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FINANCIAL STUDY OF COMMERCIALIZATION OF SOLAR CENTRAL RECEIVER POWER SYSTEMS

Final Report

March 1981

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Study:	Site Insolation Annual Energy MWth/m² (Normal)	Annual Energy Thermalized MWth/m² (Land)	Annual Collection & Thermalization Efficiency	Land Area Heliostat Field (km)²	Number of Heliostats	Reflective Area of Heliostat m²	Ground Coverage Ratio	Peak Thermal Power MWe	Land Area per Peak MWe (m²)	Annual Energy Thermalized GWth	Equivalent 30yr Coal supply (metric tonnes) x10^6	Area of Coal Mine (km)²	Coal to Solar Area Ratio
epowering													
) Water/Steam													
	1.971	0.236	12.28	0.510	2255	49.05	0.2169	73.3	6958	120.36	0.547	0.938	1.839
.	2.519	0.359	12.99	0.292	1174	56.40	0.2268	43.2	6759	105.00	0.478	0.819	2.803
.	2.649	0.201	10.99	1.029	2776	81.75	0.2205	105.3	9772	206.80	0.937	1.612	1.567
.	2.260	0.293	12.82	0.191	818	49.05	0.2103	29.3	6519	55.87	0.254	0.436	2.280
.	2.493	0.234	10.04	0.136	383	56.40	0.1588	13.9	9784	31.80	0.145	0.248	1.823
) Molten Salt													
.	2.519	0.324	12.93	2.219	10500	49.05	0.2321	319.1	6954	719.73	3.273	5.611	2.529
.	2.630	0.381	14.69	1.990	8411	56.42	0.2384	346.0	5751	759.00	3.451	5.917	2.973
) Liquid Sodium													
	2.520	0.259	10.79	1.307	4742	56.40	0.2046	158.5	8246	338.20	1.538	2.637	2.017
	2.373	0.339	13.92	0.858	4809	49.00	0.2747	139.0	6173	290.53	1.321	2.265	2.639
.	2.346	0.277	11.58	1.740	7882	49.00	0.2219	226.0	7699	482.50	2.194	3.761	2.162
) Gas (air)													
.	2.100	0.228	10.84	0.065	469	44.00	0.3218	11.9	5462	14.80	0.0673	0.115	1.775
2.	2.780	0.343	12.41	0.243	1040	56.60	0.2424	34.4	7064	83.44	0.379	0.651	2.677
3.	2.488	0.232	10.45	0.097	320	52.60	0.1730	11.5	8435	22.55	0.103	0.1758	1.812
Cogeneration													
) Water/Steam													
.	2.600	0.3795	14.59	0.1275	588	52.8	0.2435	20.8	6129.8	48.39	0.219	0.417	3.271
2.	1.685	0.185	10.95	0.0627	251	53.1	0.2125	8.98	69855	11.57	0.052	0.0997	1.589
3.	2.500	0.334	13.36	0.171	815	52.8	0.2516	26.2	6526.7	57.10	0.259	0.492	2.878
4.	2.227	0.2973	13.35	0.222	1057	52.77	0.2513	37.13	5978.9	66.00	0.299	0.569	2.562
) Molten Salt													
5.	2.270	0.1874	8.25	1.300	3295	57.4	0.1455	122.0	10656.0	243.59	1.104	2.099	1.615
6.	1.787	0.2842	15.90	0.048	242	56.84	0.2867	8.90	5393	13.64	0.062	0.1065	2.2195
) Gas (Air)													
7.	2.482	0.3911	15.75	1.662	10438	49.0	0.308	270.0	6156.2	650.0	2.945	5.077	3.055
MWe Pilot Plant	2.723	0.2993	10.99	0.330	1818	39.9	0.2197	35.7	9243.7	98.76	0.447	0.774	2.578
EA/SSPS-CRS													
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Water chillers: changing technology

A perspective on the state of central chillers today and the direction of chiller technology in coming years

By **WILLIAM J. COAD,** Vice President, Charles J. R. McClure and Associates, Inc., St. Louis, Mo.

Following 30 years of relatively constant evolutionary change in design, there have been some rather exciting revolutionary changes in refrigerated water chillers in the past five years. This article will explore the design and application of chillers in air conditioning systems and attempt to affix a perspective on the state of the art today and the direction of chiller technology in coming years.

If one were to question the place of the chiller in the air conditioning industry as an academic study, two immediate disadvantages of chilling water to condition air become evident. First, the Carnot principle reveals that using an intermediate fluid between the low temperature source and the air will tend to lower the theoretical coefficient of performance, thus increasing the energy consumption. And second, a system that conveys thermal energy via a fluid is generally less efficient (consumes more parasitic energy) than a system that uses electricity as the transport medium. In spite of these evident disadvantages, the chiller market has grown steadily, and its future appears bright. As in most other technical fields, there are obviously advantages that outweigh the disadvantages in a significant number of potential applications.

Hydronic cooling systems

Some of the features of hydronic cooling systems that cannot be inherently realized with direct refrigerant/air heat transfer are *thermal inertia, centralization of complex machinery, alternative external energy input forms,* and *ability to store cooling capability,* any or all of which are the reasons designers have employed for the decision to use water chillers. Consider each of these in a bit more detail.

Thermal inertia

The problem of control of space conditions is a complex maze of cybernetic loops attempting ultimately to cause various links in the chain of machinery to respond to deviations from setpoint of either or both of two room air properties. These properties are dry bulb temperature and moisture content. For numerous reasons, some room systems are much more sensitive to these deviations than others. In those more sensitive systems the decoupling of the refrigeration system from the psychrometric system by use of the intermediate transfer fluid has proved to be the most successful solution to the control stability problem from the standpoints of both performance and energy use. To achieve the level of control performance that is inherent in a well designed chilled water system by any other method adds both complexity and energy burdens to those alternative solutions.

. . . the design and selection of chillers has become an art of optimization

Centralization of machinery

In larger buildings or building complexes, it is often desirable to employ numerous air handling units located as dictated by the building geometry or space use schedules. The three options open to a designer for providing the refrigeration for these units are:

1) A refrigeration unit for each cooling coil.

2) A central compressor and condenser, with a refrigerant liquid and suction piping system between them and the multitude of evaporator coils.

3) A central refrigeration plant with water chiller(s) and a chilled water distribution system serving the cooling coils.

The second system was used in times past but has fairly well faded from the scene in comfort cooling. (Since it offers some of the advantages of both the first and third alternatives, however, it is still used extensively in commercial refrigeration systems.) The reasons for its rejection are academic and could be considered conjecture, so they will not be addressed.

The first option is used in many contemporary applications. When properly applied, the decentralization of the refrigeration systems proves to be a perfectly valid option. However, for those psychrometric systems that require a buffered coupling between the air system and the refrigeration system (short control system time constant or conditioning of ventilation air), the control complexity of the refrigeration system increases the cost beyond an acceptable limit (if, indeed, successful performance can be achieved at *any* cost).

Thus, it is in these cases that the only commercially viable option is the central water chiller approach. Two problems are addressed simultaneously.

First, the refrigeration control is simplified by the decoupling, and second, the number of refrigeration systems is significantly reduced, tending to reduce both cost and maintenance/service burdens.

An additional advantage emerges with the centralization of the refrigeration apparatus—the installed capacity need only be that necessary to handle the diversified system load rather than the sum of the peak loads of all the individual air side systems. This advantage could be lost, however, if the chilled water distribution and psychrometric control systems are not designed to achieve it.

Forms of energy input

The second law of thermodynamics, paraphrased, states that to move energy from a region of lower temperature to one of higher temperature (reject) requires that energy be provided from a "level" higher than the reject temperature. The two available forms for thus motivating heat flow are shaft energy and higher temperature thermal energy. Shaft energy is, of course, used in the vapor compression cycle, and current state of the art in vapor compression technology places virtually no limits on the sizes and configurations of these units. However, for whatever reason, attempts to directly couple the refrigerants of *thermal* cycles to the air side have not been commercially successful. Thus, the only commercially viable method for refrigerating with thermal energy is with heat motivated water chillers—absorption chillers. Thus, in circumstances in which fuel or heat is readily available and/or low in cost, such that the economics favor refrigerating with thermal energy, water chillers are the only option. This is not necessarily to imply a central plant approach; many small chillers located near the loads could be employed.

Table 1—Chiller market by types of units

Type	Annual tons	Percent
Reciprocating electric	364,000	21
Centrifugal electric	1,215,000	70
Absorption	69,000	4
All other	87,000	5

Cooling storage

Although it would be conceptually possible to store cooling capability in the form of high pressure liquid refrigerant, marketplace economics have not proved this concept to be a practical option. The more practical methods are the latent heat of fusion concept or through sensible liquid temperature changes. The heat of the fusion system (in the form of ice storage) was quite common in the U.S. in past years, but maintenance problems and ready availability of electric power have greatly diminished its use. Today there is a resurgence of interest in ice storage and other phase change methods. There is currently some research and development being done using various saline type phase change fluids, but these are yet to be proved in the air conditioning marketplace. Chilled water storage, while generally quite costly from the standpoint of storage volume per thermal unit stored, is currently being applied successfully where the monetary economics of energy sources favor refrigerating at a time other than that of the needs of the load; that is, when the energy availability and the use for the refrigeration do not occur simultaneously.

Chiller market

Most skilled designers recognize the system application features stated above (as well as some likely omitted above) and elect to use a chilled water system when the needs dictate. Approximately 16 percent of the total comfort cooling capacity currently being installed is chilled water. If residential and small commercial are eliminated, chillers account for approximately 44 percent of the comfort cooling market.

Table 1 shows the breakdown of the total chiller market into four categories: electric driven reciprocating vapor compression units, electric centrifugal vapor compression, absorption (direct and indirect), and all other. Since there is a significant difference in the design and application of the machinery in each of these categories, they will each be addressed individually.

In the 30 years preceding 1975, as stated at the outset, the designs of all four categories evolved such that there appeared to be no significant changes from generation to generation, although admittedly the years and generations combined to produce a 1975 machine that had little resemblance to its forefathers of 1945. In virtually all cases, the units became smaller and lighter in weight. Contrary to the common remark about the better quality products of yesteryear, the 1975 vintage chillers were fundamentally more reliable than the earlier generations, requiring less attention and service; and with few exceptions, the compression machines required higher input energy per ton of refrigeration than the earlier models. Since the vast majority of this time span was during an era of seemingly abundant and inexpensive energy, parameters other than energy consumption prevailed in chiller genetics. The two umbrella parameters were reduced cost and improved performance. Both of these were addressed by the encasement of the electric motor drive in the refrigerant system. Higher speeds and smaller compressors reduced costs; less heat transfer surface reduced costs. All of these improvements resulted in increased energy consumption. As the components became small, field erection needs were reduced to trim and ancillary devices. For those machines that worked with subatmospheric refrigerant pressures, *R*-11 and *R*-718 (water), product design improvements and improved manufacturing processes resulted in tighter, less troublesome systems. These later developments contributed significantly to improved reliability and lower maintenance and service costs.

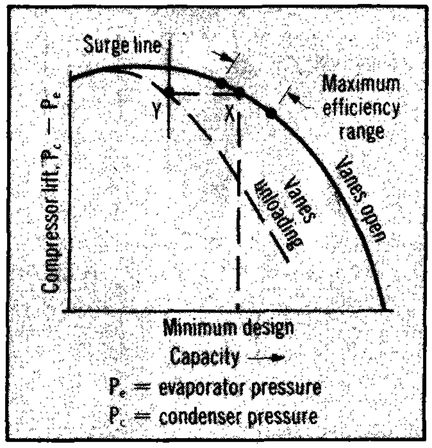
In summary, then, the chiller of 1975 was a product of many generations of design improvement aimed at lowering investment cost and improving short term reliability, and it was a successful product of these goals.

A new primary parameter

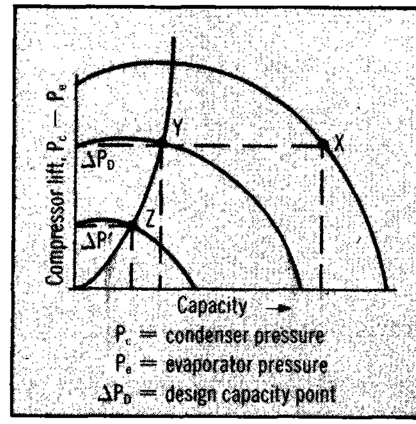
In the late 1970s a third goal was introduced in both the design and the application of water chillers (as it was in most fields of energy consuming machinery), and that parameter was, of course, energy consumption. The unique feature about this newfound parameter was that it is not unrelated to that of initial cost. Thus, the design and selection of chillers has become an art of optimization—an optimization that is not simply related to the static realm of product design but one that has the dynamic need to change with project, location, and over short time intervals. The chiller manufacturers have thus found it necessary to turn their talents toward addressing this new problem.

Vapor compression machines

In compression refrigeration systems, there are two parallel paths that can be followed if the coefficient of performance (COP) is to be improved. One is to improve the theoretical or Carnot COP, and the other is to work laboriously on system and cycle components either to reduce their losses or improve their performance (depending upon how it is "viewed"). The easiest, but not necessarily the least costly problem to solve, is the Carnot problem. This is done by simply increasing the heat transfer surface, thereby reducing condenser (head) pressures and/or increasing evaporator (suction) pressures. The same effect can be accomplished, although not as simply, by improving heat transfer coefficients. The latter technique had been exploited by most manufacturers rather extensively in



1 Centrifugal system with high efficiency impeller selection. If the impeller is selected at Point X (the maximum efficiency point), and the unit unloads with vane control, with fixed evaporator and condenser temperatures,* it will go into surge at Point Y (approximately 60 percent of design capacity).



2 Centrifugal system with speed control. Design point is X. If the unit unloads by speed control, assuming constant evaporator and condenser pressure*, it can be unloaded by speed reduction to Point Y. If the reduction in head pressure would result in a differential pressure of $\Delta P'$, the capacity could reduce to Point Z. A line connecting Points X and Z, commonly called the load line, is used in centrifugal system analysis to define the reduced load performance.

*Figs. 1 and 2 are simplified diagrams of the generic centrifugal compressor performance. They are presented for the purpose of illustrating the logic of the respective examples, and are not intended to imply specific characteristics of any actual machines. The complexities of the gas dynamics related to varying system capacity have not been addressed. Characteristic curves on compressors and chiller packages for specific units showing actual efficiencies, surge lines, speed curves, vane curves, and assumed load lines are available from most manufacturers.

previous efforts at cost reduction. Thus today's chillers are becoming available with increased heat transfer surface for both the evaporators and the condensers. The economic limits of this increase will simply be related to the volatile relationship between material/manufacturing costs and electric energy costs. To take maximum advantage of this opportunity in centrifugal machines, new generations of lower head, higher volume impellers (and possibly housing) will very likely be developed.

Analysis of generic electric driven compression cycles has shown that in 1975 state-of-the-art systems, when comparing "losses" to ideal Carnot efficiency, approximately 26 percent of the losses were in heat transfer, and the remaining 74 percent were in machinery and thermodynamic losses. It is in this latter 74 percent that future generations of water chillers will likely see their major changes. Some such changes have already begun to appear on the market in centrifugal chillers. A few of these changes are:

- Abandonment of the age-old design that required maintenance of a fixed (at design) temperature of condenser water entering the unit. This is an installation or systems design change as well as a product design change, but was instigated by the product manufacturers who were responsible for designing machines that required the fixed temperature. It is interesting to note that this change could *reduce* the installed cost.
- Increasing compressor efficiency (isentropic compression efficiency), particularly at design load conditions by critically sizing the impeller (diameter) to the optimum point of the efficiency curve. Fig. 1 illustrates the range of maximum efficiency for a typical centrifugal compressor. Note the proximity between the maximum efficiency range and the surge line. If the compressor is unloaded by vane control, the operating point is driven rapidly toward the surge point. This is one of the dangers in sizing the impeller diameter for optimum efficiency at design load—a problem that must

be recognized and resolved.

• In those machines or cycles that use liquid refrigerant or low temperature gas for cooling the motor, some manufacturers are offering open machine options to remove the energy burden of the motor losses from the refrigeration cycle. (This concept applies equally to reciprocating compressor units.)

• The use of variable speed drives in lieu of, or in addition to, inlet vanes for capacity reduction and control. Although this is an extremely costly option at present, it is quite effective in many respects. In the worst cases, if the head pressure remains constant (fixed) as the load decreases, the operating points would move to the left as shown in Fig. 2. Note that for the variable speed condition, the surge line drops down and to the left, allowing a wider range of load reduction prior to surge than is available with vane control. Also, the brake horsepower unloads a bit more effectively with speed reduction than with vane control. The full benefits of this cannot always be realized, however, because of the added losses of the variable speed drive or device at full load.

• Multiple staging with flash chamber intercooling. This is one of the early techniques that was not recognized for its true value in an era of inexpensive energy. This technique is now being expanded to additional stages, thus further reducing the compression burdens. Fig. 3a shows a typical refrigeration cycle on a Mollier (p-h) diagram and Fig. 3b shows simplistically the effect of reducing the work input per unit refrigeration by flash intercooling between compressor stages.

Electric reciprocating units

There has been considerably less activity in improving the energy consumption of reciprocating units. Perhaps this is because less opportunity exists, or perhaps it is because in the smaller size range of reciprocating machines, the absolute quanitity of potential savings does not warrant a market that would justify the research and product development beyond the Carnot savings available from improved heat transfer and the obvious return to the use of open drive machines where the economics are favorable.

Absorption chillers

The market for absorption chillers has been impacted rather dramatically by the volatile energy economics of the past five years. Although the coefficient of performance of these systems in strictly thermal units was historically quite low compared to compression cycles, the fact that they were driven by low cost thermal energy made them an economically attractive alternative. However, as the relationship between the costs of thermal energy available for buildings and electricty has readjusted, the almost mass market for absorption chillers has reduced to one of special applications. Such applications include cogeneration cycles, industrial byproduct heat, and boiler plants having minimum turndown capacities that exceed the summer thermal loads (ironically, this is a condition often created by "energy conservation" efforts). In this latter case, the steam systems are usually high pressure, and the higher pressure absorption units with improved performance coefficients can be used.

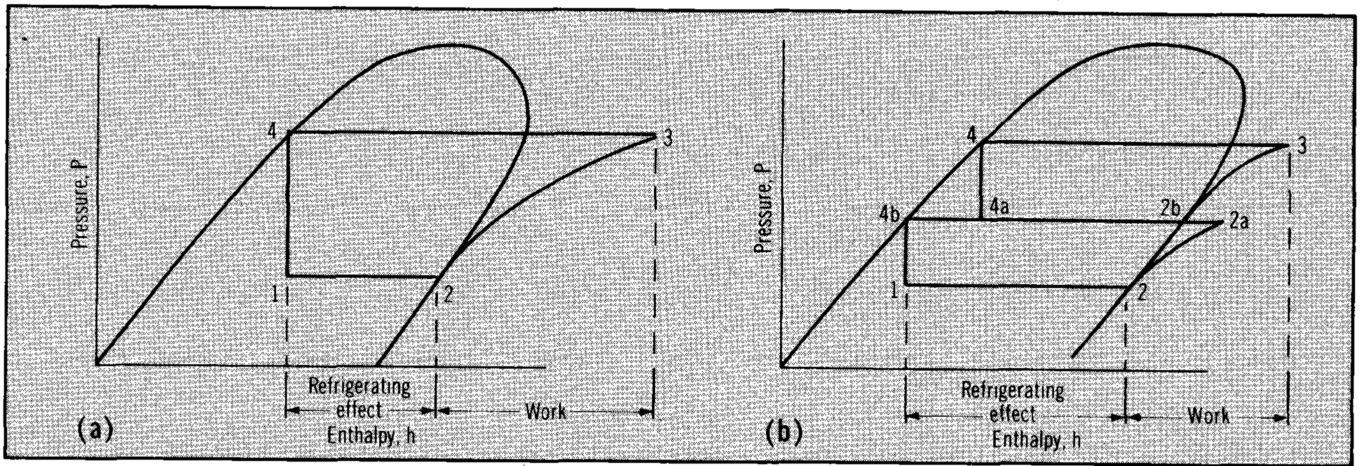
Although little else in energy improved absorption equipment has reached the marketplace, extensive research is currently being done. State-of-the-art absorption equipment is not doing as good a job in approaching Carnot performance as is compression machinery (28 percent effectiveness vs. 42 percent). Unfortunately, the ideal COP for absorption units is sensitive to the temperature of the motivating heat, and future needs (such as waste heat recovery and solar heat) keep driving toward lower temperature and lower energy effectiveness. But the needs of the market are there, and improvements can hopefully be expected.

•Increased heat transfer surfaces
•Variable entering water temperatures
•Increased compressor efficiencies

Other types of chillers

Less common chiller types and arrangements are those that employ other types of compressors and drives with vapor compression cycles. The rotary screw compressor has been making significant inroads into the market in both large capacity machines that compete with centrifugals and in the under 100 ton sizes normally served by reciprocating compressors. In some applications the rotary screw offers better energy effectiveness than the alternatives, and it is in those areas that these machines will likely make significant market impacts in the coming decades. The fundamental advantages of the screw compressor are that it can cope with higher pressure ratios than the centrifugal when the need requires, such as in heat pump applications, and it has virtually infinite capacity control, which the reciprocating compressor does not have. Some specialty chiller manufacturers are combining screw and reciprocating compressors for multiple compressor chillers to obtain the advantages of each and minimize the system power input per ton.

Prime mover options that are used much less frequently than electric motors include reciprocating internal combustion (IC) engines, gas turbines, and steam turbines. The reciprocating IC engines are used with both reciprocating and centrifugal compressors, and the turbines are generally coupled to centrifugal compressors only. In systems in which heat is needed coincident with refrigeration, these



3 Vapor compression cycle illustrating intercooling. At the left (a) is a typical vapor compression cycle as represented on a Mollier (p-h) diagram. The enthalpy difference ($h_3 - h_2$) represents the work input and ($h_2 - h_1$) represents the refrigerating effect. The figure on the right (b) illustrates a two-stage system between the same evaporator and condenser pressures. Note the decrease in work input Δh and the increase in the refrigerating effect Δh. (Mass flow changes are not accurately reflected.)

prime mover type drives can be equipped with heat recovery for combined cycle energy effectiveness well beyond that available with other more common devices. One example of this need would be an industrial process or plant where cooling and heating are required simultaneously or in a specialized building system that requires very close tolerance humidity control. Another is for water source heat pumps where the recovered heat from the engine cycle can be added to the "pumped" heat resulting in a first law fuel efficiency well in excess of 100 percent. Table 2 shows the approximate salvage heat that is available per ton of cooling with the three different types of prime mover drives.

Heat pumps

Whenever, in a building system or industrial process, there is a simultaneous need for both heating and cooling, refrigerated water chillers offer an opportunity to get either or both in an energy effective manner. Some rather popular configurations have already been on the building systems scene for some years. Others have been used to a much more limited extent, but offer promise for future applications. The well water source heat pumps mentioned above have been used successfully for years in areas where good quality shallow well water is available driven either with electric motors or reciprocating natural gas engines with heat recovery.

Commercial and institutional buildings configured with extensive interior or core spaces requiring year-round cooling have successfully employed either large central chillers arranged for heat pump ("double bundle" heat pumps) or small disbursed units with a "neutral" temperature water piping system.

Another heat pump concept that has been used rather extensively in retrofit as well as to a limited extent in new systems is the condenser water heat pump. The condenser water heat pump is a configuration in which a "standard" temperature chiller is used for providing the chilled water, and a high temperature chiller serves as a heat pump, obtaining the heat from the condenser water circuit of the low temperature unit.

•Return to open compressors
•Use of variable speed drives
•Multiple staging with flash intercooling

Application technology

One disadvantage of chilled water systems that was mentioned earlier was the energy consumption of the hydraulic system. Application technology in chilled water systems was not developed specifically to address the parameter of coupling the chillers to cooling loads (psychrometric system). Rather, most of the present day technology in

Table 2—Recoverable heat available from chiller prime movers.

Type prime mover	Available heat, Btu per ton*
Reciprocating engine	3,730
Gas turbine	11,930
Steam turbine	26,000

*Values shown are approximate and are based upon 1 hp per ton of refrigeration, no afterburning for the gas turbine, and 250 psi saturated steam turbine throttle.

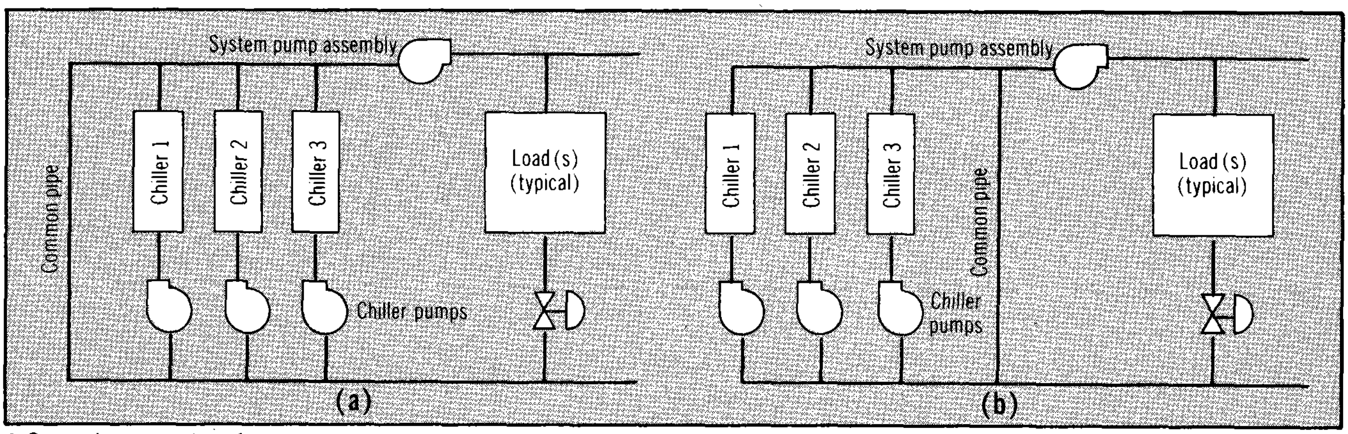
chilled water systems has simply evolved from hot water heating system technology. The changes from that heating system technology that were mandated because of faulty performance of chilled water systems appear to have all been accomplished by improvements that increased the required pumping energy.

In the earliest applications of water chillers, the need for constant water flow through the chiller was recognized. The problem was solved in the vast majority of cases by the use of three-way control valves on the load devices. Thus, almost all chilled water systems in building air conditioning service have three-way control valves on the cooling coils. Although this has had the same effect on the load control as a simple throttling valve, it achieves the needed constant flow through the chiller. It also results in constant pumping power during all hours of system operation regardless of the cooling load. Thus, although the designer of the chiller may go to all reasonable extremes to reduce the compressor energy consumption at both full load and reduced load, the pumping energy in a three-way valve system stays at 100 percent at all times.

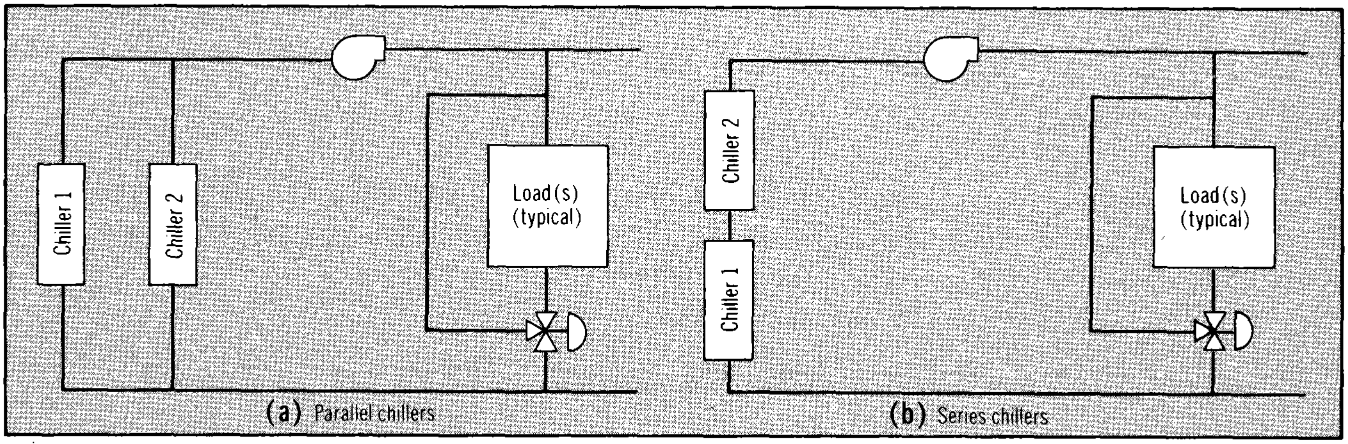
In applying water chillers to systems, the system designer cannot look simply at the chiller energy consumption at all load conditions in, say, KW per ton, but should include in the consideration the energy requirement of chilled water pumps, condenser water pumps, and heat rejection devices (cooling tower, condenser, or "dry cooler" fans). When these ancillary devices are designed into the system in such a way that they do not unload as the cooling load reduces, their seasonal or annual energy consumption can exceed that of the compressor drive.

If the three-way control valves are replaced with throttling type valves, the chilled water pumping circuit can be designed such that the variable flow caused by the valves can reflect in reduced power consumption, ideally the cube of the flow rate reduction ratio. It is this "ideal" that the systems designer should strive for—analogous to the ideal Carnot coefficient of performance in the chiller design. Since virtually no chiller currently marketed can operate safely at significantly reduced flows, flow variations should be limited to the distribution and load systems, and the chillers should be piped for essentially constant flow. This requires a separation between the chiller flow circuit and the load flow circuit. Two methods of accomplishing this are shown in simplified forms in Figs. 4a and 4b. In these diagrams, at full load, the sum of the pumping rate of the three chiller pumps is equal to the pumping rate of the "system" pumping assembly. Careful study of the two diagrams will reveal the difference between the two piping techniques is that in Fig. 4a, the chillers will unload in sequence starting with Unit 1, whereas in Fig. 4b, all chillers will unload equally when their pumps are operating.

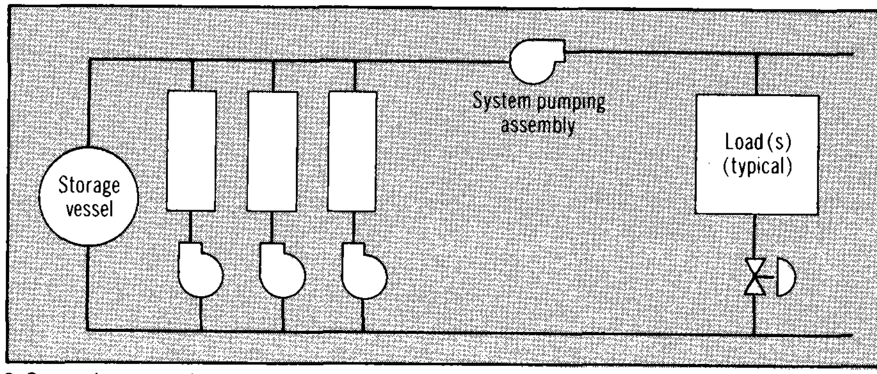
It is the responsibility of the applications or system design engineer to determine, on the basis of the load subsystem design, whether the chilled water source system is to provide constant supply water temperature, constant return water temperature, or some form of reset in either of these. Some manufacturers have provided their chiller packages with a water temperature control system, controlling from either entering or leaving water. Properly applied and operated, either type of control will generally hold a relatively fixed water tem-



4 Secondary pumping of chillers for variable flow rate systems. In both (a) and (b) the chiller pumps cycle off as the imposed load drops below the point at which the capacity of its respective chiller is not required. At design conditions, the total flow capacity of all of the chiller pumps is equal to the flow capacity of the system pumping assembly.



5 Parallel and series chiller configurations — constant flow circuits.



6 Secondary pumping chiller system with chilled water storage.

perature *leaving* the chiller. In multiple chiller plants with constant water flow rates, if the chillers are piped in parallel as shown in Fig. 5a, the supply water temperature will raise above the design point if one chiller is turned off at reduced load conditions. The only way a constant flow multiple chiller plant can hold a constant supply water temperature when unneeded chillers are turned off is if the chillers are connected in series as shown in Fig. 5b. The disadvantage of the series configuration is that the chiller pressure drops are additive—a phenomenon that not only tends to increase pumping energy consumption, but for all practical purposes limits the number of chillers that can be reasonably configured in the plant.

