Results and Conclusions

The results of the Phase two study are shown in curve form in Figures 4 through 13, plotted as differential costs (+) or savings (-) in dollars versus reactor sodium temperature differential.

The curves in Figures 4, 5, and 6 illustrate the trend as steam generator unit surface costs are progressively increased (see curve legends). The lowest unit surface costs, Figure 4, favor the 2400-psig/1000 to 1000°F steam condition; medium and high unit surface costs, Figures 5 and 6, indicate no significant advantage of the 2400-psig/1000 to 1000°F steam condition over 2400-psig/950 to 950°F. In all cases, a 350°F (±50°F) reactor sodium

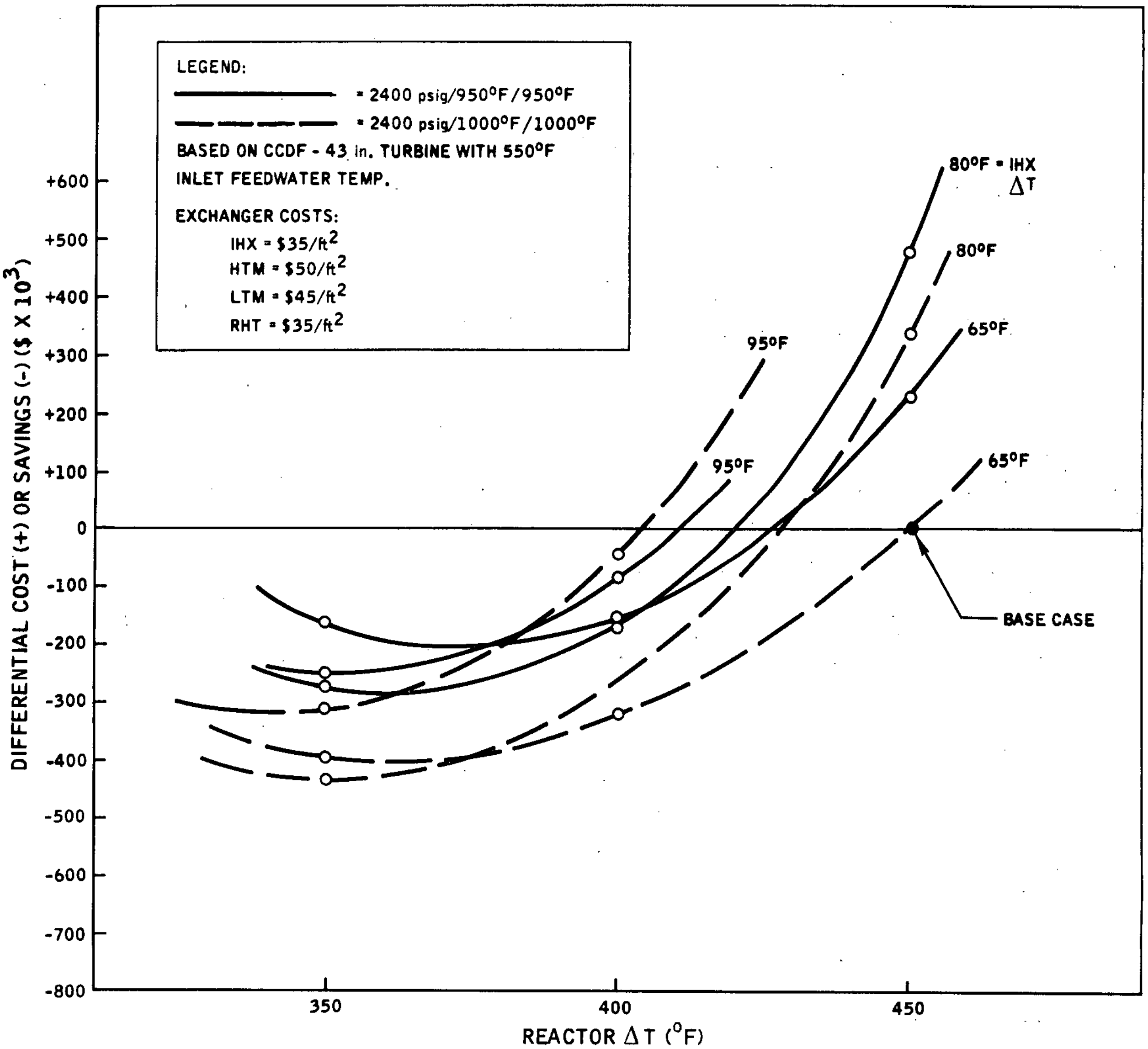

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Figure 4. Differential Costs vs Reactor ΔT for Low Heat-Exchanger Surface Costs

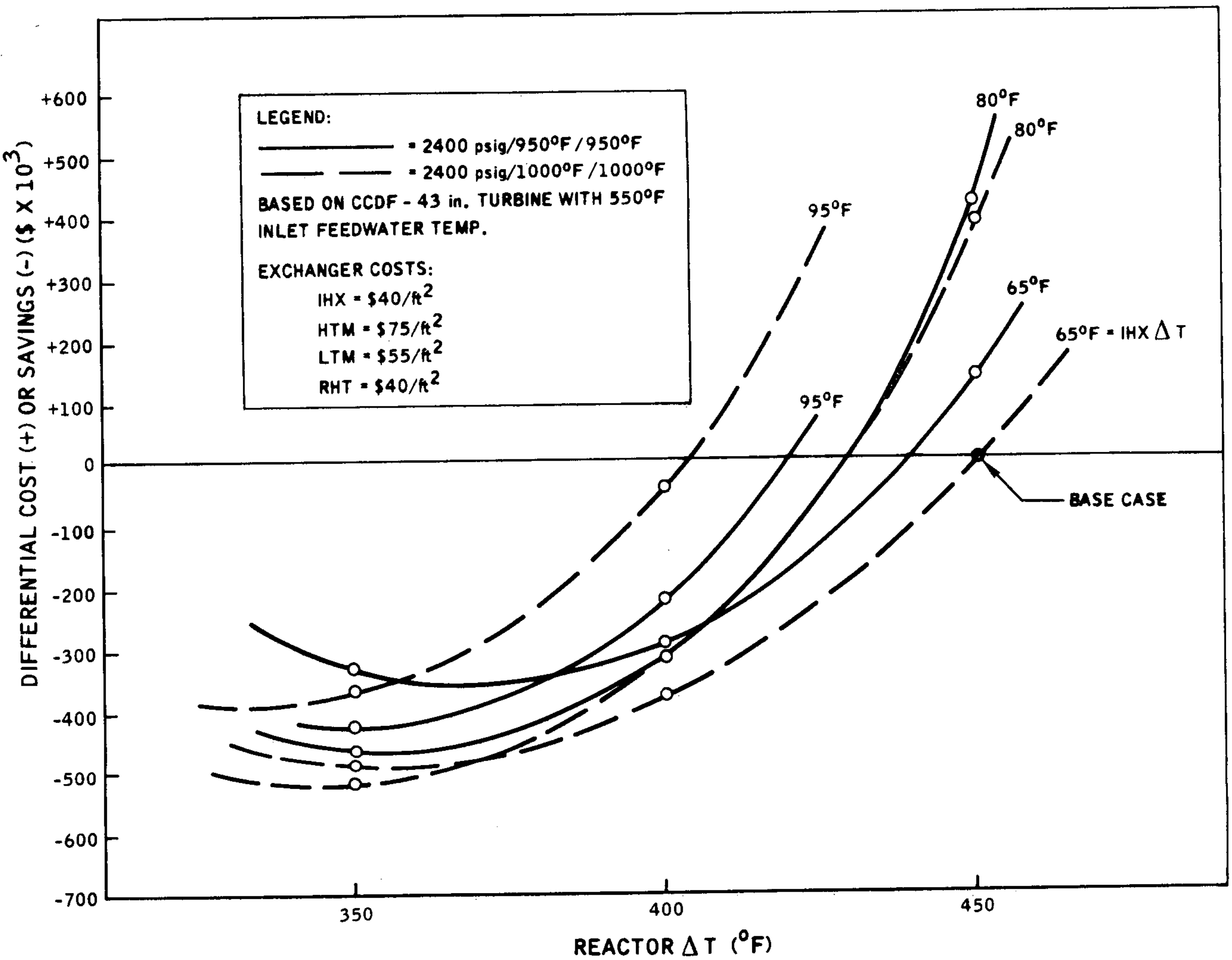

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Figure 5. Differential Costs vs Reactor ΔT for Medium Heat-Exchanger Surface Costs

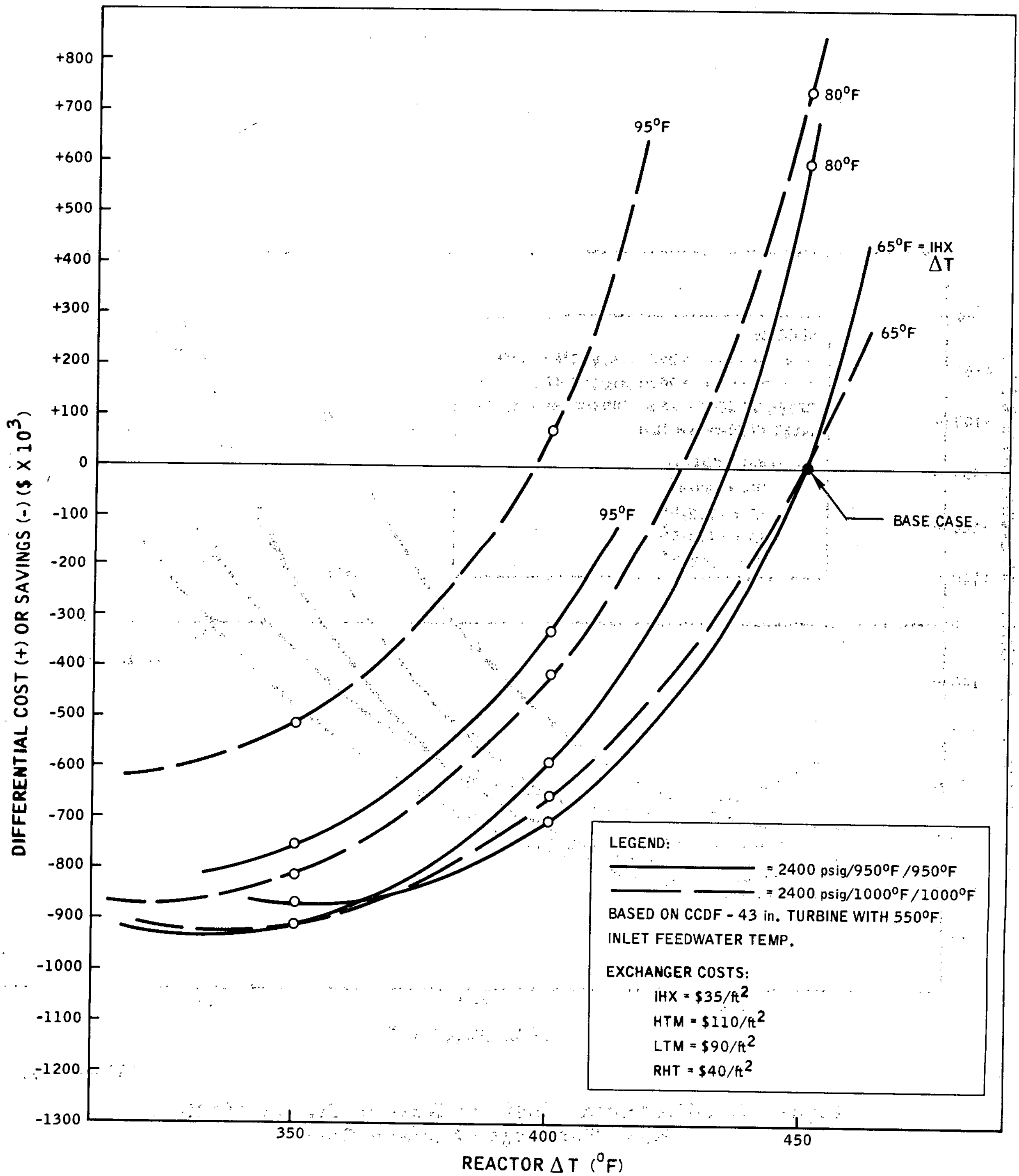

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Figure 6. Differential Costs vs Reactor ΔT for High Heat-Exchanger Surface Costs

temperature differential tends to be optimum; in all cases, an insignificant difference exists between 65 and 80°F as the preferred temperature drive across the intermediate heat exchanger.

Figure 7 illustrates the effects of feedwater temperature variations from 550 to 475°F and to 425°F for the 2400-psig/1000 to 1000°F steam condition. The trend indicates that it is not economical to design for 550°F feedwater temperature, based on the ground rules applied for this phase of the study. Since the curves for the 475 and 425°F feedwater temperature overlap in the 350 to 400°F reactor ΔT range, 475°F may be selected as the more nominal feedwater temperature. A parallel trend for 475°F feedwater temperature would apply to the 2400-psig/950 to 950°F steam condition.

Studies made of the performance and application of single reheat cycles indicate that it is most desirable to take extraction for the highest pressure feedwater heater from the cold reheat line. This is an efficient bleed point because it minimizes the difference in temperature between the extracted steam and feedwater.[1] The foregoing selection of 475°F feedwater temperature corresponds to using extraction steam from the cold reheat. The selection of the steam generator exchanger costs applied in Figure 7 were the most representative at that time.

In Figure 8, four different type turbines are compared for the 2400-psig/1000 to 1000°F condition; Figure 9 illustrates the same turbines for 2400-psig/950 to 950°F. For both steam conditions the preferred turbine selection is the tandem compound four flow 26 in. unit, the lowest cost turbine of the four reviewed.

Figure 10 represents a cross plot of the best turbine selection from Figures 8 and 9. The 2400-psig/950 to 950 steam condition is the best cycle condition, but the economic advantage over 2400-psig/1000 to 1000°F is minor.

Figure 11 is based on the identical ground rules of Figure 10, with the exception that the annual plant capacity factor was decreased from 80 to 60%. This change demonstrates a marked preference for the 2400-psig/950 to 950°F steam cycle as plant factor is decreased.

Figure 12 is based on assumptions similar to those for Figure 10, with the exception that the fuel cost was increased from 20¢/10^6 Btu to 25¢/10^6 Btu.

