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Economies of Scale in the Production of Steam with Solar Thermal-Fossil Boiler Hybrid Systems

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ECONOMIES OF SCALE IN THE PRODUCTION OF STEAM WITH SOLAR THERMAL-FOSSIL BOILER HYBRID SYSTEMS

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ABSTRACT

Levelized energy costs for steam plants in the size range 15 MMBtu/hr to 400 MMBtu/hr have been estimated for steam produced by several different technologies, including stand-alone oil and coal-burning plants as well as solar central receiver - fossil boiler hybrid plants. Models for the costs of plant subsystems used in these calculations are presented and discussed. Designs of the solar-fossil hybrids examined were optimized with respect to solar fraction and amount of thermal storage used by simulation of plant operation. The resulting levelized energy costs and their sensitivity to various modelling parameters are presented and discussed.

ACKNOWLEDGEMENTS

The development of this study has been greatly assisted by a number of people. The computer code used for optimization of the solar-fossil hybrid plants was originally written by Joe Iannucci and subsequently modified by Scott Faas and Brent Haroldsen (all SNLL) prior to our use of it.

Conversations with Richard Barnes, E. C. Fox (both ORNL), Val Greaves (SERI), Mary Kelly (Radian Corp), Emily Madine (EEA), and Tom Ponder (Ped Co) were invaluable in providing an understanding of the useage and costing of fossil-fueled industrial boilers.

Also, discussions with Jon Pohl, Reggie Mitchell, Don Hardesty, Cliff Yokomizo, and Jose Martin helped define the original scope of this study.

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Executive Summary

Nearly 10% of the energy consumed in the United States today is used for the production of steam in industry. Virtually all of the boilers in use produce steam in a temperature (<1000F) and pressure (<1000 psia) regime accessible to current solar thermal technologies. The existing boiler population is fired primarily by natural gas and oil (50% and 18% of the total U.S. steam capacity, respectively), fuels which are becoming increasingly more expensive. Furthermore, deregulation of the price of natural gas and legislative restriction of its use for firing new boilers will help force a shift away from the current fuels and technologies. These economic pressures will dictate the use of alternate fuels (e.g. coal), advanced technologies (e.g. solar), or both (e.g. atmospheric fluidized bed coal combustors) in steam systems installed in the near future. In this study, we have estimated the levelized energy cost (LEC) of steam from boilers using these competing technologies, and considered how it might vary with steam plant size.

In order to calculate LEC for steam from the various types of systems considered, it was necessary to establish cost models for both capital and operation and maintenance (O&M) costs across the size range of interest (15 MMBtu/hr - 400 MMBtu/hr). To develop these cost models, we have considered a wide variety of factors which will influence price for both stand-alone fossil boilers and solar central receiver systems. In order to meet the load curves typical in industry (24 hours per day, 7 days per week), it was necessary to use solar central receiver systems hybridized with fossil-fired boilers. We used these cost models in a computer program to optimize the solar hybrid steam plant designs (and minimize LEC) through an hour-by-hour simulation of plant operation.

Fossil Boiler Considerations--Industrial boilers may be classified according to four criteria: (1) mode of heat transfer, (2) type of construction, (3) fuel type, (4) type of fuel feed. Each of these features affects the capital cost of the installed boiler. There are three common types of boiler heat transfer technology, but we have limited our attention to the "water-tube" boilers in which the flame in a combustion chamber is used to heat water contained in tubes. This boiler type predominates in the industrial boiler population and a large body of cost data exists for it.

Depending on size, boilers may be constructed in factories (package boilers) or erected at the construction site (field erected). We have used each type in the appropriate size range. Fuel type affects the size of the boiler with the less physically dispersed fuels requiring larger (and more expensive) boilers, e.g. coal, being less dispersed than oil or gas, requires a longer residence time and more excess oxygen to burn to completion, and so requires a larger boiler. Finally, for coal fired boilers, a large number of different ways to feed the fuel into the combustion chamber exist. The most important distinction here is probably the difference between burning sized lumps of coal (stoker coal) or burning finely pulverized coal. Different types of fuel feed are most economical over different boiler size ranges.

Fuel Considerations--Obviously, delivered cost of fuel is an important consideration. The pricing of natural gas and oil (assuming price deregulation) is straightforward since the price of these fuels is relatively independent of boiler size and location. This is not ture for coal. Coal is a quite heterogeneous material having a large number of parameters which affect its use as a fuel. However, for our purposes, three properties (heating value, ash content, and sulfur content) are most important. These properties affect such things as boiler size, fuel and ash handling, and pollution control costs. For this study, we have assumed a "representative" coal with properties similar to those of coals available throughout the Southwestern United States (a heating value of 11,500 Btu/lb, 0.4% sulfur, and 9% ash). Our representative coal is fairly typical except that it has a relatively low sulfur content. This assumption is for pollution control reasons.

Transportation costs can represent a significant fraction of the delivered price of coal. For this study we have assumed the steam plant to be 500 rail miles from the mine mouth. This distance is sufficient to allow coal with the properties of our representative coal to be shipped to virtually anywhere in the Southwest. Certain other coal price premiums must be paid by the smaller steam plants in this study. These include a sizing premium for stoker coal and a unit car load shipping premium for those plants too small to buy coal by the unit trainload.

Environmental Considerations--A wide variety of federal and state regulations govern the emission of pollutants from industrial boilers. The pollutants of principle concern are oxides of sulfur (SO_x), oxides of nitrogen (NO_x), and particulate matter (PM). We have considered two levels of control. The less stringent level is sufficient to meet current regulated levels in all states except California. The stricter control level will meet California levels or else represents the best available control technology. At the lower level, no NO_x or SO_x controls are needed (in part due to the use of low sulfur coal), while particulate matter is controlled with fabric filters. At the more stringent control level, SO_x is controlled by flue gas desulfurization (for plants >30 MMBtu/hr), PM is controlled with filters, and NO_x control is accomplished through modifications of the combustion process.

Costs for Fossil-Fired Boilers--The Environmental Protection Agency has recently funded a number of studies of the costs associated with building and operating fossil fuel-fired boilers. The costs used in this report are based on the results of those studies. Capital costs have been adjusted using multiplication factors which reflect a reduced cost for construction as part of a process plant and 35% indirect loading. We found operation and maintenance costs (O&M) of fossil boilers to be a major part of the LEC for these systems. Annual O&M costs for a coal-fired boiler lie in the range 12-25% of installed capital cost in the boiler size range of this study. Gas-fired boilers have an annual O&M cost in the range 24-54%. These numbers compare with the 2% of installed capital cost figure often quoted in electric power generation. Furthermore, O&M costs exhibit significant economies of scale with specific costs increasing dramatically as boiler size decreases. All cost figures were adjusted to reflect 1981 dollars.

Advanced Fossil Technologies--In the time frame of interest in this study (i.e. plant operational in 1990), it appears that only one advanced fossil combustion technology would be in a state of development to significantly impact the U.S. boiler market. This is the atmospheric fluidized bed (AFB) combustor. Costs for the AFB were found to be quite similar to those of conventional coal-fired systems, with the exception that in-bed sulfur capture in the AFB eliminated the extra costs associated with flue gas desulfurization (FGD).

Solar Central Receiver System Costs--Unlike conventional fossil boiler technologies, solar central receiver (SCR) systems represent an advanced technology. As a result, there is little hard cost data available for use in predicting energy costs for such systems. However, previous studies in which SCR's have been designed and costed out can be used in the development of cost models. In particular, in one recent study, referred to as the February Study [9], SCR systems in the size range 10-5100 MMBtu/hr were examined. In a group of studies known collectively as the "repowering studies" [38] design data and cost figures for a number of central receiver systems in the size range 30-1000 MMBtu/hr are presented. We have used the cost figures presented in these studies to develop cost models for both capital and O&M costs for the various subsystems in a solar central receiver steam system.

The heliostat (mirror) field represents the most expensive subsystem of an SCR steam plant. Heliostat costs are usually quoted as a cost per unit area of mirror surface. For the systems examined in these studies the mirror area required per unit power output at the base of the receiver tower is nearly constant. This is true in spite of different geographical locations (within the Southwestern U.S.), mirror field geometries, receiver types, heat transfer media, etc. As a consequence, we have considered the specific cost of the heliostat subsystem to be independent of plant size across the size range of interest. We have used an "nth" plant heliostat cost (1981$) of $\$93.50/m^2$ of mirror area.

An examination of the receiver subsystem costs in the two studies reveals an interesting qualitative difference in specific cost trends. The February Study shows a specific capital cost which is independent of steam plant size. However, the repowering studies indicate that the specific cost of the receiver subsystem will increase as steam plant size decreases. In the size range of interest, receivers operating with steam conditions similar to those used here exhibit specific capital costs which decrease linearly with the logarithm of the rated output power. We have no technical reason to reject either of the two models presented by these studies, so we have chosen to consider a capital cost "band" for the receiver subsystem defined by these two approaches.

Thermal energy storage is not treated in the February Study nor in many of the repowering studies. As a result, we found it necessary to calculate the cost of storage by considering its cost explicitly with a simulation and optimization program.

Costs of land, buildings, controls, etc. are lumped into a so-called balance-of-plant (BOP) cost. We found that the specific BOP capital cost as reported in the various studies is also essentially independent of rated design point output power.

In summary, the total specific capital costs reported in the studies examined obey one of two cost models. In one, the capital cost per unit of design point power output is independent of plant size; in the other, these capital costs decrease linearly with the increase in the logarithm of the power rating over the size range of interest in this study. We have used these models to define a total installed specific capital cost "band".

Annual operation and maintenance costs from these studies (expressed as a percentage of installed capital cost) fall near one of two figures. Some reported annual O&M costs lie near 2% of the total capital costs, while others fall closer to 5%. Because of the unexpectedly high O&M costs found for the fossil boilers, we chose to use the higher figure in the present analysis.

Solar-Fossil Hybrid Steam Plants--The design details of a steam plant are quite dependent upon the pressure and temperature requirements of the delivered steam. However, steam conditions are roughly related to steam plant size; so we can define representative plant sizes and steam conditions. Across the size range of interest here, we have used six different size-steam condition combinations (see Table i). For each plant size, four different solar-fossil hybrid plants were designed conceptually. Two designs used natural gas-fired fossil systems, while the other two used coal-fired systems. For hybrid plants where no thermal storage was employed, water/steam receivers were used in parallel with the fossil-fired boiler. For those plants in which thermal storage was used, the fossil-fired boiler was modified for use as a fluid heater. The particular heat transfer fluid used (molten nitrate salt or high temperature oil) depended on the steam temperature desired. The fluid heater was used in parallel with the SCR. Table i lists the configurations of the hybrid steam systems used. Costs for the hybrid steam plant were assumed to be the sum of the costs of the two parts with appropriate allowance made for duplication in the parts.

Plant Simulation and Optimization--In order to optimize steam plant design (and so minimize the levelized energy cost of the steam produced) energy costs are calculated from an hour-by-hour simulation of plant operation. The optimal, i.e. most cost effective, amount of thermal storage needed is calculated for nine different solar multiples (SM=0 gives LEC for the stand-alone fossil plant).

TABLE i

CONFIGURATION OF THE HYBRID STEAM GENERATION SYSTEMS CONSIDERED

Q (MMBtu/hr)	Steam Conditions (°F, PSIG)	(Modified) Gas Boiler Type	(Modified) Coal Boiler Type	Solar Receiver w/Storage	System Type w/o storage
15	365, 150	package	package underfeed stoker	oil (caloria)	water/steam
30	365, 150	package	package underfeed stoker	oil (caloria)	water/steam
75	365, 150	package	field erected spreader stoker	oil (caloria)	water/steam
150	600, 450	package	field erected spreader stoker	molten nitrate salt	water/steam
200	750, 750	multiple package	field erected pulverized coal	molten nitrate salt	water/steam
400	750, 750	multiple package	field erected pulverized coal	molten nitrate salt	water/steam

In order to compare the sensitivity of the cost of steam to our initial assumptions, we have defined a "base case" scenario and examined how changes in various parameters affect the observed results. In all comparisons, LEC's for both coal and gas-fired stand alone boilers were compared with those of both coal and gas-solar hybrid plants. Energy costs for each of these steam plants at each of the six sizes of Table i were calculated.

Sensitivity of LEC to variations in eight different parameters was investigated. The parameters and the variations examined are listed in Table ii. Each of these variations was applied separately to the base case scenario.

Figure A shows the LEC of steam from the various boiler plants considered as a function of plant size under base case assumptions. The cost bands shown are a result of the cost band used in modelling the SCR capital costs. The solar hybrid costs shown are those of the optimum system at each of the sizes considered, unless the system optimizes at a solar multiple of zero, in which case the hybrid LEC shown is of the system with a minimum energy cost at a solar multiple of 0.75 (a plant with this solar multiple uses solar energy to provide most of its daytime energy requirements).

Results and Conclusions--A number of conclusions can be drawn from the base case analysis presented in Figure A. First, of the steam plant configurations examined, the coal-fired stand-alone boiler produces steam for the lowest LEC, while steam from a gas-fired stand-alone boiler has the highest LEC. The two hybrid systems fall somewhere between these extremes. Of interest is the fact that while the LCE of the hybrids seldom is less than that of the coal stand-alone boiler, the coal hybrids usually have an LEC only about 10-15% greater than that of the coal boiler over the size range studied. Also, the LEC's of the four systems presented exhibit very similar variations with plant size so that their relative ranking by LEC does not change.

In general, variations on this base case had little affect on these general trends. Less stringent pollution controls reduced the LEC for the larger coal and coal hybrid plants, but in nearly equal amounts. Higher fuel prices improved the relative position of the hybrid plants, but even so, the coal stand-alone still had the lowest LEC. Variations in capital and O&M costs also gave little qualitative change. The use of AFB coal combustors affected both coal and coal hybrid plants equally, allowing them to meet the stricter pollution control levels at a lower cost than the conventional coal-fired systems, but again, the affect was not large. It was possible to provide steam from the hybrid plants at a lower cost than from the coal stand-alone boiler for other than 4-shift load curves. This is a result of concentrating steam demand in the daylight hours; but such load curves are not typical in industry.

In general the levelized energy cost trends shown for the base case scenario of Figure A were not notably affected by changes in the parameters of Table ii nor was the optimum hybrid design. We conclude that while the LEC of steam from the solar-fossil hybrid steam plants are not lower than that of the conventional coal-fired boiler, they are still quite close--perhaps close enough for non-economic considerations to make the solar energy based system more attractive than the conventional fossil-fired plant.

TABLE ii

THE STUDY MATRIX

Parameter Variations*	Fossil Captial Costs	Coal Boiler Type	O & M Costs	Pollution Control	Fuel Costs	Load	Solar Capital Costs	Heliostat Subsystems Costs
Base Case	As presented in Section 9.1	Conventional	As presented in Section 9.2	Level 2 Table X	1.5 times Present Cost	4 shift as per Section 11.1	Cost band as presented in Section 7.2.6	$93.50/m^2$
Other Cases	Base Case ±25%	AFB	Base Case ±25%	Level 1 Table X	Present Cost	2 Shift as per Section 11.2.4		$253/m^2$
					2 times present cost	1 shift as per Section 11.2.4		

*Note that the "other cases" listed were applied individually as perturbations on the base case.

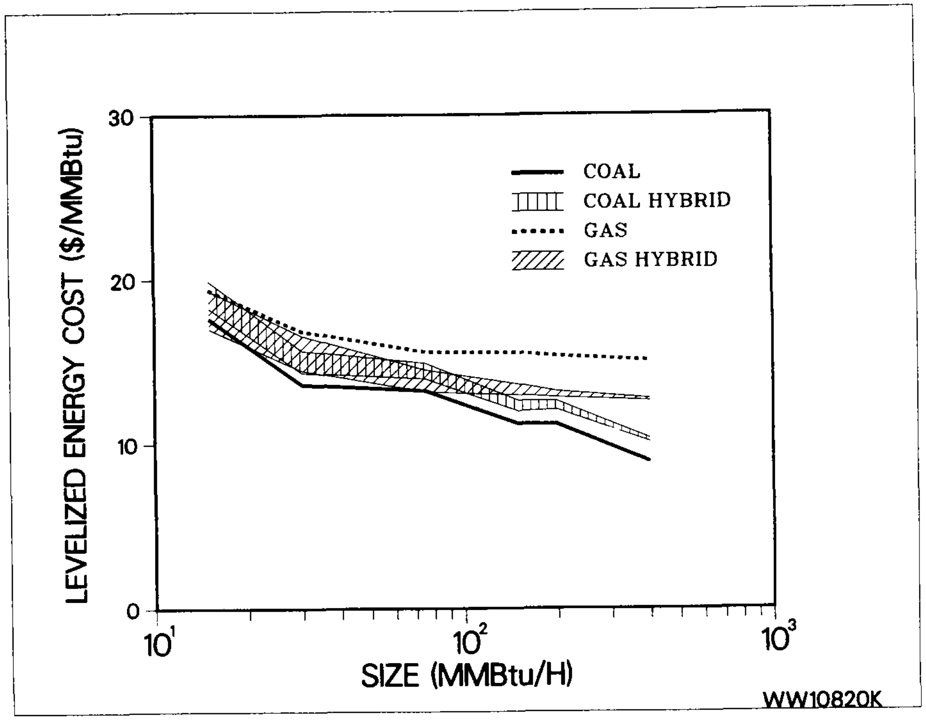

Figure A. LEC Curves for Base Case

ECONOMIES OF SCALE IN THE PRODUCTION
OF STEAM WITH SOLAR THERMAL-FOSSIL
HYBRID SYSTEMS

1. Introduction

At present, some 27% of all energy used by industry in the United States is used for the production of steam [1]. Over two-thirds of the boiler capacity in place is fired by either natural gas or oil [1]. As a result of the rapid rise in the prices of these fuels, as well as changes mandated by legislation, there will be a major shift in this decade to either alternate fuels (such as coal) or alternate technologies for the generation of steam. This shift will be facilitated by the nature of steam generation itself, since steam is completely characterized by its temperature and pressure and its use does not impose any severe uniformity or cleanliness requirements on the heat source.

One promising alternate technology of potential use in areas of high direct insolation (e.g. the Southwestern U.S.) utilizes solar central receivers (SCRs). SCRs have been extensively studied for use in electrical power generation, and a good deal of this information is applicable to industrial usage. However, SCR industrial steam generators would be much smaller than those used for generation of electricity, and they would require hybridization with a fossil-fired backup and/or thermal storage to meet load demands typical in industry. The optimum design of such a hybrid depends on many factors, including details of load and solar insolation variation, fuel prices, capital costs, economic scenarios, etc. There have been only a very limited number of studies addressing these points, and none to our knowledge have examined systems at the small sizes (10-400 MMBtu/hr) of interest here.

In the present study, we have determined the cost of steam produced by a number of different technologies: gas/oil boilers, coal boilers, coal-fired atmospheric fluidized beds, as well as solar-gas and solar-coal hybrids. Representative steam plants were costed over most of the size, temperature, and pressure ranges commonly found in U.S. industrial useage. In order to make these cost comparisons, we have developed cost models for both stand-alone fossil systems and for solar central receiver systems. Costs for hybrid systems have been determined by summing costs of the stand-alone units with appropriate allowances for any duplication of parts. Advanced technology costs are for "n^{th}" plant construction becoming operational in 1990. Plant design was optimized and energy cost minimized by simulation of steam plant operation.

In the following, we first develop the cost basis for stand-alone fossil steam plants taking capital costs, pollution control costs, fuel costs and operation and maintenance costs into consideration. Then, the solar central receiver system costs are presented by subsystem. Finally, the code used for simulation of plant operation is briefly discussed and results are presented and discussed.

2. Steam Generation - Past, Present, and Future

Table I [1] provides a characterization of industrial energy consumption in the U.S. by fuel type and functional use for the year 1974. The total consumption of 25.3 Q* is roughly equally distributed among steam generation, raw materials, process heat and other uses. Of these categories, the current study considers only steam generation. This is because boilers operate in a temperature regime ($T \leq 1000F$) wholly accessible to current and/or near-term solar technology and are of relatively standardized design (cf. process heaters). The process heat market, though well suited to solar in its need for a clean heat source, is more diverse than steam generation and consumes greater than 50% of its energy at temperatures above 1000F [2].

Currently, natural gas provides approximately 50% of the energy consumed in industrial steam generation vs. 18% and 16% for oil and coal, respectively. The dominance of natural gas and oil is primarily due to the historically low fuel and capital costs associated with these technologies, and to a lesser degree to the uniform quality, cleanliness, and convenience of the fuel. However, two related but distinct factors are likely to end this dominance and to cause a switch to coal or to alternate technologies. The first, and most obvious of these factors, is the dramatic increase in the price of oil and gas as summarized in Table II. The full impact of these price increases on industrial steam generation will only be felt after the scheduled decontrol of gas prices leads to approximate parity with oil prices.

Second, several major elements of the National Energy Act of 1978 are specifically designed to encourage alternate (other than oil or gas) fuel usage.** These measures range from a 10% investment tax credit for alternate fuel use (Energy Tax Act, ETA) to a prohibition on the use of oil and gas in new boilers larger than 100 MMBtu/hr (Power Plant and Industrial Fuel Use Act, PIFUA) to phased price decontrol for certain categories of natural gas (National Gas Policy Act, NGPA) [3]. The NGPA also establishes an incremental price ceiling for gas and that ceiling price will ultimately be that of the backup fuel (either residual or distillate oil).

Citing precisely these factors, E. I. DuPont has increased the percent of their steam generated by coal from 22% in 1973 to 39% in 1980 to a planned 75% in 1990 [6]. Other industries are expected to make similar decisions, and industrial coal usage is predicted to increase by ~ 60% from 1979 to 1985 [7]. However, diseconomies of scale in the capital and environmental control costs may argue against coal usage in small ($\lesssim$ 100 MMBtu/hr) boilers. For example, the same DuPont study [6] concluded that the cutoff size above which coal-fired steam generation makes economic sense

*1 quad = 10^{15} Btu.

**There is some uncertainty as to whether Federal legislation enacted to address other concerns--environment, safety, regional interests, reduced dependence on imported oil, inflation--significantly offset the effect of the provisions discussed above. Reference 5 discusses just this point in assessing the efficacy of Federal programs in reducing oil imports.

TABLE I

INDUSTRIAL ENERGY CONSUMPTION IN THE U.S. IN 1974 [1]
(10^{15} Btu)

Fuel Type	Use				
	Steam Generation	Process Heat	Raw Materials	Other*	Total
Coal	1.1	0.3	2.3	-	3.7
Oil (Total)	1.2	1.6	2.8	2.1	7.6
Natural Gas	3.4	2.8	0.5	1.9	8.6
Electricity	-	0.1	-	2.3	2.4
Other**	1.1	0.8	-	1.0	2.9
Total	6.8	5.6	5.6	7.3	25.3

*Miscellaneous and unclassified uses.
**Includes 0.9 quads of wood residuals and 1.0 quads of refinery (still) gas.

TABLE II

APPROXIMATE NATIONAL PRICE OF FOSSIL FUELS (1981 $/MMBTU) [3,4]

	1965	1981	2000
Natural Gas	0.92	2.50	9.00
Residual Oil	1.50	6.57	12.20
Bituminous Coal	1.25	1.91	3.00

varies from 35-75 MMBtu/hr if no scrubbing is required to 200 MMBtu/hr for mandatory scrubbing. The possibility that coal-fired generation of steam may not be economical for "small" boilers is of significant import since 30-50% of the industrial boiler capacity is below 100 MMBtu/hr and approximately 70% of it is below 250 MMBtu/hr [8].

Two advanced technologies, coal-fired atmospheric fluidized beds (AFBs) and solar central receivers (SCRs), are promising alternate technologies for industrial steam generation. These technologies are of roughly comparable maturity, and both can make significant contributions by the end of the century. The high volumetric heat release rates and high heat transfer rates of AFBs permit a 1/2 to 2/3 reduction in boiler size, thereby extending the firing range of packaged boilers, and reducing the overall cost of the steam generator. Perhaps more significantly, the AFBs capture the sulfur in the combustion bed--obviating the need for and cost of external scrubbing. The relatively low combustion temperatures (1500-1700F) also result in comparatively low NO_x emissions [3].

Solar central receivers (SCRs) have obvious environmental and fuel cost benefits, and in addition are reported [9,10] to exhibit little or no diseconomy of scale down to sizes of approximately 10 MMBtu/hr. Systems studies at significantly larger sizes have indicated comparable to favorable economics for SCR vs. gas, oil and coal in utility applications and vs. gas and oil in industrial applications [11]. Therefore, the solar economics might become even more attractive at the small sizes which characterize a significant, if not major fraction of our industrial steam capacity.