Chilled water storage

Over the years, efforts at reducing energy costs (and, generally, consumption) have inevitably led to the need to "store" energy. As stated at the outset, a chilled water system inherently provides the capability of storing "cooling energy" in the form of chilled water. The water is chilled to a temperature below the maximum utilization temperature with available or inexpensive energy at a time when the cooling is not needed, stored in a tank or storage vessel, and circulated to the loads when they so require. The storage capability, of course, is simply the sensible heat capacity of the water between the minimum storage temperature and the maximum utilization temperature:

$$q = M_W(C)\,(t_{max} - t_{min})$$

where

q = amount of cooling capacity stored, Btu

M_W = mass of the stored water, lbm

C = specific heat of water, 1 Btu per lbm per deg F

t_{max} = maximum utilization water temperature, F

t_{min} = minimum storage temperature, F

The maximum utilization temperature could range anywhere from the maximum effective temperature at which the water could adequately "serve" the loads as supply water to the design or maximum return water temperature, depending upon the design of the storage vessel. In either case, the control logic for the storage system has led to control systems of unbelievable complexity. If the flow diagram of Fig. 4 is modified by the addition of the chilled water storage vessel in the primary-secondary "common pipe" as shown in Fig. 6, the storage system control problem is solved. If, at any time, the source capacity exceeds the load requirement, the excess goes automatically into storage, and if the load requirement exceeds the source capacity, the difference will come from the storage. The scheme works equally well with averaging tanks and stratified vessels.

. . . chillers are prime candidates for purchasing on a so-called life cycle cost basis.

Life cycle purchasing

Water chillers are presently available from most manufacturers in virtually an infinite number of combinations of components that can be matched to optimize the economics between investment cost and energy cost for the unique requirements of any given project. They are also one of the major investment cost items of machinery, and will continue to be a major operating cost burden for the life of the building. For this reason, chillers are prime candidates for purchasing on a so-called life cycle cost basis. With today's technology, there is no justification for purchasing chillers on the basis of capacity and low first cost only! Some method should be incorporated in any chiller specification for addressing the energy parameter.

Summary

Water chiller design technology is experiencing and will continue to see exciting changes in the coming decade. The vast majority of the changes will be directly or indirectly related to reductions in specific energy consumption. Many of those that have surfaced in the past four years are based on designs that were in the wings or on the shelf, awaiting the time of energy price structures based upon the fundamental laws of economics. Currently, in addition to having dusted off these features that had been shelved, product designers are exploring all those system "losses" that cause deviations from ideal energy use effectiveness and will assuredly be developing subtle changes in the next 30 years. These changes will not appear as breakthroughs, but, as over the past three decades, the machines of 2005 will assuredly be much more energy effective than those of 1975 to an extent that we cannot envision.

Applications engineers and system designers are the first echelon in this effort. They must learn to specify and purchase the more energy effective units, and it is they who must develop improved expertise in the understanding of the performance and energy dynamics of chilled water systems. In this regard there is much to be done. Ω

The author recognizes the contribution of Mr. William J. Landman, manager of application engineering, The Trane Co., for his assistance in assembling the materials for this article.

Product guide to water chiller equipment

The following is a listing of literature offerings by companies manufacturing water chillers primarily for air conditioning applications. Information is provided in accordance with material published by the manufacturers, and while the editors have aimed at completeness, the literature briefed is not necessarily exhaustive of the companies' product lines. To receive information on the chillers described, circle the appropriate number on the Reader Service Card. Reader Service numbers are stated parenthetically, in boldface.

Airtemp

Individual bulletins embrace the following packaged chiller lines: Bulletin 537-246, packaged air cooled units for outdoor installation, 20 to 150 tons **(RS 417)**; Bulletin 537-247, reciprocating water cooled and remote air cooled chillers, 20 to 200 tons, **(RS 418)**; Bulletin 537-231, single stage centrifugal chillers, 200 to 300 tons **(RS 419)**; Bulletin 537-244, two-stage centrifugal chillers, 358 to 925 tons **(RS 420)**; and Bulletin 537-214, heat recovery centrifugal chillers, 252 to 631 tons **(RS 421)**.

Arkla Industries

Manufacturer offers various lines of direct fired (natural gas or propane) absorption water chillers including 2, 3, 4, and 5 ton units and multiple packages in 8, 10, 15, 20, and 25 ton capacities. Form AC 13181 covers 3, 4, and 5 ton heating-cooling packages **(RS 422)**; literature sheet covers larger models, including 25 ton direct fired chiller heaters, 25 ton hot water (245 F) and steam (15 psig) units, and a 25 ton solar powered (200 F water) unit **(RS 423)**.

Bohn Heat Transfer Div., G + W Mfg. Co.

Bulletin 9103 describes packaged air cooled water chillers for outdoor installation in 18 sizes from 20 through 134 tons **(RS 424)**; Bulletin 9503 covers packaged water cooled chillers in 22 sizes from 6 through 138 tons **(RS 425)**; and Bulletin 9550 describes packaged water chillers in 22 sizes from 5 through 128 tons designed for remote air cooled condensing **(RS 426)**. All lines are equipped with accessible hermetic compressors in all sizes.

Carrier Air Conditioning Co.

Form 30 GA, GB-2P describes packaged hermetic reciprocating air cooled chillers designed for outdoor installations in seven sizes from 20 through 120 tons **(RS 389)**; Form 30H-2P covers hermetic reciprocating models for remote air or water cooled installations in 15 sizes from 15 through 160 tons **(RS 432)**; Form 19-2P embraces four lines of hermetic centrifugal chillers covering 100 through 2000 tons **(RS 433)**; Catalog 819-048 details line of heat recovery centrifugal chillers from 150 through 400 tons **(RS 434)**. Open centrifugal chiller packages are described in the following publications: Catalog 817-007, 100 through 1600 tons **(RS 435)**; Form 17 CB-1P, 1800 through 2100 tons **(RS 436)**; Form 17 DA-1P, 2000 through 6000 tons **(RS 437)**; and Catalog 817-093, larger units up through 10,000 tons **(RS 438)**. Form 16 JB-3P covers steam powered absorption machines available in 15 sizes from 70 through 815 tons **(RS 439)**.

Continental Products Inc.

Engineering Specification Form MSA-160 describes line of packaged air cooled reciprocating water chillers sized from 20 through 140 tons and designed for comfort cooling as well as process applications **(RS 414)**. Heat recovery is new option on all sizes. Manufacturer is also involved extensively in custom design work.

Dunham-Bush, Inc.

Packaged chiller lines feature helical rotary (screw) compressors. Form 6839 describes six lines: water cooled hermetic units from 120 to 400 tons; open compressor water cooled models from 120 to 750 tons; open compressor water cooled heat recovery packages from 85 to 350 tons of cooling with 1.5 to 5.4 million Btuh heating output; open type units from 150 to 350 tons for air cooled or evaporative condensing; and two lines of industrial refrigeration units for brine cooling down to −20 F (20 to 750 tons) and −40 F (20 to 900 tons) **(RS 440)**. Form 6049 covers single compressor hermetic water cooled models from 40 through 120 tons **(RS 441)**; Form 6069 describes multiple compressor hermetic water cooled units from 180 through 360 tons **(RS 442)**; Form 6062 describes air cooled hermetic line from 120 through 360 tons designed for outdoor installation **(RS 443)**; Form 6064 covers hermetic line from 60 through 120 tons designed for outdoor installation and featuring built-in evaporative condensers **(RS 444)**.

Edwards Engineering Corp.

Form 8-CH-4-2 provides data on packaged water chillers from 1 to 240 tons in both self-contained air cooled and water cooled versions **(RS 427)**. Units of 10 tons and larger feature walk-in enclosures for outdoor installation and ease of service. Equipment is designed for commercial and industrial process applications as well as general air conditioning. Optional refrigerant heat exchanger reclaims condenser heat for process hot water.

Hitachi, Ltd. (Gas Energy Inc.)

Two bulletins describe two-stage absorption chiller-heaters. One model is for direct gas fired application **(RS 428)**; the other is a heat recovery model operating on exhaust heat from gas turbines or

Sandia National Laboratories

Albuquerque, New Mexico 87185
Livermore, California 94550

date: August 17, 1981

to: Distribution

C. E. Hackett

from: C. E. Hackett - 8452

subject: Summary of SOLTES Solar Central Receiver Applications Coordination Meeting

A meeting between the SOLTES developers and the solar thermal central receiver application users to plan and coordinate activities was held on August 5, 1981, in Albuquerque. The personnel in attendance were:

SNLL	SNLA
Diane Atwood, 8452	Norm Grandjean, 4716
Al Baker, 8452	Mert Fewell, 5513
Colin Hackett, 8453	Dave Larson, 5513
Ed Cull, 8453	
Pat DeLaquil, 8453	
Scott Faas, 8453	
Lee Griffith, 8453	

The meeting began with a summary report of the previous orientation and status meeting on June 29-30, in Livermore. Specific details of that meeting were contained in my memo to this distribution of July 9, 1981.

Then followed a discussion on the issues and priorities for plant simulations between:

(a) IEA/SSPS - CRS 0.5 MW_e
(b) CESA-1 1.0 MW_e, and
(c) 10MW_e Barstow Pilot Plant.

Al Baker reported on his recent trip to Spain and his talks with the IEA operating agency DFVLR personnel. He stated that:

"DFVLR was in concurrence with SNL's efforts to simulate the SSPS plants. Particular interest was expressed in any comparative performance evaluations between the central receiver system (CRS) and the distributed collection system (DCS). The IEA plants will be completed by September 1981 and enter a 6-month operational optimization test phase during which time component performance data can be made available to SNL for use in any empirical modeling activity. A list of the required data should be drawn up and given to DFVLR as soon as possible. Also, a first-cut SOLTES model of the IEA-CRS plant should be available for use as a simulator by the end of the optimization test phase.

The ability to model the DCS plant(s) was seriously compromised because there were no plans as yet to log directly the operational status of the components. The SOLTES load management routines require unambiguous component dispatch and control algorithms for satisfactory simulation.

The Spanish government's CESA-1 central receiver plant will not be completed until the end of 1982. Since the receiver is cavity water/steam cooled, much of the modeling will correspond to that developed for the Pilot Plant. The Spanish wish to undertake the evaluation themselves, so SNL's only commitment would be to supply a working SOLTES model based on estimated empirical component performance parameters by the end of next fiscal year.

Subsequent discussions that followed Baker's presentation led to the following commitments:

1) Fewell/Grandjean will examine the IEA/SSPS-CRS documentation and prepare a preliminary SOLTES model using empirical performance parameters wherever necessary.

2) Baker will review this model and determine the input data requirements for eventual transmission to DFVLR.

3) The Thermal Subsystems Division 8453 will assume ultimate responsibility for subsystem modeling;

i.e., Heliostat Field and Receiver -	Ed Cull
Thermal Energy Storage -	Scott Faas
Electric Power Generation -	Lee Griffith
Controls and Dynamics -	Pat DeLaquil

4) The Large Power Systems Division 8452 will assume ultimate responsibility for whole system modeling;

i.e., IEA/SSPS-CRS -	Al Baker/Diane Atwood
CESA-1 -	Al Baker/Diane Atwood
Pilot Plant -	Jim Bartel
Generic Plants -	Colin Hackett

5) The heliostat field and receiver performance estimates will be made using the existing structures established for the STEAEC program. Atwood (8452) has already completed this for the IEA/CRS plant and is in the process of generating this information for the CESA-1 plant. Cull (8453) stated that the modeling by Abrams (8124) would be sufficient to estimate the cavity receiver performance.

6) The empirical SOLTES model of the IEA/SSPS-CRS plant should be available for use by the end of CY1981.

7) The staging of subsequent SOLTES modeling and reporting activities is shown in scheduling table enclosed with this memo.

8) Documentation either in the form of a SANDIA report or a technical paper is encouraged. A suggested list of topics is incorporated into the scheduling table.

9) The national SOLTES programmer's guide workshop is presently scheduled for Sept. 29 - Oct. 1, 1981, in Albuquerque.

10) The next coordination meeting will take place on October 9, after the SOLTES IEA/SSPS-CRS workshop presently scheduled for October 6-8, 1981, in Livermore.

11) The input required for the Pilot Plant Data Dissemination Plan will be prepared by Hackett (8452) in consultation with the SOLTES developer and subsystem coordinators.

CEH:8452:jdf

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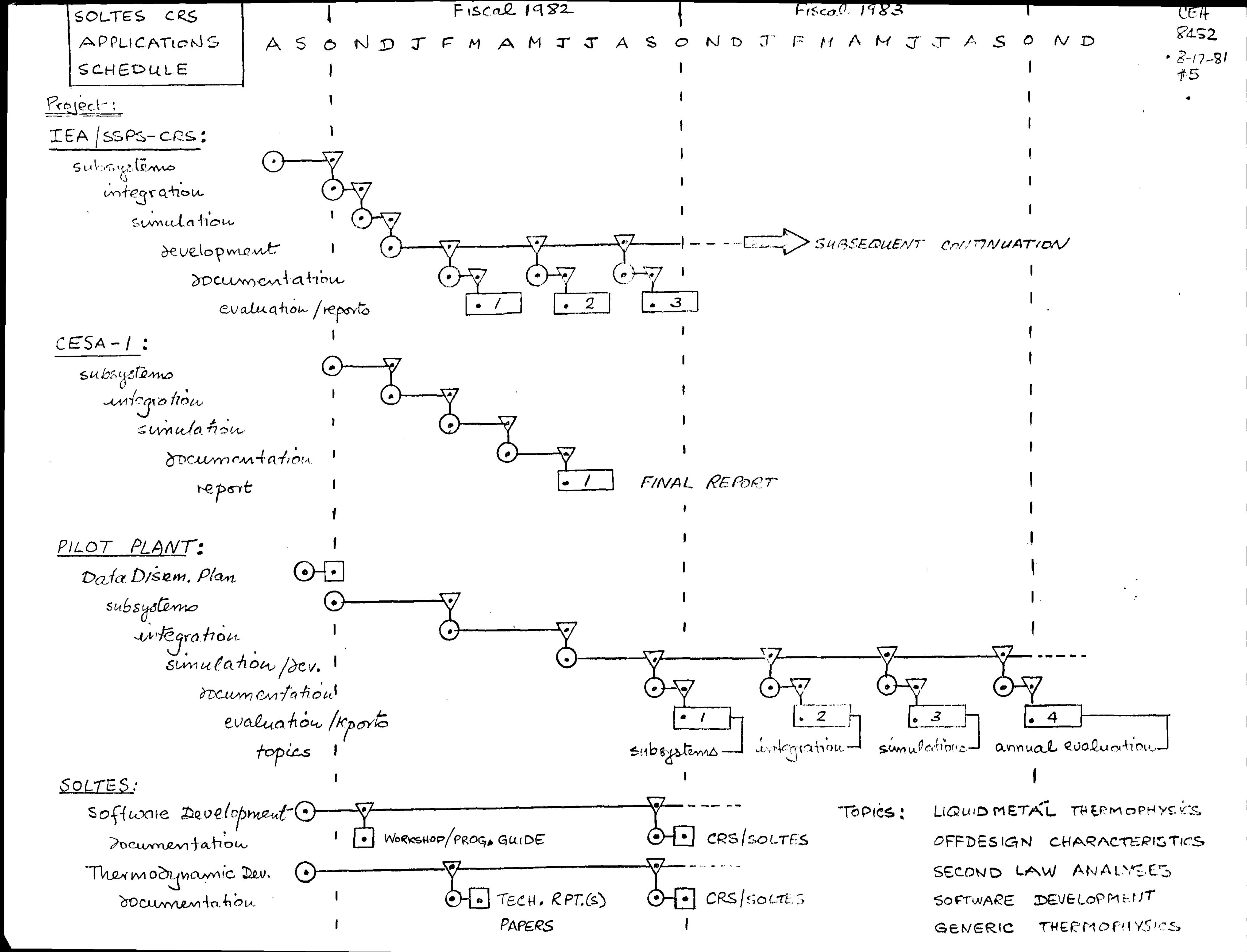
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IEA/SSPS-CRS:
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integration
simulation
development
documentation
evaluation/reports
1
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SUBSEQUENT CONTINUATION
CESA-1:
subsystems
integration
simulation
documentation
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FINAL REPORT
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FINANCIAL STUDY OF COMMERCIALIZATION OF SOLAR CENTRAL RECEIVER POWER SYSTEMS FINAL REPORT

MARCH 1981

PREPARED FOR THE
U.S. DEPARTMENT OF ENERGY
AS PART OF
CONTRACT NO. DE-AC03-80SF11421

Rockwell International

Energy Systems Group

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TABLES

FIGURES

FIGURES

1.0 SUMMARY AND CONCLUSIONS

1.1 SUMMARY

Commercialization requires that central receiver (CR) systems meet the economic criteria used by industry to select systems for capital ventures. If these systems cannot offer comparability in present and expected cost (weighted by perceived risk) to alternate energy sources, then industry simply will not invest in the equipment. This work provides quantitative estimates of the investment required by government, utilities, and the manufacturing sector to meet the energy displacement goals for central receiver technology. Initial solar repowering and stand-alone electric utility plants will not have economic comparability with competitive energy sources. A major factor for this is that initial (first of a kind) heliostat costs will be high. As heliostat costs are reduced due to automated manufacturing economies, learning, and high volume production, central receiver technology will become more competitive. Under this task, several scenarios (0.1, 0.5, and 1.0 quad/year) were evaluated to determine the effect on commercial attractiveness and to determine the cost to government to bring about commercialization of solar central receivers.

One case considered was meeting the national goal of providing 0.5 quads/year with solar by the year 2000 by the utility sector. Technological feasibility must be demonstrated as well as the construction of many commercial size plants. There are many scenarios that can be hypothesized, with variables such as: the size of demonstration plants, the number of demonstration plants needed, number of scale-up steps to a commercial size plant, time delay between demonstration plants to show operation of feasibility and the initiation of commercial size plants, and, finally, the production capabilities to construct the commercial size plants. Figure 1-1 is one example of how we might reach this goal. To demonstrate feasibility, several demonstration plants are needed with the Barstow 10-MWe pilot plant coming on-line in 1981 and on-line operation by 1985 of at least two repowering plants of medium size (60 MWe with storage). A 2-year time period is allowed for the demonstration repowering plants to demonstrate to utilities the operating aspects of a solar plant with respect to the demands of the utilities' electrical network. At this point, most of the risk aspects of new technology would be eliminated, and full-scale implementation of commercial

80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
QUADS/YR (CUM) *						0.0036	0.004	0.004	0.004	0.004	0.004	0.015	0.036	0.0555	0.104	0.148	0.218	0.292	0.392	0.492
MWe (CUM) *						120	120	120	120	120	120	420	1020	1620	2820	4020	5970	7920	10,620	13,320
HELIO/YR x 1000				8	8	–	–	–	–	25	76	101	152	203	266	330	393	456	(456)	
HELIO CUM x 1000		2	2	10	18	18	18	18	18	43	119	220	372	575	841	1171	1564	2020		
HELIO COST $/m^2				220	220					132	108	103	103	103	103	101	101	101		
PLANT COST $/MWe-HA				825	825					556	474	430	430	430	430	426	426	426		

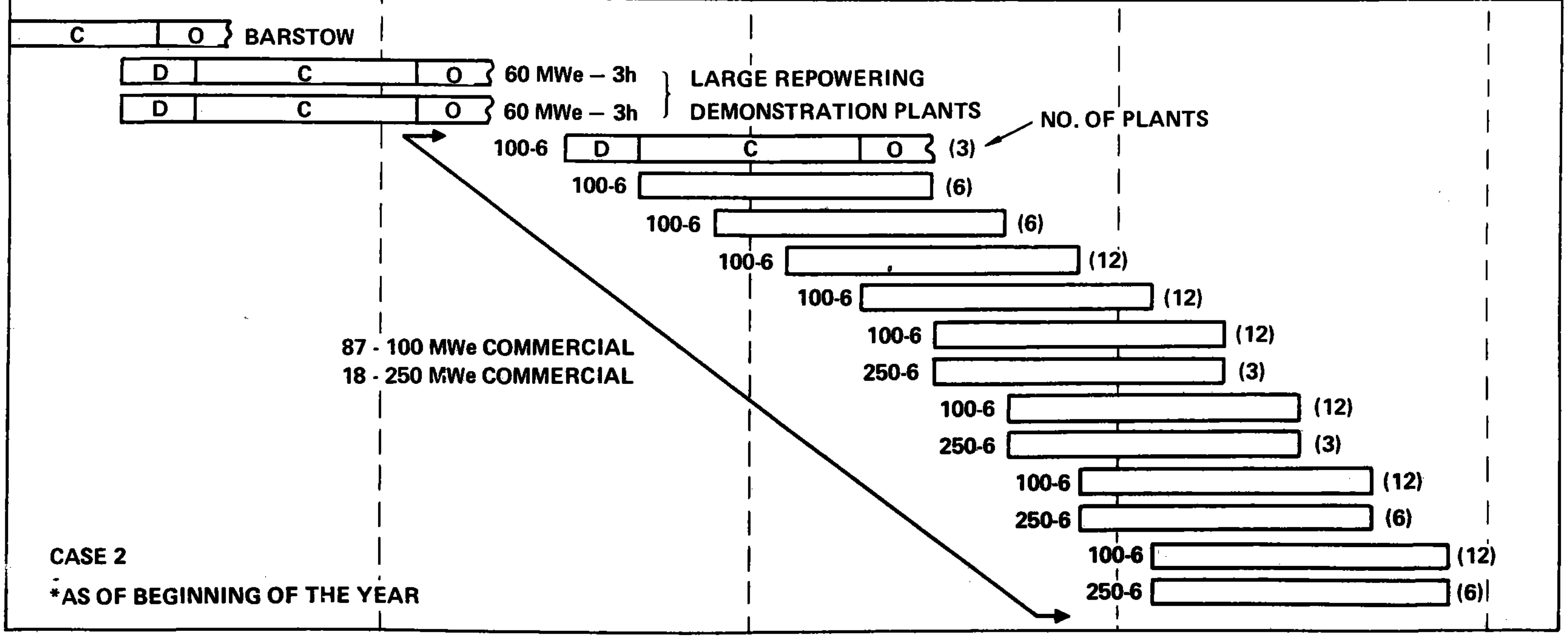

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Figure 1-1. Electric Utility Commercialization Plan
(0.5 Quads by Year 2000)

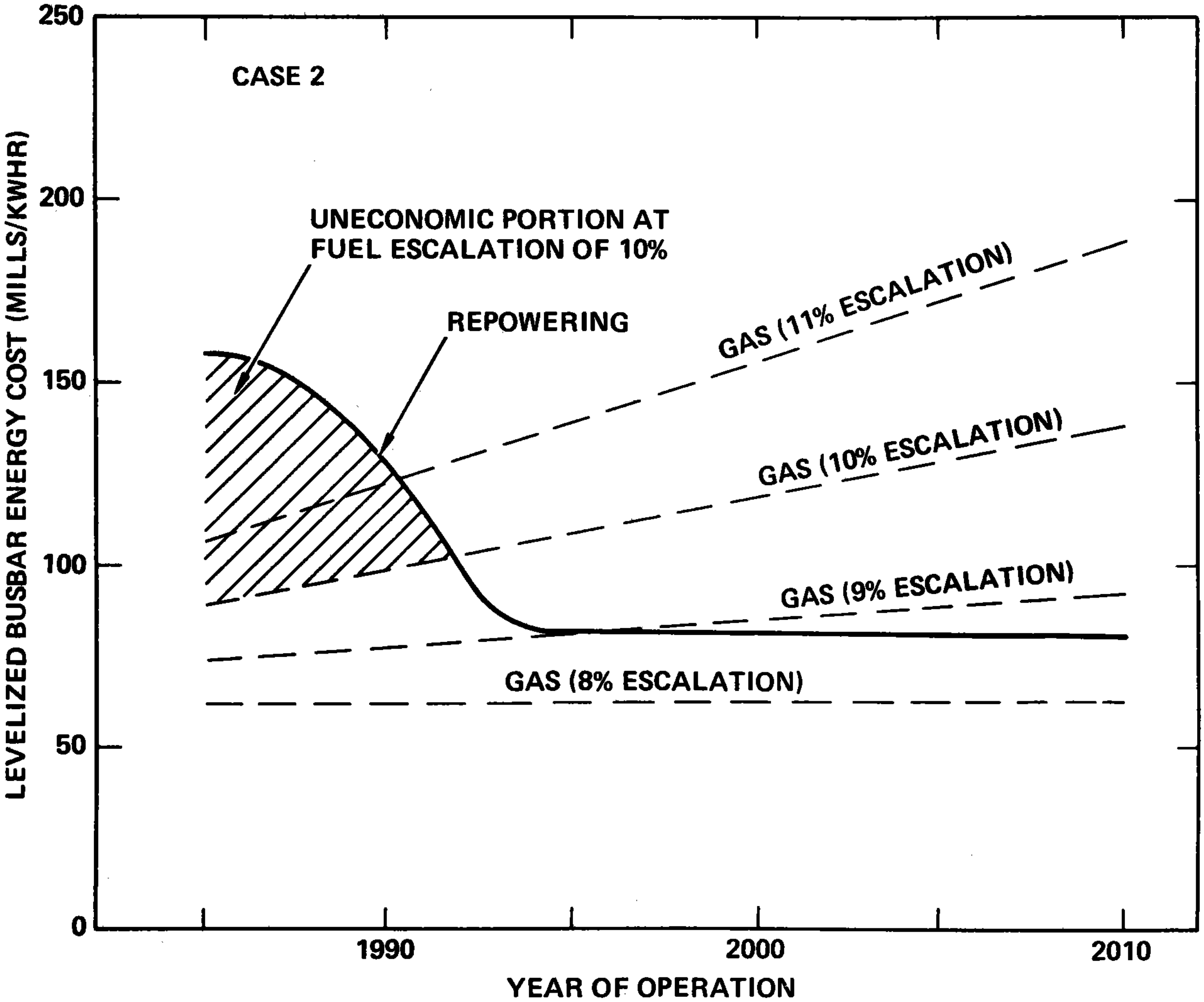
size solar plants could be initiated. By the year 2000, 87-100 MWe and 18-250 MWe plants would be operational and, thus, achieving the national goal of 0.5 quads/year.

While government subsidies would be required for the uneconomic portion, not all of the above plants would need to be subsidized. Figure 1-1 has presented the cumulative number of heliostats produced for each year. As the heliostat costs decrease, the total plant costs decrease as shown in Figure 1-2. The levelized Busbar Energy Cost ($\overline{\text{BBEC}}$) of solar repowering plants with a life of 30 years is compared to the $\overline{\text{BBEC}}$ of the gas energy fuel savings which the solar repowering plant would replace. In the year 1992, the solar repowering plant becomes economically competitive if a 10% gas escalation rate is assumed. At this time, government subsidies would cease, and the commercial marketplace would take over. The break-even point for heliostat costs in the year 1992 would be $103/m^2 in 1980 dollars. The difference in $\overline{\text{BBEC}}$ before 1992 represents a measure of the plant subsidy that would be required to induce utilities to select CR systems.

Figure 1-3 shows the total cumulative plant subsidy required to reach commercial viability. The total plant subsidy during a 10-year period would come to a total of $481 million (1980 dollars). Additional curves indicate the cost of production facilities required to produce the heliostats and other specialized components (receiver, tower, pumps, valves, controls, steam generators, etc.). The assumption is that solar equipment manufacturers would not invest in production facilities for a component that does not have a commercially viable market. After the year 1992, manufacturers would, on their own accord, continue to invest their own money. Until that time, manufacturers must invest $357 million in heliostat facilities and $127 million in balance-of-plant facilities. Government subsidies or guarantees would be required to cover this cost.

Several approaches for government incentives were considered. They are classified on the basis of the government relationship to the utility and manufacturing sectors and are as follows:

1) Utility/government cooperative



MAJOR ASSUMPTIONS

- GAS COST = $2.5/MMBTU
- 30 YEAR LEVELIZATION
- SOLAR THERMAL ELECTRIC GROWTH RATE IS BASED ON MEETING NATIONAL GOAL OF 0.5 QUADS/YEAR BY YEAR 2000

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Figure 1-2. Solar Repowering $\overline{\text{BBEC}}$ vs Gas Fuel Savings $\overline{\text{BBEC}}$

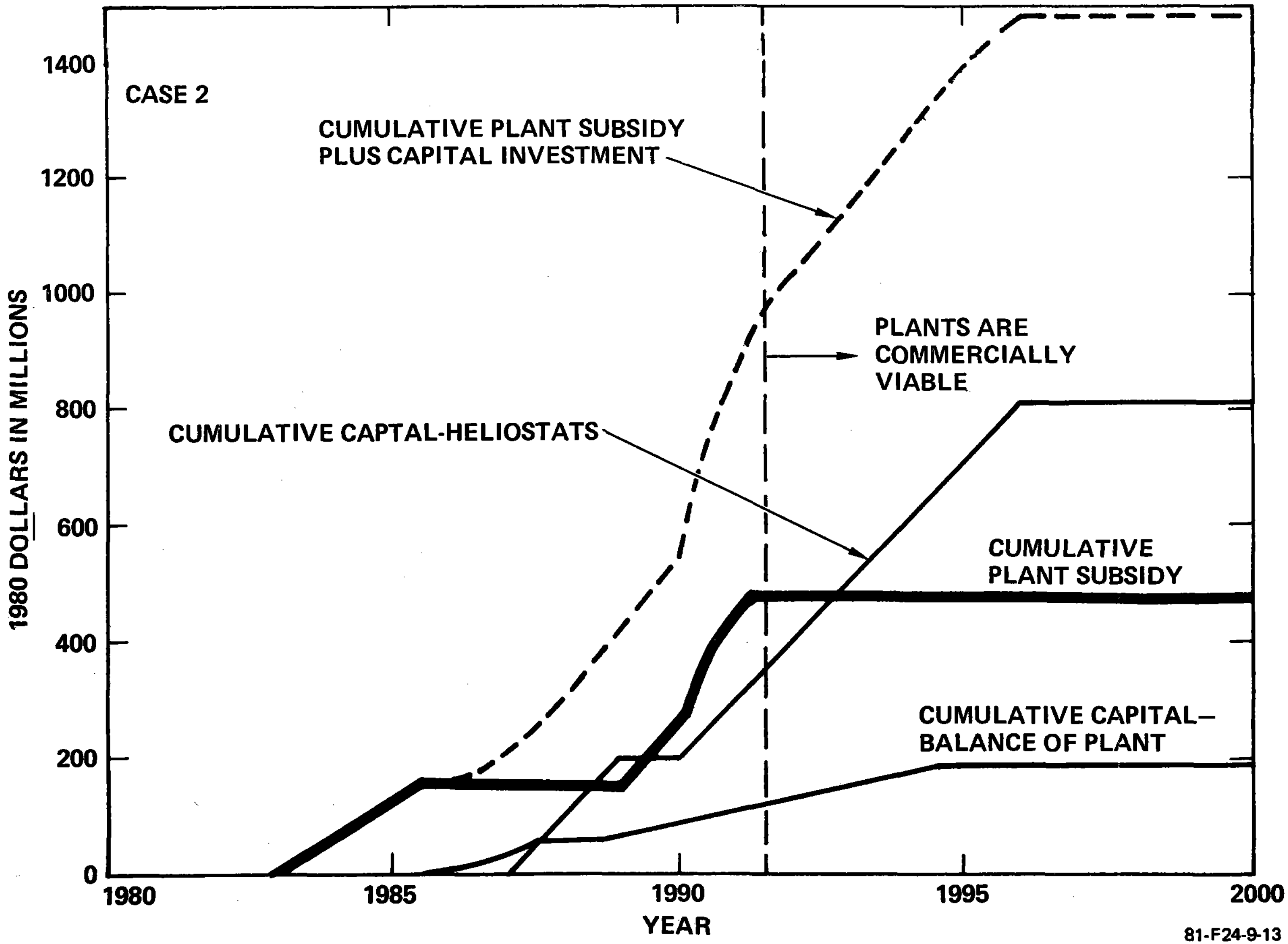

Figure 1-3. Utility Plant Subsidy and Capital Investment Needed for 0.5 Quads

2) Manufacturer/utility/government cooperative
3) Manufacturer/government cooperative.

In the utility/government cooperative, manufacturers would require a higher return on heliostats and other components in order to amortize the facilities over the initial central receiver plants. This would raise the total plant subsidy to $745 million. The other two approaches require government guarantees that there is a long-term market for solar central receivers. The second approach would require government investment or guaranteed loans of $484 million (1980 dollars) to the manufacturing sector with a return to government on that money in the form of royalties or interest, respectively. The manufacturer/government cooperative would consist of a long-term contract by government to purchase a specified number of heliostats at a given price from one or more manufacturers. The government, in turn, sells these heliostats to utilities at a price that is compatible with an acceptable $\overline{\text{BBEC}}$ for a net deficit of $481 million.

Figure 1-4 illustrates the government cash flow for these three types of incentives. Because the incentives to manufacturers carry a government commitment to create a long-term market, the last two types of incentives carry a certain risk if the program is discontinued before commercial viability. The dollar amount of that risk is indicated in Figure 1-4.

Four cases are presented in this study and are:

Case 1 0.1 quads with staggered demonstration plants

Case 2 0.5 quads with a 2-year delay between demonstration plants and the commercial plants

Case 3 0.5 quads with no delay between demonstration plants and the commercial plants

Case 4 1.0 quads with a 2-year delay between demonstration plants and the commercial plants.