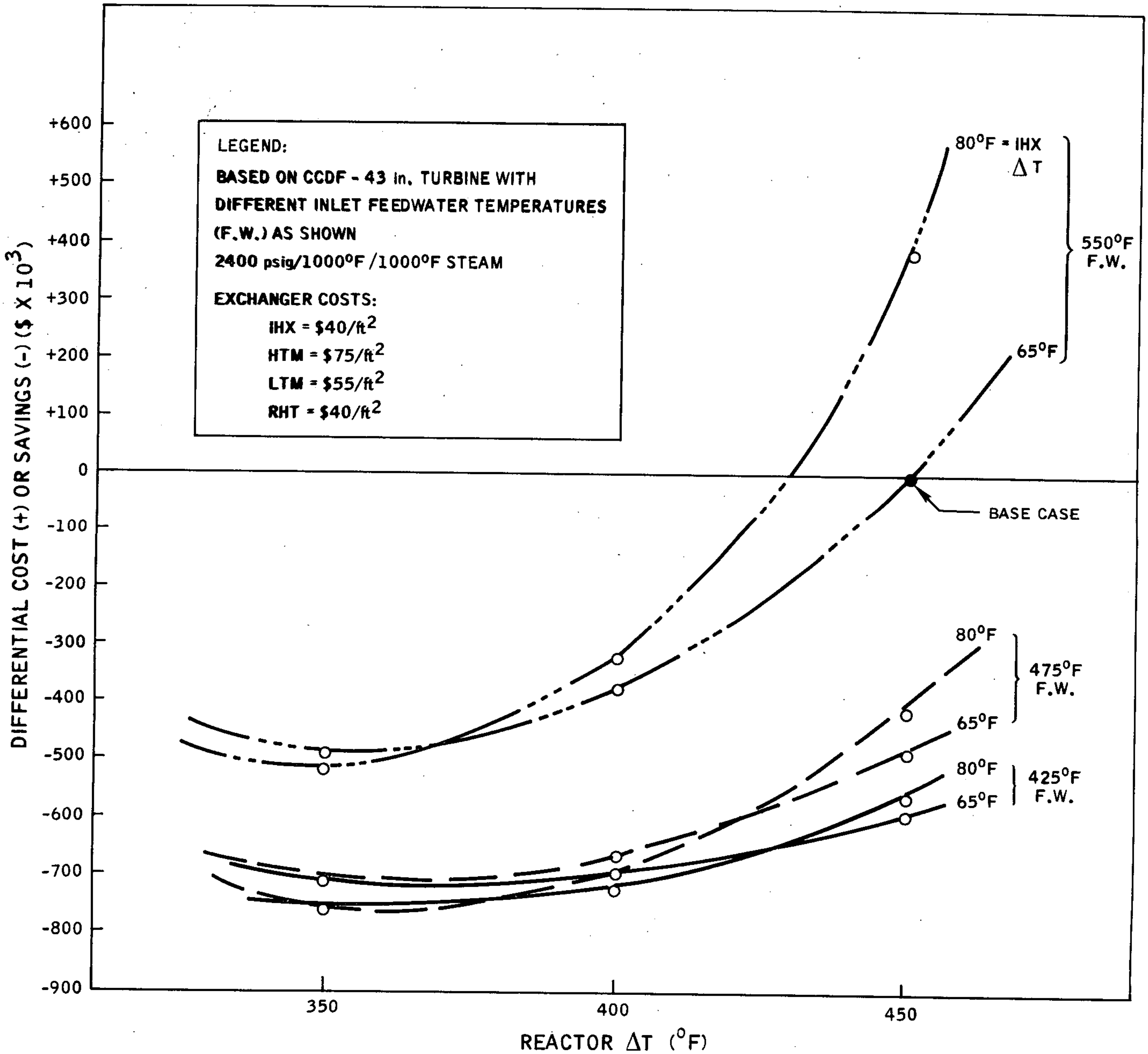

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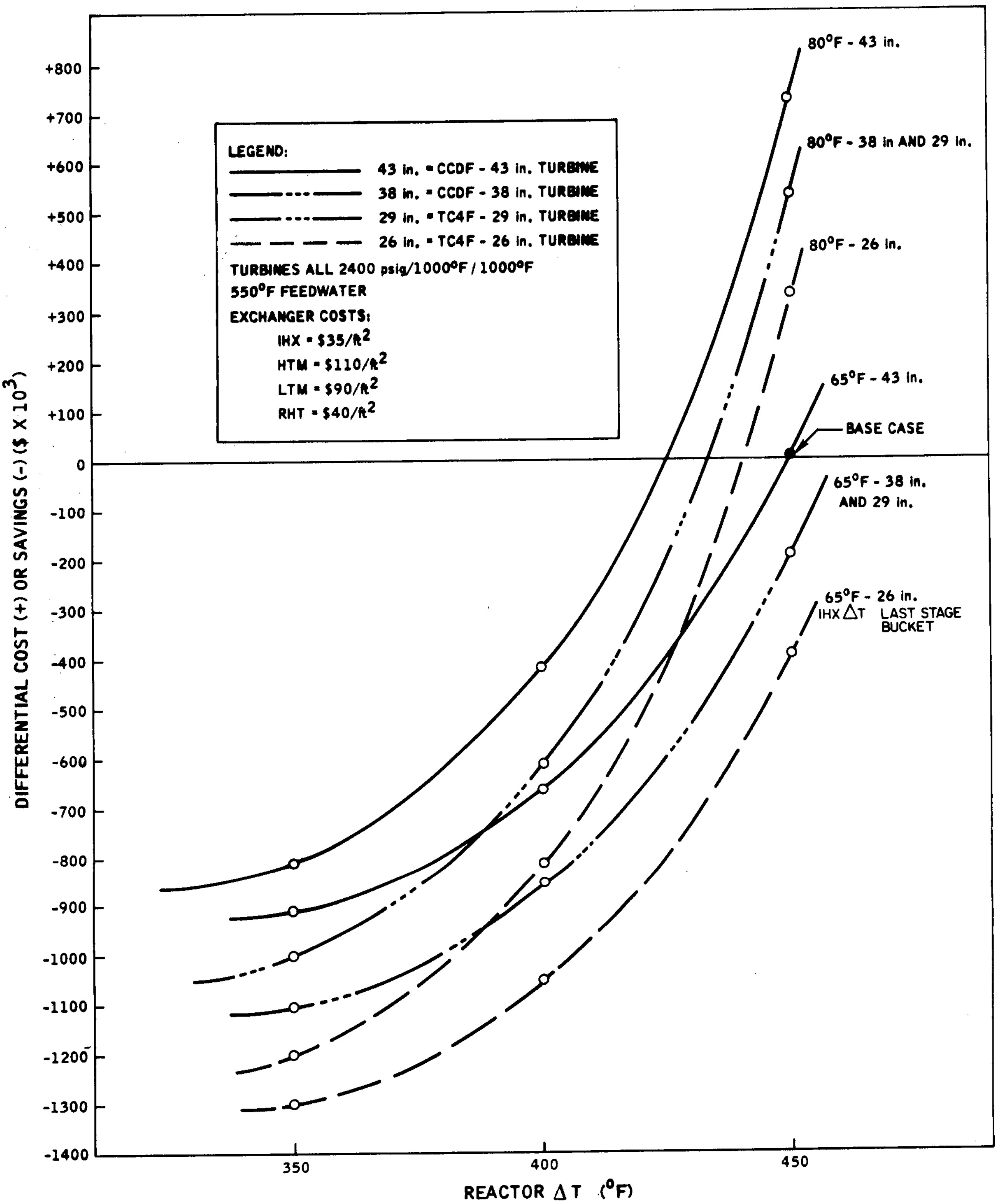
Figure 7. Differential Costs vs Reactor ΔT for Different Feedwater Temperatures



7519-54502

Figure 8. Differential Costs vs Reactor ΔT for Different Type Turbines at 2400 psig/1000 1000°F

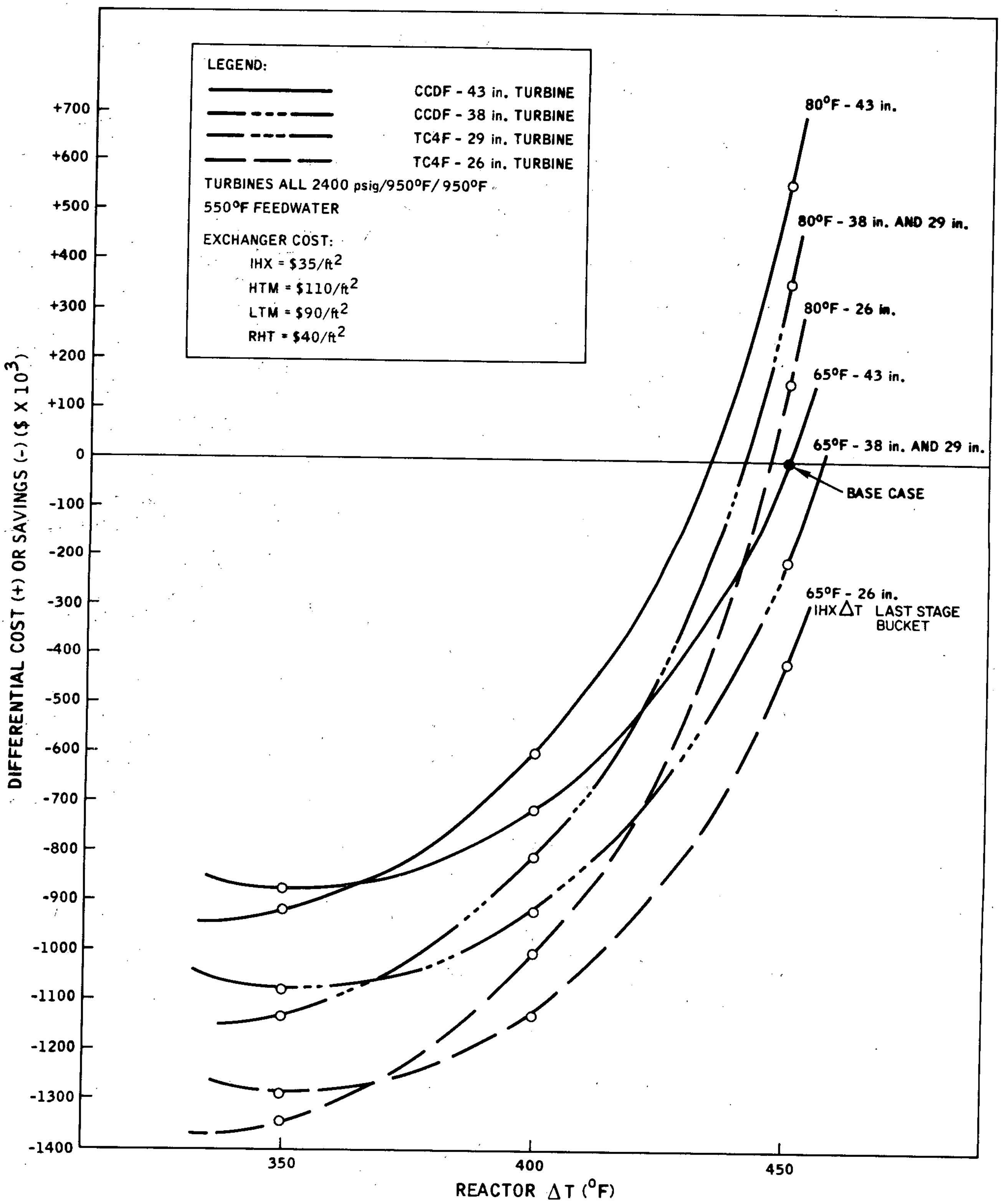
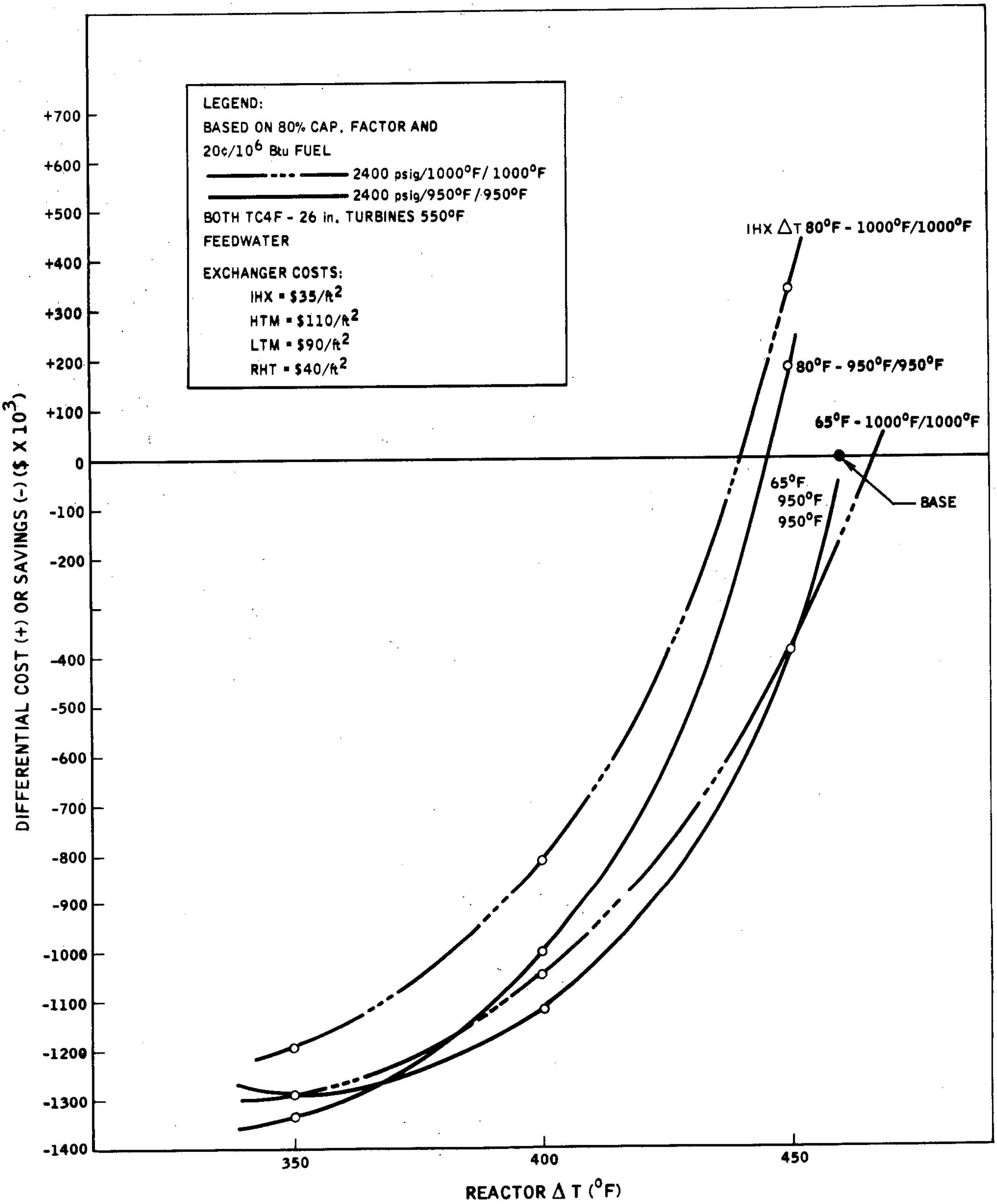
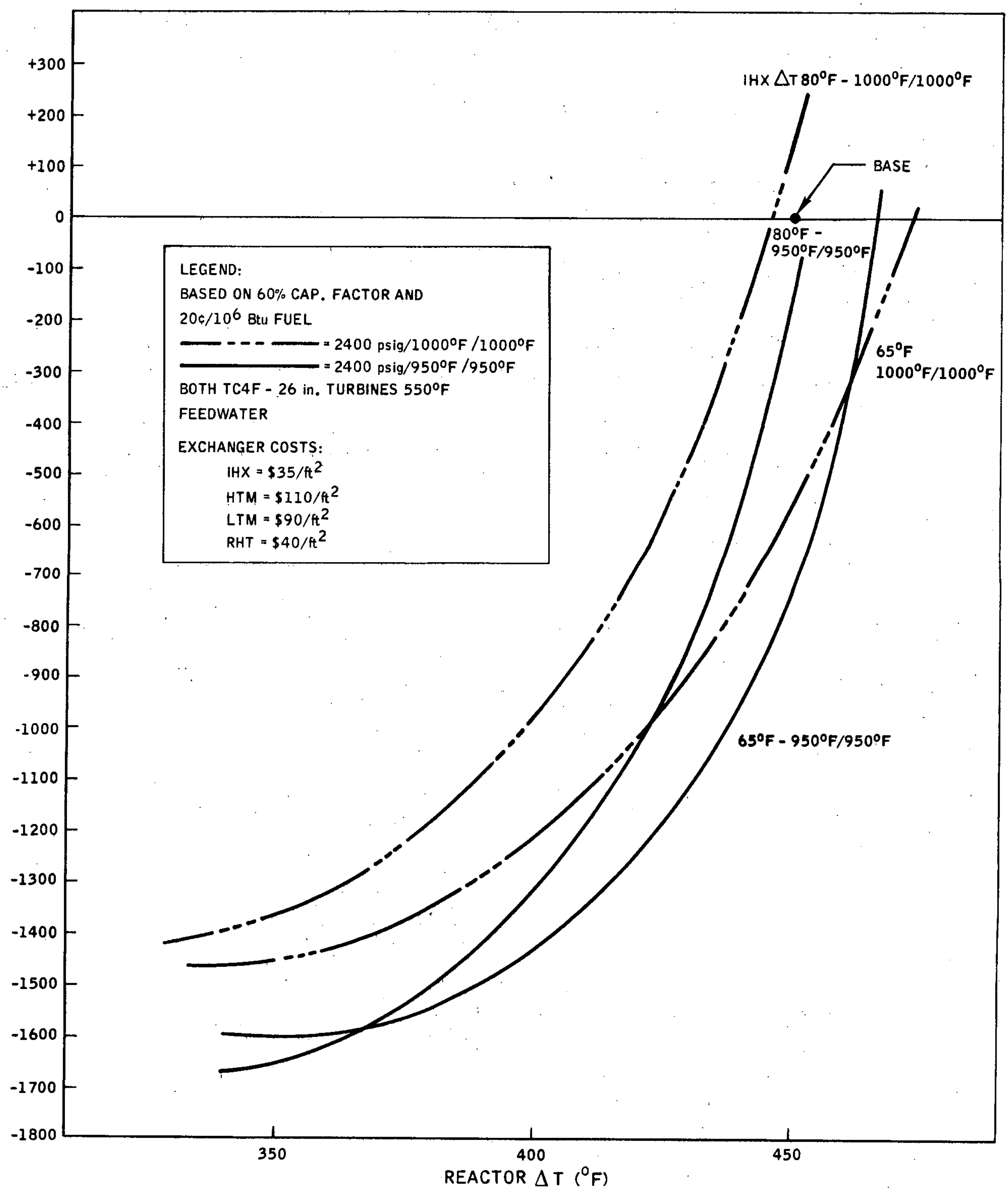


Figure 9. Differential Costs vs Reactor ΔT for Different Type Turbines at 2400 psig/950 to 950°F



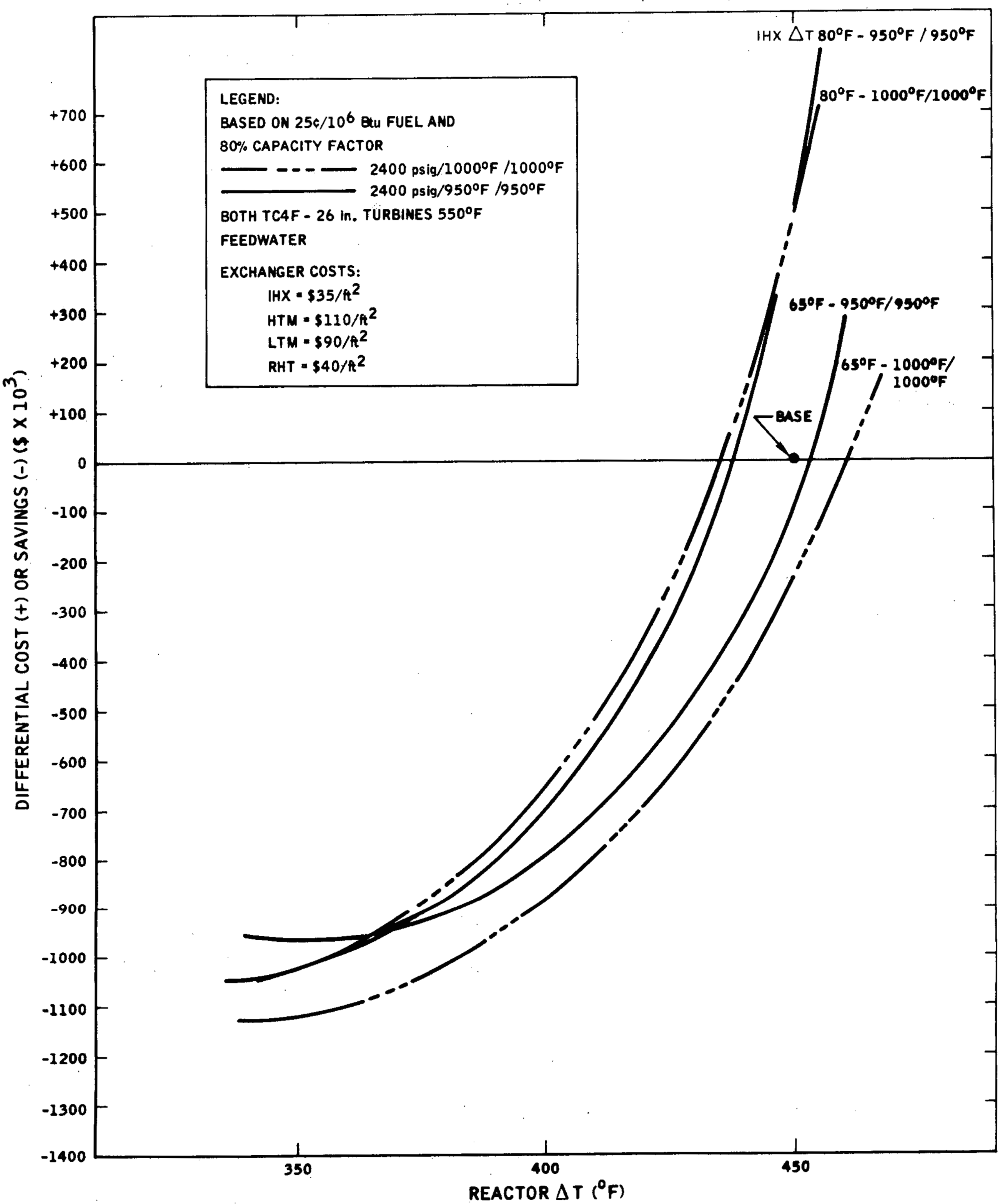
7519-54503

Figure 10. Differential Costs vs Reactor ΔT for Tandem Compound Four-Flow Turbine-26 in. at 2400 psig/1000 to 1000°F and 2400 psig/950 to 950°F



7519-54504

Figure 11. Differential Costs vs Reactor ΔT for 60% Capacity Factor



7519-54495

Figure 12. Differential Costs vs Reactor ΔT for $25¢/10^6$ Btu Fuel Cost

This variation results in a definite trend toward the 2400-psig/1000 to 1000°F steam condition. Conversely, a downward trend in fuel costs from 20¢/10^6 Btu would favor the lower steam temperatures.