Use of SCRs would probably be restricted to areas of moderately high direct insolation. Existing and projected industrial steam capacities for the manufacturing subsector in a number of states containing such areas is given in Table III [12]. The manufacturing subsector accounts for about half the energy usage in the total* industrial sector. Depending on how one includes the gulf region of Texas, the aggregate solar potential varies from 6-18% of the U.S. total. Potential demographic shifts may further increase this fraction.

3. Industrial Boilers

3.1 Classification [13-15]

Industrial boilers are classified according to mode of heat transfer, type of construction, fuel, and type of fuel feed. Mode of heat transfer may be either cast-iron, firetube, or watertube boilers. The cast-iron and firetube boilers confine the water in a single large tank which is heated either externally or internally. Piping ("firetube") is used to circulate the hot flue gases through the water, thereby improving the efficiency of

*Total industrial usage includes the manufacturing, agriculture, mining, and construction subsectors.

TABLE III

EXISTING AND PROJECTED INDUSTRIAL STEAM CAPACITY IN THE MANUFACTURING SUBSECTOR FOR THOSE STATES HAVING HIGH SOLAR INSOLATION [12]

	Industrial Steam Capacity (10^9 Btu)	
States	1977	1980
AZ	3,431	4,980
CA	121,768	137,730
CO	12,424	16,390
NV	676	1,200
NM	1,083	1,230
TX	314,636	372,780
UT	4,655	5,940
Total US	2,422,310	2,921,360

the heat transfer. These boilers are rarely used in applications $\gtrsim$ 30 MMBtu/hr because of safety considerations arising from pressure-induced rupture of the boiler. In watertube boilers the water is confined in banks of tubing and heated by convection and radiation from the combustion of fuel in the furnace. The increased safety, as well as design and operational flexibility, offered by watertube boilers has caused them to be used for all but the smallest applications. Figure 1 [8] shows the relative distribution of cast-iron, firetube and watertube boilers in the industrial and commercial sectors. Because of the predominance of watertube boilers in industry, and because of the relative scarcity of data on capital and operational costs for cast iron and firetube boilers, the current study restricts its attention to watertube boilers with design firing rates of 10-400 MMBtu/hr.

Boilers may be either packaged or field-erected. "Packaged" boilers are manufactured and assembled at a central factory and hence are less expensive than their field-erected counterparts. Transportation considerations, e.g., size of railroad cars, tunnel clearances, etc., limit the maximum practical size for a packaged coal-fired boiler to ~ 200 MMBtu/hr [16]. Above this size, experience has shown it economical to go to field-erected coal-fired boilers and to multiple packaged gas or oil-fired boilers.

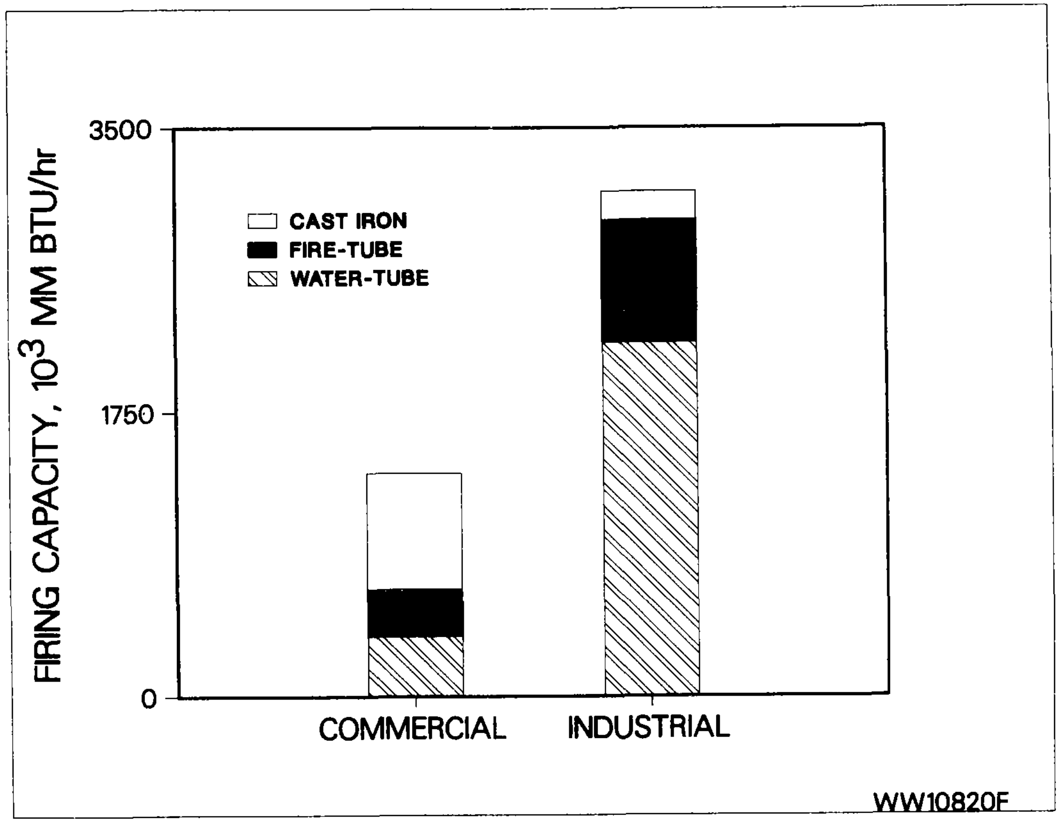

Figure 1. Distribution of Commercial and Industrial Boiler Capacity by Type (After T. Devitt *et al*. [8])

Fuel type is dictated by a number of factors including economics, availability, convenience and regulation. The influence of fuel type on boiler design and hence cost is due primarily to the physical state of the fuel*. The less physically dispersed (e.g. coal is less dispersed than oil) the fuel, the longer it takes to burn and the more difficult it is to ensure uniform distribution and access to the required combustion air. Less dispersed fuels are burned in larger boilers to increase the residence time of the fuel and with an excess of air to ensure complete combustion. Figure 2 [17] shows the increase in one manufacturer's boiler size as one goes from gas to oil to coal. Figure 3 [17] shows a similar increase as one progresses from coal having a high heating value (about 12,750 Btu/lb) to a significantly lower heating value (about 7,000 Btu/lb). The requirement for additional excess air implies a lower overall efficiency for the boiler, since some of the heated air will not be used for combustion but will merely exit with the flue gases.

Coal is either burned in a fuel bed or in suspension. In the case of fuel bed firing the coal is pushed or dropped on the bed by a stoker (under feed, overfeed, or spreader). The bed is supported on a grate (traveling, reciprocating, vibrating, or oscillating) which helps ensure optimum distribution of combustion air and continuously removes the remaining ash. The different stoker and grate combinations vary as to their heat release rates per unit volume of furnace or per unit area of heat transfer surface, their ability to handle different types of coal (caking vs. non-caking, low-ash fusion temperature, etc.), uncontrolled pollutant emissions and the rapidity with which they can adjust to fluctuations in the load. Two key parameters are the size of the coal being burned and the thickness of the fuel bed. The smaller the coal the higher the carbon carryover and ash emission, and the thicker the bed the slower the response to load fluctuations. In the popular spreader stoker, which uses a combination of coarse (1/4 - 1-1/4") and fine (0 - 1/4") coal, 25-50% of the coal is burned in suspension (i.e., in the air) and the remainder feeds a thin bed rarely containing more than a few minutes worth of coal. This enables a very fast response to load swings and a turn-down ratio as low as 12%. The suspension firing of fine coals results in increased carbon carry-over and a decrease in boiler efficiency. Carbon recovery techniques can increase the efficiency of a spreader stoker by 2-3%, but are currently economical only for boilers $\gtrsim$ 100 MMBtu/hr.

Practical considerations limit the grate size, and therefore the maximum firing rate of stokers. In addition, the efficiency of stoker-fired boilers suffers from carbon loss due to incompletely burned particles falling through the grate and from heat loss from excess air requirements. The suspension burning of pulverized (10-100 μm) coal, with 50% ash reinjection to minimize carbon carryover, reduces the carbon loss to $\simeq$ 0.4% vs. $\simeq$ 4% for a stoker, and requires only 70% of the excess air that a stoker does. However these benefits must be traded against the capital and operational costs of the pulverizer and the increased particulate emissions with attendant

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*The slagging and fouling potential of various ranks of coal significantly affects certain design details of coal-fired boilers, e.g., the number and spacing of boiler tubes and soot blowers, but appears to be less important than the heating value of the coal in determining boiler costs.

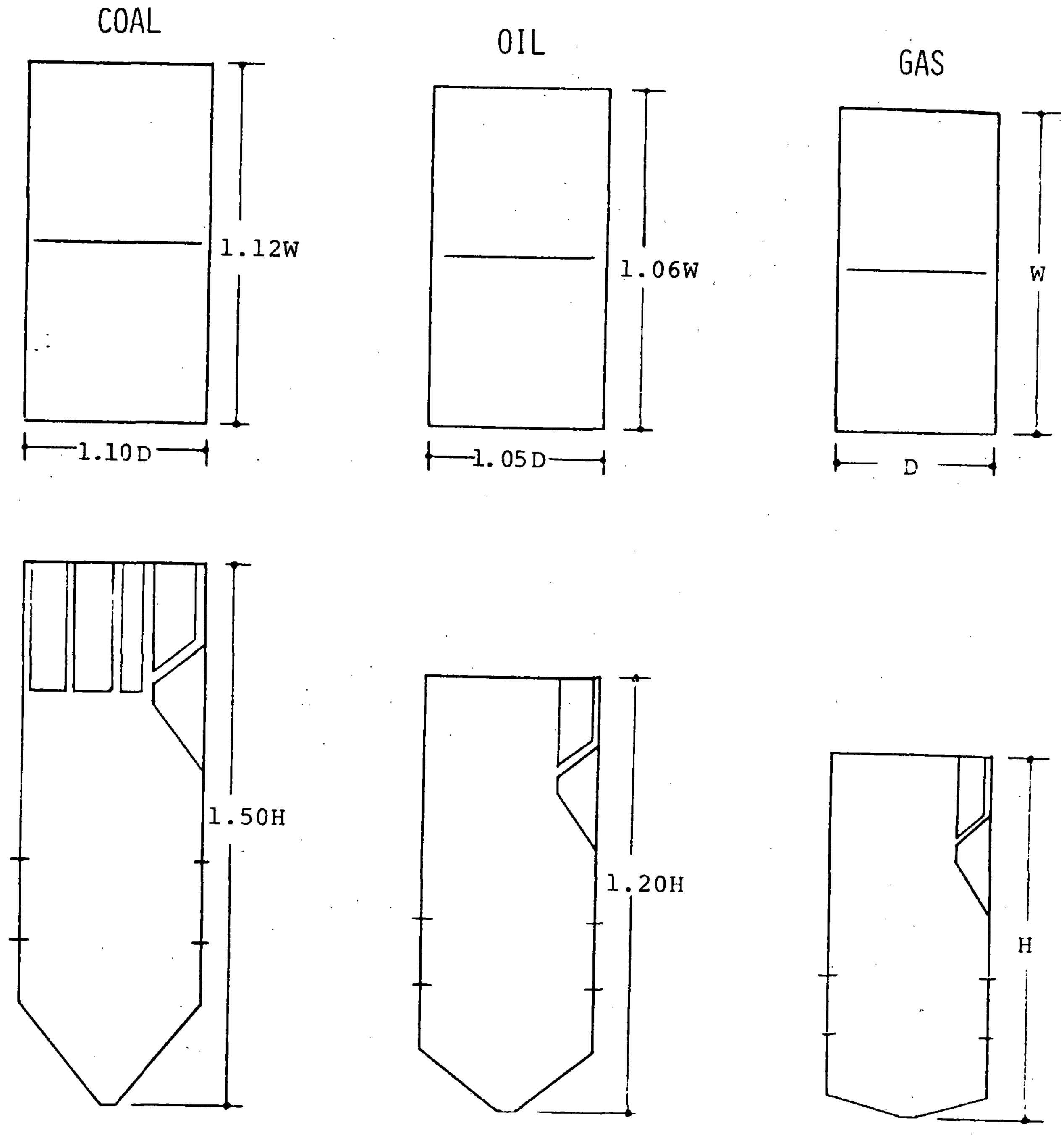


Figure 2. Relative Furnace Size for Boilers Designed for Coal, Oil and Natural Gas Fuel (From M. L. McKimmey [17])

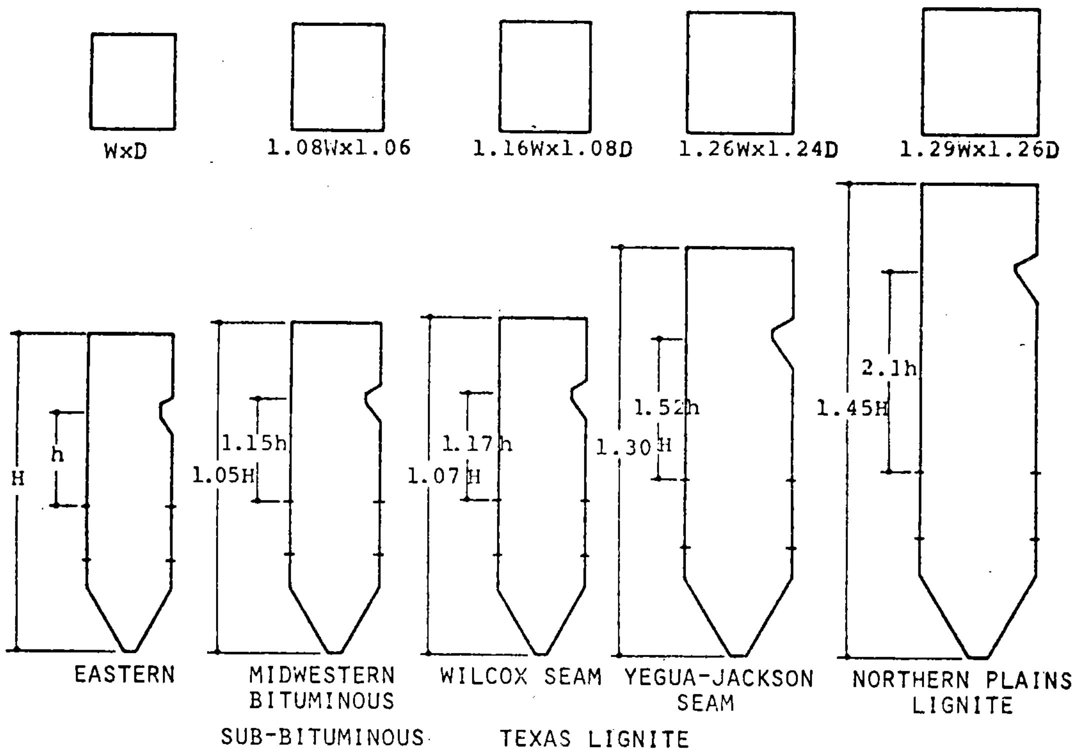


Figure 3. Effect of Coal Rank on Furnace Sizing
(From M. L. McKimmey [17])

control costs. Pulverized coal (p/c) economics become favorable for boilers $\gtrsim$ 200 MMBtu/hr; thus p/c boilers are used almost exclusively above this size.

3.2 Representative Boiler Characteristics [8]

The above classification scheme gives some indication of the potential sources of variability in the costing of industrial boilers. To minimize this variability, and to facilitate intercomparison with the rather extensive individual technology assessments reports (ITARs; see section 6.1) done under contract to the Environmental Protection Agency (EPA), we have decided to use the representative boiler sizes and steam conditions shown in Table IV. These representative conditions are in reasonable agreement with the reported [18] steam conditions for industrial boilers sold in the U.S. in 1980. The chosen boiler types correspond to current use practice and are assumed to have an average load factor of 60% [6,8,19]. Details of the load distribution--e.g., hourly, daily and seasonal variations in the demand for steam--are of considerable importance to the design of solar-fired steam generators and will be discussed in Section 11.2. The industrial requirement for $\gtrsim$ 85% availability is assumed to be met through the use of one or more standby boilers. Only differences in standby boiler practices, and hence costs, will affect the comparative economics of the various technologies. Given this, and the fact that the boiler constitutes but a fraction of the steam generation costs, the subsequent analysis will omit all consideration of standby boilers.

TABLE IV

CHARACTERISTICS OF REPRESENTATIVE COAL-FIRED, WATER-TUBE BOILERS [29]

Thermal Input (MMBtu/hr)	Type	Eff.	Steam Conditions (psig, °F)	Steam (mpph)
15	Packaged, underfeed stoker	0.78	150,365	11.8
30	Packaged, underfeed stoker	0.78	150,365	22.7
75	Field erected, spreader stoker	0.80	150,365	58.2
150	Field erected, spreader stoker	0.81	450,600	107.9
200	Field erected, pulverized coal	0.82	750,750	141.1
400	Field erected, pulverized coal	0.83	750,750	280.0

4. Fuel Considerations

The major factors to be considered are the delivered cost of fuel and, in the case of coal, the effect of coal type (heating value, sulfur and ash contents) on steam generator and environmental control costs. Treatment of natural gas and oil is relatively straightforward since an adequate industrial data base already exists [4,20] and since the price of these fuels are relatively insensitive to the size and location of the installation. Assuming that the decontrol of natural gas prices results in approximate parity in the price of gas and oil, the prime consideration is that of future price escalations and is addressed in Section 4.3. Delivered coal costs, however, depend on coal type, contractual arrangements, shipment volumes and distances, and coal sizing costs. Differences in these requirements, as well as a limited data base for the U.S. southwest, makes the published utility coal costs of limited value in estimating the cost of industrial steam coal. Coal requirements are defined in Section 4.1 and delivered costs are estimated in Section 4.2.

4.1 Coal Requirements

Coal is a complex, heterogeneous material characterized by a multiplicity of parameters including: heating value, % fixed carbons, % moisture, % volatile matter, % sulfur, % ash, ash fusion temperature, caking tendencies, friability, etc. Although all these parameters enter into the selection and design of a coal-fired boiler, three parameters appear to be of paramount importance in determining steam generator costs. These parameters are the heating value (HV), % ash (%A), and % sulfur (%S). The heating value determines the size of the fuel handling system and of the boiler, the ash content sizes the ash handling system and to some extent the particulate controls, and the sulfur content determines whether SO_x control is required.

To arrive at a representative coal for use in this study we tabulated (Table V) the HV, %A, and %S for the coal fields and coal producing districts in the states under consideration and shown in Figure 4 [21]. Based on this table, we have defined a representative coal (RC) as one having a heating value of 11,500 Btu/lb, 0.4%S, and 9.0%A. Coals of approximately this quality are available in Arizona, Colorado, New Mexico, and Utah and under the current industrial boiler new source performance standards (IBNSPS) would not require any SO_x controls (see Section 5).

4.2 Delivered Costs for Industrial Coal

Spot prices (FOB mines) for coal of similar quality to our representative coal and originating from the states of interest are shown in Table VI. Based on this, the coal price was set at $22/ton FOB the mine. Due to sizing and other requirements, stoker coal commands an additional $2-7/ton [23,24]. Therefore a premium of $5/ton was added to the price of coal for all installations having a design firing rate (Q) $\leq$ 150 MMBtu/hr.

Rail transportation costs are difficult to estimate and in some cases are in litigation. They depend on the transportation distance, the actual

TABLE V

REPRESENTATIVE COAL CHARACTERISTICS [21]

State	HV(Btu/lb)	%S	%A
AZ	11,000-13,000	0.4-2.3	3.4-50
CO	10,000-14,000	0.3-2.0	2.2-18
NM	9,000-14,000	0.4-3.5	8-13
UT	10,000-12,800	0.45-1.1	6-14

TABLE VI

REPRESENTATIVE COAL PRICES (AUGUST, 1981) [22]

	Specification			FOB Mines $/T	
Producing District	Btu/lb	%S	%A	Term	Spot
Northern CO	10,700	0.5	9.1	19.00	18.50
CO & Northeastern NM	11,600	0.5	9.0	22.00	23.50
Parts of NM & AZ	10,000	0.5	10.5	16.00	15.00
UT	11,500	0.6	9.0	20.50	22.00

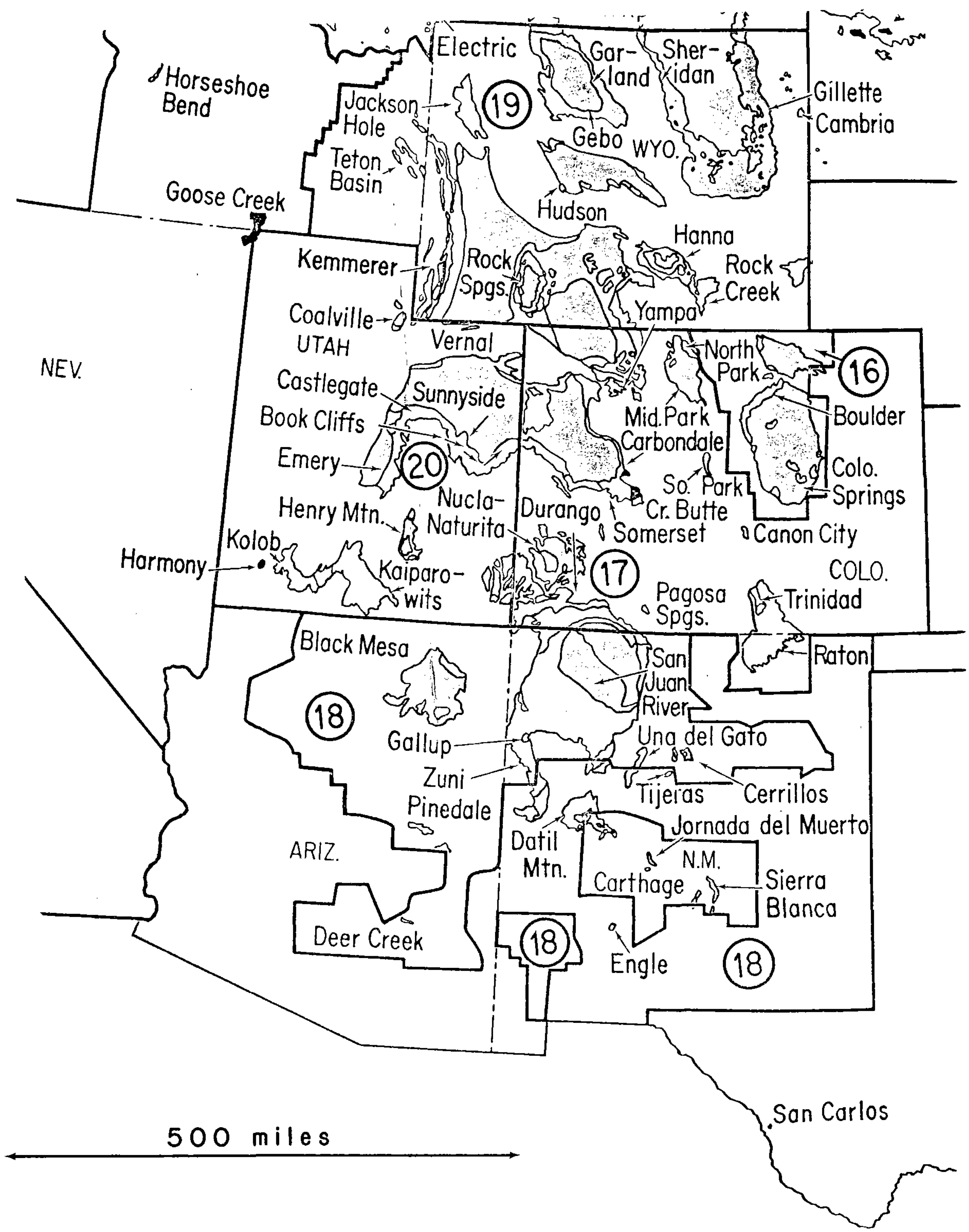


Figure 4. Coal Fields of the Southwestern United States (Reproduced with the permission of the Keystone Coal Industry Manual [21])

origin and destination, and on the volume of shipment. We have taken a somewhat simplified approach in which the rail transportation costs are approximated as 2.0 cents/ton-mile [25] for unit-train shipments. The limited available data on single car rates suggest that these are 1.5 to 2.0 times unit train rates, with a median figure of 1.75 being used in this study. Assuming a unit train consists of approximately 80 cars, each of 100 ton capacity, only the 400 MMBtu/hr steam plant would require as much as a unit-train of coal per month. Therefore single car rates were applied to coal deliveries to all smaller plants. A median shipment distance of 500 rail miles was assumed.