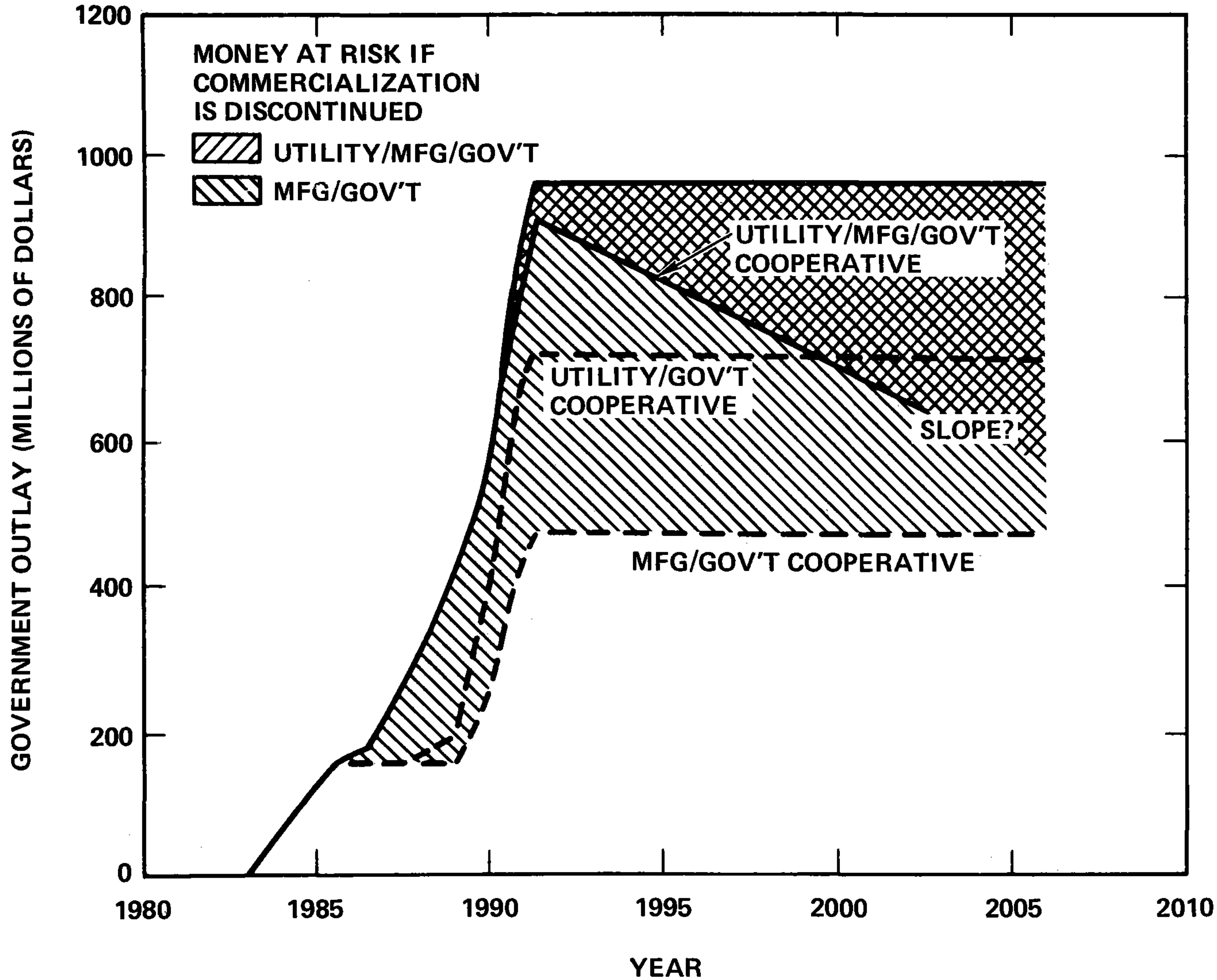

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Figure 1-4. Government Cash Flow (1980 $)

Results are shown in Table 1-1 for the four cases. The surprising result is that the total cost to government is very insensitive to the total energy goal level and approaches in timing for implementing the demonstration and initial commercial plants.

TABLE 1-1

GOVERNMENT INCENTIVES FOR FOUR SCENARIOS

	Case			
	1	2	3	4
Energy Level by Year 2000	0.1 quads	0.5 quads	0.5 quads	1.0 quads
Year of Commercial Viability	1996	1992	1990	1991
Total Plant Subsidy	$408M	$481M	$550M	$332M
Heliostat Manufacturing Investment	$253M	$357M	$205M	$330M
Balance-of-Plant Manufacturing Investment	$55M	$127M	$88M	$161M
Total Government Incentives*	$564M	$745M	$790M	$735M

*This total represents the utility/government cooperative using short-term amortization of manufacturing facilities before the year of commercial viability
General inflation at 8%
Gas escalation at 10%
Cost of gas = $2.50/MMBtu

1.2 CONCLUSIONS

The major conclusions made in the report are as follows:

1) In all four cases, as heliostat costs decreased, solar central receiver power plants were competitive with alternative fossil fuel power plants. Solar repowering became commercially viable in the very early phases of the commercial plants. Solar stand-alone plants vs coal power plants became commercially viable at a slightly later time frame (~5 years).
2) The most probable cost to Government to commercialize solar central receivers is $745 million. The net cost to Government can be reduced to $481 million if a long-term Government commitment to commercialization is made to manufacturers (particularly as it pertains to heliostat manufacturers). This approach can result in a maximum cost of $965 million if for any reason the Government discontinues the commercialization program.
3) Commercialization costs are fairly independent of the quad goal.
4) The repowering market is the most cost-effective market for achieving commercialization. The loss of this market would increase the total cost from $481 million to $2.2 billion to achieve 0.5 quad/year in the year 2000 by using solar stand-alone plants (vs coal). A go-slow approach or the manner in which the Fuel Use Act of 1978 is implemented can eliminate repowering as a potential route to achieve commercialization. Exemptions must be provided until 1996 when solar becomes competitive with coal.
5) As heliostat costs are reduced, the cost for the balance of plant becomes more critical. Two demonstration plants (a salt and a sodium system) are needed to confirm cost and performance uncertainties. Resolvement of these problems in the commercial plant phase*

---

*There will be 15 plants under construction before the first 100-MWe plant comes on-line.

could potentially result in a large increase in required Government subsidies due to initial capital cost uncertainties and/or potential plant retrofits. If only one demonstration plant using sodium or salt is built, it may very well eliminate the other working fluid from competition for the commercial plants. This could result in a cost penalty. If a water/steam demonstration plant is built, it potentially will have to be followed by a sodium/salt demonstration plant before embarking on the commercial plants (similar scenario to Case 1 with 0.1 quad/year by year 2000).

2.0 INTRODUCTION

The national investment in energy source development was conceived from the need for achieving long-term national energy independence. The government investment can only be justified by the sufficiency of the resulting impact of the investment in the energy marketplace. For the Central Receiver (CR) program, this impact equates to commercialization with significant market penetration. The mandates of the national policy for energy development, as well as the individually felt impetus for action in the energy field, infuses the element of urgency in the effort to impact energy use. Commercialization and market development under the DOE Central Receiver Program will establish an industrial base which will result in solar thermal contributing a significant share to the President's energy displacement goals for the year 2000. The development of CR components and system concepts has proceeded to the point that commercialization of the CR technology can be achieved in the 1990 to 1995 time frame which will make possible a very significant impact on energy source utilization by the year 2000. The path to this impact can only be assured, from the 1980 perspective, through the vigorous investment in precommercialization demonstration projects for repowering. No other viable response to the challenge for significant CR contribution for the year 2000 seems available to this technology.

Current economic projections indicate that a mature central receiver technology can compete with alternative energy sources. However, the initial high costs of heliostats even for commercial plants are expected to make the first commercial plants uneconomic. This will require continued government support past the demonstration phase.

The following sections explore the fundamental requirements and costs for commercialization of central receiver systems.

3.0 SELECTION OF SCENARIOS

In order to determine how commercialization might be achieved and what the cost to government would be to bring this about, a program of implementation must be formulated. National energy goals have previously been identified and were used for determining the number of plants that must be built between now and the year 2000. The following sections describe how the scenarios for commercialization were selected.

3.1 CENTRAL RECEIVER TECHNOLOGY

Previous studies funded by DOE have developed conceptual designs for central receiver electric power plants. These systems are characterized by a field of mirrors (heliostats) that reflect the sun's rays onto a central receiver mounted on a tower. The working fluid that flows through the central receiver absorbs the reflected sun's energy. In the case of water/steam, the working fluid then transports this thermal energy directly to a turbine generator for conversion to electrical power. If the receiver working fluid is sodium or salt, the thermal energy is transferred in a heat exchanger to the plants water/steam system before conversion to electricity. Thermal storage may or may not be included in the system. The advantages of thermal storage is the ability to produce electricity when the sun is not shining. These three concepts, water/steam, sodium, and salt, are illustrated in Figure 3-1. The draw salt and sodium systems are very similar to each other, differing mainly in the receiver design. Both systems provide modern steam conditions with reheat which allows the use of standard turbine design. Also, the thermal storage is provided by large tanks holding sodium or draw salt and provides a buffer between receiver transients and the steam generator. This provides a steady and regulated source of steam to the turbine independent of receiver operation and only limited by the amount of storage provided by the system. The water/steam system is better suited for the case where no thermal storage is needed. The water/steam system shown in Figure 3-1, however, illustrates the use of, for example, oil/rock thermal storage. During

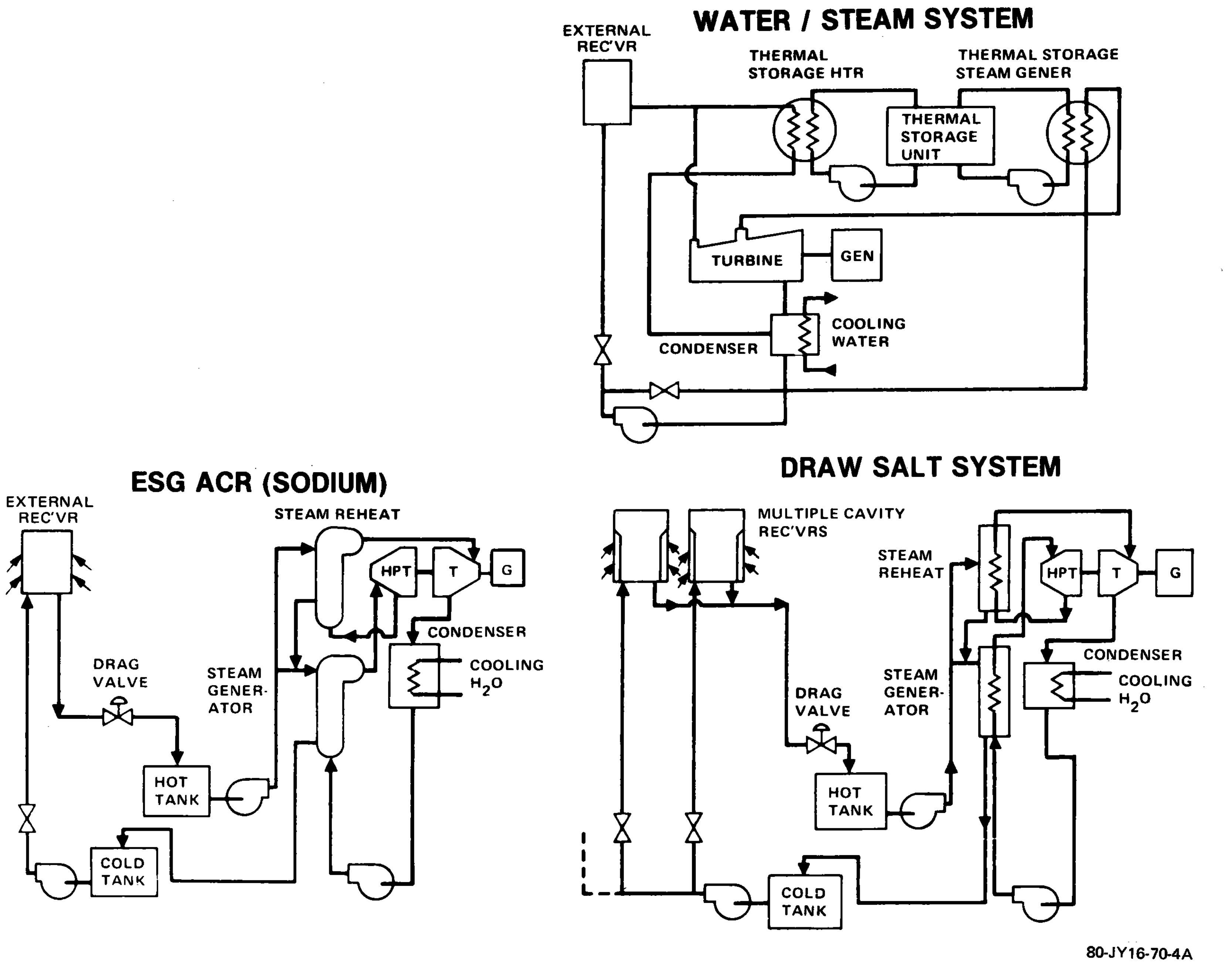


Figure 3-1. Central Receiver Concepts

operation from storage, lower temperature steam is generated which requires an alternate inlet to the steam turbine. Because of the pumping costs involved with sending low-pressure steam in the long pipe run to the receiver, steam reheat is generally not practical.

The sodium and draw salt systems are most ideally suited for large utility applications utilizing storage. The water/steam system is best suited for the smaller size applications involving industrial process heat users. For this reason, the design specifications and plant costs used in this report are specifically applicable to only the sodium and draw salt systems. Figure 3-2 is a comparison of costs between the three systems for a 100-MWe plant. For moderate storage capabilities, sodium and salt have essentially identical costs. Conclusions as to commercial viability should be applicable to both systems. In order to simplify further analysis, all system specifications and estimated costs were obtained using a sodium system. This should not in anyway impair the validity of the results to a salt system.

There are three major utility applications for solar central receivers; solar stand-alone, hybrid, and repowering. A solar stand-alone plant is a plant that has no alternate energy source. A hybrid plant is a plant that utilizes both solar energy and an alternate energy source which, most likely, would have to be coal due to the Fuel Use Act of 1978. A provision of the Fuel Use Act prohibits the use of oil and gas in electric power plants after 1990. An application for an exemption allowance to this rule can be made if 20% of the energy generated by an existing oil or gas plant is supplied by a renewable energy source. This is the incentive behind current DOE repowering program studies where a solar central receiver system is added to an existing plant. Cost savings are realized by not having to install a new electrical power generation system (EPGS). The solar central receiver system would be connected in parallel with the existing fossil-fired boiler to produce high-temperature, high-pressure steam.

It is expected that the first solar central receiver power plants will be repowering in nature. This is due to two reasons: (1) repowering will replace

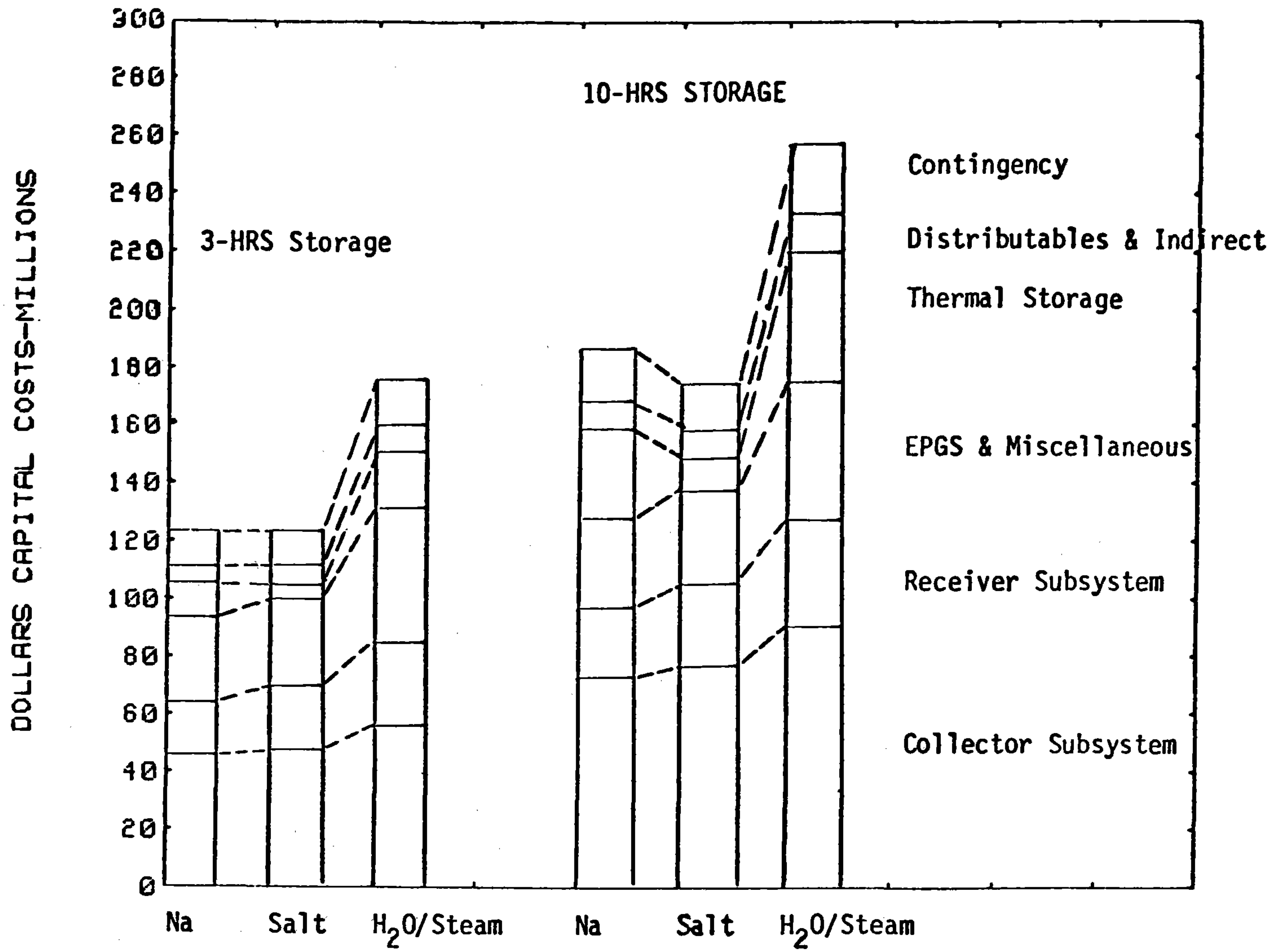


Figure 3-2. Capital Cost Comparison of Sodium, Salt, and Water/Steam Plants (1978$)

the more expensive fuels of gas and oil and (2) the exemption provision of the Fuel Use Act of 1978 will allow deferment of building a new coal plant to replace existing gas and oil plants if 20% of the energy utilized is being provided by a renewable energy source.

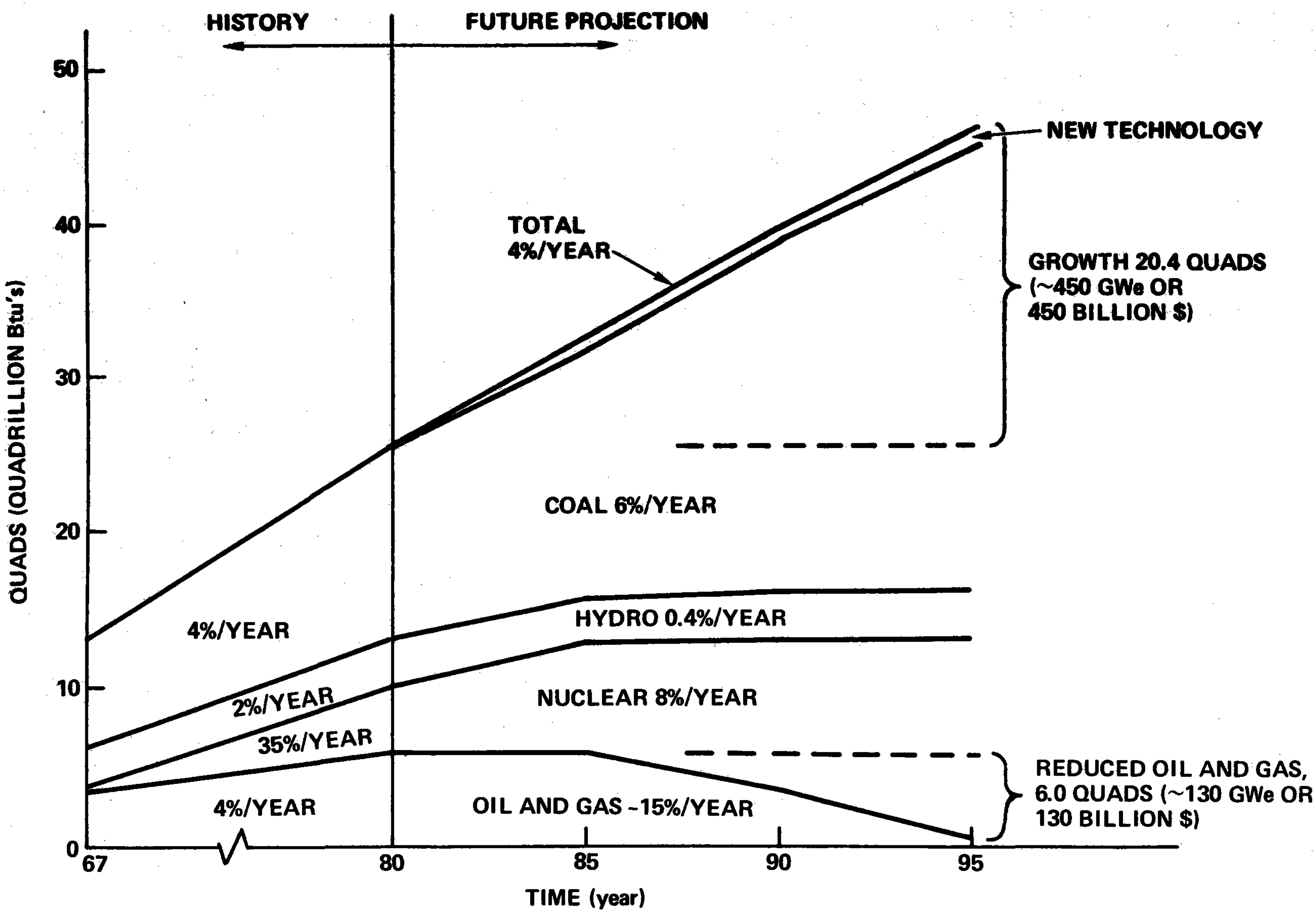
For long-range commercialization, repowering is not the answer as oil and gas plants will be gradually phased out. Solar central receivers must be competitive with other alternatives - the primary one being coal. So, while repowering may open the door for solar central receiver technology development, the final test of its viability is whether eventually, in the time frame of 1990 to 2000, it can compete with coal plants in the open market.

3.2 NATIONAL GOALS

National goals have been set up to meet the U.S. energy needs by the year 2000. Approximately 20%, or 18 quads, of this energy is to be supplied by solar directly or indirectly. The government's definition of solar-derived energy is a broad definition including not only utilizing the sun's energy directly but also solar energy stored in the atmosphere (wind), bodies of water (hydroelectric and OTEC), and plants (biomass). Solar energy utilized directly is in the form of (1) solar panels for low-temperature requirements, (2) photovoltaic cells that can convert thermal energy into electrical energy, and (3) solar concentrators (solar thermal) for mid- and high-temperature applications. Solar concentrators are expected to provide 3 quads by year 2000. Of this, 2 quads are to come from distributed systems such as parabolic dishes or troughs and the remaining 1 quad from central receiver technology. Distributed systems are usually designed for mid-temperature applications and for very small systems (<10 MWe). Reference 3-1 illustrates some cost comparisons of various solar thermal concentrators for small systems in the 0.1 to 10 MWe range. In the very small systems, parabolic dishes were most cost effective. Only at 10 MWe does the central receiver concept start to compete favorably with distributed systems. For these reasons, most of the opportunities to use solar power for industrial process heat applications, which are generally small in size, are expected to be met by the use of distributed collector systems. However, there still remains a market for solar thermal systems that require high-temperature and/or large power requirements. This market is comprised of industrial process heat applications and electric utility power plants. The solar thermal concept most compatible with this market is solar central receivers. The national goal for solar central receivers is 1 quad by the year 2000. It is the expectation that one-half of this goal will be met by the industrial process heat applications and the other half by electric utilities. However, the actual implementation will be highly dependent on the commercial viability of central receivers in these two markets. As the actual utility market penetration is not known at this time, three energy levels--0.1 quad/year. 0.5 quad/year, and 1.0 quad/year by the year 2000--were evaluated for this study. The IPH market was not evaluated, and the heliostat costs generated in this study assume no cost reduction due to higher volume production if an IPH market coexists. The final cost to government to commercialize for utility applications is, therefore, conservative in the sense that it assumes no ongoing concurrent IPH program.

DOE has set a national energy goal for solar central receivers, but this is not meaningful unless there is a valid potential market. Central receivers are expected to take only a small percentage of any new growth in electricity usage and/or replacement of existing gas and oil plants. Figure 3-3 is a DOE-projected fuel use split for the next 15 years. New growth is expected to be 20.4 quads and oil and gas replacement is a potential 6 quads. A 0.5-quad goal for central receivers represents capturing 2% of the total market. This goal certainly appears reasonable if costs are comparable.

A better approach is to look at the potential market area which is the southwest region of the United States which has good insolation. A study by MITRE and SRI (References 3-2 and 3-3) looked specifically at this area with respect to repowering potential and future projected plant additions planned by the utilities in this area. Table 3-1 is a state-by-state tabulation of the potential central



SOURCE: DOE ANNUAL REPORT TO CONGRESS 1978

80-S6-89-17

Figure 3-3. Electricity Fuel Usage (Quads)

TABLE 3-1

PROJECTED UTILITY MARKET FOR CENTRAL RECEIVERS
(References 3-2 and 3-3)

State	1977 State Capacity (10^3 MWe)	Repowering Potential (10^3 MWe)	Additional Capacity: Base Loaded (10^3 MWe)	Additional Capacity: Intermediate Loaded (10^3 MWe)	Central Receiver Market (10^3 MWe)
Washington	18.4	S		2.6	2.6
Oregon	7.9	S		2.8	2.8
California	35.7	2.2	13.3	15.3	30.8
Nevada	3.6	0.4		0.7	1.1
Utah	1.6	0.4		0.9	1.3
Arizona	8.7	0.6		2.5	3.1
Colorado	4.7	0.4	0.6	1.1	2.1
New Mexico	4.5	0.5		0.1	0.6
Montana	3.1	S	0.8		0.8
Idaho	1.8	S			0.0
Wyoming	3.3	S			0.0
Texas	46.0	12.4	26.0	17.6	56.0
North Dakota	2.1	S	0.6	0.4	1.0
South Dakota	2.2	S	0.2	0.2	0.4
Minnesota	8.2	S		1.2	1.2
Nebraska	3.9	S		1.1	1.1
Iowa	6.2	S	0.5	1.0	1.5
Kansas	6.8	0.4		0.7	1.1
Oklahoma	9.2	0.8	1.3	3.5	5.6
Arkansas	4.8	0.4*	2.7	1.9	5.0
Missouri	13.4	S	0.2	2.1	2.3
Louisiana	12.9	2.0*	6.8	5.0	13.8
Total	209.0	20.5	53.0	60.7	134.2
Total Annual Energy (Quads)†	9.2	0.9	2.3	2.7	5.9

*Estimated potential from a total oil and gas plant rating of 1500 MWe for Arkansas and 9900 MWe for Louisiana.
†Based on a 50% capacity factor.

receiver market. The total potential repowering market is 0.9 quad which takes into consideration land availability near existing oil and gas plants. A total of 5.0 quads will be added capacity or planned retirement of existing plants. A 0.5-quad goal represents 8% of this total southwest region market.

Another study (Reference 3-4) has also looked at repowering potential to determine the effective repowering market as shown in Table 3-2.

TABLE 3-2
REPOWERING MARKET SURVEY EVALUATION BY STATE
(Reference 3-4)

State	Number of Candidate Units	Rated MWe	Effective Solar MWe	Percent Repower	Percent of Effective Solar
Arizona	22	1,217	974	80.0	8.7
California	61	5,300	1,602	30.2	14.3
Colorado	9	166	35	21.1	0.3
Louisiana	25	1,664	757	45.5	6.8
Nevada	9	739	665	90.0	6.0
New Mexico	22	423	371	87.7	3.3
Oklahoma	21	1,492	885	59.3	7.9
Texas	100	8,482	5,616	70.2	50.3
Utah	1	66	66	100.0	0.6
Others	2	200	200	100.0	1.8
Total	272	19,749	11,171	56.6 (avg)	100.0

The effective solar rating was based on a survey of utilities which reported the number of plants, plant rating, and actual land availability. Assuming 6 acres/MWe, the effective solar repowering potential is reduced to 11,200 MWe (0.5 quads). Using repowering only, it is possible to reach the 0.1-quad and, marginally, the 0.5-quad goal. To achieve 1.0 quad, a combination of repowering and stand-alone plants would be required.

3.3 SCENARIOS TO REACH 0.1, 0.5, and 1.0 QUADS/YEAR

Once a national energy goal was set, the next step was to examine how this goal could be achieved. Four cases were considered as follows:

> Case 1 - 0.1 quads with staggered demonstration plants
>
> Case 2 - 0.5 quads with a 2-year delay between demonstration plants and the commercial plants
>
> Case 3 - 0.5 quads with no delay between demonstration plants and the commercial plants
>
> Case 4 - 1.0 quads with a 2-year delay between demonstration plants and the commercial plant.

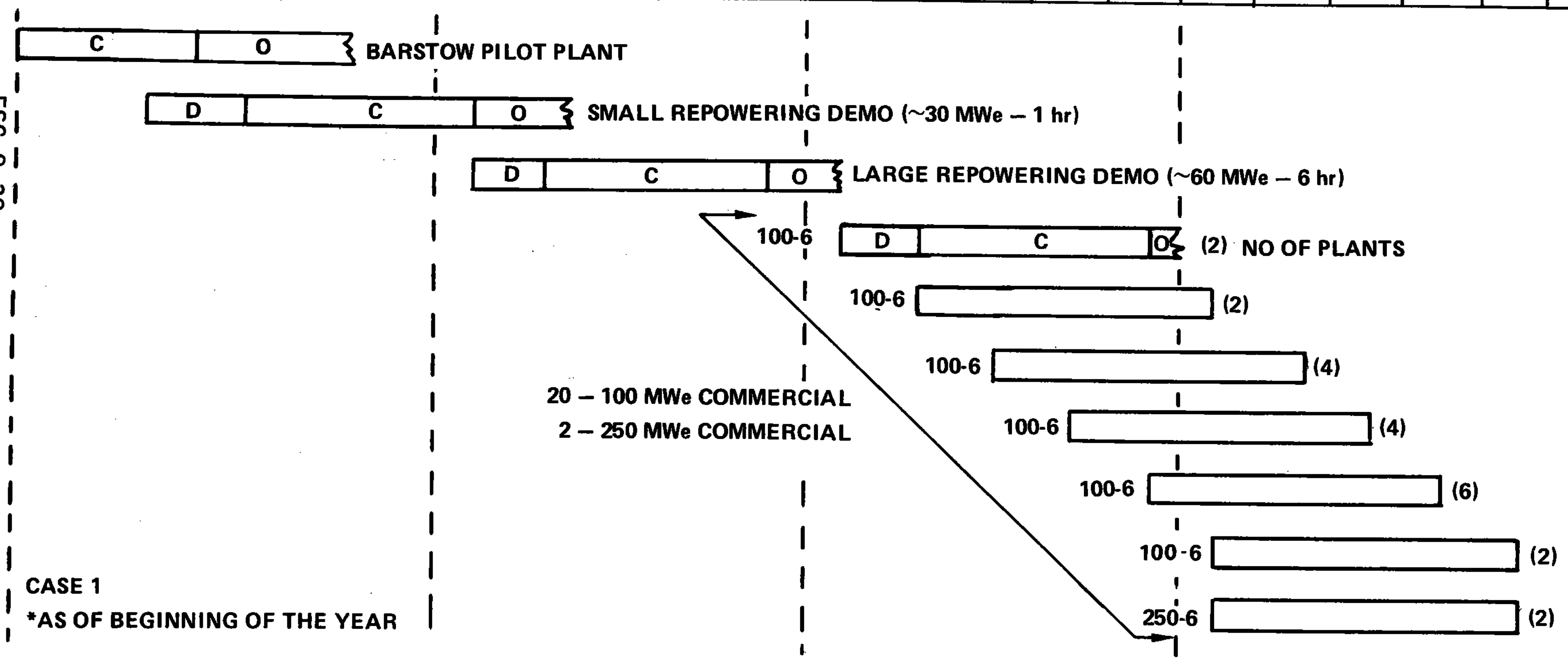
Case 2 is generally considered the baseline case with the national goal set at 0.5 quads/year. The other cases were considered to determine the effect alternate scenarios would have on the cost of commercialization. Figures 3-4 through 3-7 illustrate each of the four scenarios.