Conclusions may be classified into two categories: (a) specific design criteria, and (b) general trends.

The specific design criteria evident from the Phase two study are:

a) A 350°F sodium temperature differential across the reactor is optimum.

b) A 65 to 80°F sodium temperature drive for the intermediate heat exchanger is optimum.

c) Although the cross compound turbine generators with 1800-rpm low pressure sections are more efficient and provide improved turbine cycle heat rates over the tandem compound machines at 3600-rpm, the significantly higher cost of the cross compound unit over that of the tandem compound machine exceeds the savings in operating cost when applying low nuclear fuel costs of 20¢/10^6 Btu.

d) The optimum feedwater temperature is 475°F.

A strong trend to pinpoint one specific feedwater temperature is not exhibited in the curves. The influence of variations in heat exchanger costs, fuel costs, and plant capacity factors follow similar patterns characteristic of fossil-fired plants. These trends are:

a) As fuel costs rise (20¢/10^6 Btu in Figure 10 to 25¢/10^6 Btu in Figure 12) the trend is toward the more efficient cycle, 2400-psig/1000 to 1000°F.

b) As plant capacity factor decreases (80% in Figure 10 to 60% in Figure 11) the trend is to the less efficient cycle, 2400-psig/950 to 950°F.

c) It is difficult to justify the added capital cost of the expensive high pressure feedwater heaters (Figure 7), for feedwater temperatures above nominal values just to improve system heat rates and efficiencies, with low fuel costs.

The selection of the optimum sodium temperature differential across the reactor based on this study allows a working number for the reactor designer. Since the total plant differential costs for the average steam generator surface vary slightly between a reactor ΔT of 350 and 400°F (less than $100,000) as evident in Figures 5 and 7, the final selection by the reactor designer for large SGR's was a 400°F reactor ΔT. Some influencing factors leading to this decision were lower sodium velocity through the core and resultant lower sodium pressure drops across the core.

The highest steam generator exchanger cost figures were applied in Figures 8 through 12 to illustrate the large differences that results in combined costs as the reactor sodium ΔT is varied.

C. PHASE THREE

1. Purpose

The basic purpose of Phase three was to study in detail the merits of 2400 versus 3500 psig steam pressure for a 400-Mwe plant with a 14 and 7% capital charge rate.

2. Basis of Comparison

The lowest combined major equipment costs and capitalized energy costs (in terms of differentials) are compared as the basis for determining optimum plant parameters. The steam cycles considered were:

Steam Throttle Pressure (psig)	Steam Temperature (°F)
2400	1050-1050
	1000-1000
	950-950
3500	1050-1050
	1000-1000
	950-950
3500	1050-1050-1050
	1000-1000-1000
	950- 950- 950

The ground rules applied to this portion of the study were as follows:

a) Fix the reactor sodium outlet temperature at 1150°F.

b) Vary the sodium temperature differential across the reactor at 350, 400, and 450°F, and vary the temperature drive across the intermediate heat exchanger.

c) For the steam generator (high and low temperature modules) and first reheater, the surface costs used (in dollars per ft^2) are:

Steam Pressure (psig)	High Temperature Module	Low Temperature Module	First Reheater
2400-single reheat	46	37	35
3500-single reheat	50	40	35
3500-double reheat	50	40	40

For second reheat and IHX surface costs use $\$35/ft^2$. The prices for the 3500 psig low and high temperature modules are based on quotations[4] received by AI during April 1963. The prices for the 2400-psig main steam and reheater modules are based on AI estimated pricing, April 1963.

d) The value of the capitalized incremental heat rate based on $20¢/10^6$ Btu fuel cost, 14% capital charge rate and 80% annual plant capacity factor is \$4000 per unit heat rate differential, while the value for 7% capital charge rate is \$8000 per unit heat rate differential.

e) The capitalized pumping cost for 14% capital charge rate is \$75/kw of pumping power, while the cost for 7% capital charge rate is \$150/kw of pumping power. This is used for evaluating boiler feedpump and main sodium pump operating costs.

f) The net turbine cycle heat rates for the single reheat cycles were calculated using manufacturers published data[8] for performance of large steam turbine generators based on:

1) Turbine exhaust pressure at 1.5 in. Hg abs.

2) Motor driven boiler feedpump, pump head is 1.25 times throttle pressure, pump efficiency is 75%, motor drive efficiency is 90%.

3) Net turbine cycle heat rate includes the boiler feedpump power only. The remaining plant auxiliary power requirements were set at 3.5%.

g) The remaining items evaluated are on the same basis of comparison as presented in Phase two.

Based on the foregoing ground rules, the detailed cost breakdown of the various items were calculated for 2400 and 3500-psig steam conditions.

3. Results and Conclusions

It was evident from calculations in Phases one and two of this study that the combined value of the turbine cost and the corresponding capitalized heat rate, in terms of differentials, is one of the major cost factors influencing the selection of optimum system conditions. Therefore, for each pressure condition outlined in the foregoing basis of comparison, the type turbine was evaluated, for example, as shown in Table 3 for the 2400-psig throttle steam pressure.

The turbine selection for 2400-psig throttle steam resulting from the lowest combined cost is as follows (see Table 3):

a) For 14% capital charge rate, the type turbine is a tandem compound four flow 30 in. LSB unit.

b) For 7% capital charge rate, the type turbine is a cross compound two flow 43 in. LSB unit.

The turbine generator prices shown in Table 3 are list prices[4] with no discount applied. If a 20% discount is applied, the turbine selection for 14 and 7% capital charge rates do not change.

The remaining steam-sodium system data, major equipment costs, and evaluated operating cost data, are summarized in Table 4 for the lowest combined cost for each steam temperature at 2400-psig.

The general conclusions for the 2400-psig steam cycle study are as follows (refer to Table 4).

TABLE 3

TYPE TURBINE EVALUATION FOR 14 AND 7% CAPITAL CHARGE RATES FOR 2400-psig THROTTLE STEAM PRESSURE

Type Turbine	Evaluation Criteria	14% Capital Charge Rate			7% Capital Charge Rate		
		Steam Temperature (°F)			Steam Temperature (°F)		
		950/950	1000/1000	1050/1050	950/950	1000/1000	1050/1050
CC6F 26 in.	Net turbine cycle heat rate (Btu/kwh)	7,856	7,743	7,631	7,856	7,743	7,631
	Net heat rate differential (Btu/kwh)	327	214	102	327	214	102
	Value capital heat rate differential ($)	1,310,000	856,000	408,000	2,620,000	1,712,000	816,000
	Turbine cost differential ($)	930,000	1,130,000	1,530,000	930,000	1,130,000	1,530,000
	Total of heat rate and turbine differential ($)	2,240,000	1,986,000	1,938,000	3,550,000	2,842,000	2,346,000
TC4F 30 in.	Net turbine cycle heat rate (Btu/kwh)	7,845	7,732	7,620	7,845	7,732	7,620
	Net heat rate differential (Btu/kwh)	316	203	91	316	203	91
	Value capital heat rate differential ($)	1,265,000	812,000	364,000	2,530,000	1,624,000	728,000
	Turbine cost differential ($)	500,000	700,000	1,100,000	500,000	700,000	1,100,000
	Total of heat rate + turbine differential ($)	1,765,000	1,512,000	1,464,000	3,030,000	2,324,000	1,828,000
		Best selection					
TC4F 26 in.	Net turbine cycle heat rate (Btu/kwh)	7,980	7,867	7,755	7,980	7,867	7,755
	Net heat rate differential (Btu/kwh)	451	338	226	451	338	226
	Value capital heat rate differential ($)	1,806,000	1,352,000	905,000	3,612,000	2,704,000	1,810,000
	Turbine cost differential ($)	Base	200,000	600,000	Base	200,000	600,000
	Total of heat rate + turbine differential ($)	1,806,000	1,552,000	1,505,000	3,612,000	2,904,000	2,410,000
CC4F 38 in.	Net turbine cycle heat rate (Btu/kwh)	7,754	7,641	7,529	7,754	7,641	7,529
	Net heat rate differential (Btu/kwh)	225	112	Base	225	112	Base
	Value capital heat rate differential ($)	900,000	448,000	Base	1,800,000	448,000	Base
	Turbine cost differential ($)	2,450,000	2,650,000	3,050,000	2,450,000	2,650,000	3,050,000
	Total of heat rate + turbine differential ($)	3,350,000	3,098,000	3,050,000	4,250,000	3,098,000	3,050,000
CC2F 43 in.	Net turbine cycle heat rate (Btu/kwh)	7,768	7,655	7,543	7,768	7,655	7,543
	Net heat rate differential (Btu/kwh)	239	126	14	239	126	14
	Value capital heat rate differential ($)	956,000	504,000	56,000	1,912,000	1,008,000	112,000
	Turbine cost differential ($)	1,030,000	1,230,000	1,630,000	1,030,000	1,230,000	1,630,000
	Total of heat rate + turbine differential ($)	1,986,000	1,734,000	1,686,000	2,942,000	2,238,000	1,742,000
					Best selection		
CC2F 38 in.	Net turbine cycle heat rate (Btu/kwh)	7,853	7,740	7,628	7,853	7,740	7,628
	Net heat rate differential (Btu/kwh)	324	211	99	324	211	99
	Value capital heat rate differential ($)	1,296,000	835,000	396,000	2,592,000	1,670,000	792,000
	Turbine cost differential ($)	500,000	700,000	1,100,000	500,000	700,000	1,100,000
	Total of heat rate + turbine differential ($)	1,796,000	1,535,000	1,496,000	3,092,000	2,370,000	1,892,000

	Steam-Sodium System Data								Exchanger Surface				Evaluated Equipment and Operating Cost Data										
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Capital Charge Rate (%)	Steam Press. (psig)	Steam Temp. (°F)	Net Turbine Cycle Heat Rate (Btu/kwh)	Type Turbine	Reactor Thermal Power (Mw)	Reactor Sodium Outlet Temp. (°F)	Reactor Sodium Temp. Diff. (°F)	Intermed. Heat Exch. Temp. Drive (°F)	Intermed. Heat Exch. Surface IHX (ft^2)	High Temp. Module (Supht.) Surface (ft^2)	Low Temp. Module (Evap.) Surface (ft^2)	Reheater Module Surface (ft^2)	Increment Cost IHX Surface ($)	Increment Cost HTM Surface ($)	Increment Cost LTM Surface ($)	Increment Cost RHT Surface ($)	Increment Reactor Cost ($)	Increment Turbine Cost ($)	Increment Condenser Cost ($)	Increment Main Steam Piping and Valves Cost ($)	Increment Boiler Feed Pump Pumping Cost ($)	Increment Heat Rate Cost ($)	Total Evaluated Cost-$ Columns 14 thru 23 ($)
14	2400	1050 1050	7620	TC4F 30 in.	1019	1150	350	75	42,200	30,700	22,580	19,900	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
14	2400	1000 1000	7732	TC4F 30 in.	1034	1150	350	75	42,900	18,600	23,700	12,200	+24,500	-556,000	+41,500	-269,000	+80,000	-400,000	+22,500	-315,000	+34,500	+448,000	-887,000
14	2400	950 950	7845	TC4F 30 in.	1049	1150	350	75	43,600	14,090	24,800	9,440	+49,000	-765,000	+82,100	-366,000	+150,000	-600,000	+42,300	-505,000	+67,500	+900,000	-945,000
7	2400	1050 1050	7543	CC2F 43 in.	1009	1150	350	75	42,200	30,700	22,580	19,900	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
7	2400	1000 1000	7655	CC2F 43 in.	1025	1150	350	75	42,900	18,600	23,700	12,200	+24,500	-556,000	+41,500	-269,000	+80,000	-400,000	+22,500	-315,000	+69,000	+896,000	-405,000
7	2400	950 950	7768	CC2F 43 in.	1040	1150	350	75	43,600	14,090	24,800	9,440	+49,000	-765,000	+82,100	-366,000	+150,000	-600,000	+42,300	-505,000	+135,000	+1,800,000	+22,000

+Indicates additional cost over base.
-Indicates savings in cost over base.

TABLE 4

SUMMARY OF STEAM-SODIUM SYSTEM DATA AND EVALUATED COST DATA FOR 2400-psig STEAM PRESSURE

OSTI-000019184

a) The 950°F steam temperature is the optimum selection for the 14% capital charge rate; the 1000°F steam temperature is the preferred selection for 7% capital charge rate.

b) The 350°F sodium temperature differential across the reactor is optimum for all cases studied.

c) The best intermediate heat exchanger temperature drive is 75°F.

The same study as illustrated for the 2400-psig case was repeated for the single and double reheat cycle at the 3500 psig steam pressure. The best temperature for each pressure at 14 and 7% capital charge rates was then listed in Table 5. The 2400-psig steam pressure was arbitarily selected as the base of comparison with the 3500-psig single and double reheat cycles. The optimum steam temperatures for the 3500-psig steam pressure are similar to the results for 2400-psig steam pressure. At 14% capital charge rate, the steam temperature is 950°F and the type turbine is a tandem compound four flow 30 in. LSB unit; at 7% capital charge rate, the steam temperature is 1000°F and the type turbine is a cross compound double flow 43 in. LSB unit.

A comparison of the total evaluated cost for each steam system in Table 5 indicates the following:

a) The 3500-psig supercritical double reheat steam condition at 1000°F temperature with a 7% capital charge rate provides significant savings of $1,485,000, over the 2400-psig condition.

b) The single and double reheat 3500-psig supercritical steam costs at 950°F temperature with a 14% capital charge rate indicates savings of $292,000 and $444,000 respectively over 2400-psig steam, but additional detailed analysis would be required to verify this trend.

c) A 1050°F steam temperature is not justified for any steam pressure condition studied.

d) The tandem compound four flow 30 in. LSB turbine is the best selection at 14% capital charge rates; the cross compound two flow 43 in. LSB unit is the best with the 7% capital charge rate.

	Steam-Sodium System Data								Exchanger Surface					Evaluated Equipment and Operating Cost Data															
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Capital Charge Rate (%)	Steam Pressure (psig) S=Single D=Double Reheat	Steam Temp (°F)	Net Turbine Cycle Heat Rate (Btu/kw-hr)	Type Turbine	Reactor Thermal Power (Mw)	Reactor Sodium Outlet Temp (°F)	Reactor Sodium Temp Differ. (°F)	Intermed. Heat Exch. Temp Drive (°F)	Intermed. Heat Exch. Surface IHX (ft^2)	High Temp. Module (Supht) Surface (ft^2)	Low Temp. Module (Evap) Surface (ft^2)	1st Reheater Module Surface (ft^2)	2nd Reheater Module Surface (ft^2)	Increment. Cost IHX Surface ($)	Increment. Cost HTM Surface ($)	Increment. Cost LTM Surface ($)	Increment. Cost 1st Reheat Surface ($)	Increment. Cost 2nd Reheat Surface ($)	Increment. Reactor Cost ($)	Increment. Turbine Cost ($)	Increment. Condenser Cost ($)	Increment. Main Steam Piping and Valves Cost ($)	Increment. Feedwater Piping and Valves Cost ($)	Increment. Feedwater Heater Cost ($)	Extra Extract. Point in Turbine Cost ($)	Increment. Boiler Feed Pump Pumping Cost ($)	Increment. Main Sodium Pumps Pumping Cost ($)	Increment. Heat Rate Cost ($)	Total Evaluated Cost ($) (col 15 through 29)
14	2,400-S	950/950	7,845	TC4F 30 in.	1,049	1,150	350	75	43,600	14,090	24,800	9,440	-	Base	Base	Base	Base	-	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
14	3,500-S	950/950	7,645	TC4F 30 in.	1,022	1,150	350	95	33,400	12,100	20,400	11,690	-	-359,000	-43,000	-102,000	+79,000	-	-120,000	-75,000	+39,000	+176,000	+120,000	+330,000	+40,000	+437,000	-14,000	-800,000	-292,000
14	3,500-D	950/950/950	7,435	TC4F 30 in.	995	1,150	350	95	32,500	11,250	23,800	8,030	13,200	-391,000	-86,000	+35,000	-9,000	+462,000	-250,000	+375,000	-40,000	+371,000	+120,000	+276,000	+40,000	+321,000	-28,000	-1,640,000	-444,000
7	2,400-S	1,000/1,000	7,655	CC2F 43 in.	1,025	1,150	350	75	42,900	18,600	23,700	12,200	-	Base	Base	Base	Base	-	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
7	3,500-S	1,000/1,000	7,454	CC2F 43 in.	999	1,150	350	95	32,650	17,600	22,900	14,800	-	-358,000	+24,000	+39,000	+91,000	-	-125,000	-75,000	+32,000	+175,000	+120,000	+330,000	+40,000	+814,000	-31,000	-1,608,000	-532,000
7	3,500-D	1,000/1,000/1,000	7,244	CC2F 43 in.	970	1,150	350	95	31,800	14,680	24,600	11,320	20,200	-388,000	-122,000	+109,000	+26,000	+707,000	-270,000	+425,000	-40,000	+395,000	+120,000	+276,000	+40,000	+588,000	-63,000	-3,288,000	-1,485,000

NOTES: + indicates additional cost over base
- indicates savings in cost over base

TABLE 5

SUMMARY OF PHASE THREE STUDY, STEAM-SODIUM SYSTEM DATA AND EVALUATED COST DATA

OSTI ID: 00019184

The detailed cost breakdown of the various items outlined in the ground rules for the 2400 and 3500-psig single reheat cycles, and the 3500 psig double reheat cycles is shown in Tables 11, 12 and 13, located in Appendix A. The best steam conditions, as listed in Table 5, were selected for each steam pressure based on the lowest combined evaluated cost from Tables 11, 12, and 13.

The basic objective of this steam cycle study was to establish generalized steam conditions and to select types of turbines for use in large sodium graphite nuclear power plants. A review of the approach applied by the power industry,[9] to justify the selection of steam conditions and types of turbines reveals a broad spectrum of analytical methods depending on the plant site, system interconnections, type financing, and miscellaneous local ground rules. The final selection should be based on a specific site and ground rules as related to a specific utility company.

A major factor influencing the steam cycle studies was the change in the steam-turbine and generator price structure. The change in price structure[10] initiated in 1961 reduced the cost of 3500-psig turbines versus 2400-psig turbines to a point where the new price structure makes higher steam conditions economically attractive. In fact, turbine generators rated at 400,000 kw and above cost less for 3500-psig steam pressure than for 2400-psig.

It is reasonable to expect further improvements in equipment design and systems, which will provide additional gains in station performance. The trends of the evaluation studies for future power plant expansions may provide inducements to make even earlier advances to supercritical steam pressure cycles employing double reheat, with future parallel modifications to the turbine generator price structure.