The various factors contributing to the delivered cost of coal are summarized in Table VII.

4.3 Price Escalation

Previous price escalation scenarios, whether based on *a priori* assumptions about fuel escalation rates or on detailed economic modeling, generally predict high escalation rates for the near term (1980-1990), with lower to zero or even slightly negative rates for the mid (1990-2000) to long term (2000 and beyond) [4,20]. The existence of such a price plateau seems both "natural" and a consequence of long term price elasticities, onset of competing technologies, etc. Since this study is concerned with the 1990 timeframe and beyond, it seems reasonable to assume that such a plateau has been attained and that as a result to the cost of coal through the appropriate liquefaction and gasification technologies.

TABLE VII

ESTIMATED COST OF COAL AS A FUNCTION OF FIRING RATE (Q)

	Q (MMBtu/hr)		
	≤150	200	400
Coal (FOB mine, $/ton)	22.00	22.00	22.00
Stoker Premium ($/ton)	5.00	-	-
Transportation costs ($/ton)	17.50	17.50	10.00
Delivered costs ($/MMBtu)	1.93	1.72	1.39

The exact level of this plateau and any subsequent fuel price escalations are treated parametrically. Levelized steam costs are calculated for fuel plateau prices of 1.0, 1.5, and 2.0 times current decontrolled gas, oil ($5.00/MMBtu) and coal (Table VII) prices. Subsequent fuel escalation rates as a high as 2% per year are found to increase the levelized fuel cost over the assumed 20 year lifetime of the plant by $\leq$ 18%, i.e. less than the range of variations in plateau prices, and hence are not explicitly presented.

5. Environmental Considerations

5.1 Standards [3,26]

5.1.1 Air Quality and Emission Standards--The Clean Air Act (CAA) has chartered the Environmental Protection Agency (EPA) with the development of national ambient air quality standards (NAAQS) and the individual state governments with the implementation, attainment, and enforcement of these standards. The states are required to prepare state implementation plans (SIPs) detailing how they intend to comply with the NAAQS and to submit these plans to the EPA for approval. Table VIII [27] summarizes representative SIP boiler emission standards for the states of interest in this study. These standards apply to areas in which the air quality already meets the NAAQS and are meant to prevent significant deterioration (PSD) of the air quality. More stringent standards apply to the non-attainment (NA) areas which exceed the NAAQS for one or more pollutants, as well as to certain classes of PSD areas.

In addition, the Clean Air Act has defined a set of "least stringent" emissions standards for new or modified, large (> 250 MMBtu/hr) stationary sources. Table IX [26] summarizes these new source performance standards (NSPS) for both industrial and utility boilers. As currently enacted, the NSPS require sulfur scrubbing for all utility boilers, but not for all industrial boilers. (In the latter case it is acceptable to meet the standard by burning a low sulfur or "compliance" coal.) The EPA is currently working on a new industrial boiler NSPS. Speculations on the requirements of the new standards include the extension of current particulate limits to units as small as 50-100 MMBtu/hr and the requirement of mandatory sulfur reductions for industrial boilers $\gtrsim$ 100 MMBtu/hr [26].

5.1.2 Liquid and Solid Wastes [29]--Liquid and solid waste disposal must comply with the Clean Water Act and the Resource Conservation and Recovery Act (RCRA). Currently the Phase I RCRA regulations exempt fly ash, bottom ash, slag, and air pollutant control sludge from consideration as a hazardous waste. Thus, as for "non-hazardous" wastes, the primary consideration is to avoid contamination of the ground water in the disposal area and presents no major obstacles. Liquid waste disposal is only of consideration for certain flue gas desulphurization (FGD) technologies, and in most of these cases can be minimized by going to a closed loop system. The once-through sodium scrubbing process is the only major exception. In this case, the need to dispose of significant quantities of liquid containing sodium sulfite/sulfate salts is believed to make this process economically unattractive [1].

TABLE VIII

REPRESENTATIVE SIP EMISSION STANDARDS FOR BOILERS [27]

Design Firing Rate (MMBtu/hr)	SIPs Limits (lb/MMBtu)								
	SO_x			PM			NO_x		
	10	100	250	10	100	250	10	100	250
Arizona	0.8	0.8	0.8	0.60	0.35	0.28	(0.2,0.3)*		0.7
California**	1.0	0.1	0.04	1.0	0.1	0.04	1.0	0.1	0.04
Colorado	←(–,0.8) 1.2 →			0.27	0.15	0.10	←(0.2,0.3) 0.7→		
Nevada	0.7	0.7	0.7	0.60	0.35	0.28	← None →		
New Mexico	← None →			0.56	0.33	0.26	← None →		

*Numbers in parentheses refer to (gas,oil) limits.
**Based on new source requirement (NSR) of $\leq$ 150 lbs of pollutant/day and a 60% load factor.

TABLE IX

CURRENT NEW SOURCE PERFORMANCE STANDARDS (NSPS) [26]
(apply to all new or modified boilers $\geq$ 250 MMBtu/hr)

	Emission Standards (lbs/MMBtu, % Reduction)	
	Industrial Boilers	Utility Boilers
Particulates	0.1	0.03
SO_x: Coal	1.2	90% (60%)*
Oil	0.8	90% (0%)*
Opacity	$\leq$20%	$\leq$20%
NO_x**	0.7	0.5-0.6

*Numbers in parenthesis apply if the uncontrolled emissions rates for coal and oil are less than 0.6 and 0.2 lbs/MMBtu respectively.
**NO_x standards are from Ref. [28].

5.1.3 Emission Control Scenarios--Based on the preceding considerations, we have postulated 2 levels of emission standards (Table X). Level 1 complies with the current SIPs requirements of all the states except CA. Level 2 standards are more stringent and either comply with the California SIP or are at the limit attainable by the use of best available control technology (BACT) in conjunction with a low sulfur coal. Appropriate technologies will be discussed in Section 5.2. However, two comments seem appropriate here: (a) raising of the particulate limit for the smaller sizes ($Q < 100$ MMBtu/hr) may be warranted and would enable the use of cheaper technologies such as cyclones; (b) the California NO_x limits cannot be attained with any demonstrated technology.

5.2 Control Technologies

Table XI lists the anticipated uncontrolled emissions rates for our representative boilers and coal types [30]. Comparison of this table with the emission control scenarios of Table X indicates that level 1 control requires particulate clean-up ($\gtrsim$ 95% removal efficiency) only; level 2 control requires SO_x removal (0-90%), particulate cleanup ($\gtrsim$ 98.5%), and NO_x reduction (0-6%). Suitable technologies are identified below.

5.2.1 Flue Gas Desulfurization (FGD) [29,31]--Six FGD schemes are currently in commercial use in the U.S. These processes are lime/limestone, dual alakali, Wellman-Lord, magnesia-slurry, once-through sodium scrubbing, and spray drying. Of these, the Wellman-Lord and the magnesia-slurry scrubbing are both regenerative processes, while the remaining four are throwaway processes, with attendant waste disposal considerations. Cost penalties associated with the technical complexity of the regenerative processes and with the environmental acceptability of waste disposal from the once-through sodium scrubbing eliminate these processes from further consideration. The remaining three processes are all attractive. However, in light of the limited experience with spray-drying (particularly at 90% removal efficiencies) and the somewhat greater complexity of the lime/limestone (cf. dual alkali) we have chosen to go with dual alkali scrubbing.

In the dual alkali process the SO_x in the flue gas is scrubbed by a sodium salt solution which then passes out of the scrubber and is reacted with lime to regenerate the sodium salt solution. The resulting calcium sulfites and sulfates must be disposed of. As of 1980 the dual alkali process has been used in, or proposed for, at least ten industrial sites, mainly with high sulfur coals and SO_x removal efficiencies of > 90% [29]. There are additional complications in dealing with low sulfur coals, but these can be designed around. A limited amount of long-term reliability data is available; and it indicates a reliability slightly greater than 90% [29].

5.2.2 Particulate Matter (PM) [26,29]--Cyclones, wet scrubbers, electrostatic precipitators (ESPs) and fabric filters (FF) are the four commonly used particulate control techniques. Of these, only the ESP and the FF can economically attain the > 98% removal efficiencies required in this study. The use of a low sulfur coal complicates the operation of an ESP, requiring that the ESP be placed ahead of the air preheater or that a chemical be added to lower the "effective" resistivity of the particulate matter. Con-

TABLE X

EMISSION CONTROL SCENARIOS

Q (MMBtu/hr)	Emission Limits (lb/MMBtu)								
	SO_x			PM			NO_x		
	10	100	250	10	100	250	10	100	250
Level 1	←	0.7	→	←	0.1	→	←	0.7	→
Level 2	0.7	0.10	0.07	←	0.03	→	←	0.6	→

TABLE XI

UNCONTROLLED EMISSION RATES [30]*

Q (MMBtu/hr)	Boiler	Pollutant (lbs/MMBtu) SO_x	PM	NO_x
10	Underfeed Stoker	0.66	1.96	0.349
100	Spreader Stoker	0.66	5.09	0.616
250	Pulverized Coal	0.66	6.26	0.636

*Based on coal having a heating value of 11,500 Btu/lb, 0.4%S, and 9.0%A.

sequently, we have specified that a fabric filter be used in conjunction with the low sulfur coal. As of 1980, fabric filters are in use, or have been proposed for use, at 104 industrial boilers [29].

5.2.3 NO_x Controls [29]--NO_x emissions arise from the combination of O_2 with either fuel-bound nitrogen (fuel NO_x) or with the nitrogen in the combustion air (thermal NO_x). The common methods of NO_x control modify the combustion process (vs. post-combustion gas cleanup) to reduce O_2 availability and/or the flame temperature, and include such techniques as low excess air (LEA) firing, staged combustion (SC), flue gas recirculation (FGR), low NO_x burners (LNB), and reduced air preheat (RAP). Of these, FGR and RAP only reduce the flame temperature and hence are not well suited to coal-fired units with their relatively low temperature fuel-NO_x formation. The remaining techniques (LEA, SC, LNBs) will be used singly or in combination to limit NO_x emissions from the boilers under study. These techniques bring about only limited reductions (2-40%) in NO_x emissions.

Several new de-NO_x schemes, offering comparable or greater emissions reduction, have been proposed. Two popular techniques involve the non-catalyzed and catalyzed reaction of NH_3 with NO_x to produce N_2 and H_2O. These techniques have been successfully demonstrated on gas and oil-fired boilers in Japan but have yet to be demonstrated on coal-fired units with particle laden gas flows [29].

5.2.4 Atmospheric Fluidized Beds (AFBs) [29]--The AFBs greatest advantage over conventional coal-fired boilers is its potential for reduced pollutant emissions at minimal additional cost. SO_2 reductions of $\gtrsim$ 90% are attained by adding a sorbent, e.g., limestone, directly to the aerodynamically supported fuel bed and by limiting the combustion temperatures to 1500-1700F, i.e. the optimum for SO_2 capture. These low combustion temperatures (cf ~2700F for conventional combustors) also reduce thermal NO_x formation. Fuel-NO_x is still formed, but may be partially decomposed by subsequent reactions with incomplete products of combustion, e.g. CO. However, other design parameters may offset some or all of the potential NO_x reduction.

AFBs are still an emerging technology. R&D efforts are seeking to optimize such key SO_x control parameters as the Ca/S ratio, the sorbent particle size and the gas phase residence time. Other studies are seeking to obtain a better understanding of the parameters affecting NO_x formation and decomposition in AFBs.

5.2.5 Technologies used in this Study--Table XII summarizes the technologies to be used to meet level 1 and 2 emissions standards for conventional coal-fired boilers. These have been chosen because of their ability to provide the desired emissions reduction, compatibility with low sulfur coal, and their comparatively low costs. Considering the relatively large uncertainties in the cost of these control technologies, and the fact that they contribute $\lesssim$ 20% to the total levelized cost of steam, no attempt has been made to find the cheapest technology at each size.

The only environmental controls required for the other boilers under consideration are: (a) particulate clean-up (FF) for AFBs at both level 1

TABLE XII

POLLUTION CONTROL TECHNOLOGIES ASSUMED FOR CONVENTIONAL COAL FIRED BOILERS

	Pollutant SO_x	PM	NO_x
Level 1	none*	FF	none
Level 2	none* ($Q \leq 30$ MMBtu/hr)	FF	LEA, SC
	DA ($Q > 30$ MMBtu/hr)		

*Need for SO_x cleanup is obviated by the use of compliance coals.

DA = Dual Alkali
FF = Fabric Filter
LEA = Low Excess Air
SC = Staged Combustion

and level 2 standards, and b) the use of low NO_x burners to meet the level 2 standards for boilers firing natural gas or distillate oil.

6. Capital and O&M Costs for Fossil-Fired Plants

6.1 Sources

Costs are based on the latest updates of the Individual Technology Assessment Reports (ITARs) done under contract to the EPA. These studies were funded by the EPA specifically to support the development of a new industrial boiler NSPS and as such use a common accounting format and, with occasional exceptions, common costs for expendibles, labor, etc. The ITAR costs are in turn based on actual vendor quotes for fossil plant costs, vendor estimates for the AFB plants, and a combination of internal design and costing, vendor quotes, and installed costs for the pollution control devices. The updated ITAR costs were also recommended by various individuals in the EPA, the American Boiler Manufacturer's Association (ABMA), the Council of Industrial Boiler Owners (CIBO), and the Tenessee Valley Authority (TVA). An independent review of the ITARs is given in reference 32.

6.2 Costing Methodology

Total capital costs were obtained by multiplying the direct costs (equipment plus installation) of references 16, 29, and 33 by 1.35. This factor reflects an indirect loading equal to 35% of the direct cost to cover such factors as architect and engineering fees, construction fees, interest during construction, and contingencies. This indirect loading is less than that used in the ITARs, but is similar to that used in a number of solar studies. In cases where only grand total costs were given, these costs were converted to direct costs by multiplying by the ratio (direct cost/grand total cost) from the most closely related ITAR.

Total annual costs consist of direct and overhead costs but, unlike the ITARs, do not include capital charges. (The capital charges are, for the most part, included in the levelized costing procedure that we subsequently apply.) The direct costs include operating and maintenance labor and supervision, replacement parts, and all other expendibles except fuel. The overhead consists of a payroll overhead of 30% of the direct labor costs and a plant overhead of 26% of labor, parts, and maintenance [8].

As discussed previously, both capital costs and annual costs depend on the type fuel that is used. In the case of the conventional coal-fired steam plant, the costing algorithms [16] allow us to directly estimate the cost for burning the representative coal of section 4.1. For the other technologies, we used the costs for the coal-type most closely approximating the representative coal.

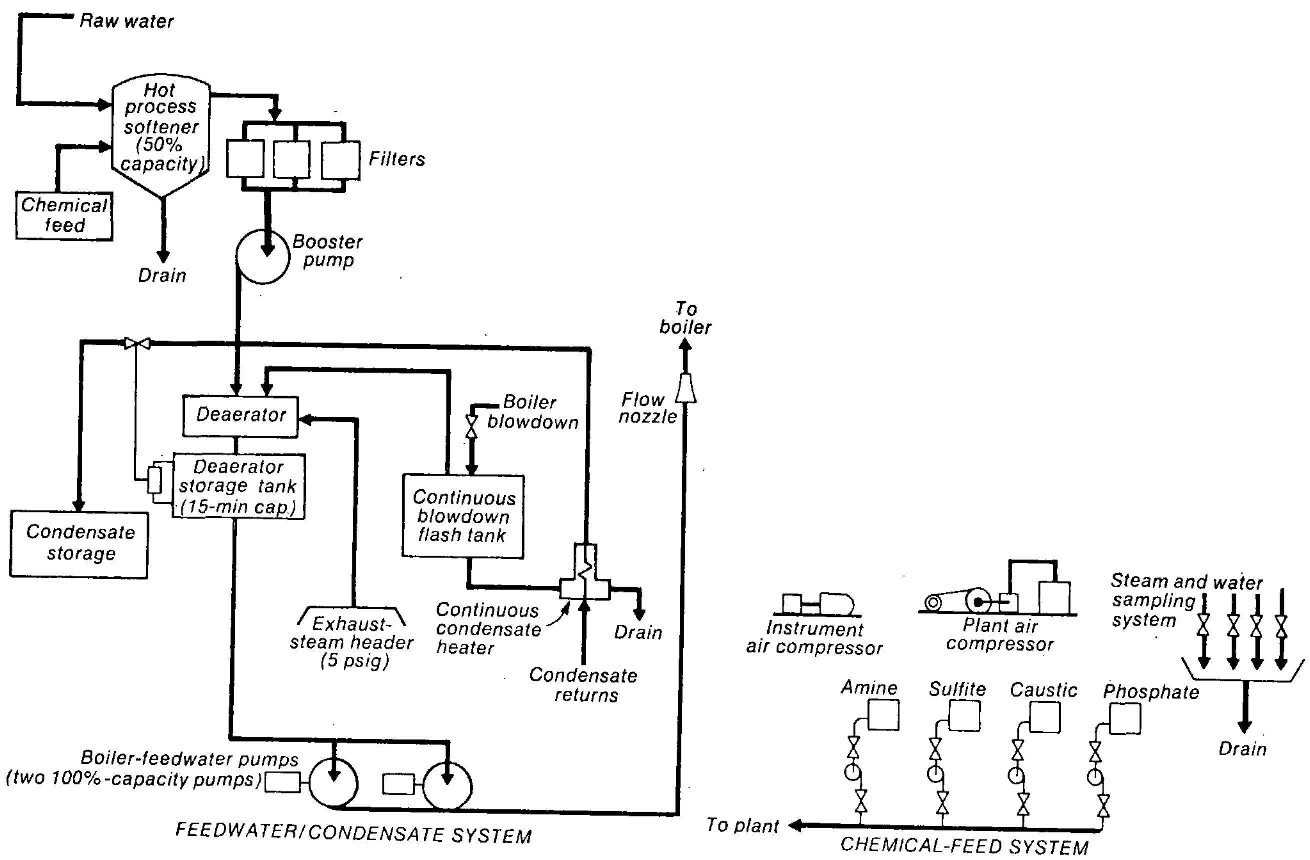
All costs were converted to 1981$ by using the appropriate GNP deflators.

6.3 Battery Limits, Greenfield Costs, Multipliers and Shift Assumptions

The term "battery limits" is commonly used to denote the boundaries or "limits" of the steam plant. Following reference 24, they extend from the fuel-receiving equipment to the ash disposal operation. Figure 5 illustrates the typical equipment contained within the battery limits of oil, stoker, and pulverized-coal-fired boiler plants. Note that the water treatment system is common to all three types of boilers. Environmental control devices are outside of the battery limits of the steam-plant and are costed independently. The following items are outside the battery limits of the steam plant and are not reflected in any of the costs: land costs, site preparation and grading, access roads, rail spur, switchyard, and transformers; raw water supply; and coal storage pile [24].

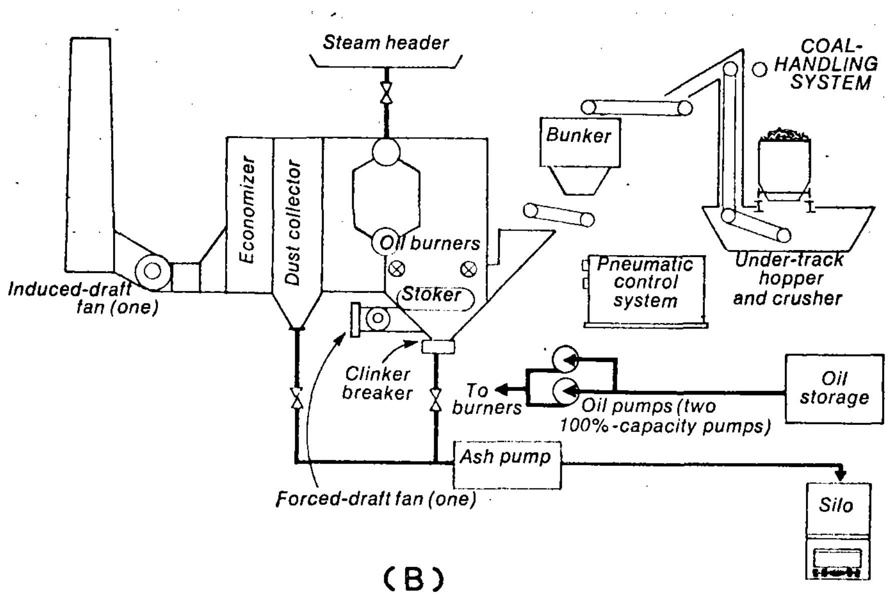
Initial ITAR costing was done for so-called greenfield installation, i.e. a new stand-alone boiler plant in which the costs are independent of any associated processing plant. Subsequently, PEDCO [16] has developed cost "multipliers" or modifiers that allow one to adjust the greenfield costs to reflect economies arising from construction and operation with an associated processing plant. (These savings arise from sharing of structures, equipment, and manpower.) These modified costs were used in the current study.

Finally, there is some question among the ITAR participants as to whether the number of manpower shifts vary with the load factor (LF) of the facility or not. Discussions with local boiler operators support the observations in reference 16: i.e. the common practice is to man a full 4 shifts

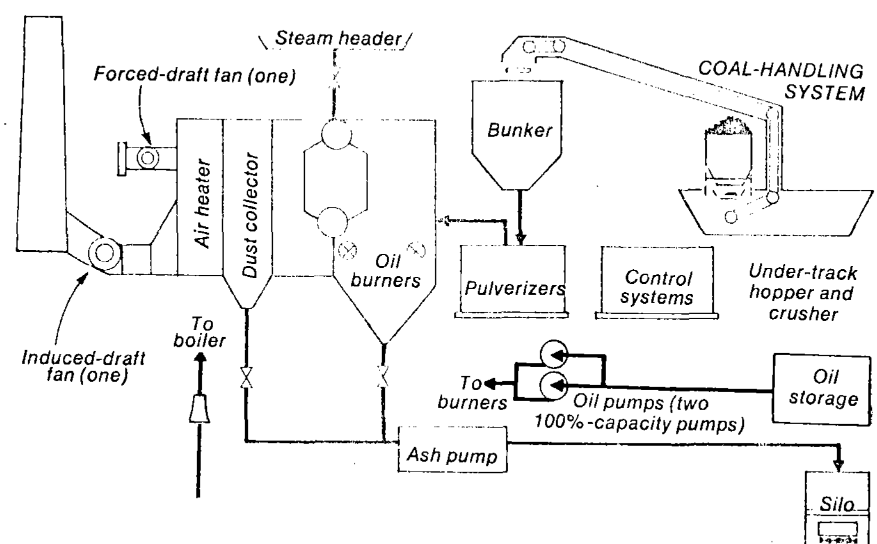


(A)

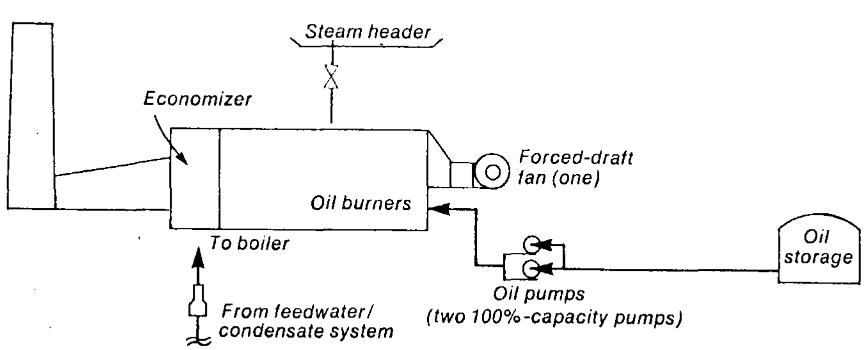
Figure 5. Battery Limits for Oil, Stoker, and Pulverized-Coal-Fired Boiler Systems. (A) Water treatment--common to all three boiler types. (B) Stoker-fired boiler plant. (C) Pulverized coal-fired plant. (D) Oil-fired plant. (From B. D. Coffin [24]. Reproduced with permission of the editors of Power Magazine)


Steam header
COAL-HANDLING SYSTEM
Bunker
Economizer
Dust collector
Oil burners
Stoker
Induced-draft fan (one)
Pneumatic control system
Under-track hopper and crusher
Clinker breaker
To burners
Oil pumps (two 100%-capacity pumps)
Oil storage
Ash pump
Forced-draft fan (one)
Silo

(B)


Steam header
Forced-draft fan (one)
COAL-HANDLING SYSTEM
Bunker
Air heater
Dust collector
Oil burners
Pulverizers
Control systems
Under-track hopper and crusher
Induced-draft fan (one)
To boiler
To burners
Oil pumps (two 100%-capacity pumps)
Oil storage
Ash pump
Silo

(C)


Steam header
Economizer
Forced-draft fan (one)
Oil burners
To boiler
Oil storage
Oil pumps (two 100%-capacity pumps)
From feedwater/ condensate system

(D)

(24 hours per day, 7 days per week) irrespective of capacity factor. Therefore we have assumed 4 shift staffing.