The scenarios consist of two phases: (1) technical demonstration and (2) construction of commercial plants. The Barstow 10-MWe pilot plant is planned for on-line operation by the beginning of 1982. This pilot plant is intended only to demonstrate central receiver technical feasibility and does not attempt to be cost effective nor even prototypical of commercial-size units. Water/steam is used in the receiver.

The Barstow plant is to be followed by two repowering demonstration plants. Conceptual design has already been completed for seven potential sites through funding provided by DOE. Two sites are to be selected with on-line operation currently planned for mid-1985. The demonstration plants are needed to provide:

1) Electric grid interaction experience
2) Intermedidate-size scaleup
3) Improved estimates for plant costs.

80 81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
QUADS/YR (CUM) *					0.001	0.001	0.001	0.001	0.003	0.003	0.003	0.003	0.003	0.011	0.018	0.033	0.047	0.070	0.095
MWe (CUM) *					30	30	30	30	90	90	90	90	90	290	490	890	1290	1890	2590
HELIO/YR x 1000			2	2	–	–	5	5	–	–	–	17	34	51	68	85	110		
HELIO CUM x 1000	2	2	4	6	6	6	11	16	16	16	16	33	67	118	186	271	381		
HELIO COST, $/m2			250	250			225	225				180	144	130	130	130	125		



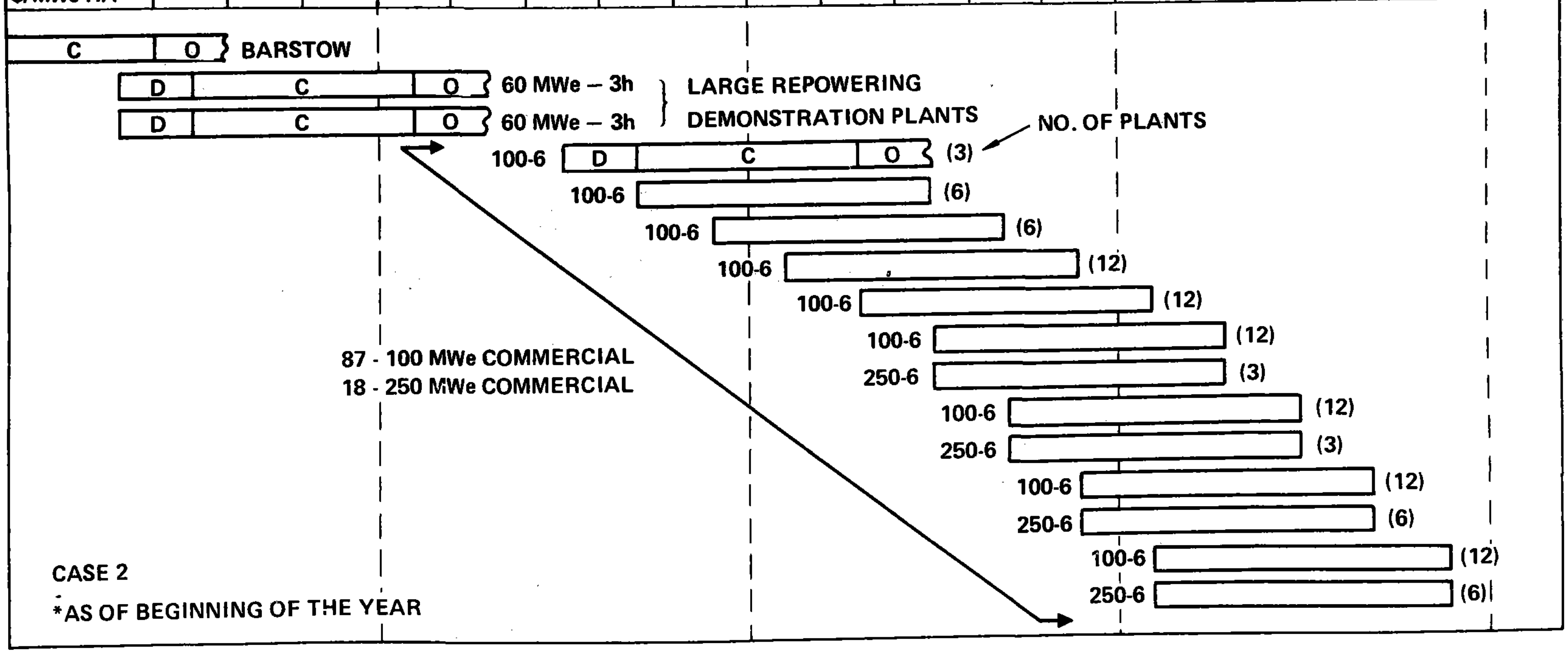
CASE 1

*AS OF BEGINNING OF THE YEAR

80-D11-109-7

Figure 3-4. Case 1 Scenario
(0.1 Quad/year)

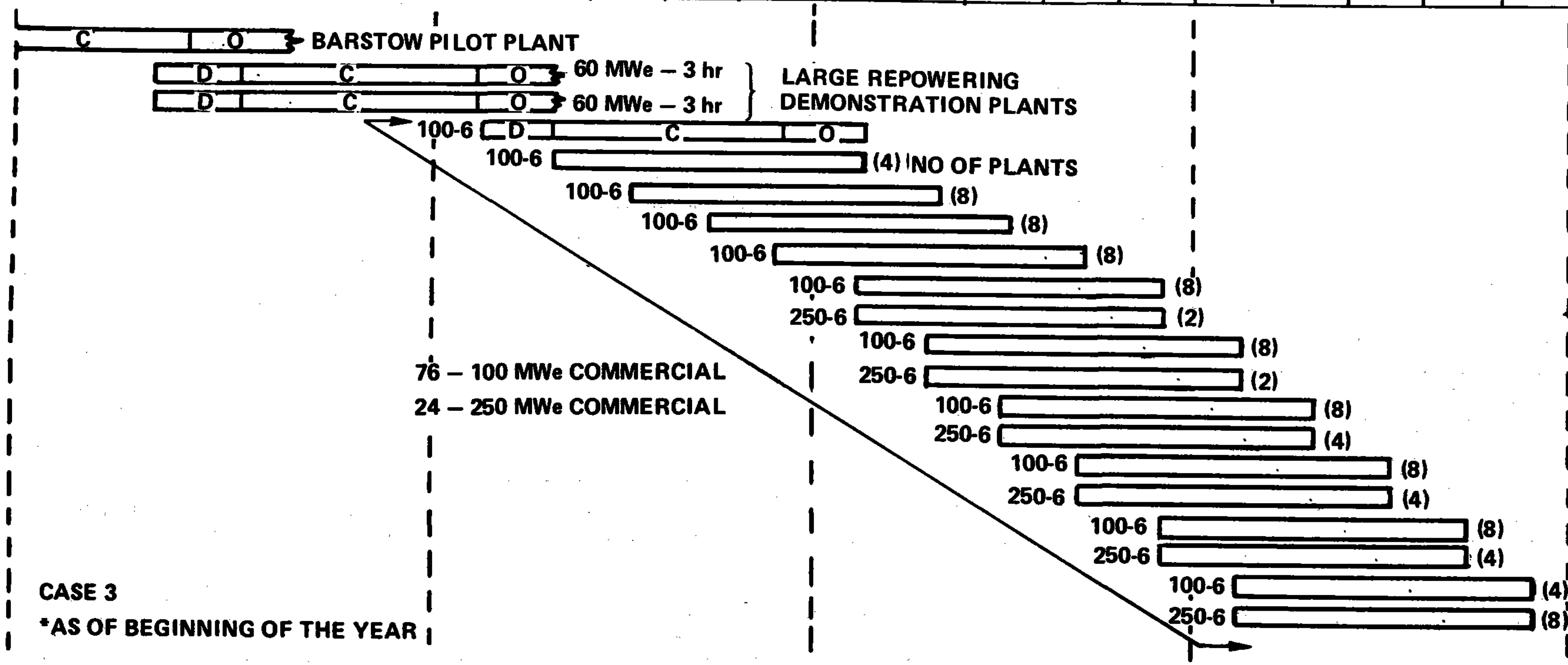
80 81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
QUADS/YR (CUM) *					0.0036	0.004	0.004	0.004	0.004	0.004	0.015	0.036	0.0555	0.104	0.148	0.218	0.292	0.392	0.492
MWe (CUM) *					120	120	120	120	120	120	420	1020	1620	2820	4020	5970	7920	10,620	13,320
HELIO/YR x 1000			8	8	–	–	–	–	25	76	101	152	203	266	330	393	456	(456)	
HELIO CUM x 1000	2	2	10	18	18	18	18	18	43	119	220	372	575	841	1171	1564	2020		
HELIO COST $/m²			220	220					132	108	103	103	103	103	101	101	101		
PLANT COST $/MWe-HA			825	825					556	474	430	430	430	430	426	426	426		



80-D11-109-4

Figure 3-5. Case 2 — Scenario
(0.5 Quad/year)

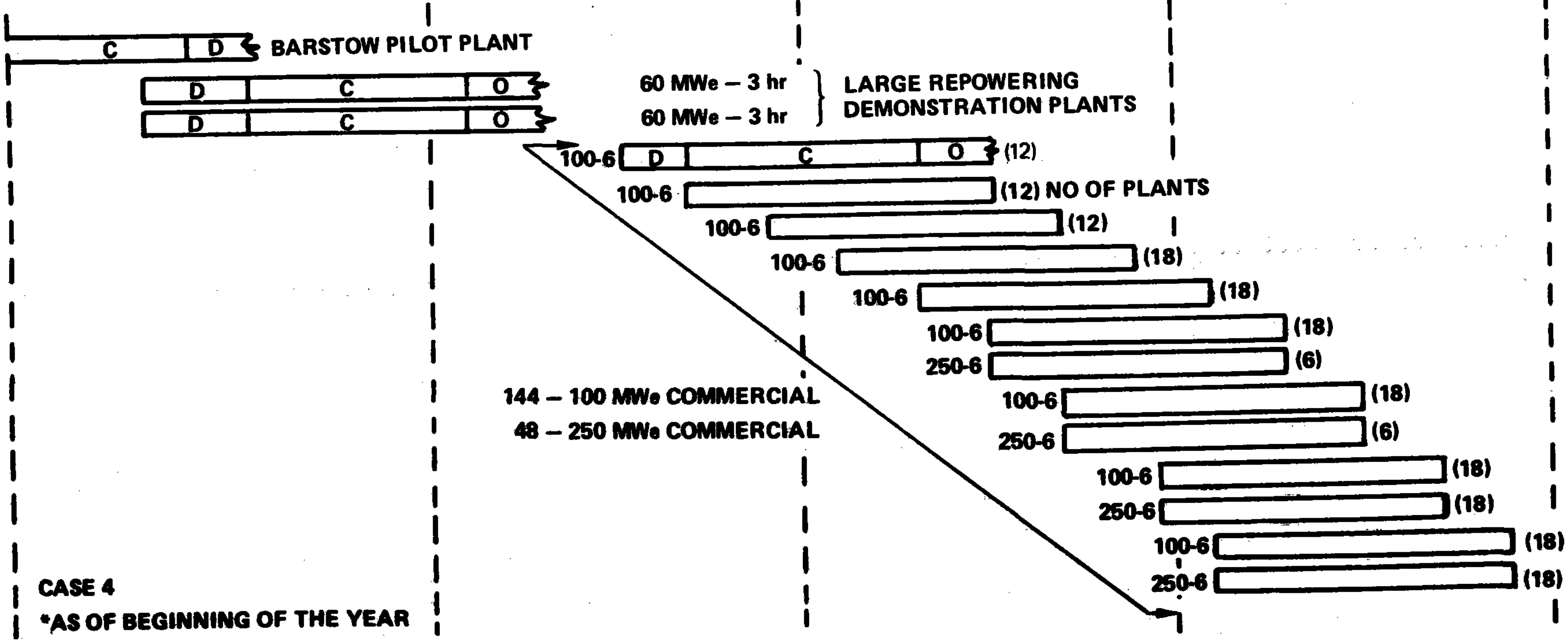
80 81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
QUADS/YR (CUM) *					0.004	0.004	0.004	0.004	0.018	0.033	0.063	0.092	0.122	0.170	0.218	0.285	0.351	0.418	0.507
MWe (CUM) *					120	120	120	120	520	920	1720	2520	3320	4620	5920	7720	9520	11320	13720
HELIO/YR x 1000			8	8	—	—	34	68	101	135	135	178	220	262	304	304	355	(406)	
HELIO CUM x 1000	2	2	10	18	18	18	52	120	221	356	491	669	889	1151	1455	1759	2114		
HELIO COST $/m2			220	220			123	108	103	101	101	101	101	101	101	101	101	101	



80-D11-109-6

Figure 3-6. Case 3 Scenario (0.5 Quad/Year)

80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
QUADS/YR (CUM) *						0.004	0.004	0.004	0.004	0.004	0.004	0.048	0.092	0.137	0.203	0.270	0.392	0.514	0.747	0.980
MWe (CUM) *						120	120	120	120	120	120	1320	2520	3720	5520	7320	10620	13920	20220	26520
HELIO/YR x 1000		–	–	8	8	–	–	–	–	101	203	203	254	304	431	558	811	1065	(1065)	
HELIO CUM x 1000		2	2	10	18	18	18	18	18	119	322	525	779	1083	1514	2072	2883	3948	5013	
HELIO COST, $\$/m^2$				220	220					98	94	93	93	93	92	92	90	90	90	



80-D11-109-5

Figure 3-7. Case 4 Scenario (1.0 Quad/yr)

It is important that the demonstration plants be sufficiently large (~50 MWe) that scaleup is not perceived as a large risk. In addition, these plants should consist of a sodium and a salt system. As previously shown in Figure 3-2, sodium and salt systems are the most cost effective in the size range that utilities are interested. Water/steam is expected to be significantly higher in cost (~40%) than sodium or salt. As there are still uncertainties in both sodium and salt systems, the demonstration plant is the ideal time to build and test these systems. It would also partially eliminate much of the cost uncertainties. Resolvement of these problems in the earliest time frame possible is needed in order to achieve the high energy goal levels of 0.5 quad/year and 1.0 quad/year by the year 2000. A fairly large number of utility plants for these cases are required even in the first few years of commercialization. This requires that a large number of components (some of which have long lead time fabrication requirements) be fabricated before even the first commercial plant comes on-line. Any design problems, as a result, could result in costly modifications to plants in operation as well as plants in the process of construction. Utilities and manufacturing facilities are unlikely to be willing to assume these kinds of risks in any large-scale buildup.

No commercial-size plants are expected to be built until the demonstration plants are on-line and have provided some operating experience. The Energy Systems Group utility advisory committee, consisting of utility representatives, has recommended that at least 2 years of operating experience is needed before utilities would consider building commercial-size plants. With this requirement, the first commercial plants would not come on-line until mid-1991. This leaves only 9 years to achieve the annual energy level set by the national solar goals.

The first commercial-size plants were assumed to be approximately 100 MWe with 6 h of storage. As operating experience is gained, the plants are expected to increase in size. For the study, we assumed the eventual implementation of a 250-MWe plant with 6 h of storage. Selecting a plant size is mainly for illustrative purposes. In practice, installed plants may, and probably will, vary considerably in size. This does not affect the final results in any significant manner.

The commercial plants are expected initially to be of the repowering type with stand-alone plants phasing in as they become economically feasible. Unless stated otherwise, most plant costs and government subsidies given are based on repowering. This provides the lowest cost to utilities and thereby reduces the total government subsidy. If this route is closed to the utilities (the manner in which the government imposes the Fuel Use Act of 1978) or an insufficient repowering market exists, some additional costs could be incurred if the government must subsidize the uneconomic portion of solar stand-alone plants. As seen currently, the 0.1- and 0.5-quad cases can be achieved entirely by repowering if implementation of the Fuel Use Act keeps this option open until year 2000. The 1.0-quad case must begin switching to stand-alone plants in the time frame of 1996-1997 (year of on-line operation).

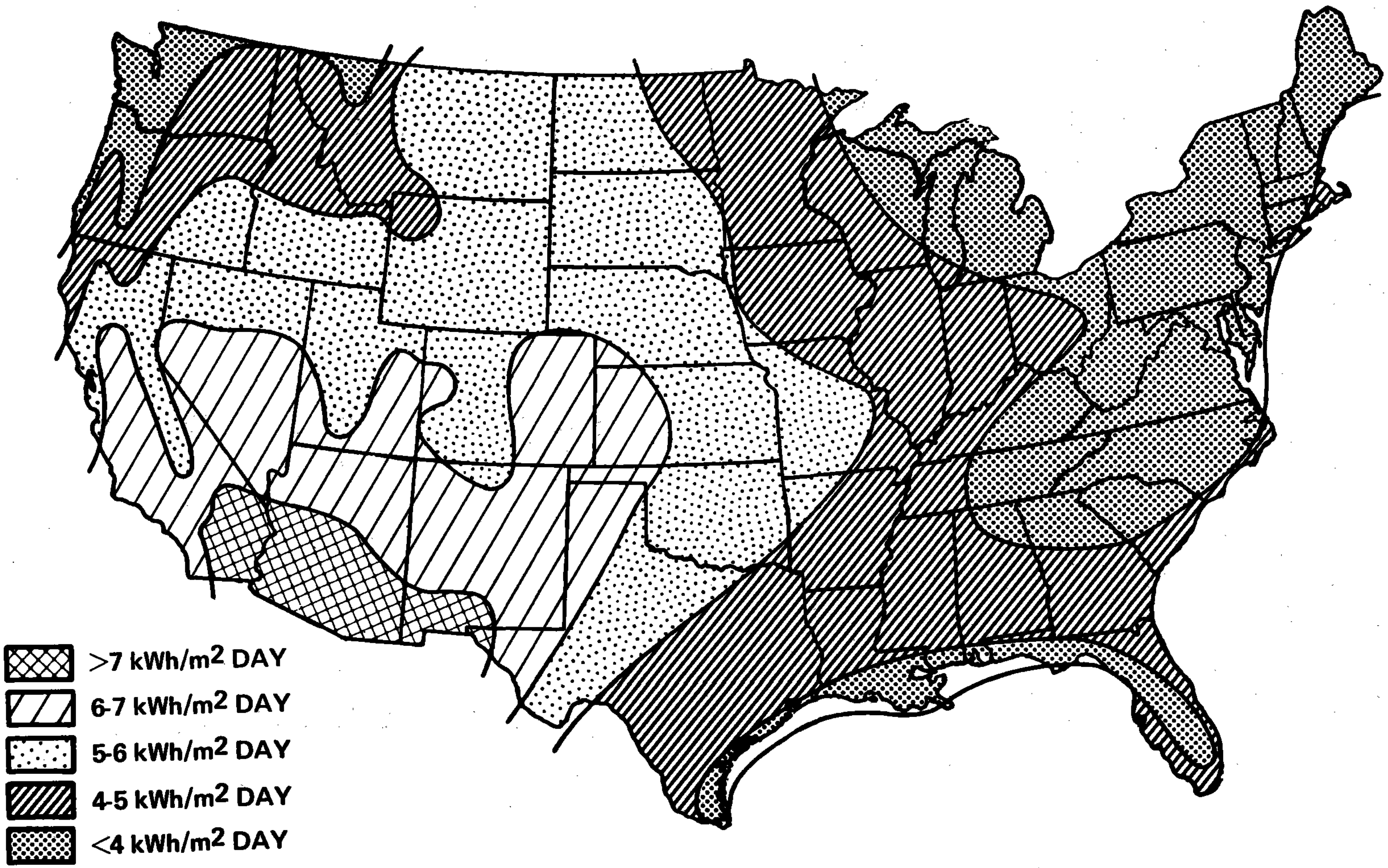
In order to determine the number of commercial plants needed to achieve the 0.1-, 0.5-, and 1.0-quad/year goal, certain assumptions were made. These were basically as follows.

An average insolation of 6.5 kWh/m^2-day was used as representative of a large southwest area of the United States. Figure 3-8 shows direct insolation values for the United States. Areas of potential central receiver sites would be in areas where the insolation is greater than 5 kWh/m^2-day. The very best insolation areas have direct insolation in excess of 7.5 kWh/m^2-day. The annual average insolation is a major factor in determining annual electrical energy production.

In determining the annual energy produced, a number of assumptions were made. First, a design point was used to determine the number of heliostats for a given power rating using the following formula:

$$\frac{\text{mirror area}}{\text{MWe}} = \frac{1}{950\ \text{W/m}^2} \cdot \frac{10^6\ \text{W}}{\text{MWt}} \cdot \frac{1}{0.60} \cdot \frac{\text{MWt}}{0.386\ \text{MWe}}$$

$$\frac{\text{mirror area}}{\text{MWe}} = 4547\ \text{m}^2/\text{MWe (0 h of storage)}$$



SOURCE: DOE/JPL-1060-17, MARCH 1979,
WATT ENGINEERING, LTD.

80-AU26-70-14

Figure 3-8. U.S. Solar Insolation Regions
(Direct Normal Insolation in kWh/m^2 Day)

where: $950 \ W/m^2$ = the design point typical heat flux at noon, March 21

0.60 = the field efficiency at noon, March 21

0.386 = representative of a combined steam cycle efficiency of 42% and a parasitic load of 8%

The hours of operation at nominal power and zero hours of storage was then determined by:

$$\text{hours/year} = \frac{6.5 \ \text{kWh}}{\text{m}^2\text{-day}} \cdot \frac{365 \ \text{days}}{\text{year}} \cdot \frac{4547 \ \text{m}^2}{\text{MWe}} \cdot 0.53 \cdot \frac{0.386 \ \text{MWe}}{\text{MWt}} \cdot 0.916$$

hours/year = 2022 h/year with 0 h of storage

where: $6.5 \ kWh/m^2$-day = the average annual insolation

0.53 = the annual average field efficiency

0.916 = accounts for 20 days planned outage in December and 4% forced outage

In order to adjust the above values for thermal storage, a solar multiple must be selected to provide sufficient additional energy to the receiver to be stored for later use in conversion to electrical energy. Figure 3-9 is a plot of hours of storage capacity versus solar multiple. For a given solar multiple (meaning a fixed number of heliostats), a range of optimum values for storage capacity can be obtained based on plant economics; particularly the effect on $\overline{\text{BBEC}}$ of net annual electrial output versus cost of the thermal storage subsystem. If the storage subsystem is designed for the average daily insolation, then there will be certain days in the summer where part of the collected energy will be

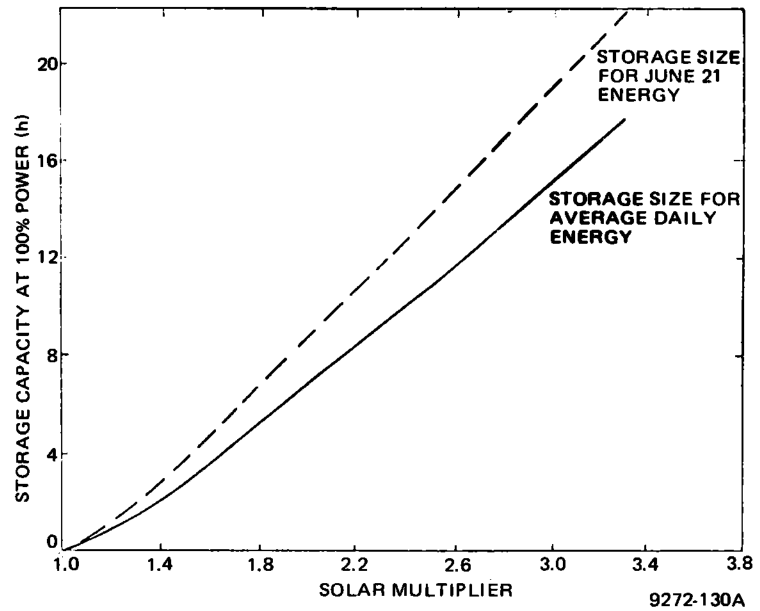


Figure 3-9. Storage Capacity vs Solar Multiplier

wasted because of insufficient storage. However, if it is designed for June 21, the longest day, then the storage will be fully utilized only 1 day of the year. Generally, the optimum value is somewhere in between. The solar multiple used was an average of the above two cases. Table 3-3 gives the number of hours of nominal operation for a given storage capacity. Once the annual hours of nominal operation have been determined, the installed MWe capacity rating can be converted to an annual energy/year of electrical energy produced. A heat rate of 10,000 Btu/kWhe was used to convert electrical energy into fuel savings (typical of a 42% steam cycle, 8% parasitic load, and 88% fossil boiler efficiency). A 100-MWe plant with 6 h of storage converted to fossil energy saved is equivalent to 3.68×10^{12} Btu/year or 0.00368 quads/year of fossil fuel energy resources saved. Energy per year as well as installed capacity is tabulated for all four cases in Figures 3-4 through 3-7.

TABLE 3-3

EFFECT OF THERMAL STORAGE ON ANNUAL HOURS OF NOMINAL OPERATION

Thermal Storage (h)	Solar Multiple	Annual Hours of Nominal Operation: No Outage (h)	Annual Hours of Nominal Operation: 8% Outage Factor (h)	Capacity Factor (%)
0.0	1.0	2198	2022	23.1
1.0	1.22	2680	2466	28.2
2.0	1.35	2966	2729	31.2
3.0	1.47	3230	2972	33.9
4.0	1.59	3494	3214	36.7
5.0	1.71	3758	3457	39.5
6.0	1.82	4000	3680	42.0
12.0	2.48	5450	5014	57.2

3.4 SCENARIOS FOR HELIOSTAT PRODUCTION LEVELS

Several studies, recently completed by two independent authors (References 3-5 through 3-7), have resulted in detailed estimates of heliostat costs for a standardized heliostat design as a function of production capacity. Installed heliostat costs of from 80 to 200 1979 dollars/M^2 were postulated for production levels ranging from 2,500 to 250,000 units/year.

General Motors (GM), the author of one of these studies, took a capital intensive approach to the problem of heliostat plant design resulting in a relatively automated plant. This approach resulted in mature installed heliostat cost estimates (1979 dollars) of $\$122/m^2$ at volumes of 25,000 units/year, and $\$89/m^2$ at volumes of 250,000 units/year. GM also suggested modifications of the heliostat design (which was based on the McDonnell Douglas first-generation heliostat) using current technology which could reduce these cost estimates. Thus, GM's estimate was viewed by SERI as conservative. GM also estimated that the investment requirement for a 25,000 unit/year plant is $87 million (1979 dollars).

The author of two independent studies of heliostat costs, Battelle Pacific Northwest Laboratory, took a labor intensive approach to the problem. Battelle found a slightly lower installed cost (1979 dollars) of approximately $\$100/m^2$ for a production volume of 25,000 units/year and $\$80/m^2$ for a production volume of 250,000 units/year. Battelle estimated installed costs of $\$216/m^2$ for a production volume of 2,500 units/year. Battelle used a McDonnell Douglas first-generation design as a basis for their cost estimate. It was found that a labor intensive approach resulted in a plant cost of $40.9 million (1980 dollars) for a 25,000 unit/year production capacity plant. Battelle also extended the results of their study to include interpolated and extrapolated heliostat costs at various production rates other than those directly considered by using the computer codes SAMICS and SAMIS III, which were adapted for heliostats. The codes were first calibrated against the known production rates and then used to predict heliostat costs at: (1) other design production rates and (2) off-design production rates.

Both authors obtained remarkable agreement as shown in Table 3-4, which shows installed cost/m^2 as a function of production level.

TABLE 3-4

HELIOSTAT COST ESTIMATE COMPARISON

Source	Volume	Installed Cost/m^2 (1979 dollars)
Battelle Memorial Institute	2,500	216
	25,000	100
	250,000	80
General Motors	25,000	122
	250,000	89

The decision as to which approach to utilize in our study is strongly dependent on the magnitude of heliostat demand dictated by the chosen solar central receiver scenarios. Assuming that each heliostat manufacturer would pursue a nominal 20% market share, a heliostat production schedule was generated for each case (scenario). Case 2 is illustrative of the trends observed and is shown in Figure 3-10. The early heliostat demands in the 1984-1985 time frame are of extremely low magnitude. So low, in fact, that it is questionable whether more than one manufacturer would enter the market. Consequently, for these extremely low-volume cases, an installed cost as a function of demand was generated by fitting a curve to the quoted (by individual manufacturers) heliostat costs for each of the recently completed solar repowering and IPH programs and the quoted costs for the Barstow plant. This curve is shown in Figure 3-11.

For the incremental production increases beyond 1989, it was assumed that each manufacturer would add capacity in increments such that his production requirements for the next 2- to 5-year time frame would just be met. This assumption is justified by the uncertainty of governmental policy with regard to heliostat procurements and the desire of manufacturers to add production capacity as inexpensively as possible. In no case did the incremental increase in capacity exceed 101,000 units/year, and in many cases, the increments were far less, a typical value for plant size being ~25,000 units/year as shown in Figure 3-10. Clearly, the limited nature of plant incremental requirements does not justify large plant expenditures that might lead to highly automated plants. Consequently, the heliostat costs used in this study were taken from the labor intensive study, and the minimum cost of heliostats were dictated by the size of the plant additions (which determined the production process).

Heliostat production histories for a manufacturer achieving a 20% market share are tabulated in Table 3-5 for each scenario.