As a result of the economic analyses described in this paper, the following may be concluded.

a) 3500 or 2400-psig steam pressure with temperatures of 950 or 1000°F are justified and can be matched with large sodium graphite reactor power plants.

b) Sodium temperature differentials across the reactor of 350 to 400°F are reasonable with a reactor outlet sodium temperature of 1150°F.

The final selection of steam conditions and sodium parameters for a sodium graphite nuclear power plant should be based on specific plant site and a specific utility companys ground rules, not on generalized steam studies.

APPENDIX A

DETAILED RESULTS OF STUDY

PHASE ONE STUDY

Tables 6 through 10 contain the detailed costs and steam-sodium parameters for the phase-one study. The graphical representations of these results based on ground rules outlined in III-A-2, are shown in Figures 13 through 24.

PHASE THREE STUDY

Tables 11 through 13 contain detailed costs and steam-sodium parameters for the phase-three study based on ground rules outlined in III-C.

	1 Reactor Outlet Temp. (°F)	2 Reactor Inlet Temp. (°F)	3 $\frac{Q_\theta}{3.167 \times 10^9}$	4 Cost (+) or Savings (-) Due to Reactor Heat Load ($)	5 IHX ΔT_D (°F)	6 IHX Area (ft^2)	7 Change in IHX Area (ft^2)	8 Cost (+) or Savings (-) Due to Change in IHX Area at $35/$ft^2$ ($)	9 Steam Gen. Sod. Inlet Temp. (°F)	10 Steam Gen. Sod. Outlet Temp. (°F)	11 Steam Temp. out of S.G. (°F)	12 Net Heat Rate (Btu/kwh)	13 Area H.T.M. (ft^2)	14 Area L.T.M. (ft^2)	15 Area Reheater (ft^2)
1	1,100	650	-	-	45	63,980	-	-	1,055	605	1,000	8,018	16,600	17,300	15,700
2	Non-	Reheat →	1.027	+135,000	-	-	+1,730	+60,550	-	-	1,000	8,236	17,400	18,500	-
3	-	-	1.017	+85,000	-	-	+1,080	+37,800	-	-	950	8,155	11,640	17,800	10,360
4	Non-	Reheat →	1.0365	+182,500	-	-	+2,330	+81,550	-	-	950	8,311	12,500	18,950	-
5	-	-	1.035	+175,000	-	-	+2,240	+78,400	-	-	900	8,301	8,750	18,300	8,060
6	-	-	1.0637	+318,500	-	-	+4,075	+142,600	-	-	830	8,529	6,500	19,150	6,350
7	-	-	1.017	+85,000	95	30,820	-33,160	-1,160,000	1,005	-	950	8,155	16,850	19,200	15,100
8	Non-	Reheat →	1.0365	+182,500	-	31,400	-32,580	-1,140,000	-	-	950	8,311	17,800	20,500	-
9	-	-	1.035	+175,000	-	31,370	-32,610	-1,141,000	-	-	900	8,301	11,620	19,850	10,400
10	-	-	1.0637	+318,500	-	32,230	-31,750	-1,111,000	-	-	830	8,529	7,850	20,650	7,650
11	-	750	1.035	+175,000	145	20,550	-43,430	-1,520,000	955	-	900	8,301	16,850	21,600	15,000
12	-	-	1.0637	+318,500	-	21,120	-42,860	-1,500,000	-	-	830	8,529	9,880	22,600	9,210
13	-	800	1.0637	+318,500	195	15,700	-48,280	-1,690,000	905	-	830	8,529	13,940	25,200	12,360
16	1,050	650	1.017	+85,000	45	-	+1,080	+37,800	1,005	-	950	8,155	16,850	19,200	15,100
17	Non-	Reheat →	1.0365	+182,500	-	-	+2,330	+81,550	-	-	950	8,311	17,800	20,500	-
18	-	-	1.035	+175,000	-	-	+2,240	+78,400	-	-	900	8,301	11,620	19,850	10,400
19	-	-	1.0637	+318,500	-	-	+4,075	+142,600	-	-	830	8,529	7,850	20,650	7,650
20	-	700	1.035	+175,000	95	31,370	-32,610	-1,141,000	955	-	900	8,301	16,850	21,600	15,000
21	-	-	1.0637	+318,500	-	32,230	-31,750	-1,111,000	-	-	830	8,529	9,880	22,600	9,210
22	-	750	1.0637	+318,500	145	21,120	-42,860	-1,500,000	905	-	830	8,529	13,940	25,200	12,360
26	1,000	650	1.035	+175,000	45	-	+2,240	+78,400	955	-	900	8,301	16,850	21,600	15,000
27	-	-	1.0637	+318,500	-	-	+4,075	+142,600	-	-	830	8,529	9,880	22,600	9,210
28	-	700	1.0637	+318,500	95	32,230	-31,750	-1,111,000	905	-	830	8,529	13,940	25,200	12,360
31	950	650	1.0637	+318,500	45	-	+4,075	+142,600	905	-	830	8,529	13,940	25,200	12,360

	16 Change in Net Heat Rate (Btu/kwh)	17 Change in Area H.T.M. (ft^2)	18 Change in Area L.T.M. (ft^2)	19 Change in Area Reheater (ft^2)	21 Value of Diff. H.R. Capitalized at 14% Fuel 20¢ ($)	22 Cost (+) or Savings (-) Due to Change in H.T.M. Area at $45/$ft^2$ ($)	23 Cost (+) or Savings (-) Due to Change in L.T.M. Area at $40/$ft^2$ ($)	24 Cost (+) or Savings (-) Due to Change in Reheater Area at $35/$ft^2$ ($)	25 Incremental Cost (+) or Savings (-) in Turbine ($)	26 Cost (+) or Savings (-) Due to Change in Condenser Surface at $4.50/$ft^2$ ($)	29 Total Evaluated Cost at 7% Cap. Charge Rate ($)	30 Total Evaluated Cost at 14% Cap. Charge Rate ($)
1	-	-	-	-	-	-	-	-	-	-	-	-
2	+218	+800	+1,200	-15,700	+784,800	+36,000	+48,000	-549,500	+60,000	+38,300	+1,397,950	+613,150
3	+137	-4,960	+500	-5,340	+493,200	-223,200	+20,000	-186,900	-190,000	+26,800	+555,900	+62,700
4	+293	-4,100	+1,650	-15,700	+1,054,800	-184,500	+66,000	-549,500	-120,000	+62,200	+1,647,800	+593,050
5	+283	-7,850	+1,000	-7,640	+1,018,800	-353,250	+40,000	-267,400	-330,000	+52,700	+1,433,000	+414,200
6	+511	-10,100	+1,850	-9,350	+1,839,600	-454,500	+74,000	-327,250	-470,000	+95,900	+3,058,400	+1,218,800
7	+137	+250	+1,900	-600	+493,200	+11,250	+76,000	-21,000	-190,000	+26,800	-185,500	-678,700
8	+293	+1,200	+3,200	-15,700	+1,054,800	+54,000	+128,000	-549,500	-120,000	+62,200	+727,200	-328,000
9	+283	-4,980	+2,550	-5,300	1,018,800	-224,100	+102,000	-185,500	-330,000	+52,700	+486,700	-532,100
10	+511	-8,750	+3,350	-8,050	+1,839,600	-393,750	+134,000	-281,750	-470,000	+95,900	+1,971,000	+131,400
11	+283	+250	+3,300	-700	+1,018,800	+11,250	+132,000	-24,500	-330,000	+52,700	+534,100	-484,700
12	+511	-6,720	+4,300	-6,490	+1,839,600	-302,400	+172,000	-227,150	-470,000	+95,900	+1,765,900	-73,600
13	+511	-2,660	+7,900	-3,340	+1,839,600	-119,700	+316,000	-116,900	-470,000	+95,900	+1,821,200	+173,400
16	+137	+250	+1,900	-600	+493,200	+11,250	+76,000	-21,000	-190,000	+26,800	+1,012,300	+519,100
17	+293	+1,200	+3,200	-15,700	+1,054,800	+54,000	+128,000	-549,500	-120,000	+62,200	+1,948,400	+893,600
18	+283	-4,980	+2,550	-5,300	+1,018,800	-224,100	+102,000	-185,500	-330,000	+52,700	+1,706,100	+687,300
19	+511	-8,750	+3,350	-8,050	+1,839,600	-393,750	+134,000	-281,750	-470,000	+95,900	+3,224,600	+1,385,000
20	+283	+250	+3,300	-700	+1,018,800	+11,250	+132,000	-24,500	-330,000	+52,700	+913,100	-105,700
21	+511	-6,720	+4,300	-6,490	+1,839,600	-302,400	+172,000	-227,150	-470,000	+95,900	+2,155,000	+315,400
22	+511	-2,660	+7,900	-3,340	+1,839,600	-119,700	+316,000	-116,900	-470,000	+95,900	+2,203,000	+363,400
26	+283	+250	+3,300	-700	+1,018,800	+11,250	+132,000	-24,500	-330,000	+52,700	+2,132,500	+1,113,700
27	+511	-6,720	+4,300	-6,490	+1,839,600	-302,400	+172,000	-227,150	-470,000	+95,900	+3,408,600	+1,569,000
28	+511	-2,660	+7,900	-3,340	+1,839,600	-119,700	+316,000	-116,900	-470,000	+95,900	+2,592,000	+752,400
31	+511	-2,660	+7,900	-3,340	+1,839,600	-119,700	+316,000	-116,900	-470,000	+95,900	+3,845,600	+2,006,000

TABLE 6

PHASE ONE SUMMARY FOR 1450-psig STEAM PRESSURE; NON- AND SINGLE-REHEAT

1 Reactor Outlet Temp (°F)	2 Reactor Inlet Temp (°F)	3 $\frac{Qt}{3.080 \times 10^9}$	4 Cost (+) or Savings (-) Due to Reactor Heat Load ($)	5 IHX ΔT_D (°F)	6 IHX Area (ft^2)	7 Change In IHX Area (ft^2)	8 Cost (+) or Savings (-) Due to Change in IHX Area @ $35/ft^2	9 Steam Gen. Sod. Inlet Temp (°F)	10 Steam Gen. Sod. Outlet Temp (°F)	11 Steam Temp Out of S. G. (°F)	12 Net Heat Rate (Btu/kwh)	13 Area High Temp Mod (ft^2)	14 Area Low Temp Mod (ft^2)	15 Area Reheater (ft^2)	16 Change In Net Heat Rate (Btu/kwh)	17 Change In Area HTM (ft^2)	18 Change In Area LTM (ft^2)	19 Change In Area Reheater (ft^2)	20 Value of Diff H. R. Capitalized @ 14% and 20¢ Fuel ($)	21 Cost (+) or Savings (-) Due to Change In HTM Area @ 50/ft^2 ($)	22 Cost (+) or Savings (-) Due to Change In LTM Area @ 45/ft^2 ($)	23 Cost (+) or Savings (-) Due to Change In Reheater Area @ 35/ft^2 ($)	24 Incremental Cost (+) or Savings (-) In Turbine ($)	25 Total Evaluated Cost @ 7% Cap. Charge Rate ($)	26 Total Evaluated Cost @ 14% Cap. Charge Rate ($)
1,150	680	-	-	45	62,100	-	-	1,105	635	1,050	7,788	17,650	15,400	15,000	-	-	-	-	-	-	-	-	-	-	-
-	-	1.016	+80,000	-	63,100	+1,000	+35,000	-	-	1,000	7,913	12,600	15,800	9,750	+125	-5,050	+400	-5,750	+450,000	-252,000	+18,000	-202,000	-385,000	+194,000	-256,000
-	-	1.0316	+123,000	-	64,200	+2,100	+73,500	-	-	950	8,034	9,860	16,250	7,510	+246	-7,790	+850	-7,990	+885,000	-390,000	+38,200	-280,000	-577,000	+757,700	-127,300
-	730	1.016	+80,000	95	29,900	-32,200	-1,130,000	1,055	-	1,000	7,913	18,400	17,000	14,000	+125	+750	+1,600	-1,500	+450,000	+37,500	+72,000	-52,500	-385,000	-478,000	-928,000
-	-	1.0316	+123,000	-	30,400	-31,700	-1,110,000	-	-	950	8,034	12,600	17,450	9,560	+246	-5,050	+2,050	-5,940	+888,000	-252,000	+92,400	-208,000	-577,000	-161,600	-1,046,600
-	780	1.0316	+123,000	145	19,600	-42,500	-1,400,000	1,005	-	950	8,034	18,150	18,750	13,650	+246	+500	+3,350	-1,850	+888,000	+25,000	+151,000	-64,700	-577,000	-62,700	-947,700
1,100	680	1.016	+80,000	45	63,100	+1,000	+35,000	1,055	-	1,000	7,913	18,400	17,000	14,000	+125	+750	+1,600	-1,500	+450,000	+37,500	+72,000	-52,500	-385,000	+686,500	+236,500
-	-	1.0316	+123,000	-	64,200	+2,100	+73,500	-	-	950	8,034	12,600	17,450	9,560	+246	-5,050	+2,050	-5,940	+885,000	-252,000	+92,400	-208,000	-577,000	+1,021,900	+136,900
-	730	1.0316	+123,000	95	30,400	-31,700	-1,110,000	1,005	-	950	8,034	18,150	18,750	13,650	+246	+500	+3,350	-1,850	+885,000	+25,000	+151,000	-64,700	-577,000	+317,300	-567,700
1,050	680	1.0316	+123,000	45	64,200	+2,100	+73,500	1,005	-	950	8,034	18,150	18,750	13,650	+246	+500	+3,350	-1,850	+885,000	+25,000	+151,000	-64,700	-577,000	+1,500,800	+615,800

TABLE 7

PHASE ONE – SUMMARY FOR 1800 psig STEAM PRESSURE, SINGLE REHEAT

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Reactor Outlet Temp (°F)	Reactor Inlet Temp (°F)	$\frac{Q}{3.00 \times 10^9}$	Cost (+) or Savings (-) Due to Reactor Heat Load ($)	IHX ΔT_D (°F)	IHX Area (ft^2)	Change in IHX Area (ft^2)	Cost (+) or Savings (-) Due to Change in IHX Area ($)	Steam Gen Sodium Inlet Temp (°F)	Steam Gen Sodium Outlet Temp (°F)	Steam Temp Out of Steam Gen (°F)	Net Heat Rate Btu/kwh	Area HTM (ft^2)	Area LTM (ft^2)	Area Reheater (ft^2)	Change in NHR Btu/kwh	Change in Area HTM (ft^2)	Change in Area LTM (ft^2)	Change in Area Reheater (ft^2)	Valve of Diff H. R. Capitalize @14% and 20¢ Fuel ($)	Cost (+) or Savings (-) Due to Change in HTM Area @$55/ft^2 ($)	Cost (+) or Savings (-) Due to Change in LTM Area @$50/ft^2 ($)	Cost (+) or Savings (-) Due to Change in Reheater Area @ $35/ft^2 ($)	Incremental Cost (+) or Savings (-) in Turbine ($)	Total Evaluated Cost @7% Capital Charge Rate	Total Evaluated Cost @ 14% Capital Charge Rate
1150	700	-	-	45	60,600	-	-	1,105	655	1,050	7,606	17,580	16,100	14,710	-	-	-	-	-	-	-	-	-	-	-
-	-	1,014	+70,000	-	61,500	+900	+33,500	-	-	1,000	7,712	12,220	16,600	10,120	+106	-5,360	+500	-4,590	+381,600	-294,800	+25,000	-160,650	-385,000	+50,250	-331,350
-	-	1,031	+155,000	-	62,500	+1900	+66,500	-	-	950	7,842	9,330	17,100	8,030	+236	-8,250	+1,000	-6,680	+849,000	-453,750	+50,000	-233,800	-577,500	+705,600	-143,950
-	750	1,014	+70,000	95	29,200	-31,400	-1,100,000	1,055	-	1,000	7,712	17,600	17,800	14,250	+106	+20	+1,700	-460	+381,000	+1,100	+85,000	-16,100	-385,000	-583,000	-964,000
-	-	1,031	+155,000	-	29,600	-31,000	-1,085,000	-	-	950	7,842	12,100	18,450	10,190	+236	-5,480	+2,350	-4,520	+849,000	-301,400	+117,500	-158,200	-577,500	-151,600	-1,000,600
-	800	1,031	+155,000	145	19,400	-41,200	-1,442,000	1,005	-	950	7,842	17,700	19,900	14,150	+236	+120	+3,800	-560	+849,000	+6,600	+190,000	-19,600	-577,500	+10,500	-838,500
1100	700	1,014	+70,000	45	61,500	+900	+32,500	1,055	-	1,000	7,712	17,600	17,800	14,250	+106	+20	+1,700	-460	+381,000	+1,100	+85,000	-16,100	-385,000	+549,500	+168,500
-	-	1,031	+155,000	-	62,500	+1,900	+66,500	-	-	950	7,842	12,100	18,450	10,190	+236	-5,480	+2,350	-4,520	+849,000	-301,400	+117,500	-158,200	-577,500	+999,900	+180,900
-	750	1,031	+155,000	95	29,600	-31,400	-1,100,000	1,005	-	950	7,842	17,700	19,900	14,150	+236	+120	+3,800	-560	+849,000	+6,600	+190,000	-19,600	-577,500	+352,500	-496,500
1050	700	1,031	+155,000	45	62,500	+1,900	+66,500	1,005	-	950	7,842	17,700	19,900	14,150	+236	+120	+3,800	-560	+849,000	+6,600	+190,000	-19,600	-577,500	+1,519,000	+670,000