6.4 Assumed Costs

Assumed capital and O&M costs for the various technologies are summarized in Tables XIII-XV. Conventional coal-fired steam plants are optimized for a coal with a heating value of 11,500 Btu/lb, 0.4%S, 9.0%A. A steam plant capable of handling large variations in coal type may cost from 30-40% more. Such fuel flexibility may be a consideration for small plants which cannot insure a consistent supply of coal. Dual alkali scrubbing costs are for 90% SO_x removal and are a moderate function of removal efficiency [1]. Lower SO_x removal efficiencies ($\lesssim$ 70%) would be met by combined SO_x-PM removal via spray drying and a fabric filter. Fabric filter costs are for 99% particulate removal. Lower removal efficiencies may be met by wet scrubbers ($\lesssim$ 98%) or mechanical collectors (< 90%) with attendant cost reductions [1]. As noted earlier, AFBs are an emerging technology and therefore their costs are subject to larger uncertainties from those quoted for other technologies.

6.5 Comments - Capital Costs

6.5.1 Steam Generators--The greenfield capital costs of conventional coal-fired steam plants used here (Tables XIII - XIV) are in good ($\lesssim \pm$20%) agreement with several other studies [34] and are 3 to 4 times those of gas-fired units. Three different boiler types are used to cover the range 10-400 MMBtu/hr and to minimize the increases in specific capital costs at smaller sizes that would characterize the use of any single boiler type. The resulting size dependence of specific capital costs show a size variation that is, in fact, comparable to, or less than, that exhibited by gas-fired units.

AFB capital costs are similar to those of conventional coal fired boilers and to the limited AFB costs reported by Kurzius and Barnes [34]. Note that in this case the moderate increase in specific capital cost as size decreases is intrinsic to the technology and not a result of changes in boiler type. As anticipated, the primary economic advantage of the AFB arises from savings in SO_x control costs.

6.5.2 Pollution Control Costs--Particulate control costs are approximately 10% of the capital cost of a coal-fired steam plant over the entire size range studied. However scrubbing costs vary from 33% (Q = 30 MMBtu/hr) to less than 9% (Q = 400) of the capital costs of the steam plant. The scrubbing costs for large Q are low compared to those reported in ref. 34, but when extrapolated to even larger Q appear to be in reasonable agreement with utility experience.

TABLE XIII

ASSUMED COSTS FOR CONVENTIONAL COAL-FIRED STEAM PLANTS AND ASSOCIATED CONTROL TECHNOLOGIES (Subsequent Analyses use $M_1=0.84$, $M_2=0.54$ [16] and a Capacity Factor CF=0.60)

	Costs (000 1981$)					
Thermal Input	Steam Plant*		Fabric Filter**		Dual Alkali**	
(MMBtu/hr)	Cap	O&M	CAP	O&M†	Cap	O&M†
15	1,297M_1	587 M_2 +49 CF	140	28	--	--
30	2,030M_1	676 M_2 +82 CF	263	50	592	295
75	4,669M_1	869M_2 +159 CF	654	83	860	349
150	8,438M_1	1,193M_2 +279 CF	1,119	155	1,167	421
200	13,669M_1	1,970M_2 +711 CF	1,317	187	1,303	447
400	20,008M_1	2,958M_2 +1,170 CF	2,104	347	1,813	597

*Steam generator costs are based on reference 16.
**Environmental control costs are based on reference 29.
†O&M costs are for a 60% capacity factor.

TABLE XIV

ASSUMED COSTS FOR COAL BURNING AFB STEAM PLANTS
(Subsequent Analyses use M_1=0.84, M_2=0.54 [16]
and a Capacity Factor CF=0.60)

Thermal Input (MMBtu/hr)	Costs* (000 1981$) Steam Plant Cap	O&M
15	1,506 M_1	587 M_2 + 49 CF
30	2,568 M_1	653 M_2 + 78 CF
75	5,201 M_1	1,129 M_2 + 208 CF
150	8,999 M_1	1,598 M_2 + 417 CF
200	11,114 M_1	2,050 M_2 + 557 CF
400	18,874 M_1	2,958 M_2 + 1,170 CF

*Based on reference 33.

TABLE XV

ASSUMED COSTS FOR GAS-FIRED STEAM PLANTS
(Subsequent Analyses use M_1=0.94, M_2=0.54 [16]
and a Capacity Factor CF=0.60)

Thermal Input (MMBtu/hr)	Costs* (000 1981$) Steam Plant	
	Cap	O&M
15	429 M_1	382 M_2 + 20 CF
30	731 M_1	382 M_2 + 39 CF
75	1,272 M_1	523 M_2 + 51 CF
150	1,978 M_1	753 M_2 + 72 CF
200	2,718 M_1	1,163 M_2 + 183 CF
400	5,033 M_1	1,781 M_2 + 311 CF

*Based on reference 16. Single packaged boilers used for $\lesssim$ 150 MMBTU/hr, multiple packaged boilers above that.

6.6 Comments on Annual O&M Costs

Annual O&M costs of steam plants are the major surprise of the study. They are significantly higher than anticipated or than estimated in ref. 34. The O&M costs range from 12-25% of the initial capital cost for coal-fired steam generators to 24-54% of the initial capital cost of gas-fired units with the larger numbers characteristic of the smaller plants. Manpower costs account for $\gtrsim$ 75% of the annual O&M costs. These costs reflect a conservative preventative maintenance approach (vs. a "don't fix it 'till it breaks" approach) that is characteristic of perhaps only 10% of current boiler installations. However, PEDCO feels that "a new boiler plant today would be better maintained and operated than most of the existing plants. The economic importance of efficient operation and scheduled maintenance cannot be overstated considering the price of fuel and the increasing regulatory pressure for clean operation" [16]. These O&M costs are disporportionately increased at small sizes by the requirement of many local (state) boiler ordinances that boilers and fired pressure vessels not be left unattended [35].

The PEDCO O&M costs do reflect the views of many boiler manufacturers, agree well with O&M costs at the Sandia, Livermore boiler plant ($218,000 vs. 230,000) [36], and have been used in the current study. However, they do represent a major grey area in the costing and would benefit from a better understanding of external constraints (legislation, unions, ...) as well as corporate O&M practices and philosophies.

7. Cost Scaling of Solar Central Receiver Systems with Size

7.1 Introduction

If we are to accurately calculate the cost of energy delivered from solar-fossil hybrid steam plants for a variety of system sizes, then we must have reasonable models for the variation of capital and annual O&M costs with plant size. The derivation of such models can be approached in two different ways. One method involves the design and optimization of a central receiver system at one specific size. Accurate costs can be obtained for each subsystem (e.g. the receiver, the tower, etc.) of the plant, so that overall costing analysis is quite good. At the same time, scaling models for parts of each subsystem can be built into the analysis. Obviously, such an approach can lead to accurate costing of systems which do not differ too much either in size or design from the optimized reference plant. However, extrapolations to systems quite different from the reference plant are potentially inaccurate.

The second method consists of the design and optimization of systems at several different sizes. Accurate subsystem cost figures are obtained at each size considered and costs for plants of any size are then obtained by interpolation between points provided by the reference systems. This method has the potential to provide accurate costs across a wider range of system sizes than the first, but it also requires a great deal more work. Furthermore, it is not apparent how results from either of these methods could be used to obtain costs for plants of a different design (e.g. use of different heat transfer fluids) than the reference plants.

Both of these methods have been used previously in studies of the size dependence of the cost of energy from a solar central receiver system. The first method is used in the program DELSOL [37] utilizing a 300 MW_t* reference plant. DELSOL was used to study plant size effects on the cost of energy at the base of the tower by T. Dellin [10]. A similar study over a more limited size range was included as part of a solar central receiver system repowering study by Martin Marietta [38d]. (In Figure 6--notice that the original Martin Marietta study used heliostats priced at $\$253/m^2$--we also include the curve which would result from using heliostats at $\$93.50/m^2$ instead.) From Figure 6, we note that costs derived from Dellin's study and those of the Martin Marietta study are in quite good agreement--as one might expect since both were obtained using the scaling equations of DELSOL.

*To be consistent with normal useage, solar subsystem power ratings are design point output power ratings. Fossil boiler ratings (or fluid heaters) use maximum input power ratings. Fossil heater output powers are obtained using the efficiency curve of Figure 12, below.

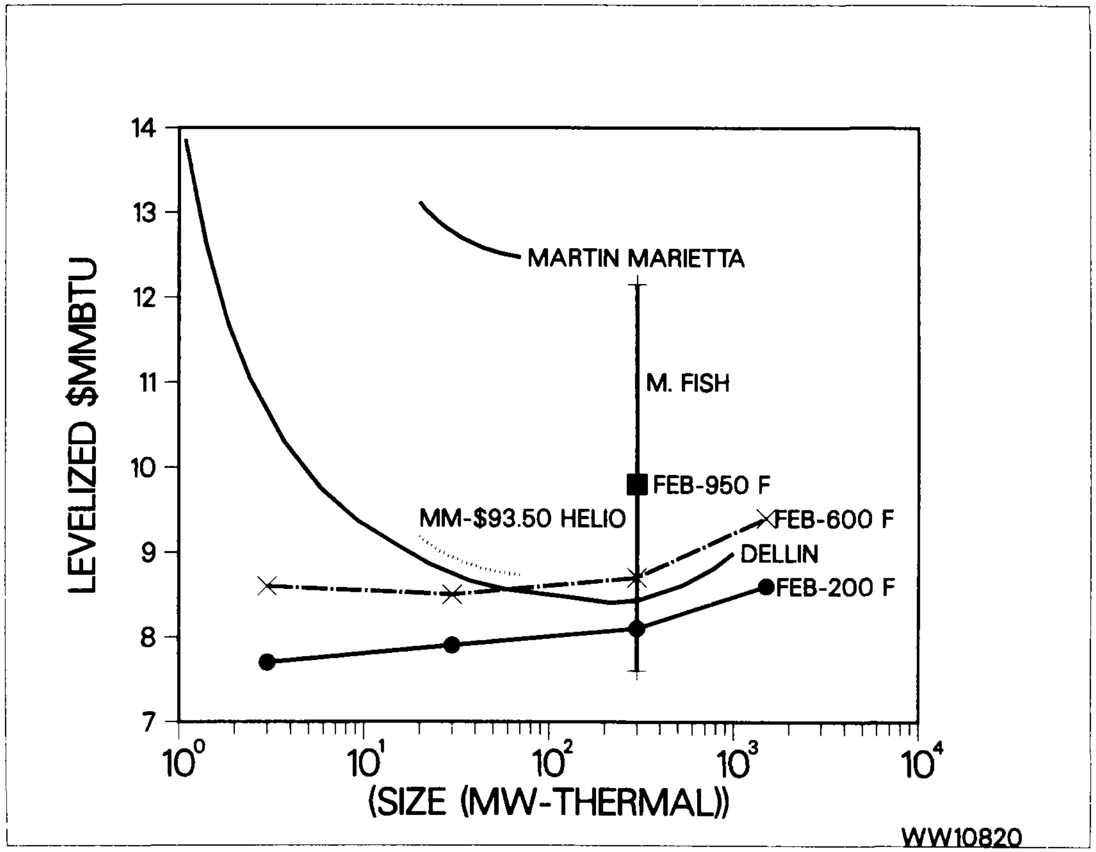


Figure 6. Cost of Energy at the Base of the Receiver Tower from a Number of Previous Studies: Martin Marietta Data from Ref. 38d; Dellin Data from Ref. 10; February Study Data from Ref. 9

The second method of analysis was used by Eicker et al. [9] (hereafter referred to as the February Study) to compare several different solar thermal energy technologies. They optimized solar central receiver systems at sizes of 3, 30, 300 and 1500 MW_t producing hot water or saturated steam at temperatures of 200°F, 300°F, and 600°F. They also examined some higher temperature systems at the 300 MW_t size. Figure 6 includes data for the downtower cost of energy from some of their systems.

Figure 6 shows that the results of the study by Dellin differ qualitatively from those of the February Study for small systems. This difference could be the result of the inability of the scaling equations in DELSOL to accurately model costs at plant sizes orders of magnitude different from the size of the reference plant. (Note that it is possible to change the characteristics of the reference plant used in DELSOL--use of a smaller reference plant could be expected to result in more accurate numbers at smaller plant sizes). A study by M. Fish [11] of sensitivity of the levelized energy costs (for a 300 MW_t plant) to a variety of factors led to the cost range shown in Figure 6. Note that energy costs predicted by both the Dellin study and the February Study fall within the cost error bars defined by Fish.

7.2 Development of Cost Models

7.2.1 Strategy--The design and optimization of solar central receiver power systems at a variety of sizes is well beyond the scope of the present study, but at the same time, it appears that such an approach would be the one most likely to give accurate cost models. Fortunately, the February Study [9] contains subsystem cost information for central receiver systems at a wide range of sizes. Furthermore, a great deal of similar information is available in the Solar Thermal Repowering Studies, in which thirteen solar central receiver systems ranging from 9.5 MW_t to 330 MW_t (32 MMBtu/hr to 1125 MMBtu/hr) were designed and costed by different engineering teams [38]. Table XVI is a brief summary of these studies. Our strategy in developing cost models for the solar part of the hybrid plant consisted of treating the subsystem costs presented in the repowering studies and in the February Study as "data" in an attempt to discover regularities in the costs that could be used to generate cost models for each subsystem. In order to more accurately compare costs of the various systems in the repowering studies, we have used cost figures determined by Kaiser Engineers [38p] in a study in which costs reported in the repowering studies were redistributed in order to make subsystem costs more consistent throughout the studies. Furthermore, a uniform heliostat cost of $93.50/m^2 was used in calculations.

7.2.2 Heliostat Subsystem Capital Costs--Because of the large number of heliostats required in a solar central receiver power system, it is expected that they will be manufactured in a single model [39]. Under such a manufacturing strategy, the cost per unit heliostat should be constant and thus the cost per unit mirror area should be constant. Indeed, heliostat costs are usually quoted as a cost per square meter of mirror area. Given this costing method, a model of mirror field area as a function of power plant size will give us a heliostat subsystem cost model. In Fig. 7 we plot heliostat area data vs. design point power at the tower base. As can be seen the total mirror field area is proportional to the power output. This

TABLE XVI

REPOWERING STUDIES SUMMARY

Study	Plant	Size (MW_t)	Heat Transfer Media	Receiver Type	Field Type	Ref.
1	ARCO - Natural Gas Refinery (CA)	9.5	Oil	External	North Field	38a
2	U.S. Gypsum (TX)	11.9	Air	Cavity	North Field	38b
3	Gulf R&D Ore Refinery (NM)	13.9	Water	External	North Field	38c
4	Exxon Oil Recovery (CA)	29.3	Water	Cavity	North Field	38d
5	Valley Nitrogen (CA)	34.5	Gas	Cavity	North Field	38e
6	Provident Oil Refinery (AZ)	43.5	Water	External	North Field	38f
7	Public Service of OK	73.3	Water	External	North Field	38g
8	El Paso Electric (TX)	130	Water	External	North Field	38h
9	South Western Public Service (TX)	141.8	Sodium	External	Surround	38i
10	Texas Electric Service	158.5	Sodium	External	Surround	38j
11	West Texas Utilities Co.	226	Sodium	External	Surround	38k
12	Arizona Public Service	316	Molten Salt	Cavity	Surround	38m
13	Sierra Pacific Power (NV)	330	Molten Salt	External	North Field	38n

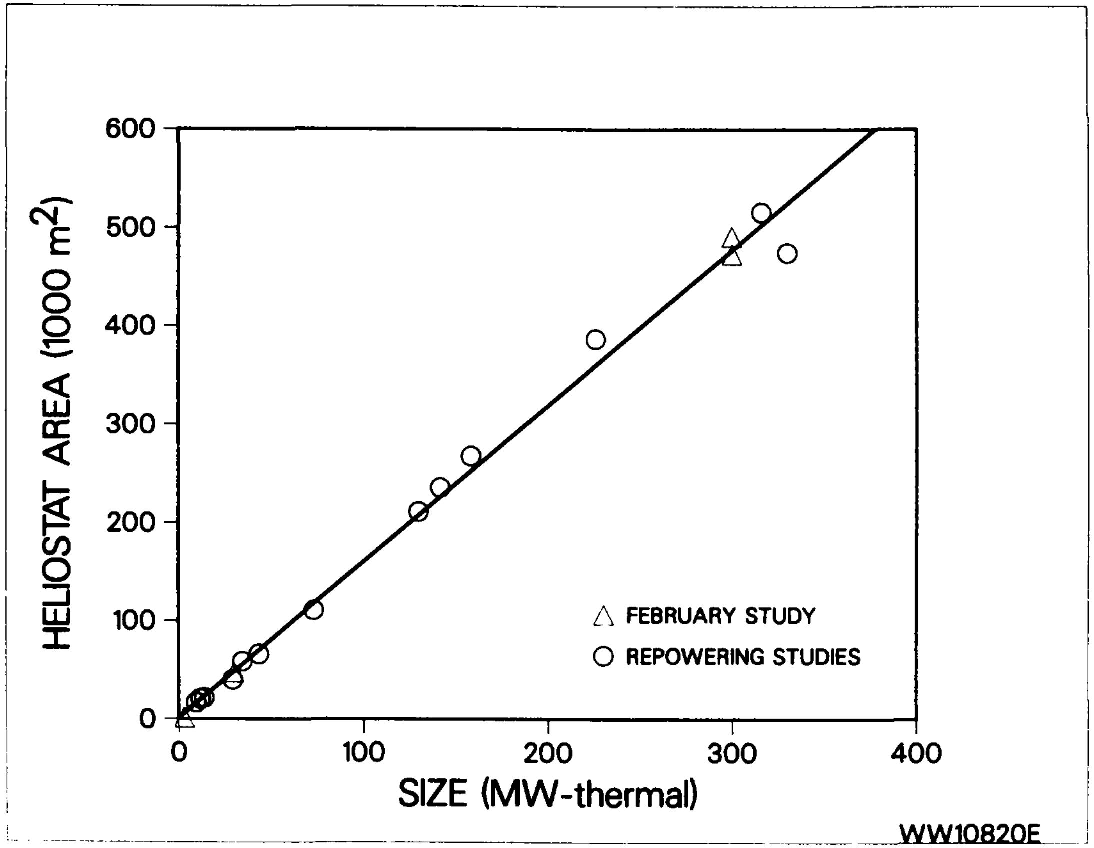


Figure 7. Variation of Total Mirror Area with Rated Design Point Power Output

is equivalent to stating that the collection efficiency of the plant is not strongly dependent on size, at least for the size range considered here. It is interesting to note that such variables as heat transfer media, receiver type (external vs. cavity), field type (north field vs. surround field), etc. have no major influence on the energy collection efficiency. From the slope of the line in Fig. 7, we can calculate the mirror area per unit output power (1600 m^2/MW_t) and using a cost for heliostats of $93.50/$m^2$ we get a heliostat subsystem capital cost of $150/$kw_t$ = $44,000/(MMBtu/hr), which is independent of plant size, receiver type, etc.

7.2.3 Receiver Subsystem--The receiver subsystem consists of the receiver itself, the tower, and the associated piping (the riser and downcomer). Figure 8 shows a plot of reported specific receiver subsystem costs against the logarithm (base 10) of the design point output rating over the size range of interest in this study. With the exception of one high pressure, high temperature water/steam receiver, all data fall on one of two lines.

Results of the February Study show specific receiver subsystem capital costs to be essentially independent of plant size. This behavior is qualitatively different from that exhibited by the low pressure repowering studies systems, in which subsystem capital cost decreases linearly with the logarithm of receiver size. The reason that the receiver subsystem cost should scale with the log of the plant size is not known, but the scaling observed here undoubtedly reflects some feature in a costing algorithm in common use in estimating tower or heat exchanger (or both) costs.

We have no reason to reject either the linear cost model presented by the February Study results, or the logarithmic cost model derived from the repowering studies results. As a consequence, we have treated these two models as defining a "band" of costs within which we expect the receiver subsystem capital cost to lie. Again, notice that the particulars of the receiver design do not dictate different cost models (if we ignore high pressure systems*) but rather result in noise on the basic cost model used.

7.2.4 Thermal Storage Subsystem--Neither the systems considered in the February Study nor many of the systems designed in the repowering studies included thermal storage subsystems. Consequently, we found it necessary to consider the design of this subsystem in considerably more detail than the others in order to obtain accurate capital cost scaling information. The methods used in calculating these costs are essentially those used by S. Faas in his computer code, QDSTOR [40].

As discussed below in section 8, we have used one of three heat transfer fluids (water/steam, molten nitrate salt, or oil) in the design of steam generation systems. The water/steam systems utilized no thermal storage. Oil systems used a single stage oil/crushed granite thermocline storage system contained in a cylindrical carbon steel tank. Molten salt systems used a single stage, dual tank storage method. Materials and tankage geometry

*None of the systems under consideration in the present study utilize high pressure (>1000 psia) steam.

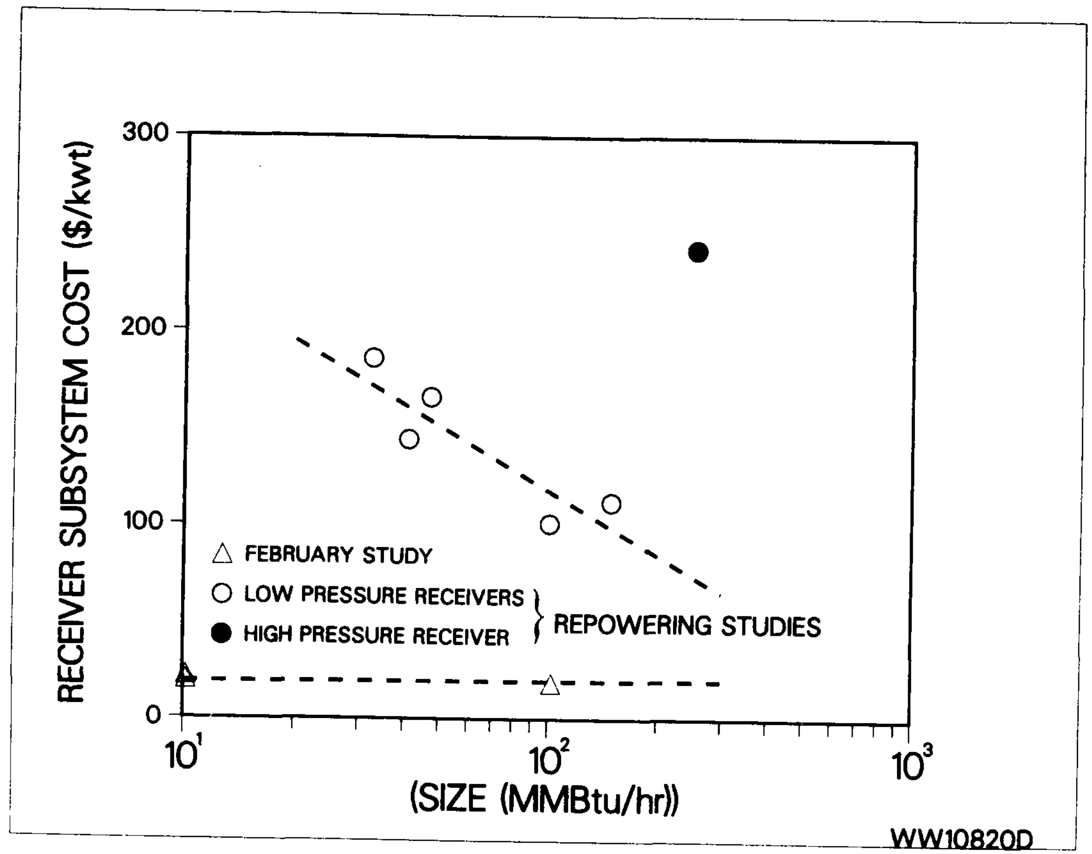


Figure 8. Variation of the Receiver Subsystem Specific Capital Cost with Design Point Power Rating

used in the molten salt case were dependent on salt temperature (see Table XVII).

