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Solar Thermal Repowering Utility Value Analysis

Final Report

Roger Taylor
in cooperation with
Westinghouse Electric Corporation
East Pittsburgh, Pennsylvania

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SOLAR THERMAL REPOWERING UTILITY VALUE ANALYSIS

FINAL REPORT

DECEMBER 1979

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PREPARED UNDER SUBCONTRACT
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FOR THE

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PROJECT MANAGER
ROGER TAYLOR

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FOREWORD

This report was prepared jointly by the Systems Analysis Branch of SERI and the Advanced Systems Technology Division of Westinghouse Electric Corporation under Subcontract Number XH-9-8016-1. The report represents the results of the Demand Task of the Repowering Strategy Analysis. The objective of the Repowering Strategy Analysis is to define a government role in repowering that constitutes an efficient program investment in pursuit of viable private markets for heliostat-based energy systems. The purpose of the Demand Task is to determine and quantify the sources of value for solar-thermal power plants to electric utilities as a function of penetration and time.

The authors wish to recognize the valued contributions, insight and assistance made by J. W. Doane, of SERI, in interpreting results and extracting salient factors of the analysis. Other Westinghouse analysts contributing to the results in this report include: W. G. Parker, T. E. Mousseau, E. L. Schlatz and K. Gunnell. We also wish to acknowledge R. J. Copeland, G. R. Fegan, J. B. Gresham, T. Stoffel, D. A. Nordman and C. D. Percival, of SERI, for their assistance during the project and review of this report.

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SUMMARY

The retrofit of solar central receiver energy supply systems to existing steam-electric generating stations, an application known as "repowering," is being considered as a major programmatic thrust by the Department of Energy's Large Solar Central Power Systems Program. The determination of a government response appropriate to the opportunities of repowering is an important policy question, and is the major reason for the Repowering Strategy Analysis. The study objective is:

> To define a government role in repowering that constitutes an efficient program investment in pursuit of viable private markets for heliostat-based energy systems.

In support of that objective, the study is designed to identify the scope and nature of the repowering opportunity within the larger context of its contributions to central receiver technology development and commercialization. The Repowering Strategy Analysis consists of tasks in three areas: Supply, Demand and Institutional. In addition, there is an Integration Task to synthesize the results and recommend the government strategy. This report documents the Demand Task.

The objective of the Demand Task portion of the Repowering Strategy Analysis is to determine and quantify the sources of the value of repowering (and of central receiver technology in general) to electric utilities. In order to accomplish this task with reasonable accuracy, it is necessary to determine the components of value as a function of solar penetration and time. This must be done on a dynamic basis by considering the initial conditions of the utility and comparing optimum generation expansion plans, through time, with and without solar penetration. These comparisons are then used along with a detailed analysis of certain individual years in order to assess the value of solar thermal capacity to the utility.

The methodology used in this report consists of two parts: the dynamic analysis which determines utility generation mix over time, and the static analysis which determines the yearly impact of solar capacity on utility production costs. While the static analysis is used to obtain impact data for specific solar unit additions, the dynamic penetration analysis is the principal tool in this study. Only the dynamic analysis has the ability to analyze a specific penetration pattern of solar plants and to show how that pattern would change the utility's generation expansion plan and revenue requirements. Thus, dynamic analysis determines the impact of the scenario rather than the impact of a single plant.

For impact assessment purposes, a hypothetical utility system was used. The system, based upon EPRI synthetic utility system E, was chosen as being representative of a utility in the southwestern United States, an area considered prime for repowering. The slightly modified EPRI synthetic utility and the insolation data used most nearly approximates 1985 projections for west Texas. This hypothetical utility contains a large proportion of oil-fired generating units, making the number of candidate repowering units high and the potential economic savings due to the displacement of oil very attractive.

The major assumptions used in this analysis are as follows:

- Modified EPRI Synthetic System E (a representative 1985 Southwestern electric utility)
- Moderately high Southwest insolation level, 2500 kWh/m^2-yr, typical year data
- Oil escalates at 12%/year starting from $5.50/MBtu in 1985 (roughly $32/bbl)
- High performance solar plants
- Only storage-buffered repowered and three-hour storage coupled solar-thermal plants were considered; high capacity factor solar plants were not considered
- Three different penetration scenarios each with three different rates of penetration achieving a maximum of 8% of system capacity by 2009 forced onto the system
- No special solar tax credits or other incentives were considered

Ten key findings have been obtained from this analysis. The first seven have policy implications, the last three have to do more with the methods used in the analysis.

- Numerous situations exist where the value of heliostats is greater than the cost goals which have been proposed
- The relatively high value of solar may not be great enough to compete with new baseload coal and nuclear generation sources in utilities with high operating cost baseload capacity
- The value of solar thermal electricity is not constant nor even monotonic with time
- Solar thermal value trends are consistent with a program plan emphasizing repowering early, followed by the later implementation of new stand-alone plants
- There is a near-term window for repowering which is based upon the current high value of displacing oil-fired capacity, not on unit retirements alone
- The dynamic analysis results reveal financial problems not identified in the static analysis
- The institutional constraints on nuclear and coal generation facilities strongly affect the time value of solar-thermal capacity
- Taking capacity credit for solar on a system that is adding only new baseload capacity may be economically unwise

- Optimizing the conventional generation mix around a solar penetration scenerio does not eliminate penetration effects

- Dynamic analysis is essential to fully understand the value question (for a plant) in a changing environment

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TABLE OF CONTENTS

	Page
1.0 Introduction and Objectives	1
1.1 Perspective on the Repowering Strategy Analysis	1
1.2 Objectives of this Report	3
2.0 Key Findings	5
2.1 Caution on Interpretation	5
2.2 Key Findings	6
2.2.1 Numerous Situations Exist Where the Value of Heliostats is Greater Than the Cost Goal	6
2.2.2 The Relatively High Value of Solar May Not be Great Enough to Compete With New Baseload Coal and Nuclear Generation Sources	7
2.2.3 The Value of Solar-Thermal Electricity is Not Constant With Time	7
2.2.4 Solar-Thermal VAlue Trends are Consistent with a Program Plan Emphasizing Repowering Early Followed by the Later Implementation of New Stand-Alone Plants	7
2.2.5 There is a Near-Term Window for Repowering not Based on Retirements Alone	8
2.2.6 The Dynamic Analysis Results Reveal Financial Problems not Identified in the Static Analysis	8
2.2.7 The Institutional Constraints on Nuclear and Coal Generation Facilities Strongly Affect the Time Value of Solar	9
2.2.8 Taking Capacity Credit May Be Harmful in the Long Run	9
2.2.9 Optimizing the System around Solar Does Not Eliminate Penetration Effects	9
2.2.10 Dynamic Analysis is Essential to Fully Understand the Value Question in a Changing Environment	9
3.0 Methodology	11
3.1 General	11
3.2 Methodology Structure	11
3.2.1 Determination of the Generation Mix over Time	11
3.2.2 Determination of the Yearly Production Cost and Present Worth of Revenue Requirements	14
4.0 Economic and Performance Assumptions	15
4.1 Economic Assumptions	15
4.1.1 General	15

TABLE OF CONTENTS (Continued)

Page

4.1.2 Fuel Cost 16
4.1.3 Conventional Plant Cost 17
4.1.4 Solar Plant Cost 17
4.1.5 Solar/Conventional Cost Comparison 20

4.2 Solar Plant Characteristics 22
4.2.1 General 22
4.2.2 Stand-Alone Solar Plant 22
4.2.3 Hybrid Repowered Solar Plant 24
4.2.4 Barstow Technology 28
4.2.5 Plant Availability 28
4.2.6 Collector Field Experiment 28

5.0 Utility and Insolation Characteristics 33

5.1 Utility System Assumptions 33
5.1.1 General 33
5.1.2 Load Characteristics 33
5.1.3 Generating Capacity Mix 35
5.1.4 Retirements 36

5.2 Insolation Assumptions 36
5.2.1 General 36
5.2.2 Source 38
5.2.3 Annual Quality/Statistics 39

6.0 Reference Case System Expansion 41

6.1 General 41

6.2 Overexpansion and Nuclear Limitation 41

6.3 Constrained Reserves Plan 44

6.4 Perspective on Reference Utility System Expansion 46
6.4.1 Insight Derived from Generation Expansion 48
6.4.2 Generation Expansion End Effects 51

7.0 Solar Penetration 53

7.1 Penetration Scenarios 53
7.1.1 Southwest Penetration Scenario - Repowering 53
7.1.2 Southwest Penetration Scenario - Stand-Alone 55
7.1.3 Southwest Penetration Scenario - Repower/Stand-Alone .. 55
7.1.4 Utility System E Penetration Scenarios 55

7.2 Dynamic Expansion With Solar Penetration 59
7.2.1 Capacity Displacement 61

TABLE OF CONTENTS (Concluded)

Page

7.2.2 Energy and Fuel Displacement 66
7.2.3 Cost Summary 68

7.3 Static Analysis 72
7.3.1 General 72
7.3.2 Economic Merit 75
7.3.3 Components of Solar Plant Value 77
7.3.4 Capacity Displacement 77
7.3.5 Operating Cost Savings 79
7.3.6 Penetration Effects 84
7.3.7 Value of Heliostats 85

8.0 Parametric Analysis 89

8.1 General 89
8.2 Installation Timing and Penetration 89

8.3 Alternate Fuel Scenarios 90

8.4 Solar Plant Cost Sensitivity 91

8.5 Balanced Utility System Sensitivity 95

8.6 Coal Plant Static Analysis 96

8.7 Thermal Buffering 100

8.8 Sensitivity Comparison 101

8.9 Sensitivity Conclusions 102

9.0 References 105

Appendix A Solar-Thermal Power Plant Evaluation Methodology 107
Appendix B Dynamic Expansion Analysis Details 159
Appendix C Static Analysis Results 183
Appendix D Cost Estimates 203
Appendix E Estimation of a Solar-Thermal Repowering Market 213

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LIST OF FIGURES

		Page
1-1	Structure of Repowering Strategy Analysis: Supply and Demand Tasks	2
1-2	Structure of Repowering Strategy Analysis: Institutional and Integration Tasks	3
2-1	Representative Heliostat Value Trends	8
3-1	Determination of Generation Mix Over Time (Dynamic Analysis)	12
3-2	Determination of Current Year Production Cost and Present Worth of Revenue Requirements (Static Analysis)	13
4-1	30-Year Levelized Annual Cost Curve	21
4-2	Improved Stand-Alone Annual Average Efficiency Train	25
4-3	Improved Stand-Alone Plant Schematic	25
4-4	Improved Hybrid Repowered Annual Average Efficient Train	27
4-5	Improved Hybrid Repowered System Schematic	27
4-6	Barstow Technology Hybrid Repowered Annual Average Efficiency Train	30
4-7	Barstow Technology Hybrid Repowered Schematic	30
4-8	Solar Power Plant Collector Field Experiment	32
5-1	Regional Synthetic Utility Models	34
5-2	Regional Electric Reliability Council Areas	34
5-3	Typical Daily Load Curves	35
5-4	Average Annual Direct Normal Insolation	37
5-5	Average Daily Direct Normal Insolation Comparison	39
6-1	Nonsolar Deferred Capacity Expansion	49
6-2	Deferred Nonsolar Energy Expansion Summary	50
7-1	Utility E Penetration Scenario - Repowering	54
7-2	Utility E Penetration Scenario - Stand-Alone	56
7-3	Utility E Penetration Scenario - Repower/Stand-Alone	57
7-4	Solar Plant Lifetime Cost and Value Time Characteristics	60
7-5	Expansion Plan Changes from Reference Case	62
7-6	Revenue Requirement Changes from Reference Case	62
7-7	Improved Stand-Alone, Deferred Expansion Plan Cost Summary	70

LIST OF FIGURES (Continued)

		Page
7-8	1985 Load Profile and Fuel Mix - Reference Case	80
7-9	1998 Load Profile and Fuel Mix - Reference Case	80
7-10	2005 Load Profile and Fuel Mix - Reference Case	81
7-11	50 MW Solar Plant Power Output Fuel Distribution ISA Experiment - Nominal Penetration	82
7-12	50 MW Solar Plant Power Output Value Capacity ISA Experiment - Nominal Penetration	83
7-13	Improved Stand-Alone Value Versus Penetration	85
7-14	Heliostat Value Curves	88
8-1	50 MW Solar Plant Fuel Escalation Rate Sensitivity ISA Experiment - Nominal Penetration	92
8-2	50 MW Solar Plant Cost Sensitivity ISA - Nominal Penetration	94
8-3	Representative Heliostat Value Trends	95
8-4	50 MW Solar Plant Value Comparison with Generating Mix ISA - Low Penetration	97
8-5	50 MW Coal Power Plant Fuel Displacement Coal Experiment	98
8-6	50 MW Coal Power Plant Value Components Coal Experiment	99
8-7	50 MW Coal Power Plant Value Components Coal Experiment	102

LIST OF TABLES

		Page
4-1	New Conventional Unit Characteristics, Reference Economic Assumptions	16
4-2	Existing Conventional Unit Characteristics	18
4-3	Solar Plant Cost Comparison	19
4-4	Improved Stand-Alone Solar Plant Performance Data	23
4-5	Improved Hybrid Repowered Solar Plant Performance Data	26
4-6	Barstow Technology Hybrid Repowered Solar Plant Performance Data	29
4-7	Average Annual Efficiency Train Comparison 100 MWe Solar Plant	31
5-1	1985 Generating Mix Comparison	36
5-2	Existing Units' Scheduled Retirement Dates	38
6-1	Unconstrained System Expansion Installation Schedule	42
6-2	Modified Utility E Nonsolar Expansion Constrained Nuclear Installations	43
6-3	Modified Utility E, Nonsolar Expansion Constrained Nuclear Installations and Constrained Reserves	44
6-4	Modified Utility E, Nonsolar Expansion, Constrained Nuclear Installations, and Constrained Reserves Reference Case Cost Summary	45
6-5	Cost Comparison of Nonsolar Cases (25-Year Present Worth in 1985 Billions $)	46
6-6	Modified Utility E, Nonsolar Expansion, Constrained Nuclear Installations, Constrained Reserves Reference Case	47
7-1	25-Year Cost Summary of Expansion Plans (PWRR 1985 Billions $)	60
7-2	Capacity Displacement Comparison, Improved Stand-Alone Nominal Penetration, Conventional Expansion (25-Year Summary GW)	64
7-3	Capacity Displacement Cost Summary, Improved Stand-Alone Nominal Penetration, Conventional Expansion (PWRR, 1985 Billions $)	64
7-4	Unit Addition Summary, Deferred Expansion Cases (25-Year Summary, GW)	65
7-5	Improved Stand-Alone, Deferred Expansion Plan Nominal Penetration Installation Schedule	66

LIST OF TABLES (Continued)

		Page
7-6	Energy Displacement, (GWh) ISA Nominal Penetration	67
7-7	Cost Summary, Deferred Expansion Cases (PWRR 1985 Billions $)	69
7-8	Improved Stand-Alone, Deferred Expansion Plan, Nominal Penetration Cost Summary (PWRR, 1985 M$)	71
7-9	Lifetime Value and Cost/Value Ratios by Installation Year for Improved Stand-Alone Solar-Thermal Plants	73
7-10	Lifetime Value and Cost/Value Ratios by Installation Year for Improved Hybrid Repowered Solar-Thermal Plants	73
7-11	Lifetime Value and Cost/Value Ratios by Installation Year for Combination Solar-Thermal Experiment	74
8-1	Economic Scenario Fuel Comparison (Fuel Cost in 1985 Dollars)	90
8-2	Economic Scenario Comparison of Solar Plant Value and Cost/Benefit, Improved Stand-Alone, Nominal Penetration (PWRR, 1985 M$, 50 MWe)	91
8-3	Impact of Solar Plant Fixed Charge Rate (PWRR, 1985 Billions $)	95
8-4	Transient Buffer Value Analysis Present Worth 1985 M$	101

SECTION 1.0

INTRODUCTION AND OBJECTIVES

1.1 PERSPECTIVE ON THE REPOWERING STRATEGY ANALYSIS

The retrofit of solar central receiver energy supply systems to existing steam-electric generating stations, an application known as "repowering," is being considered as a major programmatic thrust by the Department of Energy's Large Solar Central Power Systems Program. Several promising features of repowering lead to this interest:

Technical: Repowering offers a relatively low-risk technical path to large scale test and demonstration of central receiver technology. Partial reliance on existing hardware places both cost and technical emphasis on the energy supply system, where the major uncertainties lie. Also, the hybrid nature of repowered plants permits them to operate even if the solar energy supply system is temporarily unavailable.

Demand: The confinement of risk to the solar portion of the plant makes utility involvement more attractive, and facilitates cost-sharing arrangements between the public and private sectors. Early involvement of the eventual user group promises to increase the market development value of the test and demonstration program in several important areas: relevance, credibility, information dissemination, and response.

Supply: The value of the solar energy supply system is possibly higher in repowering than in new capacity applications. (This question is addressed in this report.) If this is so, then the opportunity for early hardware sales (when costs are higher) for repowering may be an important advantage for the development of the supply industry. (This question is addressed in the report of the Repowering Supply Task.)

Energy Displacement: While the likely population of repowerable plants in the Southwest is not large (roughly 4-6 GWe--see Appendix E), it is heavily reliant on oil and gas. Thus, the direct effects of repowering on fuel displacement are in the desired categories.* Realization of these effects depends on the successful use of repowering as a test and demonstration program.

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*It will be argued in the main project report, A Government Role in Repowering, SERI/TR-51-340, that the indirect energy displacement effects of repowering are potentially far more important. Indirect energy displacement refers to the contribution made by repowering through the acceleration of cost-effective stand-alone applications.

The determination of a government response appropriate to the opportunities of repowering is an important policy question, and is the major reason for the Repowering Strategy Analysis. The study objective is:

> To define a government role in repowering that constitutes an efficient program investment in pursuit of viable private markets for heliostat-based energy systems.

In support of that objective, the study is designed to identify the scope and nature of the repowering opportunity within the larger context of its contributions to central receiver technology development and commercialization. The structure of the overall Repowering Strategy Analysis is shown in Figures 1-1 and 1-2. The Supply Task and Integration Task are documented separately. This report documents the Demand Task.

SUPPLY TASK

Employs:

- Detailed Production Engineering
- Process-based Computer Model of a Manufacturing Company

To Estimate:

Manufactured cost of Heliostats as a function of design, production process, and production volume

Leading to:

Estimates of supply price of heliostats as function of design, production process, and production volume

DEMAND TASK

Employs Standard Electric Utility Modeling Techniques for:

- Generation System Planning
- Electricity Production Cost

To Estimate:

Value to utility of solar-thermal plants as function of time and solar penetration

Leading to;

Estimates of demand price for solar hardware as function of time and solar penetration

Figure 1-1. STRUCTURE OF REPOWERING STRATEGY ANALYSIS: SUPPLY AND DEMAND TASKS

INSTITUTIONAL TASK

Employs:

Descriptions of actual and probable institutional constraints on solar-thermal plant siting

To Estimate:

Institutional requirements for commercial deployment of solar-thermal plants (i.e., requirements beyond technical and economic viability)

Leading to:

Requirements on technology development and commercialization programs and/or on public policy to permit rapid commercial deployment of cost-effective solar-thermal plants

INTEGRATION TASK

Employs Models of:

- Power Plant Life-Cycle Cost
- Electric Utility Adoption of New Technology
- Investor (Producer) Adoption of New Technology

and

- Outputs from All Other Tasks

To Estimate:

Impacts of various government actions on commercial prospects for solar-thermal plants

Leading to:

Recommended federal strategy for use of repowering opportunity as an efficient investment in commercializing heliostat-based energy systems

Figure 1-2. STRUCTURE OF REPOWERING STRATEGY ANALYSIS: INSTITUTIONAL AND INTEGRATION TASKS

1.2 OBJECTIVES OF THIS REPORT

The objective of the Demand Task portion of the Repowering Strategy Analysis is to determine and quantify the sources of the value of repowering (and of central receiver technology in general) to electric utilities. In order to accomplish this task with reasonable accuracy, it is necessary to determine the components of value as a function of solar penetration and time. This must be done on a dynamic basis by considering the initial conditions of the utility and comparing optimum generation expansion plans, through time, with and without solar penetration. These comparisons are then used along with a detailed look at certain individual years in order to assess the value of solar thermal capacity to the utility. This report describes the modeling tools and assumptions used in the Demand Task, and presents and interprets the results.

Section 2.0 points out the key findings. Sections 3.0 through 8.0 discuss, in detail, the approach, assumptions, and results of this portion of the Repowering Strategy Analysis.

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SECTION 2.0

KEY FINDINGS

2.1 CAUTION ON INTERPRETATION

As was described in the introduction, this report is one portion of a larger analysis. The key findings described in Section 2.2, which are very important in assessing the large solar-thermal program, are not sufficient in themselves to develop a policy position. This study does show the value of solar-thermal installations in the Southwest over time; however, there are many other factors which must be considered in making a policy recommendation for the development of large solar-thermal systems. The most important of these factors include: the supply side economics (especially heliostat costs), institutional and environmental considerations, and decisions involving the development of solar-thermal power plants vis-a-vis other new electric generating technologies.

For impact assessment purposes, a hypothetical utility system was used. The system, based upon EPRI synthetic utility system E, was chosen as being representative of a utility in the southwestern United States, an area considered prime for repowering. The slightly modified EPRI synthetic utility and the insolation data used most nearly approximates 1985 projections for west Texas. This hypothetical utility contains a large proportion of oil-fired generating units, making the number of candidate repowering units high and the potential economic savings due to the displacement of oil very attractive. Also, the insolation level used is reasonably high.

There are many decisions which must be made in developing the input parameters to be used in any analysis of this type. A great deal of time was spent in developing the assumptions necessary to perform this analysis. They were developed in such a way as to provide the maximum amount of useful information from which conclusions could be drawn.

The major assumptions used in this analysis are as follows.

- Modified EPRI Synthetic System E (a representative 1985 Southwestern electric utility)
- Moderately high Southwest insolation level, 2500 kWh/m^2-yr, typical year data
- Oil escalates at 12%/year starting from $5.50/MBtu in 1985 (roughly $32/bbl)
- High performance solar plants
- Only storage-buffered, repowered and three-hour storage coupled solar-thermal plants were considered; high capacity factor solar plants were not considered
- Three different penetration scenarios each with three different rates of penetration achieving a maximum of 8% of system capacity by 2009

- No special solar tax credits or other incentives were considered

It was necessary to postulate penetration scenarios with which to compare the reference (no solar) system. The scenarios contain a range of solar penetration rates, starting points and ultimate penetration levels in order to sufficiently bound the problem for analysis. These scenarios should in no way be taken as predictions--instead they are exogenously forced in order to indicate trends.

In addition to the assumptions listed above, there were three important institutional assumptions. All of these have to do with conventional generation sources. First, for the utility system examined it was assumed that nuclear installations would be limited to one 1000 MW unit every five years. This assumption was based upon recent trends in the installation of nuclear facilities and a capital-constrained environment. The nominal utility size is 10,000 MW in 1985. Second, it was assumed that there would be a sufficient supply of coal, at the prices used, to fill the baseload generation gap left by the limitation on nuclear capacity. Third, the maximum rate of introduction of new baseload capacity is limited by restricting the maximum generation reserve to 25%, again due to capital constraints.

Even with these constraints the generation expansion is idealized. The utility is likely to encounter many institutional problems during the 25-year planning horizon which will force it to have installations different from those selected by the program. Further, the process of expanding a generation system is analagous to trying to hit a moving target. Circumstances are continually changing and the most reliable portion of a 25-year expansion is the first five years. However, the analysis is still useful for indicating long-term trends, and necessary to estimate long-term impacts.

Two additional qualifications must be made at this point. First, this study is not a market survey or projection. Second, the repowering of plants with technologies other than solar was beyond the scope of this study.

The details of all these assumptions are presented in Sections 4.0, 5.0, and 7.1.

2.2 KEY FINDINGS

Ten key findings have been obtained from this analysis. The first seven have policy implications, the last three have to do more with the methods used in the analysis.

2.2.1 Numerous Situations Exist Where the Value of Heliostats Is Greater Than the Cost Goal

While the value of heliostats obtained from the dynamic simulation of the synthetic utility is not a single number, the value in many cases is greater than the cost goals which have been proposed. Under certain circumstances where solar-thermal electricity competes primarily with expensive premium fuels, the value of heliostats is very high.

2.2.2 The Relatively High Value of Solar May Not Be Great Enough to Compete with New Baseload Coal and Nuclear Generation Sources

Although the cost/benefit ratio of solar-thermal systems is often less than unity, there are competing technologies for which investment dollars will return even greater benefits. The synthetic system studied, and Southwestern utilities like it, have some unique characteristics. Most important is the fact that these systems are severely deficient in low-operating cost units (oil is being used for baseload capacity). Any generation expansion optimization will be "looking" for large amounts of new nuclear and coal-fired capacity in the early years. Solar-thermal power systems, which operate in an "intermediate" to "peaking" mode, will therefore be in competion for capital investment dollars which the utilities can invest more profitably in baseload generation. Consequently, in the early years, solar-thermal installations will have to be installed on their fuel saving merit alone. The same characteristics which cause solar-thermal to be attractive from a static (one year production cost) standpoint cause severe capital competition from a dynamic (multiyear optimized expansion) standpoint.

2.2.3 The Value of Solar-Thermal Electricity Is Not Constant with Time

The combining of the static and dynamic analysis tools has led to some interesting results. Due to the highly nonoptimum initial generation mix with 60% of its capacity in oil-fired plants, the value of solar-thermal plants in the early years is very high. The system generation mix improves with time as large amounts of new low-operating cost capacity are added, causing a dramatic drop in the value of the electricity generated by solar. Then, in later years, the continually growing system requires new intermediate and peaking capacity. The combination of this requirement with ever increasing oil or substitute premium fuel prices makes the solar systems very valuable again after the year 2000.

2.2.4 Solar Thermal Value Trends are Consistent with a Program Plan Emphasizing Repowering Early Followed by the Later Implementation of New Stand-Alone Plants

The breakeven value of heliostats is a good way to compare the economic competitiveness of solar thermal technologies. Figure 2-1 shows the overall value trends from two of the scenarios used in the study. From this it is seen that repowering has a slightly higher value for heliostats in the period before 2000 and that stand-alone plants have a slightly higher value after this time. This finding is consistent with a solar-thermal development program that emphasizes repowering early followed by the implementation of new stand-alone plants. However, it must be remembered that this trend on the demand side is not a sufficient reason in itself around which to develop a government policy. Only with a clear understanding incorporating the supply and institutional effects can this be done. The period beyond 2000 has been drawn with dashed lines because of the great uncertainty of what will be the competing technologies and fuel prices in that time frame.

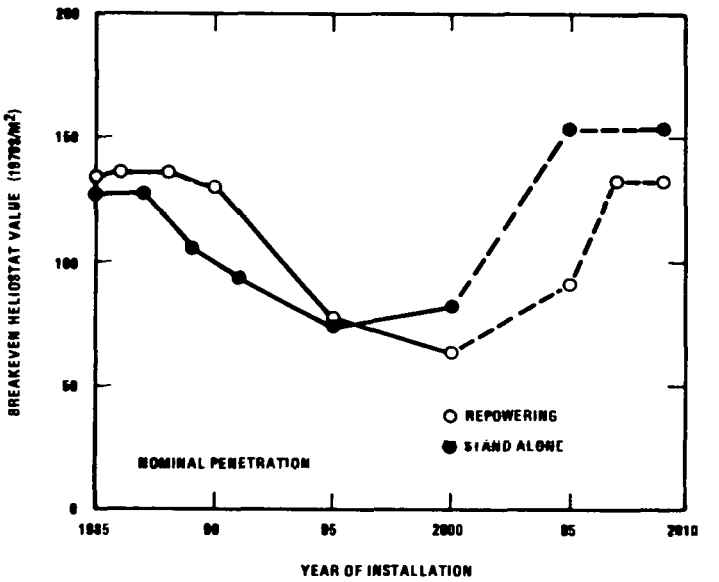

Figure 2-1. REPRESENTATIVE HELIOSTAT VALUE TRENDS

2.2.5 There Is a Near-Term Window for Repowering not Based on Retirements Alone

Not only is there the longer term window which becomes closed due to plant retirements (all of the plants fired with #2 oil are retired on the synthetic utility system by the end of the study), but there is a near-term economic window. The value of repowering is high at the start of the study (1985) due to the abundance of oil-fired capacity. If it wasn't for the maximum capacity reserve constraint, the most economic option would have been to install a very large amount of new baseload coal or nuclear capacity in 1985, the first study year. This would have immediately reduced the value of solar-thermal electricity. However, due to the constraint the new baseload capacity must now be installed over a period of several years. Thus, the value of solar-thermal starts high and falls off gradually during the first ten years of the study. By the time the value has again risen to its original level, all of the candidate repowerable plants have been retired due to old age.

2.2.6 The Dynamic Analysis Results Reveal Financial Problems not Identified in the Static Analysis

The dynamic penetration of a utility by a capital intensive product such as solar-thermal plants can cause an ever-increasing net negative cash flow. This is caused by the added capital requirements of the new solar plants outweighing the current fuel savings of the solar units. Not until sometime after the penetration stabilizes will yearly benefits overcome yearly outlays. Even though the static (plant lifetime) analysis may show a favorable cost/benefit ratio, the switch to solar-thermal plants will cause a cash flow problem lasting much longer than the payback period of an individual solar-thermal unit. This is an effect likely to be encountered in any switch to capital intensive renewable energy resources.

2.2.7 The Institutional Constraints on Nuclear and Coal Generation Facilities Strongly Affect the Time Value of Solar

There are two institutional constraints which were applied which significantly influenced the value of solar. When the generation expansion was first run, it immediately installed nuclear capacity equal to about 50% of the existing system and continued to add large amounts in future years. This is so contrary to current trends in the electric utility industry that the first institutional constraint was to limit the amount of nuclear additions which could be made. Even after this limitation, the system was still severely baseload deficient and the generation expansion program chose to fill the void with coal. This resulted in a 58% installed reserve margin, judged to be higher than what an electric utility could finance and higher than any public utility commission is likely to allow. Thus, the second institutional constraint applied was one which limited the percent reserve to a maximum of 25%. These limitations cause the value of solar-thermal plants to decrease more slowly in the early years than they otherwise would have.

2.2.8 Taking Capacity Credit May Be Harmful in the Long Run

In a system which is deficient in low-operating cost (baseload) units, only new baseload plants will be added for many years. In a baseload deficient system which is also trying to add solar, the only capacity displacement which can be taken during the years of only baseload addition is against that baseload capacity. The resultant deferral of baseload capacity causes a higher production cost to be incurred, an economic effect which outweighs the capital savings. The analysis determined that in the early years solar plants should be installed only for their fuel savings value, and capacity displacement should be deferred until the point when new intermediate and peaking capacity is again being added.

2.2.9 Optimizing the System around Solar Does Not Eliminate Penetration Effects

As has been shown in many previous static utility/solar analyses, the incremental value of a certain type of solar capacity decreases with penetration. For the types of solar plants considered, these penetration effects remain in a system which is dynamically optimized for various levels of solar penetration.

2.2.10 Dynamic Analysis is Essential to Fully Understand the Value Question in a Changing Environment

Much of the analysis for this study was performed using a dynamic utility expansion computer program in conjunction with detailed simulation of solar plant operation. Supplementary analysis was performed using a static analysis approach involving single-year simulation with extrapolation. The dynamic approach, though more costly, yields a better picture of the role of solar plants in a changing environment. Especially for a utility system with a poor initial generating mix that improves with time, such as the synthetic utility studied, the dynamic analysis produces a much better basis for the solar plant value determination. While the static analysis is valuable for economically determining the comparative merits of different solar plant concepts and locations, it is the more extensive dynamic analysis, or alternatively lifetime detailed simulation, that utilities will require before making any significant investment decision.

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SECTION 3.0

METHODOLOGY

3.1 GENERAL

The objective of this study was to determine the sources and extent of value to a representative utility for solar-thermal plants. This objective determines the basic requirement on a methodology for the analysis: that it permit accurate determination of the economic impact of integrating a solar-thermal plant into an electric utility system. Further, because the Repowering Strategy Analysis examines repowering as part of the longer term process of central receiver technology development, it is important to measure changes in value over time. Thus, the methodology chosen must be a combination of static and dynamic analyses. While the static analysis is used to obtain impact data for specific solar unit additions, the dynamic penetration analysis is the principal tool in this study. Only the dynamic analysis has the ability to analyze a specific penetration pattern of solar plants and to show how that pattern would change the utility's generation expansion plan and revenue requirements. Thus, dynamic analysis determines the impact of the scenario rather than the impact of a single plant. The general structure of the value analysis methodology is described in the next section.*

3.2 METHODOLOGY STRUCTURE

For purposes of discussion, the overall value analysis methodology divides conveniently into two parts: the dynamic analysis which determines generation mix over time, and the static analysis which determines the yearly impact of solar capacity on utility production costs. These parts are represented schematically in Figures 3-1 and 3-2, respectively.

3.2.1 Determination of the Generation Mix over Time

It is well understood that the benefit's stream created by a solar-thermal plant depends on the specifics of the utility system of which it is a part. The value analyses are performed around a "reference utility system," chosen to be representative of the sunshine-abundant, gas/oil-dependent Southwest, where most of the interest in repowering has been focused. The reference utility system used, and its accompanying weather conditions are discussed in detail in Section 5.0, and a perspective on the system is given in Subsection 6.4. It is sufficient for this discussion to note that the system is initially heavily dependent on premium fossil fuels for baseload as well as intermediate and peaking generation, and that it enjoys a high coincidence of solar energy availability and system load.

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*The methodology is explained in greater detail in Appendix A to this report, and in several other publications (see References 1 and 2).

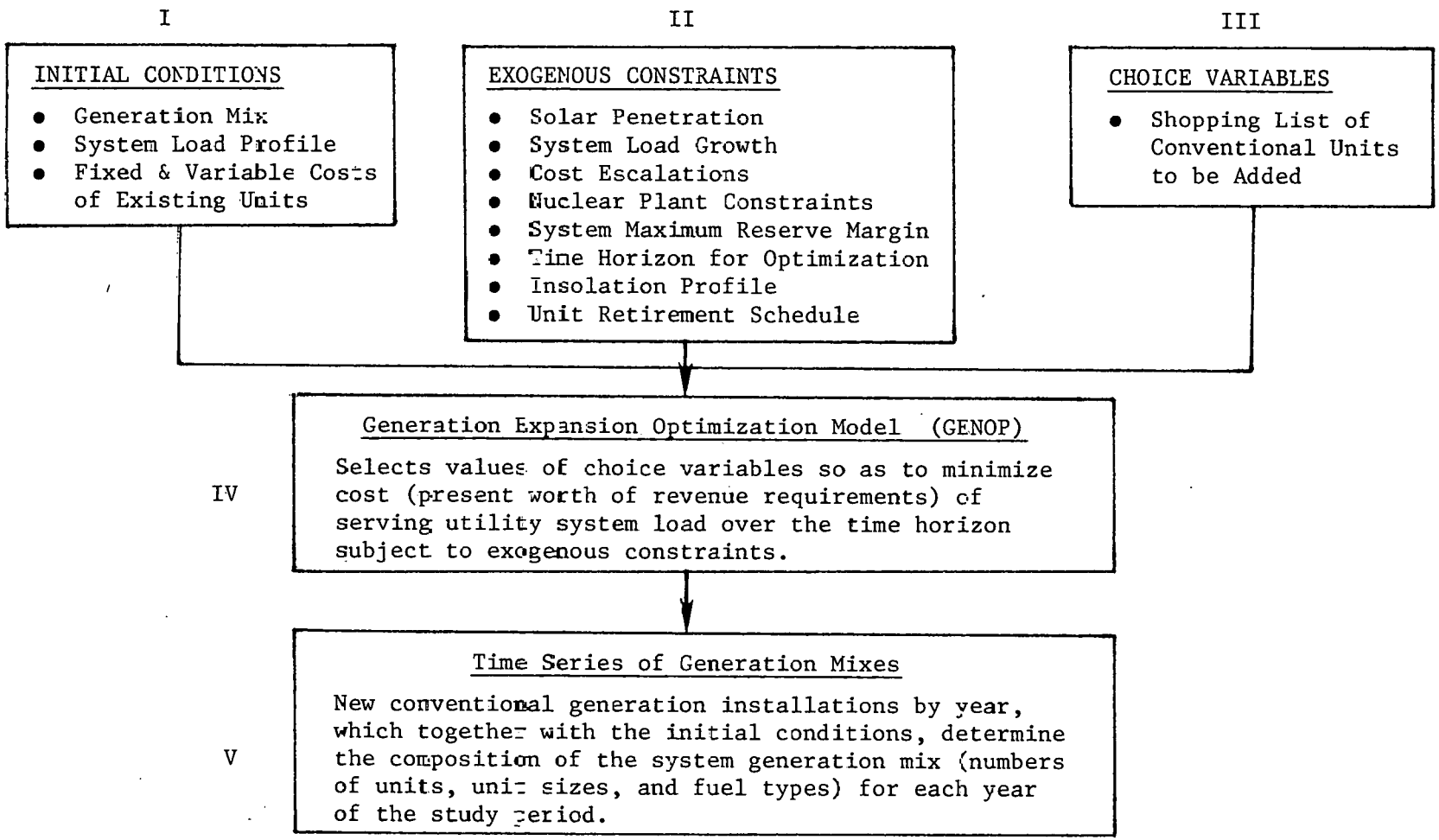

Figure 3-1. DETERMINATION OF GENERATION MIX OVER TIME (DYNAMIC ANALYSIS)

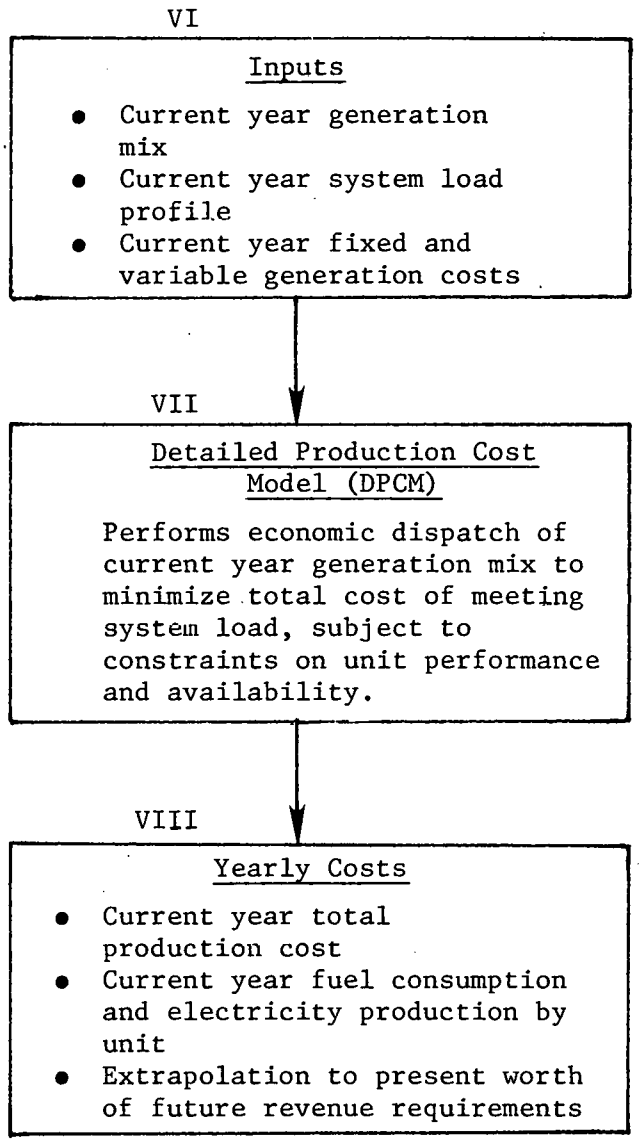

Figure 3-2. DETERMINATION OF CURRENT YEAR PRODUCTION COST AND PRESENT WORTH OF REVENUE REQUIREMENTS (STATIC ANALYSIS)

The reference utility system information enters the flow of analysis in Block I of Figure 3-1. (The insolation data, because it is not changed by the model, enters in Block II.) The initial system conditions are altered over time by the selection of types and installation dates of new generating units from the shopping list of expansion alternatives in Block III, and by the exogenous solar penetration and conventional unit retirement schedules, Block II. This selection is performed by the Westinghouse GENOP model, Block IV, so as to minimize the present worth of revenue requirements needed to meet the system load over the entire analysis period, subject to the exogenous constraints of Block II. Block V represents a housekeeping function, updating the initial generation mix to reflect exogenous solar penetration and retirements, as well as GENOP-selected new installations. The resultant time series of generation mixes forms the "moving background" for the static analyses of yearly production costs shown in Figure 3-2.

3.2.2 Determination of the Yearly Production Cost and Present Worth of Revenue Requirements

A solar-thermal plant derives its value from its ability to displace fuel and capacity that would otherwise be needed to serve the system load. The methodology used in this study to determine value of a given increment of solar capacity is based on this relation. The production cost of meeting system load is computed for two distinct GENOP-determined generation mixes, one including the solar increment, the other without that increment. Production cost for the first mix is then subtracted from that of the second mix, and the difference in cost is attributed to the performance of the solar increment. This cost differential is the basic source of solar plant value. Additionally, a comparison based on system reliability determines a capacity savings due to the solar increment. The capital charges thereby saved are a separate component of value.

Figure 3-2 shows this process in more detail. The inputs in Block VI come from a variety of sources. Current year generation mix comes from Block V; system load profile is escalated exogenously from the initial conditions; fixed and variable costs apply at the generating unit level, and reflect the original generating mix as modified by retirements, solar penetration, and selections made by GENOP.

The Detailed Production Cost Model (DPCM) of Block VII is the heart of the static analysis. It allocates system load (in two-hour intervals throughout the entire year) to individual conventional generating units based on lowest incremental cost. This minimizes the total variable cost of serving the load, and (since fixed costs are constant within a year) total production cost as well. This allocation, known as economic dispatch, is performed for both the solar-augmented and reference (expanded without solar) generation mixes. The difference in the resulting production cost values is extrapolated to produce a difference in 30-year revenue requirements, adjusted to reflect capital charge differences, and expressed in present value terms. This difference in present worth of revenue requirements (PWRR) is the basic value measure of the study.

SECTION 4.0

ECONOMIC AND PERFORMANCE ASSUMPTIONS

4.1 ECONOMIC ASSUMPTIONS

4.1.1 General

The methodology used for the economic impact analysis of the solar-thermal power plants was described in Section 3.0. The economic principles applied are based upon revenue requirements analysis requiring the application of escalation rates, present worth discounting, and capital carrying charge rates. In order to carry out this analysis it was necessary to make assumptions for solar and conventional plant capital cost, operation and maintenance cost, and fuel cost as well as the escalation of these costs for 30 years into the future. All costs are expressed in 1985 dollars, the base year of the study, excpet where noted otherwise.

The impacts of improved solar-thermal plants and improved hybrid (solar/fossil) repowered plants were analyzed under various forced solar penetrations. Estimates for commercialized Barstow technology are provided only for comparison purposes. The objective of this analysis was to study solar plant value; however, some assumptions as to cost were necessary to properly normalize the results. For example, a larger plant may have a greater value, but for proper perspective this needs to be normalized against the increase in cost.

Four different types of conventional plants were made available for new plant additions by the automatic generation expansion model. These were: (1) combustion turbine plants, (2) combined cycle plants, (3) coal-fired plants, and (4) nuclear plants.

The reference economic assumptions shown in Table 4-1 were developed by Westinghouse Electric Corporation in conjunction with a utility review panel for EPRI RP-648 entitled "Requirements Definition and Impact Analysis of Solar-Thermal Power Plants." It is realized that this set of assumptions along with individual economic parameters is open to dispute. For this reason, along with the general uncertainty of the future, some type of sensitivity analysis is appropriate and was performed with regard to selected economic parameters. The specific sensitivities will be pointed out in Section 8.0.

The discount rate used in this analysis (11%) is representative of that currently in use by electric utilities. It is the same rate used in EPRI RP-648 solar analysis under the guidance of a utility panel. It is recognized in some economic circles that a lower "after tax" rate is preferred. The fixed charge rate of 18%, which was used, reflects conservatism in that it is probably high for today's investment tax credit provisions. Lowering of discount and fixed charge rates would tend to favor all capital intensive technologies.

The reference economic assumptions shown are estimated to be somewhat consistent with a general inflation rate of approximately 8%. More details on these economic parameters follow.

4.1.2 Fuel Cost

The fuel costs shown in Table 4-1 reflect the delivered fuel costs represented in 1985 dollars. The escalation of these base year fuel costs over time is also shown. Unlike oil and coal, nuclear fuel was assumed to escalate at two different rates during the period of consideration, 9% to the year 2000 and 13% thereafter.

Gas was assumed not to be available for electric generation in the time frame of this study. The gas-burning fossil steam units shown in the original synthetic utility E generating mix were assumed to be converted to #2 oil-burning units, or thought of another way, gas, if available, would follow the same cost characteristics per MBtu as #2 oil.

Table 4-1. NEW CONVENTIONAL UNIT CHARACTERISTICS, REFERENCE ECONOMIC ASSUMPTIONS (1985$, PRESENT WORTH DISCOUNT RATE 11%)

Economic Parameter	Unit			
	100 MWe Combustion Turbine	250 MWe Combined Cycle	600 MWe Coal Plants	1000 MWe Nuclear Plants
Capital Cost ($/kWe)	300	600	1400	1500
Capital Escalation Rate (%/yr)[a]	10%	10%	10%	10%
Fixed Charge Rate (%)	20%	18%	18%	18%
Fixed O&M ($/kWyr)	1.0	2.5	15.0	10.0
Variable O&M (mills/kWh)	8.0	1.85	3.16	0.76
O&M Escalation Rate (%/yr)[a]	8%	8%	8%	8%
Fuel Cost ($/MBtu)	5.5[c]	5.5[c]	2.0	1.25
Fuel Escalation Rate (%/yr)[a]	12%	12%	10%	9/13%[b]
Average Heat Rate (Btu/kWh)	12,000	8,400	10,000	10,400
Scheduled Maintenance (weeks/yr)	2	4	5	7
Forced Outage Rate (%)	10%	10%	18%	15%
Plant Life (yrs)	20	30	30	30

[a]escalation rates include inflation

[b]9% to the year 2000; 13% thereafter.

[c]oil or surrogate premium fuel

4.1.3 Conventional Plant Cost

As mentioned earlier, some alterations to the original Synthetic Utility E existing generating units were made, particularly the conversion of gas fossil steam units to #2 oil. The cost characteristics of these existing units were made to be consistent with the reference economic assumptions. The unit characteristics, such as heat rate, scheduled maintenance, and forced outage rate, were based on data received from the EPRI Technical Assessment Guide [3] and the Synthetic Utility Guide [4]. These characteristics are summarized in Table 4-2. The characteristics of the new conventional generating units, available for addition to the utility system, were summarized in Table 4-1.

4.1.4 Solar Plant Cost

The benefit of a solar plant on a utility system can be determined independent of its cost. The procedure used for determining this benefit was briefly described in Section 3.0. However, in order to better determine the net impact of a solar plant some assumption of cost must be made.

The cost of the two types of solar plants used in this study, plus a Barstow type plant, are shown in Table 4-3. Although the Barstow technology hybrid repowered solar plant was not considered in the generation expansion analysis, it is included for comparison purposes. These costs are based on data developed by the various contractors under the Advanced Central Receiver Conceptual Design Program and additional input developed by SANDIA Livermore Laboratories [5,6,7,8].

Appendix D contains the numbers used in this analysis in the Cost Breakdown Structure (CBS) format. Excluding heliostats, the estimate for the stand-alone plant is within $\pm$ 7% of the SANDIA corrected costs for the range of design concepts. The improved repowering cost estimates were extrapolated from the stand-alone estimates, corrected and modified where necessary for a repowering application. The balance of plant retrofit costs were estimated at 10% of a new electric power generating system (EPGS). This retrofit cost estimate is about midway in the range of costs generated by Stearns-Roger under the systems integration work done as a part of the overall Repowering Strategy Analysis [9]. The receiver tower was assumed to be 5000 feet from the EPGS for repowered plants. The Barstow receiver unit was estimated from the McDonnell Douglas 20th 100 MW_e unit [10]. The installed cost of heliostats was assumed to be $\$75/m^2$ ($\$7/ft^2$). The O&M cost estimates were built up from assumptions of the required operating and maintenance personnel, and the maintenance materials were estimated at a percentage of the installed cost per year. The cost estimates are broken down in more detail in Appendix D. It is realized that any costs are open to dispute; thus, sensitivity analysis on this parameter was performed. The results of this analysis are shown in Section 8.0.

Table 4-2. EXISTING CONVENTIONAL UNIT CHARACTERISTICS

Unit Type	Number	1985 Costs			Escalation Rates		Heat Rate	Unavailability Data	
		Fuel Cost $/MBtu	Variable O+M Mills/kWh	Fixed O+M $/kW-yr	Fuel Esc. %/yr	O+M Esc. %/yr	Average Btu/kWh	Scheduled Maint. Wks/yr	Forced Outage %/yr
Nuclear									
800 MW	1	1.25	0.76	10.0	9/13[a]	8	10400	7	15.0
300 MW	1	1.25	0.76	10.0	9/13[a]	8	10400	7	15.0
Coal-Fired									
800 MW	1	2.0	3.16	15.0	10	8	10100	5	20.0
600 MW	2	2.0	3.16	15.0	10	8	10200	5	18.0
500 MW	1	2.0	3.16	15.0	10	8	10200	5	18.0
400 MW	1	2.0	3.16	15.0	10	8	9950	5	13.0
200 MW	1	2.0	3.16	15.0	10	8	10500	3.5	9.0
#6 Oil-Fired									
800 MW	1	5.0	0.91	2.5	12	8	9270	5	16.0
600 MW	2	5.0	0.91	2.5	12	8	9480	5	15.0
400 MW	1	5.0	0.91	2.5	12	8	9580	5	12.4
200 MW	1	5.0	0.91	2.5	12	8	10100	3.5	8.1
#2 Oil-Fired									
400 MW	2	5.5	0.91	2.5	12	8	9580	5	12.4
200 MW	11	5.5	0.91	2.5	12	8	10100	3.5	8.1
Combustion Turbine									
50 MW	10	5.5	8.0	1.0	12	8	14000	2	10.5

[a]9% to the year 2000; 13% thereafter

The life of the solar plants was assumed to be 30 years, resulting in an annual fixed charge rate of 18%, equivalent to that used for large conventional power plants. The 18% fixed charge rate is the same as that established by a review panel of electric utility planners in conjunction with EPRI Study RP 648, "Requirements Definition and Impact Analysis of Solar-Thermal Power Plants." It was established as a base for investor-owned plants with a 30-year life, consistent with a 11% weighted cost of capital. No special tax incentives were assumed. The capital and O&M escalation rates are consistent with the reference economic assumptions.