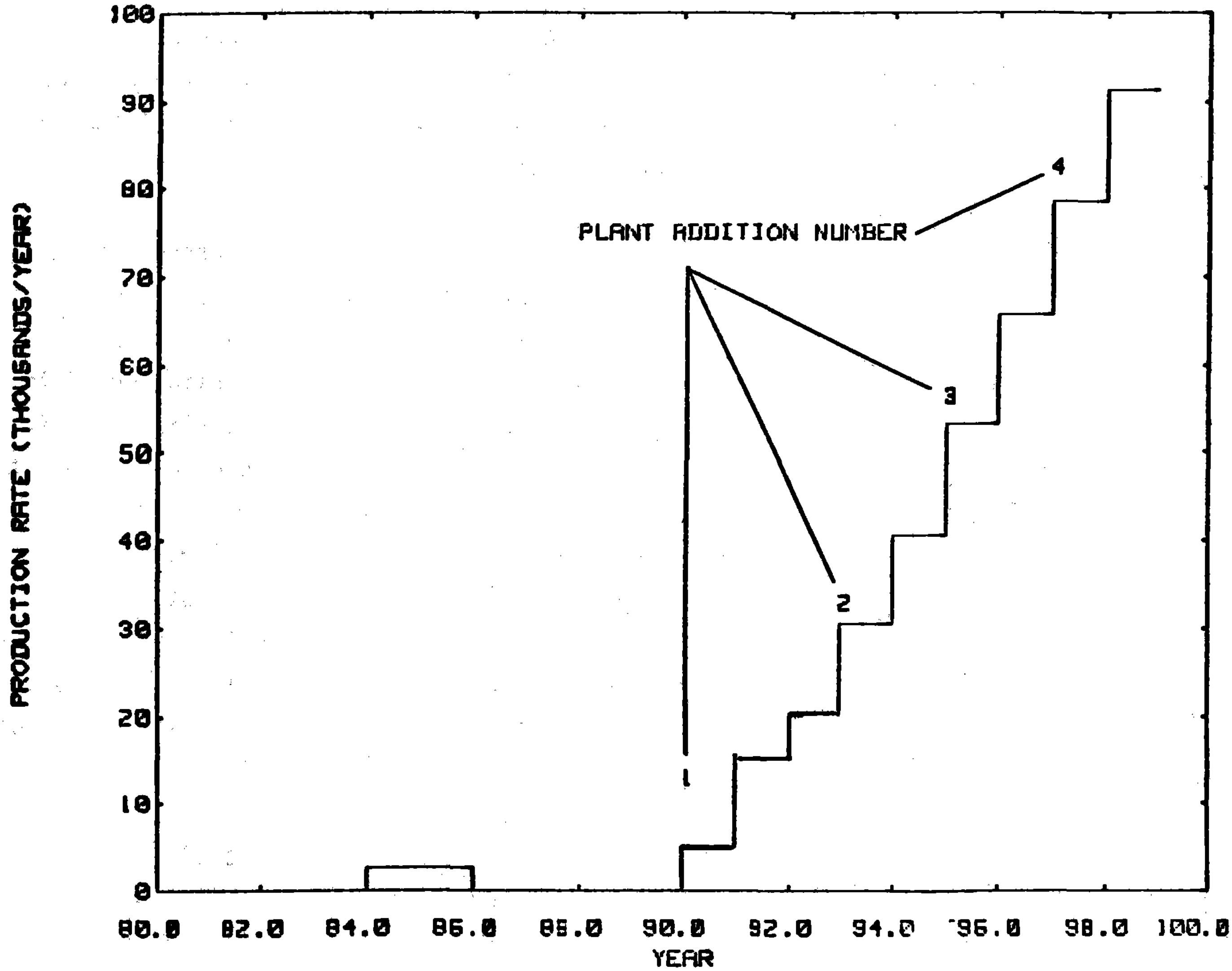


Figure 3-10. Case 2 — 20% Market Share Heliostat Production History

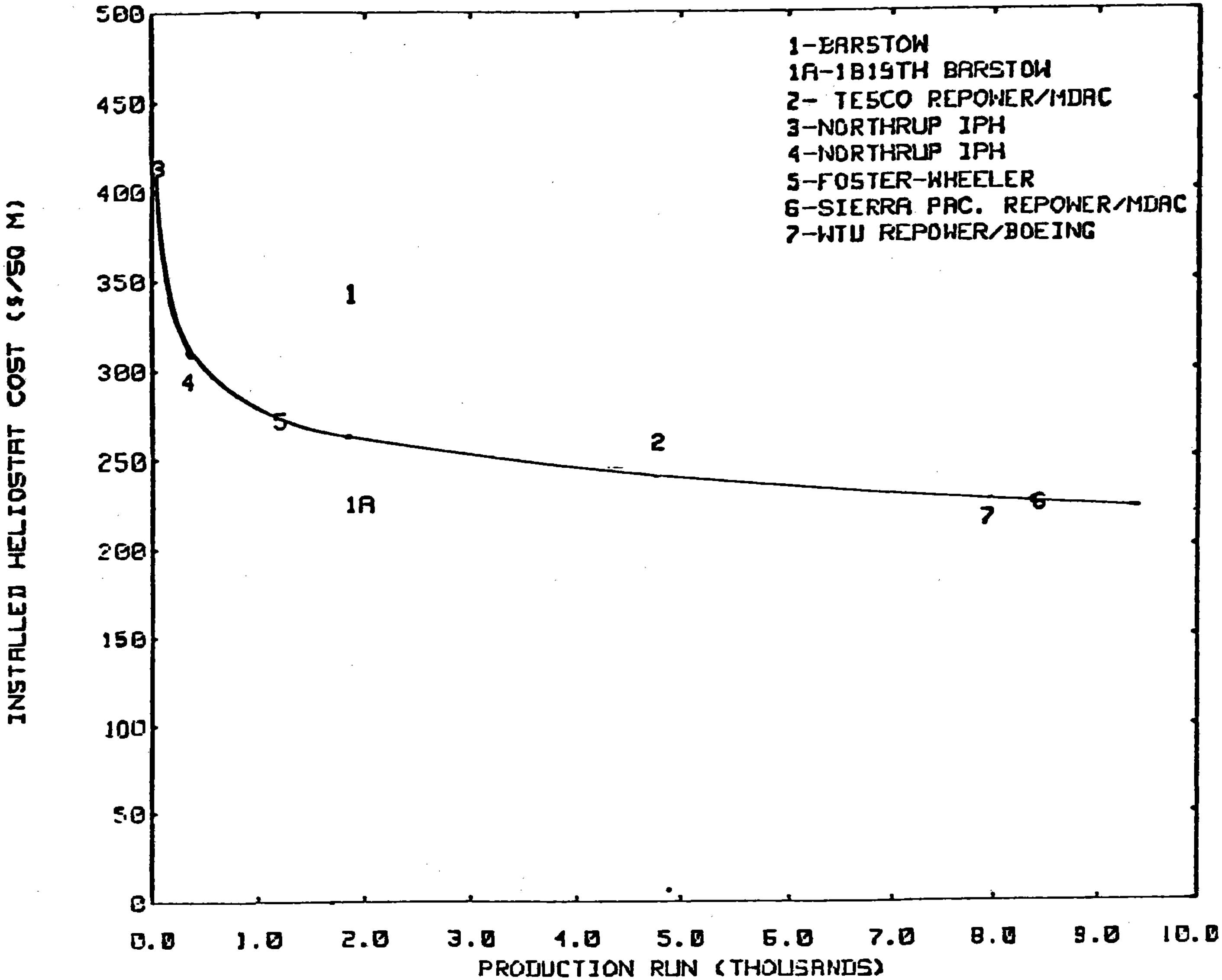


Figure 3-11. Demonstration Plant Heliostat Costs (Low Volume)

TABLE 3-5

HELIOSTAT PRODUCTION HISTORY FOR A 20% MARKET SHARE

Case		Year										
		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	Number of Heliostats Sold/Year						3,380	6,670	10,140	13,520	16,900	21,980
	Size of Plant Addition (heliostats/year)						10,000			12,000		
2	Number of Heliostats Sold/Year			5,070	15,210	20,280	30,420	40,560	53,240	65,920	78,600	91,280
	Size of Plant Addition (heliostats/year)			25,000			25,000		25,000		25,000	
3	Number of Heliostats Sold/Year	6,760	13,520	20,280	27,040	27,040	35,470	43,930	52,370	60,810	60,810	70,950
	Size of Plant Addition (heliostats/year)	27,000					25,000			20,000		
4	Number of Heliostats Sold/Year			20,280	40,560	40,560	50,700	60,840	86,200	111,540	162,240	212,940
	Size of Plant Addition (heliostats/year)			50,000				60,000			100,000	

REFERENCES

3-1 "Comparative Ranking of 0.1-MWe Solar Thermal Electric Power Systems," John P. Thornton, SERI paper presented at Solar Central Receiver Semiannual, San Francisco, September 1980

3-2 "Solar Thermal Repowering, Utility/Industrial Market Potential in the Southwest," The MITRE Corporation, MTR-7919, December 1978

3-3 "Fuel and Energy Price Forecasts," Electric Power Research Institute, EPRI-433, Palo Alto, California (1977)

3-4 "Technical and Economic Assessment of Solar Hybrid Repowering," Public Service Company of New Mexico, EG-77-C-03-1608, September 1978

3-5 "The Cost of Heliostats in Low Volume Production," SERI/TR-8043-2, Pacific Northwest Laboratory, Battelle Memorial Institute, Solar Energy Research Institute

3-6 "Heliostat Manufacturing Cost Analysis," SERI/TR-8043-1, Pacific Northwest Laboratory, Battelle Memorial Institute, Solar Energy Research Institute

3-7 "Heliostat Production Evaluation and Cost Analysis," SERI/TR-8052-1, General Motors Corporation, Solar Energy Research Institute, Golden, Colorado, December 1979

4.0 SOLAR AND FOSSIL FUEL PLANT ECONOMICS

Commercialization requires that central receiver systems meet the economic criteria used by industry to select systems for capital ventures. If these systems cannot offer comparability in present and expected cost (weighted by perceived risk) to alternate energy sources, then industry will not invest in the equipment.

4.1 GENERAL ECONOMIC FACTORS

The standard method used in comparing solar costs vs fossil energy alternatives is levelized busbar energy costs ($\overline{BBEC}$). The JPL methodology was used and is described in Reference 4-1. The basic economic parameters used in determining $\overline{BBEC}$ are presented in Table 4-1. Most of the baseline values used are taken from References 4-2 and 4-3. Values are not meant to be indicative of present economic conditions but, instead, are representative of average expected conditions during the next 20 years. All costs given in this report are in constant 1980 dollars. On several critical parameters, alternate values were used to determine the effect on Government subsidies required.

4.2 SOLAR PLANT COSTS

4.2.1 Collector Field Heliostat Costs

Having selected heliostat production scenarios and a cost data base in Section 3.4, the final methodological question involved interpolation between known heliostat production levels and their associated costs. The selected data base also included off-design production cost estimates which were used for initial commercial plant heliostat costs when the production facility was under-utilized. Battelle generated this data for plant design volumes of 2,500, 25,000, and 250,000 units per year. The computer codes extrapolated costs by assuming plant capacity expansions but no change in manufacturing technology or methods. By superimposing these off-design curves on a curve describing heliostat cost vs design production levels, the heliostat costs for early years of each heliostat

TABLE 4-1

COMMERCIALIZATION ECONOMIC ASSUMPTIONS

	Baseline	Variations
Cost of Capital		
(Weighted Average after Tax)	10%	
Fixed Charge Rate	16.23%	
Escalation Rates		
General Inflation	8%	
Capital Investment	8%	
Operations and Maintenance	8%	
Fuel - Coal	9%	8-10%
- Oil*	11%	8-12%
- Gas*	10%	8-11%
Plant Life and Amortization Period	30 years	
Construction Time Period	4 years	
Capital Investment Cash Flows	JPL	
Depreciation	SOYD (Depreciation)	
Annual Insurance	0.02	
Annual Property Taxes	0.0025	
Operations and Maintenance		
Fixed (% of Capital)	1%	
Variable (% of Fuel Costs)		
- Coal†	30%	
- Oil	10%	
- Gas	0%	
Capital Cost		
- Coal	$860/kWe	±20%
- Solar (Less Heliostats)	ACR/Repowering	
Fuel Costs		
- Coal	$1.45/MMBtu	±20%
- Oil	$4.00 MMBtu	
- Gas	$2.50 MMBtu	
Heliostat Costs	Variable	±25%
Capacity Factor		
- Coal	60%	
- Solar (6 hours Storage)	42%	
Heat Rate		
- Coal	9,400 Btu/kWhe	
- Oil	10,000 Btu/kWhe	
- Gas	10,200 Btu/kWhe	

†Coal O&M assumes flue gas desulfurization

*Gas is used for baseline fuel savings for all cases. Oil is run for Case 2 only.

plant were predicted. An example of this is shown in Figure 4-1 for a design production level of 25,000 units per year.

For instance, in Case 2, the first-year production level is 5,070 heliostats assembled in a production facility designed to produce 25,000 heliostats. This results in a heliostat cost of $\$132/m^2$. When the facility is producing at full capacity, the cost is $\$101/m^2$. Heliostat installed costs have been included in the scenarios shown in Figures 3-4 through 3-7.

As stated earlier in Section 3.4, the heliostat costs for the demonstration plants were taken from actual estimates provided under Barstow and the recent DOE-contracted studies for repowering and industrial process heat applications. Costs used in Cases 1-4 ranged from $\$220/m^2$ to $\$250/m^2$.

Learning (or experience) curves were not used in this study. It was desired to predict investments in manufacturing facilities as well as heliostat costs. The above-presented methodology, and in Section 3.4, allowed a direct connection between heliostat costs and the production facilities needed to provide the heliostats. This approach differs significantly from the learning curve methodology. A check was made to see whether these two approaches provide comparable costs for heliostats. Reference 4-4 recommends a 85% learning curve which implies a 15% cost reduction for each time the cumulative number of heliostats doubles. Figure 4-2 compares the results from Reference 4-4 with heliostat costs predicted for the four scenarios. Agreement was very good. Potentially there probably should be further cost reductions in the latter years of the scenarios as production experience is gained. The approach taken is conservative. The effect on government subsidies should be small as additional heliostat cost savings would occur after the year of commercial viability. The learning curve predictions do, however, reduce some of the risks as to the total amount of government subsidies that are required for commercialization.

4.2.2 Balance-of-Plant Costs

As stated before, solar plant costs were determined on the basis of a sodium system. References 4-5 and 4-6 were used as the basis for solar plant costs with

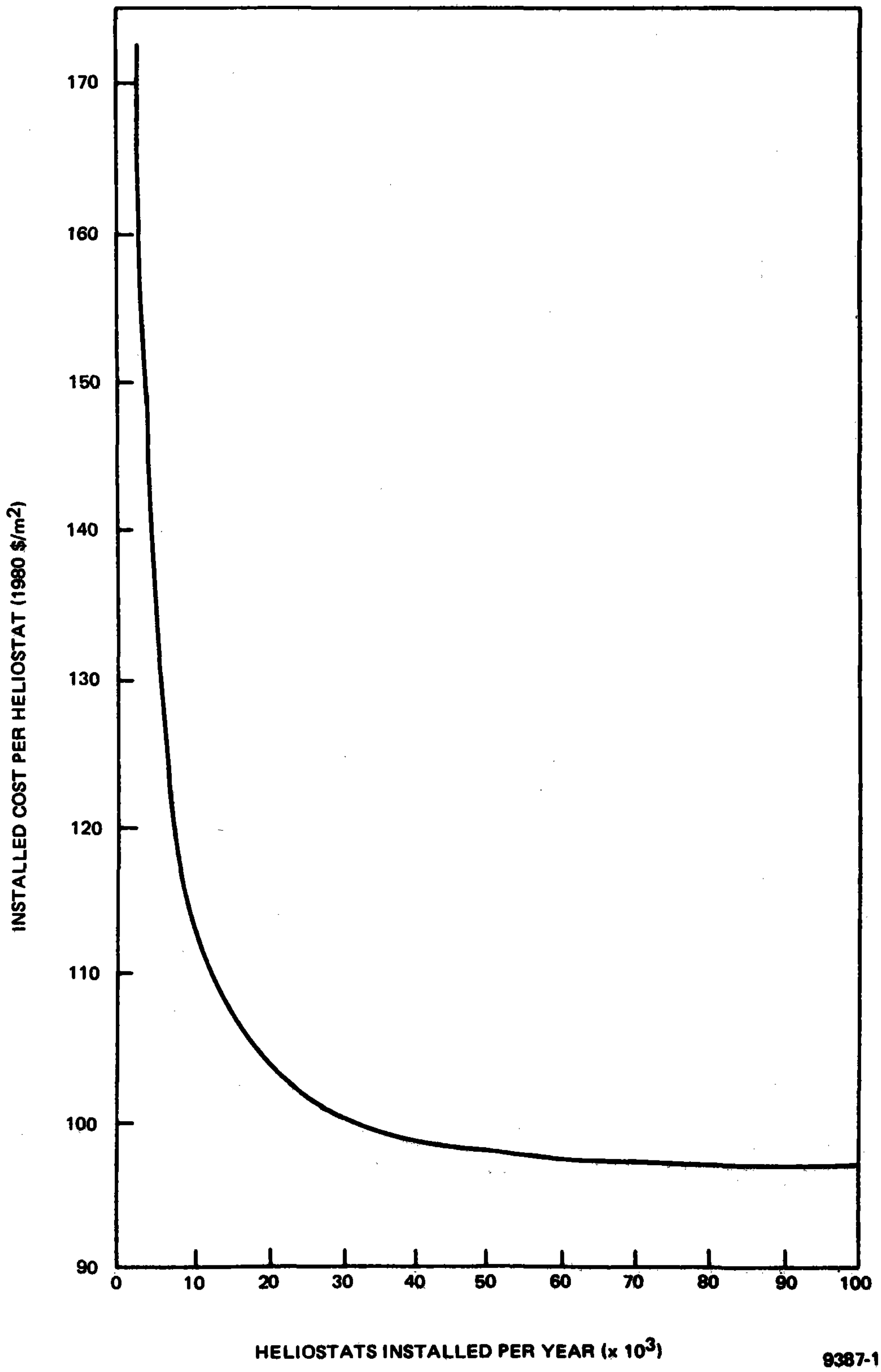


Figure 4-1. Off-Design Heliostat Cost
(25,000/year capacity)

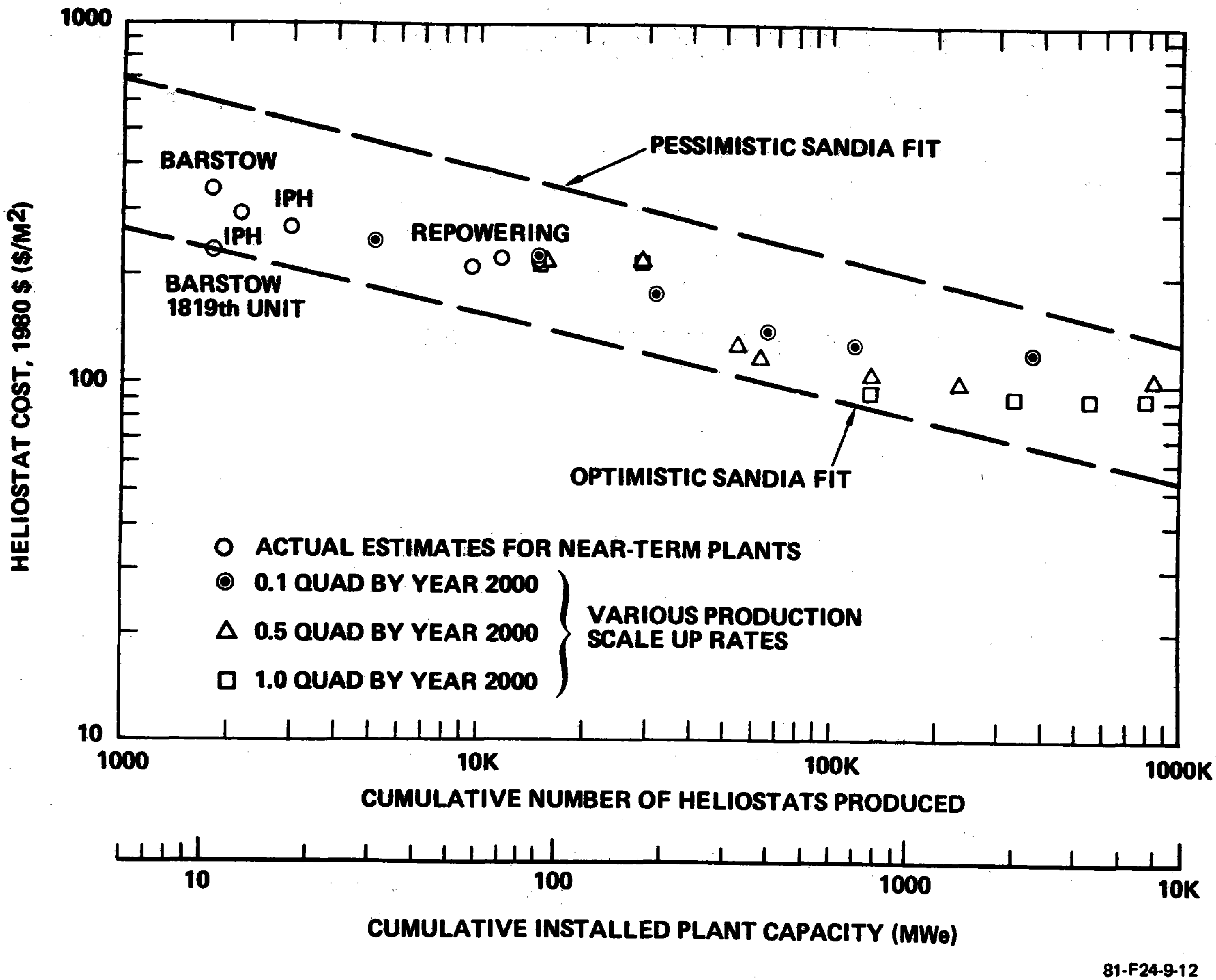


Figure 4-2. Heliostat Costs vs Cumulative Number Produced

plant component size and cost scaled to the actual plant ratings and thermal storage used in the scenarios. Tables 4-2 and 4-3 are summaries of plant costs for solar repowering and stand-alone plants, respectively. The total plant costs listed are for a representative heliostat cost of $230/m^2 for the demonstration plants and $110/m^2 for the commercial plants. In the scenarios, actual estimated heliostat costs for each year were used to adjust the collector field cost and, thereby, the total plant cost. As the commercial plants contain a large thermal storage capacity (6 hr), it was assumed that sodium systems would incorporate a more economical storage capacity than the current designs utilizing hot and cold sodium storage tanks. Current studies (Reference 4-7) indicate that air/rock storage can provide significant cost savings as shown in Figure 4-3. At 6 hr of storage, air/rock and salt storage subsystem costs are shown to be approximately equal in costs. For purposes of the scenario, cost savings utilizing air/rock storage was not implemented until the third year of the commercial plants. The 250-MWe plants were not considered feasible for repowering applications and were not considered. However, for stand-alone plants, it was expected that plant size would increase as more plants are built and operating experience gained. For stand-alone vs coal economic comparisons, some additional $\overline{\text{BBEC}}$ reduction (~10%) is incurred during the fifth year of commercialization due to larger size plants.

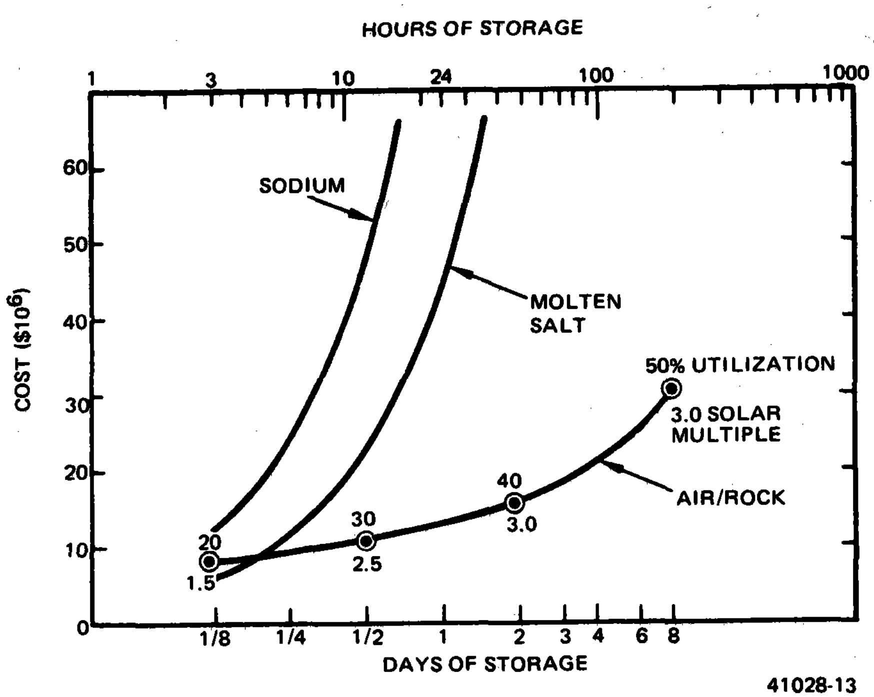


Figure 4-3. Comparison of Sodium, Molten Salt, Air/Rock Storage Concepts

TABLE 4-2

SOLAR REPOWERING PLANT COSTS
(1980 $)

Subsystem	Costs in 10^6\$ for Plant Size (MWe) Thermal Storage (h)				
	30 MWe (1 h)	60 MWe (3 h)	60 MWe (6 h)	100 MWe (6 h)	100 MWe (6 h) Air/Rock†
Collector*	38.2	92.6	115.0	92.0	92.0
Receiver	9.4	18.4	20.8	32.0	32.0
Thermal Storage	3.1	9.8	16.1	24.7	14.3
Miscellaneous	1.3	2.2	2.3	3.4	3.4
Subtotal	52.0	123.0	154.2	152.1	141.7
Distributables and Indirect (5%)	2.6	6.2	7.7	7.6	7.1
Contingency (10%)	5.5	12.9	16.2	16.0	14.9
Engineering§	6.0	7.0	7.0	0**	-
Grand Total	66.1	149.1	185.1	175.7	163.7
BOP Total (w/o Heliostats)	27.9	56.5	70.1	83.7	71.7

*Demonstration plants (<100 MWe) assume $230/M^2$ and commercial plants (≤100 MWe) assume $110/M^2$ to get contingency total.
§Engineering includes Title I, II, and III for a first-of-a-kind plant.
**First commercial plants only, a one-time engineering cost of $10.0M was added.
†Uses air/rock thermal storage rather than sodium hot and cold tanks.

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TABLE 4-3

SOLAR STAND-ALONE PLANT COSTS
(1980 $)

Subsystem	Costs in $10^6$$ (1980 $) for Plant Size (MWe)-Thermal Storage (h)						
	30 MWe (1 h)	60 MWe (3 h)	60 MWe (6 h)	100 MWe (6 h)	100 MWe (6 h) Air/Rock†	250 MWe (6 h)	250 MWe (6 h) Air/Rock†
Collector*	38.2	92.6	114.9	92.0	92.0	216.4	216.4
Receiver	7.1	13.6	15.5	23.6	23.6	51.5	51.5
Thermal Storage	2.5	9.1	15.4	23.7	13.4	52.4	29.2
Misc. & EPGS	16.0	24.5	24.8	34.2	34.2	62.4	62.4
Subtotal	63.8	139.8	170.6	173.5	163.2	382.7	359.5
Distributables & Indirect (6%)	3.8	8.4	10.2	10.4	9.8	23.0	21.6
Contingency (10%)	6.8	14.8	18.1	18.4	17.3	40.6	38.1
Engineering (Title I, II, III)	5.1	9.9	11.8	0**	-	-	-
Grand Total	79.5	172.9	210.7	202.3	190.3	446.3	419.2
BOP Total (w/o Heliostats)	41.3	80.3	95.8	110.3	98.3	229.9	202.8

*Demonstration plants (<100 MWe) assumes $230/M^2 and commercial plants (≥100 MWe) assumes $110/M^2 to get contingency total.

**First commercial plants only, a one time engineering cost of $13.2M was added.

†Uses air/rock thermal storage rather than sodium hot and cold tanks.

4.3 BUSBAR ENERGY COST COMPARISONS

Given the economic parameters and plant costs derived in Sections 4.1 and 4.2, the JPL methodology was applied to calculate $\overline{BBEC}$ for solar central receivers and alternative competing fossil fuel plants. The cumulative government subsidy is based on the uneconomic portion of solar repowering vs gas fuel savings. While repowering is expected to dominate the near-term market, the long-term market must be based on the economic parity of solar stand-alone plants with coal plants. The following sections describe results of the $\overline{BBEC}$ comparisons.

4.3.1 Cumulative Plant Subsidy for Four Scenarios

$\overline{BBEC}$ comparisons of repowering vs gas fuel savings are shown for the four cases in Figures 4-4 through 4-7.

Initially, the $\overline{BBEC}$ for solar plants is very high due to the high cost of heliostats. The difference between the $\overline{BBEC}$ for repowering and the lower $\overline{BBEC}$ for fuel savings represents the uneconomic portion of the repowering plant. For utilities to consider investing in solar plants, some type of financial incentives must be provided by Government until central receiver costs have been reduced to a competitive cost with competing fuel sources.

In all cases, repowering is eventually competitive with gas fuel savings at the Sandia-recommended 11% fuel escalation rate for gas (3% over a general inflation rate of 8%). At a very conservative fuel escalation rate of 8% (same as general), solar central receivers cannot compete unless future developments can reduce solar plant costs further. A comparison of the baseline 0.5 quad case with oil fuel savings, Figure 4-8, indicates that repowering can eventually compete at any fuel escalation rate that is equal to or higher than general. Unfortunately, the market for repowering oil-fired plants is very limited as many are located in densely populated areas. For government planning purposes, required Government subsidies should be based on a comparison of repowering plant costs with gas fuel savings. Table 4-4 indicates the procedure used in determining cumulative required government subsidies. In order to account for the uneconomic

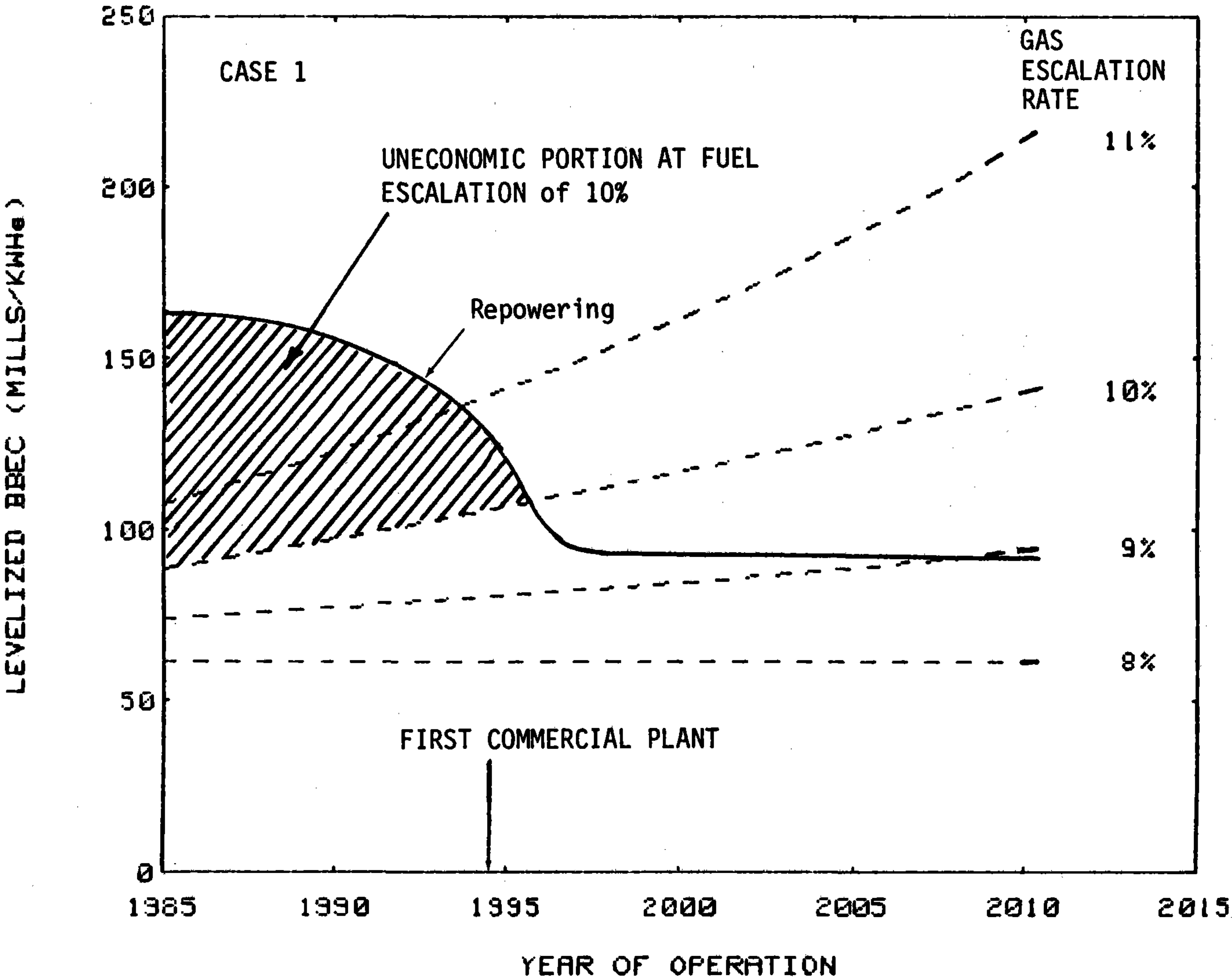

Figure 4-4. Solar Repowering $\overline{\text{BBEC}}$ vs Gas Fuel Savings $\overline{\text{BBEC}}$ (Case 1)

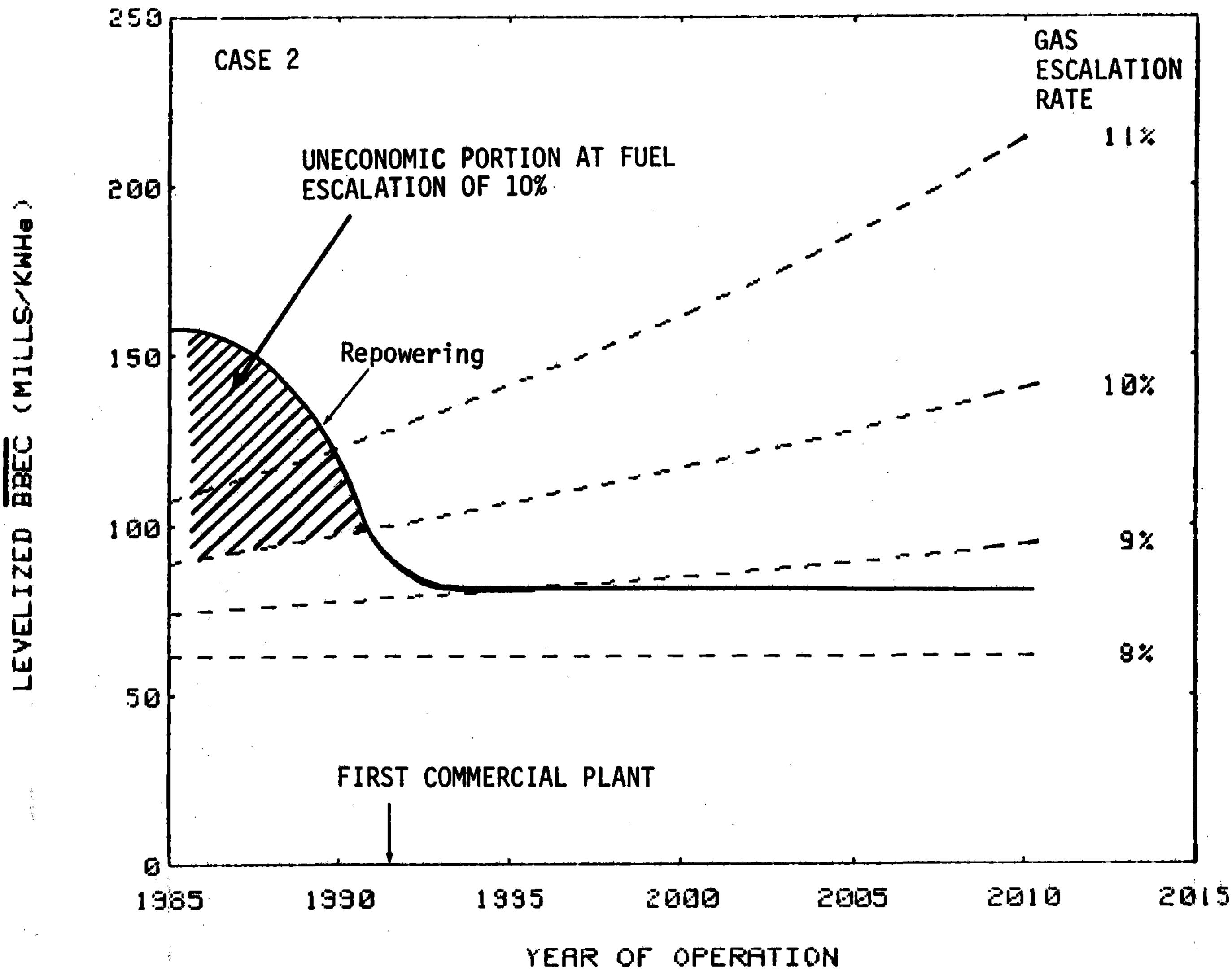

Figure 4-5. Solar Repowering $\overline{\text{BBEC}}$ vs Gas Fuel Savings $\overline{\text{BBEC}}$ (Case 2)