TABLE 8

PHASE ONE – SUMMARY FOR 2400 psig STEAM PRESSURE, SINGLE REHEAT

1 Reactor Outlet Temp (°F)	2 Reactor Inlet Temp (°F)	3 $\frac{Q_t}{3270 \times 10^6}$	4 Cost (+) or Savings (-) Due to Reactor Heat Load ($)	5 IHX ΔT_D (°F)	6 IHX Area (ft^2)	7 Change In IHX Area (ft^2)	8 Cost (+) or Savings (-) Due to Change In IHX Area @ 35/ft^2 ($)	9 Steam Generator Sodium Inlet Temp (°F)	10 Steam Generator Sodium Outlet Temp (°F)	11 Steam Temp Out of S. G. (°F)	12 Net Heat Rate (Btu/kwh)	13 Area Reheater (ft^2)	14 Area High Temp Module (ft^2)	15 Area Low Temp Module (ft^2)	16 Change In Area Reheater (ft^2)	17 Change In N. H. R. (Btu/kwh)	18 Change In Area HTM (ft^2)	19 Change In Area LTM (ft^2)	20 Value of Diff Heat Rate Capitalized @ 14% and 20¢ Fuel ($)	21 Cost (+) or Savings (-) Due to Change In HTM Area @ 60/ft^2 ($)	22 Cost (+) or Savings (-) Due to Change In LTM Area @ 50/ft^2 ($)	23 Cost (+) or Savings (-) Due to Change In Reheater @ 40/ft^2 ($)	24 Incremental Cost (+) or Savings (-) In Turbine ($)	25 Total Evaluated Cost @ 7% Cap. Charge Rate ($)	26 Total Evaluated Cost @ 14% Cap. Charge Rate ($)
1,150	750	1.00	-	45	66,000	-	-	1,105	705	1,050	7,216	17,100	16,900	18,150	-	-	-	-	-	-	-	-	-	-	-
-	-	1.013	+60,000	-	66,860	+860	+30,000	-	-	1,000	7,310	11,400	13,420	17,650	-5,700	+94	-3,480	-500	+368,000	-209,000	-25,000	-228,000	-415,000	-51,000	-419,000
-	-	1.028	+140,000	-	67,850	+1,850	+65,000	-	-	950	7,416	9,100	10,600	17,600	-8,000	+200	-6,300	-550	+785,000	-378,000	-27,500	-320,000	-615,000	+434,500	-350,500
-	800	1.013	+60,000	95	31,700	-34,300	-1,200,000	1,055	705	1,000	7,310	16,600	18,250	20,800	-500	+94	+1,350	+2,650	+368,000	+81,000	+132,500	-20,000	-415,000	-625,500	-993,500
-	-	1.028	+140,000	-	32,150	-33,850	-1,185,000	-	-	950	7,416	11,600	14,270	20,150	-5,500	+200	-2,630	+2,000	+785,000	-158,000	+100,000	-220,000	-615,000	-368,000	-1,153,000
-	850	1.028	+140,000	145	21,000	-45,000	-1,545,000	1,005	705	950	7,416	16,700	21,400	24,200	-400	+200	+4,500	+6,050	+785,000	+270,000	+302,000	-16,000	-615,000	+76,000	+709,000
1,100	750	1.013	+60,000	45	66,860	+860	+30,000	1,055	705	1,000	7,310	16,600	18,250	20,800	-500	+94	+1,350	+2,650	+368,000	+81,000	+132,500	-20,000	-415,000	+604,500	+236,500
-	-	1.028	+140,000	-	67,850	+1,850	+65,000	-	-	950	7,416	11,600	14,270	20,150	-5,500	+200	-2,630	+2,000	+785,000	-158,000	+100,000	-220,000	-615,000	+882,000	+97,000
-	800	1.028	+140,000	95	32,150	-33,850	-1,185,000	1,005	705	950	7,416	16,700	21,400	24,200	-400	+200	+4,500	+6,050	+785,000	+270,000	+302,000	-16,000	-615,000	+466,000	-319,000
1,050	750	1.028	+140,000	45	67,850	+1,850	+65,000	1,005	705	950	7,416	16,700	21,400	24,200	-400	+200	+4,500	+6,050	+785,000	+270,000	+302,000	-16,000	-615,000	+1,716,000	+931,000

TABLE 9

PHASE ONE – SUMMARY FOR 3500 psig STEAM PRESSURE, SINGLE REHEAT

1 Reactor Outlet Temp (°F)	2 Reactor Inlet Temp (°F)	3 $\frac{Q_t}{3\,270 \times 10^6}$	4 Cost (+) or Savings (-) Due to Reactor Heat Load ($)	5 IHX ΔT_D (°F)	6 IHX Area (ft^2)	7 Change in IHX Area (ft^2)	8 Cost (+) or Savings (-) Due to Change in IHX Area at $35/ft^2	9 Steam Gen Sod. Inlet Temp (°F)	10 Steam Gen Sod. Outlet Temp (°F)	11 Steam Temp From Sod. Gen. (°F)	12 Net Heat Rate Btu/kwh	13 Area High Temp Module (ft^2)	14 Area Low Temp Module (ft^2)	15 Area Reheater No. 1 (ft^2)	16 Area Reheater No. 2 (ft^2)	17 Change in Net Heat Rate (Btu/kwh)	18 Change in Area High Temp Module (ft^2)	19 Change in Area Low Temp Module (ft^2)	20 Change in Area Reheater No. 1 (ft^2)	22 Value of Differ. Net Heat Rate Capitalized at 14% and 20¢ Fuel ($)	23 Cost (+) or Savings (-) Due to Change in HTM Area at $60/ft^2 ($)	24 Cost (+) or Savings (-) Due to Change in LTM Area at $50/ft^2	25 Cost (+) or Savings (-) Due to Change in Reheater No. 1 Area at $40/ft^2 ($)	26 Cost (+) or Savings (-) Due to Reheater No. 2 Area at $35/ft^2 ($)	27 Incremental Cost (+) or Savings (-) in Turbine ($)	29 Total Evaluated Cost at 7% Cap. Charge Rate ($)	30 Total Evaluated Cost at 14% Cap. Charge Rate ($)
1,150	750	0.975	-125,000	45	64,350	-1,650	-57,800	1,105	705	1,050	7,039	14,700	20,150	15,100	20,900	-177	-2,200	+2,000	-2,000	-695,000	-132,000	+100,000	-80,000	+731,000	+712,500	-241,300	+453,700
-	-	0.986	-56,000	-	65,080	-920	-32,200	-	-	1,000	7,119	11,050	19,600	9,920	12,700	-97	-5,850	+1,450	-7,180	-381,000	-352,000	+72,600	-287,000	+445,000	+110,000	-861,600	-480,600
-	-	1.0015	+7,500	-	60,099	+99	+3,500	-	-	950	7,227	8,350	19,000	7,820	9,310	+11	-8,550	+850	-9,280	+43,200	-513,000	+42,500	-371,000	+326,000	-150,000	-568,100	-611,300
-	800	0.986	-56,000	95	30,800	-35,200	-1,230,000	1,055	705	1,000	7,119	15,520	22,600	14,500	19,200	-97	-1,380	+4,450	-2,600	-381,000	-83,000	+222,000	-104,000	+672,000	+110,000	-1,231,000	-850,000
-	-	1.0015	+7,500	-	31,300	-34,700	-1,215,000	-	-	950	7,227	11,520	22,400	10,000	12,100	+11	-5,380	+4,250	-7,100	+43,000	-322,000	+212,000	-284,000	+424,000	-150,000	-1,241,500	-1,284,500
-	850	1.0015	+7,500	145	20,500	-45,500	-1,590,000	1,005	705	950	7,227	17,680	26,800	14,450	18,100	+11	+780	+8,650	-2,650	+43,000	+46,800	+433,000	-106,000	+634,000	-150,000	-638,700	-681,700
1,100	750	0.986	-56,000	45	65,080	-920	-32,200	1,055	705	1,000	7,119	-	-	-	-	-97	-	-	-	-381,000	-83,000	+222,000	-104,000	+672,000	+110,000	-33,200	+347,800
-	-	1.0015	+7,500	-	66,099	+99	+3,500	-	-	950	7,227	-	-	-	-	+11	-	-	-	+43,000	-322,000	+212,000	-284,000	+424,000	-150,000	-23,000	-66,000
-	800	1.0015	+7,500	95	31,300	-34,700	-1,215,000	1,005	705	950	7,227	-	-	-	-	+11	-	-	-	+43,000	+46,800	+433,000	-106,000	+634,000	-150,000	-263,700	-306,700
1,050	750	1.0015	+7,500	45	66,099	+99	+3,500	1,005	705	950	7,227	-	-	-	-	+11	-	-	-	+43,000	+46,800	+433,000	-106,000	+634,000	-150,000	+954,800	+911,800

TABLE 10

PHASE ONE – SUMMARY FOR 3500 psig STEAM PRESSURE, DOUBLE REHEAT

OSTI ID: 000019184

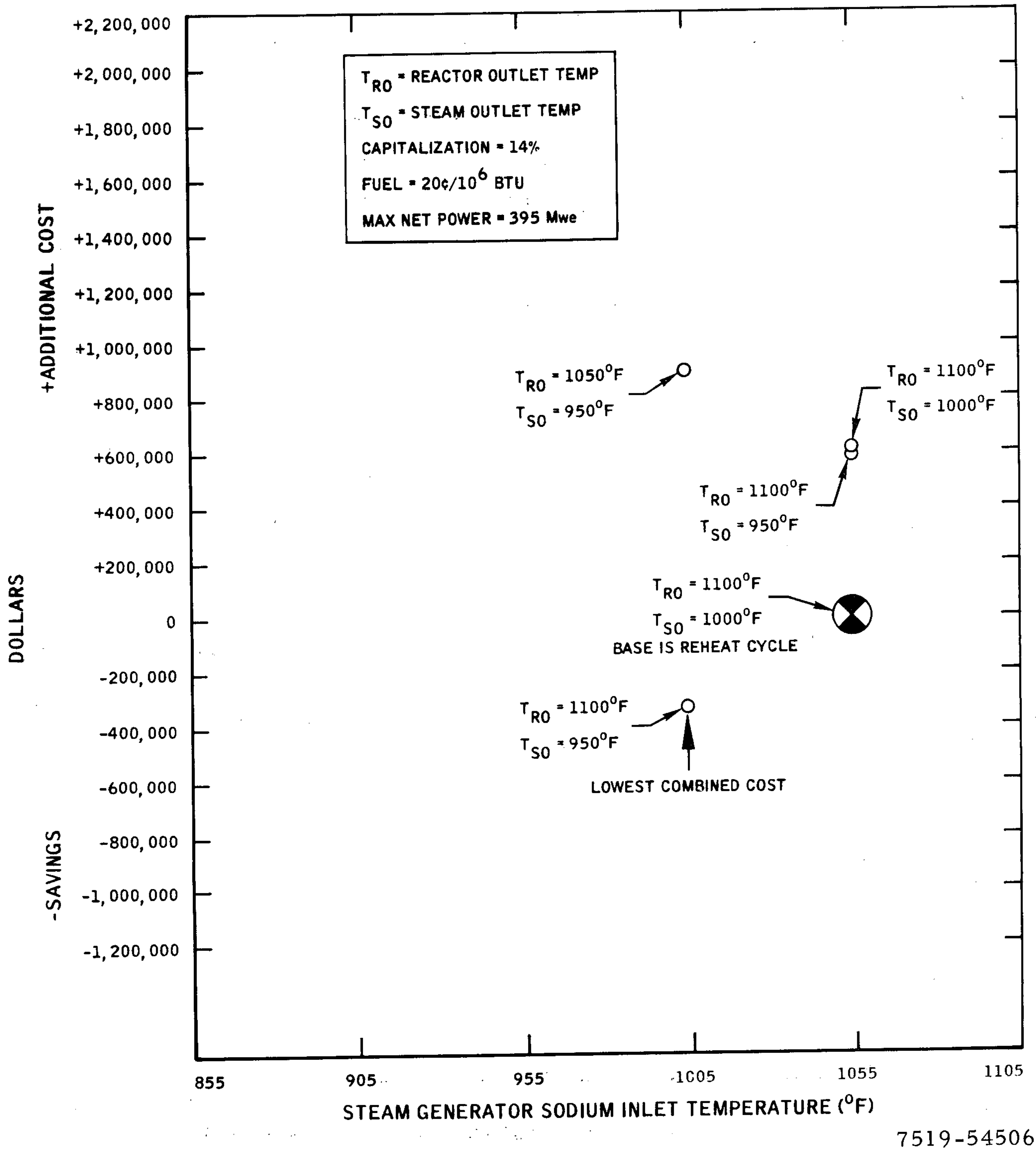


Figure 13. Phase-I Differential Costs for 1450-psig Nonreheat Steam Cycle at 14% Capital Charge Rate

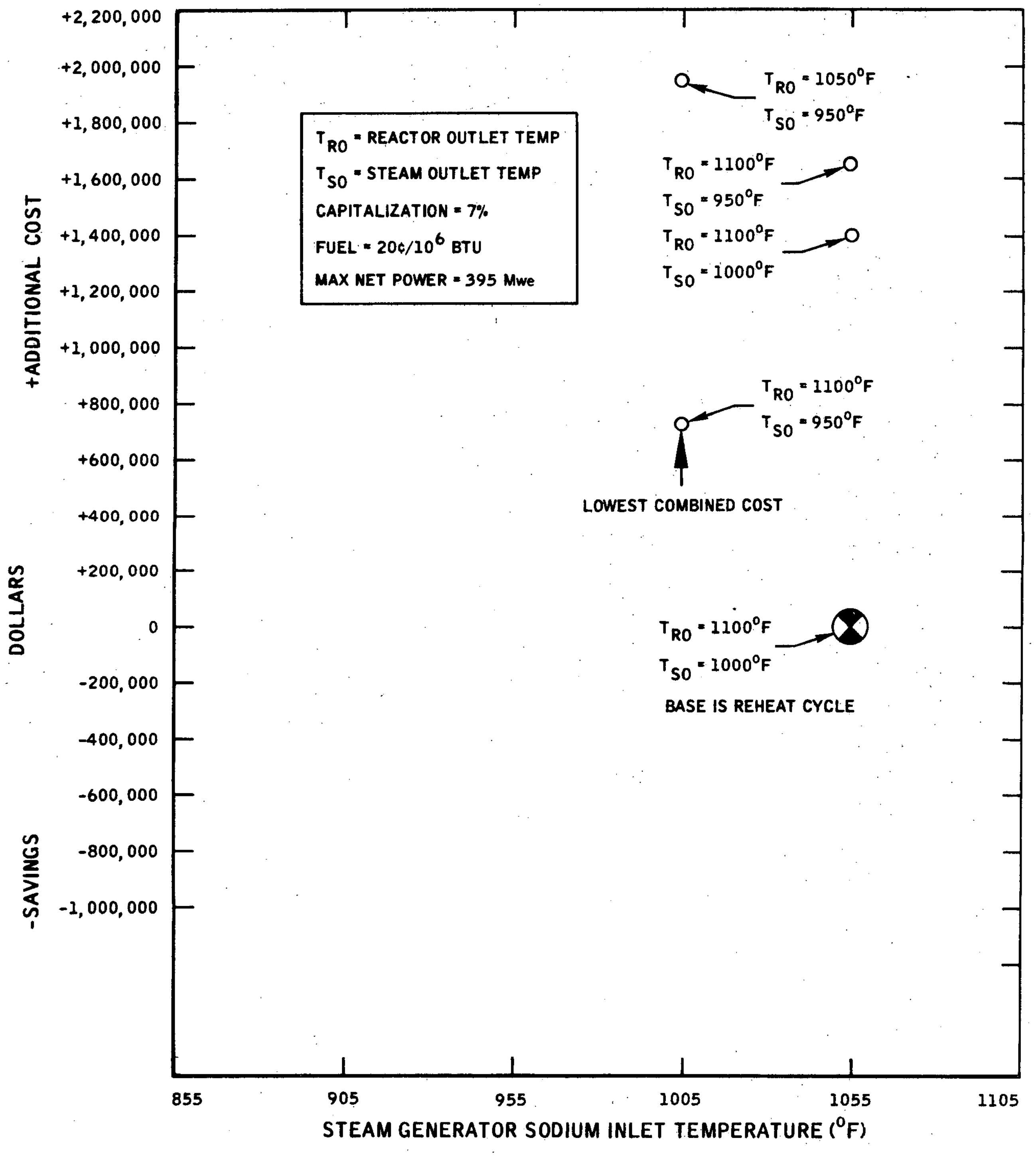
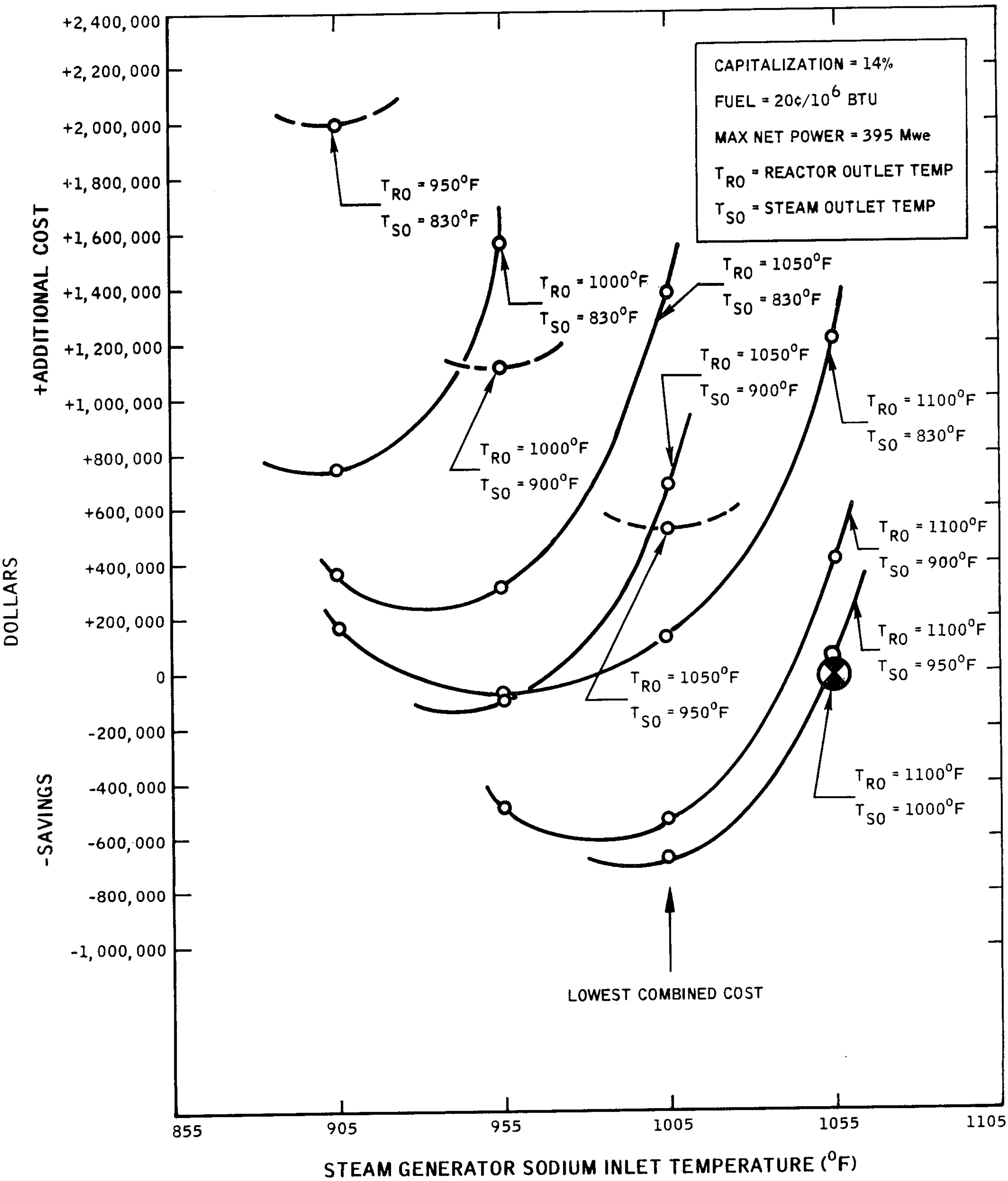
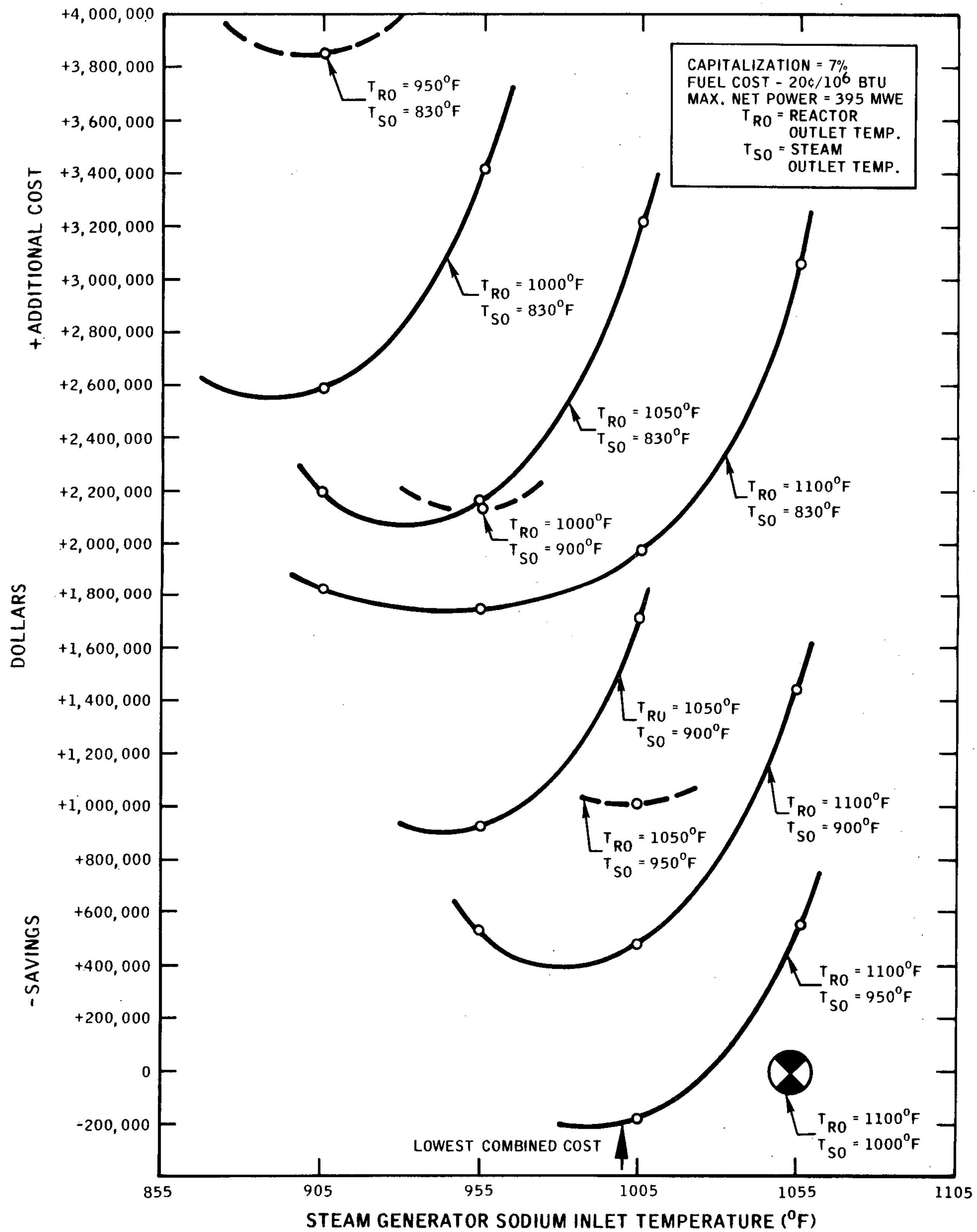