As can be seen from Table 4-3, the heliostat cost is a significant portion of the total solar plant cost. This cost is based on the size of the collector field used. The area of collectors shown in the table was selected from a preliminary collector field experiment described in detail in Section 4.2.6 of this report.

Table 4-3. SOLAR PLANT COST COMPARISON

[1978 M$, 100 MWe plant, costs adjusted to base collector fields]

Cost Component	Improved Stand-Alone 3 Hours Storage AC=650,000 m^2 [a]	Improved Hybrid Repowered AC=500,000 m^2	Barstow Hybrid Repowered AC=585,000 m^2
Land	3.0	1.9	2.2
Structures and Facilities	5.9	1.9	1.9
Heliostats	49.0	37.7	44.1
Receiver	13.9	18.1	17.2
Tower	2.2	1.7	1.6
Storage	7.6	2.0	0.0
Turbine Plant	19.0	1.9	1.9
Electric Plant Equipment	4.0	0.4	0.4
Miscellaneous	1.0	1.0	1.0
Total Direct	105.6	66.6	70.3
Contingency and Spares	13.0	8.2	8.7
Indirect Costs	18.2	11.6	12.1
Total Capital Investment	136.8	86.4	91.1
Interest During Construction (15%)	20.5	13.0	13.7
Total Capitalization (1978)	157.3	99.4	104.8
Total Capitalization (1985) (escalated at 7%)	252.6	159.6	168.2
Annual O&M (1985)	5.9	4.9	4.9

[a] AC=Area of collector. See subsection 4.2.6 on collector sizing.

4.1.5 Solar/Conventional Cost Comparison

One way of roughly estimating the competitive economics of generating plant alternatives is through the use of breakpoint or screening curves (see Figure 4-1). This type of plot shows the trade-off between capital and operating costs for a spectrum of plant utilization. The costs are annualized from the plant lifetime cost projections. The bounds of the envelope around the bottom area of the plot indicate those plants most economical for various utilizations. The intersection of plant lines indicate break-even conditions between plant alternatives.

Although this plot can provide a quick estimate of a plant's competitive potential, its limitations must be recognized. This method assumes identical plant utilization annually, throughout the plant's life. In actuality, a plant's utilization will change from year to year as the plant matures, as system generating mix changes, and as fuel costs change. No allowance is made for system reliability, size, or scheduled outage requirements. Also, no representation is made for existing system mix. However, this type of plot can provide a quick, easily interpretable perspective.

The conventional unit information given in Table 4-1 plus the solar plant cost assumptions given in Table 4-3 were used to generate the graph shown in Figure 4-1. Shown is the total 30-year levelized annual generating cost versus operating hours for each new conventional unit and solar-thermal plant, expressed in 1985 dollars. Also indicated, at the bottom, is the operating time, in hours, at which the most economical unit type changes; for example, the combustion turbine is the most economical unit if operated no more than 613 hours per year, at higher utilizations the combined cycle becomes more economical, and remains so until 1391 hours when the nuclear unit takes over. The zero hour intercept is the yearly levelized fixed charge for each plant type, which is composed of capital and fixed O&M charges. The slope of the curve is a function of the variable O&M charges and fuel expense. The solar stand-alone line is terminated at its expected capacity factor. Unlike the hybrid plant, there is no option for it to operate at higher capacity factors.

As can be seen from this graph, new solar stand-alone and hybrid plants will probably not be the most economic additions to the system mix. As will be shown in Section 7.0, this will indeed be true. However, it needs to be pointed out that this graph reflects only economic parameters. The effects of dispatch order, reliability, and existing utility system mix are not included. From this simple plot it was also predicted and later verified by the expansion optimization model that the generation expansion would be dominated by the addition of nuclear units. Special constraints were then placed on the expansion model to limit the amount of nuclear added to the system in the generation expansion to one 1000 MW plant every five years. The prohibited nuclear additions were replaced by new coal plants. Section 6.0 contains more information on this subject.

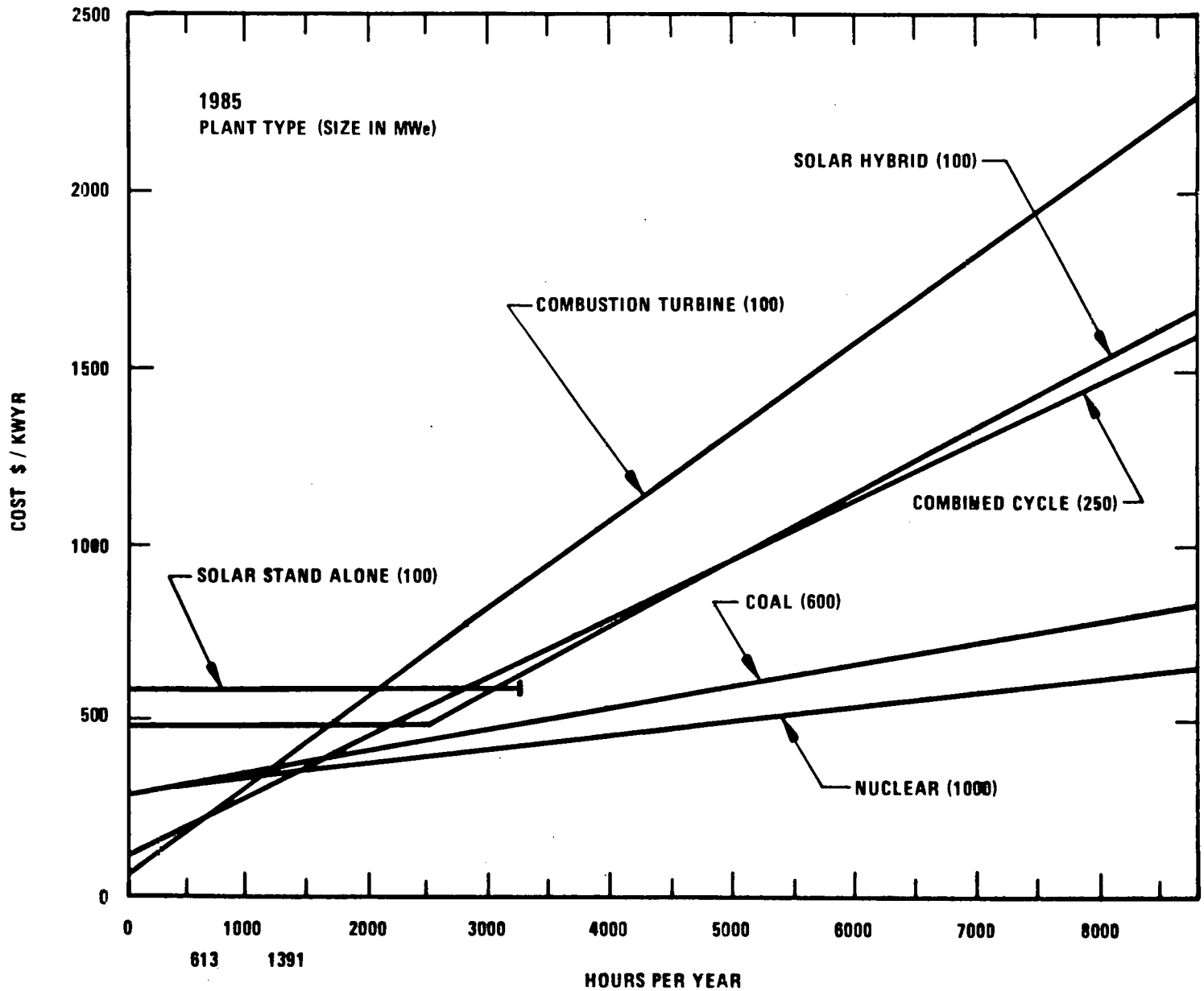

Figure 4-1. 30-YEAR LEVELIZED ANNUAL COST CURVE

4.2 SOLAR PLANT CHARACTERISTICS

4.2.1 General

There are two classes of solar-thermal electric power plants under investigation in this study; repowered plants which become hybrid plants capable of operating from solar energy and/or burning liquid or gaseous fossil fuel, and stand-alone plants which have a thermal storage system to supplement direct solar energy generation. The plants were assumed to employ the central receiver concept for the collection of solar energy.

The solar plants examined, both hybrid and stand-alone, were assumed to have better overall efficiencies (solar to electric) than the Barstow 10 MWe solar plant design. This improved efficiency would be due to many factors characteristic of second generation central receiver design. Higher temperatures, reheat cycles and high efficiency storage are the most significant features. In order to obtain these characteristics, the solar plants might utilize a working fluid other than water/steam, such as molten salt or liquid metal, in the receiver system. However, this study is based on improved performance characteristics and not on the actual method of achieving them. Significant improvements can be expected in advanced water/steam systems in the second generation design. These performance characteristics are, therefore, representative of the characteristics likely to be achieved in commercial installations of central receiver technology. More details on the performance of these improved technologies follow.

The hybrid technology was applied to existing oil-fired fossil steam units operating on the utility system. In other words, only hybrid repowered solar plants were analyzed; no new hybrid solar plants were examined.

In addition to these two improved technologies, the characteristics of the first generation hybrid repowered plant (Barstow technology) are included in this section. The Barstow hybrid repowered plant is included only for comparison purposes. It was not considered as a candidate solar plant technology in the dynamic or static plant analysis.

The solar plant characteristics shown in this section were developed from the Advanced Central Receiver Conceptual Design studies [5,6,7].

4.2.2 Stand-Alone Solar Plant

Table 4-4 summarizes the improved stand-alone solar plant performance data. The operation of this 100 MWe, three-hour storage plant was modeled on the modified synthetic utility system E using Midland, Texas insolation data (see Section 5.2).

The 650,000 m^2 collector area was determined from a collector field experiment (Section 4.2.6) and represents a 1.3 to 1.4 solar multiple based on 950 watts/m^2. The efficiency of the heliostat field, taking into account shading, blocking, and cosine losses, was determined from the latest field design having a ground coverage fraction of approximately 23%. The field efficiencies for the central receiver system configuration are given in Appendix D. The field design

Table 4-4. IMPROVED STAND-ALONE SOLAR PLANT PERFORMANCE DATA

General

- Size: 100 MWe
- Simulation Period: 1 Year
- Simulation Step Size: 1 Hour
- Insolation Site: Midland, Texas
- Load: Modified Synthetic Utility E

Collector

- Field Size: 650,000 m^2 Mirror Area
- Annual Field Efficiency (Shading/Blocking/Cosine Losses): See Appendix D
- Net Reflective Efficiency (Mirror/Attenuation): 86%
- Wind Limit Before Defocus: 11.62 m/sec (26 mph) Average for Hour

Turbine Generator

- Net Efficiency (Including Auxiliaries): Maximum 39.3% Direct Receiver; Maximum 40.6% from Storage
- Operation Limits: 100 MWe Maximum; 10 MWe Minimum
- Efficiency Correction: Wet Cooling Part Load Efficiency Correction

Receiver

- Efficiency: Radiation and Convection Loss: 18 MW th
- Minimum Insolation Requirement: 40.0 MW th

Storage

- Maximum Capacity: 3 Hours at 100 MWe Turbine Generator Output
- Minimum Drawdown: 13.05% of Maximum Storage kWh
- I/O Efficiency: 100%
- Heat Loss Rate: 0.1%/Hour

Miscellaneous

- Line Thermal Loss: 0.02 kW th/m^2 Loss per Unit Collector Area (13 MW th)
- Plant Forced Outage Due to Equipment Failure: 10%
- Plant Scheduled Outage: 3 Weeks per Year

losses were based on work performed by McDonnell Douglas Astronautics Company [11]. The heliostats were assumed to be stowed when the average hourly wind speed exceeds 11.62 m/sec or 26 mph.

The turbine generator operating limit assumptions were 100 MWe maximum and 10 MWe minimum. The part load turbine generator efficiency correction curve is given in Appendix D.

The solar stand-alone plant is capable of operating from storage at 100% turbine generator output (100 MWe) for three hours. Storage thermal losses of 0.1%/hour were assumed.

Figure 4-2 depicts the 100 MWe central receiver improved stand-alone average annual efficiency train. This efficiency train was generated from the actual yearly computer run. The resultant average annual plant efficiency is 19.3%. A system schematic of the storage coupled, improved stand-alone plant is shown in Figure 4-3.

4.2.3 Hybrid Repowered Solar Plant

The improved hybrid repowered performance characteristics are shown in Table 4-5. A 100 MWe plant (100% repowered) was also modeled on the modified synthetic utility system E utilizing the Midland, Texas insolation data.

The 500,000 m^2 collector field was also determined from the collector field experiment. This represents a solar multiple of 1.0 to 1.1 based on 950 watts/m^2. The heliostat field efficiency was treated the same as in the stand-alone case.

The turbine generator, with operating limits of 10 MWe minimum to 100 MWe maximum, has the same part load efficiency curve (shown in Appendix D) when operating from fossil fuel (in the direct mode). In addition to this, when operating in the fossil fuel mode a boiler efficiency correction curve (shown in Appendix D) is used.

The improved hybrid repowered solar plant has a series thermal buffer storage system capable of handling insolation transients of up to one-half hour in duration. This storage system acts to smooth these short duration thermal transients before they reach the turbine generator. However, if the average hourly direct normal insolation level is below that required to operate the plant at its minimum output, the plant will shut down. Because of this storage system, no burning of oil is required to buffer transients. The thermal buffer storage system characteristics of this plant limit the fossil fuel mode of operation to that of economic dispatch. Before the hybrid repowered solar plant can operate from the oil-fired boiler, oil is burned to meet the startup requirements of time and energy needed to bring the fossil boiler up to temperature and pressure.

The average annual efficiency train of the improved hybrid repowered solar plant is shown in Figure 4-4. The schematic is shown in Figure 4-5.

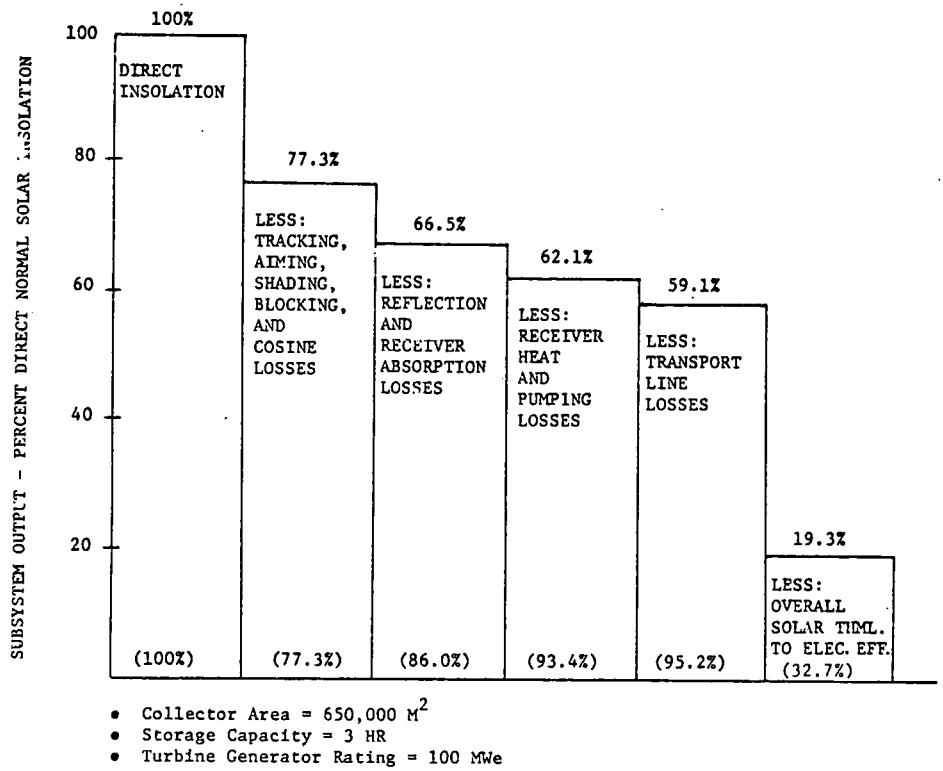

Figure 4-2. IMPROVED STAND-ALONE ANNUAL AVERAGE EFFICIENCY TRAIN

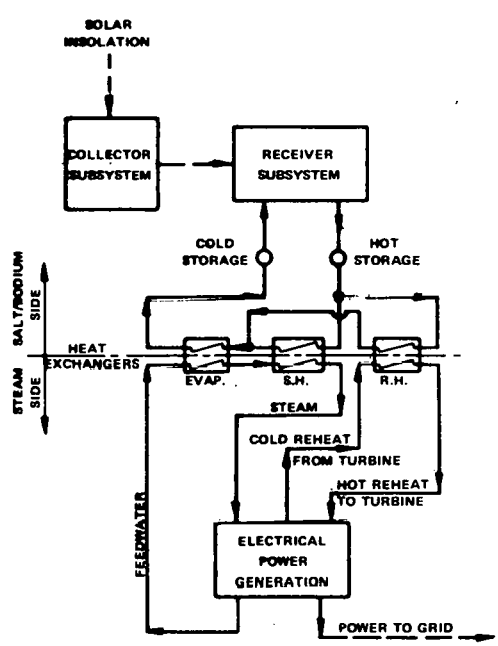

Figure 4-3. IMPROVED STAND-ALONE PLANT SCHEMATIC

Table 4-5. IMPROVED HYBRID REPOWERED SOLAR PLANT PERFORMANCE DATA

General

- Size: 100 MWe (100% Repowered)
- Alternate Fuel: #2 Oil
- Simulation Period: 1 Year
- Simulation Stepsize: 1 Hour
- Insolation Site: Midland, Texas
- Load: Modified Synthetic Utility E

Collector

- Field Size: 500,000 m^2 Mirror Area
- Annual Field Efficiency (Shading/Blocking/Cosine Losses): See Appendix D
- Net Reflective Efficiency (Mirror/Attenuation): 86%
- Wind Limit Before Defocus: 11.62 m/sec (26 mph) Average for Hour

Turbine Generator

- Net Efficiency (Including Auxiliaries): Maximum 40% Direct Receiver; Maximum 35.6% from Oil Boiler
- Operation Limits: 100 MWe Maximum; 10 MWe Minimum
- Efficiency Correction: (1) Wet Cooling Part Load Efficiency Correction
  (2) Boiler Efficiency Correction

Receiver

- Efficiency: Radiation and Convection Loss: 13.8 MW th
- Minimum Insolation Requirement: 31.0 MW th

Storage

- Fuel Oil: #2 Oil
- Series Thermal Buffer: 1/2 Hour at Half Capacity, No Use of Oil for Insolation Transients

Miscellaneous

- Line Thermal Loss: 0.02 kW th/m^2 Loss per Unit Collector Area (10 MW th)
- Fossil Boiler Startup Requirements: 8 Hours Totaling 433 MW th
- Plant Forced Outage Due to Equipment Failure: 10%
- Plant Scheduled Outage: 3 Weeks per Year

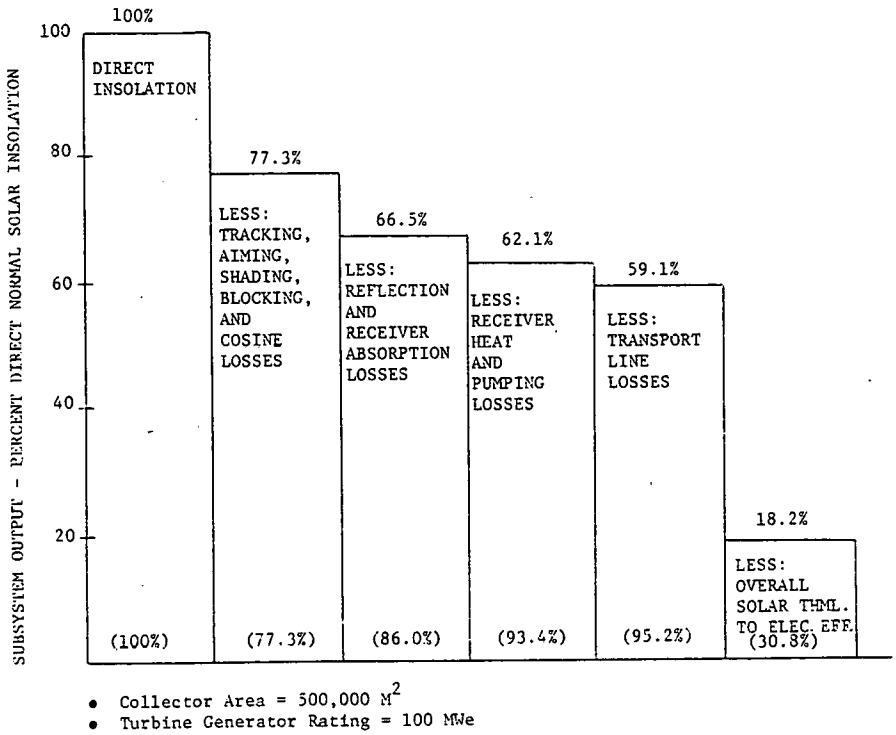

Figure 4-4. IMPROVED HYBRID REPOWERED ANNUAL AVERAGE EFFICIENT TRAIN

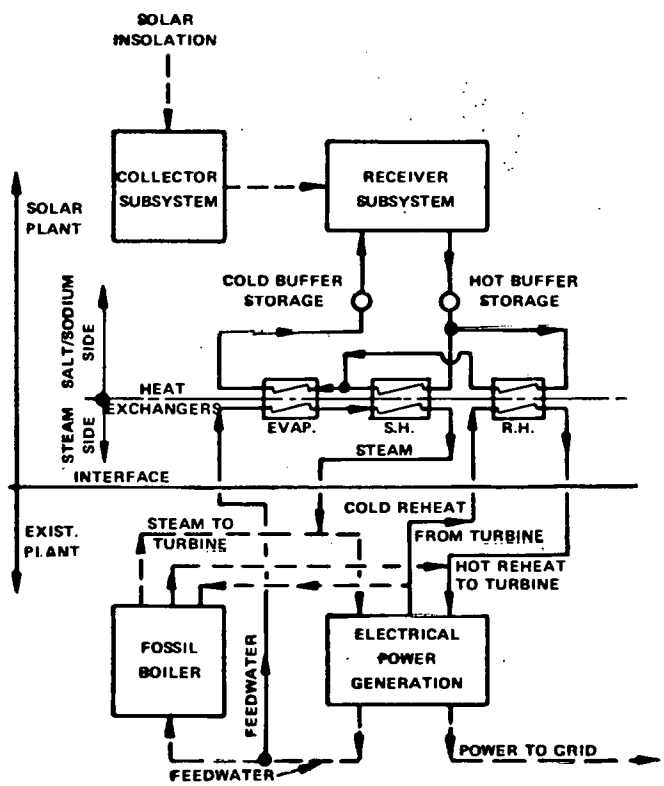

Figure 4-5. IMPROVED HYBRID REPOWERED SYSTEM SCHEMATIC

4.2.4 Barstow Technology

For comparative purposes the characteristics of the Barstow water/steam technology are given. No further analysis of this option was performed.

The characteristics of a first generation hybrid repowered solar plant (Barstow technology) are shown in Table 4-6. Two important assumption differences are the lower turbine generator efficiencies due to lower temperatures and non-reheat turbines and the handling of insolation transients. If the percentage of sky cover is greater than 50%, then oil is used to buffer these transients. There is no series thermal buffer storage system. The average annual efficiency train for the Barstow technology hybrid repowered plant is shown in Figure 4-6. The system schematic is shown in Figure 4-7.

Table 4-7 summarizes the efficiency trains of all three solar technologies. These efficiency trains were generated from the hourly simulation. The improved technologies, both stand-alone and hybrid repowered, have better overall solar to electric efficiencies than the Barstow technology, which is shown for comparison purposes only.

4.2.5 Plant Availability

The solar plant mechanical availability affects the plant value in terms of capacity displacement and operating credit. The two technologies investigated are assumed to have the same availability characteristics. The solar-thermal scheduled maintenance was assumed to be three contiguous weeks per year and was scheduled during the winter months. The plants were scheduled out during periods of low insolation and high system reliability in order to maximize the solar plant value.

The forced outage rate due to plant equipment failures was assumed to be 10% per year. The forced outage days were determined from a pseudorandom outage process which spread the outages throughout the year.

4.2.6 Collector Field Experiment

As mentioned previously, the capital cost of a solar plant is heavily dependent upon the size of the collector or heliostat field. The heliostat field size is controlled by the plant rating, overall efficiency, hours of storage, and insolation characteristics. In addition, the optimum field size (lowest cost/benefit for the utility) is also dependent on the characteristics of the utility system itself.

In order to optimize the collector field size, a collector field experiment was run which consisted of modeling the solar plant operation for various collector field areas, keeping all other characteristics except cost the same. The area of collector that resulted in the lowest cost/benefit was then used as the collector area for that plant configuration. Figure 4-8 graphs the results. The collector areas suggested by the results of this experiment are summarized in Table 4-8. Since the Barstow technology is presented for comparative purposes only, the field size was obtained by scaling from the improved hybrid repowered field size using the receiver and turbine generator efficiencies.

Table 4-6. BARSTOW TECHNOLOGY HYBRID REPOWERED SOLAR PLANT PERFORMANCE DATA

General

- Size: 125 MWe (80% Repowered = 100 MWe Solar)
- Alternate Fuel: #2 Oil
- Simulation Period: 1 Hour
- Simulation Stepsize: 1 Hour
- Insolation Site: Midland, Texas
- Load: Modified Synthetic Utility E

Collector

- Field Size: 585,000 m^2 Mirror Area
- Annual Field Efficiency (Shading/Blocking/Cosine Losses): See Appendix D
- Net Reflective Efficiency (Mirror/Attenuation): 86%
- Wind Limit Before Defocus: 11.62 m/sec (26 mph) Average for Hour

Turbine Generator

- Net Efficiency (Including Auxiliaries): Maximum 35% Direct Receiver; Maximum 31% from Boiler
- Operation Limits: 125 MWe Maximum; 25 MWe Minimum
- Efficiency Correction: (1) Wet Cooling Part Load Efficiency Correction
  (2) Boiler Efficiency Correction

Receiver

- Efficiency: Radiation and Convection Loss: 16.2 MW th
- Minimum Insolation Requirement: 118 MW th

Storage

- Fuel Oil: #2 Oil
- Series Thermal Buffer: No
- Sky Cover Transient Operating Mode: Above 5 Tenths Cloud Cover

Miscellaneous

- Line Thermal Loss: 0.02 kW th/m^2 Loss per Unit Collector Area (12 MW th)
- Fossil Boiler Startup: 8 Hours Totaling 433 MW th
- Plant Forced Outage Due to Equipment Failure: 10%
- Plant Scheduled Outage: 3 Weeks per Year

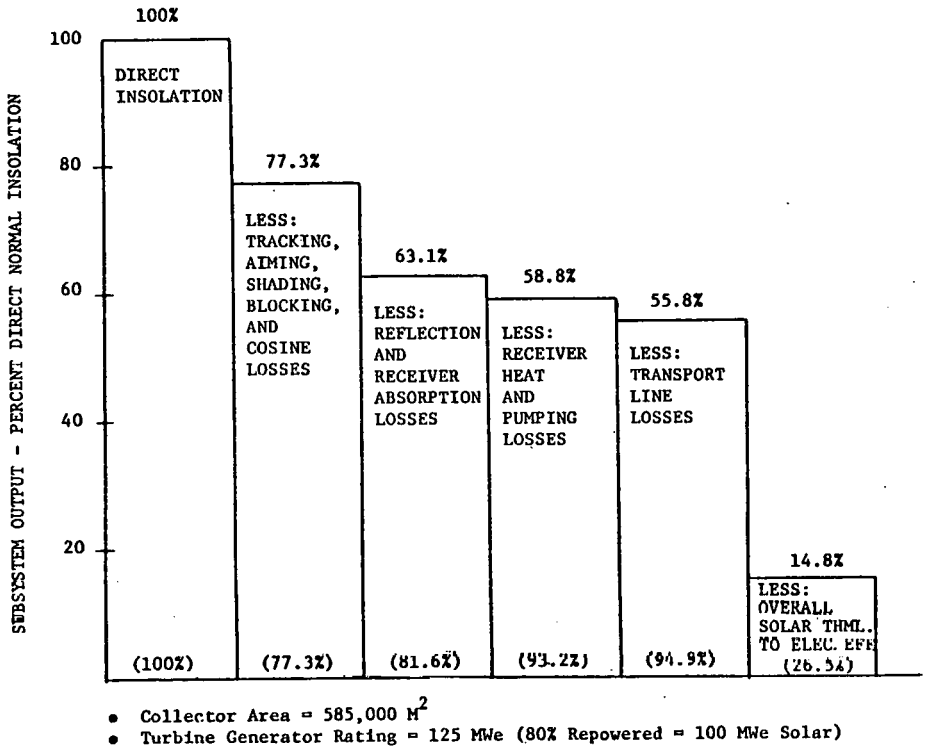

Figure 4-6. BARSTOW TECHNOLOGY HYBRID REPOWERED ANNUAL AVERAGE EFFICIENCY TRAIN

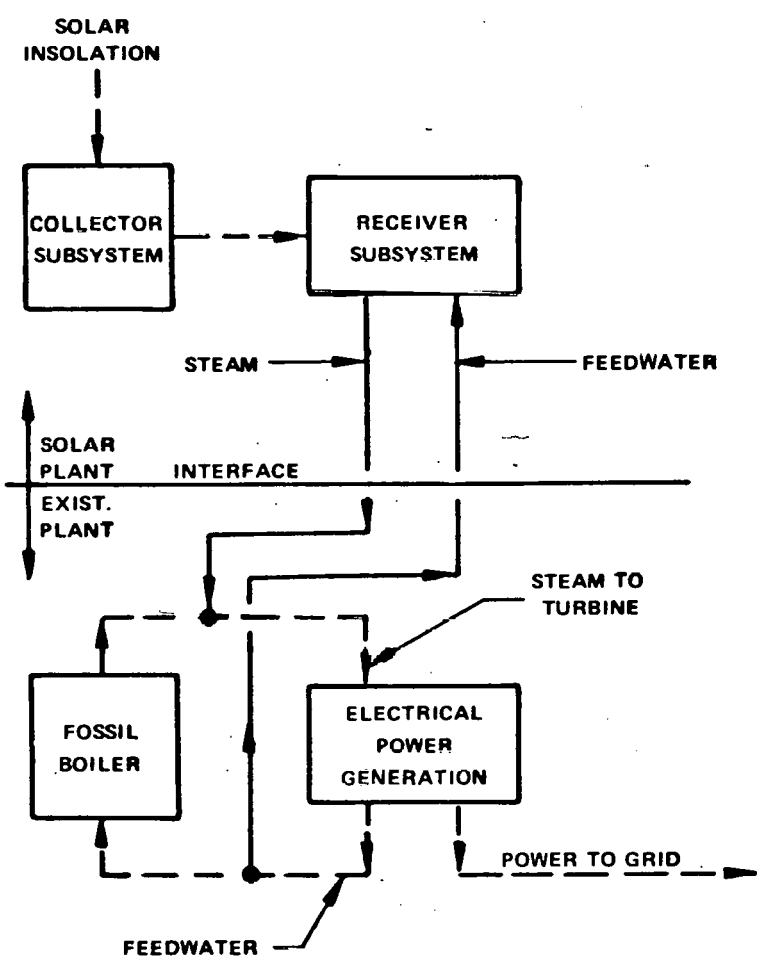

Figure 4-7. BARSTOW TECHNOLOGY HYBRID REPOWERED SCHEMATIC

Table 4-7. AVERAGE ANNUAL EFFICIENCY TRAIN COMPARISON
100 MWe SOLAR PLANT

	Improved Stand Alone	Improved Hybrid Repowered	Barstow Hybrid Repowered
Total Gatherable Insolation	100%	100%	100%
Less Tracking, Aiming, Shading, Blocking, and Cosine Losses	77.3%	77.3%	77.3%
Less Reflection and Receiver Absorption Losses	66.5%	66.5%	63.1%
Less Receiver Heat and Pumping Losses	62.1%	62.1%	58.8%
Less Transport Line Losses	59.1%	59.1%	55.8%
Overall Solar to Electric Efficiency After Outages	19.3%	18.2%	14.8%

Table 4-8. SUGGESTED SOLAR PLANT
COLLECTOR AREAS

Plant	Collector Area
Improved Stand-Alone	650,000 m^2
Improved Hybrid Repowered	500,000 m^2
Barstow Hybrid Repowered	585,000 m^2

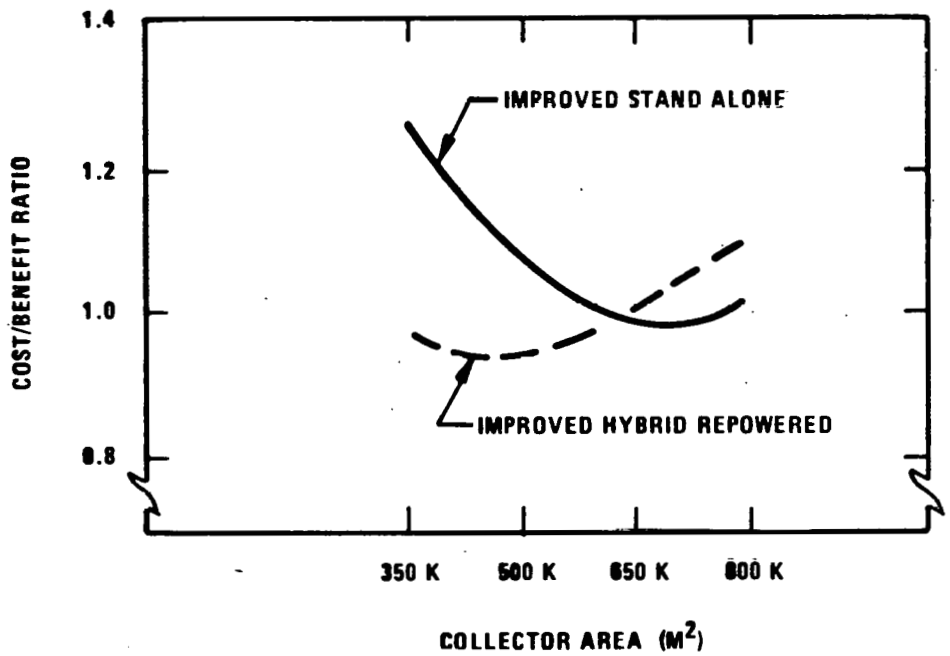

Figure 4-8. SOLAR POWER PLANT COLLECTOR FIELD EXPERIMENT
Modified Utility E, Midland, TX
1985 Installation, 100 MWe Plant

SECTION 5.0

UTILITY AND INSOLATION CHARACTERISTICS

5.1 UTILITY SYSTEM ASSUMPTIONS

5.1.1 General

To establish the value of solar plants, it is imperative that the utility system on which these plants are to be placed be specified. The modeling in some detail of the utility system is essential to the methodology described in Section 3.0 and Appendix A, and summarized in Figures 3-1 and 3-2. Details of the system generating mix, conventional unit characteristics, demand profiles and other load characteristics, and insolation must be specified in addition to the economic and solar plant performance assumptions discussed in Section 4.0.

The electric utility system used for the study is a modified version of EPRI synthetic utility E [4]. Utility E represents the south central region of the United States roughly depicted in Figure 5-1. To more closely resemble a typical Southwest-based utility, the scaled-down version of the regional utility E system given in the synthetic guide (nominal 10,000 MW) was used, with minor changes in the generation mix. The modified version of utility E is described in this section.

A utility based on information obtained from the EPRI Synthetic Utility Manual was chosen for several reasons. The synthetic utility E closely approximates the size and load characteristics of many Southwest utilities. The synthetic system was modified slightly to be more representative of western Texas, even though the Texas region as a whole has been previously identified as containing the largest number of candidate units for repowering [2,3]. This was done for two reasons. First, eastern Texas has large fields of lignite coal that are currently being developed to meet the baseload deficiencies. These lignite developments will make the competition by solar thermal difficult in the timeframe of interest. Second, eastern Texas has dramatically poorer insolation than western Texas. The combination of these effects has driven the selection of the utility and insolation characteristics which are representative of the Southwest region to be a modified synthetic system E located at Midland, Texas.

5.1.2 Load Characteristics

All load data (monthly peaks, weekly load shapes, etc.) were obtained through the synthetic utility guide. A base system capacity of 10,300 MW for the scaled-down utility system E is used for 1985 with peak demand of 8078 MW. The peak demand is assumed to escalate at a rate of 5% for each year of the study. The 5% escalation rate was arrived at by taking an average of the 20-year load growth projections of the Electric Reliability Council of Texas (ERCOT) power pool (see Figure 5-2) [13,14 .

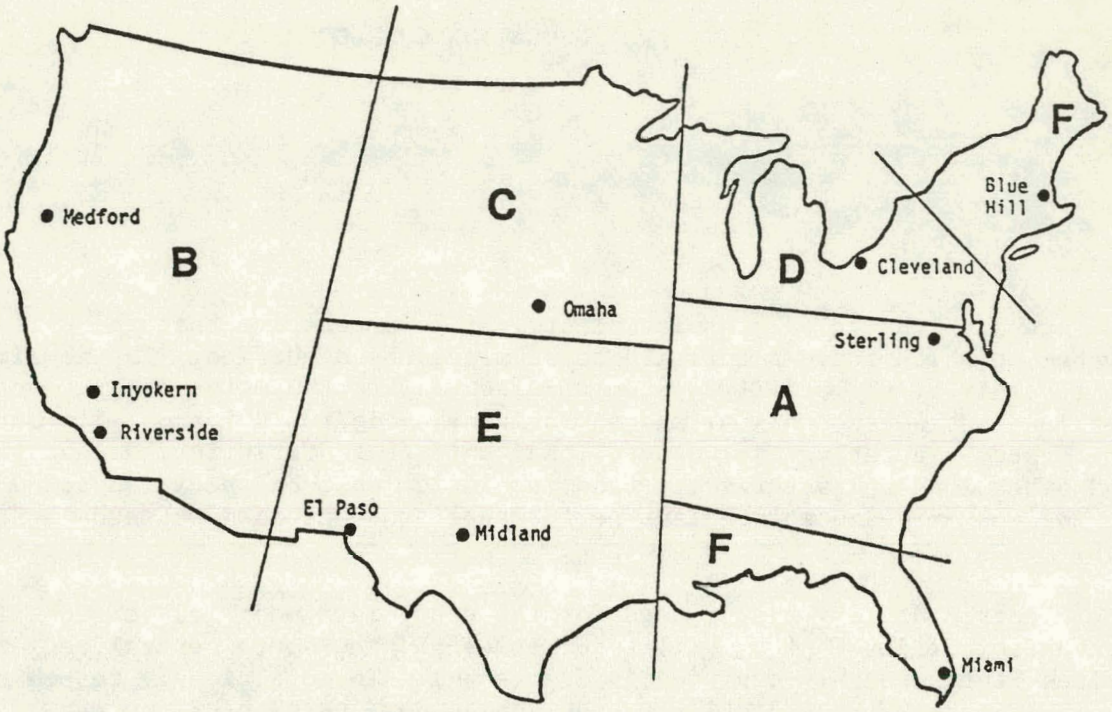

Figure 5-1. REGIONAL SYNTHETIC UTILITY MODELS

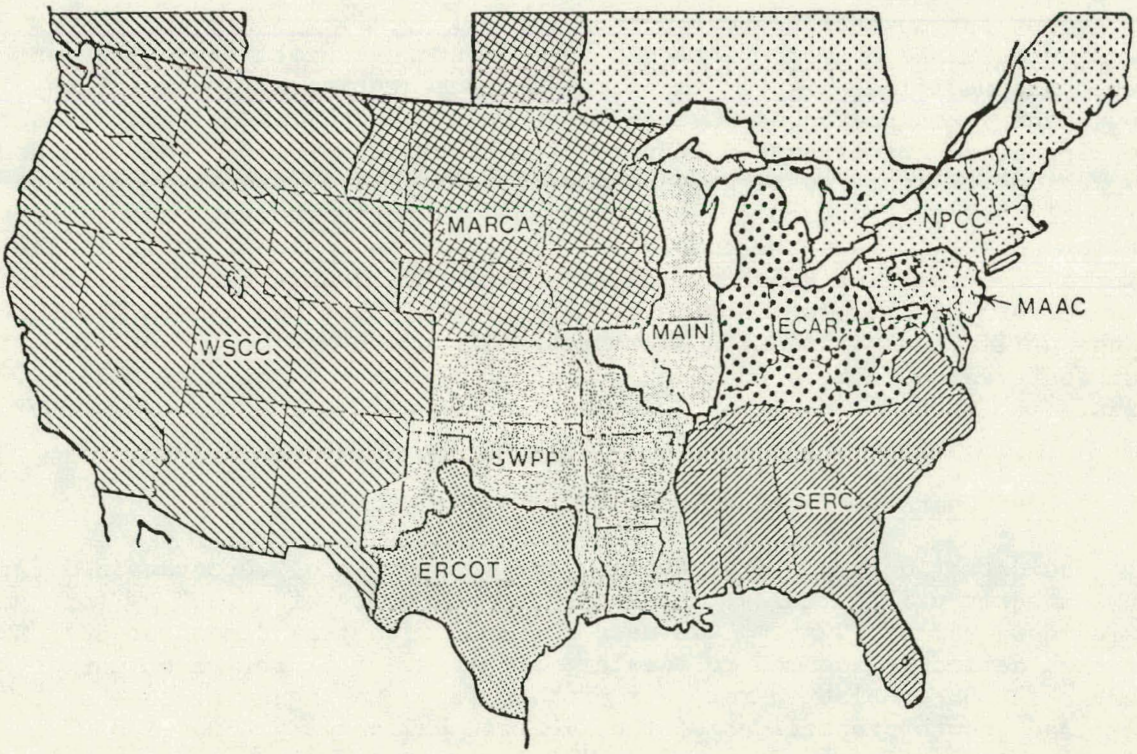

Figure 5-2. REGIONAL ELECTRIC RELIABILITY COUNCIL AREAS

Typical daily load curves for each season are illustrated in Figure 5-3. The loads for sample weeks given in the EPRI synthetic utility description [4] were expanded by Westinghouse into a full year of hourly loads. These were then scaled annually by the assumed 5% annual growth rate. One should note that utility E is a summer peaking system with the smallest demand occurring in the winter months. ERCOT has similar load characteristics.

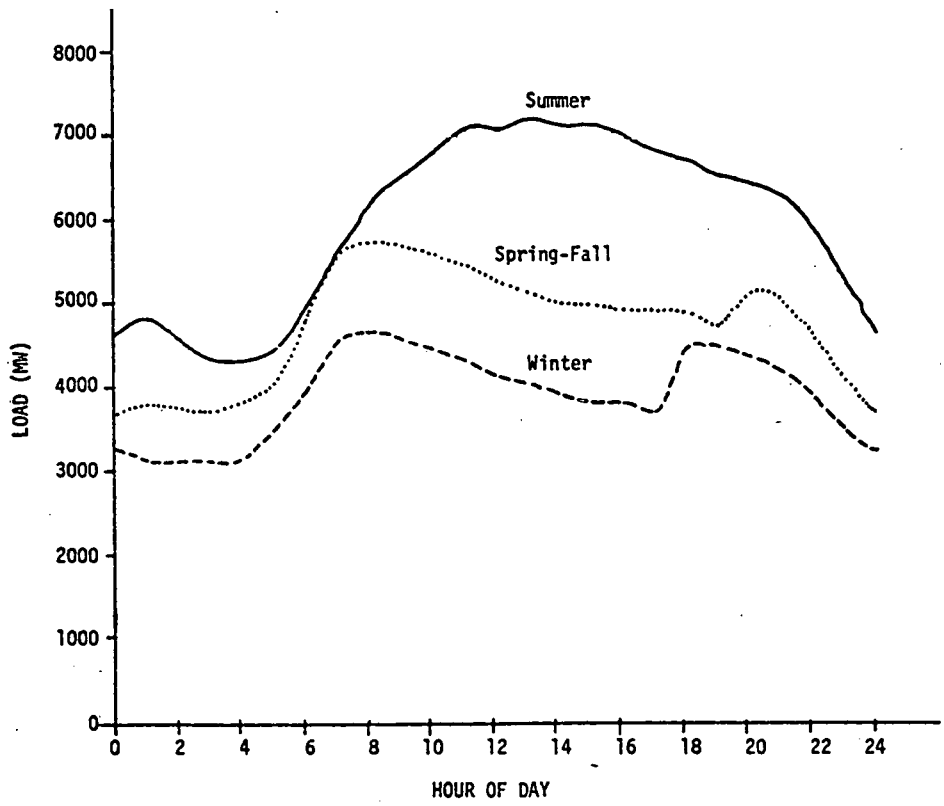

Figure 5-3. TYPICAL DAILY LOAD CURVES
Utility E, 1985, Summer/
Winter/Spring-Fall,
Wednesday

5.1.3 Generating Capacity Mix

The value analysis depends upon a stated existing (at the beginning of the study period, 1985) generating mix. From that time forward the solar plants are forced onto the system, according to prescribed scenarios, and the conventional units are automatically added by the generation expansion program to form the most economic expansion pattern. As will be seen, the early value solar plants are quite dependent upon the existing system generating mix.

Utility E is consistent with the Texas-based power pools. Table 5-1 shows the original and adjusted utility E generation mix as well as the mix estimated for ERCOT. Utility E is predominantly a gas generation system with some coal

and nuclear capacity. To more closely approximate recent projections for Texas utilities, 5% of the 1985 nuclear capacity was shifted to coal. It was also assumed that by 1985 and throughout the 25-year penetration period, that all existing combustion turbines and gas-burning plants would be converted to burn an oil distillate or an alternate premium fuel which would assume the oil price profile.

Table 5-1. 1985 GENERATING MIX COMPARISON

	EPRI Synthetic Utility E Original Mix	EPRI Synthetic Utility E Adjusted Mix	ERCOT
Gas	49%	0%	0%
Oil	6%	55%	55%
Nuclear	16%	11%	10%
Coal	25%	30%	30%
CT, CC	5%	5%	4%
Hydro	0%	0%	1%

5.1.4 Retirements

Existing unit retirement data is based on information obtained from the synthetic utility guide. Of particular interest is the amount of #2 oil-fired units which are retiring throughout the study period. These units are likely candidates to be repowered as solar hybrid plants. Because the unit sizes represent classes of individual units, portions of these units were repowered to meet the penetration levels for each scenario.

For the higher penetration scenarios in the later years of the study, it was necessary to repower a certain amount of #6 oil-fired units in addition to some of the larger unit classes. The repowering of plants burning #6 oil in later years was necessitated by the prior retirement or repowering of all #2 oil steam plants. Existing units' scheduled retirement dates are given in Table 5-2.

5.2 INSOLATION ASSUMPTIONS

5.2.1 General

Midland, Texas was chosen as the insolation site for the study for two reasons. First, it is within the area represented by the synthetic system E so that the insolation characteristics and the load profiles should both be representative of the region. Secondly, as shown in Figure 5-4, Midland is neither the best, nor the worst insolation site in the region. This is important to the assumption that the study be representative of the Southwest. The effect of varying insolation levels is shown in Section 8.7.

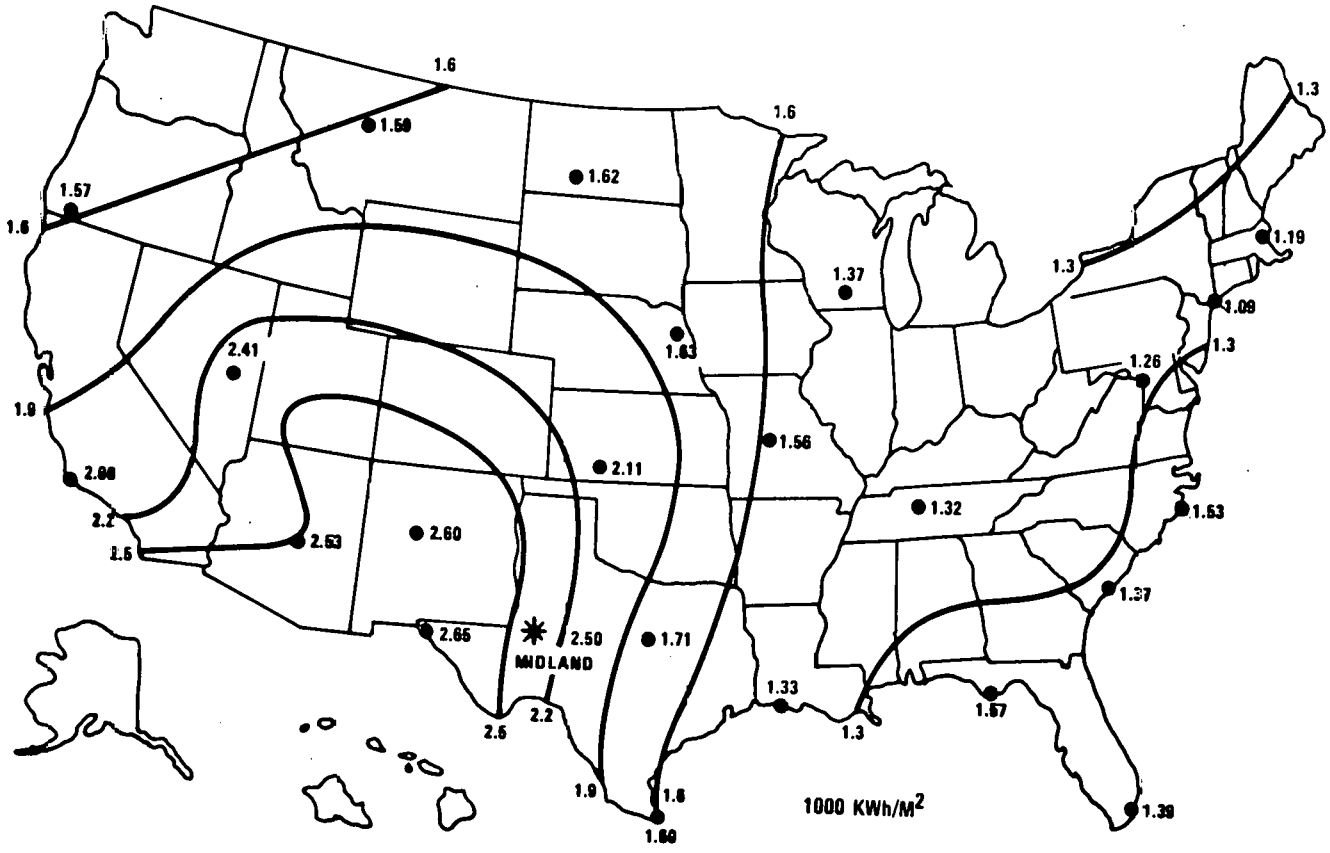

Figure 5-4. AVERAGE ANNUAL DIRECT NORMAL INSOLATION. (Rough sketches from seasonal charts and revised SOLMET data in SAND 77-0885, "Availability of Direct, Total & Diffuse Solar Radiation for Fixed and Tracking Collectors in the U.S.A.," Rev. 1/30/78.)