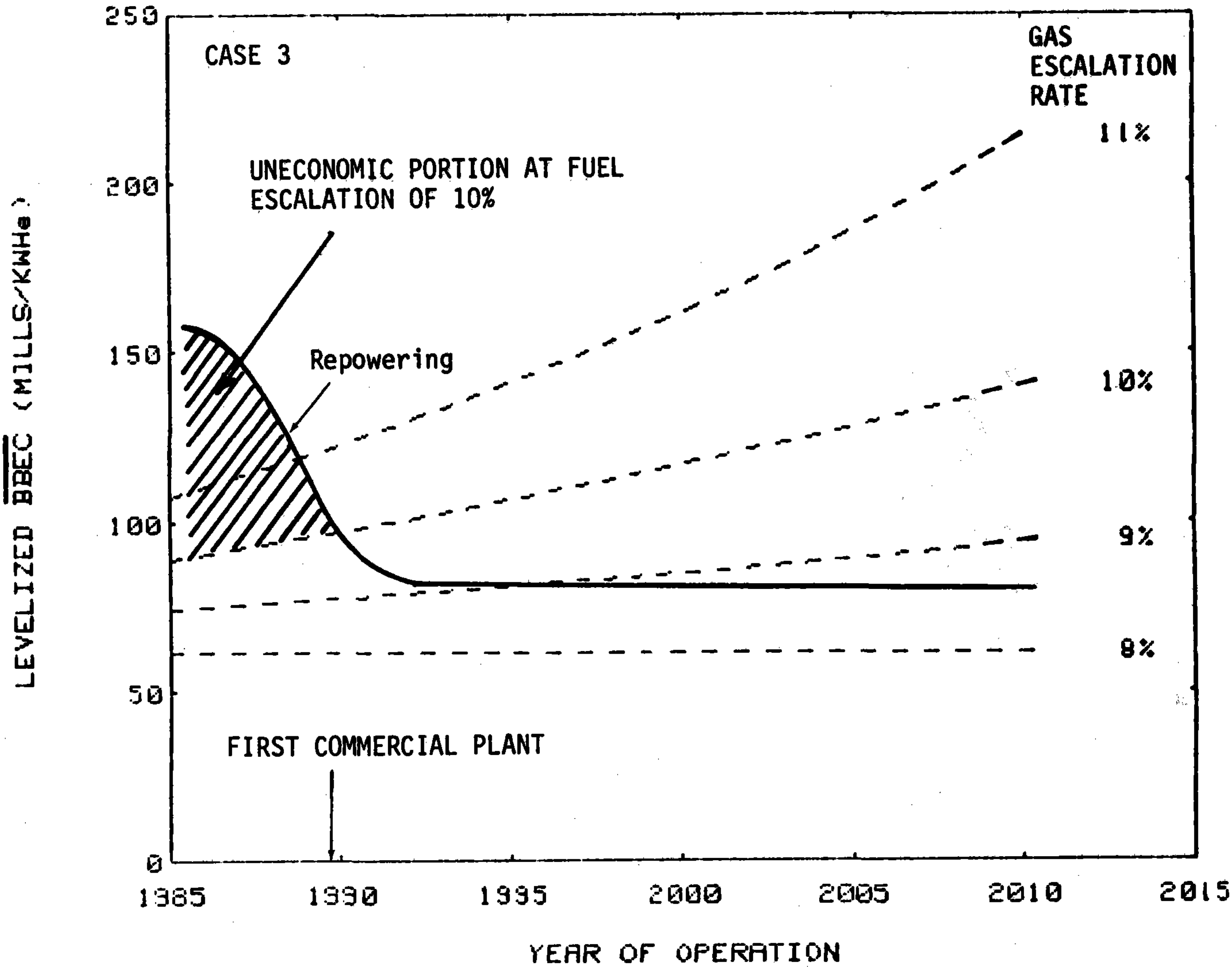

Figure 4-6. Solar Repowering $\overline{\text{BBEC}}$ vs Gas Fuel Savings $\overline{\text{BBEC}}$ (Case 3)

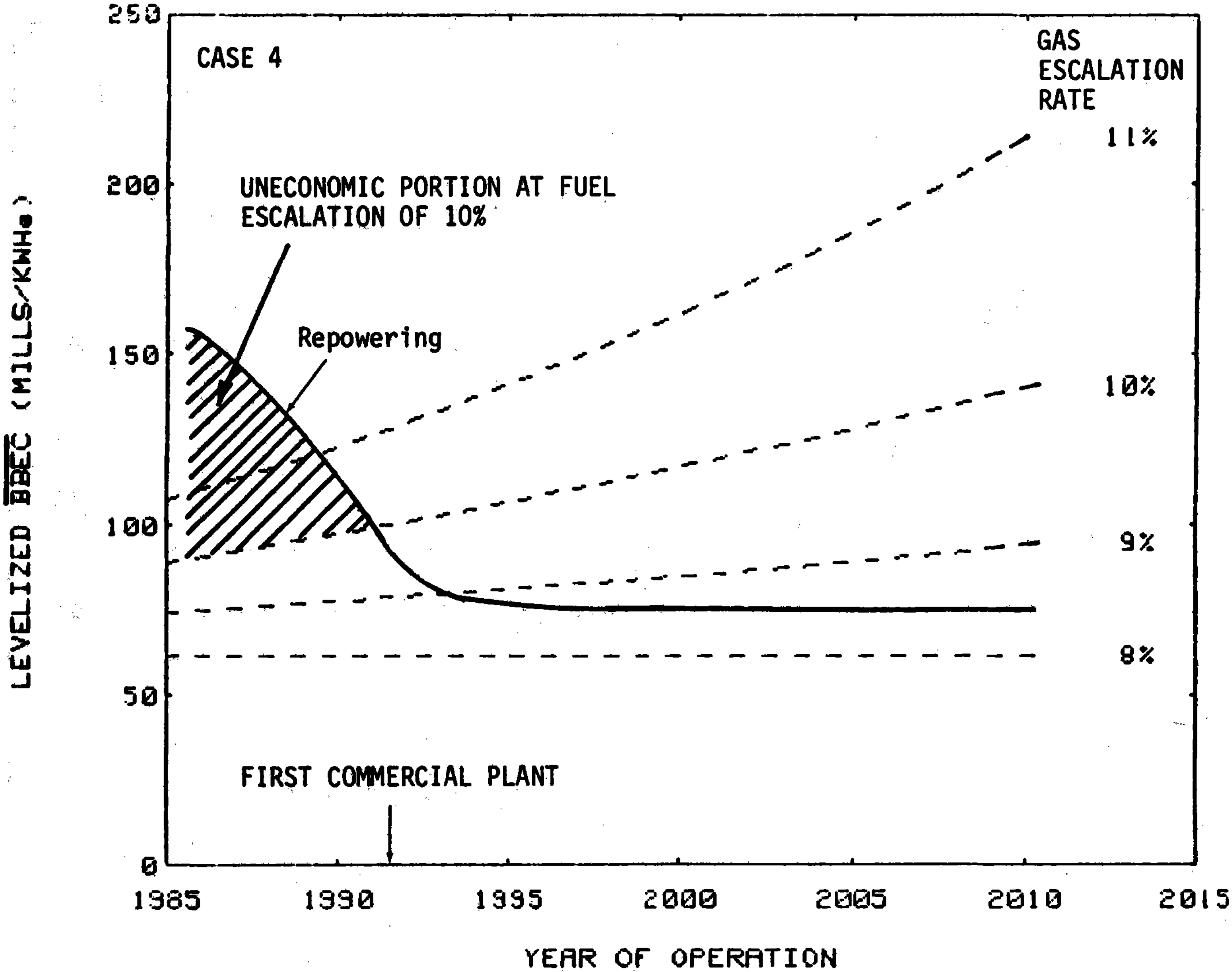

Figure 4-7. Solar Repowering $\overline{\text{BBEC}}$ vs Gas Fuel Savings $\overline{\text{BBEC}}$ (Case 4)

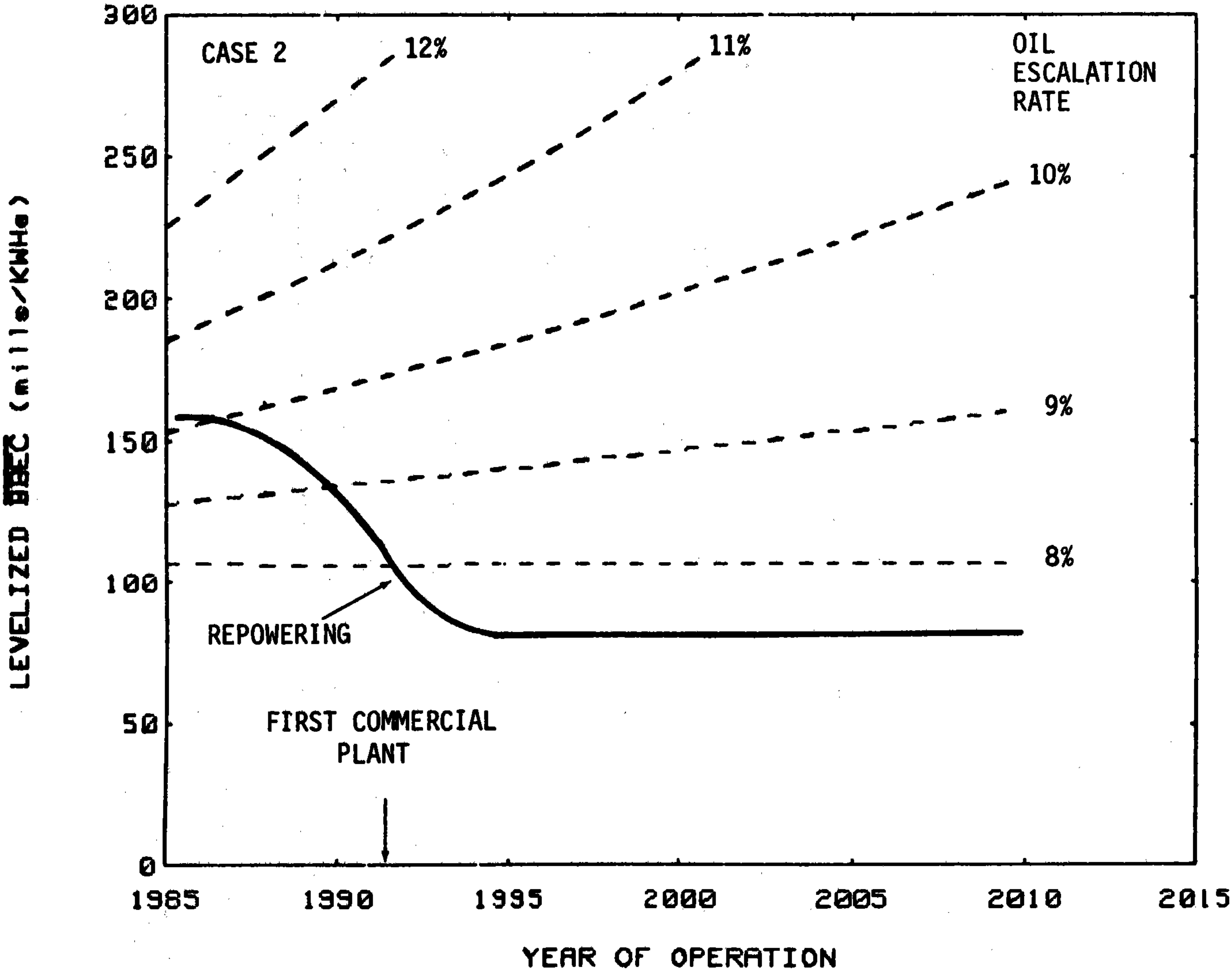

Figure 4-8. Solar Repowering $\overline{\text{BBEC}}$ vs Oil Fuel Savings $\overline{\text{BBEC}}$ (Case 2)

TABLE 4-4

CUMULATIVE GOVERNMENT SUBSIDY TO REACH COMMERCIALIZATION
(Case 2 - 0.5 Quads)

Year	"Equiv." Added MWe-HA	Installed MWe-HA	$\Delta \overline{BBEC}$* Mills/KWHe	Solar Plant Subsidy $/MWe-HA	Solar Plant Subsidy $M/yr	Solar Plant Subsidy Cum, $M
1983	0.071		72.2	445	31.6	32
1984	0.143		70.9	437	62.4	94
1985	0.143	0.357	69.2	426	60.9	155
1986	-					
1987	-					
1988	-					
1989	0.221		38.4	237	52.2	207
1990	0.883		29.0	179	157.7	365
1991	1.766	1.104	10.7	66	116.6	481
1992	3.091	2.208	0.0	0	0.0	481
1993	3.533	2.208	Commercially Viable			
1994	4.968	4.416				
1995	6.072	4.416				
1996	7.728	7.176				
1997	8.832	7.176				
1998	7.949	9.936				
1999	3.974	9.936				

*Fuel is gas at 10% escalation.

portion as plants are being built, the plant rated capacity was spread over a 2-1/2-year.time period to give an "equivalent" added MWe times annual hours of nominal operation (MWe-HA). Plants coming on-line in a year are indicated as installed MWe-HA. The delta $\overline{\text{BBEC}}$ is converted to a \$/MWe-HA by dividing the delta $\overline{\text{BBEC}}$ by the fixed-charge rate of 16.23%. The cumulative plant subsidy required for Case 2 with gas escalating at 10% is \$481 million. Similar calculations were made for other escalation rates. The effect of fuel escalation on cumulative plant subsidy is shown in Figure 4-9. The required plant subsidy is extremely sensitive to the fuel escalation rate. Obviously, at a low escalation rate, neither the utilities nor the government would want to pursue commercialization. While Sandia has recommended an 11% escalation rate, for utility economic planning purposes, a more conservative 10% escalation rate for gas was considered more appropriate and is used in all further calculations of cumulative plant subsidies.

The effect of alternate scenarios on cumulative government subsidies is shown in Figure 4-10. The most surprising result is the most aggressive case (1.0 quads) requires the smallest plant subsidy of \$332M. This was basically due to lower heliostat costs resulting from high-volume production facilities capable of producing 50,000 heliostats/year.

Another conclusion is that there does not appear to be significant differences in the total cost with cumulatives ranging from \$332M to a maximum of \$550M. When these totals are adjusted in Section 5 to account for short-term amortization of manufacturing facilities, relative differences become even less pronounced. The bottom line is that, if the national priorities indicate the need to bring about commercialization, there is little to be gained by taking a very conservative approach. The staggered demonstration plants in Case 1, while it does reduce risk and delays government expenditures, almost automatically precludes central receivers from providing any significant energy source before Year 2000. Also, by not bringing the first commercial plants on-line until 1994, the Fuel Use Act of 1978 may have eliminated any repowering market that might have existed. This would increase costs of commercialization even more (see Section 4.3.3).

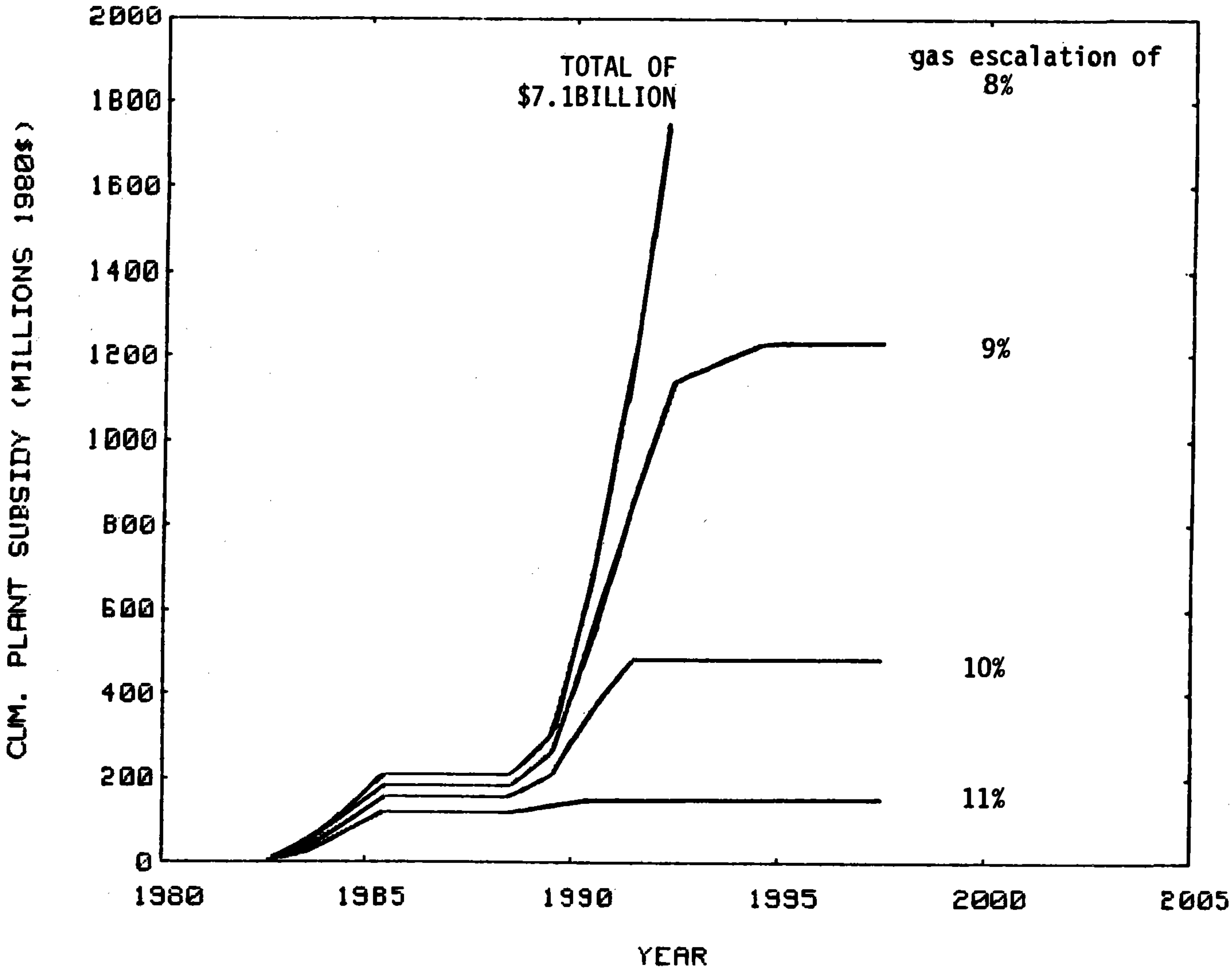

Figure 4-9. Effect of Fuel Escalation on Cumulative Plant Subsidy

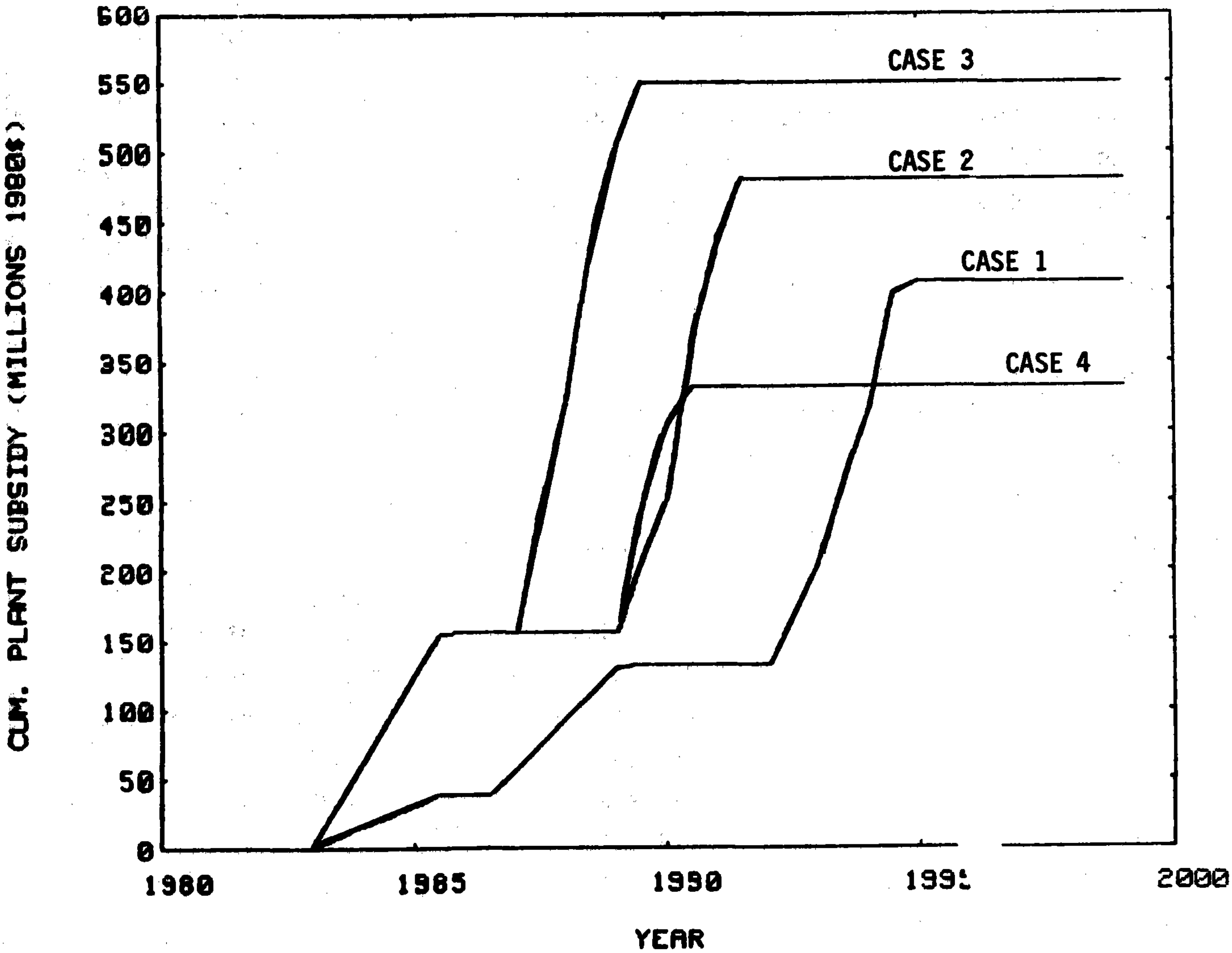

Figure 4-10. Effect of Alternate Scenarios on Cumulative Government Subsidy

4.3.2 Long-Term Market Potential

While the cumulative Government subsidy was based on subsidizing repowering plants, it must be remembered that this is only a short-term market and a relatively limited market, as well. Solar stand-alone plants must supply the long-term market. Only the 0.1-quad/year and, marginally, the 0.5-quad/year cases could potentially be met through the repowering market alone. The 1.0 quad must eventually incorporate solar stand-alone plants in the later years. In any case, the nature of the short-term market for repowering plants requires that eventually the mix of plants coming on-line must switch from repowering to stand-alone plants.

The only major energy alternatives to solar stand-alone plants are coal and nuclear plants. Given today's environmental concerns, costs, and feasibility of building,nuclear plants are very much in question and were not considered for this study. This made coal plants the primary competing technology. Figures 4-11 through 4-14 are the $\overline{\text{BBEC}}$ comparisons of solar stand-alone vs coal plants. Economic parameters used were defined in Section 4.1. The coal plant cost of $860/kWe was considered a representative value that was perhaps slightly high for some areas, i.e., Texas, but very conservative compared to costs incurred by recent coal plants being planned for California (SCE and PG&E were using $1,100/kWe and $2,000/kWe, respectively. This was due to more stringent pollution requirements). At the Sandia-recommended coal escalation rate of 10% (2% above general), solar stand-alone is competitive for all cases and occurs at a fairly early phase of the commercial plants. If the coal escalation rate is the same as general, solar plants cannot compete without further cost reductions. As with gas, the Sandia-recommended value, while it may actually occur, was considered too high for economic planning purposes. The 9% escalation rate seemed to be more representative of utility planning.

For the 1-quad case, solar stand-alone plants should be competitive for either 100-MWe or 250-MWe plants. It becomes competitive in a time frame that allows an easy transfer from repowering to stand-alone without exceeding the potential repowering market.

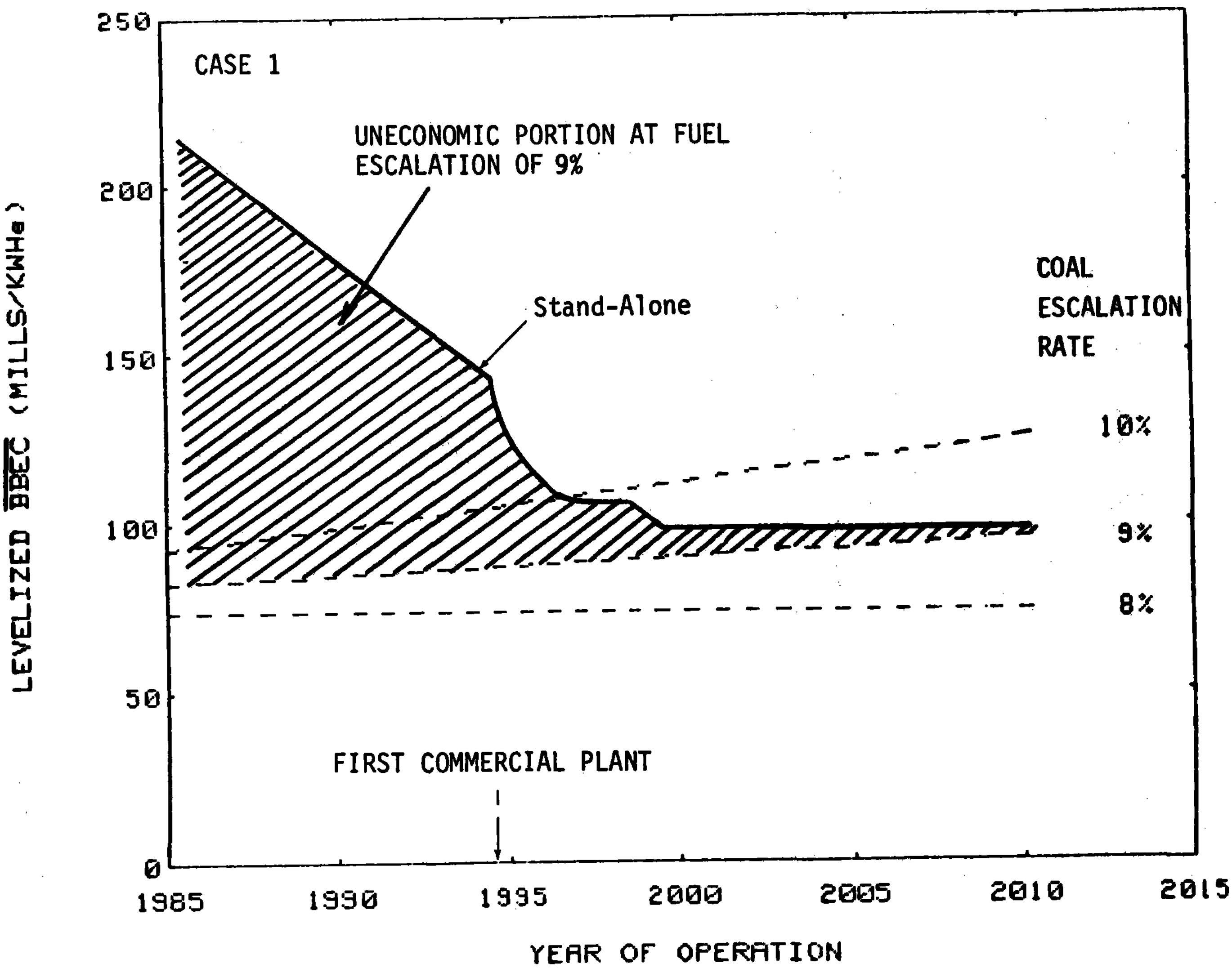

Figure 4-11. Solar Stand-Alone $\overline{\text{BBEC}}$ vs Coal Plant $\overline{\text{BBEC}}$ (Case 1)

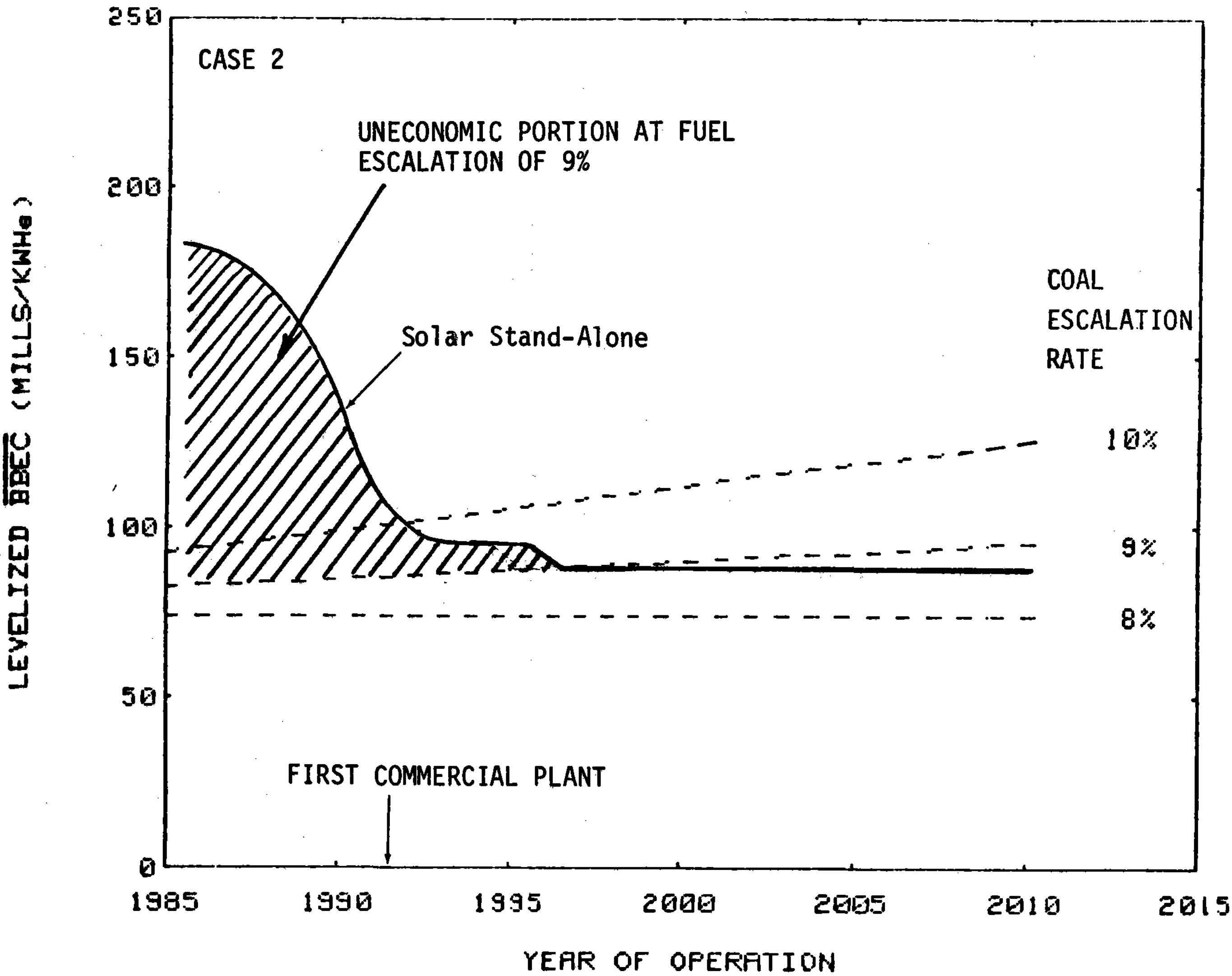

Figure 4-12. Solar Stand-Alone $\overline{\text{BBEC}}$ Vs Coal Plant $\overline{\text{BBEC}}$ (Case 2)