Water/steam systems were assumed to require no heat exchangers since such systems used no thermal storage, while the systems using either oil or molten salt did (see section 8). Materials used in the exchangers were determined by operating temperature and compatibility with operating fluids (see Table XVII).

Storage tanks were limited to 45 ft. in height and constructed in 5 foot high sections of steel of differing thickness to account for differences in hydrostatic loading. The amount of insulation used on the storage tanks was such that heat losses were limited to 2.4%/day. Tanks were placed on concrete slab foundations. The number of heat exchangers from storage was either two (for saturated steam) or three (to produce superheated steam). Exchangers were sized to provide the necessary steam heating rate and costed by exchanger area (see Table XVIII). Pumps were costed on the basis of the pressure head needed and the flow rate of heat transfer fluid required (see Table XVIII). Storage cost is minimized by optimizing the temperature swing across the heat exchangers [40].

7.2.5 Balance of Plant Capital (B.O.P.) Costs--The cost of the remainder of a solar central receiver plant (buildings, controls, land, etc.) is usually handled in a somewhat arbitrary manner. Either a constant cost is assumed [37] or else a constant cost per unit energy output is assumed [9]. We have used the latter assumption, and determined the constant value to be used by calculating a weighted average of the B.O.P. cost reported in the February [9] and repowering studies [38]. Weighting favored the results of the February Study since a number of the repowering studies had B.O.P. costs which were unusually large due to some unique feature of the particular repowering project (e.g. exceptionally long pipe runs to interface to an existing plant, etc.). The value used is $82.50/kW$_t$ (= $24,200/MMBtu/hr). Figure 9 compares this value with those reported in the various studies. As can be seen, the repowering studies, taken by themselves, indicate somewhat of an increase in the specific B.O.P. capital cost as plant size decreases. Consequently, the B.O.P. capital cost may be underestimated by our assumption of constant specific cost. However since B.O.P. costs are only a small fraction of the cost of energy from a solar-fossil hybrid plant (see section 11) the results of the present study will be only very slightly affected if our constant cost assumption is not quite accurate.

7.2.6 Total Capital Costs--Figure 10 shows a comparison between the total capital cost models developed above and the total capital costs reported in the February and Repowering Studies. Recall that the costs in those studies have been used as redistributed by Kaiser Engineering [38p] with no attempt to bring them to a common accounting method except that the heliostat cost has been adjusted to a value of $93.50/m^2 (an nth plant cost) for all studies. In the present study the range of capital costs defined by the two curves in Fig. 10 has been used as a total capital cost band to show sensitivity of energy cost to variation in capital cost. Notice that while the models do not predict reported capitals costs exactly, the agreement is quite good in view of the different designs, accounting methods, etc. used in the various studies.

TABLE XVII [43]

STORAGE SUBSYSTEM MATERIALS CRITERIA

Tankage		
	$T \leq 700°F$	: Carbon Steel, Cylindrical
	$T > 700°F$	: Stainless Steel, Spherical
Heat Exchangers		
	$T \leq 600°F$	: Carbon Steel
	$600°F < T \leq 800°F$	: Chrome-Molybdenum Alloy
	$T > 800°F$	: Stainless Steel

TABLE XVIII [43]

STORAGE SUBSYSTEM COMPONENT CAPITAL COST DATA (1981$)

Media	Caloria: \$0.385/lb Nitrate Salt: \$0.165/lb Crushed Granite: \$0.006/lb
Tanks	Cylinderical Carbon Steel: \$0.55/lb Spherical Stainless Steel: \$4.40/lb Insulation: \$6.60/ft^3
Pumps	Carbon Steel Pumps: \$76.5 $(\Delta p \cdot f)^{0.43}$ Stainless Steel Pumps: \$125.5 $(\Delta p \cdot f)^{0.43}$ Note: Δp = pressure head (psia) f = fluid flow rate (ft^3/hr)
Heat Exchangers	Carbon Steel: \$19.5/ft^2 @ 10000 ft^2 Chrome-Moly: \$23.3/ft^2 @ 10000 ft^2 Stainless Steel: \$40.9/ft^2 @ 10000 ft^2 Scaling is by the equation: $\text{capital cost (\$)} = R\left(\frac{\text{Area}}{10000}\right)^{1.05} (10000)$ where R = reference cost given above

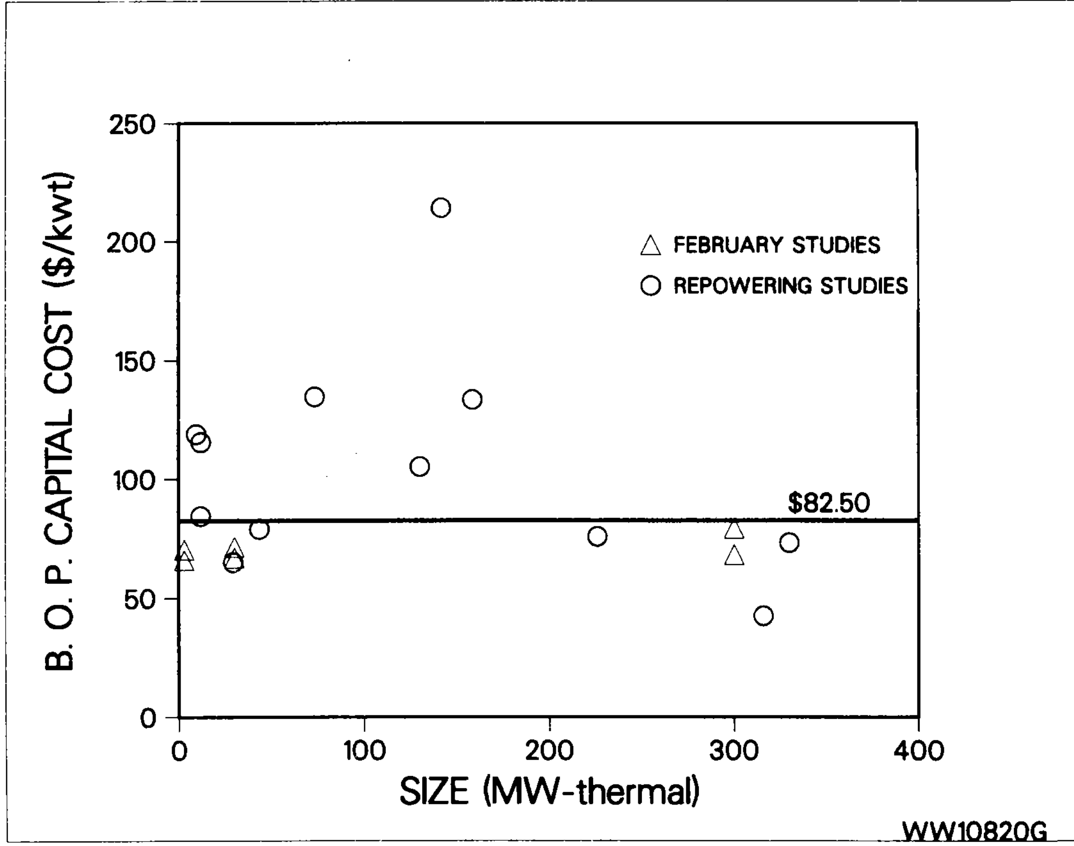


Figure 9. Variation of the Balance-of-Plant Specific Capital Costs

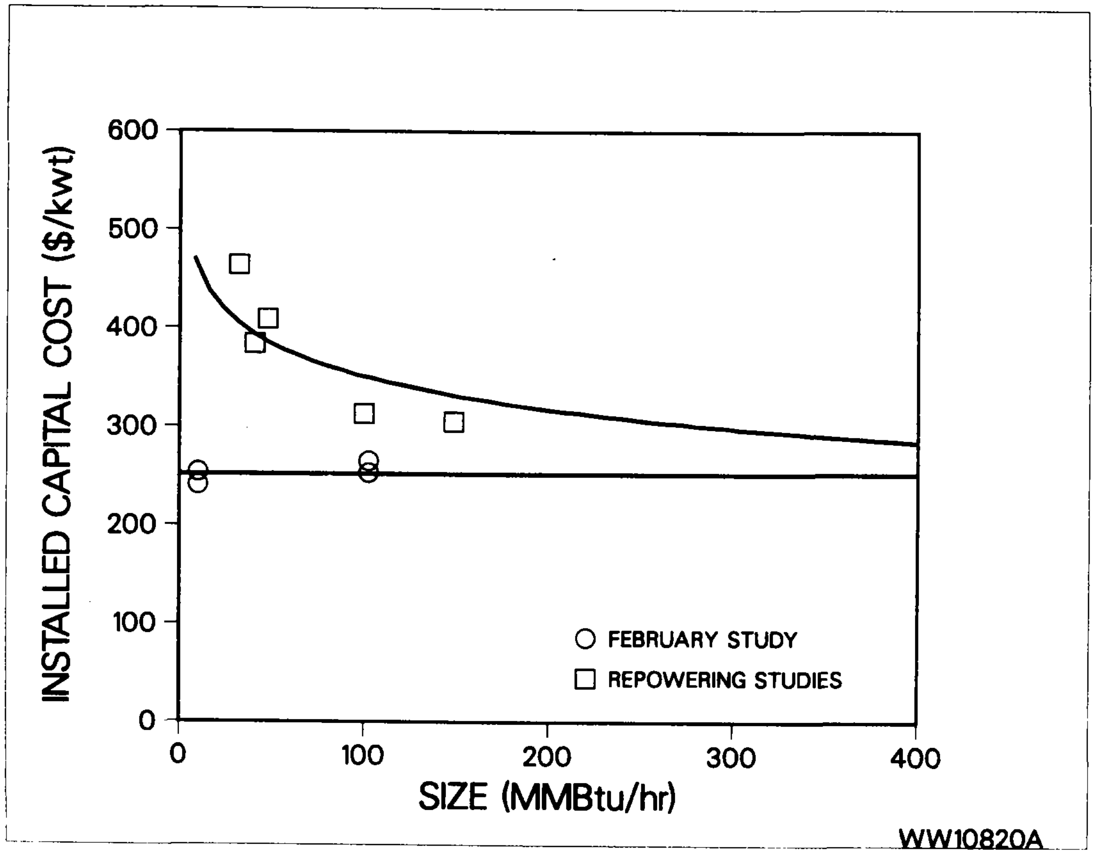


Figure 10. Variation of Total Capital Cost of a Solar Central Receiver System. Lines are generated by the cost models used in this study. Points are those reported in the several studies with heliostat costs adjusted to a price of $93.50/m^2$

7.2.7 Operation and Maintenance Costs--In general, operation and maintenance (O&M) costs for solar central receiver systems are calculated as a percentage of total capital costs [39]. This percentage is usually taken to be 2%, in agreement with the O&M costs assumed in the electric power generation industry [41]. Figure 11 shows the reported size variation in O&M cost as reported in the various studies consulted here [9,38]. Again, the total capital cost has been adjusted to reflect a uniform heliostat capital cost of $\$93.50/m^2$. The reported BOP costs fall into two bands: one near the usual 2% of capital costs, the other closer to 5% of total capital cost. In part because of the high O&M costs known to be associated with small fossil systems (see section 6.6) and in part because some of the repowering studies which report low O&M costs fail to provide adequate manning of the plants*, we have used an annual O&M cost for the solar portion of the plant of 5% of total solar capital cost.

8. Solar Central Receiver - Fossil Hybrid Plant Design

8.1 Plant Requirements

The details of the design of a steam generation plant are quite dependent upon the required steam characteristics (pressure and temperature). However, steam conditions used are roughly related to the size of the steam plant. As a result, one can define representative plant sizes and steam conditions for study. We have chosen to use the representative plants used in earlier EPA studies (see section 3.2 and Table IV for a description). Those plants require saturated steam for sizes of 75 MMBtu/hr and smaller, while they use superheated steam for larger sizes.

As a base case, we require the steam plants considered here to operate at an average of 60% of capacity, 24 hours a day, seven days a week (see section 11.1 for details of the load curves used). Power for steam generation during hours of darkness comes either from thermal storage or else from the burning of fossil fuel (either coal or gas, depending on plant design).

The fossil portion of the plant was considered to have a minimum firing rate of 8% of rated capacity. A boiler efficiency correction as a function of size was imposed on the fossil boiler (or fluid heater) as shown in Fig. 12 [42].

8.2 Water/Steam Receiver Systems

Since the end product desired from the plants under consideration here is steam, the simplest design uses a water/steam receiver system as shown in

*For example, some of the studies use one person for both system operation and maintenance. Many local or state boiler ordinances require that an operator be present at all times during operation of a boiler system, so such proposed manning could be illegal.

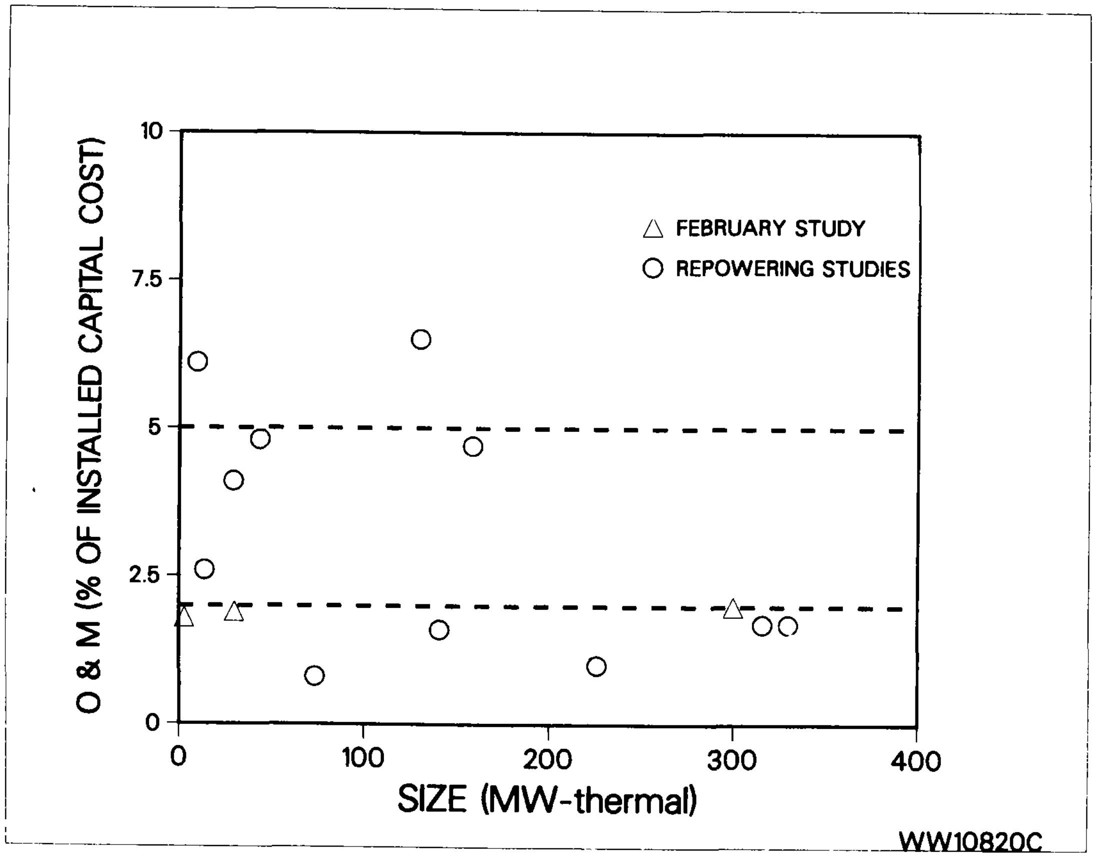


Figure 11. Variation in Operation and Maintenance Costs

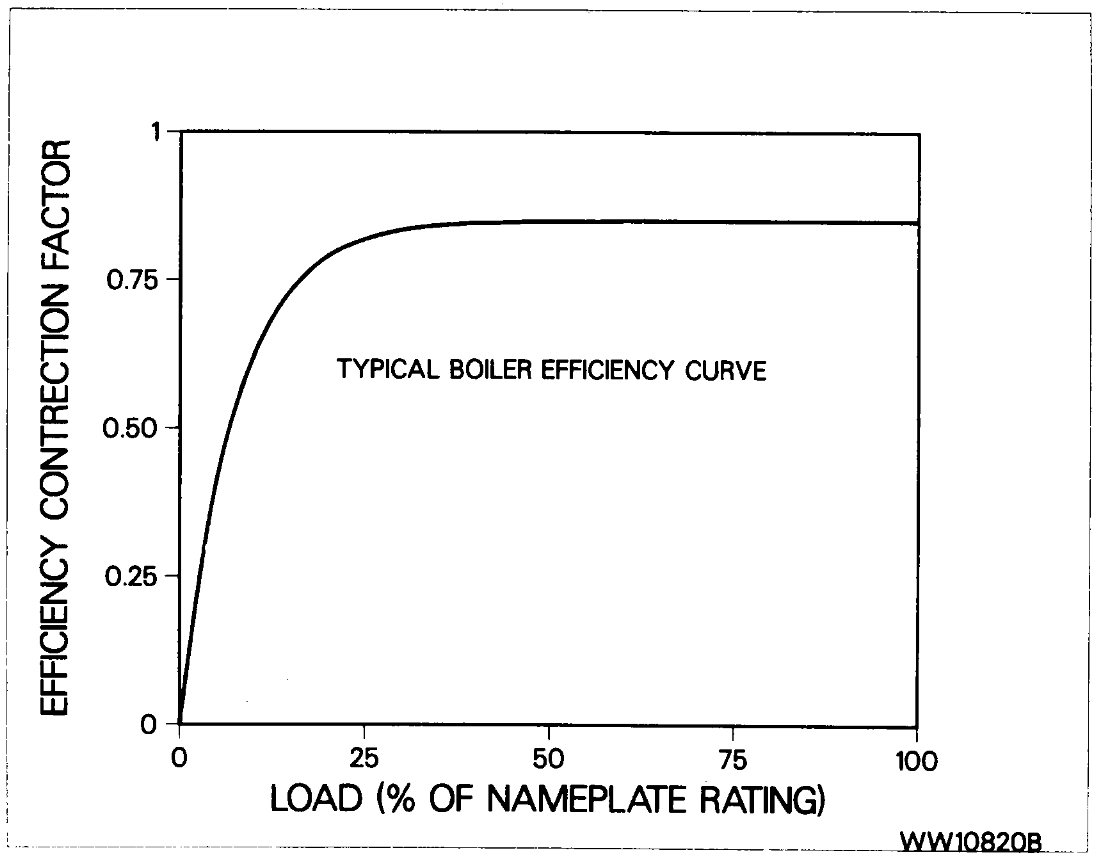


Figure 12. Boiler Efficiency Correction Curve

Figure 13. These systems were used to cost hybrid plants which did not utilize any thermal storage. No water/steam receiver systems utilizing thermal storage were considered since other work has shown such plants to be uneconomical when compared to systems using either oil or molten nitrate salts as receiver heat transfer fluids [43].

8.3 Oil Receiver Systems

Previous work [43] has shown oil receivers coupled with oil/rock thermocline thermal storage to represent the least expensive solar central receiver technology for low temperature steam generation. Therefore, we have used such a system in the design of the representative plants with capacities of 15, 30, and 75 MMBtu/hr (and requiring thermal storage). Figure 14 is a schematic of the design used for these representative plants.

Notice that this design uses a fossil fired oil heater rather than using a fossil fired boiler in parallel with the receiver. This was done for two reasons; first, since the boiler operates out of thermal storage, the system is well buffered against insolation transients. Second, this configuration allows the oil heater to charge storage during periods when no steam load is required (e.g. overnight for some load curve scenarios-see section 11.2). Consequently the power generated with the oil heater at minimum firing (8%) is potentially not wasted.

The oil heater was designed conceptually as a modified water-tube boiler. Modifications would include addition of extra tubes to increase heat transfer efficiency. However, the oil heater is not a pressure vessel as is the boiler, so that parts with thinner walls can be used throughout. As a first approximation we have assumed these two effects balance each other and that an oil heater would cost the same as a conventional boiler.*

Only two heat exchangers are necessary on this system since the representative plants operating in the temperature region where oil receivers are useful use saturated rather than superheated steam.

8.4 Molten Salt Receiver Systems

For the representative plants which produce high temperature (> 600F) superheated steam, molten nitrate salt was chosen as a heat transfer fluid in those cases in which thermal storage was necessary. Previous work [43,45] has shown such a plant to produce the least expensive power under the conditions of high temperature. Figure 15 is a schematic of the plant design used for these systems.

A two tank thermal storage scheme is used. The rationale for using a fossil salt heater in parallel with the central receiver is analogous to

*This probably overestimates the cost of the oil heater by ~3%, a negligible amount. The analysis is analogous to that of salt heaters in ref. 44.