Figure 14. Phase-I Differential Costs for 1450-psig Nonreheat Steam Cycle at 7% Capital Charge Rate



7519-54508

Figure 15. Phase-I Differential Costs for 1450-psig Single-Reheat Steam Cycle at 14% Capital Charge Rate



7519-54509

Figure 16. Phase-I Differential Costs for 1450-psig Single-Reheat Steam Cycle at 7% Capital Charge Rate

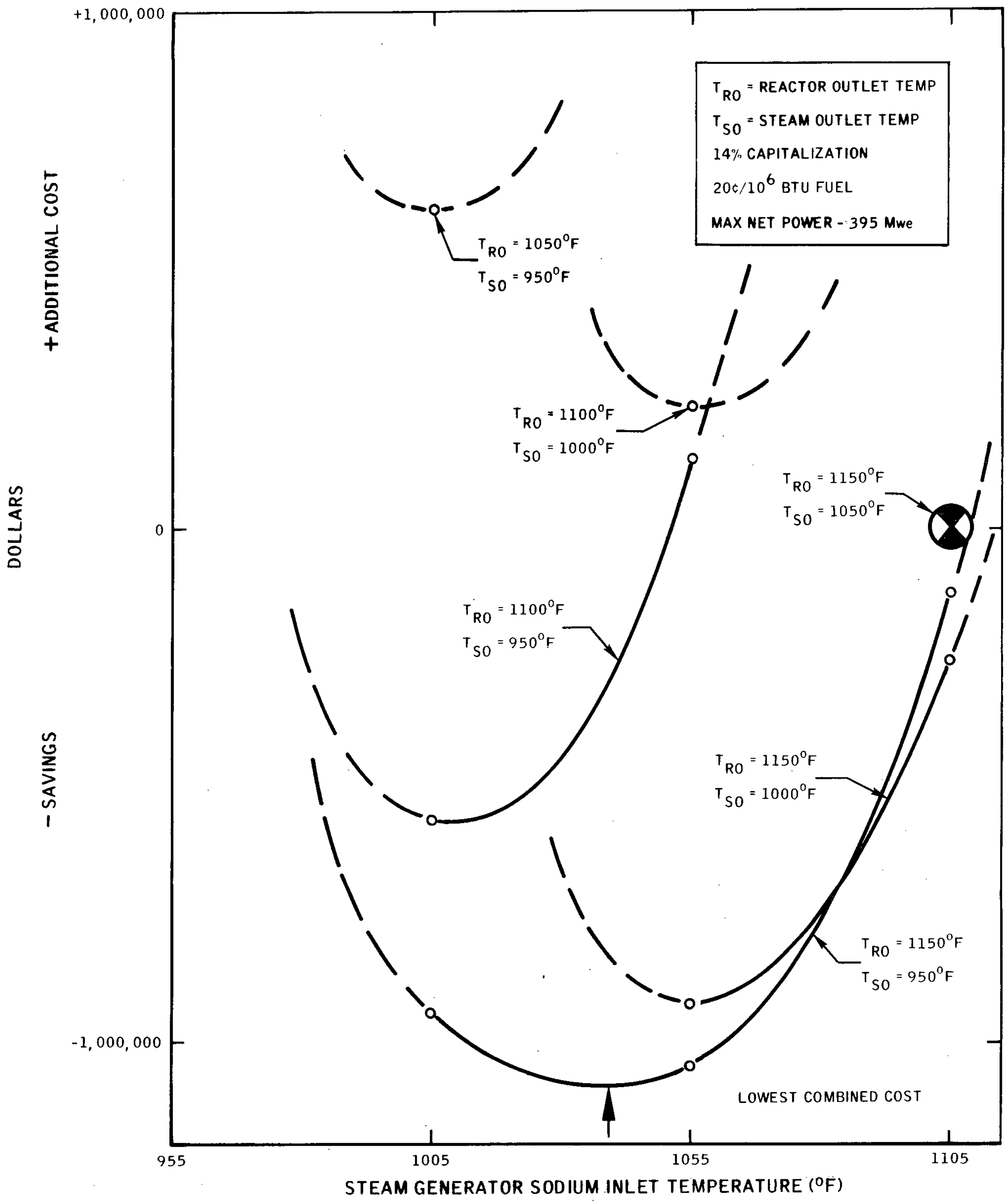


Figure 17. Phase-I Differential Costs for 1800 psig Single-Reheat Steam Cycle at 14% Capital Charge Rate

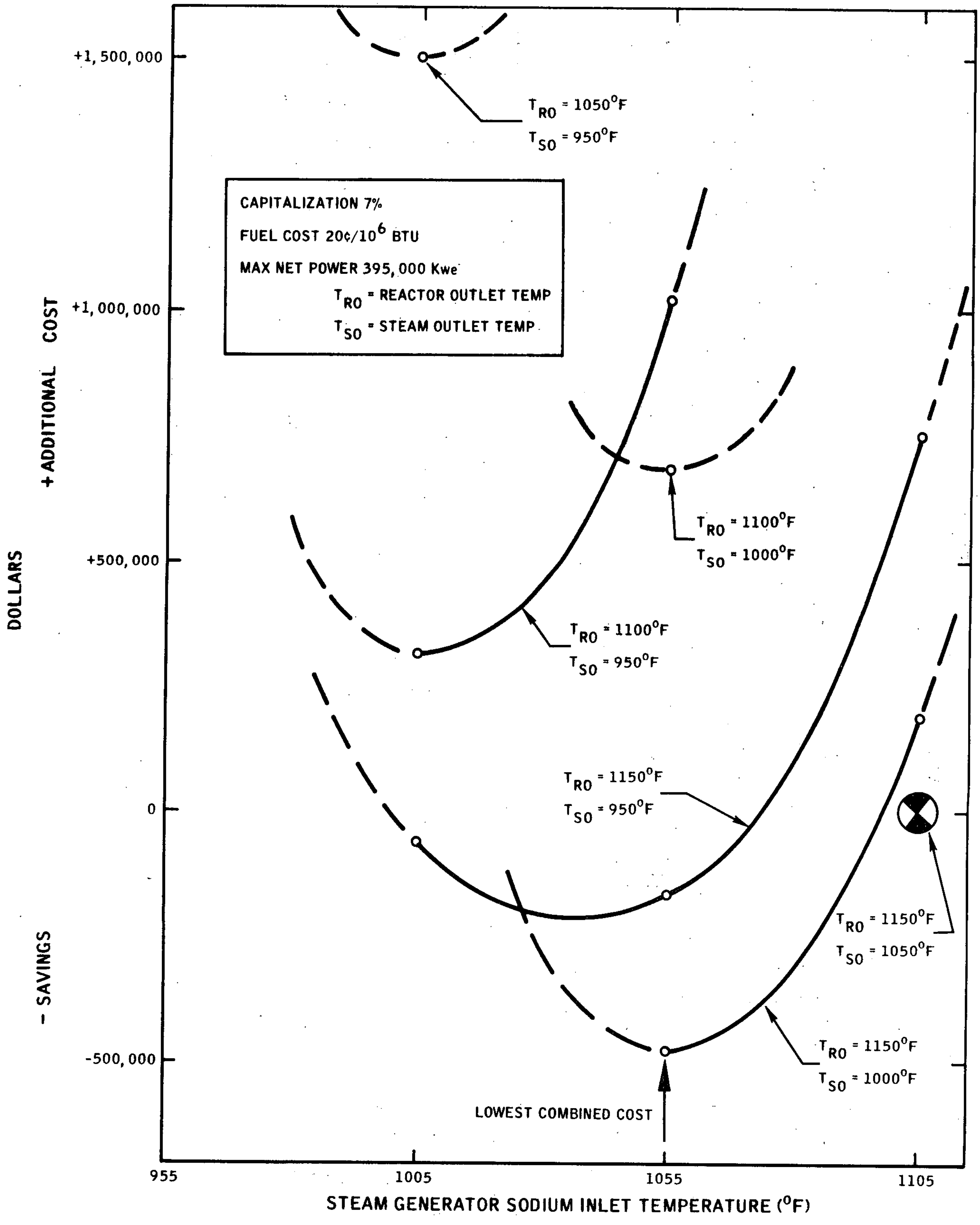
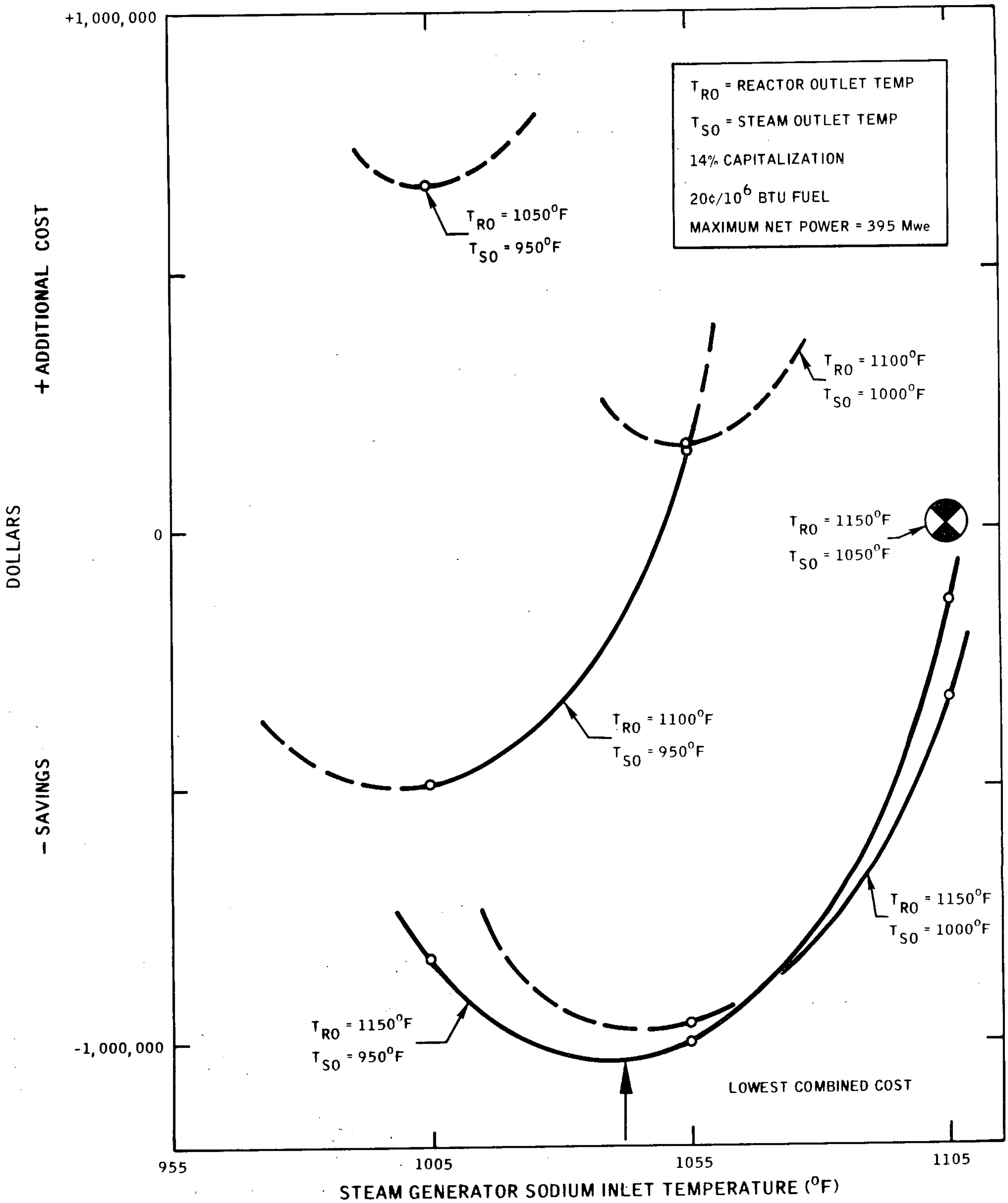
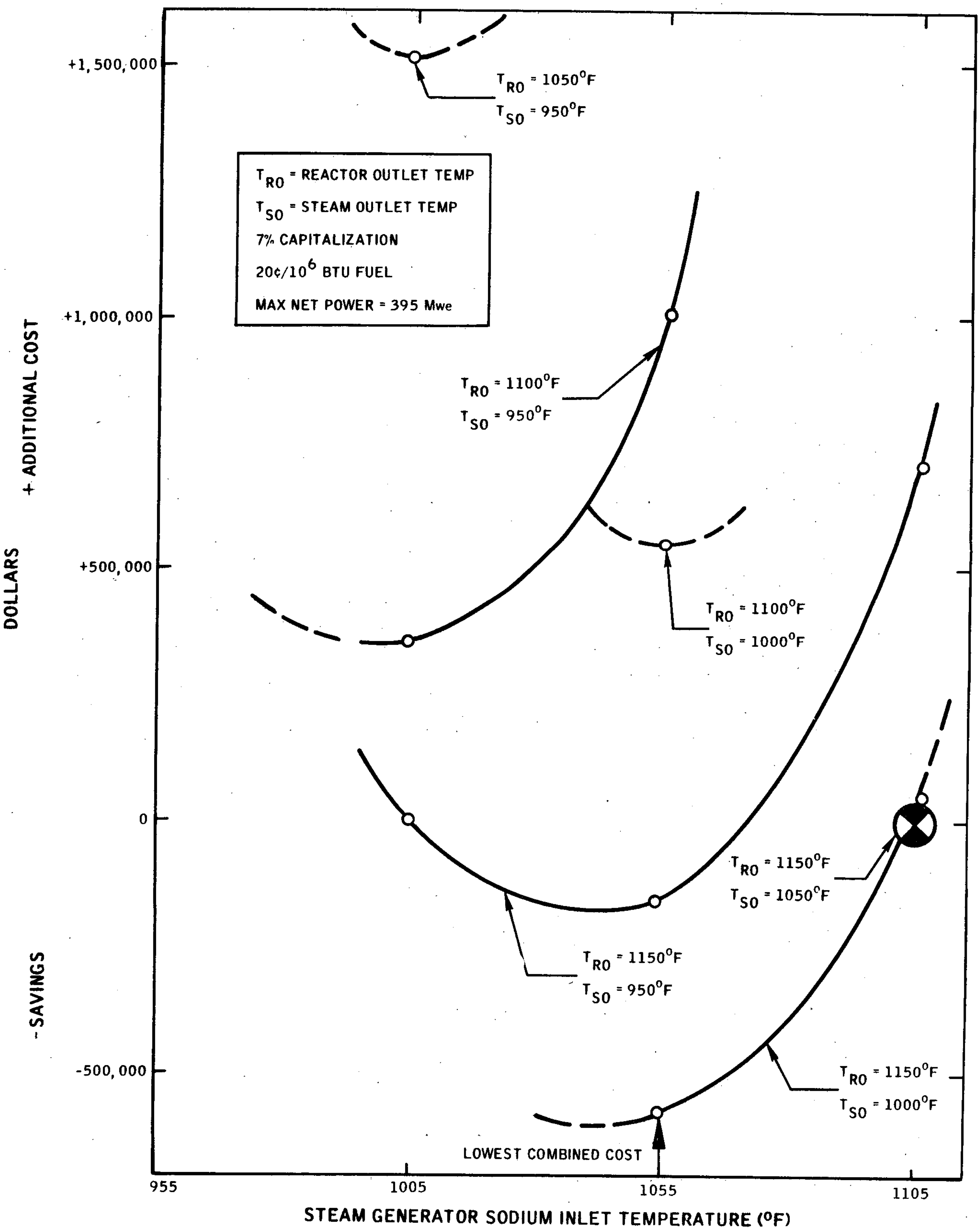