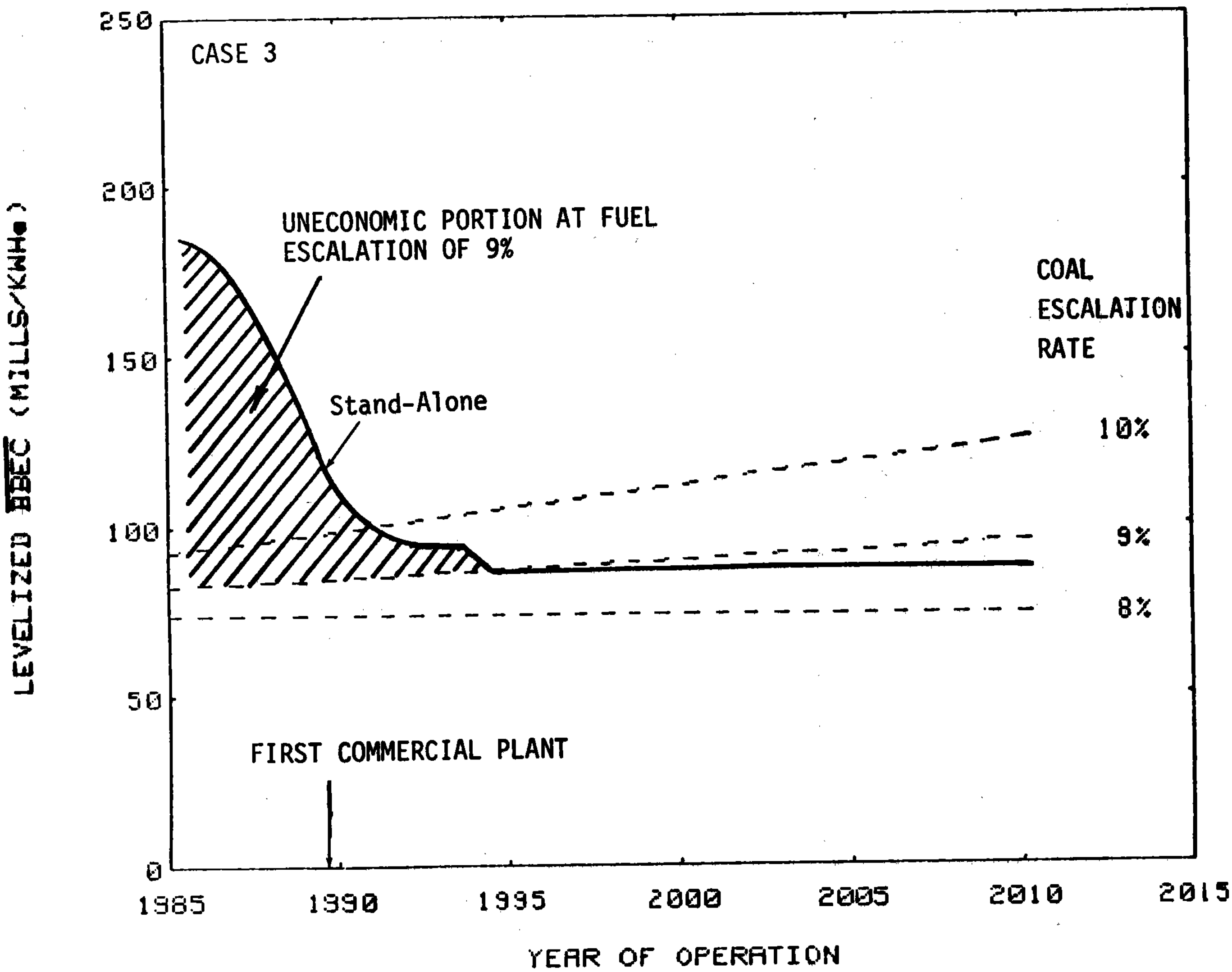

Figure 4-13. Solar Stand-Alone $\overline{\text{BBEC}}$ vs Coal Plant $\overline{\text{BBEC}}$ (Case 3)

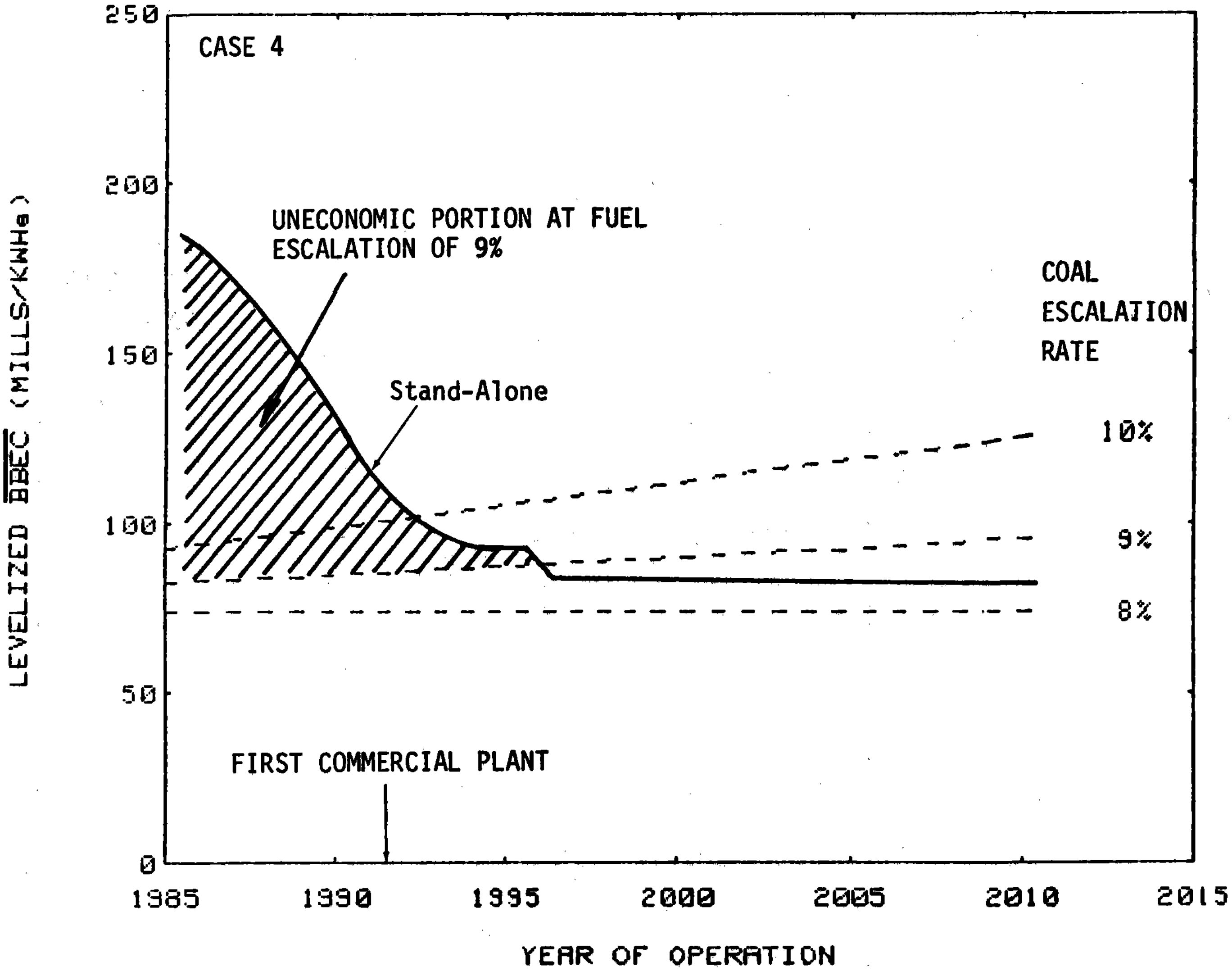

Figure 4-14. Solar Stand-Alone $\overline{\text{BBEC}}$ vs Coal Plant $\overline{\text{BBEC}}$ (Case 4)

For the 0.5-quad cases, the economic savings of scaling up to 250 MWe is needed for parity with coal on a timely basis. This could cause some problems as it would be preferable if the 100-MWe plant size was an option. Further reduction in heliostat costs would be desirable. If an ongoing IPH central receiver market is building up to 0.5 quads/year concurrently, the 100-MWe plant would be competitive. Additionally, the cost differences shown are less than 8%. Local differences in insolation, coal plant costs, and coal costs including coal transportation could easily make solar stand-alone plants competitive with coal plants in local areas. The effect of alternate coal and coal plant costs were considered. A 20% change in coal costs causes a 14% change in $\overline{\text{BBEC}}$ and a 20% change in plant costs causes a 6% change in $\overline{\text{BBEC}}$. A 100-MWe solar plant in the long-term can compete with any region that must pay $1,100/kWe for a coal plant or $1.62/MMBtu for coal. This is certainly consistent with current regional differences. While marginally close, it appears that a 0.5-quad goal for utilities with no requirements for a concurrent IPH program can provide a smooth transition from repowering to stand-alone without exceeding the potential repowering market.

For the 0.1-quad/year case, the stand-alone plants do not compete economically with coal plants at a fuel escalation rate of 9% until Year 2015 and only as large-scale plants. The heliostat costs must be reduced from the estimated $\$125/m^2$ by either a concurrent IPH program, fewer heliostat vendors, or learning curve cost reductions. While there may be some isolated cases where central receivers would be the preferred system, this scenario as it is presently presented, with no concurrent IPH program, may have some difficulties in receiving wide-spread acceptance by utilities. Certaintly, the transition from repowering to stand-alone is going to present some problems.

4.3.3 Effect of Market Uncertainties on Commercialization

Several crucial parameters were reviewed to determine their efffect on commercialization. They are:

1) Heliostat and Balance of Plant costs
2) Coal plant economics

3) Fuel escalation rates
4) Lack of a repowering market for the commercial plants
5) Concurrent IPH program.

Results are tabulated in Table 4-5.

The uncertainties in plant costs can potentially affect the required government subsidy significantly. Most of the cost impact is in the commercialization phase when many plants are coming on line. As heliostat costs become more firm and start coming down because of high-volume production, the balance of plant costs are going to play a more significant role. It is important to reduce balance of plant costs during the demonstration phase. It is highly unlikely that utilities would begin construction of 15 commercial plants without on-line operation of a similar type demonstration plant. If balance-of-plant costs do indeed come in 25% higher than expected, one would want to know this before reaching the commercialization phase where the government has committed itself to building 15 plants before the first commercial plant comes on-line. Two demonstration plants would create a competitive situation for suppliers of sodium and salt systems during both the demonstration and commercialization phases. Construction of only one demonstration plant will almost automatically eliminate the alternative systems from contention. Also, two demonstration plants would provide extra assurance of timely implementation of commercial plants.

It was found that coal plant and coal fuel costs vary significantly in the southwest region of the United States. In general, it was found that the initial plants would still be of the repowering type and therefore the government subsidy initially was not affected by coal plant economics. However, in California where there are high coal plant costs and/or coal fuel costs, potentially the economics could prefer a solar stand-alone plant over a repowering plant. Further study is needed in this area as there are certain geographical areas in the United States that solar power plants could compete with coal on an economical basis at a much earlier date than the Sandia-supplied coal plant economics.

TABLE 4-5

EFFECT OF MARKET UNCERTAINTIES ON COMMERCIALIZATION
(Case 2 - 0.5 Quad)
(Sheet 1 of 2)

Variable	% Variation	Year Commercially Viable		Required Govt. Subsidy (10^6 $)	Remarks
		Repowering	Stand-Alone		
Baseline*	-	1992	1997	481	
Heliostat Costs	+25 -25	1993 1991	2015 1993	885 159	Long-term market difficulties
Balance of Plant Costs	+25 -25	1993 1991	2015 1993	890 190	Long-term market difficulties
Coal Plant Costs					
$1200/kWe	+40	1992	1993	481	
$1030/kWe	+20	1992	1996	481	
$ 690/kWe	-20	1992	2004	481	Long-term market difficulties
Coal Fuel Costs					
$2.03/MMBtu	+40	1992	1992	481	Do not need repowering option
$1.74/MMBtu	+20	1992	1994	481	
$1.16/MMBtu	-20	1992	2013	481	Long-term market difficulties
Gas Escalation Rate					
11%		1991	1997	152	
9%		1995	1997	1235	
8%		Never	1997	∞	

TABLE 4-5

EFFECT OF MARKET UNCERTAINTIES ON COMMERCIALIZATION
(Case 2 - 0.5 Quad)
(Sheet 2 of 2)

Variable	% Variation	Year Commercially Viable		Required Govt. Subsidy (10^6 $)	Remarks
		Repowering	Stand-Alone		
Oil Escalation Rate†					
11%		Now	1997	0	This is a very limited market.
8%		1992	1997	262	
Coal Escalation Rate					
10%		1992	1993	481	
9%		1992	1997	481	
8%		1992	Never	481	
Loss of Repowering Option for Commercial Plants		N/A	1997	2175	
Concurrent IPH Program		1991	1996	200	

*Baseline $101 mature heliostat costs, $860/kWe coal plant, $1.45/MMBtu coal at 9% escalation, $2.50/MMBtu gas at 10% escalation.
†Oil at $4/MMBtu in 1980 $.

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Fuel escalation rates have a significant impact on the expected uneconomic portion. More importantly is how utilities perceive the gas escalation rate, as the $\overline{\text{BBEC}}$ is based on a 30-year projected escalation rate (the delta over general inflation is really the important criteria). Even if utilities expect a high escalation rate, they still must convince the Public Utility Commission to allow the higher capital expenditures and, thereby, higher utility rates for today's user in return for utility savings for tomorrow's user. This is a political problem and must, eventually, be taken into consideration. From a purely economic standpoint, it would be great to replace oil (at any escalation rate) in a repowering application. Unfortunately, most of the existing oil plants are located in metropolitan areas and, therefore, unavailable for repowering. Solar stand-alone plants could even compete quite well with the potential oil savings, but, if a utility currently burning oil chooses to build a new plant, the solar stand-alone plant must still compete against the coal alternative.

The repowering market is the most cost-effective market for achieving commercialization. The loss of the repowering option could potentially result in an increase in the required government subsidy from $481 million to $2.2 billion to achieve 0.5 quad/year. A go-slow approach or the manner in which the Fuel Use Act of 1978 is implemented can eliminate repowering as a potential route to achieve commercialization. Exemptions must be provided until 1996 when solar becomes competitive with coal. However, in the discussion of coal plant economics, it was pointed out that this cost could be reduced from the calculated $2.2 billion by introducing solar plants into geographical areas such as California with particularly high coal costs.

A concurrent IPH program which results in a combined 1.0 quad/year energy production by the Year 2000 gives results very similar to Case 4 (1.0 quad/year). It is very desirable to reach high heliostat production levels in order to reduce solar plant costs.

REFERENCES

4-1 "The Cost of Energy from Utility-Owned Solar Electric Systems," Jet Propulsion Laboratory, Pasadena, California, JPL 5040-29 (ERDA/JPL-1012-76/3), June 1976

4-2 J. C. Gibson, "Technical Assumptions for the Repowering/Industrial Retrofit Conceptual Design Studies," Sandia letter dated November 6, 1979

4-3 J. C. Gibson, "Solar Repowering/Industrial Retrofit Technical Information Memo Number 6," Sandia letter dated January 18, 1980

4-4 E. D. Eason, "The Credibility of Cost Estimates for Mass-Produced Heliostate," Sandia Laboratories, Albuquerque, New Mexico, SAND79-8222, October 1979

4-5 "Conceptual Design of Advanced Central Receiver Power Systems Sodium-Cooled Receiver Concept Final Report," Energy Systems Group, Rockwell International, Canoga Park, California, ESG-79-2 (SAN/1483-1/1), June 1979

4-6 "Conceptual Design of the Solar Repowering System for West Texas Utilities Company Paint Creek Power Station Unit No. 4," Energy Systems Group, Rockwell International, Canoga Park, California, ESG-80-18, July 15, 1980

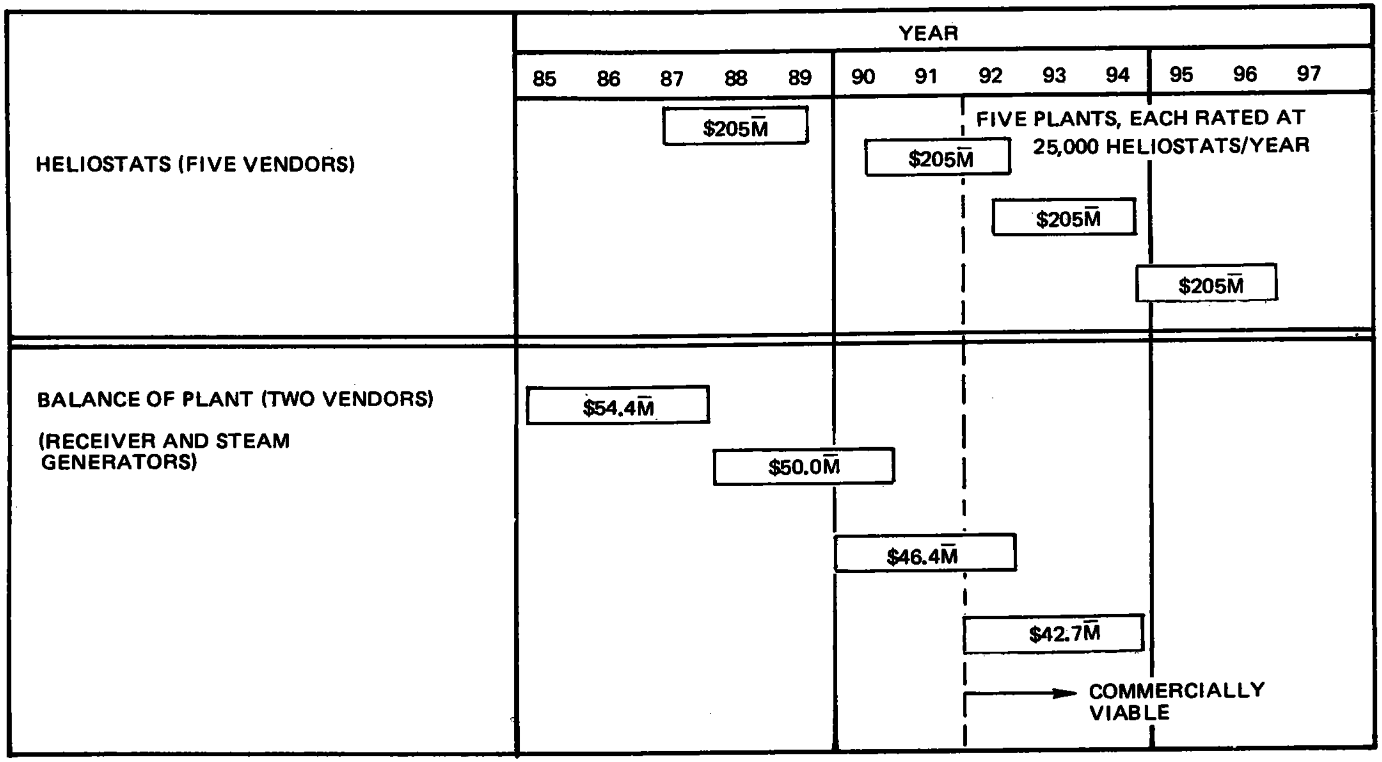
4-7 W. B. Thomson, et al., "Air/Rock Storage for Solar Central Receiver Power Stations," Intersociety Energy Conversion Engineering Conference, Seattle, Washington, August 1980

5.0 INVESTMENT IN MANUFACTURING FACILITIES

If a readily available market can be identified for a product, manufacturing firms will normally invest in the capital facilities and tooling necessary to manufacture a component. Until there is a commercially viable market, manufacturing facilities are not likely to invest their own money in capital investments for building and equipment unless the investment can be written off immediately on the initial central receiver plants built. This amortization cost is in addition to labor (direct and indirect) and material costs. Costs for heliostats and other specialized components in the previous sections were based on long-term amortization for the commercial plants. As such, Battelle used a 20% fixed-charge rate to amortize capital expenditures over a ~20- to 30-year plant life. The purpose of this section is to investigate the additional costs to commercialization if component costs are based on short-term amortization. Until such time, central receiver technology is competitive with fossil fuel alternatives.

Figure 5-1 illustrates the investment timetable to provide manufacturing capabilities to meet the Case 2 (0.5 quads/year) market demand. Much of this capability must be built before central receiver technology is commercially viable. Assuming that manufacturers will require short-term amortization for a product that is not commercially viable, the total government subsidy must increase to cover this cost plus the previously calculated plant subsidy. The total cost to the government to commercialize central receivers is shown in Table 5-1. Details of how these values were calculated are explained in Sections 5.1 and 5.2.

This section does not address the costs of manufacturing facilities for the demonstration plants. It is assumed that the heliostat and other component costs used for these plants include amortization of the entire facility and any special tooling. Because there is a 4-to 6-year delay between the demonstration plants and the commercial plants, it is also assumed that these initial facilities will have been converted to other uses during the interim period.



9387-2

Figure 5-1. Capital Investment in Manufacturing Facilities (1980$)

TABLE 5-1

TOTAL GOVERNMENT SUBSIDY INCLUDING AMORTIZATION OF MANUFACTURING FACILITIES (1980 $)

Case	Quad Level by Year 2000	Year Commercially Viable	Plant Subsidy (10^6 $)	Short-Term Amortization Cost Adjustment (10^6 $)			Total Government Subsidy (10^6 $)
				Heliostats	BOP	Total	
1	0.1	1996	408	113	43	156	564
2	0.5	1992	481	190	74	264	745
3	0.5	1990	550	190	50	240	790
4	1.0	1991	332	306	97	403	735

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5.1 INVESTMENTS IN MANUFACTURING FACILITIES — HELIOSTATS

The Battelle studies (References 3-5 and 3-6) estimated cost of manufacturing facilities for three plant sizes are as given in Table 5-2.

TABLE 5-2

CAPITAL INVESTMENT IN HELIOSTAT MANUFACTURING FACILITIES (1980 $)

Facility Size (heliostats/year)	Building (10^6 $)	Tooling (10^6 $)	Total (10^6 $)	Amortization (20% FCR) ($/m^2)
2,500	3.1	8.1	11.2	18
25,000	9.8	31.1	40.9	7
250,000	40.7	195.2	235.9	4

These capital costs were used for the basis of heliostat production for the commercial plants with interpolated values where needed. Heliostat manufacturing facility capital costs are summarized by case and time in Table 5-3. With five vendors, the smallest plants built were capable of producing 10,000 heliostats/year in Case 1 and the largest plants built were producing 100,000 heliostats/year in Case 4. Section 3.4 detailed the basis of plant additions.

In Section 4, the heliostat costs included a fixed-charge rate of 20%. At a capital cost of 10% and a 2-year production life, the fixed-charge rate should be 66.3%. Until commercially viable, it would be expected that heliostat manufacturers would charge the higher fixed-charge rate and, therefore, higher heliostat costs in order to assure recovery of their investment. To get the true cost of commercialization, an additional 46.3% on initial capital investment should be added to each year of a 2-year production life up until time of commercial viability. For Case 2, this would work out to an additional $190M for the initial $204.5M capital investment (five vendors x $40.9M each). The remaining plants

TABLE 5-3

Heliostat Facility Capital Costs
(Millions 1980 $)

Year	Case 1		Case 2		Case 3		Case 4	
	Authorization	Expenditure	Authorization	Expenditure	Authorization	Expenditure	Authorization	Expenditure
1985					204.5	51.1		
1986						102.3		
1987			204.5	51.1		51.1	330	82.5
1988				102.3				165
1989				51.1				82.5
1990	122	30.5	204.5	51.1	204.5	51.1		
1991		61		102.3		102.3	378	94.5
1992		30.5	204.5	102.3		51.1		189
1993	131	32.5		102.3	204.5	51.1		94.5
1994		65.5	204.5	102.3		102.3	588	147
1995		33		102.3		51.1		294
1996				51.1				147
1997								
TOTAL	253		818.0		614.0		1,296	
TOTAL/ VENDOR*	51		164.0		123.0		259	

*Five vendors with 20% of market.

would not be producing heliostats until after 1992, the date of commercial viability, and, therefore, no extra costs would be involved. A similar approach was taken for the other three cases with results as shown in Table 5-4.

TABLE 5-4
HELIOSTAT COST ADJUSTMENT FOR SHORT-TERM AMORTIZATION
(1980 $)

Case	① Year Commercially Viable	Total Capital Investment Prior to ① ($M)	Short-Term Amortization Cost Adjustment on Heliostats Produced Prior to ① ($M)
1	1996	253	113
2	1992	357	190
3	1990	205	190
4	1991	330	306

Case 2 involves investment in a second plant addition prior to 1992 but does not produce heliostats until after 1992. This explains why Case 2 and Case 3 resulted in the same cost adjustment, although, the total investment was considerably different.

5.2 INVESTMENTS IN BALANCE OF PLANT MANUFACTURING FACILITIES

The balance of plant (BOP) is defined as all components except the collector field. In defining specialized manufacturing facilities needed for procurement of solar central receiver components, a review of the major components for a sodium system was made and listed in Table 5-5. Special facilities are needed for the receiver panels, receiver toroidal tanks, and steam generators (evaporator, superheater, and reheater). In general, similar results would be obtained for a salt system. Component sizes used in facility costing, however, for salt systems would be somewhat larger due to the poorer heat transfer characteristics. While this would have some impact on total facility costs, it is not seen as having a significant impact on the total study.

TABLE 5-5

BALANCE OF PLANT MAJOR COMPONENTS
(SODIUM SYSTEM)

	New Facilities	Existing Facilities	Fabricated at Site
Receiver System			
Sodium Pump		X*	
Receiver Absorber Panels and Tanks	X		
Valves and Piping		X	
Tower			X
Steam Generators (3)	X		
Auxiliary Sodium Subsystems		X	
Argon Subsystem		X	
Storage System			
Hot and Cold Storage Tanks			X
or			
Air/Rock Storage		X	X
Sodium Pump		X*	
Electric Power Generation System		X	

*It was felt that sufficient pump manufacturing facilities were available for the initial commercial plants. Therefore, no additional costs for plant subsidies would be incurred initially. However, eventually, new facilities would be needed to meet the increasing market. This was a simplification that could be further investigated.

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Facility and tooling requirements were derived by ESG/Rockwell International manufacturing personnel. Rockwell International has had manufacturing experience in both steam generators (MSG and CRBR programs) and receiver panels (Barstow Solar I). Appendix A contains a relatively detailed outline of building and tooling costs plus a timetable for building the facilities for each of the four cases. An example of facility costs for production rates of 6 plants/year and 12 plants/year are shown in Table 5-6. As can be seen, the building cost is, relatively, a much more significant item than it was for heliostat facilities. This is due in a large part to the size of the components and a long production schedule (~18-24 months/unit). Also, the cost of floor space was generally higher ($125/ft^2) because the weight of the components requires a stronger building support structure. A facility-construction timetable was shown for Case 2 in Figure 5-1. Total investment in facilities to meet the market demand, as defined in the four scenarios, is shown in Table 5-7.

As was done for the heliostats, all costs for the steam generators and receiver components built before central receivers are competitive with fossil fuel alternatives must include an additional cost due to short-term amortization. Some amortization is included in the original cost estimate (FCR assumed to be 20%). With a 2-year production life assumed, a 63.3% FCR is needed. The difference in FCR is 43.3% which is an additional cost that must be covered in the government subsidies. The cost adjustment for the four cases is shown in Table 5-8.

TABLE 5-6

CAPITAL INVESTMENT IN BOP MANUFACTURING FACILITIES
(1980 $)

	6 Plants/Year*	12 Plants/Year*
Building floor space (ft^2)	333,900	652,800
Building costs (10^6 $)	41.7	81.6
Tooling costs (10^6 $)		
Steam generator	7.8	14.4
Receiver components	4.8	8.5
Total (10^6 $)	54.3	104.5

*100-MWe plants with 6 h of storage.

TABLE 5-7

FACILITY INVESTMENT TO MEET MARKET DEMAND

Case	Energy Goal by Year 2000 (Quads/Year)	Total BOP Manufacturing Investment (1980 $)
1	0.1	54.9M
2	0.5	193.5M
3	0.5	200.8M
4	1.0	314.8M

TABLE 5-8

BOP COST ADJUSTMENT FOR SHORT-TERM AMORTIZATION
(1980 $)

Case	1 Year Commercially Viable	Total Capital Investment Prior to 1	Short-Term Amortization Cost Adjustment on BOP Components Produced Prior to 1
1	1996	$ 55M	$43M
2	1992	127M	74M
3	1990	88M	50M
4	1991	161M	97M

6.0 GOVERNMENT INCENTIVES

Plant subsidies with adjustments made for capital investment in manufacturing facilities were determined in Sections 4 and 5. A summary of those results is given in Table 6-1. Because manufacturing facilities are not assured of a long-term market, the total government subsidy required is considerably higher than that predicted by the noneconomic portion of the $\overline{\text{BBEC}}$ comparisons. Various government cost sharing and/or financial incentives that would offset the differential, noneconomic cost factors were considered.

TABLE 6-1

GOVERNMENT INCENTIVES FOR FOUR SCENARIOS

	Case			
	1	2	3	4
Energy Level by Year 2000	0.1 quads	0.5 quads	0.5 quads	1.0 quads
Year of Commercial Viability	1996	1992	1990	1991
Total Plant Subsidy	$408M	$481M	$550M	$332M
Heliostat Manufacturing Investment	$253M	$357M	$205M	$330M
Balance-of-Plant Manufacturing Investment	$55M	$127M	$88M	$161M
Total Government Incentives*	$564M	$745M	$790M	$735M

*This total represents the utility/government cooperative using short-term amortization of manufacturing facilities before the year of commercial viability

Reference 6-1 is a detailed look at economic incentives for commercialization of wind systems. Many of the conclusions made are applicable, as well, to solar central receiver commercialization. Some major points made for utility applications are:

1) The current lack of a fully developed system is a major constraint to initially developing any market (utility, industrial, agricultural, etc.). "Particularly, economic incentives are likely to be

ineffective until the technology has been demonstrated and made available commercially."

2) A wide variety of economic incentives should be considered, including:
   a) Direct cash subsidies
   b) Tax credits
   c) Low interest loans and loan guarantees
   d) Sales tax exemptions
   e) Property tax exemptions
   f) Accelerated depreciation.

3) A mature "Technology Delivery System (TDS) will involve equipment manufacturers, engineering firms, installation and service contractors, financial institutions, utilities, and a variety of Governments and Associations." "The utility market TDS will differ significantly from the others* and be dominated by utilities, architectural/engineering firms," and manufacturers. "The major constraints to accelerating TDS development are lack of market demand, institutional interference in achieving sales, and lack of capital for risk investments." Three kinds of capital investments will be important, corresponding to the three key stages of corporate growth - seed capital, sustaining capital, and growth capital.

4) "The electric utility industry is perhaps the most economically rational in its investment decision process of all the market sectors considered in this study.* It is therefore the one most likely to be successfully influenced by economic incentives. Direct investment subsidies appear to be the economic incentives which will most dramatically impact the installation of "(solar central receivers)" on utility systems in the near future - but they must be preceded by successful demonstrations."

*Others meaning residential, commercial, industrial, and agricultural users.

In general, the DOE-funded programs to date have coincided with these recommendations. Current emphasis is on technical demonstration and risk reduction. Central receiver technology currently is on the verge of entering the next phase of commercial development. As shown in Reference 6-1, government incentives should take into consideration not only market incentives (the utilities) but also the TDS which, in the case of the utilities market, includes primarily:

1) Utilities
2) Architectural/engineering firms
3) Manufacturers
4) Government

Reference 6-1 did not include government in its list of dominant participants for wind systems. Government regulations are expected to play a dominant role for solar central receivers, especially as pertains to the Fuel Use Act of 1978. Also, environmental and safety regulations can play a significant role in determining economic competitiveness between central receivers and alternative fossil fuels.

Developing a market without regard to the TDS can result in not meeting the national energy goal. A delivery system must exist to provide the engineering services and the manufacturing capabilities to build central receiver plants. While architectural and engineering firms may play an important part, no problem is seen in this area as there is no large capital investment and technical expertise will be gained during the demonstration phase. Manufacturing, however, must be considered because of the large capital expenditures required for manufacturing facilities. It is not necessarily sufficient to only develop the market side. Manufacturers must perceive that the market is real and long-term. Once that is decided, there still is the problem of lack of capital for risk investments. Outside financing can often times be difficult. Cash flows may be such, in a growing market, that no cash is available for plant additions. For these reasons, three types of government incentives were investigated based on the relationship between the government, the utilities, and the manufacturing sector. They are defined as follows:

1) Utility/government cooperative
2) Manufacturer/utility/government cooperative
3) Manufacturer/government cooperative (component contract/price supports).