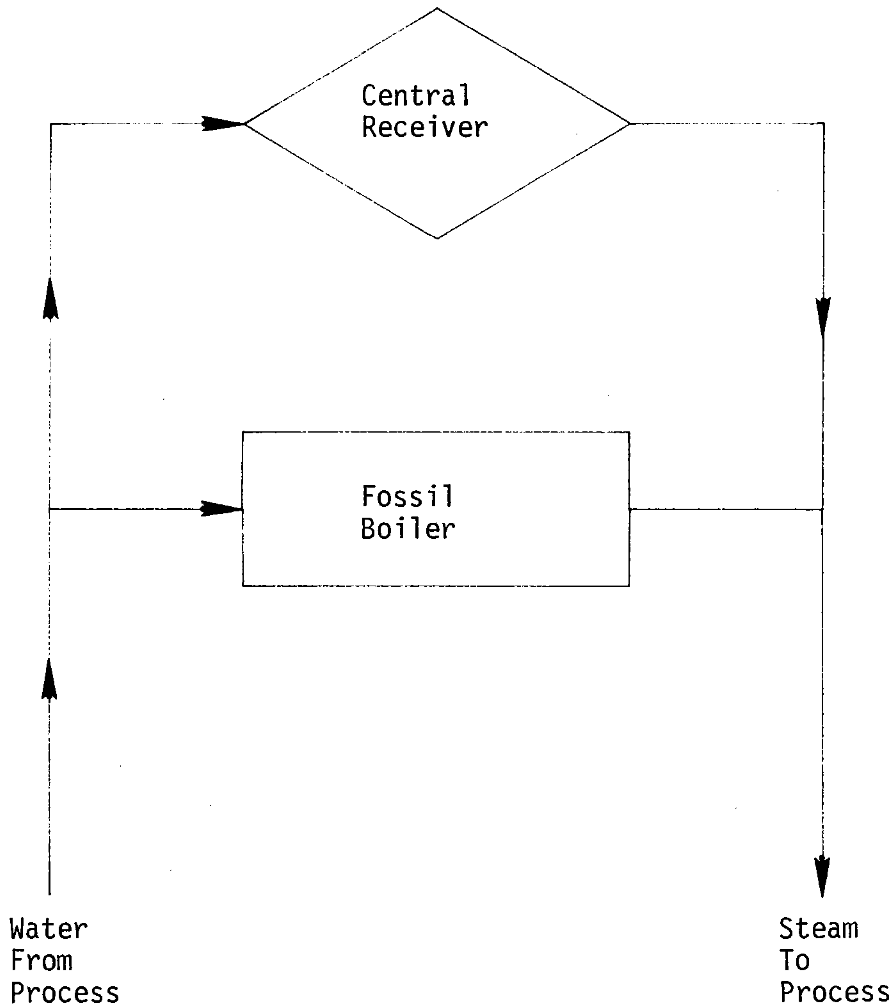


Figure 13. Water/Steam Receiver System

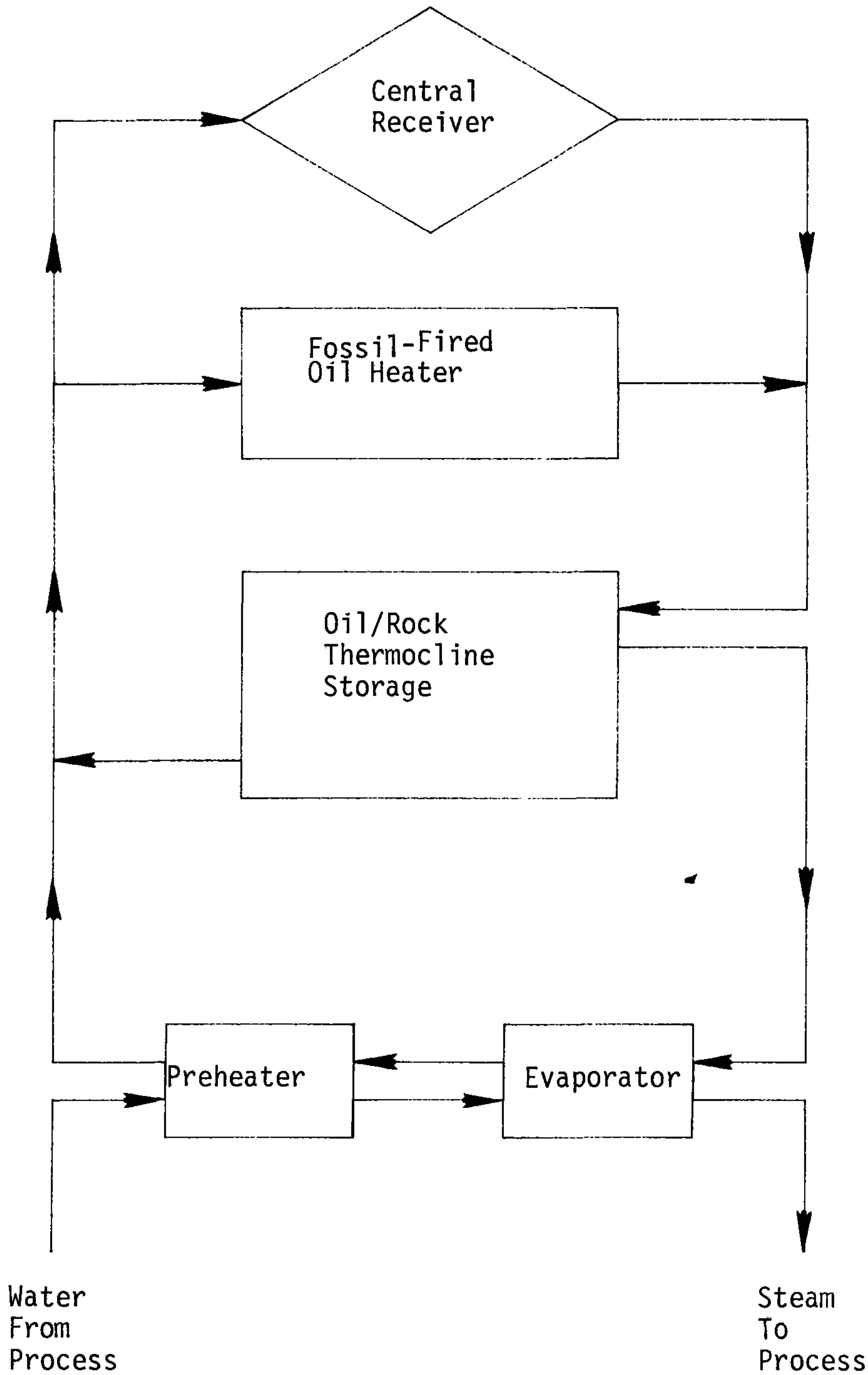


Figure 14. Oil Receiver Based Hybrid System

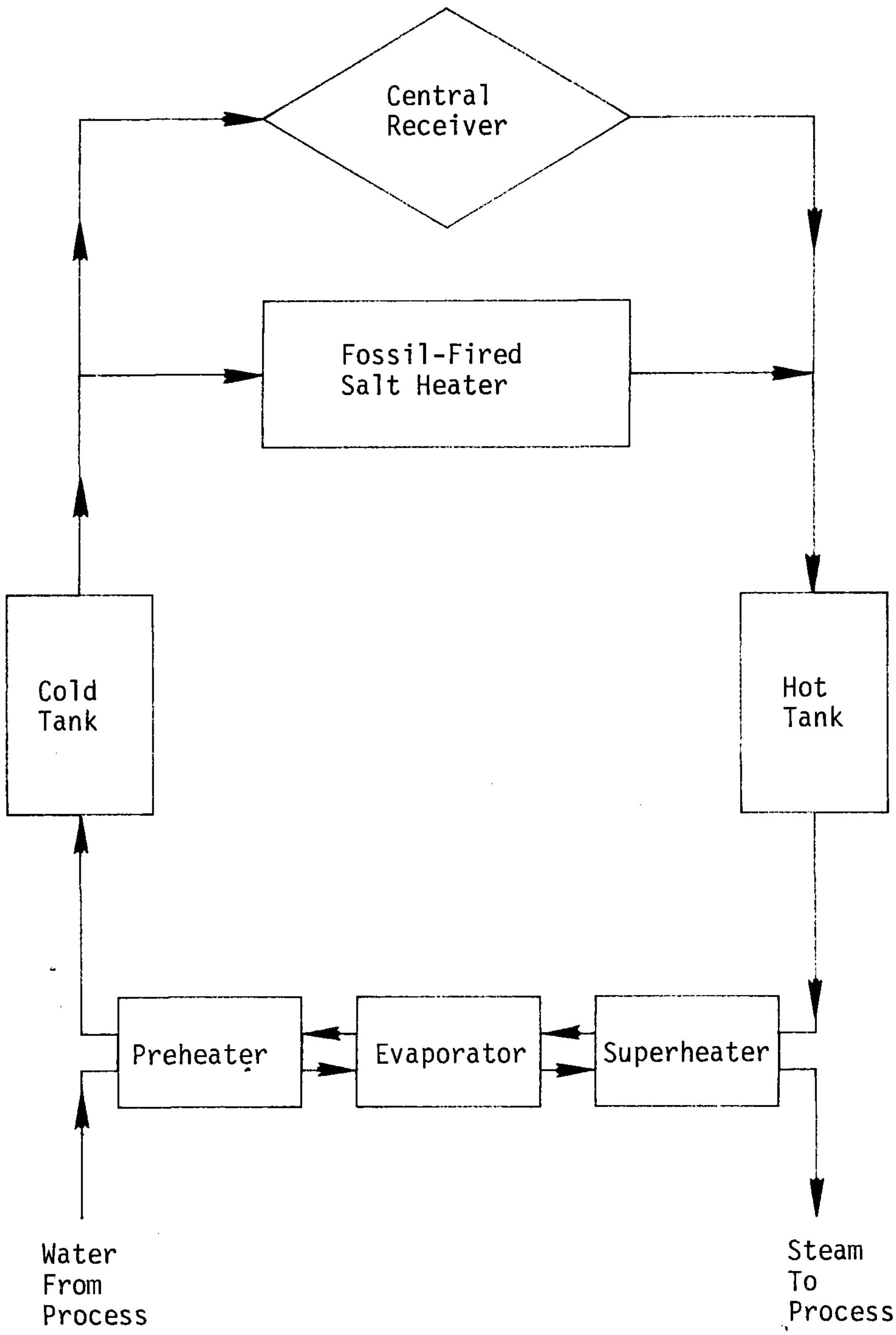


Figure 15. Molten Salt Receiver Based Hybrid System

that for the similar oil receiver system (see section 8.3). Notice that for this system, three heat exchangers are required in order to produce superheated steam.

The salt heater is a modified conventional water tube boiler. Modifications include increasing the number of tubes to improve heat transfer and replacement of all parts in contact with the hot molten salt with parts made of stainless steel. Also, wall thickness has been reduced somewhat since the salt heater operates at low pressures. The resulting salt heater is assumed to have an 8% higher capital cost than a water tube boiler of the same size [44].

8.5 Reference Plant Designs

Table XIX presents a summary of the solar hybrid design used in each of the reference steam generation plants.

9. Energy Cost Analysis For the Solar-Fossil Hybrid Plant

9.1 Capital Costs

The preceeding discussion has itemized the costs of both fossil boiler plants and solar central receiver plants as stand-alone units. The capital cost of a solar-fossil hybrid plant is essentially the sum of the costs of the two component systems (with a cost penalty for conversion of the fossil boiler to a salt or oil heater, if necessary, see sections 8.3 & 8.4). However, simply summing the costs results in some duplication in the costs of buildings and controls.

We have attempted to account for this duplication by correcting the cost for the fossil part of the plant. This was done by treating the boiler as if it were being erected as part of a process plant. Cost correction factors for this situation are available [16]. They reduce the capital cost of the oil/gas fossil plant by 6% and that of the coal plant by 16%. Capital cost of the solar portion of the hybrid plant is as presented in section 7 with no modification.

9.2 Operation and Maintenance (O&M) Costs

As shown in section 7.2.7, we calculated annual O&M costs for the solar fraction of the plant at 5% of the capital cost of that portion of the plant. Fossil O&M costs used were those presented in section 6.4. Boiler staffing is included only in the fossil O & M costs. Therefore, total O & M costs were assumed to be the sum of the costs of the two parts. Some sharing of personnel between the solar and fossil portions of the plant is possible and was incorporated through the use of multipliers [16] for the fossil portion of the O&M costs.

TABLE XIX

CONFIGURATION OF THE HYBRID STEAM
GENERATION SYSTEMS CONSIDERED

Q (MMBtu/hr)	Steam Conditions (°F, PSIG)	(Modified) Gas Boiler Type	(Modified) Coal Boiler Type	Solar Receiver w/Storage	System Type w/o storage
15	365, 150	package	package underfeed stoker	oil (caloria)	water/steam
30	365, 150	package	package underfeed stoker	oil (caloria)	water/steam
75	365, 150	package	field erected spreader stoker	oil (caloria)	water/steam
150	600, 450	package	field erected spreader stoker	molten nitrate salt	water/steam
200	750, 750	multiple package	field erected pulverized coal	molten nitrate salt	water/steam
400	750, 750	multiple package	field erected pulverized coal	molten nitrate salt	water/steam

9.3 Economic Conditions

Economic assumptions suitable for construction of industrial construction of a steam plant have been assumed [46]. These assumptions are presented in Table XX. Different economic assumptions would change the absolute values of levelized costs calculated here, but the qualitative comparisons would not be greatly affected.

10. Calculation Methods

10.1 Introduction

The configurations used for solar hybrid steam plants in this study are shown in Figures 13-15. The rationale underlying the selection of these configurations and the cost and performance of the individual components has been discussed in the preceding sections. The most cost efficient size of both the solar central receiver system itself and its thermal storage capacity is not at all obvious. Thus to estimate the optimum size of the collector and storage subsystems and to examine the relationship between the levelized energy cost and subsystem sizes, the computer program referred to in reference 47 was modified slightly to reflect the cost algorithms presented earlier in this report. A short description of this approach and some of its important features are presented below.

10.2 System Optimization

Given the boiler name plate power rating, hourly direct insolation data and a set of hourly load values, the program estimates the optimum amount of storage (i.e., that amount resulting in the lowest cost energy) at ninedifferent preset solar multiples.* During the optimization procedure (a gradient search method was used) the levelized energy cost (LEC) associated with a given amount of storage is calculated through an hour by hour simulation of actual plant operation. The simulation is effected by calculating energy production by the solar collector and requiring thermal storage and the fossil heater** to make up the necessary energy to meet the given load. (These calculations include a 0.1% per hour loss rate of the stored energy.)

To obtain a set of energy cost curves as a function of storage size, four additional energy costs are calculated by perturbing the optimum storage capacity for each solar multiple (except the stand alone fossil heater) by ± 50 and ±100%. If the optimum occurs at zero storage, then additional costs are calculated at a storage capacity of 1, 2, 3 and 4 hours of maximum boiler output. An example of this output is shown in Fig. 16.

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*The solar multiple is defined to be the design point power output of the solar receiver divided by the nameplate power output of the fossil boiler. The nine values used are: 0., .5, .75, 1., 1.33, 1.67, 2.0, 2.5, and 3.0.

**The terms 'heater' and 'boiler' will be used interchangably throughout the rest of the report.

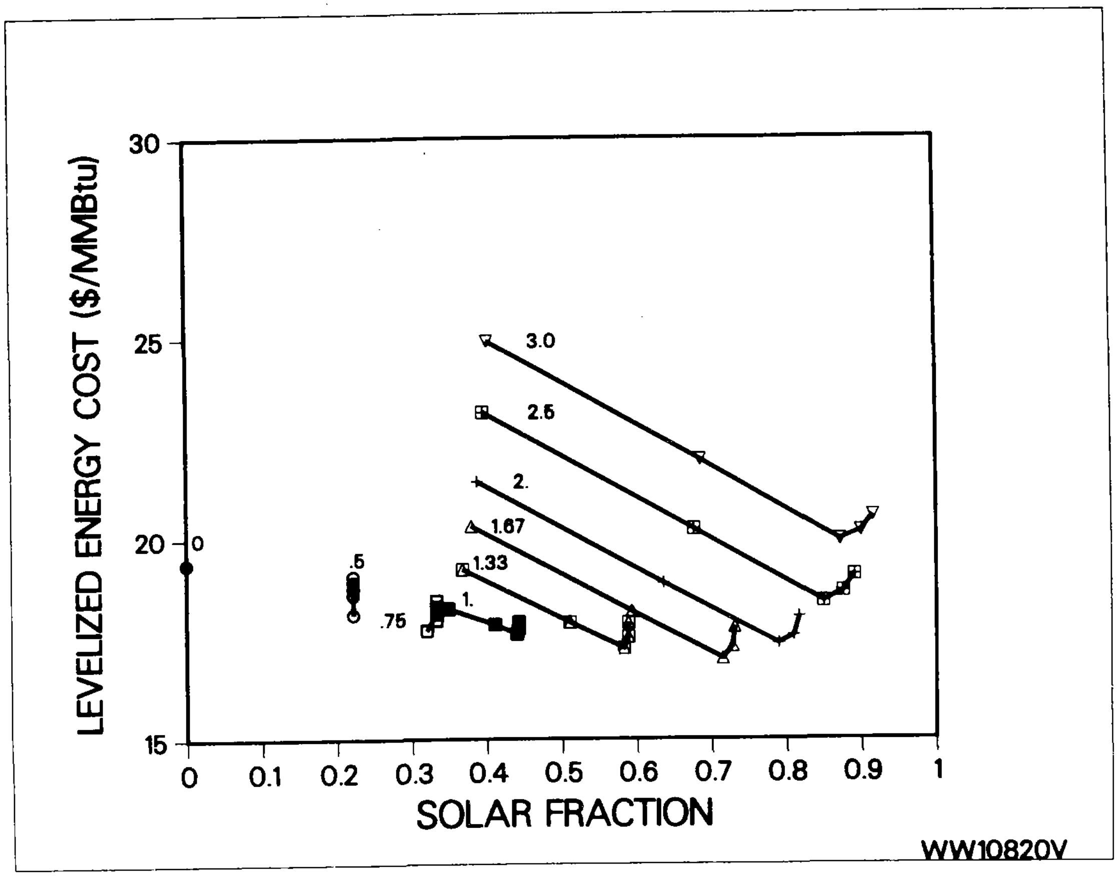

Figure 16. Example of Program Output. These particular results are for a 15 MMBtu/hr gas boiler using the linear solar costing algorithm. Each curve is for a different solar multiple. The points on any one curve are for 0, 0.5, 1.0, 1.5, 2.0 times the optimal amount of thermal storage at that solar multiple. Notice that the apparent discontinuity especially evident at the smaller solar multiples is a result of the change in receiver type as thermal storage is added (c.f. Table XIX)

TABLE XX

ECONOMIC ASSUMPTIONS
(COSTS EXPRESSED IN 1981 DOLLARS)

Begin Construction:	1988
Year of Start-up:	1990
General Inflation:	6%
Debt Fraction	0.3
Debt Cost	9%
Equity Fraction	0.7
Equity Cost	15%
Tax Rate	48%
Property Tax + Insurance	2%
Tax Life*	16 years
Operating Life	20 years
Investment Tax Credit	10%
Operation and Maintenance Escalation:	6%
Indirects	35%

*Sum-of-Years Digits (SYD) depreciation used.

One of the important advantages of this type of detailed simulation is that the effects of both day to day and seasonal variations in available insolation are taken into account. This study utilized insolation data from Albuquerque, NM for what is thought to be an average year for insolation (1957).

In order to more accurately reflect the actual operation of a hybrid plant, two changes were made to the computer code of reference 47. First, a minimum boiler input power of 8% of the maximum is maintained at all times, just enough to maintain a stable flame. Second, following Fig. 12 the boiler efficiency was made to vary as a function of power input, p_i, so that the output power, p_0, takes the form:

$$p_o = \varepsilon \, p_i \left(1 - e^{-13.22 \, p_i / p_m}\right)$$

where p_m and ϵ are the input power and efficiency at full capacity.*

10.3 Output Utilization

From output as shown in Fig. 16 the optimum system design (i.e., the one with the lowest LEC) can be determined. One can also get some idea of the stability of the estimated minimum LEC with respect to solar multiple. In addition, at any solar multiple the price stability of the design with respect to storage is easily inferred. For example, since the data points on either side of the minimum (Fig. 16) are the energy costs for thermal storage at ± 50% and ±100% of the optimum, it is apparent that a much smaller economic penalty is paid for providing too much storage than for too little. Furthermore, it is possible to estimate the lowest cost design which produces any given solar fraction as well as the largest solar fraction attainable for a given price. Thus, the code produces an immense amount of information, only a fraction of which will actually be discussed here.

11. Results and Conclusions

A basic problem with any kind of economic pricing study is inherent uncertainties in both the cost models for the various components and estimates for recurring expenses such as labor, fuel and other expendibles. In an attempt to address this problem, a base case scenario was examined and then sensitivity studies were done with respect to construction costs, operation and maintenance costs, fuel prices, imposed loads and pollution controls. The values of the various parameters used for the base case scenario as well as pertubations applied to them in this study are summarized in Table XXI. Each variation on any parameter listed was studied separately as an independent perturbation of the base case.

11.1 Base Case

The base case parameters are as follows. The fuel prices are set to 1-1/2 times present values (from Table VII). All construction and operation and maintenance costs used are as presented in section 6 and level 2 pollution controls are required (see Table X). In addition, the following 4-shift load curve is imposed: 70% of full boiler capacity from 8 a.m. to 4 p.m., 60% from 4 p.m. to midnight and 50% from midnight to 8 a.m., seven days a week. This particular load curve was chosen to have an average load of 60%, which falls within the industry standard range of 60 to 70% [48], and yet reflects some minor shift changes. The resulting levelized energy

*This inefficiency at low level operation suggests that it might be advantageous to set a minimum fireup higher than 8% of maximum to allow efficient operation while storing the excess energy. The maximum efficiency is not reached until the boiler is operated at 15% of full capacity. However, when the minimum fire up percentage was used as a parameter to be optimized the optimum value was always the minimum allowed, 8%.

TABLE XXI

THE STUDY MATRIX

Parameter Variations*	Fossil Captial Costs	Coal Boiler Type	O & M Costs	Pollution Control	Fuel Costs	Load	Solar Capital Costs	Heliostat Subsystems Costs
Base Case	As presented in Section 9.1	Conventional	as presented in Section 9.2	Level 2 Table X	1.5 times Present Cost	4 shift as per Section 11.1	Cost band as presented in Section 7.2.6	$93.50/m^2$
Other Cases	Base Case ±25%	AFB	Base Case ±25%	Level 1 Table X	Present Cost	2 Shift as per Section 11.2.4		$253/m^2$
					2 times present cost	1 shift as per Section 11.2.4		

*Note that the "other cases" listed were applied individually as perturbations on the base case.

costs (LEC) as a function of boiler capacity are shown in Fig. 17.

The solar pricing envelope discussed in section 7 produces a band for both the coal and gas hybrids. The solar hybrid costs are those of the optimum (minimum LEC) system, unless the system optimizes at a solar multiple of zero (i.e. fossil only), in which case the hybrid LEC shown is that of the 0.75 solar multiple system with the minimum LEC. The 0.75 solar multiple is used since in such a design the collector is capable of providing all or almost all daytime energy requirements. The hybrid cost band is bounded above by the curve obtained using the logarithmic cost model and below by the linear cost model.

Several important trends can be discerned in Figure 17. First coal stand-along boilers generally have the lowest LEC, with solar-hybrids a close second. Gas stand-alone boilers are the most expensive choice. Second, solar-gas hybrids produce steam at a significantly lower price than a gas stand-alone plant. Furthermore, solar-coal hybrids have a LEC only 10-15% greater than that of a coal stand-alone, while obtaining nearly all their daytime energy requirement from sunlight. Finally, the increase in LEC as size decreases is less than a factor of 2, and does not dramatically affect the cost ordering of the various technologies. As will be seen, these trends persist through most of the sensitivity studies examined here.

Figure 18 presents a breakdown of the base case LEC's presented in Figure 17 into their component parts. Several important features can be noticed. First, for the hybrid to be economically attractive, the solar portion of the plant must pay for itself by displacing fuel since none of the stand-alone fossil capital cost and only a very small portion of the stand-alone fossil O & M cost is displaced in a hybrid design. Consequently, the more expensive the fuel that is displaced the more attractive the hybrid plant is relative to its stand-alone counterpart. In this case, the gas hybrid underprices the gas stand-alone system by displacing fuel at $7.50/MMBtu, while the coal hybrid cannot underprice the stand-alone coal plant (although it comes close) by displacing coal priced in the range $2.09 - $2.89/MMBtu. Figures 18a and b also illustrate how large O & M costs for fossil boilers are relative to capital costs - especially in the case of gas hybrids. Finally, increases in O&M costs are seen to be the major source of increases in LEC as plant size decreases (although coal prices also show some such increases - see section 4.2).

11.2 Sensitivity Studies

Figures 19 through 24 show the results of the sensitivity studies (summarized in Table XXI) done with respect to various component costs, pollution control requirements, etc.

11.2.1 Pollution Control--Figure 19 shows the LEC versus size curves resulting from using level 1 pollution controls (Table X). As might be expected, this relaxation of control requirements lowers the cost of energy from the coal and coal hybrid plants by the amortized cost of flue gas desulfurization (FGD) (approximately $2/MMBtu) for sizes greater than 75 MMBtu/hr heat output. This makes the gas systems even less attractive at large sizes but has no effect on the relative differences in the LEC of the coal stand alone and the coal hybrid plants.