Table 5-2. EXISTING UNITS' SCHEDULED RETIREMENT DATES

Year	MW Total	Cumulative MW Total	Description
1996	200	200	200 MW #2 Oil
1997	100	300	2 (50 MW CT)
1998	400	700	2 (200 MW #2 Oil)
1999	300	1000	2 (50 MW CT) 200 MW #2 Oil
2000	400	1400	2 (200 MW #2 Oil)
2001	400	1800	2 (200 MW #2 Oil)
2002	300	2100	2 (50 MW CT) 200 MW #2 Oil
2003	200	2300	200 MW #2 Oil
2004	700	3000	2 (50 MW CT) 200 MW #2 Oil 400 MW #2 Oil
2005	200	3200	200 MW Coal
2006	300	3500	2 (50 MW CT) 200 MW #6 Oil
2008	400	3900	400 MW #2 Oil
2009	600	4500	600 MW #6 Oil

5.2.2 Source

The insolation data used in modeling the operation of the solar plants was supplied to Westinghouse Electric Corporation, Advanced Systems Technology Division, by SERI in the required Aerospace format. The data tape supplied reflects a typical meteorological year for the Midland, Texas area and is based on information received from the National Climatic Center (NCC) and SOLMET weather data. A typical meteorological year is a hypothetical one constructed by NCC using weather data from specific months in various years to construct a representative year.

Since only mean daily global insolation data per month was available for Midland, Texas (NCC publication entitled "Input Data for Solar Systems," November 1978), a typical El Paso, Texas meteorological insolation year, obtained from SOLMET, was used to generate the needed Midland weather data. The SOLMET data reflects information received from a number of insolation years. The procedure used for generating this weather data is described in Appendix A (A.4.3).

5.2.3 Annual Quality/Statistics

The daily average direct normal insolation for each month, taken from the SERI Midland insolation tape, is shown in Figure 5-5. For the purpose of comparison, these monthly insolation figures are plotted along with the previously used 1962 Aerospace insolation data and the El Paso data from which they were derived. Also noted in this figure is the yearly average direct normal insolation determined from the three insolation tapes.

On a yearly average, the SERI revised insolation tape has 4.5% lower daily direct normal insolation than the Aerospace data tape.

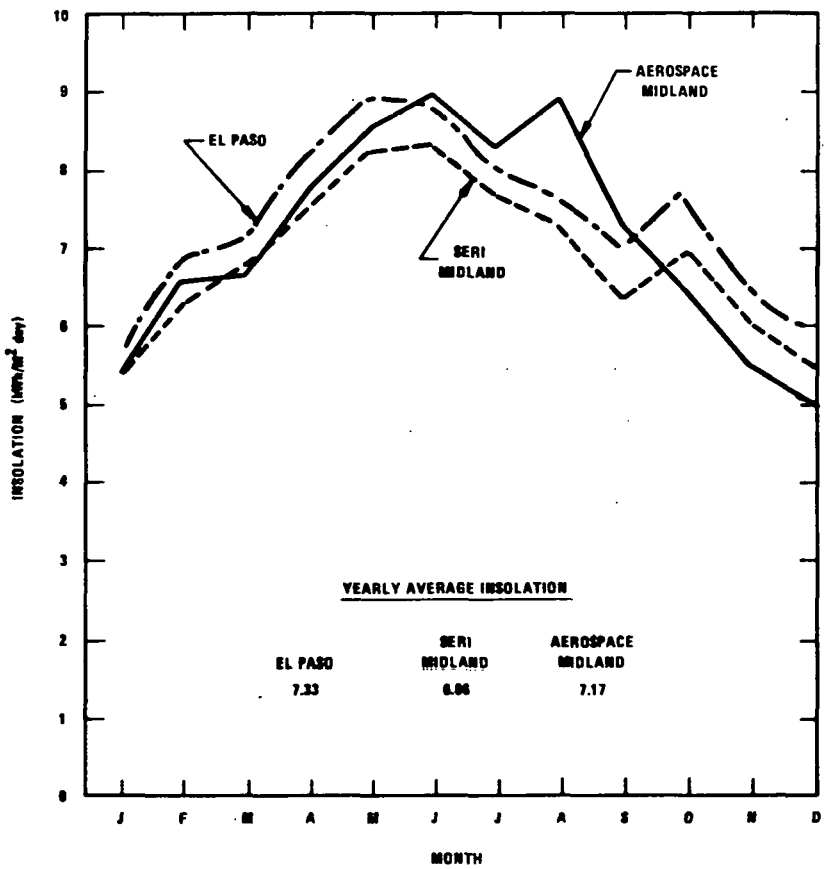

Figure 5-5. AVERAGE DAILY DIRECT NORMAL INSOLATION COMPARISON (kWh/m^2-day)

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SECTION 6.0

REFERENCE CASE SYSTEM EXPANSION

6.1 GENERAL

In order to accurately determine the economic impact of solar-thermal plant penetration on a utility system, some type of dynamic or multiple year analysis is needed. This analysis, which is described in Section 3.0, see Figure 3-1, and in detail in Appendix A, basically consists of utilizing the Westinghouse Generation Expansion Optimization Program (GENOP) to optimally expand the modified synthetic utility system E twenty-five years into the future (1985 being the base year). Two expansions are needed for economic value comparisons, one before and one after solar plant penetration. In each case the GENOP program selects the optimal installation pattern for conventional units. The solar penetrations are forced per prescribed scenarios. The before, or nonsolar, reference expansion is described in this section. The system is expanded assuming a load growth rate of 5% per year with a required minimum annual capacity reserve of 20%. The results from a generation expansion run include a conventional unit addition and revenue requirement summary of the twenty-five year expansion plan, a detailed year-by-year unit installation and cost summary, and other information concerning capacity mix, percent annual capacity reserve, and yearly peak load and energy.

6.2 OVEREXPANSION AND NUCLEAR LIMITATIONS

In Section 4.1.5 of this report it was pointed out that initially the dominant addition was likely to be nuclear units in the expansion plan because of their economic preferability at high capacity factors. Table 6-1 shows the first attempt at expanding this system for twenty-five years. As can be seen, the economic optimum is to immediately install 4267 MW of nuclear capacity on the system in the first year. This represents 53% of the system capacity in the first year and creates a reserve margin of 80%. The impetus behind the program to overbuild was to relieve the utility from its large dependence upon oil. As will be shown later, this was the most economic option even though other constraints might make it impractical. The overbuild option can be properly identified only through use of multiyear optimization program. It was recognized that no utility will be able to afford to, nor be allowed to, make this type of a commitment. Therefore, certain constraints were applied. A look at the generation expansion plans for ERCOT indicated that for a utility of the size of synthetic system E, one 1000 MWe nuclear unit was to be added about every five years. Therefore, the nuclear additions were limited to this amount.

Table 6-1 shows an expansion plan consisting of only baseload (nuclear) additions until the year 1999, at which time peaking plant (combustion turbine) additions begin. In the latter years intermediate plants (combined cycle) are also added. The intense program of baseload additions is an effort to relieve the system of the high-priced oil consumption. With the economics used, nuclear plants were slightly more economic for baseload applications than coal, thereby excluding coal addition. The retirement schedules for existing plants are partially responsible for some of the lumpiness of the unit addition pattern.

Table 6-1. UNCONSTRAINED SYSTEM EXPANSION INSTALLATION SCHEDULE

Nuc=Nuclear, CC=Combined Cycle, CT=Combustion Turbine

Year		Unit Type			
		CT 100 MW	CC 250 MW	Coal 600 MW	Nuc 1000 MW
1	1985	0.000	0.000	0.000	4.267
2	1986	0.000	0.000	0.000	.265
3	1987	0.000	0.000	0.000	.000
4	1988	0.000	0.000	0.000	.301
5	1989	0.000	0.000	0.000	.455
6	1990	0.000	0.000	0.000	.477
7	1991	0.000	0.000	0.000	.501
8	1992	0.000	0.000	0.000	.527
9	1993	0.000	0.000	0.000	.552
10	1994	0.000	0.000	0.000	.000
11	1995	0.000	0.000	0.000	.055
12	1996	0.000	0.000	0.000	.592
13	1997	0.000	0.000	0.000	.969
14	1998	0.000	0.000	0.000	1.550
15	1999	11.157	0.000	0.000	.165
16	2000	11.964	0.000	0.000	.289
17	2001	10.585	0.000	0.000	.538
18	2002	7.609	0.000	0.000	.821
19	2003	6.615	0.000	0.000	.852
20	2004	13.522	0.000	0.000	.964
21	2005	11.351	1.669	0.000	.018
22	2006	10.097	3.409	0.000	.000
23	2007	4.148	3.996	0.000	.000
24	2008	6.483	2.940	0.000	.922
25	2009	7.696	3.909	0.000	.965
Cumulative Totals		101.227	15.924	0.000	16.044

The results of the optimum expansion analysis indicated an economic preferability to overbuild; i.e., add more units than is necessary to meet the minimum annual capacity reserve requirement. This overbuild occurs for a couple of reasons: (1) most importantly, the system is initially severely baseload deficient and the tendency is to add base units as soon as possible to reduce oil usage; and (2) to meet the load with a minimal amount of emergency power being purchased. As a result, the percent reserve is very high in the first few years, then gradually decreases and levels off to a point which is still greater than the required minimum percent reserve.

Using the limitation of one nuclear unit every five years, Table 6-2 shows the year-by-year installation schedule of the new unit types. At the bottom of the table is a twenty-five year summary of the number of units installed for each type. In order to see the effects of small amounts of solar penetration, a continuous solution, where fractional units can be added, was deemed more useful for this analysis than one where the unit additions were integerized. As can be seen in Table 6-2, most of the nuclear capacity was replaced by coal.

Table 6-2. MODIFIED UTILITY E NONSOLAR EXPANSION CONSTRAINED NUCLEAR INSTALLATIONS

Year		Unit Type CT 100 MW	CC 250 MW	Coal 600 MW	Nuc 1000 MW	Total Capacity MW	Peak Load MW	Percent Reserve
1	1985	0.000	0.000	2.438	1.000	12763	8078	58.0
2	1986	0.000	0.000	.784	0.000	13233	8482	56.0
3	1987	0.000	0.000	.822	0.000	13727	8906	54.1
4	1988	0.000	0.000	.142	0.000	13812	9351	47.7
5	1989	0.000	0.000	.020	0.000	13823	9819	40.8
6	1990	0.000	0.000	0.000	1.000	14823	10310	43.8
7	1991	0.000	0.000	0.000	0.000	14823	10825	36.9
8	1992	0.000	0.000	.735	0.000	15264	11367	34.3
9	1993	0.000	0.000	1.004	0.000	15867	11935	32.9
10	1994	0.000	0.000	.472	0.000	16150	12532	28.9
11	1995	0.000	0.000	0.000	1.000	17150	13158	30.3
12	1996	0.000	0.000	1.664	0.000	17948	13816	29.9
13	1997	2.979	0.000	1.199	0.000	18866	14507	30.0
14	1998	7.509	0.000	1.102	0.000	19878	15232	30.5
15	1999	11.038	0.000	.295	0.000	20859	15994	30.4
16	2000	4.039	0.000	.366	1.000	22082	16794	31.5
17	2001	15.159	0.000	0.000	0.000	23198	17633	31.6
18	2002	6.768	3.259	0.000	0.000	24389	18515	31.7
19	2003	2.947	4.531	.008	0.000	25621	19441	31.8
20	2004	15.221	0.000	1.264	0.000	27202	20413	33.3
21	2005	6.922	0.000	.018	1.000	28704	21433	33.9
22	2006	10.318	.355	1.383	0.000	30355	22505	34.9
23	2007	4.149	.929	1.433	0.000	31862	23630	34.8
24	2008	6.483	2.940	1.525	0.000	33760	24812	36.1
25	2009	7.696	3.910	1.597	0.000	35865	26052	37.7
Cumulative Totals		101.227	15.924	18.268	5.000			

Also shown in Table 6-2 is the yearly peak load, total system capacity (taking into account retirements as well as additions), and the percent capacity reserve for this nonsolar expansion plan.

6.3 CONSTRAINED RESERVES PLAN

Even with the nuclear limitations, the expansion plan previously discussed was realized to be impractical because the capacity reserve was larger than utility financing and public utility commissiona are likely to allow. For this reason, the expansion plan was deferred in order not to exceed a 25% maximum capacity reserve (a level typical of much of the industry). The total revenue required to support this type of unit installation schedule was then determined with the aid of the simulation feature of the optimal expansion program described in Appendix A.

Table 6-3 shows the installation schedule considering both nuclear restrictions and limited reserve. Note that the nuclear unit additions were deferred by two years. The first nuclear unit is now added in 1987.

Table 6-3. MODIFIED UTILITY E, NONSOLAR EXPANSION CONSTRAINED NUCLEAR INSTALLATIONS AND CONSTRAINED RESERVES

Year		Unit Type			
		CT 100 MW	CC 250 MW	Coal 600 MW	Nuc 1000 MW
1	1985	0.000	0.000	0.000	0.000
2	1986	0.000	0.000	.504	0.000
3	1987	0.000	0.000	0.000	1.000
4	1988	0.000	0.000	.144	0.000
5	1989	0.000	0.000	.975	0.000
6	1990	0.000	0.000	1.023	0.000
7	1991	0.000	0.000	1.073	0.000
8	1992	0.000	0.000	0.000	1.000
9	1993	0.000	0.000	.646	0.000
10	1994	0.000	0.000	1.244	0.000
11	1995	0.000	0.000	1.304	0.000
12	1996	0.000	0.000	1.704	0.000
13	1997	0.000	0.000	0.000	1.000
14	1998	2.979	0.000	1.620	0.000
15	1999	9.884	0.000	.440	0.000
16	2000	11.804	0.000	.366	0.000
17	2001	14.500	0.000	0.000	0.000
18	2002	1.557	.987	0.000	1.000
19	2003	6.768	2.725	0.000	0.000
20	2004	2.947	4.078	1.001	0.000
21	2005	13.126	0.000	.271	0.000
22	2006	9.017	0.000	1.231	0.000
23	2007	2.153	.355	.170	1.000
24	2008	8.165	.805	1.433	0.000
25	2009	4.690	3.064	1.525	0.000
Cumulative Totals		87.590	12.014	16.674	5.000

Table 6-4 summarizes the revenue requirements for the plan shown in Table 6-3. This case will be used as a nonsolar reference against which to compare solar penetration scenarios.

Table 6-4. MODIFIED UTILITY E, NONSOLAR EXPANSION, CONSTRAINED NUCLEAR INSTALLATIONS, AND CONSTRAINED RESERVES REFERENCE CASE COST SUMMARY

Present Worth Cost Given in Millions of 1985 Dollars				
Year		Carrying Charges	Production Cost	Yearly Totals
1	1985	0.000	1156.314	1156.314
2	1986	79.963	1204.457	1284.420
3	1987	346.981	1100.085	1447.067
4	1988	335.940	1184.238	1520.177
5	1989	453.743	1206.565	1660.308
6	1990	566.197	1231.181	1797.379
7	1991	674.073	1258.296	1932.369
8	1992	871.609	1193.763	2065.372
9	1993	883.908	1259.606	2143.514
10	1994	981.828	1293.433	2275.261
11	1995	1077.553	1330.387	2407.940
12	1996	1219.878	1356.761	2576.639
13	1997	1353.603	1333.144	2686.746
14	1998	1469.121	1380.442	2849.563
15	1999	1443.932	1485.242	2929.174
16	2000	1420.209	1620.554	3040.763
17	2001	1361.974	1800.870	3162.844
18	2002	1502.322	1821.192	3323.514
19	2003	1458.433	2010.161	3468.594
20	2004	1562.434	2151.427	3713.861
21	2005	1516.455	2412.314	3928.769
22	2006	1578.315	2581.178	4159.493
23	2007	1696.272	2641.763	4338.036
24	2008	1776.471	2826.711	4603.183
25	2009	1891.242	3014.274	4905.515
Cumulative Totals		27522.456	41854.360	69376.816

The revenue requirements to support the capital investment for new plants appear as carrying charges. These are obtained by multiplying a fixed charge rate, nominally 18%, times the capital investment and then adding the fixed operating and maintenance costs. This produces an annual requirement for revenues to cover capital related items such as return on investment, depreciation, taxes, insurance, and the fixed operating and maintenance expenditures. The production cost is obtained by an economic dispatch against the system load, and is a function of generating unit efficiency (heat rate), fuel cost,

and other variable operating and maintenance costs. All revenue requirements are shown in 1985 dollars using a discount rate of 11% per year. For further details see Appendix A.

Table 6-5 summarizes the revenue requirements for the three nonsolar cases previously rresented. As can be seen, by imposing additional constraints the total plan cost increases. However, the plan with constrained nuclear additions and constrained percent reserve appears to be most plausible considering capital and regulatory constraints. The nuclear issue is unresolved; however, this constraint should not impact the solar plant value as significantly as the limited reserve. The constrained nuclear and reserve case was used as a reference basis for the solar impact and value analysis.

Table 6-5. COST COMPARISON OF NONSOLAR CASES (25-YEAR PRESENT WORTH IN 1985 BILLIONS $)

	Carrying Charges	Production Cost	Total
Unconstrained	33.58	28.43	62.01
Constrained Nuclear	30.45	38.50	68.95
Constrained Nuclear & Reserves	27.45	41.85	69.37

Table 6-6 shows details of the nonsolar reference case, including system peak load, annual energy, capacity mix, and percent reserve. Classification of existing units as base, intermediate, or peaking io comewhat arbitrary. The base refers to coal and nuclear, intermediate to oil steam plants, and peaking to combustion turbines, regardless of their utilization. Thus, the large initial amount of oil steam plants serves some of the peaking and base function although identified in the table as intermediate. The later years show a more typical mix.

Figures 6-1 and 6-2 graphically display the changing capacity mix and energy production by fuel type. It is the need to obtain and recognize the dynamics of capacity mix that makes the use of a generation expansion optimization program in the analysis anecessity.

6.4 PERSPECITVE ON REFERENCE UTILITY SYSTEM EXPANSION

Utilities similar to synthetic system E have some unique characteristics. From the conventional unit expansion plan, certain conclusions can be drawn about the problems facing solar penetration without looking at any penetration scenarios.

Table 6-6. MODIFIED UTILITY E, NONSOLAR EXPANSION, CONSTRAINED NUCLEAR INSTALLATIONS, CONSTRAINED RESERVES REFERENCE CASE

Year	Peak Load (MW)	Energy (GWh)	Retirements (MW)	Additions (MW)	Total Capacity (MW)	% Capacity Mix			% Reserve
						Base	Inter.	Peak	
1985	8078	38590	-	--	10300	40.8	54.4	4.8	27.5
1986	8482	40521	-	303	10603	42.5	52.8	4.7	25.0
1987	8906	42551	-	1000	11603	47.4	48.3	4.3	30.3
1988	9351	44677	-	86	11689	47.8	47.9	4.3	25.0
1989	9819	46908	-	585	12274	50.3	45.6	4.1	25.0
1990	10310	49252	-	613	12887	52.7	43.4	3.9	25.0
1991	10825	51720	-	644	13531	54.9	41.4	3.7	25.0
1992	11367	54308	-	1000	14531	58.0	38.5	3.5	27.8
1993	11935	57018	-	388	14919	59.1	37.5	3.4	25.0
1994	12532	59863	-	746	15665	61.1	35.7	3.2	25.0
1995	13158	62853	-	783	16448	62.9	34.0	3.1	25.0
1996	13816	65997	200	1022	17270	65.8	31.3	2.9	25.0
1997	14507	69297	100	1000	18170	68.1	29.7	2.2	25.3
1998	15232	72759	400	1270	19040	70.1	26.3	3.6	25.0
1999	15994	76399	300	1252	19992	68.1	24.0	7.9	25.0
2000	16794	80217	400	1400	20992	65.9	20.9	13.2	25.0
2001	17633	84221	400	1450	22042	62.7	18.2	19.1	25.0
2002	18515	88433	300	1403	23145	64.1	17.5	18.4	25.0
2003	19441	92845	200	1358	24303	61.0	18.6	20.4	25.0
2004	20413	97486	700	1915	25518	60.5	19.4	20.1	25.0
2005	21433	102353	200	1475	26793	57.5	18.5	24.0	25.0
2006	22505	107462	300	1640	28133	57.4	16.9	25.7	25.0
2007	23630	112809	-	1406	29539	58.4	16.4	25.2	25.0
2008	24812	118436	400	1878	31017	58.4	14.9	26.7	25.0
2009	26052	124348	600	2150	32567	58.4	14.7	26.9	25.0

6.4.1 Insight Derived from Generation Expansion

Looking first at Figure 6-1, some obvious trends can be isolated which will have a significant bearing upon the value of the solar power systems to be discussed later. In 1985 the system starts off with nearly 60% of its capacity in oil fired units. As was mentioned earlier, baseload capacity was added rapidly until it reaches a maximum of around 70% in 1998. As will be discussed in more detail later, the typical winter loads are around 50% of the typical summer peaks. Thus, as the baseload capacity grows from about 40 to 70 percent, the value of any energy that can be displaced by solar will drop dramatically during the off-peak seasons. This trend will be the most important factor driving the solar value curves presented in Section 7.0.

As time progresses past the year 2000, Figure 6-1 shows the percentage of baseload (coal plus nuclear) capacity decreasing slightly and a significant amount of combustion turbines being added. There are two primary reasons for this. First, the utility system has continued to grow at a steady 5% per year since 1985. In 1998 the point is suddenly crossed where the system is deficient in peaking capacity. The system has finally caught up with its baseload requirements and spends about five years installing combustion turbines for peaking and reserve. After about 2002 the system settles down to more or less equal additions of all types of capacity. Insofar as the value of solar goes, we will see a gradual increase in value during this period due to the displacement of oil again during the spring and fall, coupled with the fact that oil has become very expensive by this point. This trend of decreasing value in the early years followed by a rise in value in the later years will be presented in detail in Section 7.0.

The second reason for the shape of the baseload capacity curve throughout the expansion is that it is based on a total cost minimization procedure. The objective is to produce the required energy with sufficient reliability at the least possible total (operating plus capital) cost over the complete 25-year planning horizon. In order to accomplish this, the trend is to overbuild high first cost, low operating cost units in the early years and to coast out in the later years with less expensive, higher operating cost units. This is a characteristic of all generation planning programs which are optimized over the entire planning horizon. The likely magnitude of this end effect and its influence upon the results is discussed more fully in Section 6.4.2.

Figure 6-2 shows the energy expansion summary which, when combined with Figure 6-1, gives a fairly complete picture of what any solar system will have to compete with on this electric generating system.

There are two significant conclusions that can be drawn at this point about the likely value of solar energy systems without looking at any solar penetration scenarios. First, because of the baseload deficient nature of the utility in the early years, solar-thermal power systems which operate primarily in an intermediate to peaking mode will see strong competition for capital investment dollars which the utilities can invest more profitably in new baseload generation. Thus, the same characteristics which cause solar thermal to be attractive from a static (one year) production cost standpoint cause severe capital competition from a dynamic expansion standpoint. The second important conclusion is that solar thermal's real benefits are not likely to be seen until utility

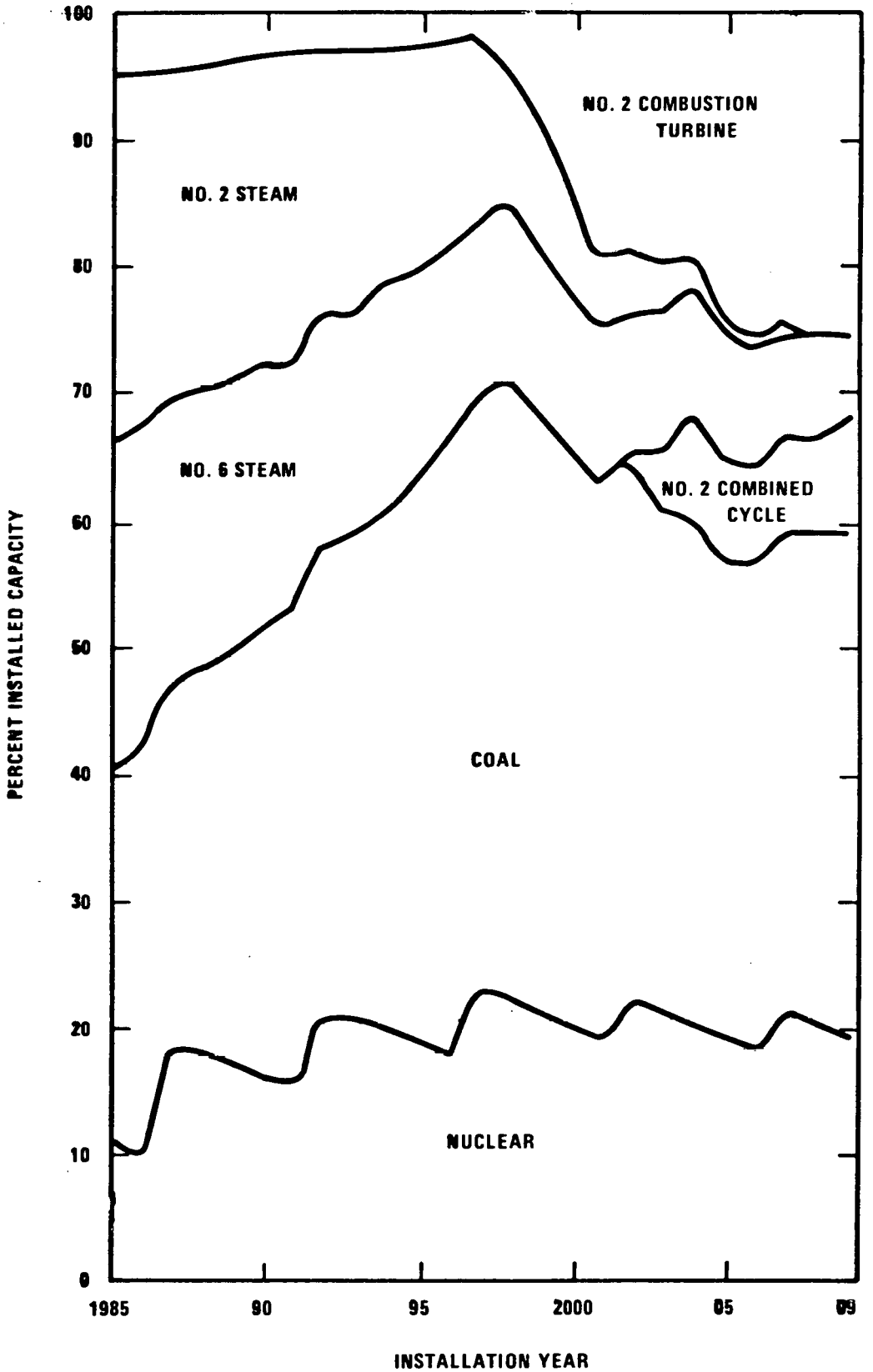

Figure 6-1. NONSOLAR DEFERRED CAPACITY EXPANSION

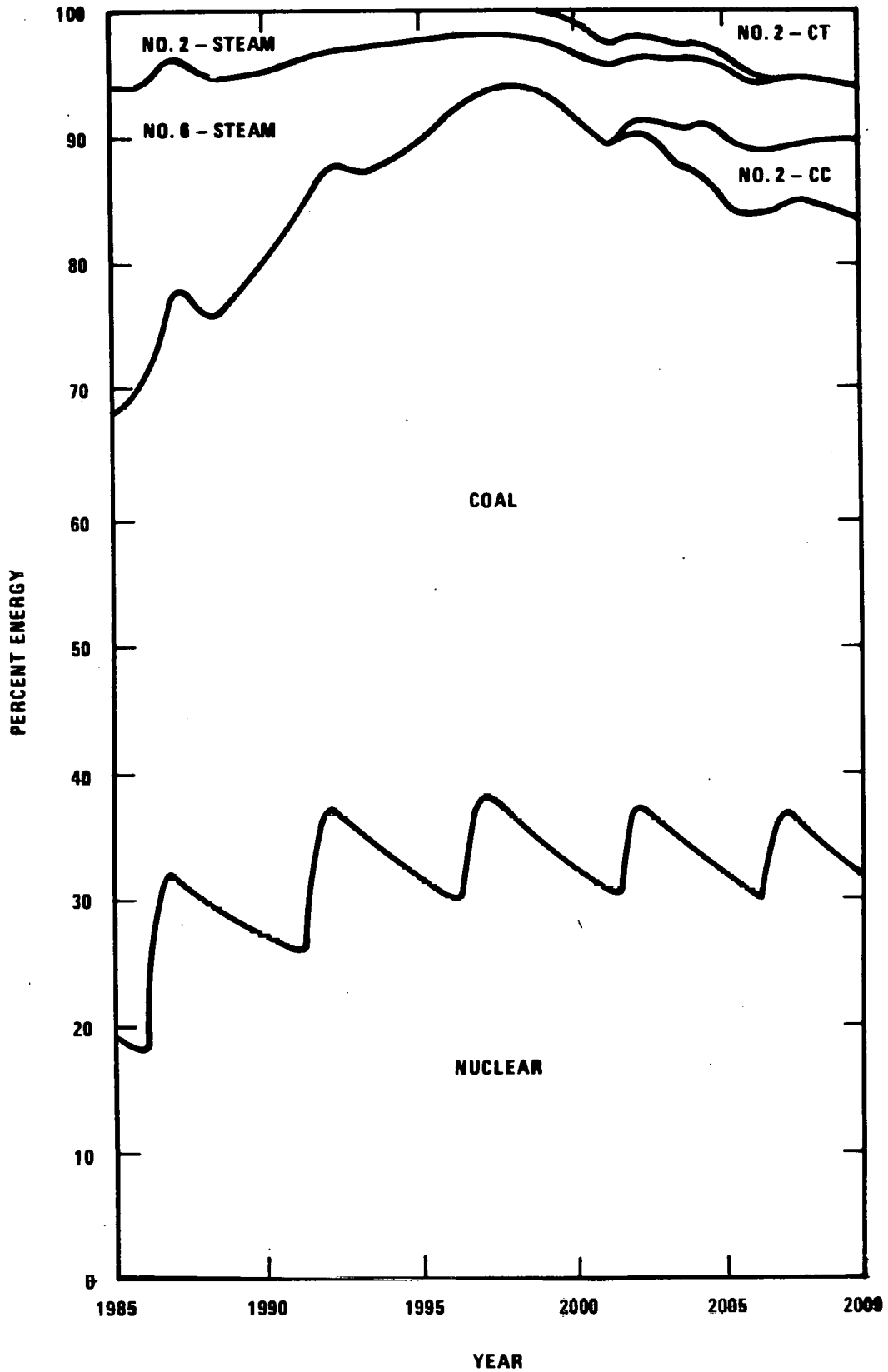

Figure 6-2. DEFERRED NONSOLAR ENERGY EXPANSION SUMMARY

systems are more or less in balance with today's economics. After the year 2000, with the ever increasing demand for intermediate and peaking capacity, coupled with expensive liquid fuels, solar-thermal technologies will see an abundance of economically viable electric applications.

6.4.2 Generation Expansion End Effects

Looking at Figure 6-1, a slight reduction in baseload capacity is seen in the last years of the 25-year planning period. This is due partly to the introduction of combined-cycle plants and partly to the economics of expansion plan termination.

The combined-cycle plants were not introduced earlier in the plan because of the large presence of oil-steam plants to serve the intermediate load. Once significant oil-steam retirements had taken place, the optimization program determined it was economic to add new intermediate capacity in the form of combined-cycle plants. Because of the high combined-cycle plant efficiency, coal cannot compete at as low a capacity factor as it could against the old oil-steam plants. Thus, the need exists for less coal capacity once the combined-cycle plants were introduced.

Of lesser impact on the later expansion plan years is the termination logic. High capital cost/low operating cost plants added in the latter years do not achieve their full lifetime benefits when the plan is truncated. Thus, the expansion plan is slightly biased against baseload in favor of peaking plants in the last few years. This may make the value of solar plants slightly optimistic in this period. However, the solar plant's principal value is in fuel displacement, and as seen in Figure 6-2 the effect of changing capacity mix in terms of energy production by fuel type is fairly small.

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SECTION 7.0

SOLAR PENETRATION

7.1 PENETRATION SCENARIOS

In order to fulfill the prime objective of this study (to determine the value of solar-thermal power plants as a function of penetration and time), it was necessary to postulate the future development of the solar-thermal industry. Reasonable bounding of this problem was accomplished by developing three different scenarios, each with three different levels and rates of penetration. The three scenarios include: first, the installation of solar repowered plants only; second, the installation of only new solar stand-alone plants; and third, the installation of solar repowered plants followed in later years by new stand-alone plants.

The southwestern United States currently has about 45,000 MWe of installed capacity. It was assumed that the growth in capacity would be 5% per year which makes the installed capacity 204,000 MWe at the end of the study (year 2010). The solar penetration scenarios were first developed for the entire Southwest region and then scaled down to the size of the synthetic utility system.

The Solar-Thermal Multiyear Program Plan (October 1978) specifies plans for four significant size projects. These include the 10 MWe Barstow Pilot Plant, one 25 MWe repowering project, and two 50 MWe repowering projects to be completed in 1981, 1983, 1984 and 1986, respectively. In developing the penetration scenarios, these projects were used as the initial driving force for the penetration curves.

7.1.1 Southwest Penetration Scenario - Repowering

Figure 7-1 shows the penetration curves for the Southwest for the repowering-only scenario. The rapid penetration in early years would have to be created by government stimulation such as the current development and demonstration program. There are three primary growth rate curves (10%, 13% and 15% per year). It was postulated that an early government pullout from the demonstration program, around the mid 1980's, before the technology was well developed, would cause a slower (10%/year) penetration of solar-thermal systems into the market. If this path is followed, the maximum number of installations amounts to only 1500 MWe or 0.8% of the Southwest generation by 2010. However, if government involvement were to continue in the technology development and market stimulation until sometime later, say 1000 MWe by 1990, it seems very likely that the commercial market will develop significantly faster (15%/year).

As can be seen from Figure 7-1, the repowering-only scenario is a dead end. This will inevitably be caused by market saturation (see Appendix E). There is some disagreement as to the actual number of repowerable megawatts in the Southwest (see Appendix E); so, a reasonable bounding on two different saturation levels was used, 4000 MWe and 8000 MWe. These limit the maximum possible penetration to 2.0% and 3.9% respectively, in 2010. However, it should be noted that these penetration levels will then decline over time, as a percentage of the total, as the systems continue to expand.

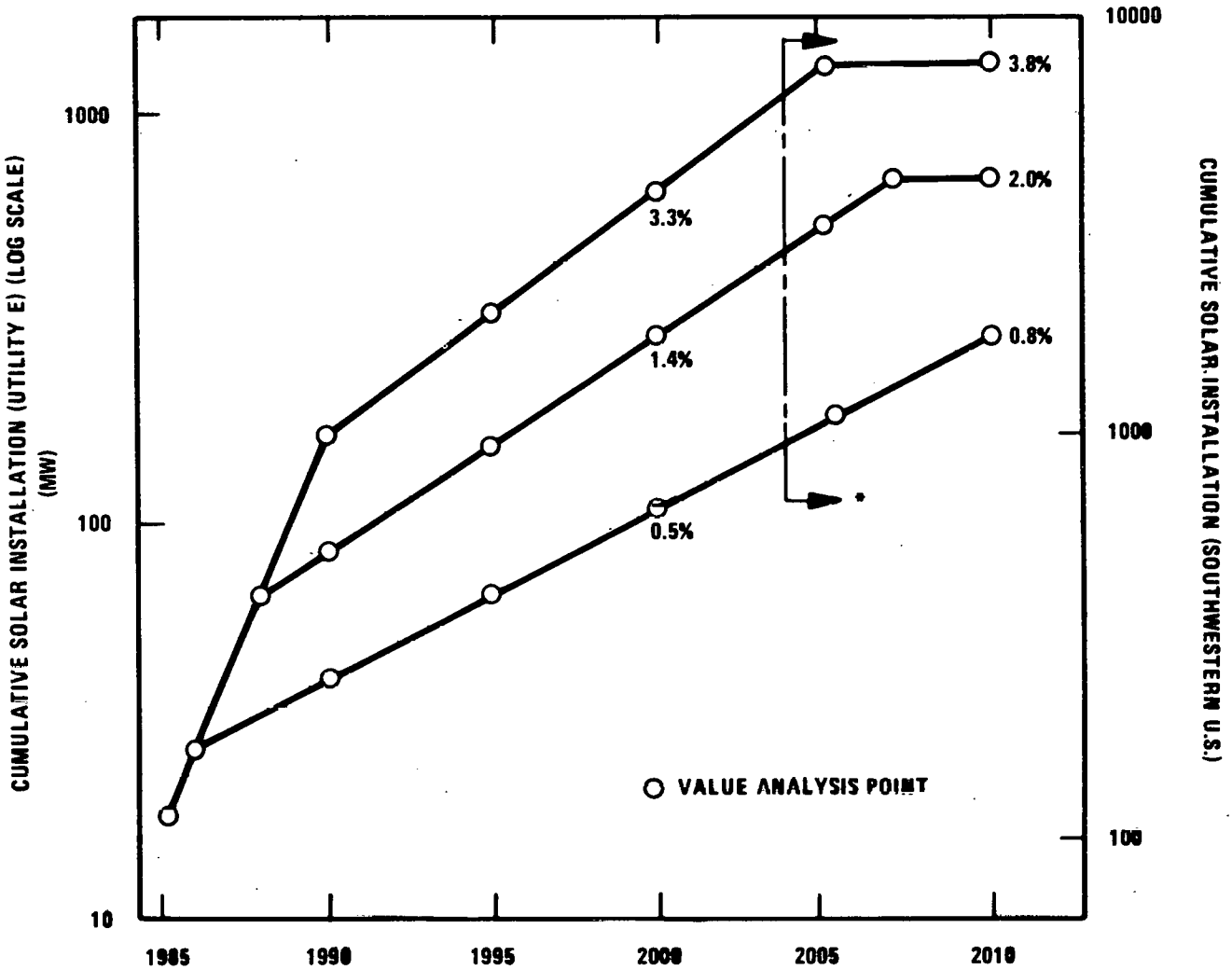


Figure 7-1. UTILITY E PENETRATION SCENARIO - REPOWERING

*(Beginning of #6 oil repowering of additional units repowered due to retirement of all candidate #2 oil plants.)

7.1.2 Southwest Penetration Scenario - Stand-Alone

Figure 7-2 shows the penetration curves for the stand-alone only scenario. Again, the rapid penetration in early years must be created by government stimulation. However, if there is a shift in the program emphasis at this point, there would be a delay of about three years in the operation of the initial demonstrations. This would be caused partially by having to redirect the inertia which has already been built up in the repowering program, partially due to the increased funding that would be required to implement stand-alone instead of repowering projects, and partially due to the long lead time required to purchase the turbine-generator set. Figure 7-2 shows the first three stand-alone projects shifted in time due to these effects.

The slope of the penetration curves is the same as was postulated for the repowering curves, and presumably due to the same effects. A longer, more intense government involvement causes a higher commercial penetration rate, starting at a higher initial level. Even though the program starts later, the high implementation rate causes a greater penetration of solar thermal (over repowering) by the end of the 25-year study period due to the fact that the solar-thermal stand-alone market does not saturate like the repowering market. The high implementation rate, if continued, leads to a 5.3% penetration by 2010 and a very significant 20.6% penetration by 2025.

7.1.3 Southwest Penetration Scenario - Repower/Stand-alone

The third and final penetration scenario is shown in Figure 7-3. This scenario takes advantage of the beneficial characteristics of both of the previous scenarios. Repowering is used in the early years to cause the earliest possible demonstration of the technology which then allows the possibility of greater penetration in later years. However, early government pullout would still result in technologies and economic uncertainties causing a slow growth of commercial repowering and a delay in the introduction of new stand-alone plants. Extended government stimulation in repowering would cause a more rapid expansion of commercial repowering and an earlier introduction of stand-alone plants. If the government stimulation continues into stand-alone plants beyond repowering, there will very likely be a rapid penetration of commercial solar-thermal plants due to the establishment of economic and technical viability.

The penetration curves show a firm demarcation between repowering and stand-alone plants. In all probability, this would be a gradual transition. If repowering is truly economically viable, it may well proceed to saturation and contribute to the overall level of penetration. It was necessary to specify a clear demarcation in order to facilitate the computer simulation.

If this latter scenario is followed, the high implementation curve shows an 8% penetration by 2010 and a possibility of a 31% penetration by 2025.

7.1.4 Utility System E Penetration Scenarios

In order to use the penetration scenarios on the synthetic utility under consideration, it was necessary to scale down the curves just presented. The

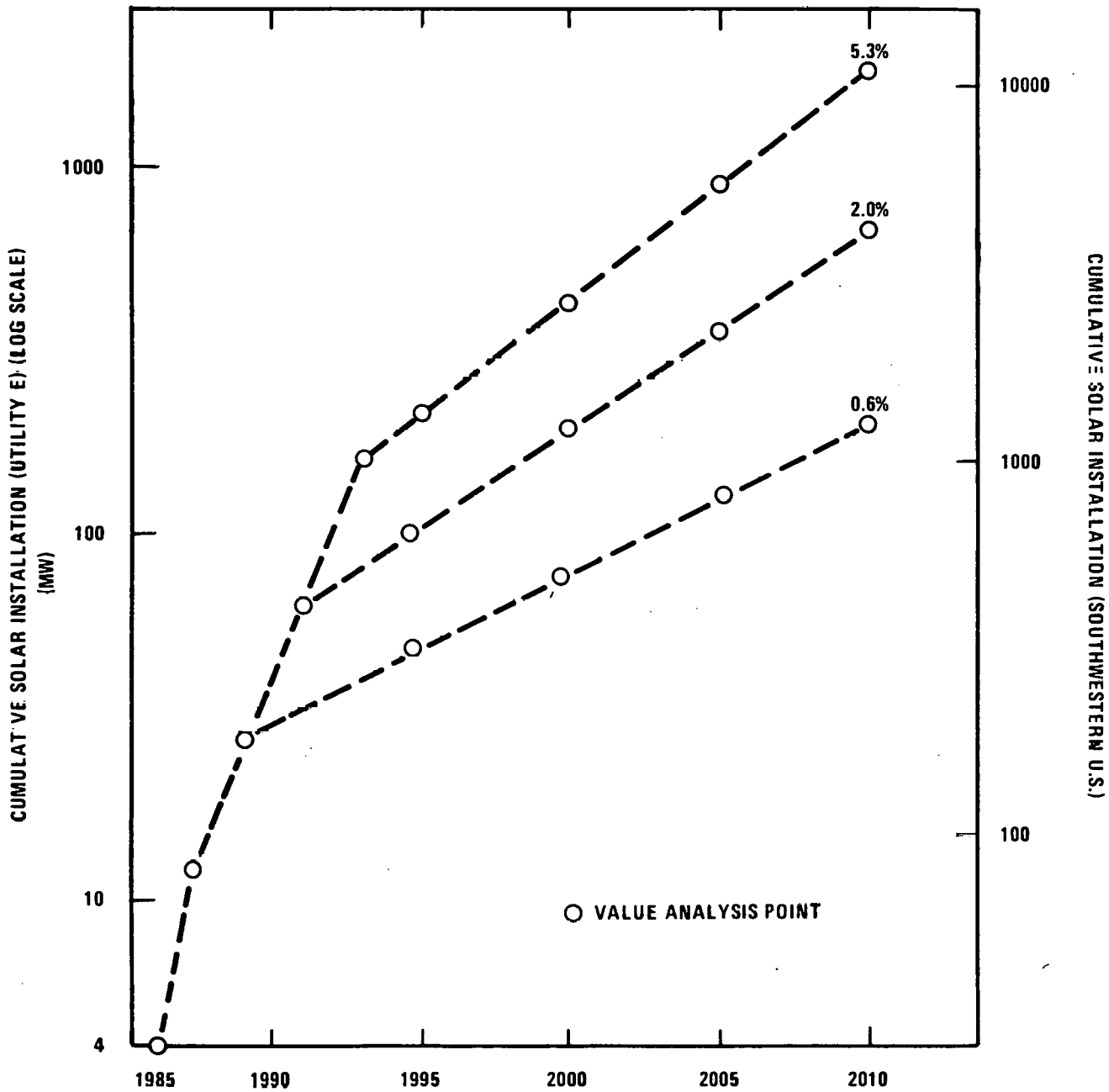


Figure 7-2. UTILITY E PENETRATION SCENARIO - STAND-ALONE

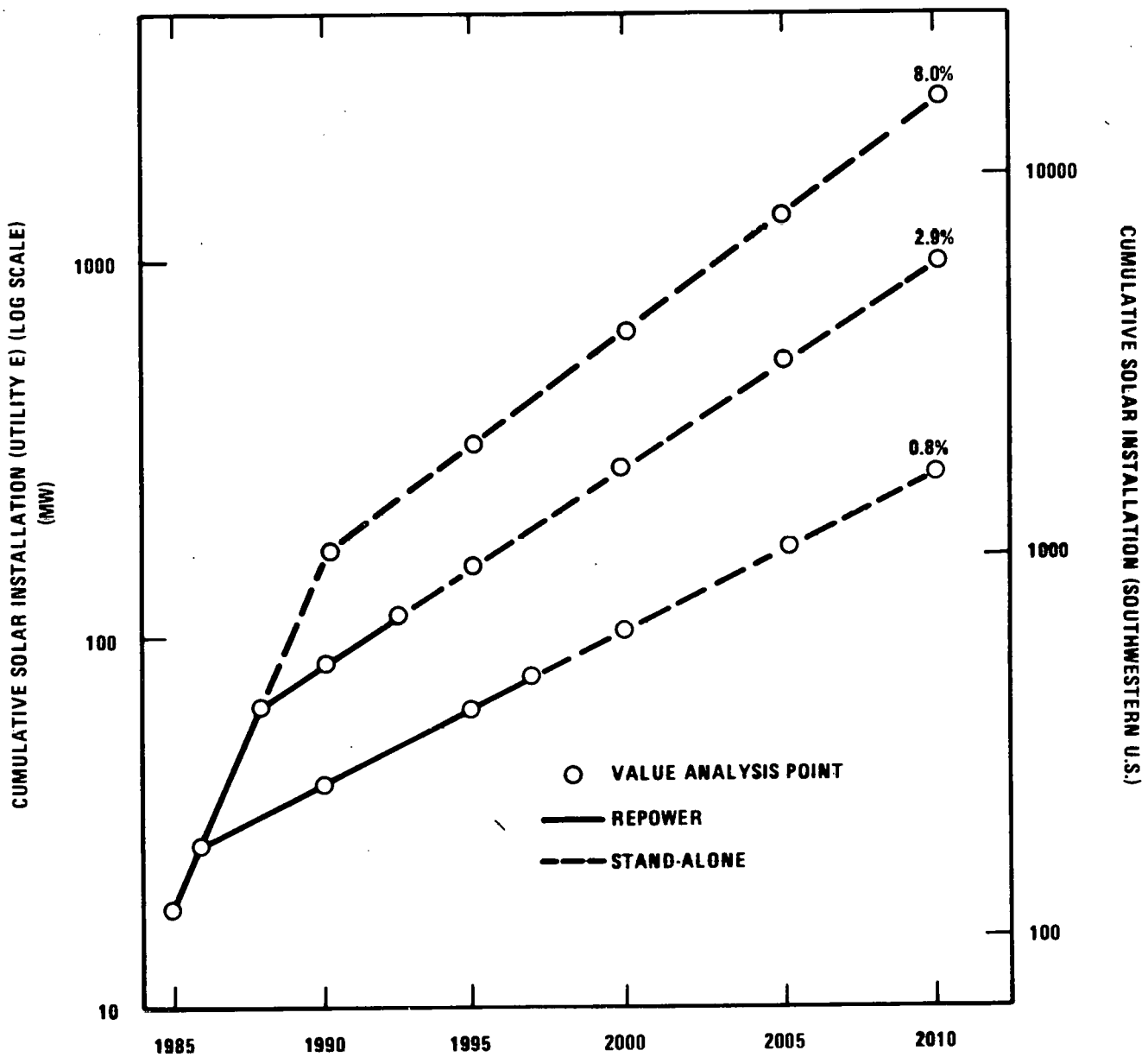


Figure 7-3. UTILITY E PENETRATION SCENARIO - REPOWER/STAND-ALONE

modified EPRI synthetic utility E has a capacity of 10,300 MWe installed on the system in 1985, the first year of the study. At a 5% per year growth rate, the total Southwest generation capacity will be about 63,300 MWe in 1985. Thus, the synthetic utility represents about 16% of the Southwest. The penetration curves were scaled down appropriately for the analysis. The curves which were used in the study were shown in Figures 7-1, 7-2, and 7-3. Also shown on the curves are the points where the static utility value analysis simulations were run.

7.2 DYNAMIC EXPANSION WITH SOLAR PENETRATION

The nine forced solar penetration scenarios were examined using the Westinghouse Generation Expansion Optimization Program to analyze their impact on the balance of the utility system (see Appendix A). These nine scenarios, shown in Figures 7-1, 7-2, and 7-3, include low, nominal and high penetration scenarios for improved stand-alone (ISA) solar-thermal plants, improved hybrid repowered (IHR) solar-thermal plants, and a combination of these two technologies. In no case did the solar capacity penetration exceed 8% of the total generating capacity, so the term "high" penetration is a relative descriptor.

The solar penetrations were forced additions to the utility system according to each solar scenario examined. The conventional unit expansion was determined by the optimization program, recognizing in each case the presence of the solar plants and their contribution (see Figure 3-1).

A 25-year planning period, 1985-2009, was examined. For convenience of comparison, the results (costs and savings) will generally be shown for the entire planning period in present worth 1985 dollars. As previously mentioned, (Section 3.0) the revenue requirements economic methodology is used.

A summary of the cost results for the nine solar penetration scenarios and the nonsolar base case are shown in Table 7-1. As would be expected, a reduction in capital (carrying charges) and production costs for conventional plants takes place with increasing solar penetration. However, all of the solar scenarios have very slightly higher total costs than the nonsolar base case. As with many generation expansion evaluations, the percentage difference in total cost between alternatives appears relatively small; however, the absolute dollars, in most contexts, are quite large.