Figure 18. Phase-I Differential Costs for 1800-psig Single-Reheat Steam Cycle at 7% Capital Charge Rate



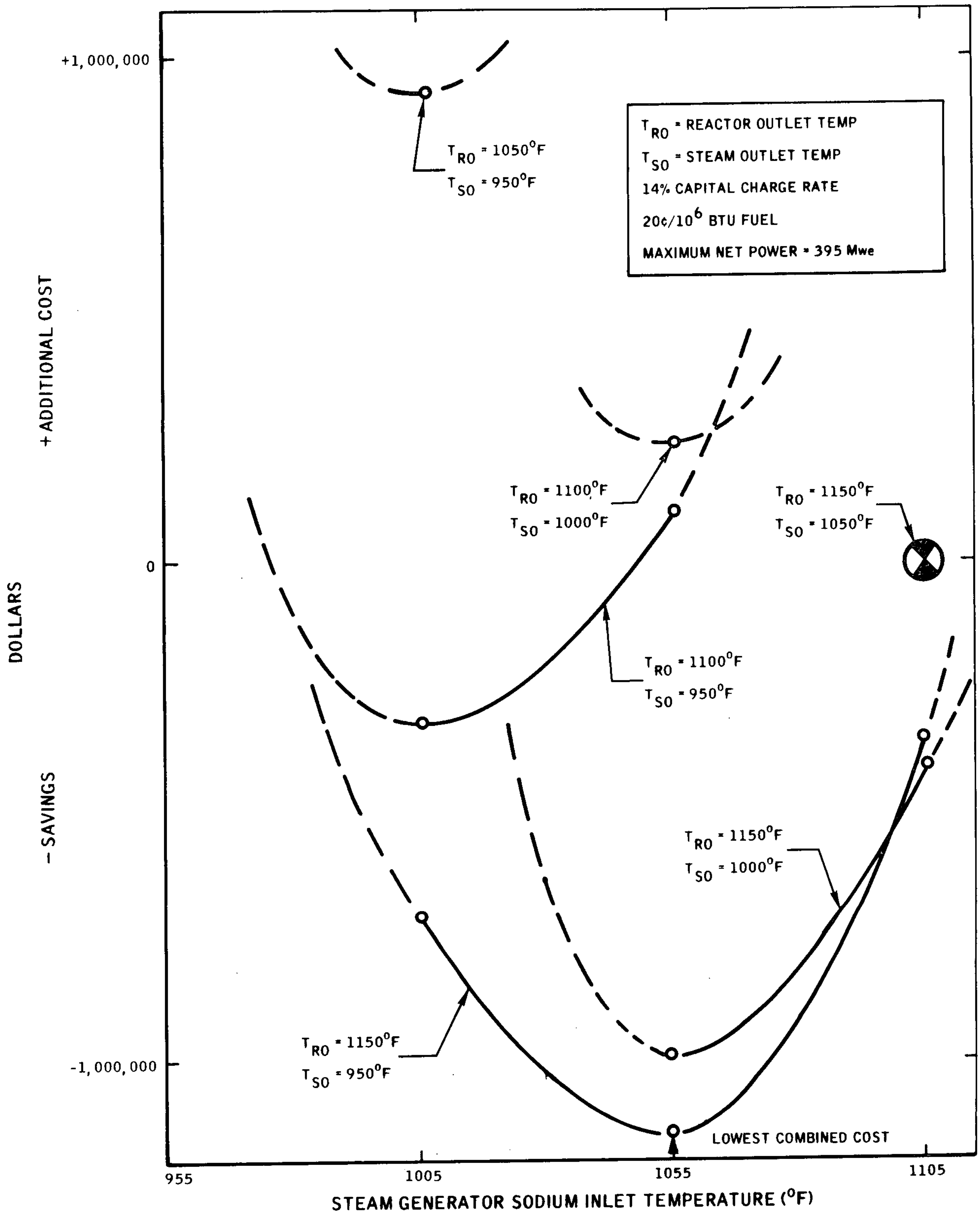
7519-54512

Figure 19. Phase-I Differential Costs for 2400-psig Single-Reheat Steam Cycle at 14% Capital Charge Rate



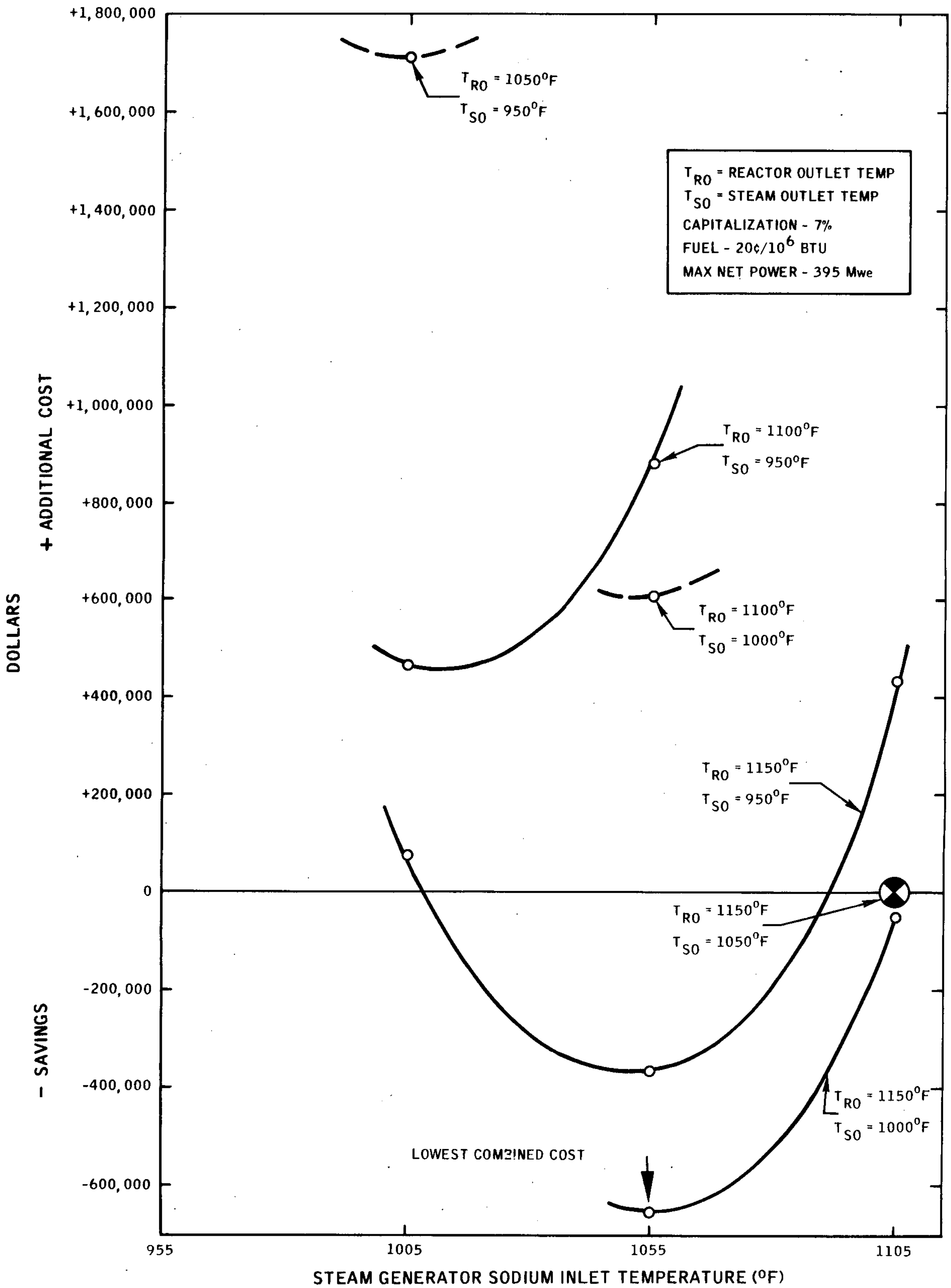
7519-54514

Figure 20. Phase-I Differential Costs for 2400-psig Single-Reheat Steam Cycle at 7% Capital Charge Rate



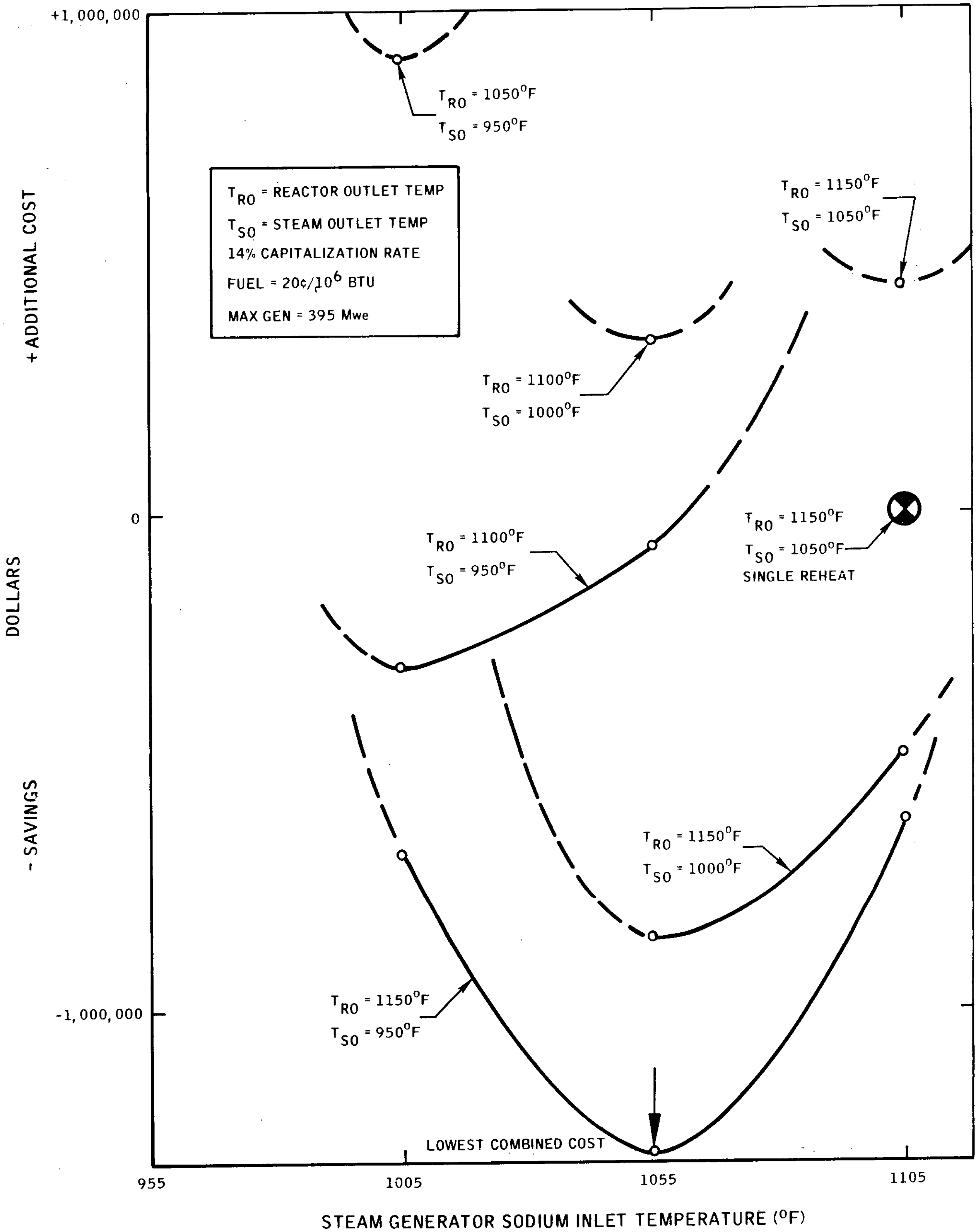
7519-54515

Figure 21. Differential Costs for 3500-psig Single-Reheat Steam Cycle at 14% Capital Charge Rate



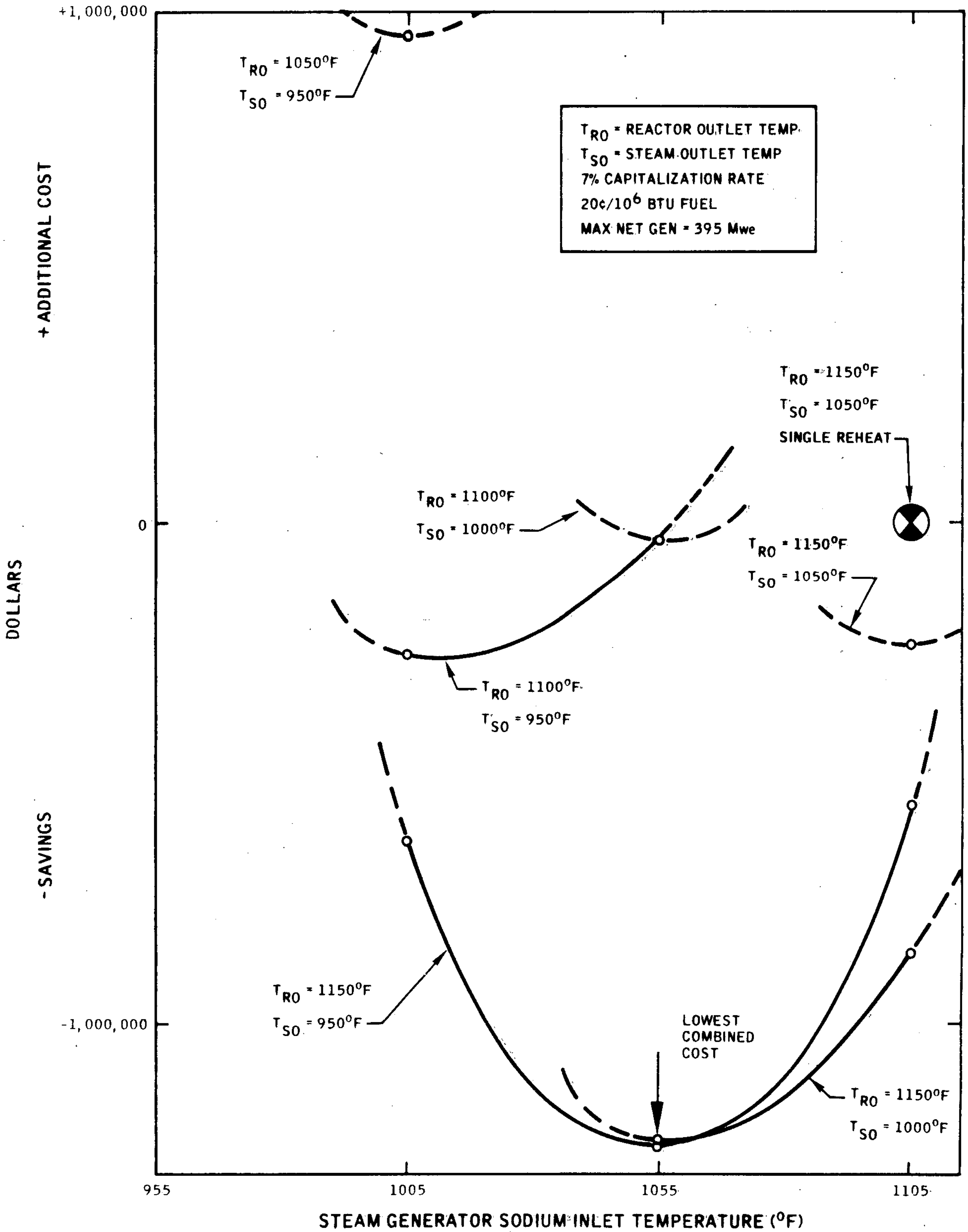
7519-54516

Figure 22. Phase-I Differential Costs for 3500-psig Single-Reheat Steam Cycle at 7% Capital Charge Rate



7519-54517

Figure 23. Phase-I Differential Costs for 3500-psig Double-Reheat Steam Cycle at 14% Capital Charge Rate



7519-54518

Figure 24. Phase-I Differential Costs for 3500-psig Double-Reheat Steam Cycle at 7% Capital Charge Rate

Capital Charge Rate	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	
	Steam Temp (°F)	Net Turbine Cycle Heat Rate Btu/kwhr	Reactor Power (Mw)	HTM Surface (ft^2)	LTM Surface (ft^2)	RHTR Surface (ft^2)	IHX Surface (ft^2)	HTM Diff. Surface (ft^2)	LTM Diff. Surface (ft^2)	RHTR Diff. Surface (ft^2)	IHX Diff. Surface (ft^2)	Heat Rate Diff. Btu/kwh	Value Heat Rate Diff. @ 20¢ Fuel ($)	HTM Diff. Cost @ $46/$ft^2$ ($)	LTM Diff. Cost @ $37/$ft^2$ ($)	RHTR Diff. Cost @ $35/$ft^2$ ($)	IHX Diff. Cost @ $35/$ft^2$ ($)	Total Exch Diff. Cost ($)	Turbine Cost TC4F-30" (x 10^3 $)	Turbine Diff. Cost ($)	Condenser Diff. Cost ($)	Steam Piping and Valving Diff Cost ($)	B. F. Pump Diff. Oper. Cost ($)	Reactor Δ$ Due to Heat Load ($)			Total Evaluated Cost ($)	
	1,050/1,050	7,620	1,019	26,200	21,600	17,150	48,600	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	10,275	Base	Base	Base	Base	Base			Base	
14%	1,000/1,000	7,732	1,034	16,420	22,700	11,290	49,500	-9,780	+1,100	-5,860	+900	+112	+448,000	-450,000	+40,700	-205,000	+31,500	-582,000	9,875	-400,000	+22,500	-315,000	+34,500	+80,000			-711,000	All IHX Drive = 65°F
	950/950	7,845	1,049	13,300	23,700	9,050	50,400	-12,900	+2,100	-8,100	+1,800	+225	+900,000	-594,000	+77,800	-283,500	+63,000	-737,000	9,675	-600,000	+42,300	-505,000	+67,500	+150,000			-682,000	
	1,050/1,050	7,620	1,019	30,700	22,580	19,900	42,200	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	10,275	Base	Base	Base	Base	Base			Base	
14%	1,000/1,000	7,732	1,034	18,600	23,700	12,200	42,900	-12,100	+1,120	-7,700	+700	+112	+448,000	-556,000	+41,500	-269,000	+24,500	-758,000	9,875	-400,000	+22,500	-315,000	+34,500	+80,000			-887,000	All IHX Drive = 75°F
	950/950	7,845	1,049	14,090	24,800	9,440	43,600	-16,610	+2,220	-10,460	+1,400	+225	+900,000	-765,000	+82,100	-366,000	+49,000	-1,000,000	9,675	-600,000	+42,300	-505,000	+67,500	+150,000			-945,000	
													$8,000/ΔH.R.						x 10^3 $ CC2F-43"									
	1,050/1,050	7, 543	1,009	26,200	21,600	17,150	48,600	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	10,805	Base	Base	Base	Base	Base			Base	
7%	1,000/1,000	7,655	1,025	16,420	27,700	11,290	49,500	-9,780	+1,120	-5,860	+900	+112	+896,000	-450,000	+40,700	-205,000	+31,500	-582,000	10,405	-400,000	+22,500	-315,000	+69,000	+80,000			-229,000	All IHX Drive = 65°F
	950/950	7,768	1,040	13,300	23,700	9,050	50,400	-12,900	+2,240	-8,100	+1,800	+225	+1,800,000	-594,000	+77,800	-283,500	+63,000	-737,000	10,205	-600,000	+42,300	-505,000	+135,000	+150,000			+285,000	
	1,050/1,050	7,543	1,009	30,700	22,580	19,900	42,200	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	10,275	Base	Base	Base	Base	Base			Base	
7%	1,000/1,000	7,655	1,025	18,600	23,700	12,200	42,400	-12,100	+1,120	-7,700	+700	+112	+896,000	-556,000	+41,500	-269,000	+24,500	-758,000	9,875	-400,000	+22,500	-315,000	+69,000	+80,000			-405,000	All IHX Drive = 75°F
	950/950	7,768	1,040	14,090	24,800	9,440	43,600	-16,610	+2,720	-10,460	+1,400	+225	+1,800,000	-765,000	+82,100	-366,000	+49,000	-1,000,000	9,675	-600,000	+42,300	-505,000	+135,000	+150,000			+22,000	