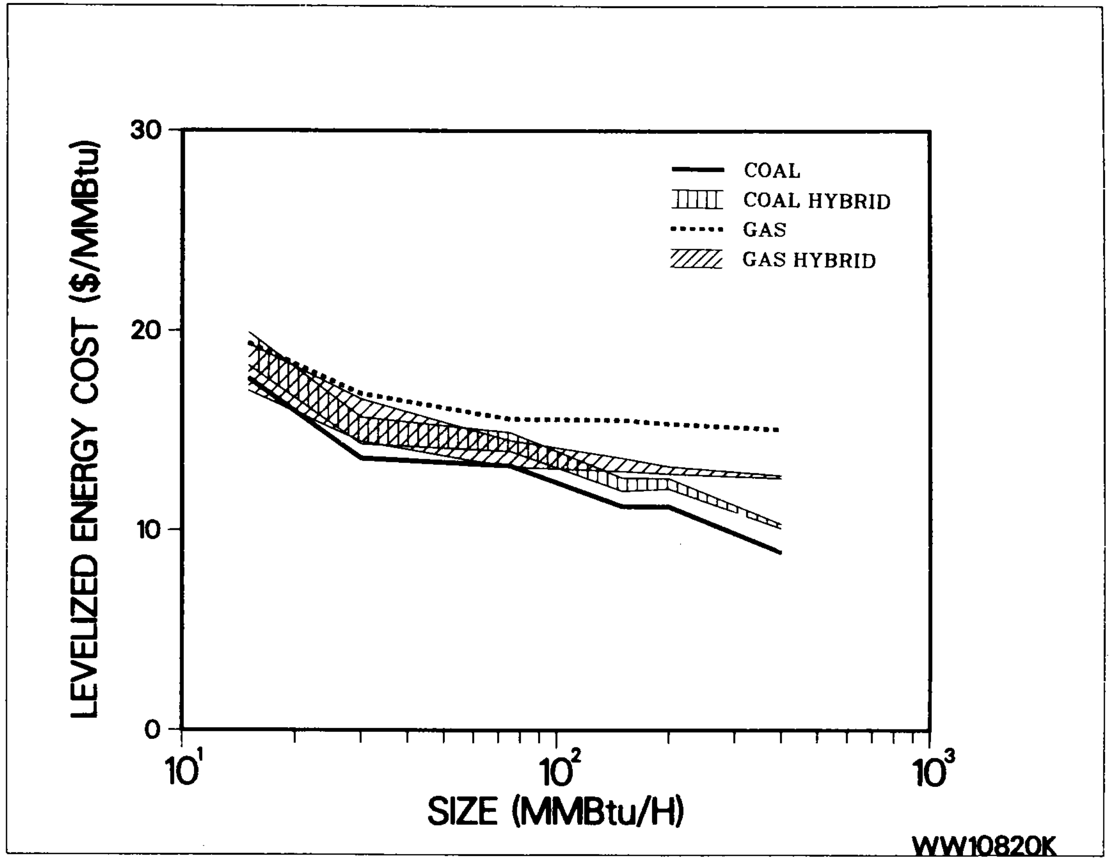

Figure 17. LEC Curves for Base Case

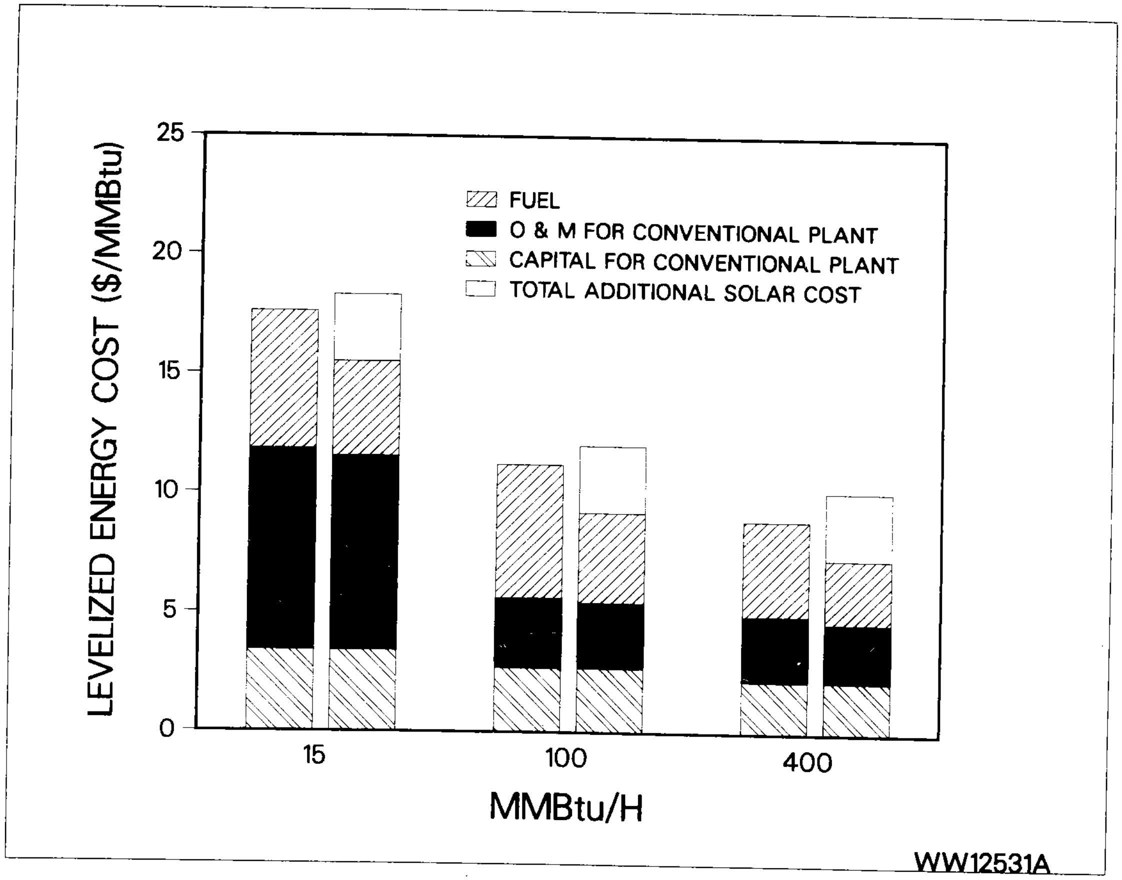

Figure 18a. Component cost breakdown for coal hybrid and coal stand-alone designs at three different plant sizes. A linear cost model solar design with SM = 0.75 and no storage was used throughout.

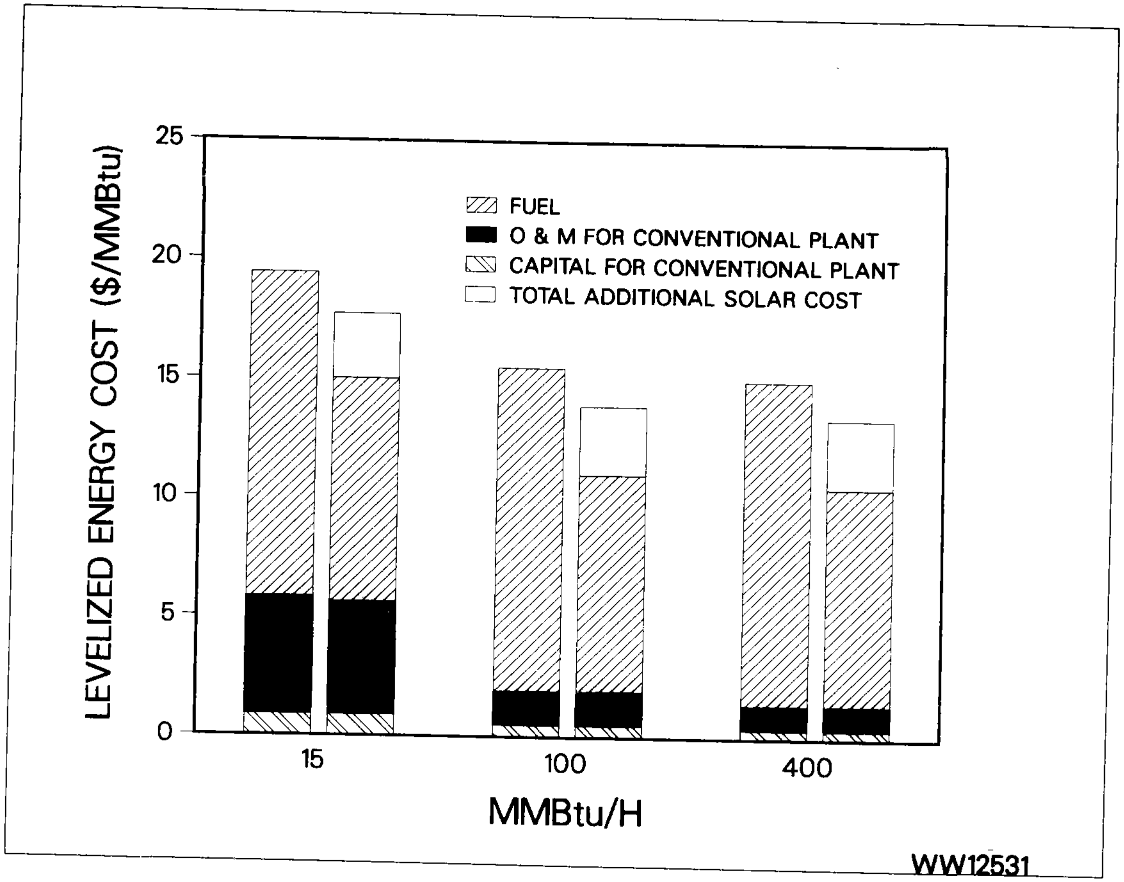

Figure 18b. Component cost breakdown for gas hybrid and gas stand-alone designs. A linear cost model solar design with SM = 1.67 and ~8 hours of thermal storage is used throughout.

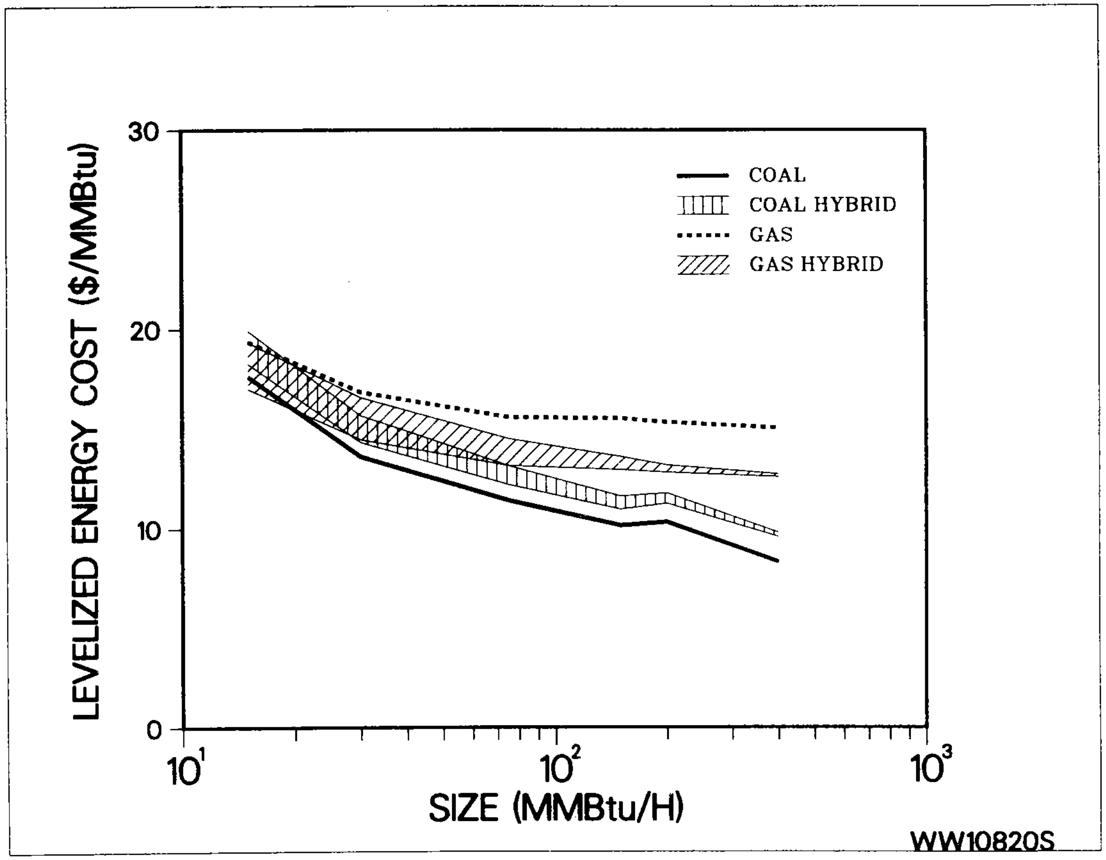

Figure 19. LEC Curves Obtained Using Level 1 Pollution Controls. (All other parameters base case)

11.2.2 Fuel Prices--Effects on LEC of varying the fuel prices from those of the base case are shown in Figures 20a and b. Levelized steam costs for plants burning fuel at present prices* (assuming decontrolled natural gas) are shown in Figure 20a. The effect of burning fuel at twice current prices is shown in Figure 20b. Since the LEC of steam generated by the stand-alone gas plant is dominated by the price of fuel (see Figure 18b), this LEC is particularly sensitive to fuel price changes. While one might expect the gas hybrid LEC to exhibit a similar sensitivity, a comparison of Figures 17 and 20 show that this is not quite the case. As fuel price increases, the LEC of the gas hybrid is "buffered" from the full impact because the optimal design favors larger amounts of thermal storage as fuel price increases. (In the least expensive fuel case considered here the gas hybrid design used has no thermal storage - in the other fuel price scenarios the optimum design uses about eight hours of thermal storage-giving the plant a solar fraction in the range 0.7-0.8).

On the other hand, the coal stand-alone plant produces steam at a price that is not as sensitive to fuel price because the LEC is dominated by capital and O & M costs- see Figure 18a. Furthermore, the coal hybrid plants shown do not use any thermal storage and hence do not exhibit the "buffering" affect with increasing fuel price shown by the gas hybrids. The net result is that as fuel prices increase over the range considered here, the LEC of the coal stand-alone plant exhibits very little change relative to those of the hybrid plants, while the gas LEC becomes increasingly non-competitive. What change there is indicates an absolute rise in the LEC of all systems as fuel price rises and a small relative decrease in the LEC differential between the coal stand-alone plant and each of the hybrids.

11.2.3 Capital and O & M--To determine sensitivity of LEC to variations in the construction capital and O&M costs of the fossil portions of the plant, both were perturbed by ±25% from base case values. The resulting LEC curves are shown in Figure 21. As expected, these perturbations have a much greater effect on the coal systems than the gas systems as a result of the higher fraction of LEC represented by capital and O & M costs for coal systems. However, there is little qualitative change from the base case under this perturbation.

11.2.4 Load--In addition to the four shift load curve considered thus far, two other load curves were also used to represent one and two shift operations. The two shift curve uses a 70% (of maximum boiler output) load on the daytime shift (8 a.m. - 4 p.m.) and a 60% load on the swing shift (4 p.m. - midnight) with zero load from midnight to 8 a.m., 7 days a week. The one shift curve's only nonzero load is 70% from 8 a.m. to 5 p.m. on weekdays. Figure 22 shows the LEC which results when these two load curves are used. As can be seen, the LEC for steam from the coal systems increases considerably due to the infrequent use of expensive equipment (at 15/MMBtu /hr stand alone coal plant LEC rises from $15/MMBtu for four shifts to nearly $45/MMBtu for one shift operation). However, the gas systems experience comparitively little change (the gas LEC rises from ~$20/MMBtu to $30/MMBtu under the same circumstances). The relative position of the solar hybrid systems changes little within fuel technologies as a result of the

*Gas at $5.00/MMBtu and coal in the range $1.39-$1.93/MMBtu - see section 4.

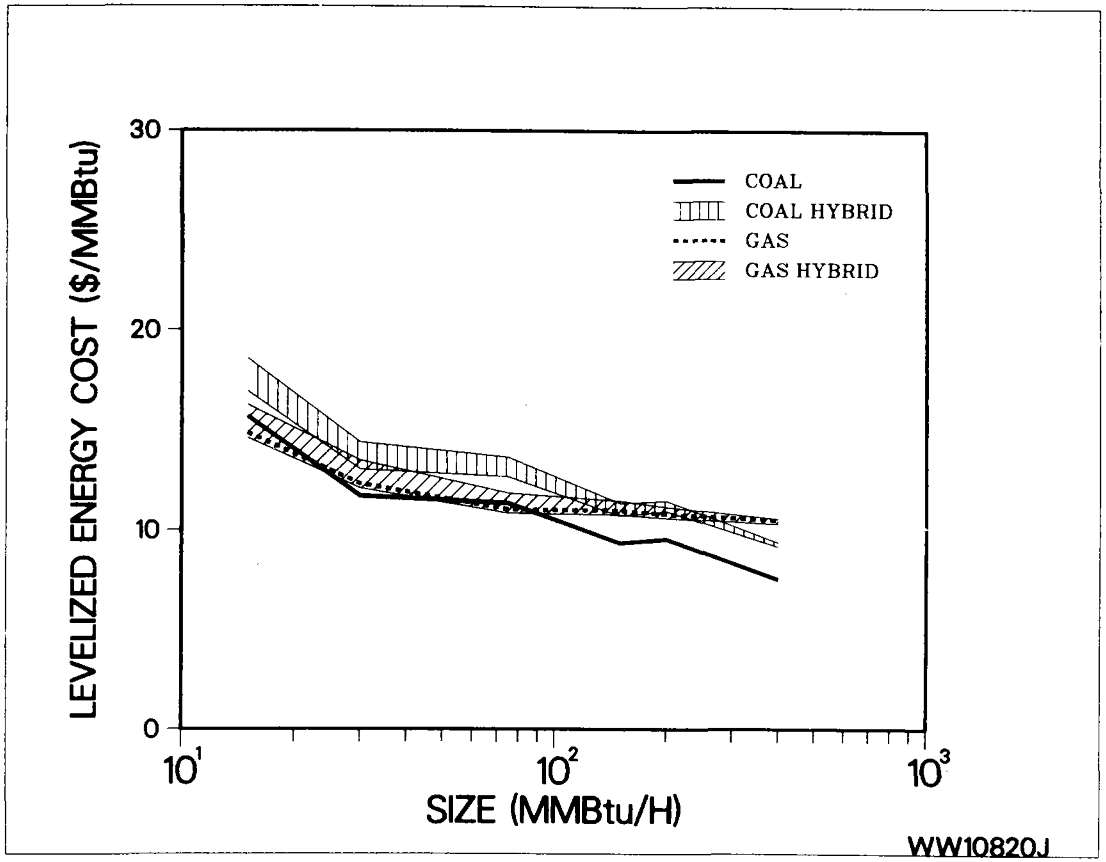

Figure 20a. LEC Curves which Result when Current Fuel Prices (assuming decontrol of natural gas) are Used

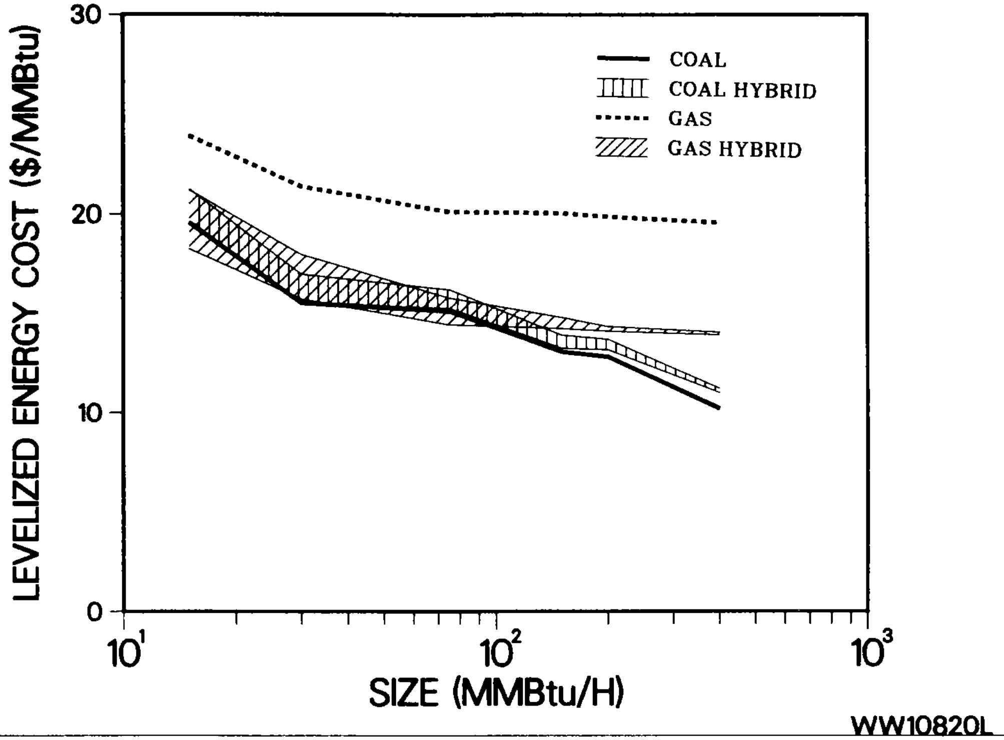

Figure 20b. LEC Curves which Result when Fuel Prices which are Twice Current Decontroled Prices are Used

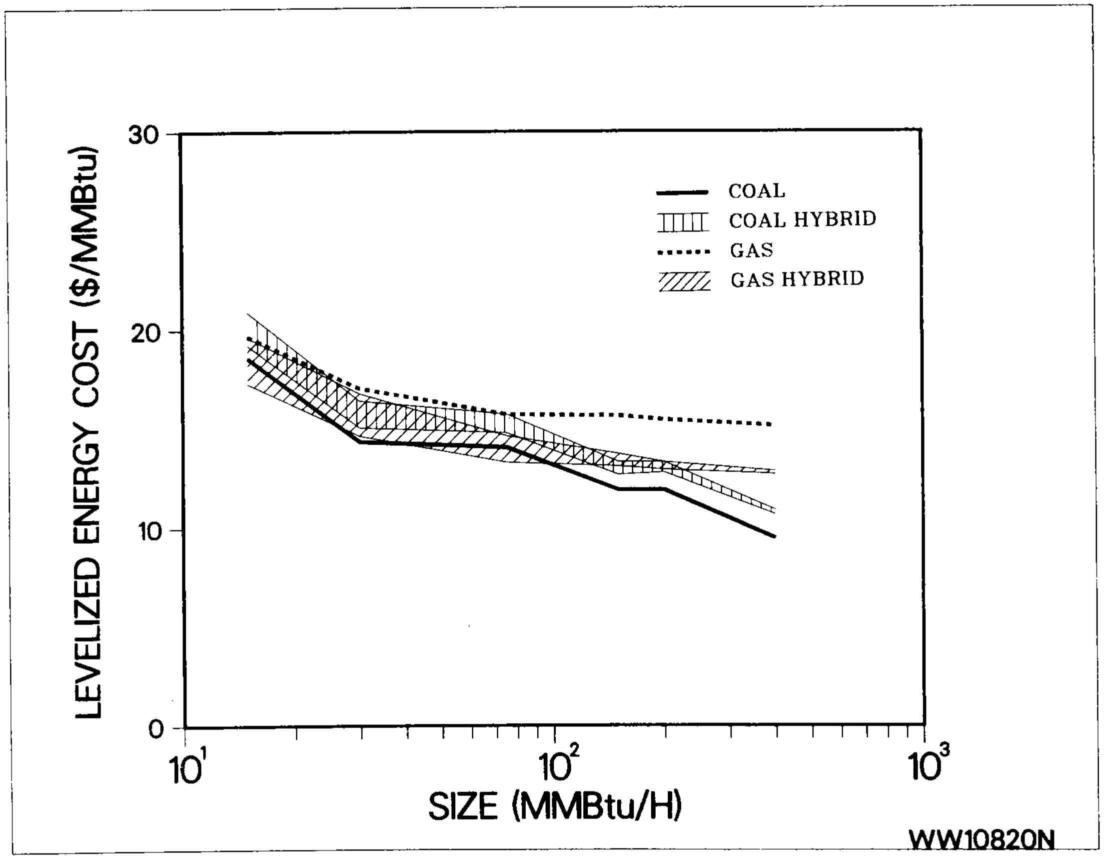

Figure 21a. Cost Curves Resulting from Adding 25% to Capital Costs of the Fossil Portion of the Plants

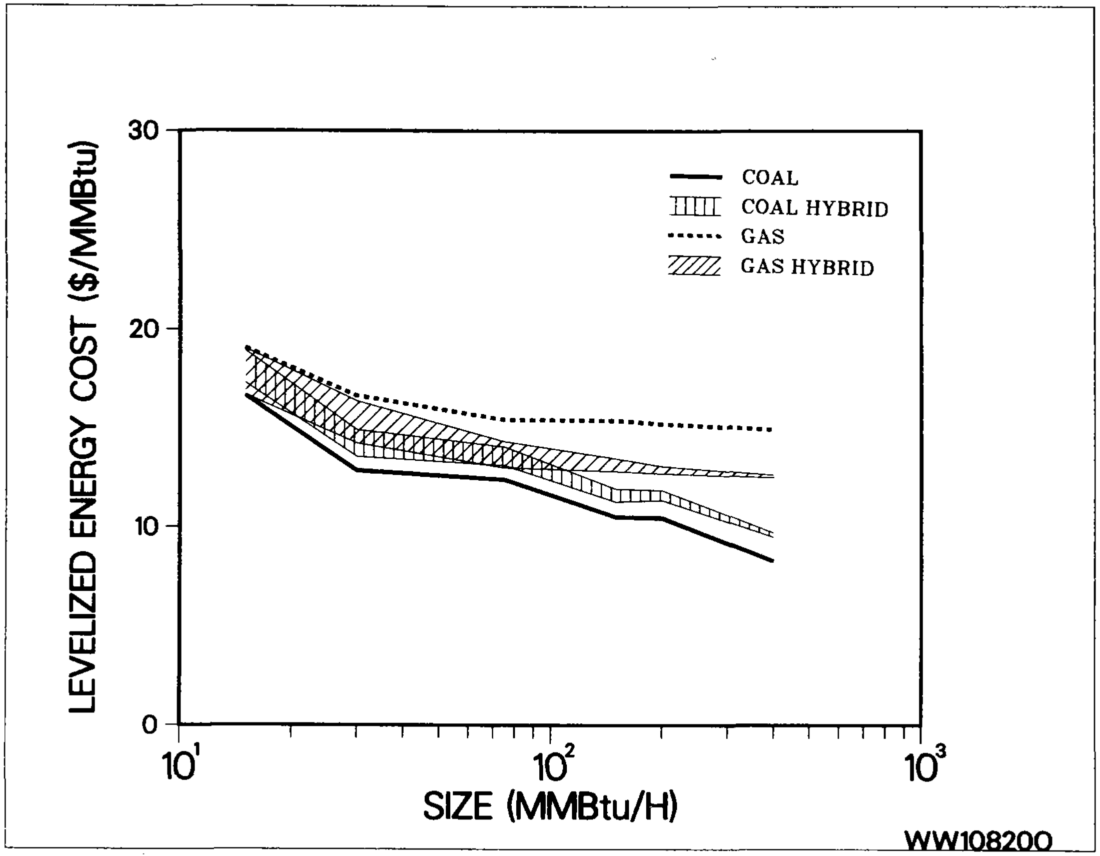

Figure 21b. Cost Curves Resulting from Subtracting 25% from Capital Costs of the Fossil Portion of the Plants