Part of the reason the solar scenarios have higher costs is the front-end cost associated with solar plants. To explain further, translated to revenue requirements, the costs and value take a form like that shown in Figure 7-4. The major part of the solar plant cost is the levelized (equal annual) fixed or carrying charges. The other (smaller) cost component is the solar plant operating and maintenance cost which escalates from year to year. It is this latter component which accounts for the upward trend of the solar plant cost curve. The value is made up primarily of conventional plant operating (fuel) savings. The cost of fuel ($/MBtu) escalates with time. Because the value has a larger component which is escalating, and because the fuel escalation rates are generally higher than that for O&M, the value tends to overtake the cost at some future time. When looking at a single solar plant, its lifetime value may exceed its lifetime cost, but with a truncated plan, or a plan where one increasingly adds solar plants over time, the tail-end benefits may never catch the front-end costs. This is a real phenomena for front-end cost loaded plants, which have long-term benefits in an expanding scenario. Later in this section, using static analysis, the lifetime cost/value ratios of some of these solar plants, looked at singly, will be shown to be less than one.

Table 7-1. 25-YEAR COST SUMMARY OF EXPANSION PLANS
(PWRR 1985 BILLIONS $)

	Improved Stand-Alone			Improved Hybrid Repower			Combination			Base
	High	Nom	Low	High	Nom	Low	High	Nom	Low	Nonsolar
Conventional Plant										
Carrying Charges	27.06	27.28	27.39	26.61	27.25	27.40	26.39	27.20	27.33	27.52
Production Cost	40.62	41.34	41.71	41.33	41.29	41.63	40.60	41.09	41.68	41.85
Total	67.68	68.61	69.10	67.94	68.54	69.03	66.99	68.29	69.01	69.38
Solar Plant	3.28	1.36	0.49	2.59	1.22	0.43	4.72	1.78	0.53	--
Total	70.96	69.97	69.59	70.53	69.76	69.46	71.71	70.07	69.54	69.38
Total Solar Capacity Installed (MWe)	1600	600	180	1300	680	250	2300	850	250	0

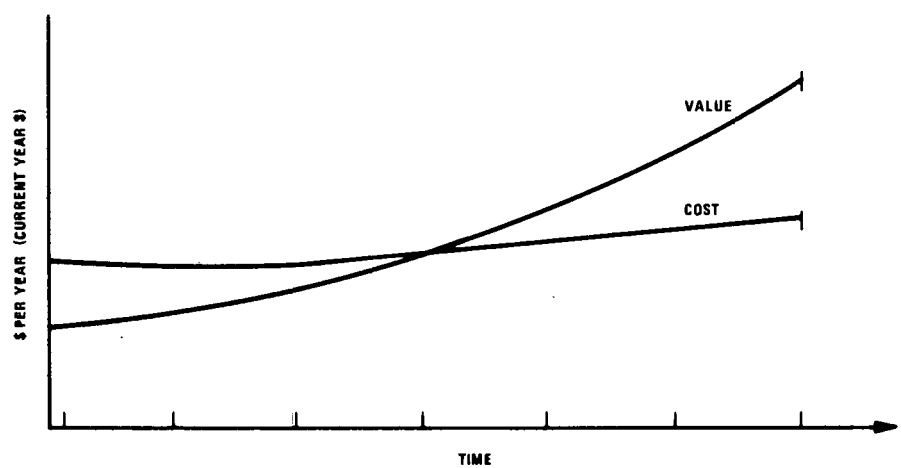


Figure 7-4. SOLAR PLANT LIFETIME COST AND VALUE TIME CHARACTERISTICS

With the small penetrations examined, it is difficult to deal with the aggregate and sometimes more informative to look at the differentials. Figures 7-5 and 7-6 show in bar chart form, respectively, the differences in conventional capacity additions between the solar cases and the reference nonsolar case, and the differences in revenue requirements.

Figure 7-5 shows that the hybrid repowered plant displaces mostly peaking additions (combustion turbines), and the solar stand-alone plant with storage displaces intermediate duty additions (combined-cycle plants). This is consistent with the observed capacity factors of the two solar-thermal concepts.

Figure 7-6 shows that in this type of value analysis one must carefully evaluate specific situations since generalizations can be misleading. For example, at high penetrations the hybrid repowered plant has larger carrying charge savings than production cost savings. This is due to the lack of degradation in capacity displacement, as a function of penetration, associated with hybrid plants and the phenomenon of not fully recovering solar operating benefit in a truncated plan as mentioned above. On the other hand, for the solar stand-alone high penetration case the carrying charge savings are significantly less than the savings in production costs, even in the face of truncated accounting. This is driven by the drop in capacity credit savings with higher penetration and the higher capacity factor of the stand-alone plants. It should be noted that the penetration assumptions were higher for stand-alone than for repowering, and highest of all for the combination scenarios.

It will be noted in Table 7-1 that the combination, high penetration scenario appears to be the least economic option. This is driven more by the level of solar penetration, which is the highest of all nine cases investigated, rather than the technology examined. As shown previously in Figures 7-1 through 7-3, the high penetrations for ISA, IHR, and Combination cases go to 3.8%, 5.3%, and 8.0% respectively.

7.2.1 Capacity Displacement

The issue of how much and what type of conventional capacity can be displaced, cannot be handled simply. For solar/fossil hybrid plants the capacity displacement is potentially on a megawatt-for-megawatt basis; however, for repowered plants one must take account of original retirement date. In other words, capacity credit against new conventional capacity cannot be taken before the original retirement date. For new stand-alone plants during certain conditions (periods of only baseload additions), it might not be economic to take any capacity credit initially.

For solar stand-alone plants a loss-of-load probability analysis must be performed, modeling the operation of the solar plants, to account for both insolation and equipment outages. Once the effective (reliable) capacity is

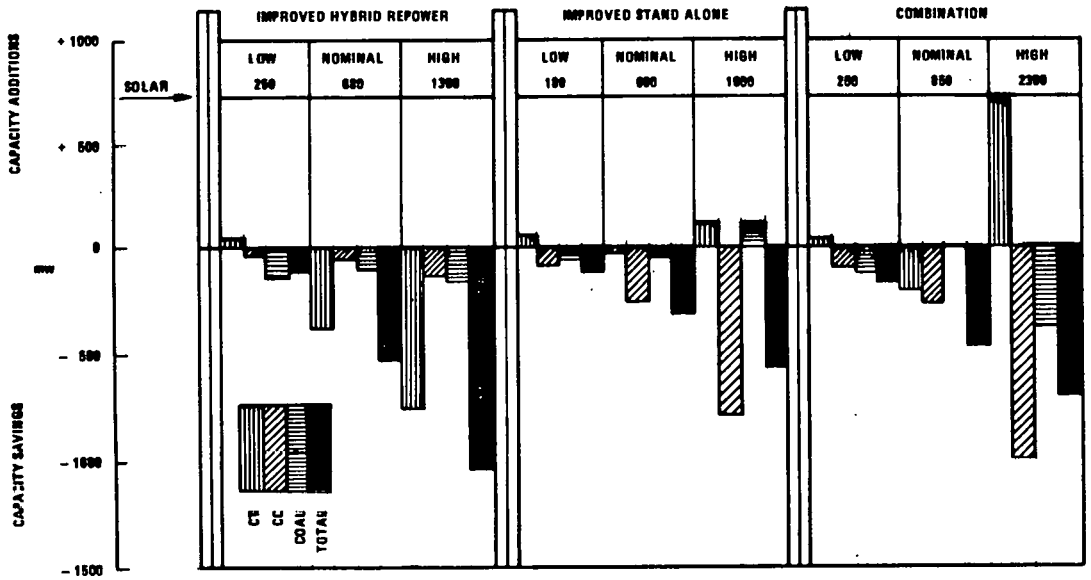


Figure 7-5. EXPANSION PLAN CHANGES FROM NONSOLAR REFERENCE CASE

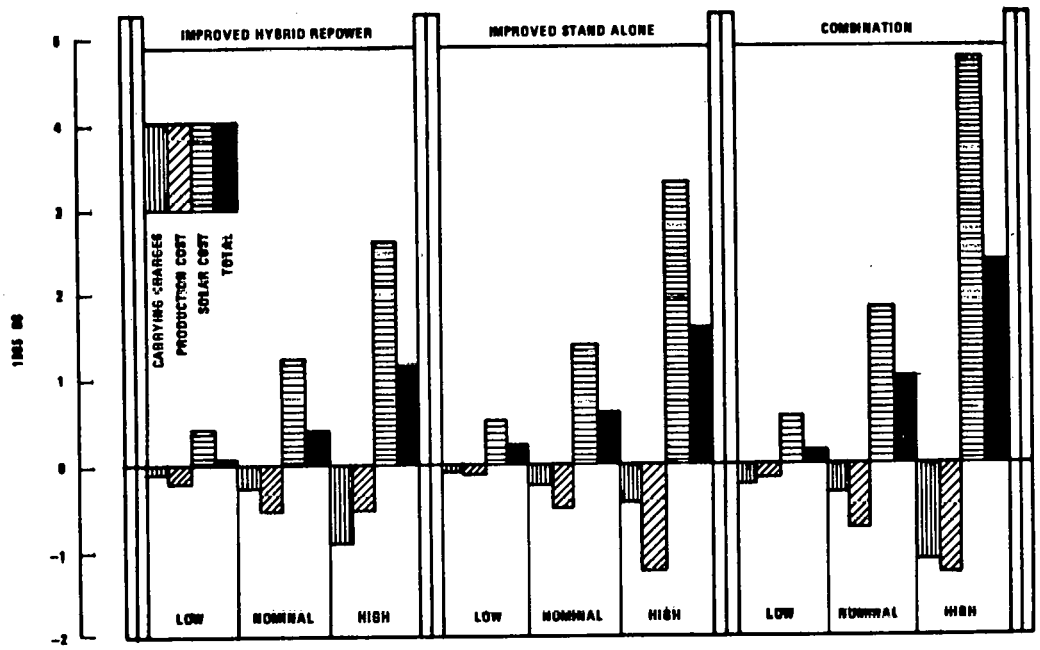


Figure 7-6. REVENUE REQUIREMENT CHANGES FROM REFERENCE CASE

established, the solar plant megawatt capacity displacement is determined. This is a function of load shape, insolation, solar plant configuration, storage capacity, and total solar penetration.

The issue of what type of conventional capacity can be displaced is dependent on how the solar plant operates under system economic dispatch. Frequently, the solar plant's optimum displacement is a mix of different types of conventional capacity. This is best determined by a generation expansion optimization code such as the Westinghouse GENOP Program. For utility systems having a close to optimum generating mix, estimates of the best types of displacement can be made with differential load duration curves and breakpoint curves similar to that shown in Figure 4-1.

The procedure for determining the conventional installation schedules for each of the nine solar penetration scenarios consisted of three steps. First, an optimum conventional expansion plan was obtained for each solar plant penetration scenario using GENOP. Secondly, for reasons explained in Section 6.0 of this report, the optimum conventional expansion plans were then deferred to maintain a capacity reserve which was 25% greater than the system peak load. Finally, the deferred installation schedules were then adjusted for the amount of conventional capacity displaced (capacity credit) by the solar plants penetrated on the system. A more detailed explanation of capacity credit is found in Appendix A.

In order to obtain the most favorable (lowest revenue requirements) expansion plan an experiment was conducted to determine how, if at all, this capacity displacement was taken. The improved stand-alone, nominal solar penetration case was used as a benchmark, in which three capacity displacement alternatives were investigated. The first case assumed no conventional capacity displacement attributed to the solar plants. In the second case full conventional capacity displacement was credited to a solar plant in the year in which that solar plant was added to the system. If only coal units were scheduled for addition in a given year, then coal capacity was assumed displaced by the solar plant. However, if there was a mixture of conventional capacity scheduled for addition then the solar plant assumed peaking capacity displacement first, followed by intermediate and base, if needed. No nuclear capacity displacement was assumed by the solar plant. If only a nuclear plant was scheduled for addition, then the capacity displacement was delayed and added to the following year's displacement. The third and final case assumed only a peaking capacity displacement. No intermediate or base capacity was assumed displaced. In the early years of the expansion when only coal units were added, no capacity displacement was given; it was, instead, accumulated and given in the first year a peaking unit was added. Table 7-2 summarizes these three cases along with the optimum installation schedule.

Shown in Table 7-3 is the cost summary including both carrying charges and production cost of the conventional expansion plans summarized in the previous table. It is apparent from the table that the peaking capacity displacement alternative resulted in the lowest revenue requirements of the three deferred cases. Therefore, only peaking capacity displacement was used for the remaining solar plant penetration scenarios.

Table 7-2. CAPACITY DISPLACEMENT COMPARISON, IMPROVED STAND-ALONE NOMINAL PENETRATION, CONVENTIONAL EXPANSION (25-YEAR SUMMARY, GW)

	No Capacity Displacement	Deferred Full Capacity Displacement	Deferred Peaking Capacity Displacement
Combustion Turbine	9.06	8.82	8.74
Combined Cycle	2.75	2.75	2.75
Coal	9.96	9.88	9.96
Nuclear	5.00	5.00	5.00
Total	26.77	26.45	26.45

Table 7-3. CAPACITY DISPLACEMENT COST SUMMARY, IMPROVED STAND-ALONE NOMINAL PENETRATION, CONVENTIONAL EXPANSION (PWRR, 1985 BILLIONS $)

	No Capacity Displacement	Deferred Full Capacity Displacement	Deferred Peaking Capacity Displacement
Carrying Charges	27.36	27.13	27.28
Production Cost	41.34	41.52	41.34
Total	68.69	68.65	68.61

The nine solar penetration scenarios along with the base, nonsolar twenty-five year unit additions are summarized in Table 7-4. The table shows the sum, in gigawatts, of each type of conventional unit added during the study period, with the conventional system capacity also totaled. Shown at the bottom is the amount of solar capacity penetrated on the system. All of the solar penetration scenarios add less conventional capacity in the expansion period than the base case, as expected. Within each solar plant penetration scenario the total conventional capacity additions decrease as the penetration of solar plants increase. It is difficult to compare the individual conventional unit type addition summaries from one solar penetration scenario to another because of the many factors which influence these expansion plans.

As mentioned before, each installation schedule was based on its own optimum expansion plan which was affected by the operation as well as the penetration of the solar plants. The conventional capacity displacement was also affected by the type and penetration level of the solar plants.

Table 7-4. UNIT ADDITION SUMMARY, DEFERRED EXPANSION CASES
(25-YEAR SUMMARY, GW)

	Improved Stand-Alone			Improved Hybrid Repower			Combination			Base
	High	Nom.	Low	High	Nom.	Low	High	Nom.	Low	
Combustion Turbine	8.87	8.74	8.81	8.01	8.38	8.81	9.44	8.56	8.79	8.76
Combined Cycle	2.21	2.75	2.91	2.87	2.96	2.97	2.00	2.73	2.90	3.00
Coal	10.11	9.96	9.93	9.85	9.90	9.87	9.62	10.00	9.89	10.00
Nuclear	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Conventional Total	26.19	26.45	26.65	25.73	26.24	26.65	26.06	26.29	26.58	26.76
Solar	1.60	0.60	0.18	1.30	0.68	0.25	2.30	0.85	0.25	---
System Total	27.79	27.05	26.83	27.03	26.92	26.90	28.36	27.14	26.83	26.76

The year-by-year unit installation schedule for the improved stand-alone, nominal solar penetration, deferred expansion case is shown in Table 7-5. The conventional and solar plant installations are shown. Complete year-by-year installation schedules for the nine solar penetration scenarios and base case are included in Appendix B.

Table 7-5. IMPROVED STAND-ALONE, DEFERRED EXPANSION PLAN NOMINAL PENETRATION INSTALLATION SCHEDULE

		Conventional				Solar
Year		CT 100 MW	CC 250 MW	Coal 600 MW	Nuc 1000 MW	100 MW
1	1985	0.000	0.000	0.000	0.000	0.04
2	1986	0.000	0.000	.504	0.000	0.04
3	1987	0.000	0.000	0.000	1.000	0.04
4	1988	0.000	0.000	.144	0.000	0.06
5	1989	0.000	0.000	.975	0.000	0.10
6	1990	0.000	0.000	1.023	0.000	0.14
7	1991	0.000	0.000	1.073	0.000	0.22
8	1992	0.000	0.000	0.000	1.000	0.08
9	1993	0.000	0.000	.646	0.000	0.10
10	1994	0.000	0.000	1.244	0.000	0.10
11	1995	0.000	0.000	1.304	0.000	0.13
12	1996	0.000	0.000	1.704	0.000	0.13
13	1997	0.000	0.000	0.000	1.000	0.15
14	1998	2.058	0.000	1.606	0.000	0.22
15	1999	1.482	0.000	.155	0.000	0.20
16	2000	13.876	0.000	0.000	0.000	0.25
17	2001	13.360	.396	0.000	0.000	0.26
18	2002	0.000	1.610	0.000	1.000	0.28
19	2003	4.982	1.996	.547	0.000	0.33
20	2004	3.327	3.181	1.280	0.000	0.37
21	2005	14.346	0.000	.033	0.000	0.41
22	2006	7.494	.129	1.392	0.000	0.48
23	2007	3.804	0.000	0.000	1.000	0.55
24	2008	7.749	.838	1.441	0.000	0.62
25	2009	4.891	2.835	1.534	0.000	0.70
Cumulative Totals		87.368	10.985	16.605	5.000	6.000

7.2.2 Energy and Fuel Displacement

Because the solar plants operate during low load seasons of the year, on weekends, and during some low load periods of the day, they displace energy throughout the spectrum of units from peaking to baseload. Table 7-6 shows the year-by-year total displacement of conventional energy by the improved

stand-alone solar plants following the nominal penetration scenario. This table was obtained through a comparison of the energy generated by each type of unit in the nonsolar base expansion with the ISA nominal penetration expansion. A negative energy displacement means that type of unit generated more energy in the ISA nominal penetration case than in the nonsolar base case. This was possible because the installation schedules (Tables 6-3 and 7-5) were different in these years. More coal energy was displaced in years 1999 through 2003 because more coal was on the nonsolar base case system during those years. Because this coal was not on the ISA nominal penetration system, more energy was produced by the oil-burning units. Similarly, more combined-cycle plants were on the ISA nominal penetration system during those years, which naturally added to the increased operation of combined-cycle plants.

Table 7-6. ENERGY DISPLACEMENT, (GWh) ISA NOMINAL PENETRATION

Year	CT	#2 Oil	CC	#6 Oil	Coal	Total
1985	0.2	5.4	--	5.6	0.6	11.8
1986	0.3	10.8	--	11.1	1.8	24.0
1987	0.5	12.3	--	19.8	7.2	39.8
1988	0.5	22.7	--	27.6	9.9	60.7
1989	0.7	28.3	--	37.2	20.0	87.2
1990	0.5	39.2	--	59.3	38.9	137.9
1991	0.6	53.2	--	80.5	64.3	198.6
1992	1.1	54.9	--	89.7	91.3	237.0
1993	1.1	67.9	--	100.7	100.7	270.4
1994	1.0	72.7	--	107.5	123.7	304.9
1995	1.4	77.7	--	109.6	160.4	349.1
1996	1.4	74.2	--	104.9	215.9	396.4
1997	1.2	70.3	--	118.6	255.2	445.3
1998	13.1	67.0	--	118.7	309.5	508.3
1999	-3.7	-25.2	--	-73.4	667.1	564.8
2000	-126.9	-143.2	--	-310.8	1201.2	620.3
2001	-98.9	-64.6	-243.5	-267.5	1378.2	703.7
2002	66.5	19.4	-579.0	-82.8	1373.3	797.4
2003	212.2	54.7	-113.5	167.5	579.3	900.2
2004	159.1	12.9	500.7	193.7	148.0	1014.4
2005	47.2	1.7	446.8	84.1	568.6	1148.4
2006	271.6	27.5	503.3	163.9	321.5	1287.8
2007	35.1	-4.2	617.4	53.8	737.8	1439.9
2008	102.8	--	630.8	83.7	808.1	1625.4
2009	66.1	--	804.8	70.9	888.8	1830.6

As noted earlier, these energy displacements were for all solar plants operating on the system. Included in the Static Analysis Section (7.3) is an explanation of the energy displaced by the incremental addition of a single solar plant.

7.2.3 Cost Summary

The cost of the nine solar penetration scenarios and the base, nonsolar expansion cases shown in Table 7-4 are summarized in Table 7-7. The carrying charges and production costs of the conventional units, along with the solar plants' total revenue requirements, are summarized for the twenty-five year study period. The costs are expressed in terms of present worth 1985 billions of dollars. Approximately 40% of the total conventional unit cost is composed of carrying charges, with the other 60% being production costs. Because fewer conventional units were added as the amount of solar capacity increased, the total conventional units' carrying charges decreased. In general, the production costs of the conventional units also tended to decrease as the solar penetration within each scenario increased, because the portion of system load met by conventional unit generation decreased. However, there was a slight deviation from this trend in the improved hybrid repowering scenario. The conventional unit production cost of the high solar penetration case was slightly more than the nominal penetration; however, the total conventional unit costs (carrying charges plus production costs), which was the variable optimized in GENOP, were lower. Again, because each solar penetration scenario was based on its own optimum expansion, this phenomena was possible. The total system (including solar) revenue requirements of all nine solar penetration scenarios were higher than the nonsolar base case. This was due in part to the front-end loading phenomena explained in the beginning of Section 7.2.

The year-by-year costs incurred by the improved stand-alone, nominal penetration, deferred installation schedule (Table 7-5) are shown in Table 7-8 and Figure 7-7. Both conventional and solar revenue requirements tabulated are expressed in present worth 1985 millions of dollars. Complete year-by-year cost summaries of all nine solar penetration scenarios and the nonsolar base case are included in Appendix B.

Table 7-7. COST SUMMARY, DEFERRED EXPANSION CASES
(PWRR 1985 BILLIONS $)

	ISA			IHR			Comb			Base
	High	Nom.	Low	High	Nom.	Low	High	Nom.	Low	
Carrying Charges	27.06	27.28	27.39	26.61	27.25	27.40	26.39	27.20	27.33	27.52
Production Cost	40.62	41.34	41.71	41.33	41.29	41.63	40.60	41.09	41.68	41.85
Conventional Total	67.68	68.61	69.10	67.94	68.54	69.03	66.99	68.29	69.01	69.38
Solar Plant	3.28	1.36	0.49	2.59	1.22	0.43	4.72	1.78	0.53	---
System Total	70.96	69.97	69.59	70.53	69.76	69.46	71.71	70.07	69.54	69.38

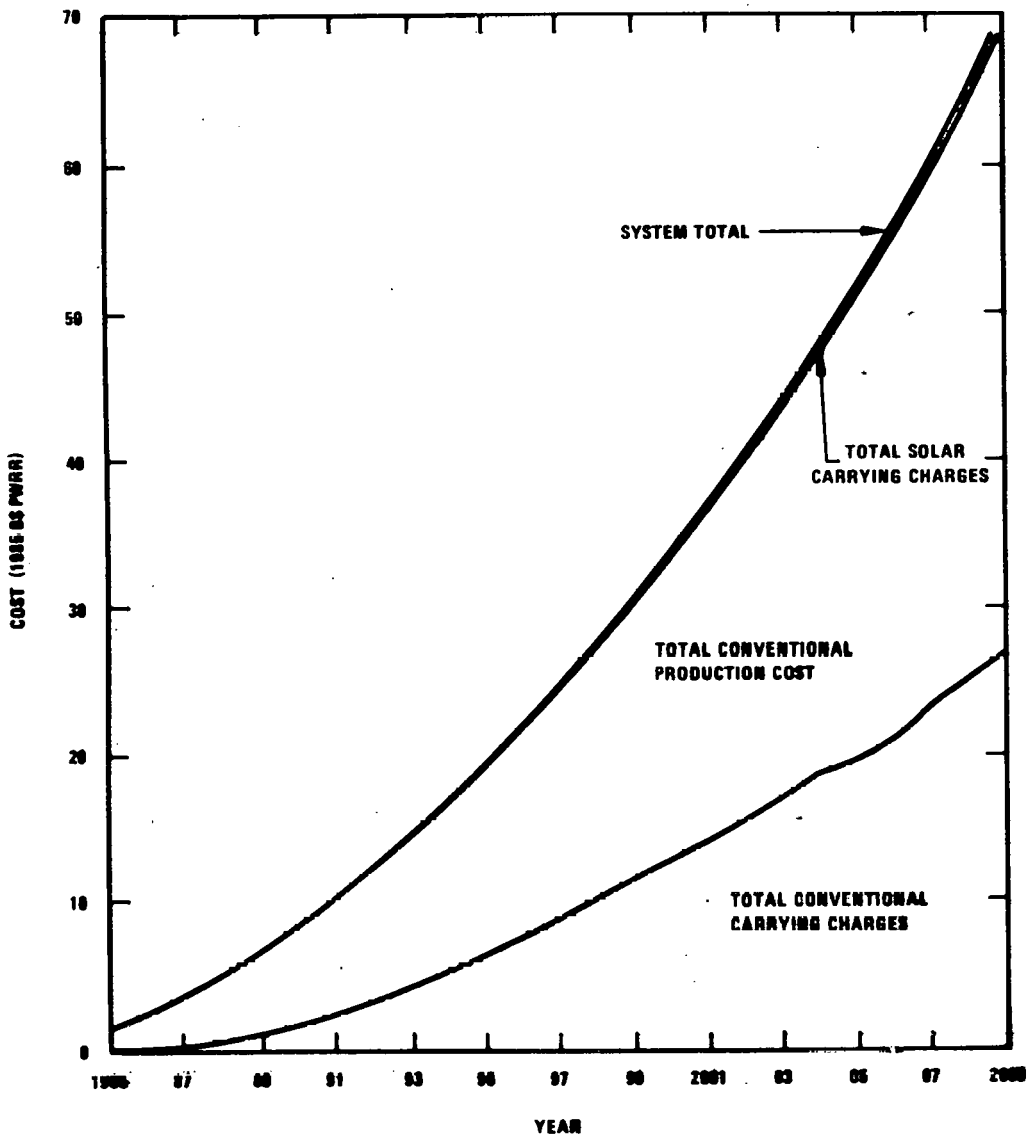


Figure 7-7. IMPROVED STAND ALONE, DEFERRED EXPANSION PLAN COST SUMMARY

Table 7-8. IMPROVED STAND-ALONE, DEFERRED EXPANSION PLAN, NOMINAL PENETRATION COST SUMMARY (PWRR, 1985 M$)

		Conventional			Solar
Year		Carrying Charges	Production Cost	Yearly Totals	Yearly Totals
1	1985	0.000	1155.695	1155.695	2.055
2	1986	79.959	1203.155	1283.114	3.392
3	1987	346.977	1098.149	1445.126	5.597
4	1988	335.940	1181.168	1517.108	8.072
5	1989	453.743	1202.397	1656.141	12.256
6	1990	566.202	1224.734	1790.936	17.952
7	1991	674.078	1249.218	1923.296	26.904
8	1992	871.613	1183.426	2055.039	29.224
9	1993	883.917	1247.516	2131.432	32.231
10	1994	981.831	1280.061	2261.892	35.379
11	1995	1077.551	1315.616	2393.167	39.565
12	1996	1219.872	1341.058	2560.931	41.934
13	1997	1353.597	1315.975	2669.573	44.937
14	1998	1462.216	1362.296	2824.511	48.495
15	1999	1406.544	1477.312	2883.856	52.541
16	2000	1346.891	1632.406	2979.297	57.010
17	2001	1299.078	1813.327	3112.405	63.142
18	2002	1451.959	1823.331	3275.289	70.311
19	2003	1459.882	1974.299	3434.181	77.964
20	2004	1581.910	2094.934	3676.843	86.869
21	2005	1508.954	2367.551	3876.505	96.868
22	2006	1587.738	2511.440	4099.177	107.409
23	2007	1683.104	2585.501	4268.605	119.626
24	2008	1764.263	2759.767	4524.030	133.307
25	2009	1877.261	2938.602	4815.864	148.262
Cumulative Totals		27275.080	41338.934	68614.014	1361.302
System Total				69975.316	

7.3 STATIC ANALYSIS

7.3.1 General

As described previously, the Demand Task methodology is divided into two parts: the dynamic analysis which determines the generation mix over time, and the static analysis which finds the yearly impact of an increment of solar capacity on the system production costs. Figure 3-2 is a schematic representation of the static analysis.

A number of investigations were performed using the detailed static analysis described in Appendix A. This analysis involved the detailed simulation of the operation of solar plants (in hourly increments) and the utility system (in bi-hourly increments) for a year. From this one year's detailed simulation, information was derived as to the conventional fuel displacement and reliability impact. Projections were made as to solar plant impact over its lifetime, based upon this one year's detailed analysis. In the sense that the impact is based upon one year's detailed analysis as a basis of evaluation, and the system's configuration in that year is used to be representative of future conditions (with the exception of costs), the analysis is referred to as being static. The static analysis evaluation points are shown in Figures 7-1 through 7-3. These evaluation points involve different amounts of installed solar capacity in each year according to the growth scenario.

Summaries of the results, showing the lifetime value and the cost/value (or cost/benefit) ratios, are given in Tables 7-9, 7-10, and 7-11. These tables reflect solar plant lifetime costs and value based upon the static analysis procedures. The values shown are more credible than the costs of the solar plants used in the cost/benefit ratios. However, it can be misleading to look solely at value. For example, the improved stand-alone plant generally has a higher value than the hybrid repowered plant. However, the stand-alone plant has a larger collector field and thermal storage, making it more expensive. Thus, to put the values in some perspective the cost/benefit ratios are shown. Even though the emphasis is on the solar plant value, for comparability, it is necessary to make some assumption as to the cost of the solar plant.

The cost/benefit ratios between the scenarios are so close that no clear economic choice exists between the Improved Stand-Alone and the Improved Hybrid Repowered solar-thermal plants for the assumed costs. Although the cost/benefit ratios indicate economic preference, (are less than one) it must be recognized that these ratios have been developed on a microeconomic basis. As will be shown in Section 8.6 the cost/benefit ratios for other technologies may be even more attractive. Traditional utility economics were used based upon assumptions stated in Section 4.0.

Tables 7-9, 7-10, and 7-11 show the lifetime cost/value estimates of the last increment of solar capacity added in the year indicated. If the total solar capacity for a year was less than 50 MWe, then the entire capacity was assessed. If more than 50 MWe cumulative solar capacity existed for a year, then only the impact of adding the last 50 MWe, in that year, is shown. The MWe solar additions shown are cumulative, up through the year indicated.

Table 7-9. LIFETIME VALUE AND COST/VALUE RATIOS BY INSTALLATION YEAR FOR IMPROVED STAND-ALONE SOLAR-THERMAL PLANTS

Installation Year	Penetration Scenario								
	Low			Nominal			High		
	Cum. MWe Solar	Value[a]	Cost/ Value Ratio	Cum. MWe Solar	Value[a]	Cost/ Value Ratio	Cum. MWe Solar	Value[a]	Cost/ Value Ratio
1985	4	336.0	.84	4	336.0	.84	4	336.0	.84
1987	12	334.9	.82	12	334.9	.82	12	334.9	.82
1989	28	282.2	.94	28	282.2	.94	28	282.2	.94
1991	--[b]	--	--	64	264.1	.98	64	264.1	.98
1993	--	--	--	--	--	--	160	267.6	.95
1995	50	240.1	1.03	105	236.5	1.04	210	216.2	1.14
2000	80	241.6	.96	200	236.1	.98	440	214.3	1.08
2005	125	319.4	.69	365	310.8	.70	900	280.3	.78
2009	180	336.2	.62	600	305.3	.68	1600	239.0	.87

[a]Value is the lifetime value (1985 PWRR M$) normalized to a 50 MWe solar plant.

[b]--No analysis done for this year (see Figure 7-1).

Table 7-10. LIFETIME VALUE AND COST/VALUE RATIOS BY INSTALLATION YEAR FOR IMPROVED HYBRID REPOWERED SOLAR-THERMAL PLANTS

Installation Year	Penetration Scenario								
	Low			Nominal			High		
	Cum. MWe Solar	Value[a]	Cost/ Value Ratio	Cum. MWe Solar	Value[a]	Cost/ Value Ratio	Cum. MWe Solar	Value[a]	Cost/ Value Ratio
1985	18	221.6	.85	18	221.6	.85	18	221.6	.85
1986	27	224.4	.83	27	224.4	.83	27	224.4	.83
1988	--[b]	--	--	64	222.1	.82	64	222.1	.82
1990	40	212.4	.83	80	214.6	.82	160	190.4	.93
1995	65	177.0	.93	150	163.8	1.01	325	178.6	.93
2000	105	165.8	.93	285	146.6	1.06	650	153.2	1.01
2005	170	206.5	.70	525	166.2	.87	1300	111.8	1.30
2007	--	--	--	680	201.3	.70	--	--	--
2009	250	164.1	.84	680	198.6	.69	1300	114.9	1.20

[a]Value is the lifetime value (1985 PWRR M$) normalized to a 50 MWe solar plant.

[b]--No analysis done for this year (see Figure 7-2).

Table 7-11. LIFETIME VALUE AND COST/VALUE RATIOS BY INSTALLATION YEAR FOR COMBINATION SOLAR-THERMAL EXPERIMENT

Installation Year		Penetration Scenario								
		Low			Nominal			High		
		Cum. MWe Solar	Value[a]	Cost/ Value Ratio	Cum. MWe Solar	Value[a]	Cost/ Value Ratio	Cum. MWe Solar	Value[a]	Cost/ Value Ratio
1985		18	221.6	.85	18	221.6	.85		221.6	.85
1986		27	224.4	.83	27	224.4	.83	27	224.4	.83
1988		--[b]	--	--	64	222.1	.82	64	222.1	.82
1990	IHR[c]	40	212.4	.83	80	214.6	.82	160	275.3	.96
1992		--	--	--	105	192.0	.90z	--	--	--
1995		65	177.0	.93	155	225.8	1.09	325	239.6	1.03
1997		80	--	1.11	--	--	--	--	--	--
2000		105	116.9	.99	285	222.8	1.04	650	196.4	1.18
2005		170	299.7	.73	525	291.1	.75	1300	271.3	.81
2009	ISA[d]	250	316.2	.66	850	292.2	.71	z2300	226.9	.92

[a]Value is the lifetime value (1985 PWRR M$) normalized to a 50 MWe solar plant.

[b]--No analysis done for this year (see Figure 7-3).

[c]IHR stands for Improved Hybrid Repowered solar-thermal power plant.

[d]ISA stands for Improved Stand-Alone solar-thermal power plant (see Section 7.0).

Two general trends can be observed in these tables.* One is the general increase and then decrease of cost/benefit ratios with year of installation, and the other is the general increase of the ratio with penetration. The latter phenomenon has been observed in almost every study addressing this issue.

The changes in cost/benefit with year of installation are driven in the early years by the changes in conventional generating mix. In 1985 the utility system modelled has a large dependence upon oil-fired generating units (60% of installed capacity). Thus, there was good opportunity for the solar plants to displace this high priced fuel, producing a very good (low) cost/benefit ratio. To achieve a more economic generating mix only baseload conventional additions (coal and nuclear) were made, until the late nineties. Then new peaking and intermediate units also began to be added. As more baseload capacity was added to the system, the solar plants begin to displace more of the lower priced coal and less oil. This phenomena occurs regardless of the level if solar penetration. Thus, until the late 1990's, the cost/benefit of solar plants, on this system, is increasing (getting worse).

*Certain short-lived counter trends appear in the results. These arise primarily from the modeling details, such as adding discrete 1000 MWe nuclear plants in the expansion plan, and will be discussed later in this section.

In the post-2000 era the utility has reached a somewhat static generation mix, thus the opportunity for displacing oil is somewhat constant. The cost/benefit improves (decreases) because the cost of the oil being displaced is rising faster than the cost of new solar plants. Thus the value increases more rapidly with time than the cost, resulting in a better cost/value ratio.

The less favorable cost/value ratio which accompanies increasing penetration solely reflects a decrease in value. This decrease results from an increasing proportion of the solar plants' energy displacing coal (versus oil) with increasing penetration. This phenomenon has been observed in other solar studies.

Comparing Tables 7-9, 7-10, and 7-11, it is virtually impossible to select the most economic concept. Although the plant values differ widely, the cost/benefit numbers are so close that it would be beyond the accuracy of the data assumptions to identify either concept as being superior. However, it is quite instructive and a most important result to learn from this study that improved stand-alone and improved repowered solar-thermal plants represent a virtual economic standoff.

Details of the results of the static analysis, showing components of cost and value, and their trends, follow.

7.3.2 Economic Merit

In the previous section a brief explanation was given of the general trends that are seen in the static analysis results. In this section the factors that influence the changes in the cost/benefit ratio with time and increased solar plant penetration will be examined. First, however, a discussion of the reasons behind use of the cost/benefit ratio as the figure of economic merit for this study will be given.

There are several criteria of economic merit which are often used in making an economic choice between generation additions. They are:

- Solar plant value (independent of solar plant cost)
- Net solar plant value (negative if solar plant cost exceeds value)
- Levelized mills/kWh solar electric energy cost
- Cost/benefit ratio (present worth of: solar plant cost divided by plant value)

These criteria are often not consistent in determining an economic figure of merit. It is possible that different figures of merit would indicate different economic choices [1,12]. This Demand Task portion of the study was directed toward determining solar plant value, but cost effectiveness is by its nature some relationship of cost and value. The cost/benefit (or cost/value) ratio has been obtained to help indicate economic choice, although one must be cautioned that costs do not represent the results obtained from the Supply Task.

The solar plant values are determined as described in Section 3.0 and Appendix A. The solar plant value is the present worth of the revenue requirements saved on the balance of the utility system over the solar plant's 30-year expected life. This value is independent of solar plant cost and reflects both operating and capital credit on the rest of the utility system. This by itself is not a good criteria for plant preferability since by increasing collector area, storage capacity, turbine-generator size, or just make a larger plant in general, the value will increase. All other categories do require use of cost assumptions. This value can be used by the reader to compare with his own solar plant cost assumptions.

The net solar plant value is determined by subtracting the present worth of solar plant cost (revenue requirements) from the solar plant value. Since this is an absolute and not a per-unit margin calculation, care must be used because when value exceeds cost economic preferability tends toward the larger plant configurations. Also, when solar plant costs exceed value one can see a driving force toward as small a solar plant as possible. For example, under the latter condition where cost exceeds value, in trying to determine the optimum collector area for a given storage and turbine-generator capacity, one could possibly find a zero area collector field to be most economic (using net value criterion).

Levelized energy cost for the plant of interest has been a popular criterion for evaluating new electric generating plant concepts such as the STC plant. Part of its popularity is in the simplicity of not having to allow for the load or operating cost characteristics of the rest of the power system to which it is attached. However, this is also the weakness in this economic criterion in that the value is not accounted for, and value is a function of not only how much electricity is generated but when. One kilowatt-hour of electricity generated during the daily peak by a new concept plant is much more valuable than one during off-peak hours such as late in the night. Likewise, supplemental energy available during the season of annual peak demands can be more valuable than the same energy during off-peak seasons.

Cost-to-benefit ratio employs both estimated plant cost and value and is calculated by dividing the present worth of the plant lifetime revenue requirements for each. It reflects dollar cost per dollar benefit and is applicable whether the cost is more or less than the benefit. The cost/benefit ratio is shown often in this report because it emphasizes that value alone cannot be used as an exclusive indicator of economic choice. Although the Demand Task study uses only representative costs, the cost/benefit ratios help indicate certain trends in the results.

All four economic indices just discussed provide some insight or additional information as to the economic merits of various alternatives. Also, again the results reflect the assumptions, and considerations other than economic ones can be influential.

7.3.3 Components of Solar Plant Value

The cost-to-benefit ratio is influenced by a great number of factors. Estimates of cost can vary widely from one expert to another. Elaborate cost estimating procedures are beyond the scope of this portion of the study (see Section 4.1.4) and, therefore, the value components are those which will be of most interest here.

There are three components which add to the solar plant's total value: fuel displacement value, variable cost savings (associated with operation and maintenance cost savings on displaced plants), and capacity displacement value (the savings that result in not having to build capacity other than a solar plant).

7.3.4 Capacity Displacement

The capacity displacement value can be interpreted as the megawatts of conventional generating capacity not required to be installed due to the presence of the solar plant, or in terms of the dollars represented by that saved capacity. Calculationally, one usually thinks in terms of the megawatt savings being obtained first and then being converted to dollars. The megawatt capacity credit is a function of many variables, some of which are site specific, utility specific, and solar plant specific. Major factors are:

- Site Insolation Characteristics
- Utility System Load Shape
- Solar Plant Collector Area
- Solar Plant Storage Capacity
- Penetration Level of Solar Plants
- Geographic Dispersion of Solar Plants
- Scheduled Maintenance Requirements
- Equipment-Related Forced Outage Rate
- Solar Plant Turbine-Generator Rating
- Daily Peak Variance of System Load

- Operational Philosophy
- Solar Plant Conversion Efficiency

Of major importance to the capacity credit is the ability of the solar plant to produce power during the utility system demand peak. The correlation of insolation with system demand on both a daily and seasonal basis is quite important. Some relaxation in the daily correlation can be accepted without major degradation in capacity credit, provided adequate solar energy is collected on a daily basis and adequate thermal storage exists.

In addition to the daily load correlation with insolation, seasonal correlation is also important. If the annual load peak for a system generally occurs in August, the quality of the insolation in August can play a dominant role in establishing the megawatt capacity credit. This is due to the peak demand month usually establishing, or being the major contributor in establishing the system installed capacity requirements.

The solar plant performance characteristics obviously affect the megawatt capacity credit as does the sizing of subsystems. Penetration also impacts the capacity credit. As more and more solar capacity is added to the system, the ease with which the next solar plant can further reduce the daily load peak is diminished. Also, the time correlation of insolation among solar plants in a service area reduces the capacity credit. Thus, the degree of geographic dispersion for several plants is also important.

Once the megawatt capacity credit of a solar plant is established, the dollar value of this credit can be determined. In this report the dollar value of capacity credit will be given in terms of present worth of the associated revenue requirements (PWRR).

The dollar value of the capacity credit is found by assuming that the solar plant displaced only peaking-type capacity. This assumption was guided by the dynamic expansion results. In order to obtain the most favorable (lowest revenue requirements) expansion plan, an experiment was conducted to determine how, if at all, the capacity credit was to be taken. This experiment was described in Section 7.2.1. The optimum way to take capacity credit was to take full displacement (megawatt for megawatt of effective load carrying capability) of peaking capacity.

The static analysis assumes that all repowered plants would have normally been retired ten years after repowering, so the hybrid plants were given capacity credit for the last twenty years of their thirty-year life. Stand-alone plants were given capacity credit in each year of their life.

7.3.5 Operating Cost Savings

The second and third components of the solar plant's total value are the fuel cost displacement, and the variable operation and maintenance (O&M) savings. These two cost savings are both a function of the reduction in energy provided by the conventional portion of the power system and, thus, will be discussed together. Variable O&M and fuel cost savings are commonly referred to as operating cost savings. Fixed O&M savings have been accounted for in the capacity displacement calculations.

The solar plant operation during peak as well as low load periods causes a spectrum of conventional units' output to be reduced. Figure 7-8 shows typical days' load shapes for three seasons of 1985 and what types of generation meet those loads. For solar plants installed in 1998 and 2005, Figures 7-9 and 7-10 show the generation types that operate to meet demand in those years. These three figures represent typical loads during the four seasons of the year. Since the solar plant operates during the daylight hours (or evening peak if the solar plant has storage), it displaces the most costly generation in the summer but much less costly generation during the winter. Thus, the solar plant operation reduces base and intermediate as well as peaking generator operation. The split between the types of generation changes from year to year.

The types of fuel displacement for the last 50 MWe of improved stand-alone solar capacity changes over the study period. Each year the ISA solar plant produces about 160 GWh_e, but the split between type of generating capacity displaced differs dramatically as is shown graphically (by the sum of the components) in Figure 7-11. This Figure shows that the displacement is dominated by oil in the first five years. This is because the system was extremely baseload deficient. As the system becomes more balanced, the solar plant output increasingly displaces baseloaded plants. In the last part of the study period additions of combined cycle and the retirements of several large #6 oil steam units cause distillate oil to be displaced more and residual oil and coal to be displaced less.

The dollar value of these electrical output displacements are found from the value of the fuel displaced plus the value of the variable O&M savings. Fuel components are charged at their fuel costs and present worthed over the thirty-year lifetime of the solar plant. The resulting fuel cost savings are shown in Figure 7-12. The net result is that the oil savings are exaggerated and the coal savings deemphasized because of the relative fuel costs and escalation rates.

The value of the O&M savings is much smaller than the fuel savings component of value. Both components of operating cost are found using the same calculational techniques. The O&M savings are totaled from the proportions of fuel types displaced times the variable O&M rate for the particular generating units corresponding to the fuel types. The O&M savings are shown along with the other value components in the bar graph, Figure 7-12.