Figures 6-1 through 6-3 illustrate the relationships that would be involved for the three types of incentives.

6.1 UTILITY/GOVERNMENT COOPERATIVE

The simplest approach is the utility/government cooperative. This approach has the highest cost of $745M, but it entails a no-risk approach by government in that government has made no guarantees that a certain market level will be reached and maintained. If solar central receiver commercialization is discontinued for whatever reason, no additional outlays besides those already committed would be required. This approach requires no interaction with manufacturers. Because there is no government commitment, manufacturers are likely to drag their feet in committing sufficient capital toward efficient production facilities for which they see no long-term utilization. Even if they think the market is real, capital funds for investment may be difficult to obtain. Achieving an energy goal could, very likely, be restricted due to limited production capabilities rather than market potential.

6.2 MANUFACTURER/UTILITY/GOVERNMENT COOPERATIVE

This plan requires government contracts with both the utilities and manufacturers. The contracts with manufacturers would commit the government to ensure that central receivers become commercially competitive in return for manufacturer's commitments to sell heliostats and other components at a cost equivalent to long-term amortization of plant facilities. This reduces the utility plant subsidy from

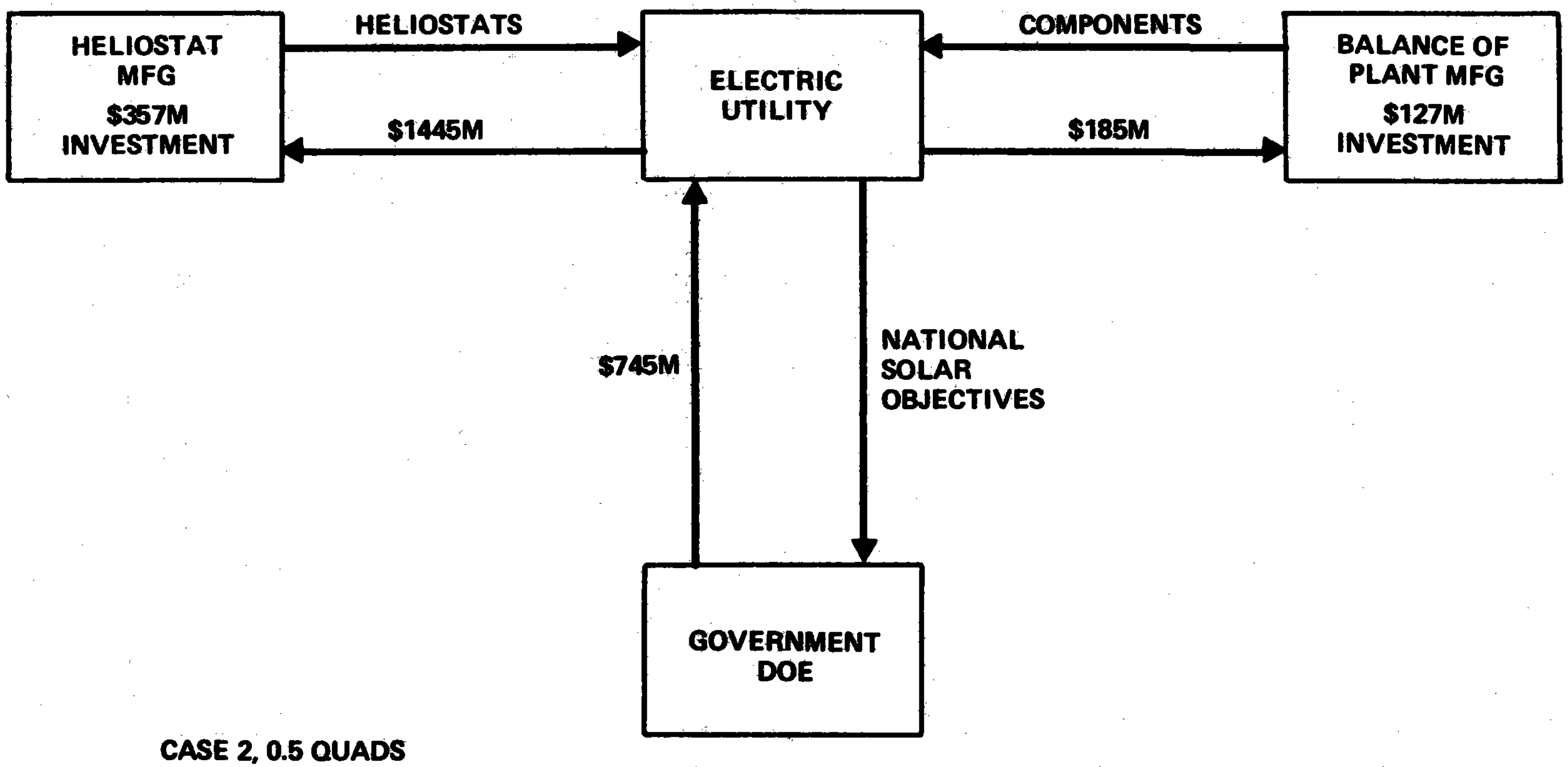

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Figure 6-1. Government Incentives —
Utility/Government Cooperative

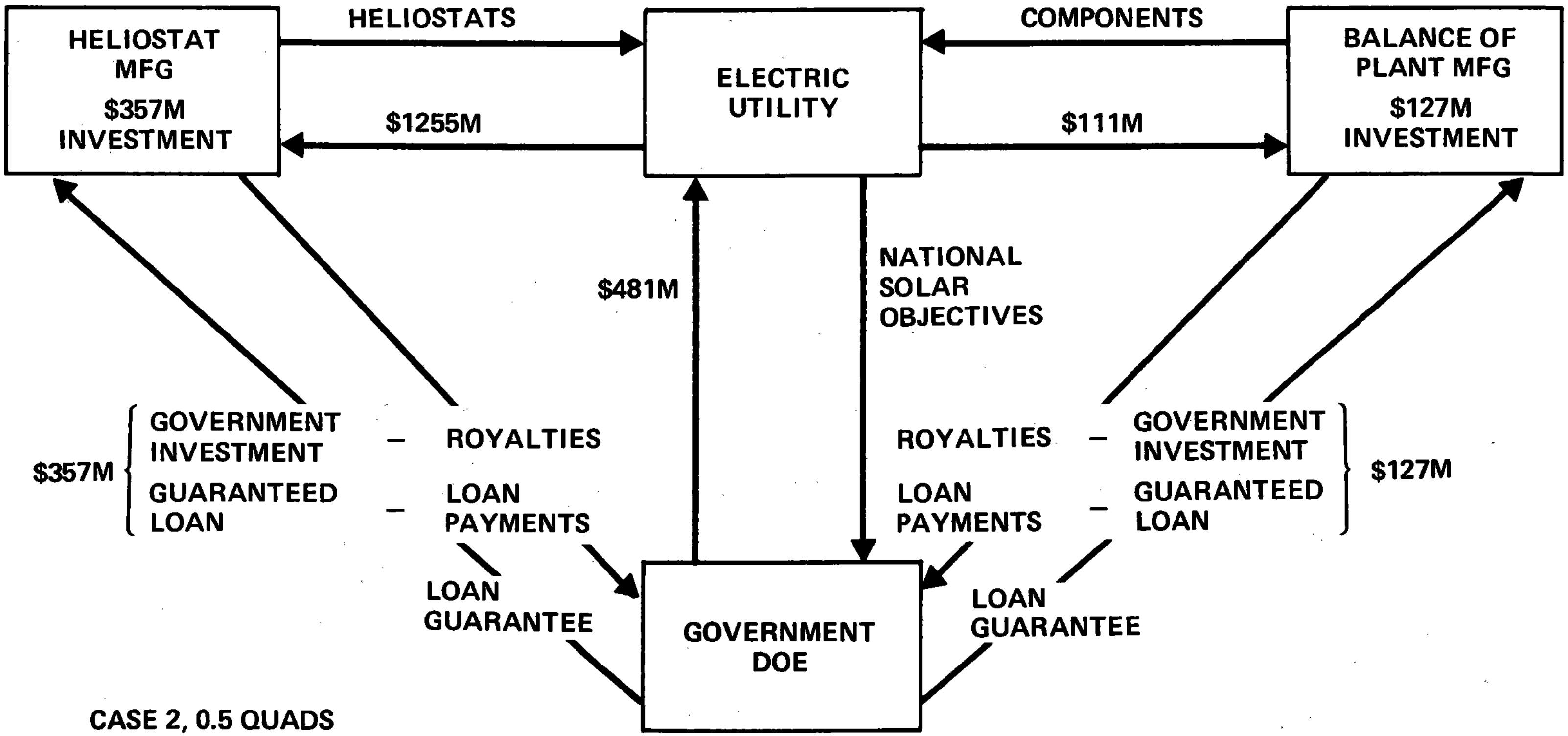

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Figure 6-2. Government Incentives — Manufacturer/Utility/Government Cooperative

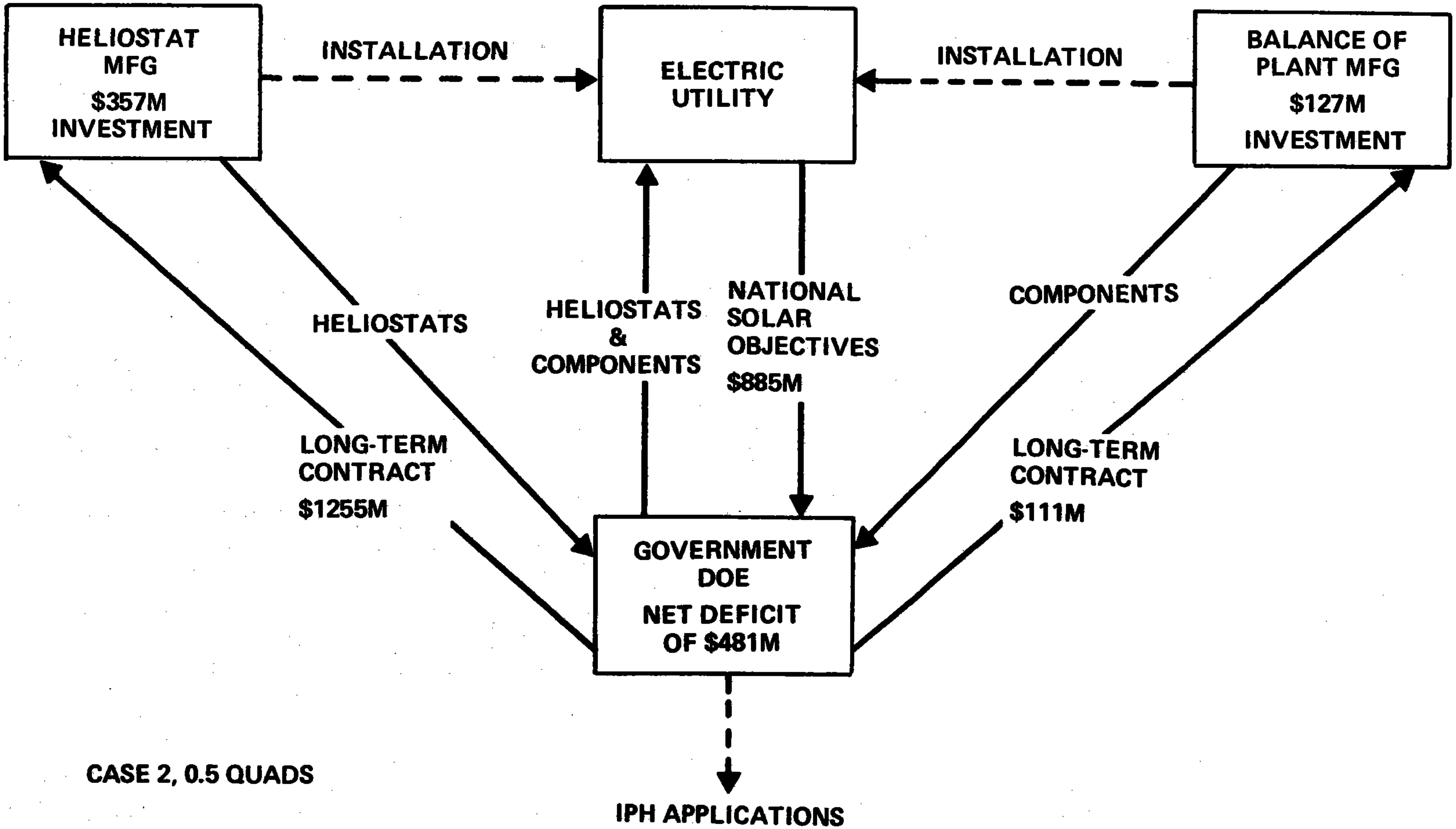

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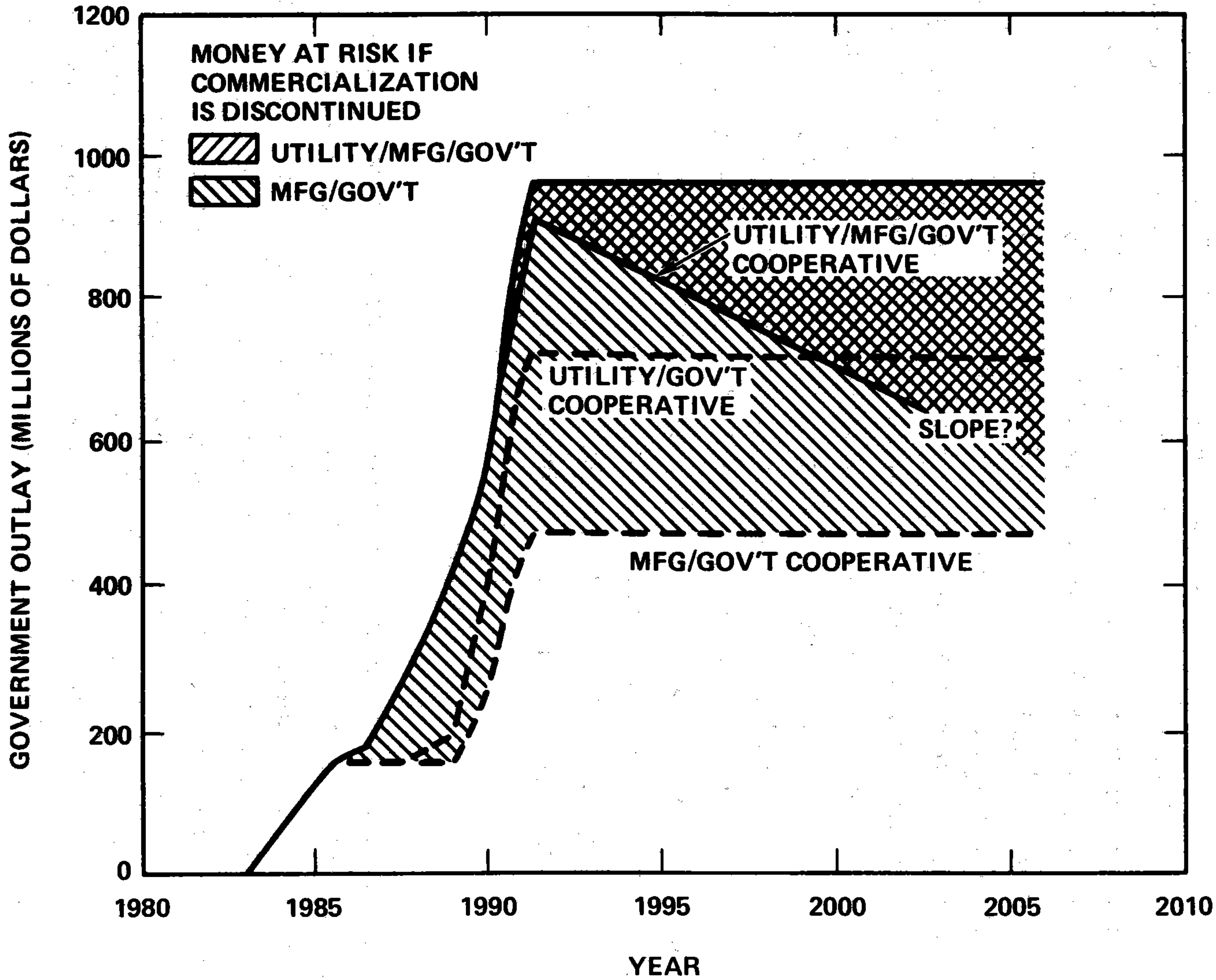
Figure 6-3. Government Incentives — Manufacturing/Government Cooerative

$745M to $481M. Funds needed for the manufacturing sector could be in several forms - outright government purchase of production facilities, guaranteed loans, and/or loan guarantees. The first two would require the government to supply the investment capital for the facilities. In return, the government would receive a rate of return on its investment commensurate with its cost of obtaining funds (T-bills). Figure 6-4 illustrates the cash outlay (1980 dollars) for such a plan. Initially, the total outlay is very high ($913M) but, as royalties or interest are earned on $484M, the net cost will eventually be reduced to the $481M plant subsidy. Loan guarantees would work similarly but private financial institutions would provide the capital funds instead of government. The government would provide the loan guarantees. The final effect is similar in the sense that the government, at one point, will have a commitment of $913M. If at any point commercialization fails, the total cost to government could go as high as $965M ($481M plant subsidy plus $485M for production facilities). If this plan is used, the government should be firmly committed to its program and have a solid economic basis for predicting commercial competitiveness. This approach will allow more long-term planning by manufacturers and provides a method to ensure that manufacturers have the necessary capital funds for investment.

6.3 MANUFACTURER/GOVERNMENT COOPERATIVE

The last plan consists of a contract by the government to purchase a specified number of heliostats at a given price from one or more manufacturers. The government, in turn, sells these heliostats to utilities at a price that is compatible with an acceptable $\overline{\text{BBEC}}$. The commitment here is to purchase heliostats and components at a cost of $1366M and, in turn, sell to utilities at a cost of $885M for a net deficit of $481M. Again, this has a low estimated cost, but contract clauses, should the government discontinue the program, could make the total cost come to $945M. This is a low cost-high risk programmatic approach. The cost flow is shown in Figure 6-4, and money not spent but at risk is indicated as that area between the top and bottom curves.



81-J23-9-6

Figure 6-4. Government Cash Flow
(1980$)

This plan provides long-term planning by manufacturers which should provide the impetus to invest in production facilities (assuming capital funds are available). The heliostats could be sold to an IPH market in addition to the utility market. There is low government involvement with the utilities, yet the government maintains control in determining market demand by fixing the heliostat cost to the utilities. A long-term contract with manufacturers does provide some problems though. It may stifle heliostat innovations due to less competitive need to reduce costs during the life of the contract. A long-term contract with balance-of-plant manufacturers is seen as unwieldly as components would have to meet government specifications which may not coincide with utility preferences. This is particularly true in the area of salt versus sodium and component sizing. Also, the government contract and, therefore, involvement will extend beyond the year of commercial viability. Politically, this program may present problems as it appears to be a \$481M give-away program. While this program has potentially the greatest cost savings to government and good assurance of achieving the desired energy goal, there are some serious problems with this approach.

6.4 CONCLUSIONS

For all four cases, as commercialization is realized and heliostat costs decrease, solar plants (repowering and stand-alone) can compete on an economical basis with the alternative energy sources. It is important to continue this program if we want to pursue this country's goal of energy independence. Currently, the problem is to overcome the initially high costs. In this, the Government can play a very important role.

The three programs could be used as is or a combination could be used which would use one plan for heliostat manufacturers and another plan for balance-of-plant manufacturers. For balance-of-plant manufacturers, only the first two plans should be considered. Government planners need to assess what their primary concerns are in order to pick the best approach. As the approaches outlined apply only to the commercial plants, plenty of time still exists for further evaluation of technical merit and economic competitiveness before making a commitment.

At this time, the best approach seems to be a combination of the first two plans. Due to the complexity of specifications for balance-of-plant components, the best approach here seems to indicate taking the higher cost penalty of $74M and going with the simple utility/government cooperative. Government should assure itself, though, that component development is sufficient that manufacturers will commit themselves to cost estimates and performance criteria. For heliostats, the manufacturer/utility/government cooperative seems the best approach. In order not to be production limited and to ensure the lowest costs for heliostats, long-term planning is needed. Also, funds for investment may be extremely difficult to obtain. Initially the cost will be high but there will be a return on investment for the $357M invested in heliostat facilities. This approach is a good compromise for limiting the total cost of commercialization, providing good control on generating market demand, and guaranteeing that the necessary production facilities exist.

REFERENCES

6-1 "Economic Incentives to Wind Systems Commercialization," Booz, Allen & Hamilton, Inc., Bethesda, Maryland, DOE Contract EG-77-C-01-4053 (HQS/4053-78/1, UC-60), August 1978

APPENDIX A

COST ESTIMATE FOR BALANCE-OF-PLANT MANUFACTURING FACILITIES

Subject: Solar Thermal Conversion - Manufacturing Facilities and Equipment - Calculation Methodology

Ref: (1) Long-Range Marketing Plan, "Solar Thermal Conversion Business Area Facilities and Equipment Requirements," M. Gonzalez, May 30, 1976

(2) "Solar Thermal Conversion," E. C. Powell, April 3, 1980

As requested, this IL will give the explanation of the method used to calculate the costs of the equipment and facilities to manufacture the steam generators and central receiver components for the varied product mixes and production capacities specified by the Case 1 through Case 4 studies.

The following outline shows the procedures used for the preparation of the "Funding Schedule" that was used in particular for Case 2 but also applied for the preparation of the other Funding Schedules.

I. Criteria

A. Components to be Manufactured In-House:

1. Evaporator

2. Superheater

3. Reheater

4. Receiver Components

B. Capacity - 0.5 QUAD Program - Case 2

C. Facility Area Requirements

1. 100 MWe - As Developed by E. Powell, April 3, 1980

2. 250 MWe - Use Data for 300 (281) MWe

D. Equipment Requirements

1. Based on M. Gonzalez Data

2. Modified for Inflation to 1980

3. Modified for Required Production Capacities

E. Data Format - Expenditure Spread Sheet - Requested by the Program Office

II. Area Requirement Summary

A. 100 MWe - 6-hr Storage

$$\text{Area}_R = 53{,}150\ R + 15{,}000\ \text{ft}^2$$

$$R = \text{Plants/Yr}$$

$$\therefore \text{Area}_6 = 6(53{,}150) + 15{,}000 = 333{,}900\ \text{ft}^2$$ 6

$$\text{Area}_{12} = 12(53{,}150) + 15{,}000 = 652{,}800\ \text{ft}^2$$ 12

B. 250 MWe - 6-hr Storage

$$\text{Area} = 100{,}020\ R + 30{,}000\ \text{ft}^2$$

$$\text{Area}_3 = 3(100{,}020) + 30{,}000 = 330{,}060\ \text{ft}^2$$ 3

$$\text{Area}_6 = 6(100{,}020) + 30{,}000 = 630{,}120\ \text{ft}^2$$ 6

C. Facility Growth Requirements

FACILITY AVAILABILITY

	1988	1991	1993	1995
Area	334,000	652,000	982,000	1,282,000
Cost at $\$125/\text{ft}^2$	$41.75M	$81.5M	$122.75M	$160.25M
Δ Cost		$39.75M	$41.25M	$37.5M

III. Equipment Requirement Summary

A. From M. Gonzalez Study, Equipment Cost to Manufacture Ten Each 100-MWe Systems is as Follows. Where Indicated (*), Changes are Made to Reflect Current Knowledge of Equipment Costs

1. Special Manufacturing Equipment

STEAM GENERATOR

Item	Yearly Production Rate 10	6	12
SG Tube Cleaning (6 units)*	$ 18,000	$ 12,000	$ 21,000
SG Tube Handling	50,000	30,000	60,000
Portable Power Drills (20 units)	20,000	12,000	24,000
Weld Positioner 10 ft (5 units)	100,000	60,000	120,000
Weld Positioner 5 ft (2 units)	30,000	30,000	45,000
TIG Subarc (6 units)	540,000	360,000	720,000
Tube/Tubesheet Weld (16 units)	1,200,000	750,000	1,500,000
OOP (8 units)	1,120,000*	700,000	1,400,000
Heat Treat (4 units)	1,200,000*	900,000	1,500,000
Portable X-Ray (2 units)	60,000	60,000	90,000
Nozzle and Cap Welding (3 sets)	180,000	120,000	240,000
Bridge Cranes (8 units)	690,000*	430,000	690,000
Radiographic Shields (10 units)*	10,000*	6,000	12,000
Subtotal	$5,218,000	$3,470,000	$6,422,000

CENTRAL RECEIVER COMPONENTS

Item	Yearly Production Rate 10	6	12
20-Ton Cranes (2)	$ 200,000	$ 100,000	$ 200,000
10-Ton Cranes (2)	150,000	75,000	150,000
OOP (5)	1,500,000	900,000	1,800,000
TIG Subarc (2)	180,000	180,000	180,000
TIG MIG (10)	50,000	30,000	60,000
Cutoff Saws (4)	80,000	40,000	80,000
Hack Saws (2)	50,000	50,000	50,000
Welding Tables (10)	100,000	60,000	120,000
Tube/Tubesheet Welders (10)	750,000	450,000	900,000
Leak Detectors (5)	100,000	60,000	120,000
Portable X-Ray (5)	200,000	120,000	240,000
Radiographic Shields (25)	250,000	150,000	300,000
Isotope System	180,000	180,000	180,000
Weld Rolls (20)	60,000	36,000	72,000
Weld Positioners (2)	60,000	60,000	60,000
Trailers (2)	150,000	150,000	150,000
Cleaning Facility	50,000	50,000	50,000
Pressure Test Facility	100,000	100,000	100.000
Subtotal	$4,210,000	$2,791,000	$4,812,000

*Units refer to those required for 10 per year production rate.

2. General Equipment

STEAM GENERATOR

Item	Yearly Production Rate 10	6	12
Pneumatic Test Facility (4)	$ 600,000	$ 450,000	$ 600,000
Air Pallet Floor	630,000	375,000	750,000
General Mfg. Equipment	1,020,000	620,000	1,225,000
General QA Equipment	650,000	400,000	800,000
Subtotal	$2,900,000	$1,845,000	$3,375,000

CENTRAL RECEIVER COMPONENTS

Item	Yearly Production Rate 10	6	12
General Manufacturing Equipment	$500,000	$300,000	$ 600,000
General QA Equipment	325,000	200,000	400,000
Subtotal	$825,000	$500,000	$1,000,000

3. Total Equipment Costs

Production - Six Systems/Year

Special Equipment, Steam Generator	$3,470,000
Special Equipment, Central Receiver	2,791,000
General Equipment, Steam Generator	1,845,000
General Equipment, Central Receiver	500,000
Total 1978 $	$8,606,000

Total 1980 $ = (1978 $)(1.464)

= ($8,606,000)(1.464)

= $12,600,000 6

Production - 12 Systems/Year

Special Equipment, Steam Generator	$ 6,422,000
Special Equipment, Central Receiver	4,812,000
General Equipment, Steam Generator	3,375,000
General Equipment, Central Receiver	1,000,000
Total 1978 $	$15,609,000

Total 1980 $ = ($15,609,000)(1.464)

= 22,852,000 12

B. Equipment Requirements for 250-MWe Systems

1. Steam Generators

Logic - Each System Requires Four Steam Generators

∴ Three 250-MWe Systems ≅ Four 100-MWe Systems

Equipment for 100-MWe Steam Generators; Six Systems/Yr =

(SME + GME)(1.464) =

($3,470,000 + $1,845,000)(1.464) = $7,781,000

Equipment for Three 250-MWe Systems/Yr =

(4/6)($7,781,000) = $5,187,000 3

Equipment for Six 250-MWe Systems/Yr =

2($5,187,000) = $10,375,000 6

2. Receiver Components

Logic - Components Similiar to 100 MWe but Larger - Add 50% to 100 MWe and Prorate for Production Capacity

∴ Three Systems/Yr Equipment =

1.5(Equipment - 100 MWe - Six Systems/Yr)(1/2) =

1.5($2,791,000 + $500,000)(1.464)(1/2) = $3,614,000 3

Six Systems = 2($3,614,000) = $7,228,000 6

C. Total Equipment - 250-MWe Systems

Three Systems/Yr = $5,187,000 + $3,614,000 = $8,801,000 3

Six Systems/Yr = $10,375,000 + $7,228,000 = $17,603,000 6

The results of these calculations were then transferred to the "Funding Schedule" which also presented the time frame for the funding authorizations and expenditures.

Attachment: Funding Schedule - Cases 1-4

		DELIVERY OF COMPONENTS TO SITE																
CALENDER YEAR →		84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	TOTALS
100 MWe · 6 HR											2	2	4	4	6	2		
250 MWe - 6 HR																2		
BUILDING SPACE 1000 ft²									121		228		334					
EQUIP. FUNDS $M	AUTH.						7.07		1.97		3.56	.50						13.10
	EXPEND						2	5.07	.5	1.47	.5	3.06	.50					13.10
FACILITY FUNDS $M	AUTH.					15.1		13.4		13.3								41.80
	EXPEND					1	7.1	8	6.4	7	6.3	6						41.80
TOTALS	AUTH.					15.1	7.07	13.4	1.97	13.3	3.56	.50						54.90
	EXPEND					1	9.1	13.07	6.9	8.47	6.8	9.06	.5					54.90

FUNDING SCHEDULE
SOLAR THERMAL CONVERSION
FACILITIES AND EQUIPMENT
0.1 QUAD PROGRAM CASE 1
DATE 8.20.80

		DELIVERY OF COMPONENTS TO SITE																
CALENDER YEAR →		84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	TOTALS
100 MWe · 6 HR								6	6	6	12	12	12	12	12	12		
250 MWe - 6 HR													3	3	6	6		
BUILDING SPACE 1000 ft^2						334			652		982		1,282					
EQUIP. FUNDS $M	AUTH.			12.60			10.25		5.19		5.19							33.23
	EXPEND			2.	10.6		2	8.25	1	4.19	1	4.19						33.23
FACILITY FUNDS $M	AUTH.		41.75			39.75		41.25		37.5								160.25
	EXPEND		1	20.75	20	1	18.75	21.	20.25	21	16.5	20						160.25
TOTALS	AUTH		41.75	12.6	0	39.75	10.25	41.25	5.19	37.5	5.19							193.48
	EXPEND		1	22.75	20.6	1	20.75	29.25	21.25	25.19	17.5	24.19						193.48

FUNDING SCHEDULE
SOLAR THERMAL CONVERSION
FACILITIES AND EQUIPMENT
0.5 QUAD PROGRAM CASE 2
DATE 8-20-80

		DELIVERY OF COMPONENTS TO SITE																
CALENDER YEAR →		84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	TOTALS
100 MWe 6 HR						4	4	8	8	8	8	8	8	8	8	4		
250 MWe - 6 HR											2	2	4	4	4	8		
BUILDING SPACE 1000 ft²				228		440			670		900			1285				
EQUIP FUNDS $M	AUTH.	9.04		7.16			5.87		5.87			11.73						39.67
	EXPEND 83	3	6.04	2	5.16	0	2	3.87	2	3.87	0	4	7.73					39.67
FACILITY FUNDS $M	AUTH 28.5		26.5			28.8		29.2			48.1							161.1
	EXPEND 1	14	14.5	13	12.5	1	14	14.8	15	13.2	2	23.1	23.					161.1
TOTALS	AUTH 28.5	9.04	26.5	7.16	0	28.8	5.87	29.2	5.87	0	48.1	11.73						200.77
	EXPEND 1	17	20.54	15	17.66	1	16	18.67	17	17.07	2	27.1	30.73					200.77

FUNDING SCHEDULE

SOLAR THERMAL CONVERSION

FACILITIES AND EQUIPMENT

0.5 QUAD PROGRAM CASE 3

DATE 8.25.80

		DELIVERY OF COMPONENTS TO SITE																
CALENDER YEAR →		84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	TOTALS
100 MWe 6 HR								12	12	12	18	18	18	18	18	18		
250 MWe - 6 HR													6	6	18	18		
BUILDING SPACE 1000 ft²						652			972		1,602		1,831					
EQUIP. FUNDS $M	AUTH.			22.85			10.41		17.60		35.20							86.06
	EXPEND			10	12.85	0	5	5.41	9.0	8.60	15.2	20.0						86.06
FACILITY FUNDS $M	AUTH.		81.5			40.0		78.6		28.6								228.7
	EXPEND		6	35	40.5	2	19	25	30	44.6	13	13.6						228.7
TOTALS	AUTH.		81.5	22.85	0	40.0	10.41	78.6	17.60	28.6	35.2							314.76
	EXPEND		6	45	53.35	2	24	30.41	39.0	53.2	28.2	33.6						314.76

FUNDING SCHEDULE
SOLAR THERMAL CONVERSION
FACILITIES AND EQUIPMENT
1.0 QUAD PROGRAM CASE 4
DATE 8.26.80

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