Basic Sodium Temperature for all cases
1. Reactor outlet temperature = 1150°F; inlet = 800°F
2. Reactor ΔT = 350°F

TABLE 11

PHASE THREE SUMMARY FOR 2400-psig STEAM PRESSURE, SINGLE REHEAT

TABLE 12. PHASE THREE SUMMARY FOR 3500 psig STEAM PRESSURE SINGLE REHEAT

Reactor Outlet Temp. (°F)	Reactor Inlet Temp. (°F)	$Q_t/3.408 \times 10^9$	Cost (+) or Savings (-) Due to Reactor Heat Load ($)	IHX ΔT_D (°F)	IHX Area (ft^2)	Change in IHX Area (ft^2)	Cost (+) or Savings (-) Due to Change in IHX Area at $35/$ft^2$	Steam Generator Sodium Inlet Temp. (°F)	Steam Generator Sodium Outlet Temp. (°F)	Steam Temp. Out of S. G. (°F)	Net Heat Rate at 14% Cap. Rate (Btu/kwh)	Reheater Area (ft^2)	Area High Temp. Module (ft^2)	Area Low Temp. Module (ft^2)	Change in Net Heat Rate (Btu/kwh)	Change in Reheater Area (ft^2)	Change in Area High Temp. Module (ft^2)	Change in Area Low Temp. Module (ft^2)	Value of Diff. Heat Rate Capitalized at 14% and 20¢ Fuel ($)	Cost (+) or Savings (-) Due to Change in H. T. M. Area at $50/$ft^2$ ($)	Cost (+) or Savings (-) Due to Change in LTM Area at $40/$ft^2$ ($)	Cost (+) or Savings (-) Due to Change in Reheater Area at $35/$ft^2$ ($)	Incremental Cost (+) or Savings (-) in Turbine ($)	Incremental Cost of Condenser ($)	Steam Piping + Valving Diff. Cost ($)	B. F. Pump Diff. Oper. Cost ($)	Change in Sodium Pumping Cost ($)	Total Evaluated Cost at 14% Cap. Charge Rate ($)	Net Heat Rate at 7% Cap. Rate (Btu/kwh)	Change in N. H. R. at 7% (Btu/kwhr)	Value of Diff. N. H. R. Cap. at 7% and Using 20¢ Fuel ($)	B.F. Pump Diff. Oper. Cost ($)	Change in Sodium Pump-ing Cost ($)	Total Evaluated Cost at 7% Cap. Charge Rate
1150	800	-	-	55	56,400	-	-	1,095	745	1,050	7,420	16,800	21,200	13,600	-	-	-	-	-	-	-	-	-	-	Base	Base	Base	-	7,343	-	-	Base	Base	Base
-	-	-	-	-	56,400	-	-	-	-	1,000	7,532	11,880	17,120	13,210	+112	-4,920	- 4,080	-390	+448,000	-204,000	-15,600	-172,000	-400,000	+7,200	-120,000	+38,000	-	-418,000	7,454	+111	+888,000	+76,000	-	+60,000
-	-	1.023	+115,000	-	57,700	+1,300	+45,500	-	-	950	7,645	9,780	13,780	11,800	+225	-7,020	- 7,420	-1,800	+900,000	-371,000	-72,000	-246,000	-600,000	+34,200	-320,000	+100,000	+14,000	-400,000	7,566	+223	+1,785,000	+200,000	+28,000	+599,000
-	750	-	-	-	56,400	-	-	-	695	1,050	7,420	16,800	19,480	20,750	-	-	- 1,720	+7,150	-	-86,000	+286,000	-	-	-	Base	Base	-69,500	+130,500	7,343	-	-	Base	-139,000	+61,000
-	-	-	-	-	56,400	-	-	-	-	1,000	7,532	11,880	14,710	20,080	+112	-4,920	- 6,490	+6,480	+448,000	-324,000	+259,000	-172,000	-400,000	+7,200	-120,000	+38,000	-69,500	-333,500	7,454	+111	+888,000	+76,000	-139,000	+75,000
-	-	1.023	+115,000	-	57,700	+1,300	+45,500	-	-	950	7,645	9,780	12,980	19,500	+225	-7,020	- 8,220	+5,900	+900,000	-411,000	+236,000	-246,000	-600,000	+34,200	-320,000	+100,000	-66,000	-216,000	7,566	+223	+1,785,000	+200,000	-132,000	+707,000
-	700	-	-	-	56,400	-	-	-	645	1,050	7,420	16,800	17,500	35,850	-	-	- 3,700	+22,250	-	-185,000	+890,000	-	-	-	Base	Base	-124,000	+581,000	7,343	-	-	Base	-248,000	+457,000
-	-	-	-	-	56,400	-	-	-	-	1,000	7,532	11,880	12,800	34,150	+112	-4,920	- 8,400	+20,550	+448,000	-420,000	+821,000	-172,000	-400,000	+7,200	-120,000	+38,000	-122,000	+80,000	7,454	+111	+888,000	+76,000	-244,000	+436,000
-	-	1.023	+115,000	-	57,700	+1,300	+45,500	-	-	950	7,645	9,780	10,430	32,500	+225	-7,020	-10,770	+18,900	+900,000	-538,000	+756,000	-246,000	-600,000	+34,200	-320,000	+100,000	-113,000	+134,000	7,566	+223	+1,785,000	+200,000	-226,000	+1,006,000
-	800	-	-	95	32,650	-23,750	-	1,055	705	1,050	7,420	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	32,650	-23,750	-831,000	-	-	1,000	7,532	14,800	17,600	22,900	+112	-2,000	- 3,600	+9,300	+448,000	-180,000	+372,000	-70,000	-400,000	+7,200	-120,000	+38,000	-	-736,000	7,454	+111	+888,000	+76,000	-	-258,000
-	-	1.023	+115,000	-	33,400	-23,000	-805,000	-	-	950	7,645	11,690	12,100	20,400	+225	-5,110	- 9,100	+6,800	+900,000	-455,000	+272,000	-179,000	-600,000	+34,200	-320,000	+100,000	+14,000	-924,000	7,566	+223	+1,785,000	+200,000	+28,000	+75,000
-	750	-	-	-	32,650	-23,750	-	-	655	1,050	7,420	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	32,650	-23,750	-831,000	-	-	1,000	7,532	14,800	15,450	37,600	+112	-2,000	- 5,750	+24,000	+448,000	-288,000	+960,000	-70,000	-400,000	+7,200	-120,000	+38,000	-69,500	-325,500	7,454	+111	+888,000	+76,000	-139,000	+83,000
-	-	1.023	+115,000	-	33,400	-23,000	-805,000	-	-	950	7,645	11,690	11,700	35,800	+225	-5,110	- 9,500	+22,200	+900,000	-475,000	+888,000	-179,000	-600,000	+34,200	-320,000	+100,000	-66,000	-408,000	7,566	+223	+1,785,000	+200,000	-132,000	+511,000
-	775	-	-	-	32,650	-23,750	-	-	680	1,050	7,420	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	32,650	-23,750	-831,000	-	-	1,000	7,532	14,800	16,700	28,600	+112	-2,000	- 4,500	+15,000	+448,000	-225,000	+600,000	-70,000	-400,000	+7,200	-120,000	+38,000	-35,000	-588,000	7,454	+111	+888,000	+76,000	-70,000	-145,000
-	-	1.023	+115,000	-	33,400	-23,000	-805,000	-	-	955	7,645	11,690	12,600	27,650	+235	-5,110	- 8,600	+14,050	+900,000	-430,000	+562,000	-179,000	-600,000	+34,200	-320,000	+100,000	-7,000	-630,000	7,566	+223	+1,785,000	+200,000	-14,000	+348,000

TABLE 12

PHASE THREE SUMMARY FOR 3500-psig STEAM PRESSURE SINGLE REHEAT

Reactor Outlet Temp (°F)	Reactor Inlet Temp (°F)	$\frac{Q_t}{3.295 \times 10^9}$	Cost (+) or Savings (-) Due to Reactor Heat Load ($)	I.H.X. ΔT_o (°F)	I.H.X. Area (ft^2)	Change In I.H.X. Area (ft^2)	($) Cost (+) or Savings (-) Due to Change in I.H.X. Area @$35/$ft^2$	(°F) Steam Generator Sodium Inlet Temp	(°F) Steam Generator Sodium Outlet Temp	Steam Temp Out of S.G. (°F)	Net Heat Rate (Btu/kwh)	Area Low Temp Module (ft^2)	Area High Temp Module (ft^2)	Area Reheater No. 1 (ft^2)	Area Reheater No. 2 (ft^2)	Change In Net Heat Rate (Btu/kwh)	Change In Area L.T.M. (ft^2)	Change In Area H.T.M. (ft^2)
1150	800	–	–	55	54,500	–	–	1095	745	1050	7210	14,420	18,500	13,920	27,050	–	–	–
–	–	1.0088	+ 44,000	–	55,000	+ 500	+ 17,500	–	–	1000	7322	14,050	14,400	8,850	15,580	+112	- 370	-4,100
–	–	1.0306	+153,000	–	56,100	+ 1,600	+ 56,000	–	–	950	7435	13,720	12,300	6,900	11,370	+225	- 700	-6,200
–	750	–	–	–	–	–	–	–	695	1050	7210	22,250	16,250	13,920	27,050	–	+ 7,830	-2,250
–	–	1.0088	+ 44,000	–	–	–	+ 17,500	–	–	1000	7322	21,600	12,360	8,850	15,580	+112	+ 7,180	-6,140
–	–	1.0306	+153,000	–	–	–	+ 56,000	–	–	950	7435	20,850	9,980	6,900	11,370	+225	+ 6,430	-8,520
–	700	–	–	–	–	–	–	–	645	1050	7210	39,200	15,600	13,920	27,050	–	+24,780	-2,900
–	–	1.0088	+ 44,000	–	–	–	+ 17,500	–	–	1000	7322	36,600	11,130	8,850	15,580	+112	+22,180	-7,370
–	–	1.0306	+153,000	–	–	–	+ 56,000	–	–	950	7435	34,800	8,740	6,900	11,370	+225	+20,380	-9,760
–	800	–	–	95	31,500	-23,000	-805,000	1055	705	1050	7210	–	–	–	–	–	–	–
–	–	1.0088	+ 44,000	–	31,800	-22,700	-795,000	–	–	1000	7322	24,600	14,680	11,320	20,200	+112	+10,180	-3,830
–	–	1.0306	+153,000	–	32,500	-22,000	-770,000	–	–	950	7435	23,800	11,250	8,030	13,200	+225	+ 9,380	-7,250
–	750	–	–	–	–	–	-805,000	–	655	1050	7210	–	–	–	–	–	–	–
–	–	1.0088	+ 44,000	–	–	–	-795,000	–	–	1000	7322	42,300	13,770	11,320	20,200	+112	+27,880	-4,730
–	–	1.0306	+153,000	–	–	–	-770,000	–	–	950	7435	39,900	9,400	8,030	13,200	+225	+25,480	-9,100
–	775	–	–	–	–	–	-805,000	–	680	1050	7210	–	–	–	–	–	–	–
–	–	1.0088	+ 44,000	–	–	–	-795,000	–	–	1000	7322	31,400	14,380	11,320	20.200	+112	+16,980	-4,120
–	–	1.0306	+153,000	–	–	–	-770,000	–	–	950	7435	30,100	10,390	8,030	13,200	+225	+15,680	-8,110

Reactor Outlet Temp (°F)	Reactor Inlet Temp (°F)	Change In Area Reheater No. 1 (ft^2)	Change In Area Reheater No. 2 (ft^2)	Value of Diff N.H.R. at 14% & 20¢ fuel ($)	Cost (+) or Savings (-) Due to Change in L.T.M. @ $40/$ft^2$ ($)	Cost (+) or Savings (-) Due to Change in H.T.M. @ $50/$ft^2$ ($)	($) Cost (+) or Savings (-) Due to Change in Reheater No. 1 Area @$40/$ft^2$	($) Cost (+) or Savings (-) Due to Change in Reheater No. 2 Area @ $35/$ft^2$	Cost (+) or Savings (-) in Turbine ($)	Cost (+) or Savings (-) in Condenser ($)	Steam Piping & Valving Diff Cost ($)	B.F. Pump Diff Oper Cost ($)	Change in Sodium Pumping Cost ($)	Total Evaluated Costs @ 14% Capital Charge Rate ($)	(Btu/kwhr) Heat Rate @ 7%	(Btu/kwh) Change in N.H.R. @ 7%	Value of N.H.R. @ 7% Capital 20¢ Fuel ($)	B.F. Pump Diff Oper Cost ($)	Change in Sodium Pumping Cost ($)	Total Evaluated Cost @ 7% Capital Charge Rate ($)
1150	800	–	–	–	–	–	–	–	–	–	Base	Base	Base	Base	7133	–	–	Base	Base	Base
–	–	-5,070	-11,470	+448,000	- 14,800	-205,000	-203,000	-401,000	-400,000	+12,600	-154,000	+ 45,000	+ 4,000	- 807,000	7244	+111	+ 888,000	+ 90,000	+ 8,000	-318,000
–	–	-7,020	-15,680	+900,000	- 28,000	-310,000	-281,000	-548,000	-600,000	+32,400	-384,000	+105,000	+ 17,000	- 888,000	7356	+223	+1,785,000	+210,000	+ 34,000	+116,000
–	750	–	–	–	+313,000	-112,500	–	–	–	–	Base	Base	- 69,000	+ 131,000	7133	–	–	Base	-138,000	+ 63,000
–	–	-5,070	-11,470	+448,000	+287,000	-307,000	-203,000	-401,000	-400,000	+12,600	-154,000	+ 45,000	- 61,000	- 672,000	7244	+111	+ 888,000	+ 90,000	-122,000	-248,000
–	–	-7,020	-15,680	+900,000	+257,000	-426,000	-281,000	-548,000	-600,000	+32,400	-384,000	+105,000	- 52,000	- 788,000	7356	+223	+1,785,000	+210,000	-109,000	+147,000
–	700	–	–	–	+990,000	-145,000	–	–	–	–	Base	Base	-118,000	+ 727,000	7133	–	–	Base	-236,000	+609,000
–	–	-5,070	-11,470	+448,000	+885,000	-367,500	-203,000	-401,000	-400,000	+12,600	-154,000	+ 45,000	-115,000	- 189,000	7244	+111	+ 888,000	+ 90,000	-230,000	+181,000
–	–	-7,020	-15,680	+900,000	+815,000	-488,000	-281,000	-548,000	-600,000	+32,400	-384,000	+105,000	-106,000	- 346,000	7356	+223	+1,785,000	+210,000	-212,000	+535,000
–	800	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
–	–	-2,600	- 6,850	+448,000	+407,000	-191,000	-104,000	-240,000	-400,000	+12,600	-154,000	+ 45,000	+ 4,000	- 923,000	7244	+111	+ 888,000	+ 90,000	+ 8,000	-434,000
–	–	-5,890	-13,850	+900,000	+375,000	-362,000	-235,500	-485,000	-600,000	+32,400	-384,000	+105,000	+ 17,000	-1,254,000	7356	+223	+1,785,000	+210,000	+ 34,000	-250,000
–	750	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
–	–	-2,600	- 6,850	+448,000	+1,116,000	-236,000	-104,000	-240,000	-400,000	+12,600	-154,000	+ 45,000	- 61,000	- 324,000	7244	+111	+ 888,000	+ 90,000	-122,000	+100,000
–	–	-5,890	-13,850	+900,000	+1,020,000	-455,000	-235,500	-485,000	-600,000	+32,400	-384,000	+105,000	- 52,000	- 766,000	7356	+223	+1,785,000	+210,000	-104,000	+164,000
–	775	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
–	–	-2,600	- 6,850	+448,000	+678,000	-206,000	-104,000	-240,000	-400,000	+12,600	-154,000	+ 45,000	- 30,000	- 701,000	7244	+111	+ 888,000	+ 90,000	- 60,000	-246,000
–	–	-5,890	-13,850	+900,000	+626,000	-405,500	-235,500	-485,000	-600,000	+32,400	-384,000	+105,000	- 19,000	–	7356	+223	+1,785,000	+210,000	- 38,000	-115,000

TABLE 13

PHASE THREE SUMMARY FOR 3500-psig STEAM PRESSURE, DOUBLE REHEAT

OSTI ID: 00019184

APPENDIX B
NOMENCLATURE

A = heat exchanger surface in ft^2

Q = duty in Btu/hr = W Cp $(T_1 - T_2)$ = $W(h_1 - h_2)$

W = fluid flow in lb/hr

C_p = fluid specific heat in Btu/lb-°F

h = fluid enthalpy in Btu/lb

LMTD = log mean temperature difference in °F where

$$\mathrm{LMTD} = \frac{\mathrm{GTTD} - \mathrm{LTTD}}{\log_e \dfrac{\mathrm{GTTD}}{\mathrm{LTTD}}}$$

GTTD = exchanger greatest terminal temperature difference $T_1 - t_1$

LTTD = exchanger least terminal temperature difference $T_2 - t_2$

APPENDIX C
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