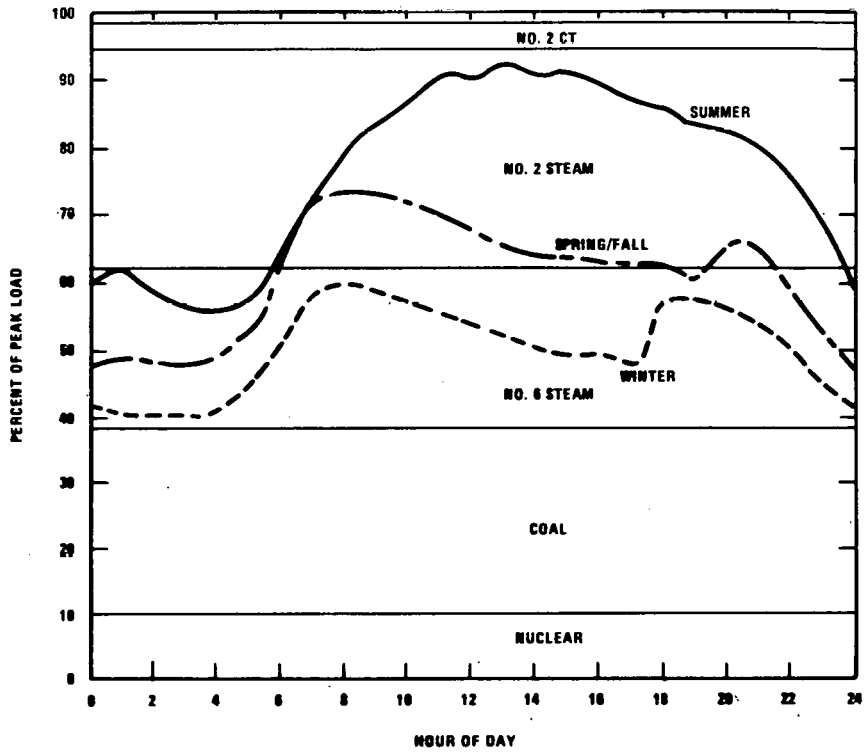


Figure 7-8. 1985 LOAD PROFILE AND FUEL MIX - REFERENCE CASE

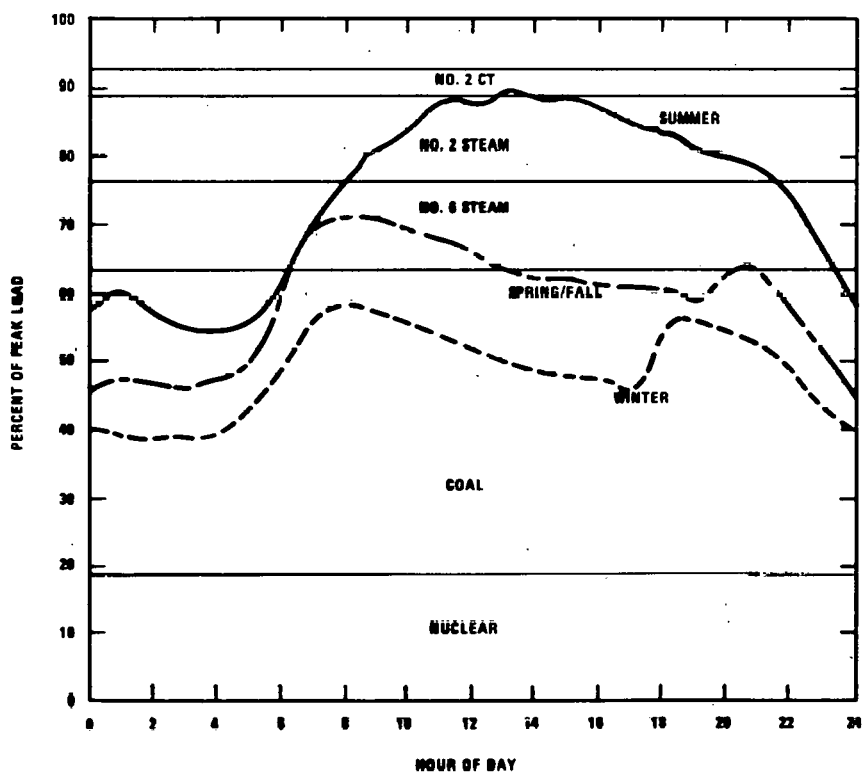


Figure 7-9. 1998 LOAD PROFILE AND FUEL MIX - REFERENCE CASE

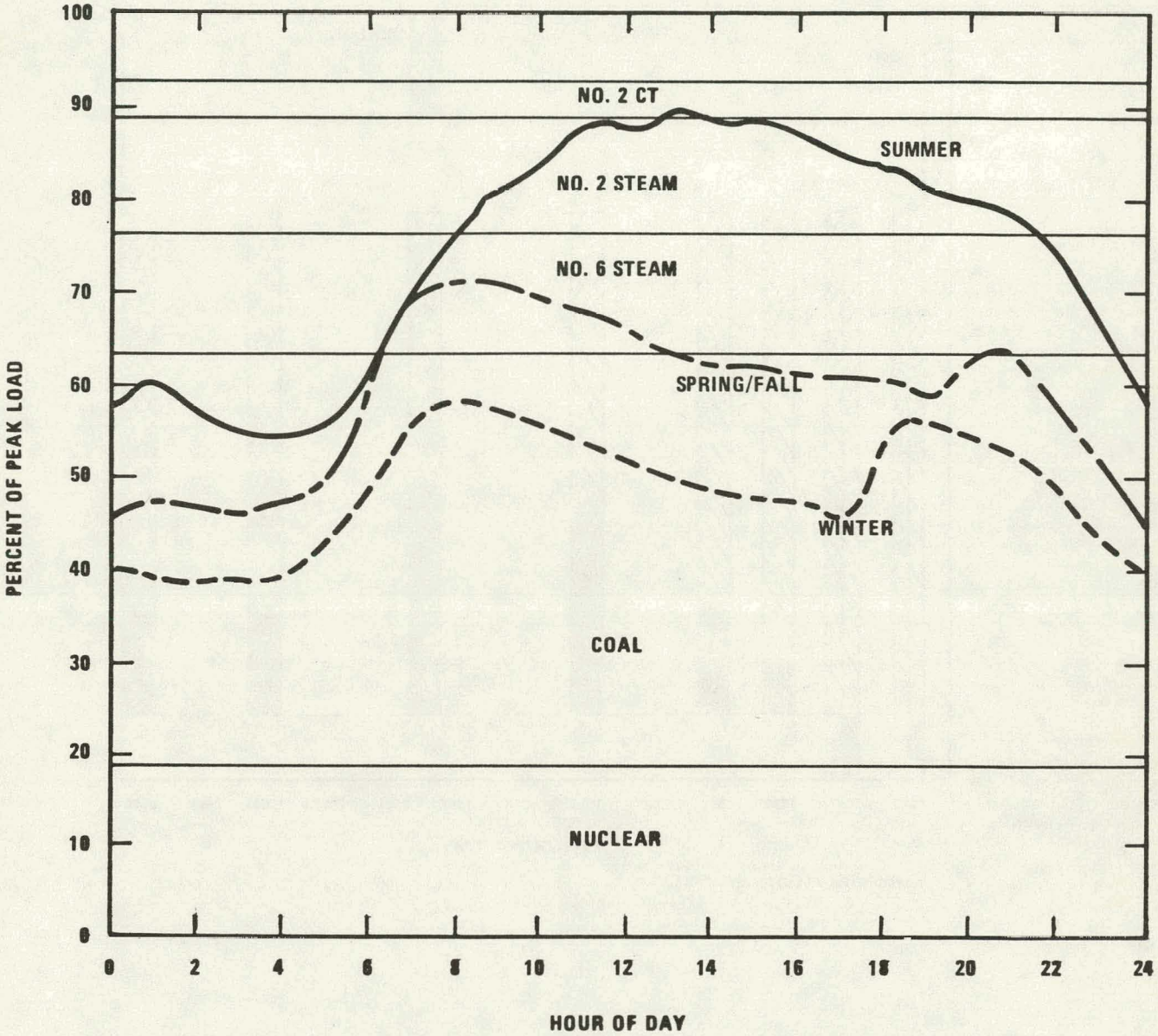
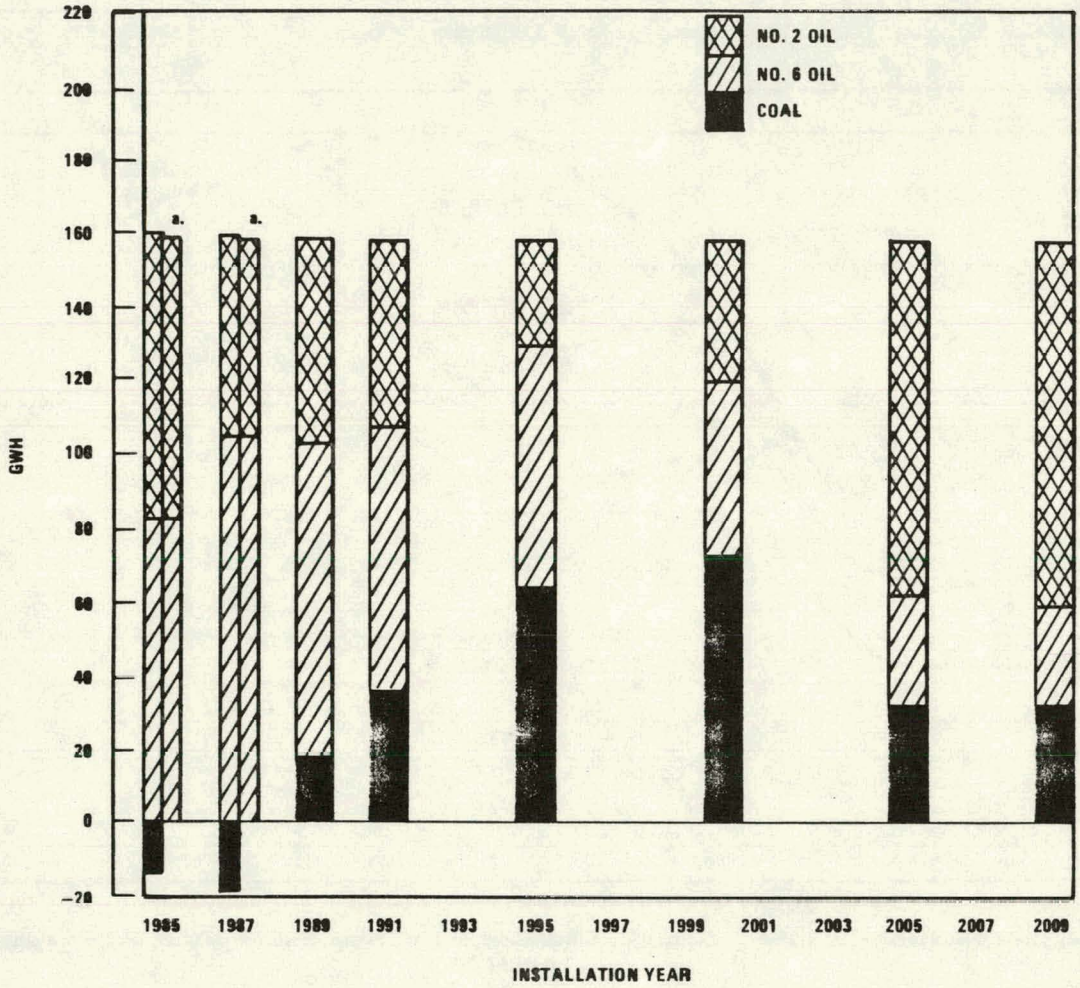
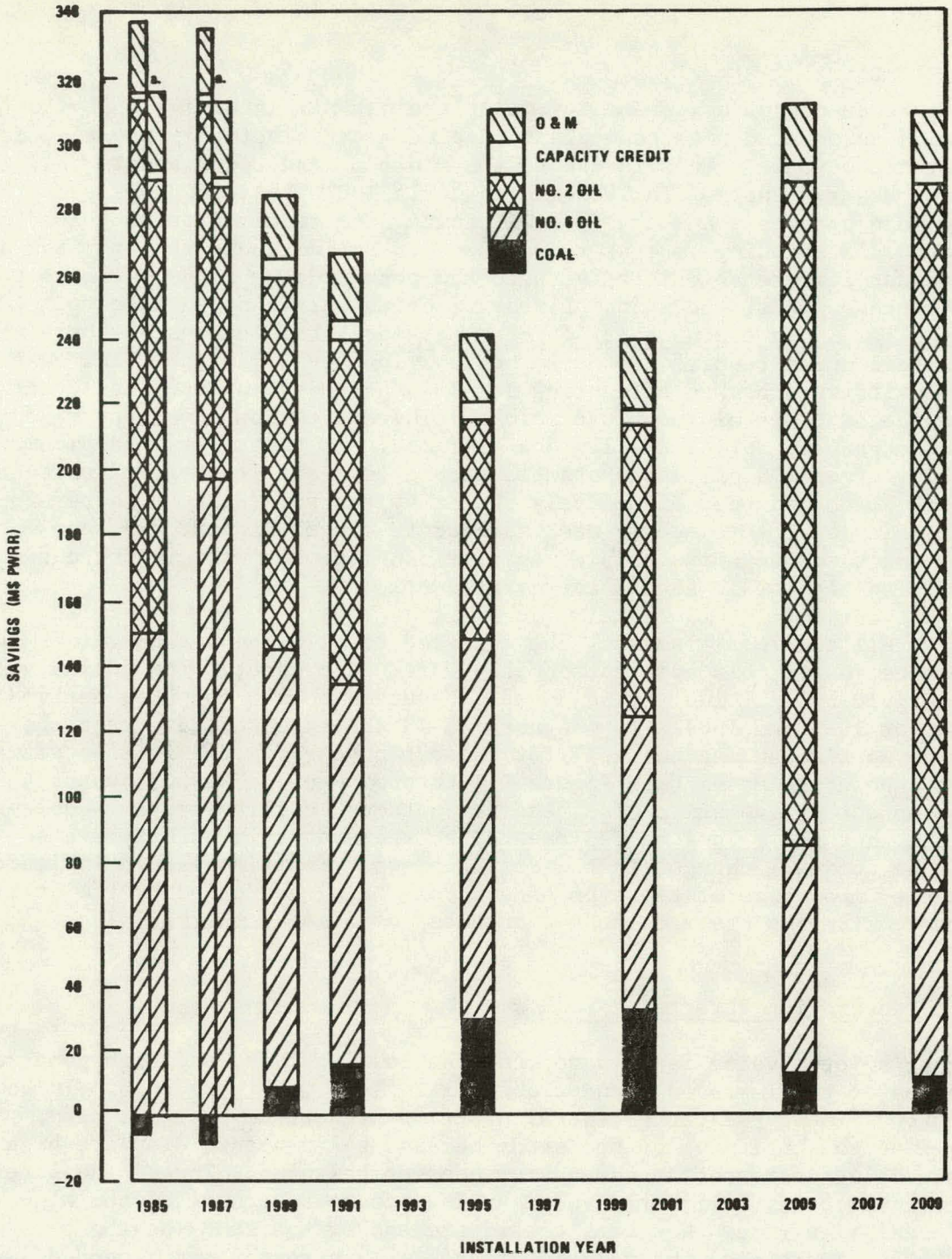


Figure 7-10. 2005 LOAD PROFILE AND FUEL MIX - REFERENCE CASE



a. ADJUSTED VALUES – SEE TEXT.

Figure 7-11. 50 MW SOLAR PLANT POWER OUTPUT FUEL DISTRIBUTION
ISA EXPERIMENT - NOMINAL PENETRATION



a. ADJUSTED VALUES – SEE TEXT.

Figure 7-12. 50 MW SOLAR PLANT POWER OUTPUT VALUE CAPACITY ISA EXPERIMENT - NOMINAL PENETRATION

The magnitude of the components of value are not all intuitively obvious. The value associated with coal plant displacement is actually negative in the first two years. This is due to the minimum load requirements on spinning reserve units. In 1985 and again in 1987 the demand was such that in low load periods a number of #6 oil units were required to meet load plus that period's spinning reserve requirements. During those same periods a significant difference existed between the peak and low loads. In order to meet those loads, the spinning reserve units were reduced in output to meet the load. In the nonsolar (higher net load) base expansion there were more #6 oil units required to meet the peak loads than in the solar case. The #6 units were backed off during low load periods, but they could not be reduced below their minimum load points. Therefore, some coal units' output had to be reduced during the low load periods. In the solar expansion case there were fewer #6 oil units started up and less net load variation because the peak loads had been effectively shared by the solar plants. Therefore, in the solar case more energy was produced from coal plants, and thus the displacement was negative. This negative displacement was countered by a higher displacement in #6 oil energy production.

Figures 7-11 and 7-12 also show the adjusted total GWH and PWRR values for this system as if this apparent anomaly were not present. The dollar values were derived by ratioing the adjusted GWH curves to the computer derived curves for 1985 and 1987. It was assumed in the adjusted case that there would be no displacement of coal for those two years. This is substantiated by the repowering cases (see Figure C-1 through C-6). These adjusted values may be more representative of a generic Southwest utility system. However, the fact that the values as represented by the synthetic utility are so sensitive to small changes in the dispatch of an individual unit indicate again the importance of the type of analysis being performed by the utility before commitments are made to the purchase of a solar thermal plant.

7.3.6 Penetration Effects

The year's total value is compared for the low, nominal, and high penetration scenarios of the improved stand-alone solar plant in Figure 7-13. In comparing the three value curves, the general high-low-high trend is replicated. Value is high at the beginning of the study because solar plants displace high cost fuels. Value decreases as the system becomes balanced. Toward the later third of the study period the value again increases because of the high fuel cost escalation rate. However, toward the end of the study as the penetration increases, the value decreases. This result was expected, as explained previously. The solar plant reduces the peak so that previous off-peak hours become the new limiting peaks. As those peaks are reduced by the solar plant, a larger number of hours become important. Thus, the peak reduction is always higher at low penetrations than at high penetrations. Also, the opportunity to displace high priced fuels decreases with penetration.

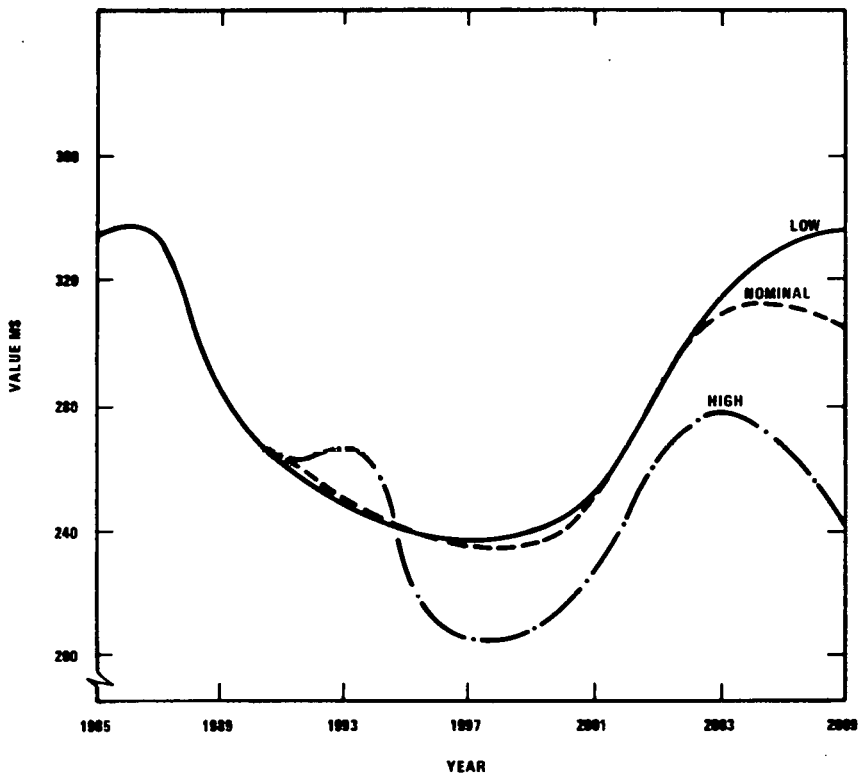


Figure 7-13. IMPROVED STAND-ALONE VALUE VERSUS PENETRATION

7.3.7 Value of Heliostats

Since heliostats are the predominant cost driver in the construction of a solar-thermal central receiver plant, one of the most important questions being asked is: What is the value of heliostats? Using the gross value numbers for an incremental 50 MW solar plant presented in Tables 7-9 through 7-11 and the cost assumptions for the solar plant without heliostats shown in Table 4-3 (corrected to a 50-MW plant), it is possible to back out the heliostat value using the following equation.

$$HV = \left[\frac{(PWRR - PWOM)\ CRF}{FCR} - PLHC\right] \frac{1}{OF * AC}$$

where:
- HV = Heliostat value in $\$/M^2$
- PWRR = Present worth of revenue requirements savings (Tables 7-9 to 7-11)
- PWOM = Present worth of the solar plant operations and maintenance costs
- CRF = Capital recovery factor
- FCR = Fixed charge rate
- PLHC = Solar plant less heliostat cost, burdened
- OF = Overall burden factor, includes: spares, contingencies, indirects, and interest during construction
- AC = Reflective area of the collector field

Figure 7-14 shows the heliostat value curves (in 1979$) for all of the penetration scenarios considered. For clarity they have been grouped by penetration level. As with the overall value curves, the value of heliostats falls initially and rises again toward the end of the study. This trend is followed, for the most part, for all of the scenarios.

By assigning the differences in solar plant value entirely to the heliostats, it is possible to detect some trends in the repowering versus stand-alone value competition. While the trend is not overpowering, in all except the high penetration scenario it appears that repowering has a slightly higher value for heliostats in the period before 2000 and that stand-alone plants have a slightly higher heliostat value after this time. This finding is consistent with a solar-thermal development program that emphasizes repowering early followed by the implementation of stand-alone plants. However, it needs to be remembered that this trend on the demand side is not a sufficient condition in itself around which to develop a government policy. Only with a clear understanding incorporating the supply and institutional effects can this be done.

In 1985 and 1987 the trend is not consistant in that stand-alone plants appear to have higher heliostat values than do repowered plants. As was mentioned at the end of Section 7.3.5 the addition of a few megawatts of solar in those years was just enough to change the conventional unit dispatch; the entire value of this change thus being attributed to the solar plant. If the conventional units had been of a different size, even with the same generation mix, this effect would not have been seen. Figure 7-14 also shows the values corrected for this effect. The values shown in Figure 2-1 are also the corrected values. This effect is not seen in repowering because the repowered plants (without storage) do not have the ability to reduce the evening peak (in the winter) which is so required for this phenomenon to take place.

The fact that the value of heliostats is so sensitive to a small change in the operating characteristics of one unit in the utility points out the importance of each utility performing this type of analysis for his specific system before a commitment is made to purchase a solar-thermal plant.

The heloistat value lines in Figure 7-14 have been drawn dashed beyond the year 2000 to emphasize a specific point. There is a great uncertainty in the future of the energy industry. It is a good possibility that around 2000 there will be the emergence of numerous electric generation technologies which, as with solar thermal, were previously too expensive. These may include such items as improved coal (gasifiers, fluidized bed combustion, MHD), synthetic fuels from coal, slate oil or biomass, gas pressure methane, improved storage technologies such as underground pumped hydro, compressed air, advanced batteries, storage-coupled coal plants, fusion and fast breeder reactors, other solar technologies (wind and photovoltaics), and fuel cells. Any of these may have a tendancy to reduce the value of solar thermal below the numbers presented. Thus the heliostat values shown after 2000 in Figure 7-14 may well be over-estimated. In addition uncertainties in fuel prices in that time frame make the results unreliable around the year 2000 and beyond.

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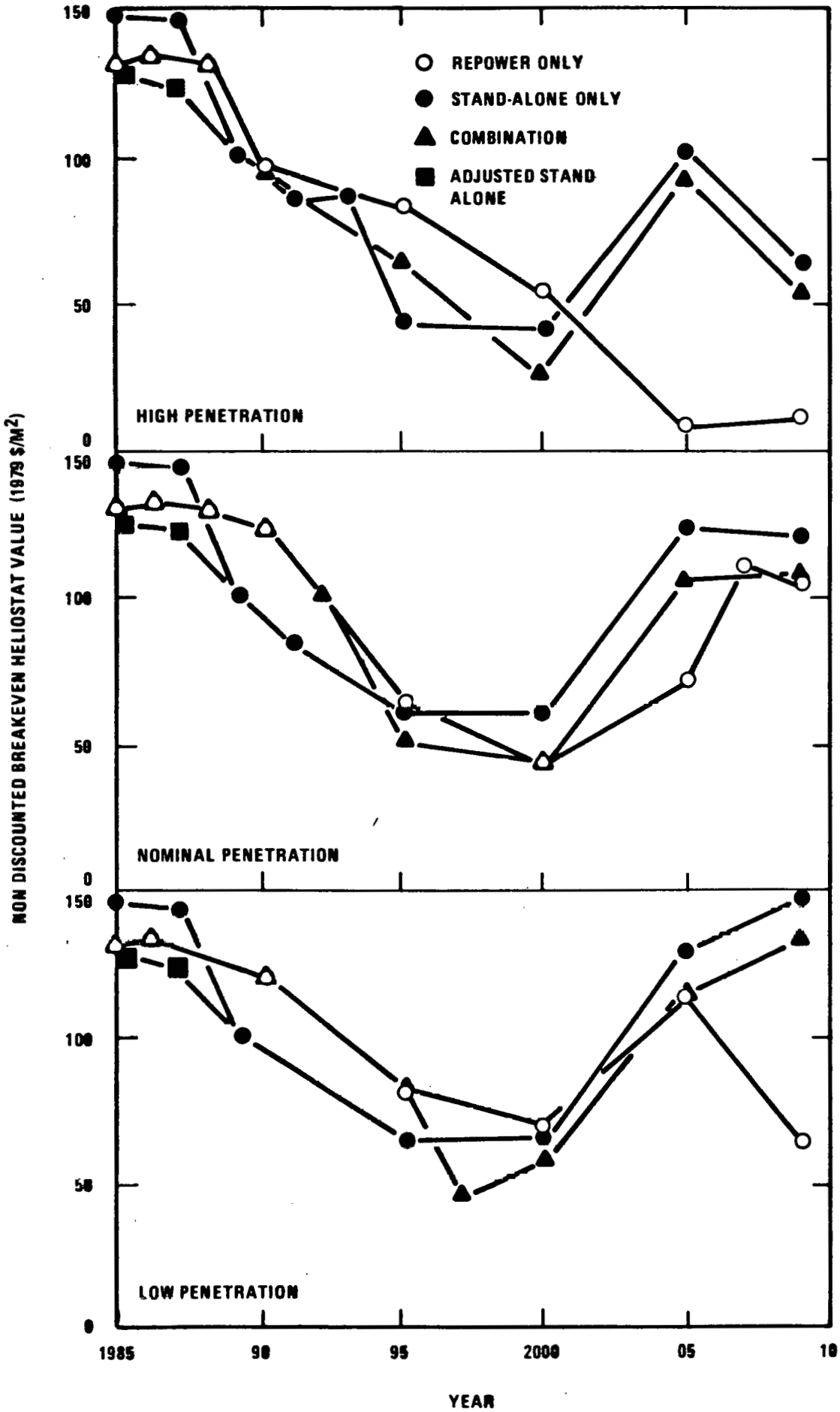

Figure 7-14. HELIOSTAT VALUE CURVES

SECTION 8.0

PARAMETRIC ANALYSIS

8.1 GENERAL

Many factors influence the value of a solar-thermal power plant. Some of the more obvious include existing and future utility system characteristics (load and generation mix), solar plant operating characteristics, and weather at the solar plant location site. In addition, economic assumptions, level of solar plant penetration, and timing of solar plant installations also affect the solar plant's value. The impacts of many of these parameters were given in Section 7.0; however, further sensitivities utilizing the static analysis methodology are shown in this section. These include:

- Installation Timing and Penetration
- Alternate Fuel Scenarios
- Solar Plant Cost Sensitivity
- Balanced Utility System Sensitivity
- Coal Plant Static Analysis
- Thermal Buffer Storage Sensitivity
- Sensitivity Comparison

The results of these sensitivities are presented in the order in which they appear above.

8.2 INSTALLATION TIMING AND PENETRATION

This section is included to generalize the effect of installation timing and penetration on the solar plant value. The specific details of this analysis were already pointed out in Section 7.0.

Generally, as time progressed the cost of fuel displaced by the incremental solar plant addition increased faster than its capital cost, which resulted in a solar plant value increase. Under these assumptions, no deviations from this value trend would have existed, provided the utility system was balanced and contained only an incremental solar plant addition; i.e., no increase in solar plant penetration with time. However, in this analysis solar penetration and utility mix both changed with time. The value of solar plants decreased with solar penetration because of the reduced opportunity to displace premium fuels and increasing backup capacity requirements. The value was also quite sensitive to the utility system generating mix as demonstrated in Section 7.0 and explained further in 8.5.

In addition to these two important elements, other factors which were encountered when the utility system was modeled in detail (such as retirement/repowering schedules, timing of nuclear additions, etc.) complicated the solar plant value generalization. However, this detailed modeling is consistent with practical utility system operation. This compounding of factors made it difficult to extract the impact of any single variable. The compound effects of these functions were described extensively in Section 7.0.

8.3 ALTERNATE FUEL SCENARIOS

It was found from previous solar-thermal plant economic analysis that the values of the solar plants are quite sensitive to conventional fuel costs and escalation rates [2,13]. For this reason an alternate fuel scenario, one in which only the fuel escalation rates were changed, was established. The alternate fuel scenario shows a 25% increase in all fuel escalation rates. All other costs are identical to those in the base reference economic scenario. Table 8-1 summarizes the fuel characteristics of these two scenarios.

Table 8-1. ECONOMIC SCENARIO FUEL COMPARISON (FUEL COST IN 1985 DOLLARS)

Fuel Type	Base		Alternate	
	Fuel Cost ($/MBtu)	Escalation Rate (%/yr)	Fuel Cost ($/MBtu)	Escalation Rate (%/yr)
#2 Oil	5.5	12	5.5	15
#6 Oil	5.0	12	5.0	15
Coal	2.0	10	2.0	12.5
Nuclear	1.25	9/13[a]	1.25	11.25/16.25

[a]First rate to the year 2000, second thereafter.

Assuming the solar plant operated in an identical manner, a substantially higher total solar plant value resulted from the alternate fuel scenario because of the larger fuel savings attributed to the increased fuel rates. By maintaining the same solar plant cost figures assumed in the base economic scenario, this increased solar plant value resulted in a significantly improved cost/benefit ratio.

Table 8-2 summarizes the values and cost/benefits of the improved stand-alone solar plants penetrated on the utility system at the nominal rate for the two fuel escalation rate scenarios. The cumulative solar plant capacity is also shown. In order to remove the effect of plant size, the values of the solar plants in years 1985 through 1991 were ratioed to represent values of 50 MWe solar plants. For years 1995 through 2009, the values shown were those attributed to the last 50 MWe of solar added to the system.

Table 8-2. ECONOMIC SCENARIO COMPARISON OF SOLAR PLANT VALUE AND COST/BENEFIT, IMPROVED STAND-ALONE, NOMINAL PENETRATION (PWRR, 1985 M$, 50 MWe)

Year	Cumulative Solar Capacity (MW)	Base		Alternate	
		Value (M$)	C/B	Value (M$)	C/B
1985	4	335.0	.84	501.2	.56
1987	12	334.2	.82	527.5	.52
1989	28	282.1	.94	462.3	.58
1991	64	264.1	.98	452.7	.57
1995	105	236.5	1.04	443.3	.56
2000	200	236.1	.98	499.3	.46
2005	365	310.8	.70	766.9	.28
2009	600	305.3	.68	838.3	.25

Figure 8-1 shows a band of solar plant values and cost benefits which has as its bounds the data shown in Table 8-2. This figure shows a widening of the solar plant value with time, which is a direct result of the increased fuel escalation rates. The values and resulting cost/benefits of solar plants would be within these bands if evaluated under an economic scenario in which the increase in fuel escalation rates were between 0 and 25%. Similar results were found for the other solar penetration scenarios.

Figure 8-1 also shows the sensitivity to a 50% increase in the base price of coal, escalated at the base (10%) rate. While the price of coal appears to be the long run limiting factor on the value of solar thermal plants (and hence maximum penetration), for the penetrations achieved in this study coal displacement is only a very small fraction of the total value (see Figure 7-12). Thus a 50% increase in the base price of coal creates a very small increase in value and a modest improvement in the cost/benefit ratio.

8.4 SOLAR PLANT COST SENSITIVITY

Although the determination of solar plant costs was not within the jurisdiction of this study, a sensitivity to the cost parameters given in Section 4.1.4 was considered valuable and quite easily performed. This static analysis consisted of evaluating the impact of a ±25% change in total solar plant cost (capital and O&M) on the cost/benefit ratios. Again, only the results of the improved stand-alone, nominal penetration solar plant scenario are illustrated here; however, similar results were obtained for the other solar scenarios.

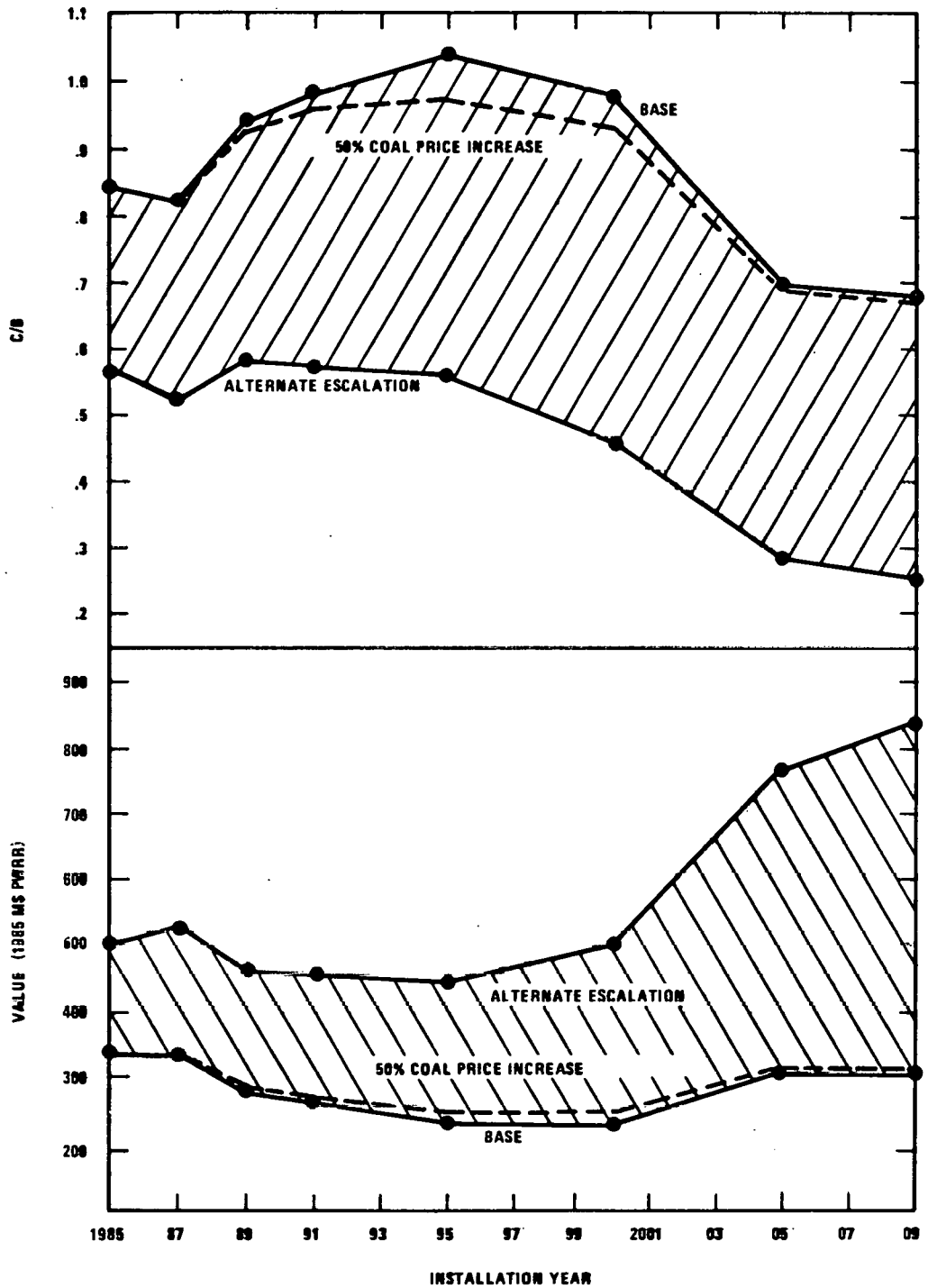

Figure 8-1. 50 MW SOLAR PLANT FUEL ESCALATION RATE SENSITIVITY ISA EXPERIMENT - NOMINAL PENETRATION

The ±25% change in total solar plant cost was used as a boundary to create, over time, the band of costs shown in Figure 8-2. The area within this band represents smaller percentage changes in the magnitude of the solar plant cost. These costs are thirty-year present worth of revenue requirements expressed in 1985 millions of dollars. This band has a negative slope because the discount rate is higher than the capital escalation rate. These solar plant costs when ratioed with the value of the solar plant (see Figure 7-13) produced a band of cost/benefit ratios, which is also shown in Figure 8-2. The solid lines in these bands represent the reference costs and resulting cost/benefit ratios.

Because the value, or benefit, of the solar plant was determined independent of its cost, a ±25% change in cost, with no change in value, resulted in a ±25% change in cost/benefit ratios as illustrated in this figure. A solar plant cost percentage change of a different amount will result in that same percentage change in cost/benefit ratio. This is true for all solar scenarios.

Figure 8-2 also shows (as a dotted line) the reference plant cost and cost/benefit ratio for a capital escalation rate of 8%, instead of 10%. This creates a three percentage point difference between the capital escalation and the discount rate which significantly improves the cost effectiveness of capital intensive plants in future years. Some theories [17] support that capital will escalate at approximately the same rate as inflation (about 8% in this study). If this is indeed the case, the long-run, capital intensive plants will become increasingly cost-effective. However, it must be remembered that the dotted curves in Figure 8-2 are based only on the static analysis. Under a nulti-year dynamic analysis with a reduced capital escalation rate, new coal and nuclear capacity would also be more desirable in future years. Since solar-thermal plants derive their value primarily from fuel savings, a decrease in capital escalation could reduce the value by a switch to more capital intensive, lower fuel cost conventional units. Thus the "real" cost benefit ratios may be less favorable than the dotted curves would indicate.

Figure 8-3 shows the band of heliostat values for the two capital escalation rates, for the repowering and stand-alone nominal penetrations. As in Figure 7-14, the region beyond 2000 is shown by broken lines to indicate uncertainty in that time frame.

In addition to the previously described static analysis, a dynamic solar plant cost sensitivity was also performed. This analysis, however, assumed a change in solar plant fixed charge rate, not total solar plant cost. It should be pointed out that no tax incentives were applied to the solar plant costs with a full 18% fixed charge rate being used. However, a reduction in fixed charge rate could be assumed provided tax incentives were granted. In the Improved Stand-Alone (ISA) nominal penetration case, a reduction in the fixed charge rate from 18 to 15% reduces the present worth of the costs for the solar plants by 15% over the study period (see Table 8-3).

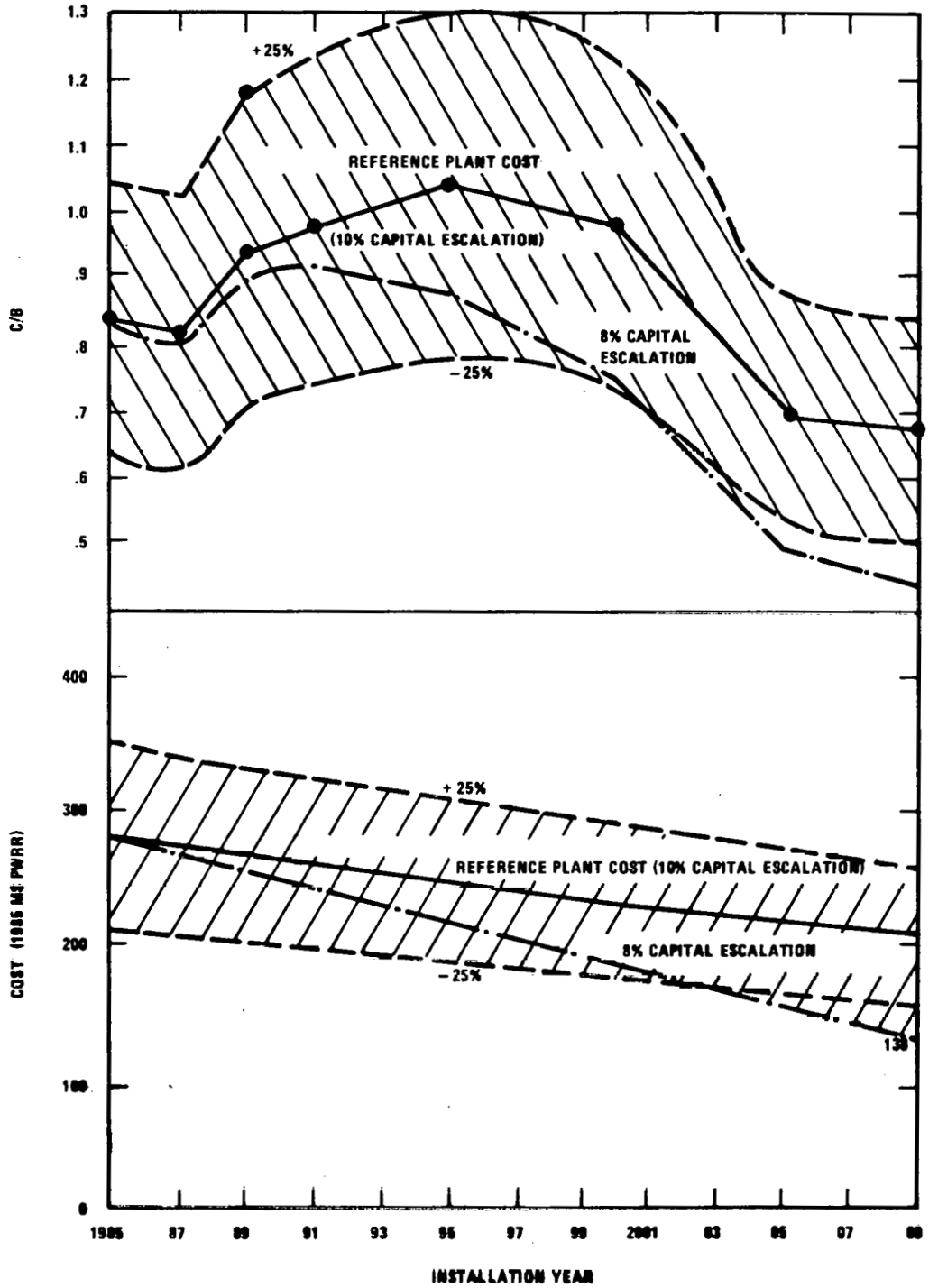

Figure 8-2. 50 MW SOLAR PLANT COST SENSITIVITY
ISA - NOMINAL PENETRATION

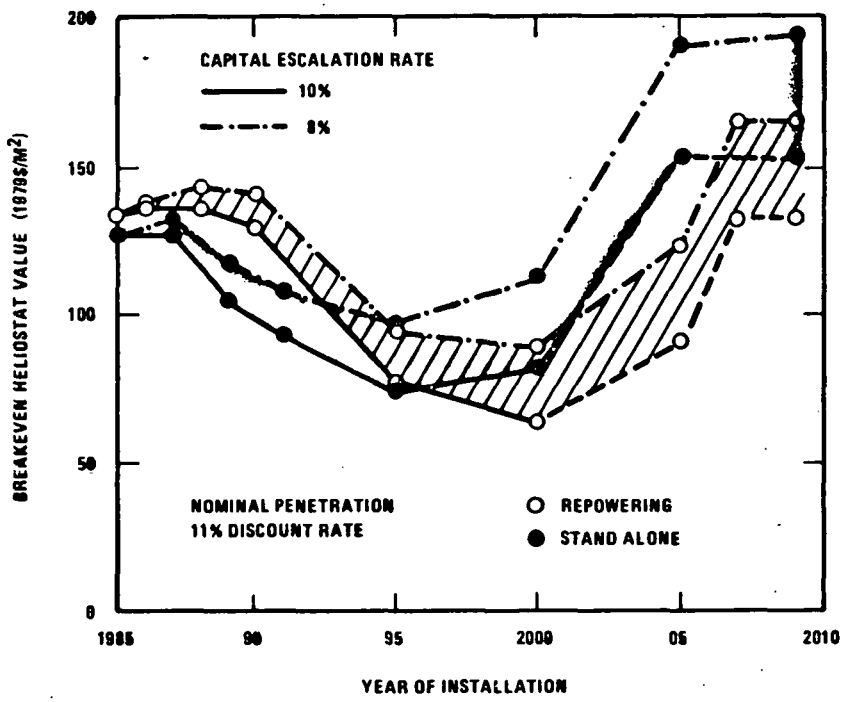

Figure 8-3. REPRESENTATIVE HELIOSTAT VALUE TRENDS

Table 8-3. IMPACT OF SOLAR PLANT FIXED CHARGE RATE (PWRR, 1985 BILLIONS $)

	Base Case Nonsolar	ISA-Nom 18% FCR	ISA-Nom 15% FCR
Conventional	69.38	68.61	68.61
Solar Plant	---	1.36	1.16
Total Cost	69.38	69.97	69.77

8.5 BALANCED UTILITY SYSTEM SENSITIVITY

As has been pointed out several times, the value of the solar-thermal plants was very high in the early years due to the unbalance in the system generation mix (60% oil capacity in 1985). Solar plant value sensitivity to this generation mix parameter was performed by modeling the lifetime operation of a solar plant on a balanced utility system. This was done by first choosing a year from the expansion period in which solar plant static analysis was performed on what appeared to be a balanced utility system. Then the operation of the last 50 MWe of solar penetrated on the utility system in this year was assumed constant for every year in the study period. In other words, the type and quantity of fuel displaced by the solar plant in this year was assumed constant through time. Its operation did not change.

Based on the nonsolar reference case percent capacity mix summary shown in Table 6-6, the year 2005 most closely approximated a balanced generation mix. At this time, the system capacity consisted of 57.5% base, 18.5% intermediate, and 24% peaking. All of the intermediate and peaking capacity was comprised of oil, which made the total oil capacity 42.5%. The operation of the last 50 MWe of solar added under the ISA low penetration solar scenario was assumed constant during the study period. The low penetration solar scenario was selected to minimize the effect of solar penetration. In the year 2005 there was a total of only 125 MWe of solar on the utility system, so the penetration effect was small, if there was any at all.

Figure 8-3 graphically displays the value comparison of the solar plants when operating on balanced and unbalanced systems. The curves are expressed in terms of thirty-year present worth of revenue requirements, 1985 millions of dollars. The value of the solar plant on the balanced system is well behaved and increases with time due to the increased cost of fuel. This comparison points out how much of the solar plants' value in the early years was attributed to the unbalanced system generating mix. The value of the solar plant in the intermittent years was lower on the unbalanced system due to the large amounts of baseloaded coal capacity added in this timeframe. These curves intersect in the year 2005 because both systems have identical generating mixes. The solar plant value is again higher in the unbalanced system in year 2009 because more conventional oil energy was displaced by the solar plant in this year (see Figure C-14, Appendix C).

8.6 COAL PLANT STATIC ANALYSIS

Although the values of the solar-thermal plants often exceeded their projected costs, they were not necessarily the most cost effective technology available for addition to the utility system. For comparison purposes, an experiment was conducted in which the cost/benefit of an additional coal plant was determined. This experiment closely followed the combination nominal penetration solar scenario, differing only in that the last 50 MWe forced onto the system was coal instead of solar. The value of the coal plant was found by simulating the plant's operation on the solar-thermal model for the years in which the combination solar scenario static analysis was performed. The cost of the plant was obtained by derating the cost of the 600 MWe coal plant, shown in Table 4-1, to be representative of a 50 MWe unit. Both cost and value were expressed in terms of 30-year present worth of revenue requirements, 1985 millions of dollars.

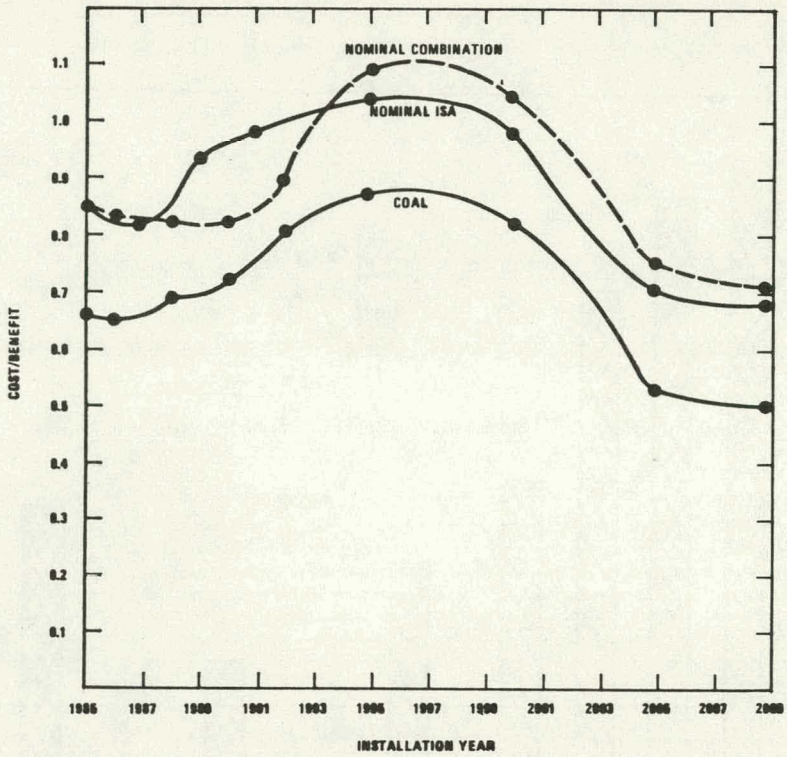

Figure 8-4. 50 MW SOLAR PLANT VALUE COMPARISON WITH GENERATING MIX ISA - LOW PENETRATION

Shown in Figure 8-4 are cost/benefits obtained from the coal experiment compared against those found in the combination and improved stand-alone, nominal penetration solar scenarios. It is apparent from this figure that the coal plant was more cost effective than the solar plants penetrated under either scenario, for the entire study period.*

The cost and operating characteristics of the 50 MWe coal plant were such that it was dispatched after the new but before the existing coal plants in the production cost model. The changes in the yearly energy produced by the 50 MWe coal plant were directly influenced by this dispatch order. The 50 MWe coal plant displaces energy of the amount and type illustrated in Figure 8-5. The coal energy displaced was initially supplied by the existing coal units. The energy produced by the 50 MWe coal plant was very high in the early years (74% capacity factor) due to the system's baseload deficiency. However, as more and more new coal plants were added to reduce this deficiency, the 50 MWe coal plant's energy production steadily decreased. During the years 1999 through 2002 the combination scenario, conventional unit expansion plan,

---

*Cost/benefit ratios were not developed for conventioanl oil-fired plants. If they had been, it would be seen that solar-thermal plants are indeed cost effective with new oil-fired facilities. This follows directly from the fact that the cost/benefit ratio for solar thermal is often less than one given the generation mix and expansion for the synthetic system E.

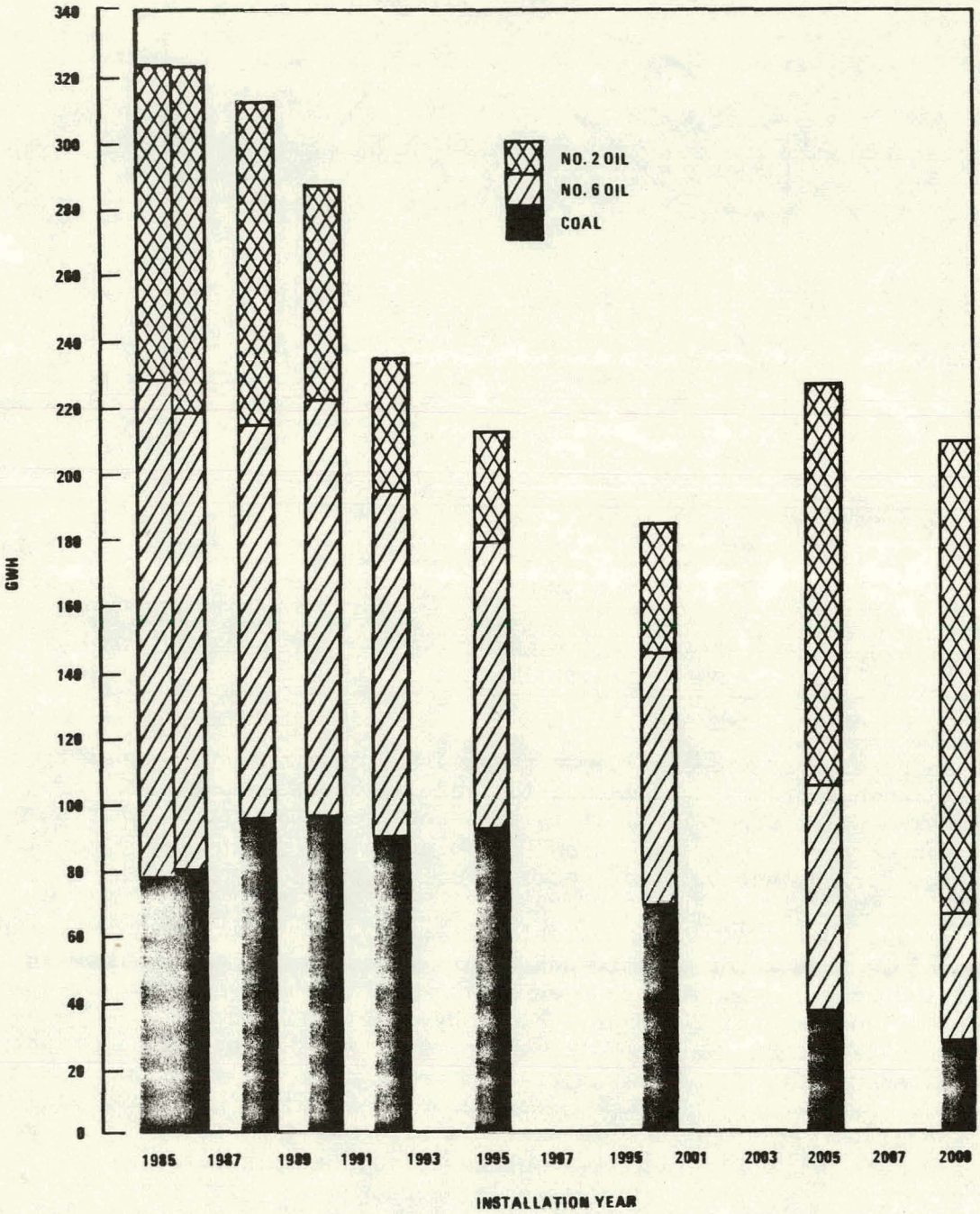

Figure 8-5. 50 MW COAL POWER PLANT FUEL DISPLACEMENT COAL EXPERIMENT

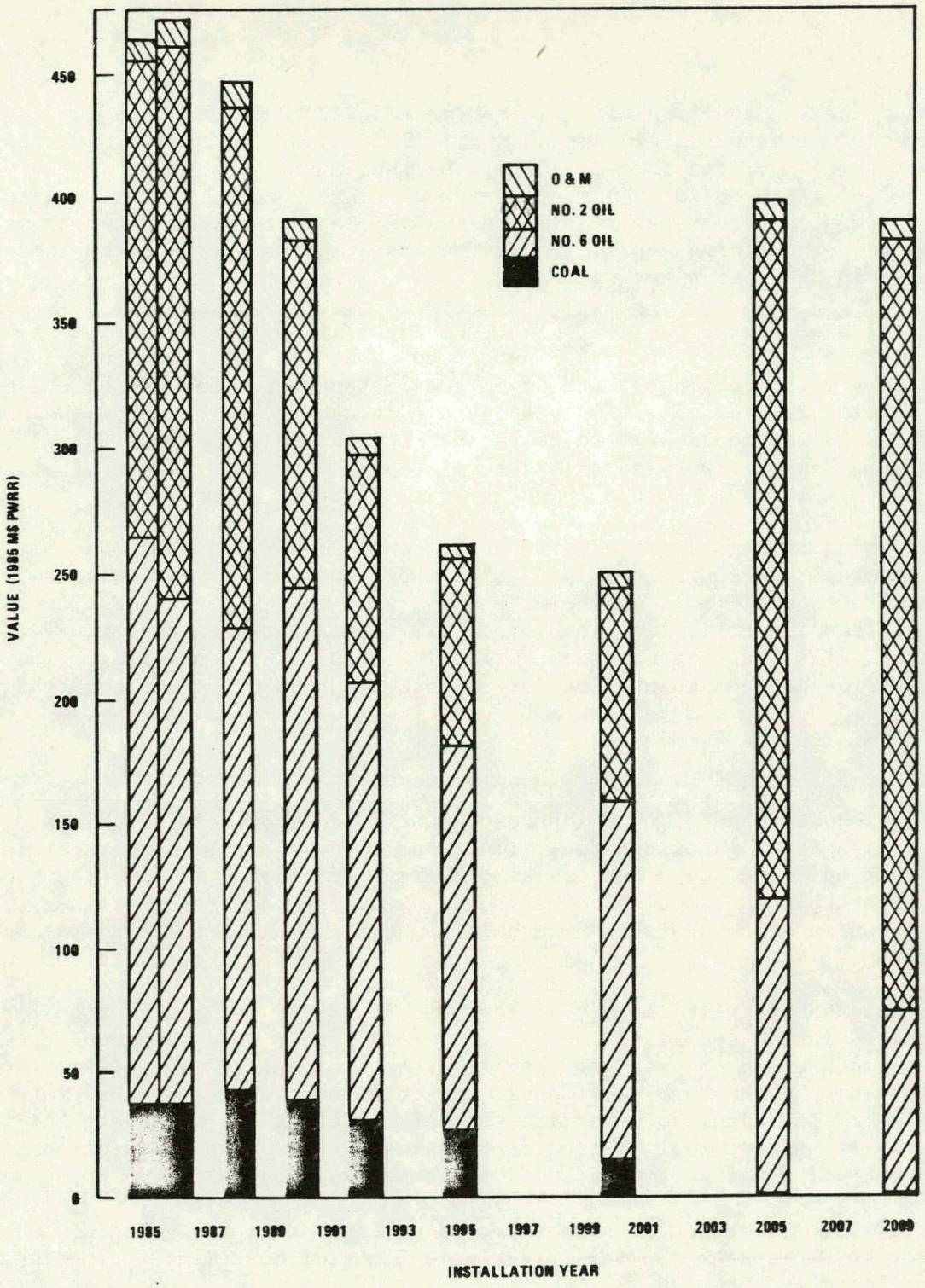

Figure 8-6. 50 MW COAL POWER PLANT VALUE COMPONENTS
COAL EXPERIMENT

called for the addition of only peaking and intermediate units, no coal was added (see Figure B-17 in Appendix B). This meant the system required cycling capacity. Thus, the forced addition of the 50 MWe coal plant in the year 2000 compelled it to operate in a cycling mode (42% capacity factor). After the year 2002 the system was in balance and all three types of capacity were added during the remaining years. Since coal capacity was needed, the energy produced by the 50 MWe coal plant increased.