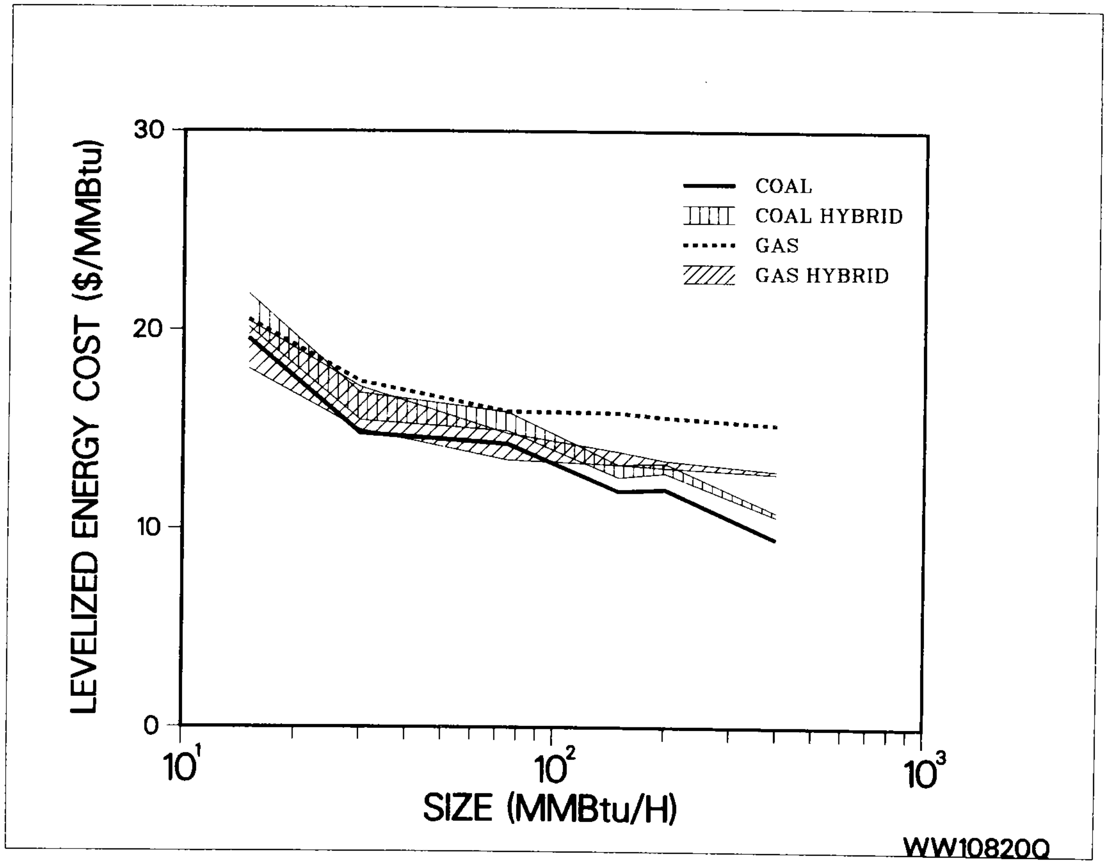

Figure 21c. LEC Curves Resulting from Adding 25% to O&M Costs of the Fossil Portion of the Plants

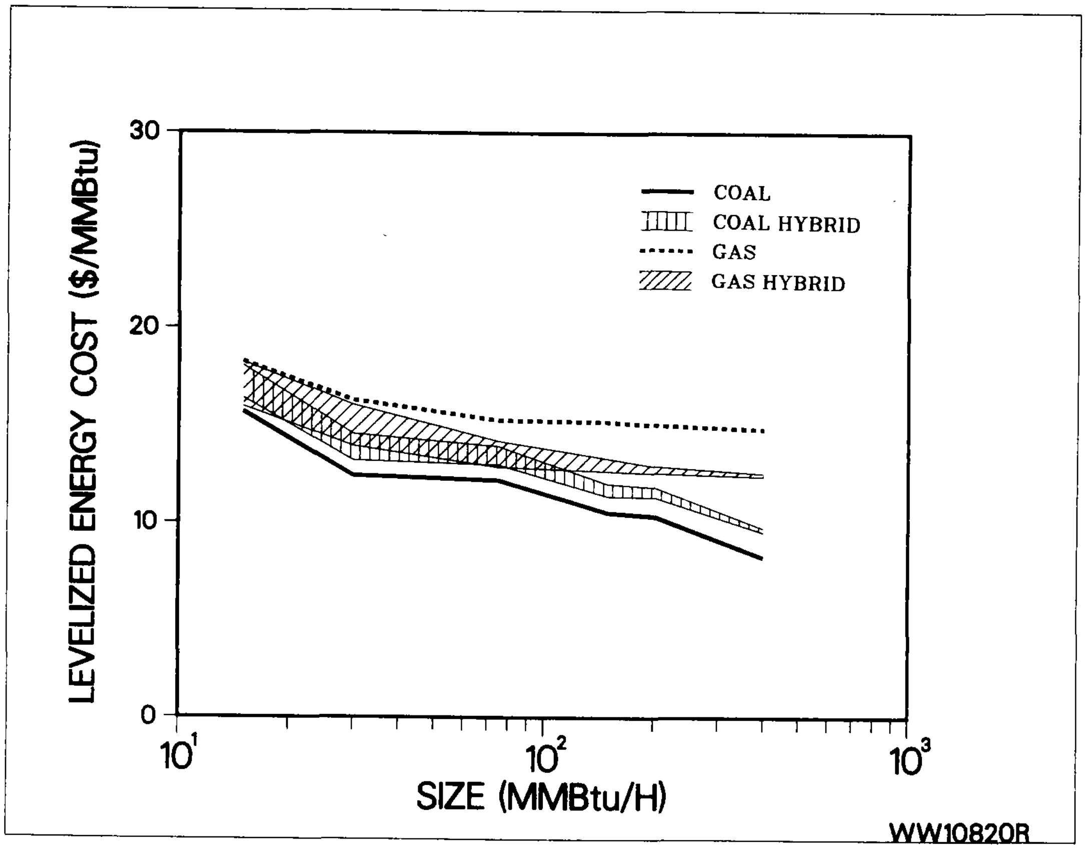

Figure 21d. LEC Curves Resulting from Reducing O&M Costs of the Fossil Portion of the Plants by 25%

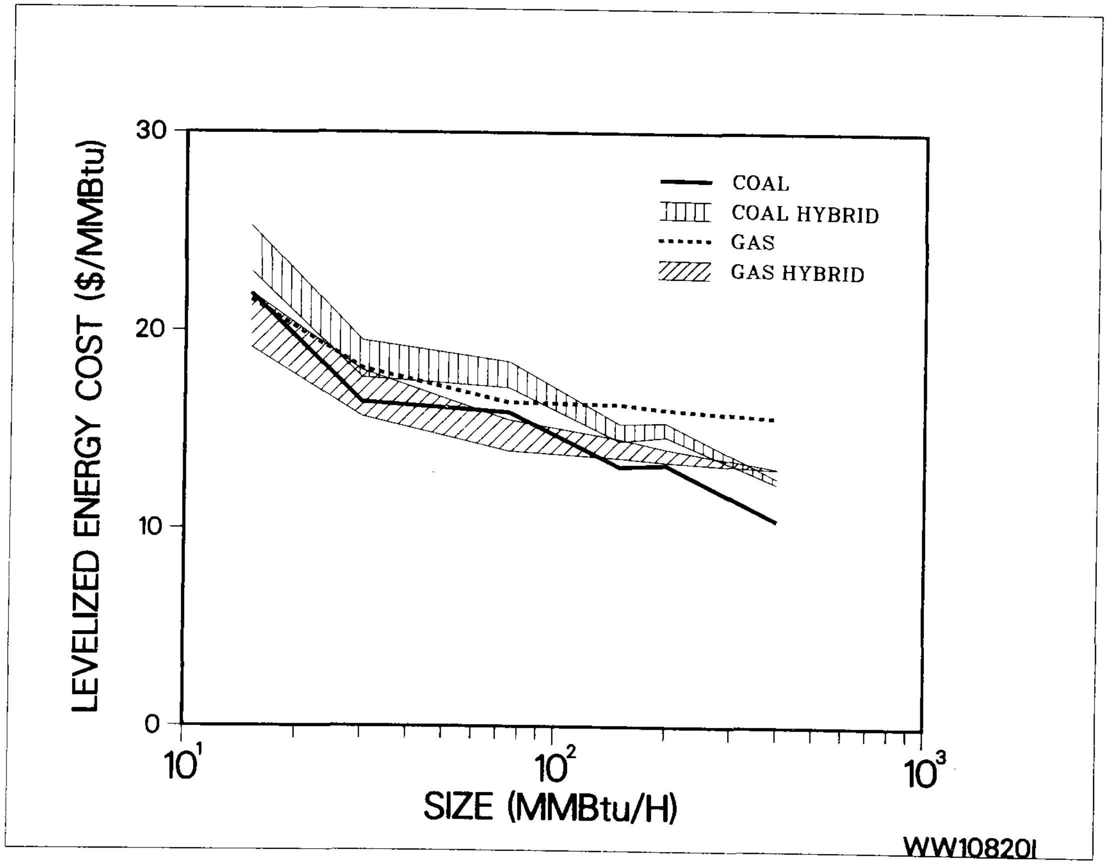

Figure 22a. Result of Using the Two Shift Load Curve

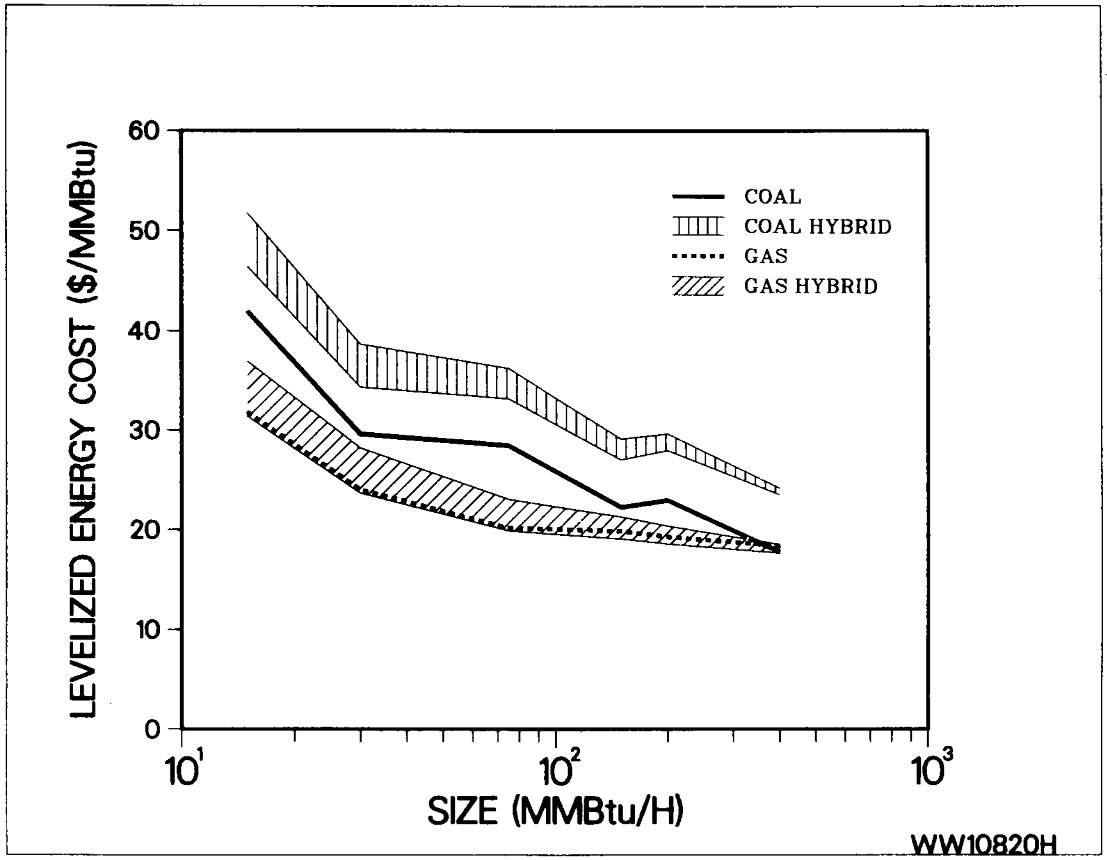

Figure 22b. Results of Using the One Shift Load Curve

transition from four shifts to two. However, in the change from two shifts to one, the underutilization of capital significantly increase LEC for the more capital intensive solar systems as well.

11.2.5 AFB Boilers--Figure 23 gives the LEC versus plant size curves obtained when an atmospheric fluidized bed (AFB) boiler is used in place of a conventional coal-fired boiler. These curves very closely resemble those for the level 1 pollution control requirements in Fig. 19. However, AFB boiler systems meet level 2 pollution control requirements. Thus coal systems with AFB boilers will provide steam with a lower LEC than systems using conventional coal-fired boilers if more stringent pollution control regulations are established. However, since stand-alone coal systems and coal hybrid systems would be equally affected by use of AFB's, no relative change in the LEC of these two systems occurs.

11.2.6 Heliostat Costs--The heliostat price used thus far is $\$93.5/m^2$, a mass production price goal which can not actually be attained at this time. Therefore, a scenario was considered using a price of $\$253/m^2$, more than doubling the cost of the collector subsystem, but reflecting a cost much closer to the current limited-production price. The cost curves produced are shown in Figure 24 and indicate that this high heliostat price limits the economic attraction of solar hybrids.

11.3 A Short Note on Storage

Thus far, little mention has been made of the amount of storage or the solar multiple used to obtain the hybrid energy costs shown in the various graphs. This is because of the unexpected consistency of both parameters (regardless of solar cost algorithm) in virtually all cases. All coal hybrid systems presented are either .5 or .75 (the vast majority are .75) solar multiple systems with no storage. For the most part, the gas hybrids optimized at solar multiples between 1.33 and 2.0 with storage between 4 and 8 hours. Essentially, the optimum amount of storage in these cases is approximately enough to store any excess energy which could be used that night. Little storage was provided for cloudy days. This could well be a result of the consistency of Albuquerque insolation. The only exceptions among the gas hybrids occured in Fig. 22b (1 shift operation) and most of the small (15 MBtu/hr) hybrids using the logarithmic cost scheme. In both these instances, the optimum prices given represent low solar multiples and no storage.

11.4 Conclusions

Several conclusions can be drawn from the results presented in this report. First is that solar hybrid plants can produce steam at prices close to those of conventional fossil-fired boilers over the entire size range studied. In most of our simulations the solar hybrid systems supplied energy at a price less than a gas stand-alone boiler and more than a coal stand-alone.* More specificaly, both the coal and gas hybrids produce steam

*The only exceptions are the reduced shift scenarios, the lowest fuel price scenario and the simulation using $\$253/m^2$ heliostats.

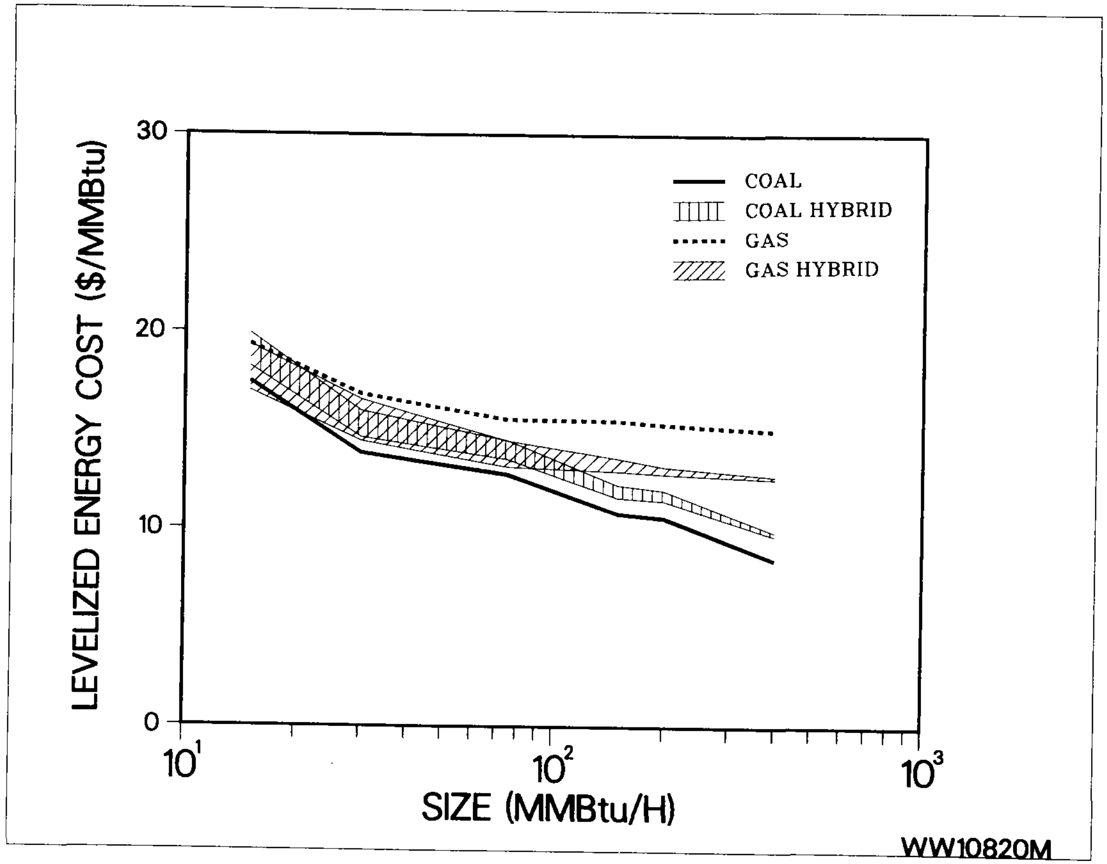

Figure 23. Costs Curve Resulting from the Use of AFB Boilers Instead of Conventional Coal Fire Boilers

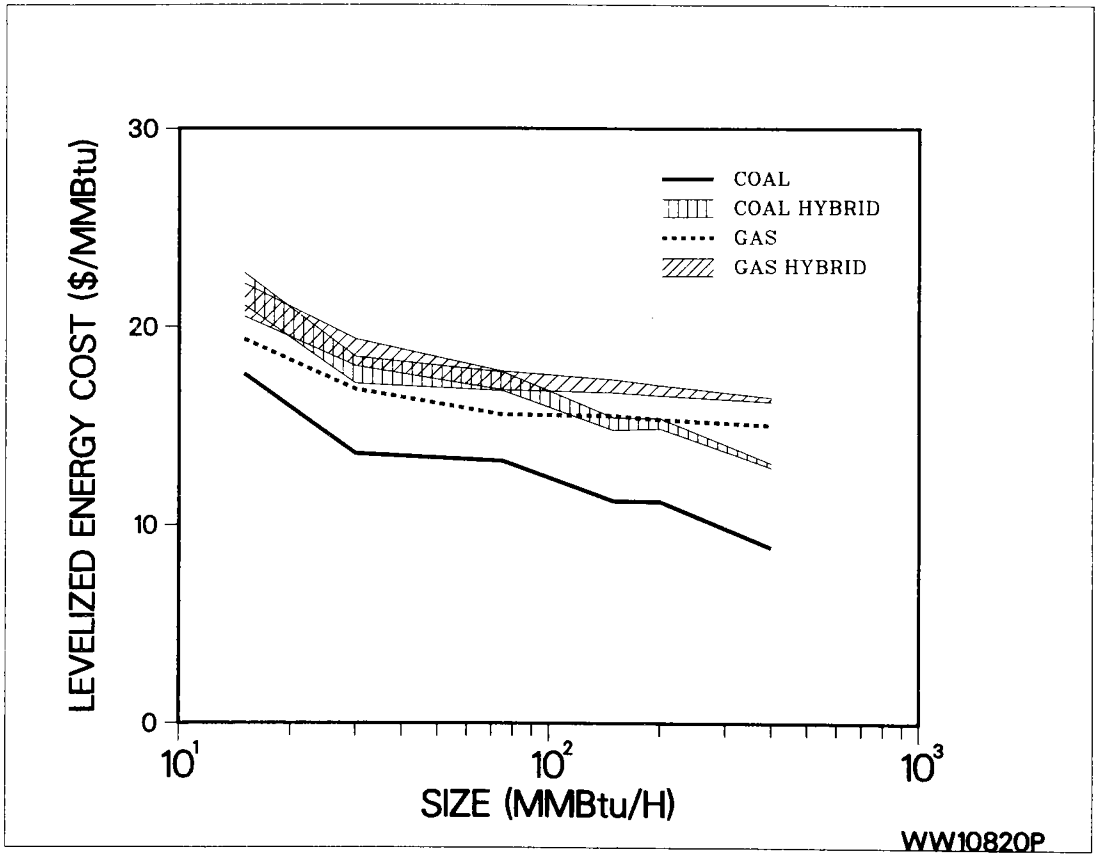

Figure 24. LEC Curves Resulting from Use of $253/m Heliostats

at a cost within 10-20% of the coal stand-alone LEC for sizes less than approximately 100 MMBtu/hr with the gas hybrid generally being the least expensive of the two. This is of particular interest since fuel use is not legally restricted at these smaller sizes. At the larger sizes, the solar-gas hybrid has an LEC greater than that of the solar-coal hybrid, although the coal hybrid still has an LEC within 10-20% of that of the coal stand-alone.

We also find that the LEC of steam from any of the configurations examined exhibits some increase with decreasing plant size but the various types of steam plants are affected to nearly the same extent so the relative ranking by LEC does not change with size. The increase in LEC as plant size decreases can be primarily attributed to increases in O & M costs. This results because specific capital costs of solar central receiver systems and also those of gas or oil fired boilers are nearly constant over the range studied. And, although any particular coal-fired boiler technology does exhibit important increases in LEC as plant size decreases a large number of such technologies exist. Consequently, changes in the technology used at each plant size across the range we have studied results in nearly constant specific capital costs for coal burning systems throughout the size range.

Third, we found the O & M costs for boilers to be unexpectedly large, particularly at the smaller sizes. In somes cases these O & M costs are more than 25% of the total installed boiler plant capital cost. This is in contrast to the 2% figure commonly used for the very large boilers in the electric power generation industry.

Finally, the use of atmospheric fluidized bed (AFB) boilers in place of conventional coal-fired boilers as stand-alone units does not seem economically attractive unless pollution control requirements become more stringent than those currently in place (except in California). Furthermore, since a coal stand-alone boiler and a coal-solar hybrid system would be equally affected by use of an AFB, their relative economic advantage does not change. However, AFBs do offer enhanced fuel flexibility - a potentially significant consideration for smaller facilities which may not be able to count on having a specific type of coal over the lifetime of the boiler.

11.5 Future Work

During the course of this study a number of areas which would benefit by additional study and clarification have been identified. One such area arises from the qualitative differences in the solar capital cost models presented in section 7.2.3. To really understand capital costs of solar central receiver systems at small sizes, much more engineering study of small systems is necessary.

We have assumed that coal fired boilers are designed to burn coal of very specific properties. This may not be a good assumption-especially at smaller boiler sizes where the flexibility of burning coal with a range of properties might be important. Since such flexibility could add substantially to capital cost of coal fired boiler, an understanding of this feature of boiler design philosphy could impact the results of the present study.

Operation and maintenance costs also represent an area where further study would be of value. The unexpectedly high O & M cost found for fossil boiler systems casts doubt upon the assumptions used in calculation of O & M costs for the solar central receiver portion of the plant, especially at the smaller sizes.

Finally, since O & M costs do represent such a large fraction of the levelized energy cost of steam from systems in the size range considered, it might prove valuable to investigate the possible cost benefits of displacing O & M costs with capital costs. In particular, it could prove possible to displace recurring operation costs with capital in the form of automatic controls. A study of the origins of the high O & M costs as well as barriers to their displacement with capital costs would be valuable.

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The program was extensively modified by S. E. Faas and B. L. Haroldsen and further modified by the authors.

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