The value of the 50 MWe coal plant, based on its energy displacements (Figure 8-5), is shown in Figure 8-6. As can be seen, its value was comprised almost entirely of oil savings, more so in the latter years, because of the high escalation rate of oil. No capacity credit was given to the 50 MWe coal plant because it was considered to be an incremental addition above the 25% reserve margin. However, were capacity credit (capital savings) given it would serve to further improve the cost/benefit ratio in favor of coal.

Repowering of existing plants with coal or coal-derived fuels was not considered. As shown in this section there may well be technologies which are more economic than new solar plants, even though the solar plants have a cost/benefit ratio less than one. Likewise, there may be retro-fit technologies that are more cost effective than solar repowering. The identification and quantification of these is beyond the scope of this study.

8.7 THERMAL BUFFERING

In EPRI Study RP 648, "Requirements Definition and Impact Analysis of Solar-Thermal Power Plants," Westinghouse identified a potential requirement for thermal buffering during insolation transients. That is, under partial cloud cover conditions and cloud passage, thermal transients may emanate from the receiver that should be smoothed before reaching the steam turbine. The seriousness of this problem can only be established by solar system hardware testing.

For the Barstow technology, Westinghouse in RP 648 assumed that buffering was required during specified cloud cover conditions. This function was modeled as a requirement to pass the thermal energy through the thermal storage system before use by the turbine. Hourly sky conditions on the weather tape were tested by the model to determine whether buffering was necessary for that hour. In solar/fossil hybrid plants using Barstow technology without storage, the buffering was performed by firing the fossil boiler.

One of the advantages of some improved solar-thermal technologies is an inherent short-term thermal buffering ability without significant loss in efficiency.

At the very outset of this repowering Demand Task, a value analysis was run to estimate the impact of a no-efficiency-loss buffering feature. The case was run using a model of a repowered steam (Barstow type) solar/fossil hybrid plant without storage. The results are shown in Table 8-4.

Comparison should not be made with the other tables in this report as a consistent set of assumptions are not used. In particular, an old Aerospace Midland, Texas weather tape was used, and the plant cost assumptions were on a different basis. The utility was the unmodified EPRI synthetic utility system E. No cost penalty was assessed the solar plant to implement the buffering function.

The important result is the impact upon solar plant value, an increase of 25%. The principal contribution in this case is the reduction in the oil firing required at the repowered plant. Oil requirements were necessary for boiler startup in each day that boiler-supplied buffering was required.

Table 8-4. TRANSIENT BUFFER VALUE ANALYSIS
PRESENT WORTH 1985 M$

[Barstow-type repowered plant, 50 MWe
Midland insolation, EPRI Utility E]

	No-Oil Buffering	Oil-Fired Buffer Required
PW Solar Plant Cost		
Capital Revenue Requirements	126.8	126.8
Operating Revenue Requirements	45.4	45.4
Total PWRR	172.2	172.2
PW Solar Plant Value		
Fuel Value	189.5	197.5
Fuel Used (Solar Plant)	(2.4)	(53.7)
Variable O&M	2.6	3.6
Capacity Credit	22.3	22.3
Total	212.1	169.7
Cost/Value Ratio	.81	1.02

8.8 SENSITIVITY COMPARISON

The previous sections have shown parametric sensitivities to variations in certain specific assumptions. In order to place in perspective the relative importance of several assumptions, a small computer program was written to perform sensitivity analysis on primarily economic parameters. The output of this program, was verified against the more detailed production cost simulation for the year of interest. The input parameters of interest were then changed by 25% to 50% to obtain the effect of their relative importance. Figure 8-7 shows the results for the stand-alone plant in 1985. As can be seen, the fuel

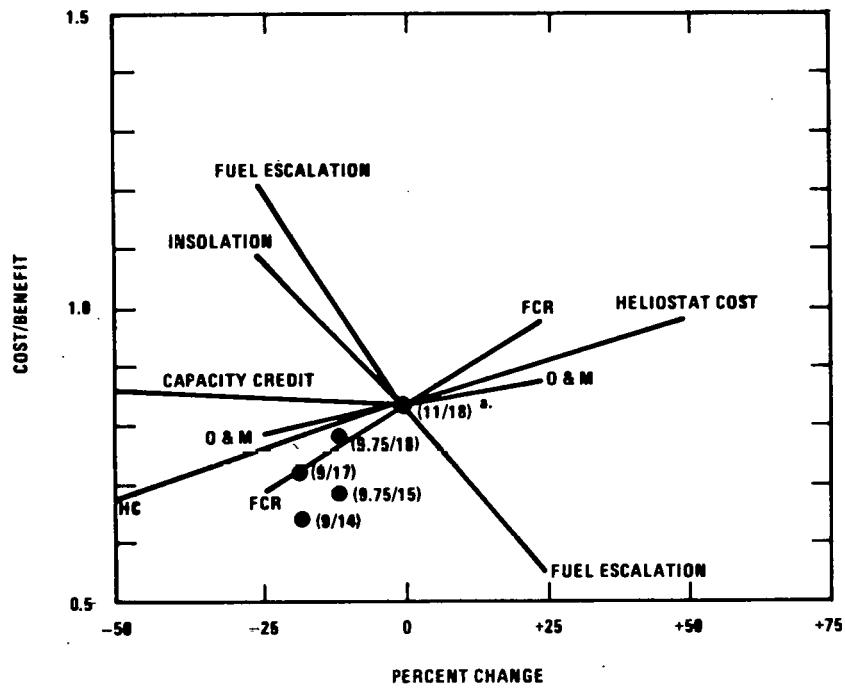

Figure 8-7. 50 MW COAL POWER PLANT VALUE COMPONENTS
COAL EXPERIMENT

escalation rate is the most sensitive assumption. If fuel escalates at a rate 25% less than was assumed as a baseline (12% for oil, 10% for coal) for the entire thirty-year economic horizon, then the viability of solar-thermal power is drastically reduced. The cost of heliostats affects the cost/benefit ratio significantly, as should be expected, but it is not as important as an equivalent change in the fixed charge rate. On the other hand, the decision as to whether or not to take capacity credit makes very little difference in the overall economics Also on the Figure are four points showing the effect of a reduction in both the discount rate and fixed charge rate. A lower discount rate is representative of certain utilities with a lower cost of capital. The lower fixed change rate for the two discount rate cases represents a tax or investment incentive program.

Only the one sensitivity chart is shown because there is no significant difference in the relative importance of the parameters as a function of time or technology (stand-alone vs. repowering). The centroid simply moves up and down, following the cost/benefit curves, moving the whole graph with it.

8.9 SENSITIVITY CONCLUSIONS

The results of any analysis are heavily dependent upon the assumptions. This section has presented several sensitivities on a variety of different parameters to show the interested reader the effects of some of these assumptions.

The future prices and escalation rates of competing fuels are extremely important and yet are one of the more uncertain parameters. A higher escalation rate than was assumed in the reference economics can create significant improvements in the cost effectiveness of solar-thermal plants, while as much as a 50% increase in the reference price of coal has little effect.

A change in the capital cost of the solar-thermal plants has, of course, a direct impact on the cost effectiveness. The difference between the long-term capital escalation rate and the discount rate, and fuel escalation rates, can also have a significant impact, but it can also create a more favorable position for capital intensive competition.

Finally, the true cost effectiveness of solar-thermal must be compared with a very large number of competing technologies. While these comparisons are beyond the scope of this study, utilities will make these comparisons before any large commitment is made to alternate energy technologies. Further study of these comparisons as well as further comparisons between solar-thermal plant configurations must become an ongoing task of solar-thermal technology development and commercialization.

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APPENDIX A

SOLAR-THERMAL POWER PLANT EVALUATION METHODOLOGY

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TABLE OF CONTENTS

		Page
A.1	INTRODUCTION AND SUMMARY	111
A.1.1	General	111
A.1.2	Objectives	111
A.2	GENERAL METHODOLOGY	113
A.2.1	General Procedures	113
A.3	EXPANSION PLANNING	115
A.3.1	Introduction	115
A.3.2	Capabilities	116
A.3.3	Mathematical Treatment	117
A.3.4	Structure	118
A.3.5	Simulation Option	119
A.3.6	Inputs and Outputs	119
A.3.7	Application	121
A.4	STATIC ANALYSIS	123
A.4.1	General Static Analysis Methodology	124
A.4.2	Simulation of Operation	125
A.4.3	Insolation Data Base	140
A.4.4	Summary	141
A.5	ECONOMIC METHODS	143
A.5.1	General Methods	143
A.5.2	Solar Plant Optimum Expansion Value Calculations	149
A.5.3	Solar Plant Static Analysis Value Calculations	149
A.5.4	Busbar Energy Cost Calculations	152
A.5.5	Utility System Cost Impact	152
A.5.6	Cost/Benefit Calculations	153
A.6	COMMENT	155
A.7	REFERENCES	157

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SECTION A.1

INTRODUCTION AND SUMMARY

A.1.1 GENERAL

This appendix is produced in partial fulfillment of SERI study XH-9-8016-1, "Repowering Strategy Analysis - Demand Task/Utility Worth Analysis."

The Demand Task study is organized into five subtasks, as shown in the task description table (Table A.1-1). The first task is concerned with creating a data base for use in the balance of the study. Task 2 is a methodology development for use in the subsequent tasks. This appendix is a product of Task 2. Tasks 3 and 4 constitute most of the numerical analysis to be performed. Task 5 involves interpretation and reporting these numerical results.

A.1.2 OBJECTIVES

The purpose of this appendix is to document the methods and procedures developed in the methodology formulation portion of Task 2 of the Demand Task study. This methodology includes the process for evaluating solar-thermal plant impact on utility expansion plans, utility reliability, backup requirements and economics. This appendix also discusses how those impacts were assessed for various levels of solar penetration.

In the following sections the methodology will be discussed in a general fashion, and then details will be given on the two specific portions of the methodology: optimized generation planning and solar plant static analysis.

Table A.1-1. TECHNICAL APPROACH TASK DESCRIPTION

TASK 1	DATA BASE FORMULATION Establish the data base concerned with (1) Plant Characterization, (2) Economic Assumptions, (3) Utility Data Base, and (4) Insolation Data Base.
TASK 2	EXPERIMENT DESIGN AND METHODOLOGY FORMULATION Finalize the methods used and then formulate experiment design.
TASK 3	BASE COMPUTER ANALYSIS Analyze the base cases using GENOP.
TASK 4	PARAMETRIC ANALYSIS Perform sensitivity analysis and single "time slice" analysis using most cost-effective means.
TASK 5	DOCUMENTATION AND MEETINGS Five reports will be delivered and frequent meetings will be held.

SECTION A.2

GENERAL METHODOLOGY

Certain general guidelines were used in establishing the methods described in this appendix. They were as follows:

- To utilize conventional utility planning methods and tools as much as possible. This serves to enhance the ease of interpretation of results by utility planners and others familiar with these techniques, it provides confidence in the results through the use of established, tested methods, and it allows the use of existing tools or computer programs.

- Utilize existing solar plant static analysis methodology which was developed in EPRI RP 648. That is, to use the tools, procedures and data developed under that or other previous studies wherever practical.

- Provide for the rapid completion of the study.

Naturally, the overriding consideration was the use of methods which would provide meaningful results.

A.2.1 GENERAL PROCEDURES

Three principal analytical methods were used in this study:

- Linear optimization techniques are used to obtain the most economic generation expansion plan in GENOP.

- Simulation of the solar plant operating with a utility system, using integrated economic dispatch

- Classical loss-of-load probability calculations to achieve a desired level of utility system reliability

These three principals are used in the two major thrusts of analysis in this study: optimized generation expansion planning with varying degrees of solar plant penetrations, and solar plant static value and impact analysis. The two analysis methods are described briefly on the following page and in more detail later in this section.

The first evaluation analyzes how particular penetration scenarios of solar plant installation affect a utility's optimum generation expansion plan. The analysis was done for several solar plant types and involved several solar plant penetration scenarios as well as sensitivity analysis on important variables. The solar plant penetration scenarios, system load characteristics and starting configuration were exogenous variables. The timing and type of conventional generator additions were endogenous to the generation expansion analysis procedure.

The dynamic penetration approach to the study has as its cornerstone the Westinghouse Generation Expansion Optimization Program. There are five classes of input data required by the program. They are (1) forecast load data, (2) existing unit data, (3) potential unit addition descriptions, (4) economic data, and (5) reliability requirements. The Westinghouse Generation Expansion Optimization Program, henceforth GENOP, developes an installation schedule for the type and size of each unit, describes the unit capacity factors, gives annual and total plan costs, and the resulting capacity reserves.

The generation expansion analysis proceeded in the following manner. Base case year utility loads were projected to all twenty-five study years. A base nonsolar generation expansion plan was found for those reference projected loads. The next phase involved finding expansion plans after the inclusion of certain solar plant penetration scenarios. The result of solar plant operating models were used to modify the system reference loads according to the particular predetermined penetration schedule being considered. After the solar plant penetration has reduced the system demand, GENOP then chooses from its "shopping list" of generating unit types a new optimum expansion plan that meets the system's modified load growth requirements in a manner that minimizes the present worth of revenue requirements for the sum of capital and operating costs. Forced penetration of solar plants on the utility and the use of the resulting modified demand is the basis for system expansion results in different solar expansion plans when compared to the base nonsolar optimum expansion plan. Differences in expansion plan installations, present worth of revenue requirements, and reserve generation percentages are found from that comparison.

The procedure used in this analysis was to force increasing solar penetration over a period of 25 years. Then GENOP is used to build the balance of the utility system which is most compatible with the solar penetration. In this manner the time-dependent planning effects of solar penetration can be observed. For example, certain adjustments may be made in early expansion phases to better accommodate solar plants which are to be installed in later years.

The solar plant static value analysis was used to identify the value of the last installation of many individual solar plants. Sequential use of the static analysis was used to obtain the values of the last solar plant for varying penetrations. For instance, an advanced hybrid repowered solar plant's value can be found for a specific installation year at a specific level of solar penetration. This detailed information on a specific plant is not available from the GENOP analysis.

The static solar plant analysis proceeds along the following line. For a particular solar plant and installation year, the simulation of solar plant output is used to modify the utility system reference loads. Production costs are compared for the balance of the system before and after the forced solar penetration. Hourly load reductions are used to calculate conventional generation capacity displacement and economic procedures are used to calculate the resulting solar plant value.

The static analysis is used to obtain specific impact data for specific solar plants (e.g., cost/benefit); however, the dynamic penetration analysis is the principal tool in this study because of its ability to analyze a complete scenario made up of changing penetrations of solar plants.and changing conventional plant generation mix. This analysis determines the impact of the scenario rather than the impact of a single plant.

SECTION A.3

EXPANSION PLANNING

A.3.1 INTRODUCTION

The Westinghouse Generation Expansion Optimization Program, GENOP, is used to automatically develop the most economic generation expansion plan before and after solar plant additions. A comparison of the plans indicates the economic impact of a specific solar plant penetration scenario. GENOP automatically selects the best timing, size, and type of generation installations, from a list of available units, to minimize the total plan costs while respecting the utility system reliability requirements. The plan costs include both capital and operating costs, and the time value of money (present worth discounting). By comparing the optimum generation plan before and after system loads have been reduced by the operation of solar power plants, the solar plant's impact on utility expansion plans, utility reliability, and economics will be determined.

The GENOP program develops the most economical expansion plan to meet the system reliability constraint, which is imposed in terms of percent reserve. In developing this plan, the optimization program considers trade-offs between large units for economy of scale and small units for increased system reliability; it balances trade-offs between units with high capital costs and low fuel costs (such as nuclear units) against units with lower capital costs, but higher operating costs; and it considers the impacts and trade-offs associated with unit installation timing, since the carrying charge penalty associated with installing a unit larger than needed in one year might be more than justified by the savings due to economy of scale and delay in subsequent installations.

The discount effects associated with present worth economics, as well as escalation of capital costs and fuel costs, influence the optimum plan selected by the program. Separate inflation rates and carrying charge rates are input for each type of generating unit as well as different inflation rates for each type of fuel.

Also important are the representation of the existing and previously committed generating units, their forced outage rates, and operating economics.

Several unit types may be input in one run for selection by the program. Gas turbines, nuclear units, coal fired steam units, combined cycle fossil units, and pumped storage hydro might typically be made available for expansion selection at one time.

The requirements for scheduled outages for maintenance as well as maintenance costs are also considered in this program, as are the effects on forced outage rate of unit maturity.

All of these considerations are balanced over a planning horizon to achieve the best expansion plan. The program does not optimize sequentially on a period-by-period (for instance, year-by-year) basis, as this can lead to a

series of local (short-range) optima which when put together do not necessarily produce the global (long-range) optimum plan.

The optimization program has obvious applications in rapidly determining the best expansion strategy for a utility system and in determining the sensitivity of the optimum strategy to economics and other system parameters.

A.3.2 CAPABILITIES

Capabilities which were felt to be important to a realistic optimum solution, and which were therefore incorporated into the Generation Expansion Optimization Program, include the following:

- Perform automatic selection of units for installation from an input shopping list of available types and sizes of available units
- Allow modification of the shopping list at specified intervals in the planning period to accommodate new technology
- Include ability to handle pumped storage hydro in the shopping list, as well as peaking units, fossil and nuclear units
- Handle systems as large as power pools or regions of the United States
- Include capital cost and production cost effects and trade-offs
- Allow separate carrying charge rates for different types of units
- Allow separate capital cost inflation rates for each type of unit
- Allow separate inflation rates for each type of fuel
- Include inflation rates for operation and maintenance other than fuel, both fixed and variable operation and maintenance
- Perform present worth evaluation
- Include evaluation of scale economy versus reserve requirements
- Consider temporary overbuilding to achieve better economy of scale versus extra carrying charges
- Retain nonlinearity of economy of scale for each type of unit
- Expand system to maintain specified system reliability, in terms of loss-of-load probability or percent reserve
- Consider peak load forecast uncertainty
- Include unit maturity effects on forced outage rates

- Include forced dispatch of selected units at specified levels
- Include specified additions and retirements to incorporate committed actions
- Represent and include effects of existing system configuration
- Allow for interchange agreements, both for reserve capacity and economy interchange
- Perform economic dispatch to determine production cost impact of trade-offs
- Account for both forced outages and scheduled maintenance requirements in dispatching
- Include in dispatch optimal use of pumped storage, considering pond size and cycle efficiency limitations
- Evaluate backward and forward effects of trade-offs in installations over a 25-year period

A.3.3 MATHEMATICAL TREATMENT

The mathematical size of the problem formulated to include all of these considerations is very large. Some thought was given to solving the problem in a sequence of time stages; for example, in 3- or 5-year increments over the planning period. This would reduce the size of the problem to be solved at any one time and reduce the computer storage requirements and the total computer running time; however, strong trade-offs often exist over longer intervals, with no certainty as to the length of such intervals for any specific system or economic environment. This factor is due to the long service and economic life of generating plants. Also, the interfaces between time stages can cause peculiar effects. Therefore, the entire planning period is included in a single optimizing process allowing all trade-offs over this period to be considered.

To optimize a problem of this size, linear programming mathematics was chosen. Linear programming requires that all relationships between variables and constraints placed upon them be expressed in a linear algebraic form. Thus, to represent the nonlinear relationships inherent in the problem, linear piecewise approximation is used. Work has been done in testing the number of linear segments required to maintain accuracy when estimating production costs with linear programming [1].

One of the features of basic linear programming that prevented it from providing, by itself, a realistic optimum solution is that the answers produced are generally noninteger. Thus, the answer to the number of units of a particular type and size needed at a particular time would usually be a fraction or a mixed number. For example, results may indicate that 0.672 of a 1100 MW nuclear unit is to be installed in 1982. To avoid this type of unacceptable solution, mixed-integer programming is usually employed; however, for the solar analysis continuous solutions were used in order to see the effects of small penetrations.

Mixed-integer programming is based upon linear programming, but designated variables are forced to their optimum integer values while still respecting the problem's constraints and effects on other variables. A continuous optimum solution is first found using regular linear programming techniques. Then a mathematical technique known as "branch-and-bound" is used, beginning with the continuous solution, to find the optimum solution respecting the integer requirements of specified variables. Unfortunately, a simple process of rounding is not sufficient. The integer variables in this problem are the number of installations of each type and size of unit in each time interval. The variables associated with dispatching of units are continuous, since fractional loading of units is meaningful.

A.3.4 STRUCTURE

The Westinghouse Generation Optimization Expansion Program package consists of three basic modules as indicated in Figure A.3-1. The first module is a data processor which takes the input data, scales it, and produces a mathematical structure convenient to the mathematical optimization module. The optimization module solves the problem by finding the values of the variables, within prescribed constraints, that minimize the plan costs. The mathematical optimization module passes the solution to the report producer module where the answers are rescaled, titled, and printed.

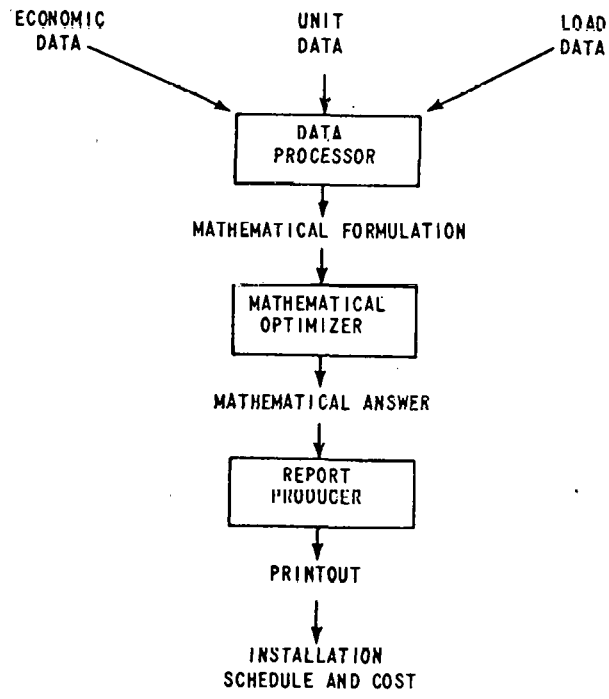

Figure A.3-1. GENERATION EXPANSION OPTIMIZATION PROGRAM MODULES

A.3.5 SIMULATION OPTION

To increase the usefulness of this expansion optimization program, a simulation feature is provided. The simulation mode allows the user to specify an expansion plan and determine its cost. The simulation mode can be used to evaluate near-optimum expansion plans or to evaluate a previously determined optimum expansion plan under different load or economic forecasts. By performing analysis on several near-optimum expansion plans for different forecasts, sufficient data can be generated to perform an evaluation of cost and risk sensitivity. The simulation option is used to perform certain sensitivity studies on the GENOP results. This represents a very cost effective way to investigate alternative fuel costs, escalation rates and reserve requirement limitations but does not do any expansion optimization since it only uses a manually input expansion plan.

A more detailed simulation program could also be used for these purposes. However, the increase in detail may not be of interest and difficulties may result in preparing additional input data and in comparing results. To facilitate comparison of results of optimum and alternate plans, input and output of the new program are in the same format and same level of detail as in the optimization program.

Most items of data input to the optimization problem can be varied in the simulation mode. For studies of alternate expansion plans or for sensitivity studies, changes in the following items are considered to be of special interest:

- Timing of generating unit installations
- Size and type of generating unit installations
- Interest rate or present worth discount factor on investment
- Capital cost of generating unit installations
- Yearly cost inflation or escalation rates
- Yearly fixed operating and maintenance cost for generating unit installations
- Unit production cost for generating unit installations
- Dispatch limitations
- Forced outage rates for generating unit installations
- Maintenance requirements for generating unit installations
- System reliability criteria

A.3.6 INPUTS AND OUTPUTS

The inputs to this package, as shown in Table A.3-1, are essentially the same as for most generation planning procedures with the exception that one does

not postulate a generation expansion plan. The detailed description of input requirements necessary for data preparation is in Westinghouse report AST-73-899 [2].

Table A.3-1. CENERATION EXPANSION OPTIMIZATION PROGRAM INPUTS

- Forecast Load Data
- Existing Unit Data
- Potential Unit Description
- Economic Data
- Reliability Requirements

Forecast load data must be input for the expansion period. The load data must include forecast peaks, seasonal variations, statistical variability of weekday peaks within each season, and weekly load duration curves. The load model used retains a probability that forecast peaks will be exceeded or not reached through implementation of explicit probability distributions. Normally a program such as the Westinghouse Historical Load Data Reduction Program is used to obtain historical statistics and trends of seasonal variations, daily load variability, and load duration curve shapes. This historical analysis is then used as a basis for formulating load forecasts.

A description of all existing and committed units is also an input requirement. This includes unit capacities, forced outage rates, operating cost characteristics, and maintenance requirements. Interchange purchase and sale commitments can also be specified, along with existing pumped storage, pondage, and run-of-river hydro.

The same data must be supplied for units which are to be made available for installation by the program as for existing units, plus base year capital costs, carrying charge rates, and immature forced outage rates. Specific sizes and/or types of units may be specified as being available for selection only after a designated year. For example, a 2000 MWe nuclear plant might be input as being available for selection only after year 1990.

Economics input data include present worth discount rate, inflation for the capital cost of each type of new unit, and escalation of fuel and other operation and maintenance costs. Both fixed and variable operating and maintenance costs can be specified for new and existing units.

The minimum acceptable system reliability may be input to the program in terms of loss-of-load probability or percent reserve.

The primary information output is that shown in Table A.3-2. The installations in any given year may be a mix of units from the shopping list provided to the

program. For example, a nuclear unit, a pumped storage hydro unit, and a couple of gas turbine units may be installed in the same year. In addition to the outputs listed in Table A.3-2, other secondary information is printed, such as the average operating mills/kWh by unit type and for the whole system for each year.

Table A.3-2. GENERATION EXPANSION OPTIMIZATION PROGRAM OUTPUTS

• Installation Schedule (timing, type, size)
• Annual Utilization Factors (unit type capacity factors)
• Annual and Total Plan Costs (capital and production costs)
• Resulting Capacity Reserves (annual, in percent of load peak)

A.3.7 APPLICATION

The advantages of a direct optimization program are obvious. A good general expansion strategy can be developed with this program without the time and effort required for a large number of simulation runs. If more detail about an expansion strategy is required, such as week-by-week implications, then a detailed simulation can be made of the plan produced by the optimization program.

Another use of the expansion optimization program is sensitivity analysis. The desired changes in strategy resulting from shifts in load or in economic or technological projections can be directly obtained by rerunning this package. In many cases execution time needed for the reruns can be shortened by using previous solutions as a starting basis for the new mathematical optimization.

Often it is desirable to determine the economic penalty of some near-optimum expansion plan. Detailed simulation programs can be used; however, the increase in detail may not be of interest. For this purpose a special expansion simulation program has been written which uses the same data formats and detail that the optimization package uses, and produces output in the same format. This allows less expensive simulation and obviates the necessity for more detailed input data.

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SECTION A.4

STATIC ANALYSIS

The evaluation of how an aggregate of solar plant installations affects a system's optimum generation expansion plan is the first of two major thrusts utilized in this study and was evaluated using the GENOP program. The second major thrust involved the static analysis of specific solar plants to ascertain their individual cost, operating value and capacity credit. Since the solar plant's economics will change with installation date, the change in its impact and value with time was obtained. For proper assessment of the prospective impact and value of a solar plant's installation on a specific utility system, detailed modeling of the operation of the solar plants was used.

A detailed methodology was developed by Westinghouse to assess a solar plant's value under EPRI RP 648. This methodology consists of the coordinated use of several computer models as shown in Figure A.4-1. The core models are the Solar Plant Model, the Westinghouse Daily Production Cost Program [3] and the Westinghouse Generation Planning Capacity Model.

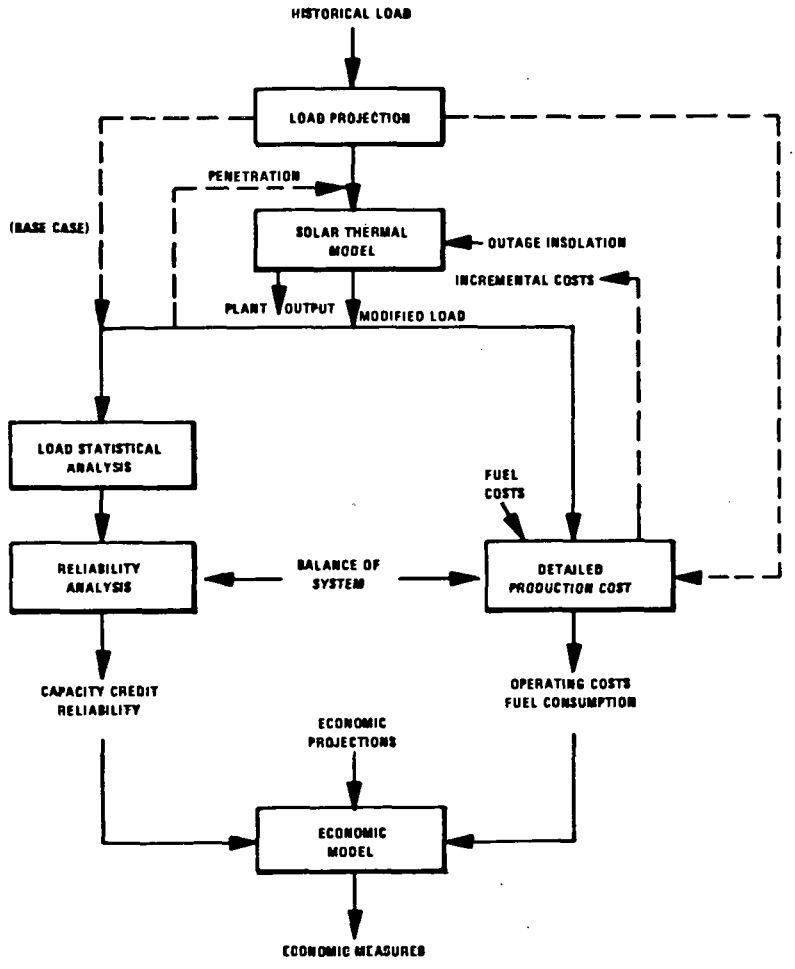

Figure A.4-1. SOLAR-THERMAL PLANT STATIC ANALYSIS SEQUENCE

A.4.1 GENERAL STATIC ANALYSIS METHODOLOGY

The general framework of the specific methods employed conforms to the following sequence of analysis:

- Develop hourly load projection for the year and utility system of interest
- Simulate the operation of conventional units on utility system for that year, producing incremental operating cost tables
- Use incremental cost tables, hourly system loads, and hourly insolation to dispatch the solar plant, subtracting solar plant electrical output from the load
- Use hourly load reduction to calculate solar plant capacity credit and conventional capacity displacement
- Resimulate operation of conventional generating units with reduced system load
- Use economic procedures to calculate resulting solar plant value for solar plant life expectancy

This framework allows the evaluation of a variety of solar plant concepts and configurations in different operating and insolation environments. It also provides a vehicle for assessing the value of either a single solar plant or a number of them, independent of their cost projections. From this process not only is the operational economic impact of the solar plant obtained, but also the effects upon fuel consumption and solar plant and conventional plant operational requirements.

The above is a general procedure from which an estimate of the value of a solar plant to a utility system may be established. These procedures permit the establishment of differences in the balance-of-system cost, with and without the presence of the solar plant. Values are established for the following factors:

- Operating credit
  - Fuel costs
  - Other displaced operating and maintenance costs
- Capacity credit
  - Capacity displacement (reduction in installed capacity)
  - Change in capacity mix

Using the procedures outlined on the previous page, the value of the solar plant to the utility system can be determined. Analysis can be performed in this manner to evaluate variations in the following:

- Existing utility system generation mix
- Insolation characteristics
- Solar plant concepts and configurations
- Load characteristics
- Solar plant size
- Solar plant storage capacity
- Solar plant operating modes

In addition, the computer simulations provide (1) base parameters on which economic sensitivity analysis may be performed and (2) operational information on both the solar plant and the balance of the utility system in the presence of a solar plant.

Iterations of the Solar-Thermal Model are used to analyze the effects of penetration. That is, one first develops the net load using the solar electric output based on insolation data from one site, and then subtracts the output of a second plant (over the same time interval). The joint effect of two or more solar plants can thus be extracted.

If a large portion of the generating capacity of a utility system is made up of solar plants, it is quite likely that not all of the solar plants should operate identically, or have the same characteristics. By successively subtracting increments of solar capacity from the net load presented to the balance of the system, as described in the previous paragraph, these changing operating effects can be observed.

A.4.2 SIMULATION OF OPERATION

In the previous section, the general procedure for the evaluation of solar-thermal plants' role in producing electricity was explained (see Figure A.4-1). Reference was made to simulation processes as a source of specific economic information. In this section the models used to simulate the operation of the solar plant(s) and the balance of the electric utility generating system are described.

The models themselves will be discussed further; however, the process of using these models is depicted in Figure A.4-1. The flow is as follows:

(1) Using historical load characteristics and load forecasts, an hourly load model is developed for some future year.

(2) A base (nonsolar) case is established by taking this projected load and simulating the operation of the utility system using

the detailed production costing model. (For this study the nonsolar base GENOP expansion was used to explicate the utility system in years following the base year.) From this comes base case utility system operating costs, fuel consumption, and system incremental costs.

(3) The same projected load is subjected to statistical analysis and these statistics are forwarded to a Capacity Model, where reliability analysis is performed and a base loss-of-load criterion established.

(4) The same projected load from (1) is used as input to the Solar-Thermal Model. Other inputs are hourly insolation and incremental utility system operating costs [from (2)]. The Solar-Thermal Model simulates the operation of the solar plant, and subtracts its output hourly from the input load to produce a net residual load.

(5) The net residual load is used in an economic breakpoint analysis to establish any shift in balance-of-system generating mix (see Section 4.1.5).

(6) The net load from (4) is subjected to statistical analysis, and subsequently to reliability analysis. The Capacity Model is used to find the load-carrying capability of the solar plant.

(7) The net load from (4) and the adjusted generation system from (5) are input to the Detailed Production Costing Model, where an economic dispatch is simulated for the balance of the system. From this comes a new system operating cost and fuel consumptions.

(8) The lifetime production cost credit is obtained by properly discounting the annual credits over the service life of the solar plant, assuming equal solar electric energy production and fuel type displacement in each year. The discounting effects over the service life of the solar plant minimize the discrepancies that would arise due to these assumptions. The present worth saving in production cost and capacity credit are combined with estimated solar plant costs to establish the net economic benefit (or loss) to the utility.

The simulation involves the use of the Solar-Thermal Plant Model and the Detailed Production Cost Model, which simulates the operation of the generating units making up the balance of the utility system. Figure A.4-2 shows how the various inputs and models are used in the simulation. This figure shows that the flow involves load projection, solar-thermal plant modeling and daily production cost modeling.

The Solar Plant Model can be used to simulate the hour-by-hour operation of many types of solar-thermal plants. It can simulate either a central receiver steam Rankine stand-alone plant, a central receiver steam Rankine hybrid

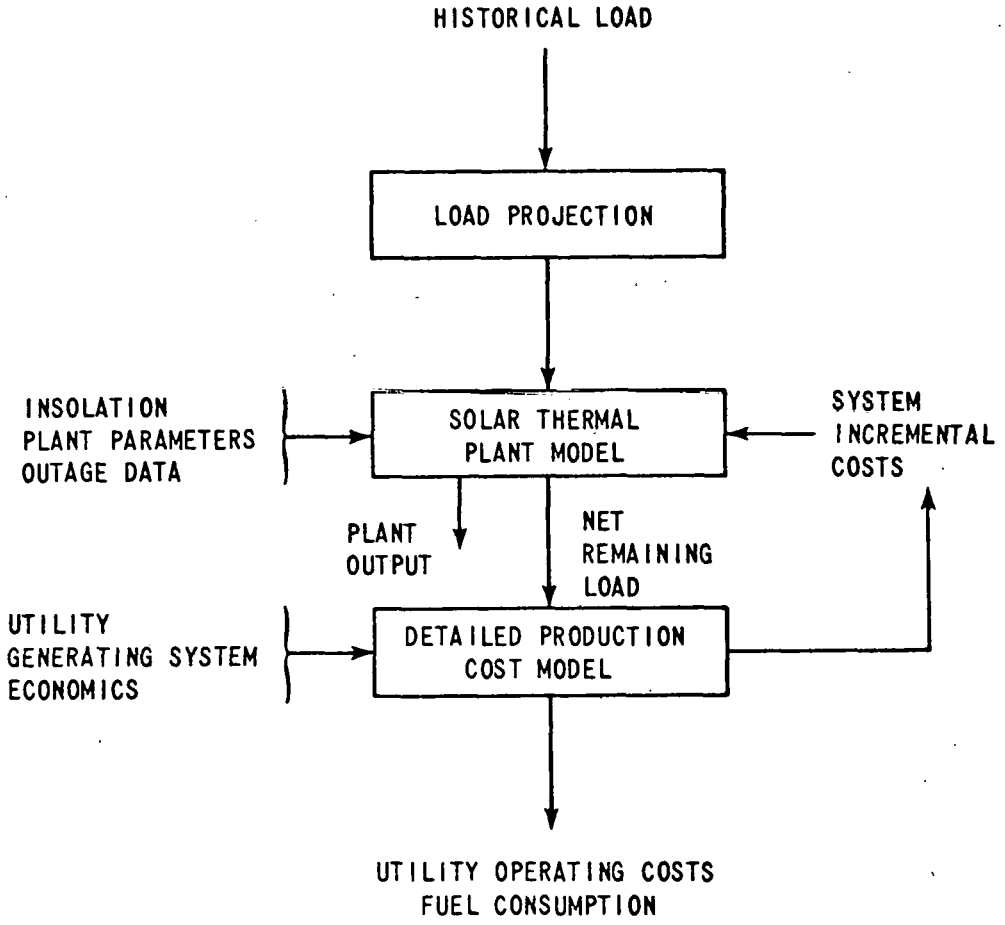

Figure A.4-2. FLOW DIAGRAM OF SOLAR-THERMAL PLANT EVALUATION SIMULATION

plant, or a solar repowered conventional gas- or oil-fired plant. Repeated computer runs of the Solar Plant Model can be used to simulate increased solar plant penetration in the utility. For this study, advanced central receiver concepts for the repowering of existing gas/oil steam plants are modeled, as are the advanced central receiver stand-alone (no hybrid capability) plant with thermal storage and the central receiver steam Rankine (Barstow technology) stand-alone plant.

The Westinghouse Daily Production Cost Program, through economic dispatch of the utility system, details system fuel consumption. With this information Westinghouse can determine the oil displacement in the plans that include solar plants compared with the nonsolar-thermal expansion plan.

Another model that is considered to be basic to the solar assessment methodology is the Westinghouse Generation Planning Capacity Model. This model is needed to determine how much conventional generating capacity (capacity credit) the installation of solar-thermal generation displaces. Among the inputs required

are descriptions of maintenance policy, reliability criteria, statistical load reduction information, and existing unit descriptions.

These three models are discussed in more detail on the following pages.

A.4.2.1 Load Projection

Although not strictly a simulation process itself, the development of an appropriate load model is essential. The desired load model is an hourly representation of demand upon the utility generating system in a standard format. The card image format chosen is basically the standard EEI format requiring two cards for the 24 hourly loads of each day. Many utilities record their actual hourly integrated loads in this format. In this analysis the format is used for future loads for input into the Solar-Thermal Plant Model and the Detailed Production Cost Model. The net residual load output of the Solar Plant Model is also in this format.

A.4.2.2 Solar-Thermal Plant Model

The computer model used in this study to simulate the operation of solar plants is a modified version of a program developed by the Aerospace Corporation, Los Angeles [4]. The use of this model is in line with the study guideline to build upon the tools used in other studies whenever possible.

The basic model was developed under federal auspices, now under the direction of DOE. A mission analysis study of solar-thermal plants in the southwestern United States was conducted in 1974 by the Aerospace Corporation using this model [5].

Since the initial studies, the Aerospace Corporation has continued to revise the model and has extended its use to other investigations sponsored by DOE and EPRI. The model which has subsequently been greatly modified by Westinghouse under EPRI funding is the Aerospace original "Simple Systems Model."

The EPRI/Westinghouse Solar Plant Model is the one used in this study. Among the extensive modifications made to the original Aerospace model are the ability to consider the following:

- Series, as well as parallel, thermal storage configurations
- Hybrid fossil/solar, as well as solar only, plants
- Economic dispatch, considering utility incremental operating costs
- Altered operation for high insolation transient conditions (that is, certain cloud conditions)
- Automatic heliostat stow simulation during high wind conditions
- More detailed turbine-generator efficiency representation

- Dry cooling tower plant efficiency impact as a function of ambient temperature

- Availability table for implementing forced and scheduled outage conditions

- Extended output, including net remaining system load, in EEI standard format

The most important of these modifications to the Solar Plant Model is the implementation of optimum dispatch logic. This logic optimally uses the energy collected by the plant, recognizing the following factors:

- Foreknowledge of current day's insolation profile

- Foreknowledge of current day's load profile

- Utility system's incremental operating cost

- Thermal storage limits and efficiency

- Turbine-generator limits and efficiencies

The purpose of the model is to take solar design parameters as specified, site specific insolation and weather data, and simulate the operation of the solar plant on an electric utility system. This operational modeling utilizes the plant in the most economic fashion, recognizing the changes in incremental operating cost of the balance of the utility system on an hourly basis.

The model simulates, on an hourly basis, the energy flow within a solar-thermal electric generating plant. The program is constructed in a modular fashion to represent the major subsystems of such a plant. These subsystems are shown in Figure A.4-3.

The model takes as input the hourly direct normal insolation, and through a series of conversion efficiency and loss calculations, develops the electrical output of the turbine generator. It accounts for the operation of thermal storage and of fossil boilers, and is capable of simulating a number of different solar plant concepts.

The collector subroutine takes the input solar insolation and combines it with the effective collector area and appropriate factors to describe the loss due to shading, blocking, reflectivity and aiming. The resulting net collected thermal energy is then passed to the receiver subroutine.

The collected energy is next subjected to corrections for receiver efficiency and receiver heat losses. This is a simulation of the effects of receiver absorption efficiency, and convection and radiation losses.

The thermal energy leaving the receiver is next adjusted to account for pumping losses, and for line thermal losses. The net remaining energy is then transmitted either to thermal storage, if desired, or directly to the turbine generator, or if the capacities of these subsystems are exceeded, to the condenser.

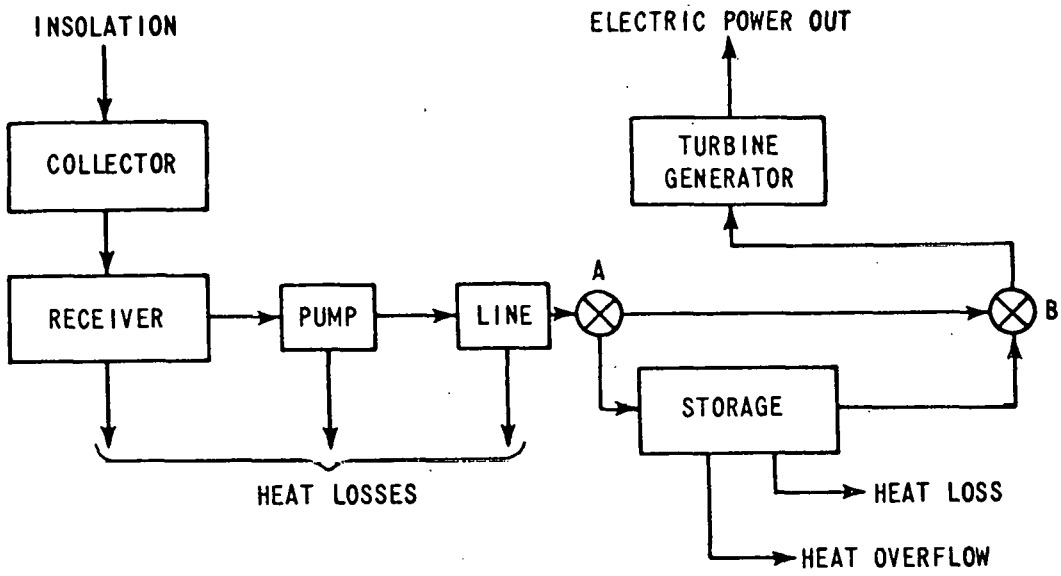

Figure A.4-3. CENTRAL RECEIVER SOLAR PLANT MODEL REPRESENTATION

A number of input thresholds control the actions of Valves A and B, shown in Figure A.4-3. Valve A determines whether the energy is directed to storage or directly to the turbine generator. For this study, the advanced hybrid repowered solar plant has a series thermal buffer storage, so all energy goes through storage. Valve B controls the withdrawal of energy from storage, which may be simultaneous with use of heat from Valve A. The control parameters define levels of system load below which plant output is not desired, and the minimum allowable heat in storage.

The energy passing from Valve A into storage is modified by a storage input efficiency factor. Thermal losses from storage, as a function of time, are also modeled. Should the energy in storage begin to exceed the maximum capacity stated by input, the limiting storage capacity is observed and the energy overflow noted in the printout.

The turbine-generator subroutine applies an efficiency factor to represent the losses in the process of conversion from input thermal energy to output electrical energy. This subroutine also incorporates limits for minimum and maximum levels of operation.

In summary, the basic approach of the model is to account for energy flows by use of device efficiencies, some of which are directly input. Others are calculated through mathematical relationships in the program.

In some subroutines the user has the option of providing the input, a simple efficiency factor, or relying upon more complex internal calculations.

The exact dispatch rules are different for the three different types of solar plants which were investigated in this study. The Advanced Stand-Alone (ASA) solar plant was modeled using the stand-alone logic. The Advanced Hybrid

Repowered (AHR) solar plant and the Brayton Hybrid Repowered (BHR) solar plant were modeled using the solar hybrid and repowered solar plant dispatch.

A.4.2.2.1 Solar Hybrid and Repowered Plant Dispatch

The solar hybrid repowered plant model used for this analysis is an outgrowth of the one developed by Westinghouse for EPRI in the performance of RP 648-1. A generalized model representation of the solar hybrid (or solar hybrid repowered plant) is shown in Figure A.4-4. This computer model has the capability of modeling the operation of a number of types and configurations of solar plants on an hourly basis. Included in the model is the economic operation of solar stand-alone plants with series or parallel storage and hybrid Brayton or Rankine systems. The hybrid capability allows the modeling of repowered plants.

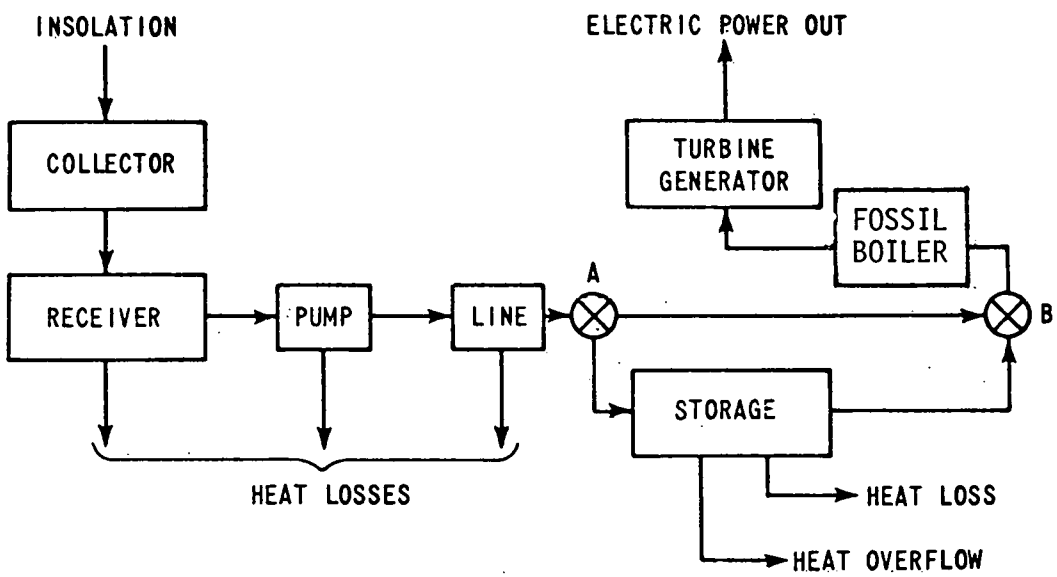

Figure A.4-4. HYBRID (OR HYBRID REPOWERED) SOLAR PLANT MODEL REPRESENTATION

For the realistic representation of solar hybrid repowered plants and their most economical operation, a number of rules and considerations have been incorporated in the Solar Plant Model and are briefly stated below, and shown in Table A.4-1.

For realism in the modeling of the operation of the hybrid plant, those items shown in Table A.4-1, including fossil fuel consumption and the time required to bring the boiler up to temperature and pressure, are considered. Operating scenarios where the boiler temperature is maintained (standby) is an option in the program.

Logic requiring fossil boiler energy to buffer the turbine during insolation transients has also been incorporated. The skycover conditions are sampled

Table A.4-1. SOLAR HYBRID PLANT MODEL DISPATCH

- Oil Startup Logic
- Oil Buffer for Insolation Transients
- Close-Up Potential Shutdown Windows
- High Wind Speed Solar Shutdown
- Boiler Efficiency Corrections
- Oil Recovery of Low Insolation
- Economic Oil Dispatch
- Hot Standby Oil (Option)
- Economic Shutdown at End of Day
- Cost/Benefit of Daily Oil Use

Recognizing

- Foreknowledge of Day's Insolation Profile
- Foreknowledge of Day's Load Profile
- Utility System Incremental Cost Curve
- Fossil Boiler Limits and Efficiency
- Turbine-Generator Limits and Efficiency
- Insolation High Transient Conditions
- Operation Wind Limits

hourly from the insolation tape to determine when insolation transient conditions apply. Presence of buffer storage can also be used to cover insolation transients.

To prevent excessive cycling of the turbine, the plant may be fired to run through what otherwise would be a brief shutdown period. When wind speeds exceed the input design limits, the heliostats are assumed stowed and no solar energy is collected for that hour.

Both boiler and turbine-generator part-load efficiency curves are incorporated in the Solar Plant Model.

When the insolation is not sufficient to operate the turbine at its minimum level and a specified insolation threshold is exceeded, the boiler is fired to provide enough supplemental energy to salvage the insolation and operate the turbine generator.

The incremental cost of competing conventional plants is tested hourly to establish whether additional fossil firing is economically justified. Also, a test is made to determine whether it is worthwhile (economic) to start up the boiler at all, each day, or to leave the boiler cold and suffer the operating consequences (e.g., no electrical output during solar transients). The proper boiler shutdown hour is also established on an economic dispatch basis.

The ability of the model to examine alternate operating strategies as well as

design parameters has been found to be extremely valuable. A list of some of the inputs and outputs of the Solar Plant Model is given in Table A.4-2.

Table A.4-2. REPRESENTATIVE SOLAR PLANT MODEL INPUTS/OUTPUTS

- INPUT
  - Site location and latitude
  - Solar collector system type and orientation
  - Hourly utility system demand
  - Utility balance-of-system incremental cost
  - Hourly insolation and meteorological data
  - Collector field area
  - Tracking efficiencies
  - Reflectivity efficiencies
  - Receiver thermal efficiency
  - Pumping efficiency
  - Line thermal power loss efficiency
  - Storage input/output efficiency
  - Thermal storage capacity
  - Turbine-generator efficiency
  - Turbine-generator operating limits
  - Cooling tower type and efficiency
  - Minimum usable insolation
  - Startup/standby oil consumption
  - Storage heat initialization
  - Plant incremental fuel cost
  - Plant availability (equipment-related forced outage table)
  - Wind-speed design limit
  - Skycover transient specification
  - Turbine-generator output windows' transient suppression
- OUTPUT
  - Plant megawatt electric output (hourly)
  - Modified utility system demand (hourly)
  - Insolation energy (hourly)
  - Energy in storage (hourly)
  - Storage energy overflow (hourly)
  - Intermediate power flows (hourly)
  - Annual and monthly electric energy output
  - Annual and monthly solar energy output
  - Annual and monthly oil consumption output
  - Operating mode transition summary
  - Windy and cloudy days table
  - Oil consumption
  - Startup and buffer oil consumption
  - Transient suppression oil consumption
  - Average solar power availability by hour
  - Average utility demand by hour
  - Monthly peak utility demand

A.4.2.2.2 Central Receiver Stand-Alone Plant Dispatch

The central receiver solar plant dispatch rule is basically a process of four steps, the objective of which is to minimize the operating costs of the balance of the utility system, within the insolation availability and plant parameter constraints:

(1) Direct Insolation Dispatch. In this first step, the entire day is simulated with all usable energy from the receiver system being routed directly to the turbine generator. If the energy collected is below the minimum level required for turbine-generator operation, it is sent to storage, as is excess energy collected beyond that required for maximum level operation.

(2) Minimize Storage Overflow. Next, the thermal energy lost due to storage overflow is minimized. Overflow intervals resulting from (1) are identified. If overflow is at the end of a direct dispatch interval and the turbine generator is not operating (because of an insufficient level of direct energy), sufficient energy is withdrawn from storage to operate the plant. For other overflow intervals, prior hours when the turbine generator is not operating at maximum limit are identified. From those, the highest incremental cost hours are selected and energy is dispatched from storage until overflow is minimized.

(3) Thermal Storage Dispatch. In this step, the available energy in thermal storage is dispatched. The hours with the highest incremental system costs in which the turbine generator is not operating at maximum output are identified. Energy is dispatched from storage beginning with the highest such incremental cost hour until the minimum allowed level of energy in storage is reached.

(4) Energy Exchange. This last step looks for any advantage of reallocating energy previously assumed to be sent directly to the turbine generator from the receiver, to storage for later use. This exchange of direct use in one hour to through-storage use in another must be justified by the system incremental cost differential. This differential must be great enough to justify the loss in efficiency when going through storage. Also, storage cannot be full in any intervening hour for the exchange to take place. The exchange is examined by searching through pairs of highest incremental cost hours not having maximum turbine-generator output, and lowest incremental cost hours with direct energy use.

Two examples of this dispatch sequence are shown in Figure A.4-5. The dashed line labeled "I" is assumed to be the insolation profile for a day, and the "L" curve is the utility system demand.

In the first example, step one shows the direct use of the insolation energy. Two storage overflow intervals result, as indicated. The program cannot avoid

the earlier overflow interval, assuming storage was at a minimum at the beginning of the day. The second overflow interval resulted when the direct energy was at too low a level to operate the turbine generator. Here, as shown in area two of the example, energy is withdrawn from storage to operate the turbine generator and avoid this overflow. In the third step the highest incremental cost hours are found during which the turbine generator is not at maximum operating level, and storage is dispatched. No exchange (step four) can take place between the hour following area three and the minimum load level during area one, since storage is full during the intervening overflow intervals.

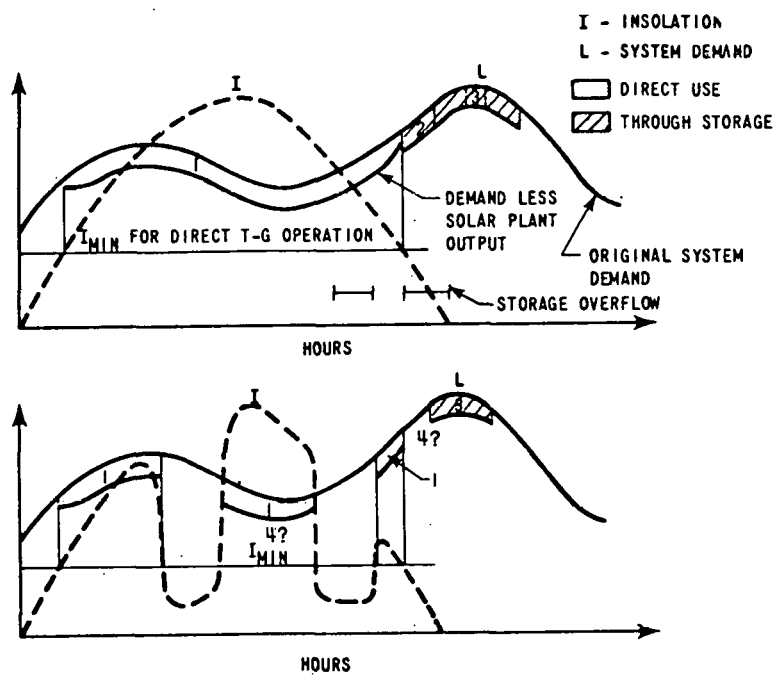

Figure A.4-5. EXAMPLES OF SOLAR PLANT DISPATCH

The second example shows a day with much poorer insolation. No overflow occurs. After the first three dispatch steps, the step four exchange logic is brought into operation. The hours indicated by "4?" are tested for exchange possibilities. If the differential in incremental system production costs for the pair is greater than the efficiency differential incurred by going through storage, then the energy in the earlier "4?" hour is directed to storage rather than to the turbine generator, and the energy is withdrawn from storage in the later "4?" hour. The next eligible pair is identified and the process repeated. Once the exchange is not justifiable, the procedure ends, because the search starts with maximum incremental cost differential pairs and works with decreasing differentials. Table A.4-3 summarizes the stand-alone solar plant dispatch rules.

A special dispatch rule has been implemented for hours identified as likely to contain severe insolation transients. For these hours the plant is forced to operate through storage to isolate the turbine generator from the transients.

Table A.4-3. SOLAR STAND-ALONE DISPATCH RULE

- Dispatch Insolation Directly to Turbine Generator
- Minimize Waste Heat Using Storage
- Dispatch Storage on Incremental Cost
- Economic Exchange of Direct Use VS Through Storage

Recognizing

- Foreknowledge of Day's Insolation Profile
- Foreknowledge of Day's Load Profile
- Utility System Incremental Cost Curve
- Storage Limits and Efficiency
- Turbine-Generator Limits and Efficiencies
- Operational Wind Limits
- Insolation Transient Conditions

Preliminary study has been performed to identify the weather parameters characteristic of such hours. Hourly integrated insolation values, such as those appearing on the Aerospace insolation tapes, are of little value in this regard because of the much shorter time interval involved in insolation variations. Thus, the new dispatch logic keys upon the tenths of skycover data; this information is included on the Aerospace insolation tapes. The tenths of skycover associated with high transient conditions are designated by input parameters. Whenever the dispatch routine detects an hour with the designated skycover, the insolation collected is directed to storage. Two consecutive nontransient hours are required to allow the solar plant to return to routing of collected (receiver) solar energy directly to the turbine generator.

A test of the wind data from the insolation tapes also affects the solar plant's simulated operation. If the wind for an hour exceeds a threshold value which is defined by input, then the heliostats are assumed to be "feathered," or stowed, and no solar heat is collected. The plant may operate from heat in storage, if advantageous, or save it for later. This test is included for all types of solar-thermal plants simulated in the revised model.

In general, the dispatch rule implemented strives to utilize as much of the solar energy as possible and to use it during the hours of highest operating cost for the balance of the utility system. No attempt is made to save usable heat in storage from one day to the next, which usually results in a drawdown of storage to its minimum allowable level each day.

A.4.2.3 Daily Utility Production Cost Model

The Westinghouse Daily Production Cost Model is used in this study to establish base case (nonsolar) utility system operating costs and other operating parameters, and for the balance-of-system simulation in cases including solar plant(s). It is an established computer program which simulates the operation of a utility system by performing economic dispatch on a bihourly basis.

Minor modifications have been implemented to enhance communication with the solar model.

Since detailed production costing programs are a fairly established methodology, only a brief description of this program will be given in this report.

The Westinghouse Daily Production Cost Program starts by establishing a base incremental cost table which includes all existing generating units (see Figure A.4-6). The input incremental heat rate and fuel cost data for each unit are combined to construct incremental cost curves for each unit. These curves are merged to construct an incremental cost table for the entire system.

In each maintenance period (considered to be weekly) the base system incremental cost table is altered. The incremental costs of those units on maintenance are removed.

The program utilizes chronological load data, as opposed to load duration curves, to allow the detail described. The model calculates the total energy generated over a period (usually a month) from these load data. Daily load shapes are used in the form of twelve two-hour integrated loads expressed in percent of the daily load peak. Normally five load shapes are supplied, representing Monday, weekdays (Tuesday, Wednesday, and Thursday), Friday, Saturday, and Sunday. In this analysis the typical daily shapes are found by the program from hourly load specification for the entire year.

Each week, run-of-river hydro and pondage hydro are dispatched first. The run-of-river hydro capacity is subtracted from the loads. The pondage hydro is then dispatched in such a way as to minimize the load peaks during the week. The pondage energy is allocated, respecting the individual unit capacity limitations, until the weekly stored energy is fully utilized. Daily energy limitations may be provided as an additional constraint.

Pumped storage energy is also allocated on a weekly pond refill cycle. The physical pond size provides the basic energy constraint. Daily water recycling is calculated within the limits of the pond size. The total weekly generation and pumping energy is calculated to minimize costs based upon the cycle efficiency, thermal incremental costs, and energy available in the pond.

For this study, no hydro energy is available, so the operation begins when a unit startup and shutdown schedule is developed for a day. Enough units are started, or continued in operation, in each bihourly load period to satisfy the load plus spinning reserve requirements. A unit startup priority list is input for selecting which units should be running.

An economic dispatch, or loading, of the started units is performed for each two-hour load period. This dispatch is based upon the incremental costs and transmission penalty factors of individual units. The dispatch logic is designed to levelize incremental costs, minimizing total production cost.

In addition to the system energy requirements, energy transfers resulting from several different types of interchange may be represented in the program.

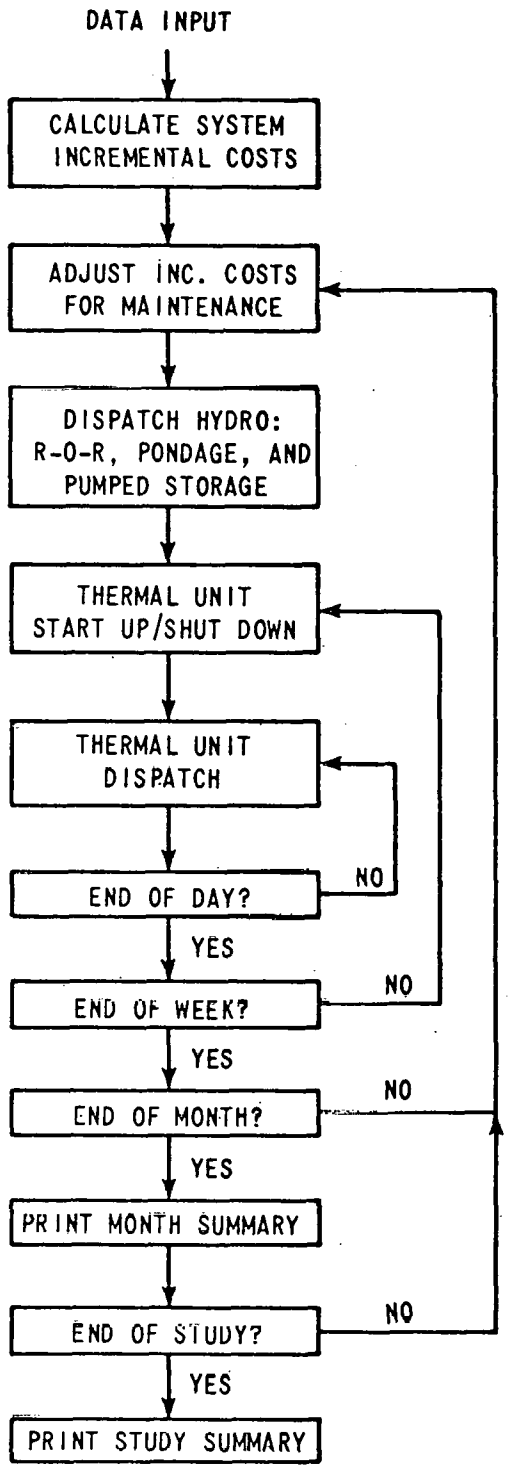

Figure A.4-6. DETAILED PRODUCTION COST MODEL FLOW

The program has the ability to output bihourly system data as well as monthly and study summaries of costs, fuels consumed, and energy produced by each unit.

A.4.2.4 Generation Planning Capacity Model

The Westinghouse Generation Planning Capacity Model uses probability mathematics to do many things. In one mode it schedules individual generating unit maintenance periods to optimize the system's reliability. In the second mode it finds the load-carrying capability of the generating system for a given loss-of-load probability. Both of these modes were used extensively in this study.

Conventional generating plants are subject to scheduled outages for routine inspections and service, and forced outage due to equipment failure. In addition to these outages, a solar plant's availability depends upon insolation characteristics, the amount of storage, and the plant operating strategy. Extensions were required to conventional utility procedures for calculating generating system reliability (loss-of-load probability, LOLP) to include the impact of these additional solar plant factors. Most LOLP calculational procedures limit the number of availability states an individual generating plant may assume to two or three. The availability state representation is a discrete probability distribution giving the likelihood of the maximum available output from the plant at some time. To adequately represent the possible capacity contributions of a solar plant, an availability distribution with numerous states was required.

To develop this distribution, hourly simulation of the solar plant's operation is used and the load reduction tabulated. The ability of the solar plant to reduce the utility system's weekday peak loads is tabulated in terms of the daily megawatt reductions. These reductions are processed for each season of interest to produce statistical moments (mean, variance, skewness, and kurtosis) of the daily peak load reductions. These moments are then used to create an effective capacity availability distribution for the solar plant. This distribution is then input to the Westinghouse Capacity Expansion Model as a common header unit. This model has the capability of accepting an almost infinite-state representation, since statistical moments are used to represent common header availability distributions. The process of making the solar plant reliability calculation is as follows:

(1) Run utility LOLP using Westinghouse Capacity Model analysis without solar plant.

(2) Simulate operation of solar plant, subtracting hourly output from system load.

(3) Calculate reduction in daily load peaks.

(4) Calculate first four moments of solar effective peak reduction.

(5) Use moments in Westinghouse Capacity Model using common header logic.

(6) Compare (1) with (5) to establish conventional capacity displacement.

This procedure will allow reliability impact assessment of colocated versus geographically distributed plants, solar plant size, solar plant penetration, storage capacity, operating strategy, and location.

A.4.3 INSOLATION DATA BASE

The insolation data used in the modeling of the solar plants was calculated from El Paso data. The procedure used for generating this weather data is shown in Table A.4-4.

Table A.4-4. MIDLAND, TEXAS INSOLATION GENERATION METHODOLOGY

Information Available	
• Midland:	Only mean daily global insolation available
• El Paso:	Mean daily global insolation Hourly global insolation for typical meteorological year Hourly direct normal for typical meteorological year

Hourly Midland Insolation Development Methodology

$$CF(\text{Month}) = \frac{\text{Mean Daily Global (Midland)}}{\text{Mean Daily Global (El Paso)}}$$

$$I_{GHr}(\text{Midland}) = I_{GHr}(\text{El Paso}) * CF\ (\text{Month})$$

$$I_{DNHr}(\text{Midland}) = I_{GHr}(\text{El Paso}) * \left(\frac{\text{Direct}_{Hr}}{\text{Global}_{Hr}}\right)(\text{El Paso})$$

Where: CF = Correction factor for each month

I_{GHr} = Global hourly insolation for the site

I_{DNHr} = Direct normal hourly insolation for the site

The direct normal insolation component of the radiant energy from the sun, which is redirected in a manner which concentrates the energy on the absorbing surface (receiver), was determined on an hourly basis in two steps. The

Midland hourly global insolation was set equal to the El Paso hourly global insolation times the ratio of the Midland to El Paso mean daily global insolation, then the Midland hourly direct normal insolation was set equal to the Midland hourly global insolation times the hourly ratio of the direct normal to the global El Paso insolation. All other weather data such as percent sky cover and wind speed was taken directly from the El Paso SOLMET insolation tape.

A.4.4 SUMMARY

The static analysis methodology involves the interaction of several models that were also used in the generation expansion methodology. For both evaluations the capacity model was used to schedule maintenance, a necessary input to the Daily Production Costing (DPC) Program. The DPC Program calculates incremental operating costs for the solar plant model. The solar model then dispatches energy to reduce the system demand. This portion of the procedure is common to both the static analysis and generation expansion methodologies. The static analysis carries the procedure one step further to examine how the day-to-day operation of the utility changed with the inclusion of the solar plant. The generation expansion methodology is used to investigate how the generation expansion plan changes for a particular solar plant installation schedule.

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SECTION A.5

ECONOMIC METHODS

Conventional revenue requirements methods were used as a basis for the economic analysis in this study. These techniques, as applied, recognize both the time value of money and independent escalation of various cost elements. They are consistent with electric utility practice and provide the needed flexibility.

Because of the uncertainty of the costs of certain portions of the solar plant, particularly under mass production conditions, it was deemed important to assess the economic value of the solar plant independent of its costs. The value arises potentially from both operating cost and capital cost savings to the balance of the utility system. The operating cost savings are derived from reduction in fuel consumption and variable operating and maintenance costs. The capital cost savings arise from reduced conventional capacity requirements and a potential shift in the mix of conventional units.

The busbar energy costs, which are consistent with DOE/EPRI guidelines, are a function of solar plant cost and electric energy production.

The net economic impact of a solar plant upon a utility system is calculated by simply subtracting the solar plant value from its estimated costs.

The cost/benefit ratio is calculated by dividing the present worth of solar plant lifetime costs (revenue requirements) by the present worth of its lifetime value.

A.5.1 GENERAL METHODS

The economic methods used in the study are designed to establish four basic economic measures of each plant configuration and each unique condition investigated. These measures are as follows:

- Value of the solar plant
- Solar plant busbar energy cost
- Economic impact upon utility system
- Cost/benefit of the solar plant

Table A.5-1 shows the input required for each case.

The methods used to obtain these measures are consistent with the practices used by many electric utilities. In fact, the revenue requirements discipline, upon which a great deal of the following is based, is attributed largely to electric utility economists. Mr. Paul Jeynes [6], formerly with the Public Service Electric and Gas Company of New Jersey, has been one of its major proponents.

Table A.5-1. ECONOMIC WORK SHEET

CASE _____

Assumptions

Solar Plant
- Plant concept:
- Plant size (MWe net):
- Collector area (effective m^2):
- Storage size (MWh net):

Utility System
- System identification of load profiles:
- Identification of generating mix:
- Insolation identification:

General Economic
- Basic cost of capital (k):

Base Fuel Costs (¢/MBtu, year; escalation rate)
- Nuclear:
- Coal:
- Oil:
- Gas:

Base Capital Cost ($/kWe, year; escalation rate)
- Nuclear:
- Coal-steam:
- Oil-steam:
- Combined-cycle:
- Combustion turbine:

Solar Plant Cost
- Capital cost ($/kWe, year):
- Operating and maintenance costs ($/year, year):
- Carrying charge rate:

Results

Plant Value
- Net capital credit ($, $/kWe):
- Annual operating costs ($, year):
- Present value of operating credit ($):
- Net plant value ($, $/kWe):
- Break-even capital cost ($, $/kWe):

Solar Plant Energy Costs
- Solar plant energy produced (MWh/year):
- Solar plant capacity factor:
- Busbar energy costs (mills/kWh):

Utility System Cost Impact
- Present value capital cost differential ($, year):
- Present value operating cost differential ($, year):
- Total present value differential ($, year):
- Levelized annual cost differential ($/year):

Cost/Benefit

The busbar energy cost calculations are taken primarily from a joint EPRI/DOE report by J. W. Doane et. al. [7] An effort has been made to make the notation used herein consistent with that used by Doane. However, certain variations on the parameters have been exercised when they were considered informative.

The handling of the following areas is fundamental to the evaluations:

- Revenue requirement components
- Time value of money
- Escalation of different costs

These factors are discussed in the following paragraphs.

A.5.1.1 Revenue Requirement Components

The concept of revenue requirements includes cost components to support the capital investment and other expenses, which in this case are primarily operating costs. The concept may apply to a single project or to an entire system made up of many projects.

The revenue requirements to support the capital investment are primarily as follows (see Table A.5-2, Glossary of Terms):

- Adequate return on the investment to cover the cost of capital (similar to interest on money borrowed), k
- Recovery of the amount invested (depreciation), d
- Income taxes required on k, T
- Other taxes, β_1
- Insurance, β_2

The annual revenue requirements for the above can usually be expressed as a percentage of the capitalized investment (CI). The letters at the end of each of the above items will be used to indicate the appropriate percentages for each item.

Additional revenue requirements for a generating plant are other expenses, which are primarily as follows:

- Fuel costs, FL
- Maintenance costs, MNT
- Other operating costs, OP

These expenses are usually not expressed as a percentage of CI, and may escalate

Table A.5-2 GLOSSARY OF TERMS

ARR - Annual revenue requirements

β_1 - Other taxes expressed as a fraction or percentage of CI

β_2 - Insurance expressed as a fraction or percentage of CI

BBEC - Levelized busbar energy costs

be - Subscript denoting break-even value

CI - Capitalized investment

CRF - Capital recovery factor, also used for converting present values to level annuities and vice versa

d - Sinking-fund depreciation factor

d' - Book depreciation factor, usually percentage derived from straight-line depreciation

d" - Levelized percentage equivalent of tax depreciation

DARR - Differential levelized annual revenue requirements for utility system with and without solar plant

DCAP - Differential in capital investment requirements to the nonsolar part of the utility system, with and without solar plant

DCRR - Difference in capital associated revenue requirements, with and without solar plant

DOP - Difference in operating cost to the nonsolar part of the utility system, with and without solar plant

DORR - Differential in utility system operating revenue requirements, with and without solar plant

DTRR - Differential in utility system total revenue requirements, with and without solar plant

D/V - Percentage of capitalization made up of debt

FCR - Annual fixed charge rate, in this case a levelized value

FL - Fuel costs

FV - Some future value

g - An annual escalation rate

IC - Investment tax credit as a percentage of capitalized investment

k - Weighted average cost of capital, used as the present worth discount rate

kd - Average interest rate on debt

MNT - Maintenance costs

MWh - Megawatt hours of electrical energy, used with subscript s to indicate from solar plant

N - Number of years involved in calculation, usually the life expectancy of solar plant

NET - Net capital value of solar plant, after solar OM costs accounted for

OM - Solar plant operating and maintenance costs

OP - Solar plant operating costs

PV - Some present value, usually at the year of first operation of solar plant

pv - Subscript indicating present value, usually at the year of first operation of solar plant

RR - Revenue requirements

RRCAP - Revenue requirements associated with the capital credit of the solar plant to the rest of the utility system

RRTOT - Revenue requirements associated with the total credit (value) of the solar plant to the rest of the utility system

T - Income tax component of revenue requirements expressed as a percentage of the capital investment

t - A time (year) subscript (Equation A.5-1); the statutory income tax rate (Equation A.5-6)

W - An artificial rate which is a function of g and k

independently. For purposes of this analysis, operating costs (excluding fuel) and maintenance costs are lumped together as operating and maintenance costs (OM).

A levelized "fixed charge rate" may be developed which, when multiplied by the capital investment (CI), gives the annual revenue requirements to support the capital investment. When added to the other expenses the total annual revenue requirements (ARR) are obtained:

$$ARR_t = FCR \cdot CI + FL_t + OM_t \tag{A.5-1}$$

The t subscript indicates values for a specific year, and FCR is a levelized value:

$$FCR = k + d + T + \beta_1 + \beta_2 \tag{A.5-2}$$

where k is the weighted average cost of capital.

The depreciation term d is the sinking-fund factor for an interest rate of k and N years. If N is the life expectancy of the plant,

$$d = \frac{k}{(1+k)^N - 1} \tag{A.5-3}$$

The sum of d and k is sometimes calculated compositely as a capital recovery factor (CRF):

$$CRF = k + d = \frac{k}{1 - (1+k)^{-N}} \tag{A.5-4}$$

The CRF is also used to obtain a future level annuity equivalent to some stipulated present value:

$$\text{Level Annuity} = CRF \cdot PV \tag{A.5-5}$$

Calculation of the proper income tax percentage is a little more complicated, and dependent upon the company's accounting practices. Assuming a before-tax average cost of capital k, straight-line book depreciation d', accelerated tax depreciation d", investment tax credit percentage IC, and flow-through accounting, the tax equation appears in the following form [8]:

$$T = \frac{t}{1 - t} \left[(k+d-d') \left(1 - \frac{D/V \cdot kd}{k} \right) + d' - d'' - IC \left(\frac{k + d}{1 + k} \right) \right] - \frac{IC(k+d)}{1 + k} \tag{A.5-6}$$

where D/V is the percent debt in the capitalization and kd is the annual rate of return on debt.

Doane takes a slightly different approach, in which an effective income tax rate, T, is established. This effective rate is not used by multiplying it directly times the capitalized investment, CI, but in another manner. The annual revenue requirements to pay other taxes and insurance are expressed as percentages of the capital investment, β_1 and β_2, respectively. From this the levelized (annualized) fixed charge rate can be developed as given in Equation A.5-2. Annual total revenue requirements associated with a generating plant may then be calculated using Equation A.5-1.

A.5.1.2 Time Value of Money

A dollar expenditure or revenue requirement in one year does not have the same value to a company as an expenditure or income in some other year. The annual rate expressing the preference of delaying expenditures is usually expressed by the average cost of capital, k. By using k in present value or future value calculations, expenditures in one year can be translated into equivalents in another year.

The familiar equation for transferring a present value N years into the future to obtain an equivalent future value is

$$FV = PV(1+k)^N \qquad \text{(A.5-7)}$$

To obtain a level annual annuity equivalent to a present value, or vice versa, the capital recovery factor will be used as shown in Equation A.5-5.

A.5.1.3 Escalation of Different Costs

At times in this analysis it will be desirable to find the equivalent present value of some revenue requirement--for instance, operating and maintenance expenses--growing at a compound annual escalation rate g. If the first year's revenue requirement for the item of interest is RR_1 the present value to the beginning of the first year of N years of RR growing at an annual compound rate g is as follows [9]:

- When $g > k$, where $1 + W = \frac{1+g}{1+k}$ (A.5-8)

$$RR_{pv} = RR_1 \left[\frac{(1+W)^N - 1}{W}\right]$$

- If $g < k$, then $1 + W = \frac{1+k}{1+g}$, and (A.5-9)

$$RR_{pv} = RR_1 (HW) \left[\frac{(1+W)^N - 1}{W(1+W)^N}\right]$$

Equations A.5-8 and A.5-9 assume beginning of year payments.

Through the use of these equations the independent escalation of various cost components may be estimated, when a simulation through a number of years is not used. This also facilitates economic sensitivity analysis on some cost components.

A.5.2 SOLAR PLANT OPTIMUM EXPANSION VALUE CALCULATIONS

The Westinghouse Generation Expansion Planning Program minimizes the present worth of the total revenue requirements over the planning period. The value of a particular solar plant penetration scenario is arrived at by comparing the present worth of the total revenue requirements before and after the solar plants operate.

A.5.3 SOLAR PLANT STATIC ANALYSIS VALUE CALCULATIONS

There is a great deal of uncertainty associated with the expected cost of solar power plants. Independent of the cost of a solar plant, its value to a utility system under specific conditions can be calculated. Also from these calculations a break-even solar plant capital investment can be established.

Simulation of the operation of an electric utility system with and without solar plants is the basis of much of this study. The general approach to this analysis and the computer models used are described in Section A.4.

The overall flow of model use is shown in Figure A.5-1. The following lists the static analysis procedure used to establish the value of a solar plant:

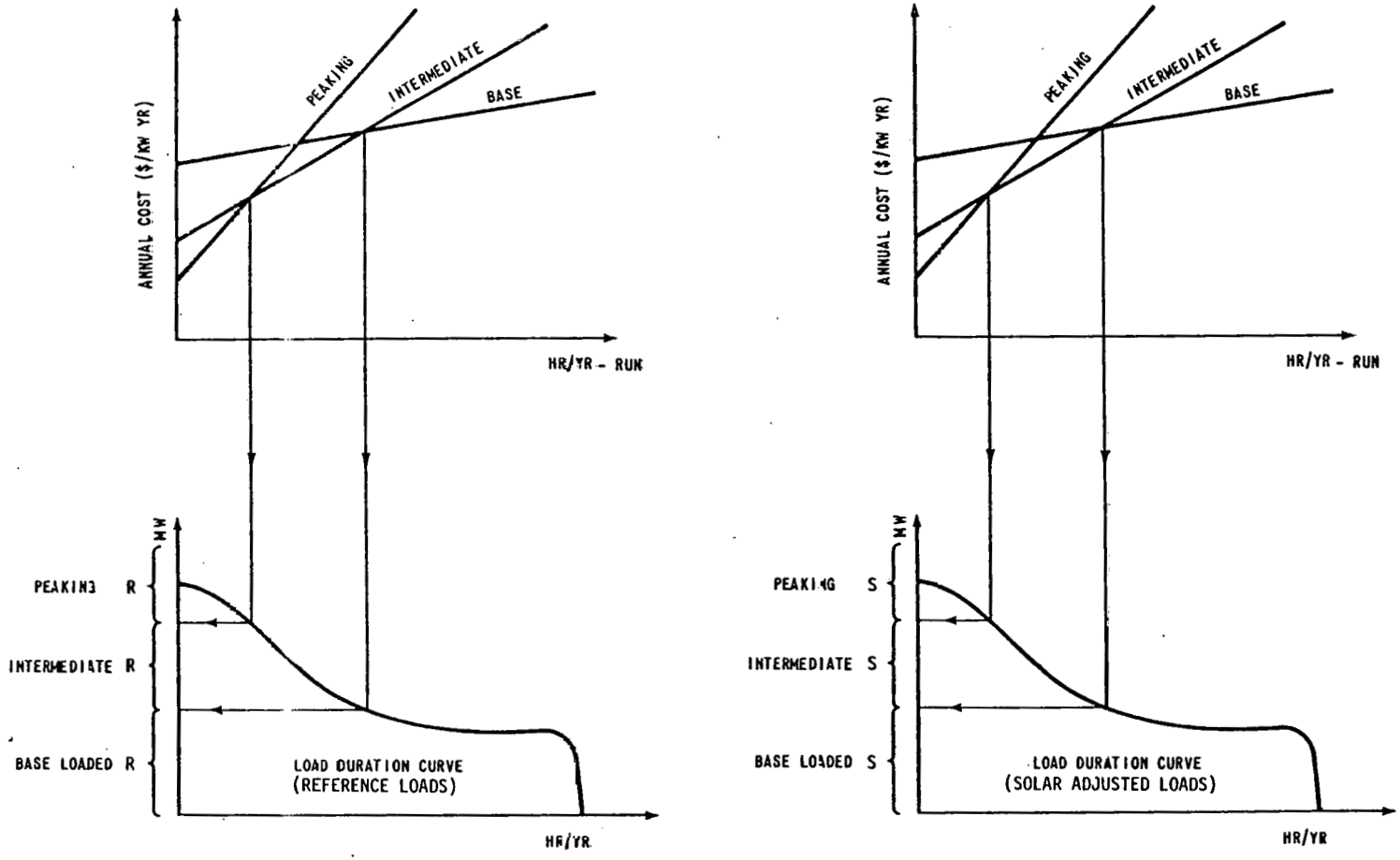
(1) Simulate operation of utility system for a year, without solar plant, to obtain base case operating cost and incremental operating cost for (2).

(2) Simulate operation of solar plant to obtain solar plant energy output (MWh) and net residual load (original load minus solar plant output).

(3) Obtain capacity required on remainder (nonsolar portion) of utility system to achieve desired reliability (loss-of-load probability) index. This is accomplished using the Generation Capacity Model.

(4) Use breakpoint analysis to determine desired change in mix of conventional generating plants to accommodate solar plant (see Figure A.5-1). Using the capacity requirements established in (3), and the breakpoint procedure, establish change in capital investment requirements for balance of system (DCAP).

(5) With adjusted capacity from (3) and (4), simulate the operation of the balance of the utility system (conventional system) using net residual load from (2) as input.



Change in Conventional Plant Mix:
- Solar Plant Peaking Displacement = Peaking R - Peaking S
- Solar Plant Intermediate Displacement = Intermediate R - Intermediate S
- Solar Plant Base Displacement = Base R - Base S

Figure A.5-1. STATIC BREAKPOINT ANALYSIS FOR OPTIMUM PLANT MIX

(6) Calculate the present value of solar savings in balance-of-system operating cost by subtracting the annual operating cost obtained in (5) from that found in (1). This difference in annual operating cost (DOP) for one year is assumed to grow over the life of the solar plant at the escalation rate of the fuel displaced (g). Through the use of Equation A.5-8 or A.5-9, the present value of the growing time series of DOP is found.

Assuming k > g, Equation A.5-9 becomes

$$DOP_{pv} = \frac{DOP}{1 + g} \left[\frac{(1+W)^N - 1}{W(1+W)^N}\right] \qquad (A.5\text{-}10)$$

(7) Establish the present value of the revenue requirements associated with the capital investment credit DCAP obtained in (4). This assumes a level annuity of the capital invested times the fixed charge rate over the life of the plant; thus, a form of Equation A.5-5 is used to obtain the PV of this credit:

$$RRCAP_{pv} = \frac{DCAP \cdot FCR}{CRF} \qquad (A.5\text{-}11)$$

(8) Express the value of the solar plant to the utility system by adding the results of (6) and (7). This expresses the value of the plant to the rest of the utility system in present value terms at the time of first solar plant operation:

$$RRTOT_{pv} = DOP_{pv} + RRCAP_{pv} \qquad (A.5\text{-}12)$$

This is independent of the cost of the solar plant.

(9) Calculate the break-even capital investment for the solar plant. However, an assumption must be made as to the operating and maintenance cost (OM) of the solar plant. Assuming that the first full year's operating and maintenance cost for the solar plant is OM, and that it is anticipated to escalate at some annual rate g (which may be different from the g used in Equation A.5-10), then the present value of OM is determined:

Assuming k > g, using Equation A.5-9

$$OM_{pv} = \frac{OM}{1 + g} \left[\frac{(1+W)^N - 1}{W(1+W)^N}\right] \qquad (A.5\text{-}13)$$

This is subtracted from the results of step (8) to obtain the net capital value, or plant value minus operating and maintenance cost, of the solar plant:

$$NET_{pv} = RRTOT_{pv} - OM_{pv} \qquad (A.5\text{-}14)$$

The capital investment which has the same present value of revenue requirements at NET_{pv} can now be found:

$$CI_{be} = \frac{NET_{pv} \cdot CRF}{FCR} \qquad (A.5\text{-}15)$$

For dynamic penetration and the use of GENOP, the value of a solar penetration scenario is arrived at by comparing the present worth of revenue requirements for the entire scenario (planning) period.

A.5.4 BUSBAR ENERGY COST CALCULATIONS

The levelized busbar energy cost for the solar plant is calculated by dividing the levelized annual cost (revenue requirements) of the solar plant by its anticipated annual energy output. This is consistent with Doane's practice [7].

In this procedure a capital investment cost CI_{pv} of the solar plant must be assumed. If the solar plant investment is known as a series of expenditures in different years prior to plant operation, then their future value in the year of first operation should be determined using Equation A.5-7. Then they can be added to obtain CI_{pv}.

In this study the annual electrical energy obtained from the solar plant is assumed to be the same throughout the life of the plant. This energy, in megawatt-hours, is obtained as described in step (2) above. With this information, the busbar energy cost is calculated as:

$$BBEC = \frac{OM_{pv} \cdot CRF + CI_{pv} \cdot FCR}{MWh} \qquad (A.5\text{-}16)$$

A.5.5 UTILITY SYSTEM COST IMPACT

The present value of the cost differential attributable to the solar plant as part of the utility system can be calculated. This is done using a combination of the value and the cost of the solar plant.

The differential in the present value of capital-associated costs can be obtained using the results of Equation A.5-11 and the estimated solar plant capital investment:

$$DCRR_{pv} = \frac{CI_{pv} \cdot FCR}{CRF} - RRCAP_{pv} \qquad (A.5\text{-}17)$$

Using the results of Equations A.5-10 and A.5-14, the differential in utility system operating costs (revenue requirements) can be developed:

$$DORR_{pv} = OM_{pv} - DOP_{pv} \qquad (A.5\text{-}18)$$

The total present value impact of implementing a solar plant upon an electric utility system is

$$DTRR_{pv} = DCRR_{pv} + DORR_{pv} \tag{A.5-19}$$

Expressed in annual levelized terms, Equation A.5-20 becomes

$$DARR = DTRR_{pv} \cdot CRF \tag{A.5-20}$$

A.5.6 COST/BENEFIT CALCULATIONS

The cost/benefit calculations are a function of the cost of a solar plant, including its operating and maintenance costs, and the value to the utility system. This value includes both fuel and other operating and maintenance costs saved on the balance of the utility system, and capacity credit. The cost/benefit calculation shown is in terms of present worth of plant lifetime costs and value. It is constructed by dividing the solar plant cost by its value:

$$\text{Cost/benefit} = \frac{CI_{pv} + OM_{pv}}{RRTOT_{pv}} \tag{A.5-21}$$

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SECTION A.6

COMMENT

The results that have been found from this study are specific to the utility system and other assumptions used. The principal conclusion drawn from this work is that a number of complex factors interact to establish the effect of solar plant installations on the system's optimal generation expansion plan and on the value of a solar plant. Only through detailed modeling of the solar-thermal plant operating with the balance of the utility system can the value and impact be established, and under those conditions, the results are case specific. Use of a planning optimization model such as GENOP is required to evaluate the potential overall impact of a scenario comprised of penetrations of solar plants that change with time.

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SECTION A.7

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APPENDIX B

DYNAMIC EXPANSION ANALYSIS DETAILS

This appendix includes the year-by-year installation schedules and cost summaries (revenue requirements) of the nonsolar base case and all nine solar penetration scenarios. These installation schedules and cost summaries are only for conventional units. They do not include solar additions and costs. The deferred expansion plan is shown with peaking capacity displacement assumed by the solar plants.

In the installation schedules, Unit Type PS (pumped storage) was not considered a candidate unit. Type 1 was a 100 MW combustion turbine, Type 2 a 250 MW combined cycle, Type 3 a 600 MW coal plant, and Type 4 a 1000 MW nuclear plant. The numbers in these tables represent quantity of unit additions. For example, a 1.0 shown under the Unit Type 3 Column means one 600 megawatt coal plant addition. Fractional unit additions were allowed. In addition to the yearly data, a twenty-five year summary is given.

The cost summary tables are given in current year and present worth 1985 millions of dollars. The carrying charges and production cost are given for each year in addition to a twenty-five year summary.

A listing of the tables shown in this appendix follows.

		Page
B-1	Nonsolar Base Installation Schedule	160
B-2	Nonsolar Base Cost Summary	161
B-3	ISA Low Penetration Installation Schedule	162
B-4	ISA Low Penetration Cost Summary	163
B-5	ISA Nominal Penetration Installation Schedule	164
B-6	ISA Nominal Penetration Cost Summary	165
B-7	ISA High Penetration Installation Schedule	166
B-8	ISA High Penetration Cost Summary	167
B-9	IHR Low Penetration Installation Schedule	168
B-10	IHR Low Penetration Cost Summary	169
B-11	IHR Nominal Penetration Installation Schedule	170
B-12	IHR Nominal Penetration Cost Summary	171
B-13	IHR High Penetration Installation Schedule	172
B-14	IHR High Penetration Cost Summary	173
B-15	Combination Low Penetration Installation Schedule	174
B-16	Combination Low Penetration Cost Summary	175
B-17	Combination Nominal Penetration Installation Schedule	176
B-18	Combination Nominal Penetration Cost Summary	177
B-19	Combination High Penetration Installation Schedule	178
B-20	Combination High Penetration Cost Summary	179

Table B-1. NONSOLAR BASE DEFERRED EXPANSION PLAN

INSTALLATION SCHEDULE

	YEAR	PS	UNIT TYPE NUMBER 1	2	3	4	5	6	7	8	9	10
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.704	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	2.979	0.000	1.620	0.000						
15	1999	0.000	9.884	0.000	.440	0.000						
16	2000	0.000	11.804	0.000	.366	0.000						
17	2001	0.000	14.500	0.000	0.000	0.000						
18	2002	0.000	1.557	.987	0.000	1.000						
19	2003	0.000	6.768	2.725	0.000	0.000						
20	2004	0.000	2.947	4.078	1.001	0.000						
21	2005	0.000	13.126	0.000	.271	0.000						
22	2006	0.000	9.017	0.000	1.231	0.000						
23	2007	0.000	2.153	.355	.170	1.000						
24	2008	0.000	8.165	.805	1.433	0.000						
25	2009	0.000	4.690	3.064	1.525	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	87.590	12.014	16.674	5.000						

Table B-2. NONSOLAR BASE DEFERRED EXPANSION PLAN

COST SUMMARY
FOR THE INSTALLATION POLICY

YEAR		CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1156.314	1156.314	0.000	1156.314	1156.314
2	1986	88.759	1336.947	1425.706	79.963	1204.457	1284.420
3	1987	427.515	1355.415	1782.931	346.981	1100.085	1447.067
4	1988	459.441	1619.600	2079.042	335.940	1184.238	1520.177
5	1989	688.813	1831.651	2520.464	453.743	1206.565	1660.308
6	1990	954.075	2074.612	3028.688	566.197	1231.181	1797.379
7	1991	1260.796	2353.536	3614.332	674.073	1258.296	1932.369
8	1992	1809.600	2478.444	4288.044	871.609	1193.763	2065.372
9	1993	2037.000	2902.809	4939.809	883.908	1259.606	2143.514
10	1994	2511.552	3308.649	5820.201	981.828	1293.433	2275.261
11	1995	3059.626	3777.529	6837.156	1077.553	1330.387	2407.940
12	1996	3844.759	4276.182	8120.941	1219.878	1356.761	2576.639
13	1997	4735.512	4663.938	9399.449	1353.603	1333.144	2686.746
14	1998	5705.010	5360.641	11065.651	1469.121	1380.442	2849.563
15	1999	6223.983	6402.050	12626.033	1443.932	1485.242	2929.174
16	2000	6795.119	7753.683	14548.802	1420.209	1620.554	3040.763
17	2001	7233.302	9564.231	16797.533	1361.974	1800.870	3162.844
18	2002	8856.330	10736.095	19592.425	1502.322	1821.192	3323.514
19	2003	9543.332	13153.598	22696.930	1458.433	2010.161	3468.594
20	2004	11348.492	15626.554	26975.046	1562.434	2151.427	3713.861
21	2005	12226.133	19448.831	31674.964	1516.455	2412.314	3928.769
22	2006	14124.600	23099.390	37223.991	1578.315	2581.178	4159.493
23	2007	16850.046	26242.151	43092.197	1696.272	2641.763	4338.036
24	2008	19587.848	31168.075	50755.924	1776.471	2826.711	4603.183
25	2009	23147.203	36892.169	60039.372	1891.242	3014.274	4905.515
CUMULATIVE TOTALS		163518.847	238583.096	402101.943	27522.456	41854.360	69376.816

Table B-3. IMPROVED STAND-ALONE
DEFERRED EXPANSION
LOW PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	1	2	3	4	5	6	7	8	9	10
		UNIT TYPE NUMBER										
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.704	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	2.334	0.000	1.654	0.000						
15	1999	0.000	10.361	0.000	.354	0.000						
16	2000	0.000	13.953	0.000	0.000	0.000						
17	2001	0.000	14.443	0.000	0.000	0.000						
18	2002	0.000	.417	1.424	0.000	1.000						
19	2003	0.000	5.144	2.460	.371	0.000						
20	2004	0.000	2.877	3.694	1.163	0.000						
21	2005	0.000	14.125	0.000	.094	0.000						
22	2006	0.000	7.717	.136	1.380	0.000						
23	2007	0.000	3.673	.128	0.000	1.000						
24	2008	0.000	7.971	.891	1.417	0.000						
25	2009	0.000	5.154	2.897	1.504	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	88.169	11.630	16.554	5.000						

Table B-4. IMPROVED STAND-ALONE
DEFERRED EXPANSION
LOW PENETRATION

COST SUMMARY
---------- FOR THE INSTALLATION POLICY ----------

		CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
YEAR		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1155.697	1155.697	0.000	1155.697	1155.697
2	1986	88.724	1335.531	1424.256	79.932	1203.181	1283.113
3	1987	427.480	1353.050	1780.530	346.952	1098.166	1445.118
4	1988	459.448	1615.416	2074.864	335.945	1181.178	1517.123
5	1989	688.820	1825.365	2514.185	453.747	1202.424	1656.172
6	1990	954.134	2067.048	3021.181	566.232	1226.692	1792.924
7	1991	1260.855	2344.016	3604.871	674.105	1253.207	1927.311
8	1992	1809.659	2467.217	4276.876	871.637	1188.356	2059.993
9	1993	2037.127	2889.390	4926.517	883.963	1253.783	2137.746
10	1994	2511.792	3293.485	5805.277	981.922	1287.505	2269.427
11	1995	3059.785	3760.140	6819.926	1077.609	1324.263	2401.872
12	1996	3844.828	4255.837	8100.664	1219.900	1350.306	2570.206
13	1997	4735.581	4639.169	9374.751	1353.622	1326.064	2679.686
14	1998	5710.124	5325.910	11036.034	1470.438	1371.498	2841.936
15	1999	6188.505	6374.029	12562.535	1435.701	1478.742	2914.442
16	2000	6572.459	7817.945	14390.404	1373.672	1633.985	3007.657
17	2001	7008.147	9659.340	16667.487	1319.579	1818.778	3138.358
18	2002	8655.851	10806.172	19462.023	1468.315	1833.079	3301.394
19	2003	9571.803	13064.618	22636.421	1462.784	1996.563	3459.347
20	2004	11465.890	15442.388	26908.278	1578.597	2126.071	3704.668
21	2005	12197.133	19347.426	31544.559	1512.858	2399.737	3912.595
22	2006	14238.041	22826.993	37065.035	1590.991	2550.740	4141.731
23	2007	16770.582	26128.024	42898.606	1688.273	2630.274	4318.547
24	2008	19496.055	31034.536	50530.590	1768.146	2814.600	4582.747
25	2009	23005.103	36776.005	59781.108	1879.631	3004.783	4884.414
CUMULATIVE TOTALS		162757.927	237604.748	400362.675	27394.552	41709.672	69104.224

Table B-5. IMPROVED STAND-ALONE DEFERRED EXPANSION PLAN NOMINAL PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	UNIT TYPE NUMBER 1	2	3	4	5	6	7	8	9	10
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.706	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	2.058	0.000	1.606	0.000						
15	1999	0.000	11.482	0.000	.155	0.000						
16	2000	0.000	13.876	0.000	0.000	0.000						
17	2001	0.000	13.360	.396	0.000	0.000						
18	2002	0.000	0.000	1.610	0.000	1.000						
19	2003	0.000	4.982	1.996	.547	0.000						
20	2004	0.000	3.327	3.181	1.280	0.000						
21	2005	0.000	14.346	0.000	.033	0.000						
22	2006	0.000	7.494	.129	1.392	0.000						
23	2007	0.000	3.804	0.000	0.000	1.000						
24	2008	0.000	7.749	.838	1.441	0.000						
25	2009	0.000	4.891	2.835	1.534	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	87.368	10.985	16.605	5.000						

Table B-6. IMPROVED STAND-ALONE
DEFERRED EXPANSION PLAN
NOMINAL PENETRATION

COST SUMMARY
FOR THE INSTALLATION POLICY

	YEAR	CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1155.695	1155.695	0.000	1155.695	1155.695
2	1986	88.754	1335.503	1424.257	79.959	1203.155	1283.114
3	1987	427.510	1353.030	1780.540	346.977	1098.149	1445.126
4	1988	459.443	1615.402	2074.844	335.940	1181.168	1517.108
5	1989	688.814	1825.324	2514.138	453.743	1202.397	1656.141
6	1990	954.084	2063.747	3017.831	566.202	1224.734	1790.936
7	1991	1260.805	2336.555	3597.361	674.078	1249.218	1923.296
8	1992	1809.609	2456.981	4266.589	871.613	1183.426	2055.039
9	1993	2037.019	2874.947	4911.966	883.917	1247.516	2131.432
10	1994	2511.560	3274.443	5786.003	981.831	1280.061	2261.892
11	1995	3059.622	3735.587	6795.209	1077.551	1315.616	2393.167
12	1996	3844.741	4226.691	8071.432	1219.872	1341.058	2560.931
13	1997	4735.494	4603.875	9339.368	1353.597	1315.975	2669.573
14	1998	5678.194	5290.175	10968.369	1462.216	1362.296	2824.511
15	1999	6062.824	6367.867	12430.691	1406.544	1477.312	2883.856
16	2000	6444.320	7810.394	14254.715	1346.891	1632.406	2979.297
17	2001	6899.264	9630.390	16529.654	1299.078	1813.327	3112.405
18	2002	8559.431	10748.702	19308.134	1451.959	1823.331	3275.289
19	2003	9552.815	12918.931	22471.745	1459.882	1974.299	3434.181
20	2004	11489.955	15216.223	26706.178	1581.910	2094.934	3676.843
21	2005	12165.656	19087.933	31253.589	1508.954	2367.551	3876.505
22	2006	14208.927	22475.290	36684.217	1587.738	2511.440	4099.177
23	2007	16719.239	25683.262	42402.501	1683.104	2585.501	4268.605
24	2008	19453.238	30429.928	49883.166	1764.263	2759.767	4524.030
25	2009	22976.095	35966.014	58942.109	1877.261	2938.602	4815.864
CUMULATIVE TOTALS		162087.413	234482.889	396570.302	27275.080	41338.934	68614.014

Table B-7. IMPROVED STAND-ALONE
DEFERRED EXPANSION
HIGH PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	UNIT TYPE NUMBER 1	2	3	4	5	6	7	8	9	10
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.704	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	3.798	0.000	1.171	0.000						
15	1999	0.000	12.265	0.000	0.000	0.000						
16	2000	0.000	11.912	.717	0.000	0.000						
17	2001	0.000	12.843	.472	.032	0.000						
18	2002	0.000	0.000	1.610	0.000	1.000						
19	2003	0.000	3.351	2.230	.671	0.000						
20	2004	0.000	5.280	1.142	1.773	0.000						
21	2005	0.000	14.227	0.000	.018	0.000						
22	2006	0.000	6.336	.444	1.432	0.000						
23	2007	0.000	2.660	.404	0.000	1.000						
24	2008	0.000	7.614	.698	1.498	0.000						
25	2009	0.000	8.424	1.120	1.635	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	88.687	8.837	16.847	5.000						

Table B-8. IMPROVED STAND-ALONE
DEFERRED EXPANSION
HIGH PENETRATION

COST SUMMARY
FOR THE INSTALLATION POLICY

YEAR		CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1155.697	1155.697	0.000	1155.697	1155.697
2	1986	88.754	1335.514	1424.268	79.959	1203.166	1283.125
3	1987	427.510	1353.034	1780.544	346.977	1098.153	1445.130
4	1988	459.443	1615.416	2074.858	335.940	1181.178	1517.118
5	1989	688.814	1825.365	2514.179	453.743	1202.424	1656.168
6	1990	954.084	2063.748	3017.832	566.202	1224.734	1790.936
7	1991	1260.805	2336.576	3597.381	674.078	1249.229	1923.307
8	1992	1809.609	2447.460	4257.069	871.613	1178.840	2050.453
9	1993	2037.019	2851.120	4888.139	883.917	1237.176	2121.093
10	1994	2511.560	3244.690	5756.250	981.831	1268.430	2250.261
11	1995	3059.622	3698.023	6757.645	1077.551	1302.386	2379.938
12	1996	3844.741	4179.809	8024.550	1219.872	1326.184	2546.056
13	1997	4735.494	4544.507	9280.001	1353.597	1299.006	2652.603
14	1998	5476.995	5283.985	10760.980	1410.404	1360.701	2771.106
15	1999	5785.788	6387.603	12173.391	1342.273	1481.891	2824.164
16	2000	6198.524	7818.135	14016.659	1295.518	1634.024	2929.543
17	2001	6670.588	9610.487	16281.075	1256.020	1809.580	3065.599
18	2002	8329.516	10681.874	19011.390	1412.958	1811.994	3224.952
19	2003	9410.575	12728.690	22139.265	1438.145	1945.226	3383.371
20	2004	11551.633	14776.748	26328.380	1590.402	2034.428	3624.829
21	2005	12206.565	18487.839	30694.404	1514.028	2293.119	3807.147
22	2006	14308.295	21643.695	35951.990	1598.841	2418.515	4017.357
23	2007	16852.300	24584.556	41436.856	1696.499	2474.895	4171.394
24	2008	19624.948	28990.088	48615.036	1779.836	2629.184	4409.020
25	2009	23052.528	34281.991	57334.520	1883.506	2801.009	4684.516
CUMULATIVE TOTALS		161345.710	227926.648	389272.359	27063.711	40621.170	67684.881

Table B-9. IMPROVED HYBRID REPOWERING
DEFERRED EXPANSION PLAN
LOW PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	UNIT TYPE NUMBER 1	2	3	4	5	6	7	8	9	10
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.704	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	2.206	0.000	1.682	0.000						
15	1999	0.000	10.965	0.000	.260	0.000						
16	2000	0.000	11.530	0.000	.370	0.000						
17	2001	0.000	14.488	0.000	0.000	0.000						
18	2002	0.000	.433	1.437	0.000	1.000						
19	2003	0.000	6.565	2.792	0.000	0.000						
20	2004	0.000	2.535	3.513	1.238	0.000						
21	2005	0.000	14.708	0.000	.008	0.000						
22	2006	0.000	7.450	.309	1.363	0.000						
23	2007	0.000	3.764	.119	0.000	1.000						
24	2008	0.000	7.403	.905	1.410	0.000						
25	2009	0.000	6.015	2.606	1.495	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	88.059	11.681	16.443	5.000						

Table B-10. IMPROVED HYBRID REPOWERING
DEFERRED EXPANSION PLAN
LOW PENETRATION

COST SUMMARY
---------- FOR THE INSTALLATION POLICY ----------

		CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
YEAR		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1154.196	1154.196	0.000	1154.196	1154.196
2	1986	88.754	1333.242	1421.997	79.959	1201.119	1281.078
3	1987	427.510	1350.754	1778.264	346.977	1096.302	1443.279
4	1988	459.443	1613.818	2073.260	335.940	1180.010	1515.950
5	1989	688.814	1825.189	2514.004	653.743	1202.309	1656.052
6	1990	954.084	2067.206	3021.290	566.202	1226.786	1792.989
7	1991	1260.805	2344.094	3604.899	674.078	1253.248	1927.326
8	1992	1809.609	2467.203	4276.812	871.613	1188.349	2059.962
9	1993	2037.019	2889.652	4926.671	883.917	1253.897	2137.813
10	1994	2511.560	3293.295	5804.855	981.831	1287.431	2269.262
11	1995	3059.622	3760.940	6820.562	1077.551	1324.545	2402.096
12	1996	3844.741	4254.908	8099.648	1219.872	1350.011	2569.883
13	1997	4735.494	4637.814	9373.307	1353.597	1325.676	2679.274
14	1998	5722.831	5318.286	11041.117	1473.711	1369.534	2843.245
15	1999	6158.746	6383.069	12541.814	1428.797	1480.839	2909.636
16	2000	6725.327	7729.633	14454.959	1405.623	1615.527	3021.149
17	2001	7162.916	9532.291	16695.207	1348.721	1794.856	3143.577
18	2002	8813.587	10670.954	19484.541	1495.0[illegible]	1810.142	3305.214
19	2003	9503.709	13065.751	22569.460	1452.377	1996.737	3449.114
20	2004	11427.046	15389.573	26816.619	1573.249	2118.800	3692.049
21	2005	12090.778	19371.982	31462.760	1499.666	2402.783	3902.449
22	2006	14134.745	22845.661	36980.406	1579.448	2552.826	4132.274
23	2007	16669.534	26134.855	42804.389	1678.100	2630.962	4309.062
24	2008	19357.419	30978.276	50335.695	1755.573	2809.498	4565.071
25	2009	22825.060	36807.527	59632.588	1864.921	3007.358	4872.279
CUMULATIVE TOTALS		162469.152	237220.169	399689.321	27400.540	41633.741	69034.281

Table B-11. IMPROVED HYBRID REPOWERING
DEFERRED EXPANSION PLAN
NOMINAL PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	UNIT TYPE NUMBER 1	2	3	4	5	6	7	8	9	10
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.704	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	2.412	0.000	1.581	0.000						
15	1999	0.000	10.845	0.000	.280	0.000						
16	2000	0.000	13.300	0.000	0.000	0.000						
17	2001	0.000	14.488	0.000	0.000	0.000						
18	2002	0.000	.519	1.[illegible]02	0.000	1.000						
19	2003	0.000	4.532	2.721	.374	0.000						
20	2004	0.000	1.574	3.550	1.225	0.000						
21	2005	0.000	14.077	0.000	.113	0.000						
22	2006	0.000	9.041	0.000	1.227	0.000						
23	2007	0.000	1.003	.853	.154	1.000						
24	2008	0.000	5.618	.888	1.623	0.000						
25	2009	0.000	6.361	2.424	1.513	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	83.769	11.838	16.507	5.000						

Table B-12. IMPROVED HYBRID REPOWERING
DEFERRED EXPANSION PLAN
NOMINAL PENETRATION

COST SUMMARY
---------- FOR THE INSTALLATION POLICY ----------

YEAR		CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1154.169	1154.169	0.000	1154.169	1154.169
2	1986	88.724	1333.203	1421.927	79.932	1201.084	1281.015
3	1987	427.480	1348.842	1776.322	346.952	1094.750	1441.702
4	1988	459.448	1609.261	2068.709	335.945	1176.678	1512.623
5	1989	688.820	1818.666	2507.486	453.747	1198.011	1651.759
6	1990	954.134	2058.466	3012.600	566.232	1221.599	1787.831
7	1991	1260.855	2332.635	3593.490	674.105	1247.122	1921.227
8	1992	1809.659	2452.375	4262.034	871.637	1181.207	2052.845
9	1993	2037.127	2869.931	4907.058	883.963	1245.339	2129.303
10	1994	2511.792	3269.022	5780.814	981.922	1277.942	2259.863
11	1995	3059.785	3731.800	6791.585	1077.609	1314.282	2391.891
12	1996	3844.828	4218.740	8063.568	1219.900	1338.536	2558.436
13	1997	4735.581	4593.380	9328.961	1353.622	1312.975	2666.598
14	1998	5671.869	5281.043	10952.911	1460.587	1359.944	2820.531
15	1999	6116.833	6329.502	12446.336	1419.074	1468.412	2887.486
16	2000	6483.916	7768.391	14252.307	1355.167	1623.628	2978.794
17	2001	6920.522	9593.719	16514.242	1303.080	1806.423	3109.503
18	2002	8567.940	10714.051	19281.992	1453.402	1817.453	3270.855
19	2003	9504.941	12921.763	22426.704	1452.566	1974.732	3427.298
20	2004	11385.840	15175.058	26560.898	1567.576	2089.266	3656.842
21	2005	12134.927	19086.707	31221.633	1505.142	2367.399	3872.541
22	2006	14029.278	22628.758	36658.036	1567.663	2528.589	4096.252
23	2007	16788.031	25689.564	42477.595	1690.029	2586.135	4276.164
24	2008	19393.210	30354.403	49747.613	1758.819	2752.917	4511.737
25	2009	22860.305	36102.897	58963.202	1867.801	2949.786	4817.587
CUMULATIVE TOTALS		161735.845	234436.346	396172.190	27246.472	41288.377	68534.848

Table B-13. IMPROVED HYBRID REPOWERING
DEFERRED EXPANSION PLAN
HIGH PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	1	2	3	4	5	6	7	8	9	10
		UNIT TYPE NUMBER										
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.704	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	4.820	0.000	1.046	0.000						
15	1999	0.000	12.525	0.000	0.000	0.000						
16	2000	0.000	12.350	0.000	0.000	0.000						
17	2001	0.000	8.933	2.222	0.000	0.000						
18	2002	0.000	1.311	1.086	0.000	1.000						
19	2003	0.000	4.172	3.326	.167	0.000						
20	2004	0.000	4.844	0.000	1.842	0.000						
21	2005	0.000	10.991	.526	.408	0.000						
22	2006	0.000	12.636	1.356	.062	0.000						
23	2007	0.000	0.000	0.000	.677	1.000						
24	2008	0.000	2.938	2.055	1.150	0.000						
25	2009	0.000	6.546	.924	2.441	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	80.064	11.495	16.410	5.000						

Table B-14. IMPROVED HYBRID REPOWERING
DEFERRED EXPANSION PLAN
HIGH PENETRATION

COST SUMMARY
FOR THE INSTALLATION POLICY

	YEAR	CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1154.084	1154.084	0.000	1154.084	1154.084
2	1986	88.724	1333.122	1421.846	79.932	1201.011	1280.942
3	1987	427.480	1348.766	1776.246	346.952	1094.689	1441.641
4	1988	459.448	1609.203	2068.652	335.945	1176.636	1512.580
5	1989	688.820	1811.965	2500.785	453.747	1193.597	1647.345
6	1990	954.134	2043.289	2997.423	566.232	1212.593	1778.824
7	1991	1260.855	2313.512	3574.367	674.105	1236.898	1911.002
8	1992	1809.659	2429.625	4239.283	871.637	1170.249	2041.886
9	1993	2037.127	2840.301	4877.428	883.963	1232.482	2116.445
10	1994	2511.792	3231.676	5743.468	981.922	1263.342	2245.264
11	1995	3059.785	3688.926	6748.711	1077.609	1299.183	2376.791
12	1996	3844.828	4162.057	8006.885	1219.900	1320.551	2540.451
13	1997	4735.581	4523.034	9258.615	1353.622	1292.868	2646.490
14	1998	5430.042	5279.262	10709.304	1398.313	1359.485	2757.798
15	1999	5744.613	6386.694	12131.307	1332.721	1481.680	2814.401
16	2000	6085.956	7868.424	13954.380	1271.991	1644.535	2916.526
17	2001	6646.157	9633.080	16279.238	1251.420	1813.834	3065.254
18	2002	8272.336	10734.677	19007.013	1403.258	1820.951	3224.209
19	2003	9106.547	13015.726	22122.274	1391.682	1989.092	3380.774
20	2004	11105.085	15008.852	26113.937	1528.922	2066.383	3595.305
21	2005	12136.275	18861.427	30997.702	1505.310	2339.456	3844.766
22	2006	13110.419	23427.264	36537.682	1664.988	2617.815	4082.803
23	2007	16294.231	26119.502	42413.733	1640.319	2629.416	4269.735
24	2008	18653.325	30831.205	49484.530	1691.717	2796.160	4487.877
25	2009	23037.957	35740.347	58778.304	1882.316	2920.164	4802.480
CUMULATIVE TOTALS		157501.178	235396.019	392897.197	26608.522	41327.154	67935.676

Table B-15. COMBINATION SOLAR EXPANSION
DEFERRED EXPANSION
LOW PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	1	2	3	4	5	6	7	8	9	10
		UNIT TYPE NUMBER										
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.704	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	2.387	0.000	1.652	0.000						
15	1999	0.000	10.497	0.000	.338	0.000						
16	2000	0.000	13.587	0.000	0.000	0.000						
17	2001	0.000	14.442	0.000	0.000	0.000						
18	2002	0.000	.941	1.210	0.000	1.000						
19	2003	0.000	5.039	2.614	.296	0.000						
20	2004	0.000	2.783	3.701	1.170	0.000						
21	2005	0.000	13.918	0.000	.119	0.000						
22	2006	0.000	7.745	.139	1.369	0.000						
23	2007	0.000	3.582	.149	0.000	1.000						
24	2008	0.000	7.931	.886	1.417	0.000						
25	2009	0.000	5.068	2.892	1.509	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	87.920	11.591	16.487	5.000						

Table B-16. COMBINATION SOLAR EXPANSION
DEFERRED EXPANSION
LOW PENETRATION

COST SUMMARY
---------- FOR THE INSTALLATION POLICY ----------

YEAR		CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1154.176	1154.176	0.000	1154.176	1154.176
2	1986	88.724	1333.255	1421.979	79.932	1201.131	1281.062
3	1987	427.480	1350.759	1778.239	346.952	1096.306	1443.258
4	1988	459.448	1613.806	2073.254	335.945	1180.001	1515.945
5	1989	688.820	1825.185	2514.005	453.747	1202.306	1656.053
6	1990	954.134	2067.164	3021.298	566.232	1226.761	1792.993
7	1991	1260.855	2344.039	3604.894	674.105	1253.219	1927.323
8	1992	1809.659	2467.163	4276.821	871.637	1188.330	2059.967
9	1993	2037.127	2889.588	4926.716	883.963	1253.869	2137.832
10	1994	2511.792	3293.151	5804.943	981.922	1287.374	2269.296
11	1995	3059.785	3760.900	6820.685	1077.609	1324.530	2402.139
12	1996	3844.828	4254.618	8099.446	1219.900	1349.919	2569.819
13	1997	4735.581	4637.127	9372.708	1353.622	1325.480	2679.103
14	1998	5710.143	5322.022	11032.165	1470.443	1370.497	2840.940
15	1999	6182.051	6370.844	12552.895	1434.204	1478.003	2912.207
16	2000	6556.681	7808.907	14365.588	1370.375	1632.096	3002.470
17	2001	6992.296	9646.220	16638.516	1316.595	1816.308	3132.903
18	2002	8626.337	10799.546	19425.883	1463.308	1831.955	3295.263
19	2003	9496.423	13081.264	22577.687	1451.264	1999.107	3450.371
20	2004	11396.667	15450.421	26845.088	1568.791	2127.177	3695.968
21	2005	12143.664	19341.062	31484.726	1506.226	2398.947	3905.174
22	2006	14173.412	22818.447	36991.860	1583.769	2549.785	4133.554
23	2007	16705.870	26096.951	42802.822	1681.758	2627.146	4308.904
24	2008	19427.649	30979.856	50407.505	1761.942	2809.641	4571.584
25	2009	22937.620	36685.118	59622.738	1874.118	2997.357	4871.474
CUMULATIVE TOTALS		162225.046	237391.590	399616.636	27328.359	41681.422	69009.781

Table B-17. COMBINATION SOLAR EXPANSION
DEFERRED EXPANSION
NOMINAL PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	1	2	3	4	5	6	7	8	9	10
		UNIT TYPE NUMBER										
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.504	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.144	0.000						
5	1989	0.000	0.000	0.000	.975	0.000						
6	1990	0.000	0.000	0.000	1.023	0.000						
7	1991	0.000	0.000	0.000	1.073	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.646	0.000						
10	1994	0.000	0.000	0.000	1.244	0.000						
11	1995	0.000	0.000	0.000	1.304	0.000						
12	1996	0.000	0.000	0.000	1.704	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	1.521	0.000	1.579	0.000						
15	1999	0.000	12.286	0.000	0.000	0.000						
16	2000	0.000	13.821	0.000	0.000	0.000						
17	2001	0.000	13.039	.509	0.000	0.000						
18	2002	0.000	0.000	1.610	0.000	1.000						
19	2003	0.000	3.976	2.074	.662	0.000						
20	2004	0.000	3.437	2.874	1.373	0.000						
21	2005	0.000	14.241	0.000	.031	0.000						
22	2006	0.000	7.229	.163	1.412	0.000						
23	2007	0.000	3.732	0.000	0.000	1.000						
24	2008	0.000	7.615	.857	1.441	0.000						
25	2009	0.000	4.669	2.835	1.554	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	85.566	10.922	16.669	5.000						

Table B-18. COMBINATION SOLAR EXPANSION
DEFERRED EXPANSION
NOMINAL PENETRATION

COST SUMMARY
FOR THE INSTALLATION POLICY

YEAR		CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1154.196	1154.196	0.000	1154.196	1154.196
2	1986	88.724	1333.228	1421.952	79.932	1201.106	1281.038
3	1987	427.480	1348.866	1776.346	346.952	1094.770	1441.722
4	1988	459.448	1609.282	2068.731	335.945	1176.693	1512.638
5	1989	688.820	1818.697	2507.518	453.747	1198.032	1651.780
6	1990	954.134	2058.552	3012.686	566.232	1221.650	1787.882
7	1991	1260.855	2332.572	3593.427	674.105	1247.088	1921.193
8	1992	1809.659	2452.707	4262.366	871.637	1181.367	2053.004
9	1993	2037.127	2869.374	4906.502	883.963	1245.098	2129.061
10	1994	2511.792	3266.703	5778.495	981.922	1277.035	2258.957
11	1995	3059.785	3725.857	6785.642	1077.609	1312.189	2389.798
12	1996	3844.828	4212.640	8057.468	1219.900	1336.601	2556.500
13	1997	4735.581	4586.255	9321.836	1353.622	1310.939	2664.561
14	1998	5652.077	5272.212	10924.289	1455.490	1357.670	2813.160
15	1999	5962.103	6376.805	12338.908	1383.177	1479.386	2862.563
16	2000	6341.824	7822.143	14163.968	1325.469	1634.862	2960.331
17	2001	6801.608	9640.977	16442.585	1280.690	1815.321	3096.011
18	2002	8461.343	10745.407	19206.750	1435.320	1822.771	3258.091
19	2003	9533.013	12840.758	22373.771	1456.856	1962.353	3419.208
20	2004	11512.222	15071.585	26583.806	1584.975	2075.020	3659.996
21	2005	12181.539	18882.736	31064.274	1510.924	2342.099	3853.023
22	2006	14243.129	22190.430	36433.560	1591.559	2479.609	4071.168
23	2007	16749.969	25333.669	42083.638	1686.198	2550.308	4236.505
24	2008	19481.441	29995.695	49477.136	1766.821	2720.385	4487.206
25	2009	23022.087	35416.602	58438.689	1881.019	2893.713	4774.732
CUMULATIVE TOTALS		161820.587	232357.951	394178.538	27204.064	41090.261	68294.325

Table B-19. COMBINATION SOLAR EXPANSION
DEFERRED EXPANSION
HIGH PENETRATION

INSTALLATION SCHEDULE

	YEAR	PS	1	2	3	4	5	6	7	8	9	10
		UNIT TYPE NUMBER										
		0 MW	100 MW	250 MW	600 MW	1000 MW	MW	MW	MW	MW	MW	MW
1	1985	0.000	0.000	0.000	0.000	0.000						
2	1986	0.000	0.000	0.000	.492	0.000						
3	1987	0.000	0.000	0.000	0.000	1.000						
4	1988	0.000	0.000	0.000	.128	0.000						
5	1989	0.000	0.000	0.000	.900	0.000						
6	1990	0.000	0.000	0.000	.944	0.000						
7	1991	0.000	0.000	0.000	1.042	0.000						
8	1992	0.000	0.000	0.000	0.000	1.000						
9	1993	0.000	0.000	0.000	.575	0.000						
10	1994	0.000	0.000	0.000	1.204	0.000						
11	1995	0.000	0.000	0.000	1.263	0.000						
12	1996	0.000	0.000	0.000	1.610	0.000						
13	1997	0.000	0.000	0.000	0.000	1.000						
14	1998	0.000	9.380	0.000	.536	0.000						
15	1999	0.000	10.932	.509	0.000	0.000						
16	2000	0.000	10.616	0.000	0.000	0.000						
17	2001	0.000	8.681	2.579	0.000	0.000						
18	2002	0.000	0.000	0.000	.601	1.000						
19	2003	0.000	3.191	1.965	.780	0.000						
20	2004	0.000	8.856	.261	1.914	0.000						
21	2005	0.000	14.312	0.000	.392	0.000						
22	2006	0.000	6.844	0.000	1.045	0.000						
23	2007	0.000	1.586	1.164	.167	1.000						
24	2008	0.000	8.445	1.369	1.201	0.000						
25	2009	0.000	13.590	.168	1.246	0.000						
CUMULATIVE TOTALS FOR THE STUDY		0.000	94.633	8.015	16.039	5.000						

Table B-20. COMBINATION SOLAR EXPANSION
DEFERRED EXPANSION
HIGH PENETRATION

COST SUMMARY
---------- FOR THE INSTALLATION POLICY ----------

	YEAR	CURRENT YEAR COST GIVEN IN MILLIONS OF DOLLARS			PRESENT WORTH COST GIVEN IN MILLIONS OF DOLLARS		
		CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS	CARRYING CHARGES	PRODUCTION COST	YEARLY TOTALS
1	1985	0.000	1154.196	1154.196	0.000	1154.196	1154.196
2	1986	86.554	1334.463	1421.017	77.976	1202.219	1280.195
3	1987	425.300	1350.012	1775.312	345.183	1095.700	1440.883
4	1988	453.927	1612.476	2066.403	331.907	1179.029	1510.936
5	1989	665.752	1822.435	2488.187	438.551	1200.494	1639.046
6	1990	910.619	2060.103	2970.721	540.408	1222.571	1762.979
7	1991	1208.307	2333.514	3541.821	646.010	1247.592	1893.602
8	1992	1756.867	2446.141	4203.008	846.210	1178.204	2024.414
9	1993	1959.877	2867.405	4827.282	850.443	1244.243	2094.686
10	1994	2419.246	3262.522	5681.768	945.743	1275.401	2221.144
11	1995	2949.691	3717.412	6667.103	1038.835	1309.215	2348.050
12	1996	3691.642	4199.548	7891.190	1171.296	1332.447	2503.743
13	1997	4581.623	4556.400	9138.023	1309.615	1302.405	2612.020
14	1998	5092.207	5403.593	10495.801	1311.316	1391.502	2702.818
15	1999	5421.340	6545.335	11966.675	1257.723	1518.484	2776.207
16	2000	5716.766	8064.420	13781.186	1194.829	1685.499	2880.328
17	2001	6312.887	9850.329	16163.216	1188.667	1854.740	3043.408
18	2002	8225.126	10705.858	18930.984	1395.250	1816.063	3211.312
19	2003	9354.776	12692.274	22047.050	1429.617	1939.661	3369.278
20	2004	11541.614	14674.869	26216.482	1589.022	2020.401	3609.423
21	2005	12595.208	18065.132	30660.340	1562.233	2240.689	3802.922
22	2006	14179.002	21449.056	35628.058	1584.394	2396.766	3981.160
23	2007	17052.211	24035.907	41088.118	1716.624	2419.664	4136.287
24	2008	19616.344	28474.481	48090.825	1779.056	2582.423	4361.478
25	2009	22492.271	34165.288	56657.559	1837.730	2791.474	4629.204
CUMULATIVE TOTALS		158709.156	226843.169	385552.325	26388.639	40601.080	66989.719

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APPENDIX C

STATIC ANALYSIS RESULTS

Appendix C contains summary figures for the static analysis. Table C-1 details the solar plant total megawatt installation by the analysis years. Three levels of solar plant penetration are shown for each of the improved hybrid repowered, the combination, and the improved stand-alone experiments. This table corresponds to Figure 7-1, 7-2, and 7-3 in the main report.

The remaining figures in Appendix C are of two types: the solar plant's power output is broken down by fuel displacement type and the solar plant's total value is shown with its components. Each of the nine penetration scenarios shown in Table C-1 have both figures included in Appendix C. The scenarios are included in the order shown in Table C-1. The energy displacement figures show solar plant output normalized to an incremental 50 MWe plant. The incremental plant is the last solar plant added to the system. The solar plant total value curves are also normalized to a 50 MWe plant. The total value components are the fuel value (coal, #6 oil, and #2 oil displacement), capacity credit, and variable operation and maintenance savings. These components are discussed in Appendix A and in Section 7.3.3 through 7.3.5.

A list of tables and figures included in Appendix C follows.

Tables		Page
C-1	Solar Plant Penetration Experiment	183

Figures

C-1	IHR Low Penetration Power Output	184
C-2	IHR Low Penetration Value Components	185
C-3	IHR Nominal Penetration Power Output	186
C-4	IHR Nominal Penetration Value Components	187
C-5	IHR High Penetration Power Output	188
C-6	IHR High Penetration Value Components	189
C-7	Combination Low Penetration Power Output	190
C-8	Combination Low Penetration Value Components	191
C-9	Combination Nominal Penetration Power Output	192
C-10	Combination Nominal Penetration Value Components	193
C-11	Combination High Penetration Power Output	194
C-12	Combination High Penetration Value Components	195
C-13	ISA Low Penetration Power Output	196
C-14	ISA Low Penetration Value Components	197
C-15	ISA Nominal Penetration Power Output	198
C-16	ISA Nominal Penetration Value Components	199
C-17	ISA High Penetration Power Output	200
C-18	ISA High Penetration Value Components	201

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Table C-1

SOLAR PLANT PENETRATION EXPERIMENT
GENERATION EXPANSION SCENARIOS AND STATIC ANALYSIS POINTS

YEAR	1985	86	87	88	89	90	91	92	93	95	97	2000	05	07	09
IMPROVED	18	27				40				65		105	170		250
HYBRID	18	27		64		80				150		285	525	680	680
REPOWERED	18	27		64		160				325		650	1300		1300
COMBINATION EXPERIMENT IHR	18	27				40				65	80				
	18	27		64		80		105							
	18	27		64											
COMBINATION EXPERIMENT ISA												105	170		250
										150		285	525		850
						160				325		650	1300		2300
IMPROVED	4		12		28					50		80	125		180
STAND	4		12		28		64			105		200	365		600
ALONE	4		12		28		64		160	210		440	900		1600

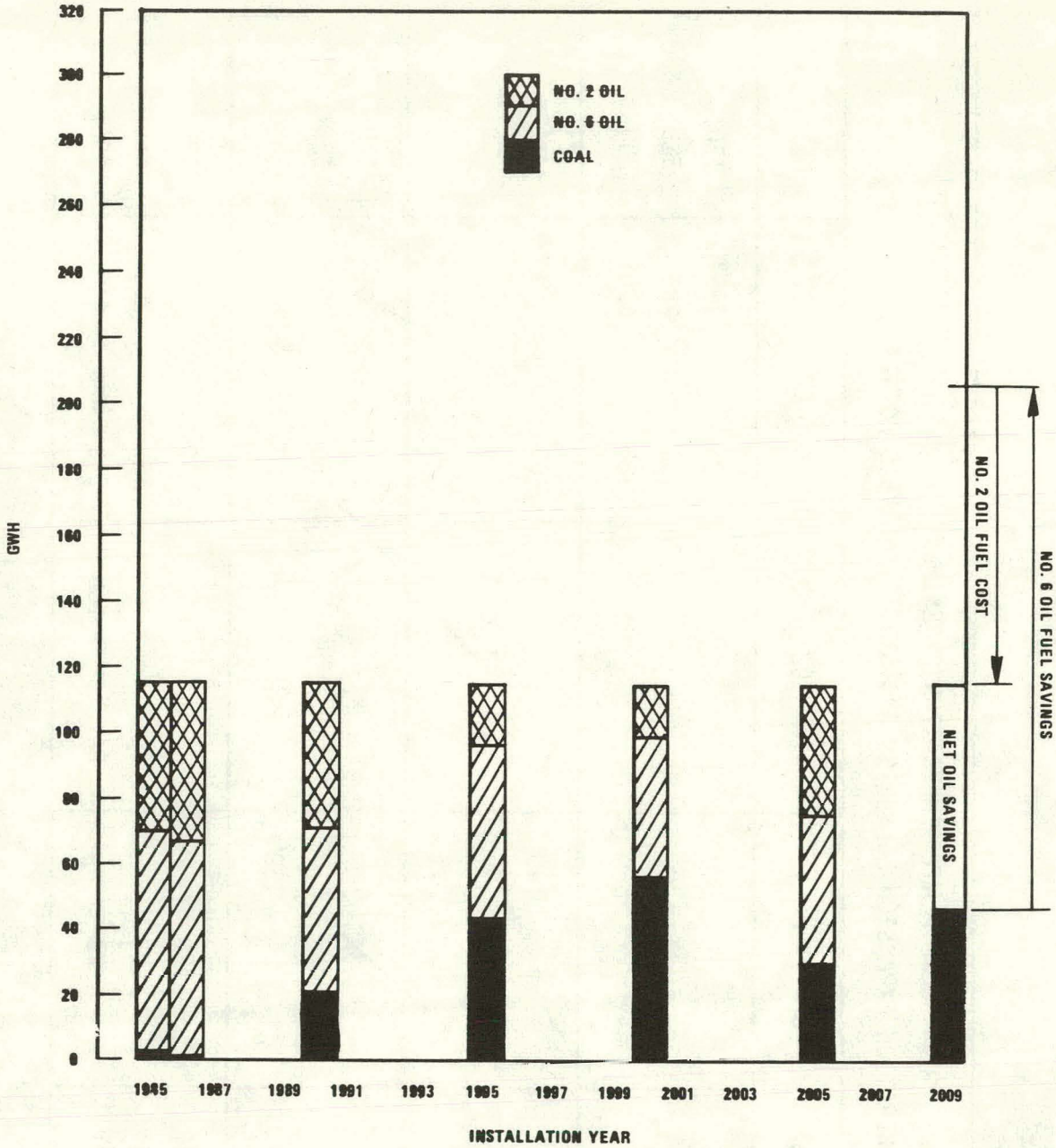

Figure C-1. 50 MW SOLAR PLANT POWER OUTPUT FUEL DISPLACEMENT IHR EXPERIMENT - LOW PENETRATION

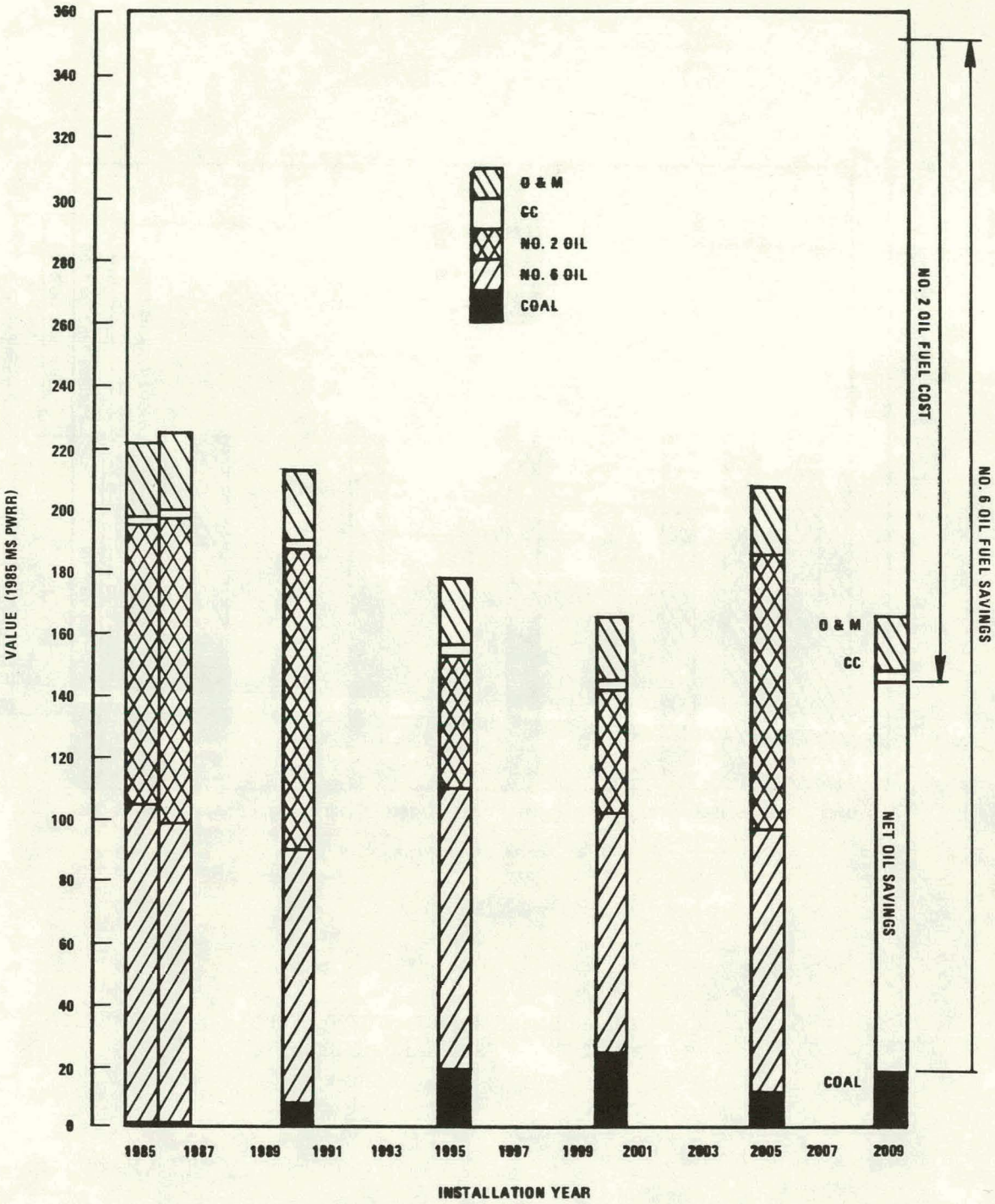

Figure C-2. 1985 M$ SOLAR PLANT POWER OUTPUT VALUE COMPONENTS
IHR EXPERIMENT - LOW PENETRATION

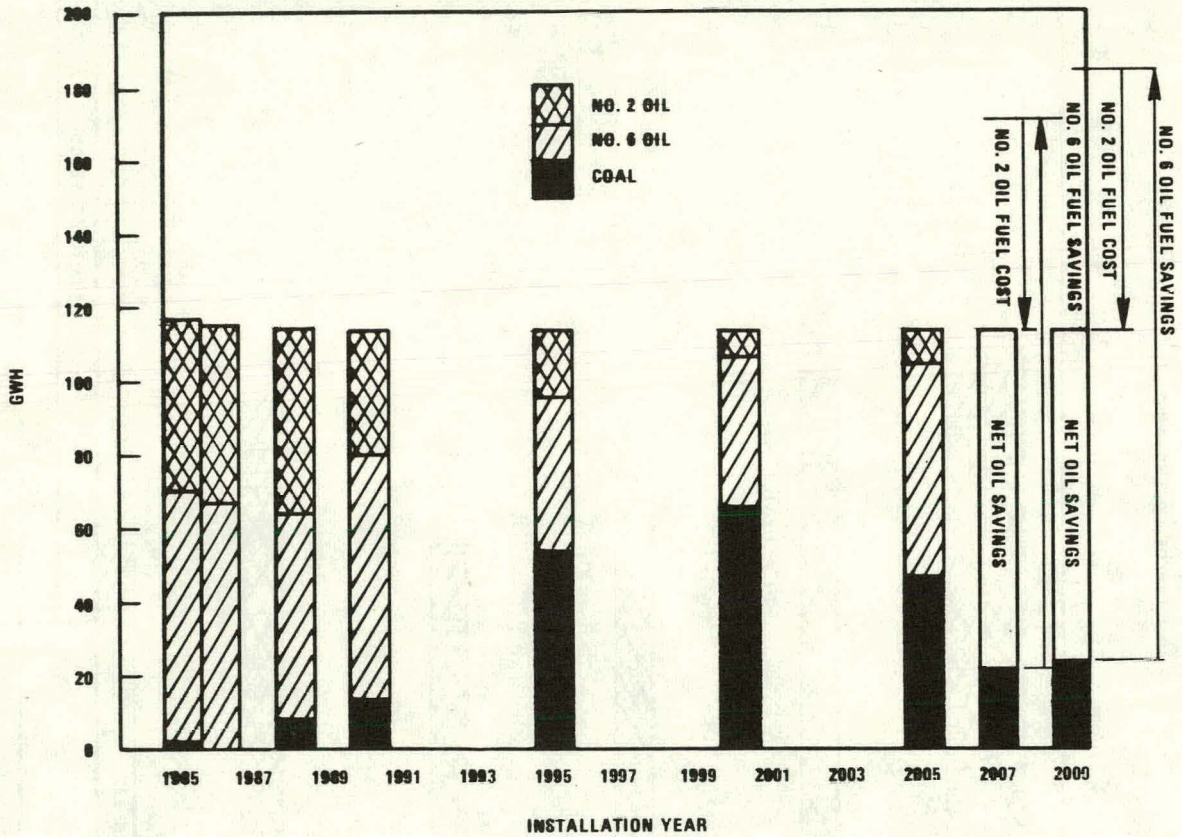

Figure C-3. 50 MW SOLAR PLANT POWER OUTPUT FUEL DISPLECEMENT IHR EXPERIMENT - NOMINAL PENETRATION

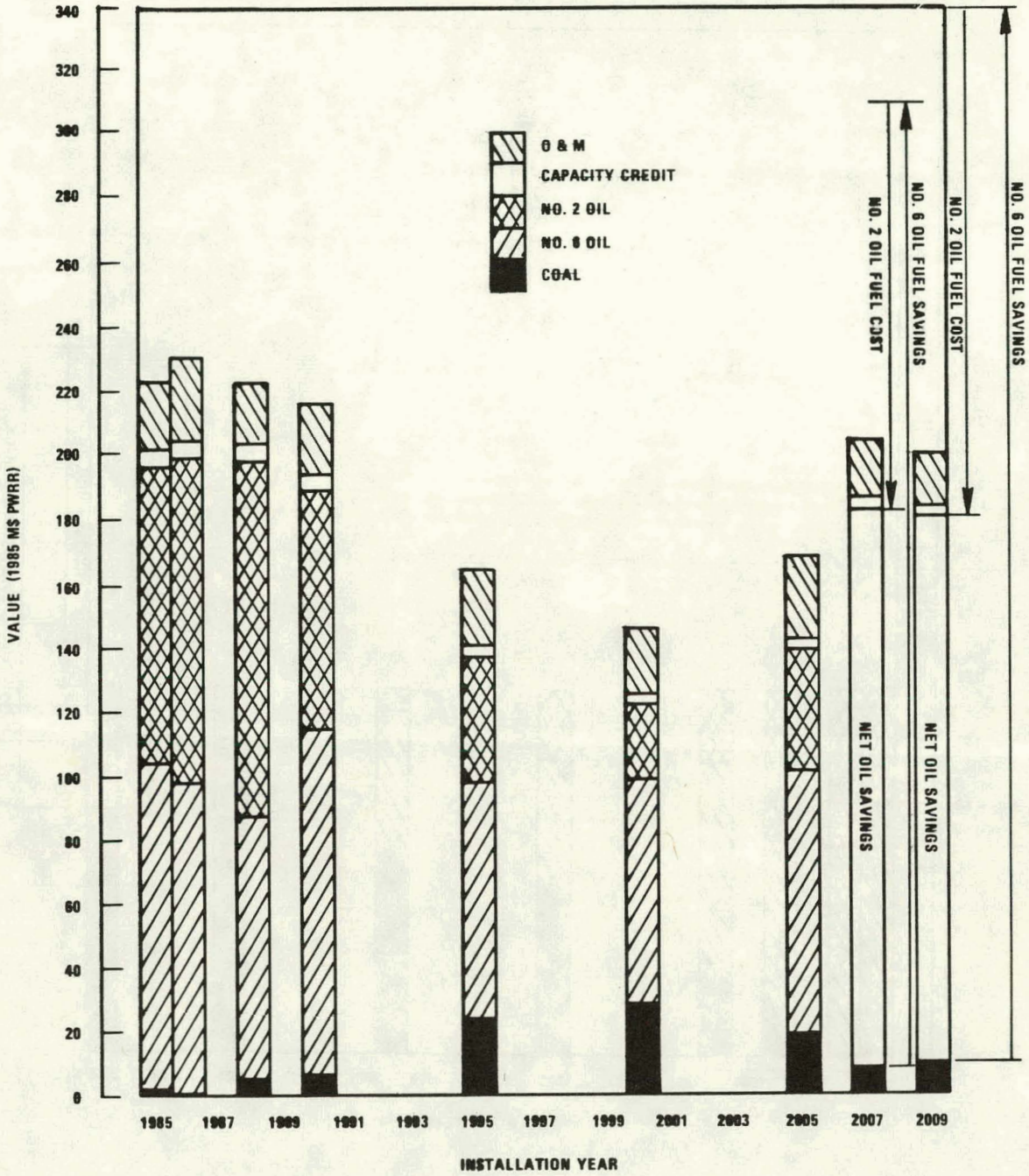

Figure C-4. 1985 M$ SOLAR PLANT FUEL VALUE DISPLACEMENT
IHR EXPERIMENT - NOMINAL PENETRATION

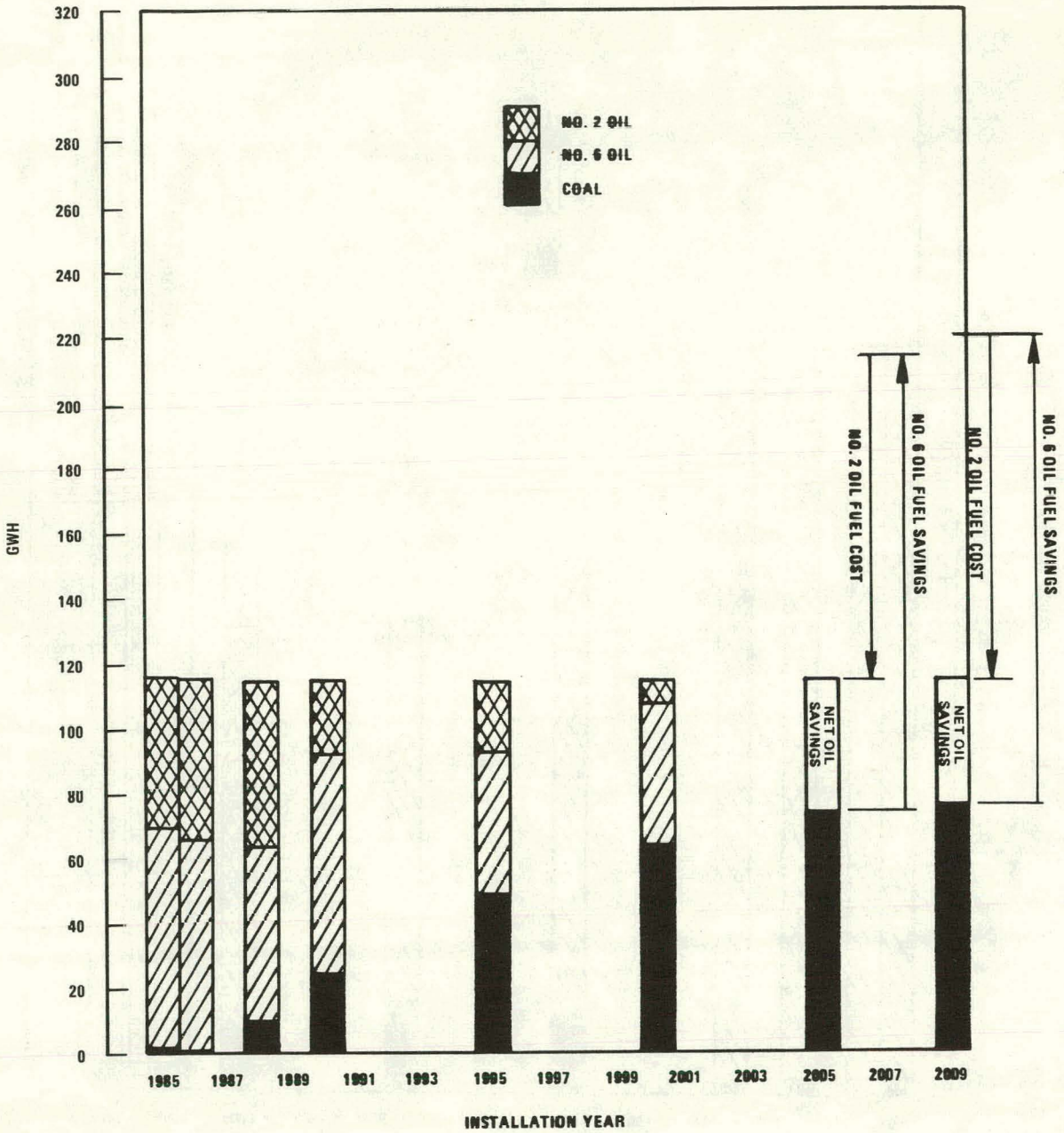

Figure C-5. 50 MW SOLAR PLANT POWER OUTPUT VALUE COMPONENTS
IHR EXPERIMENT - HIGH PENETRATION

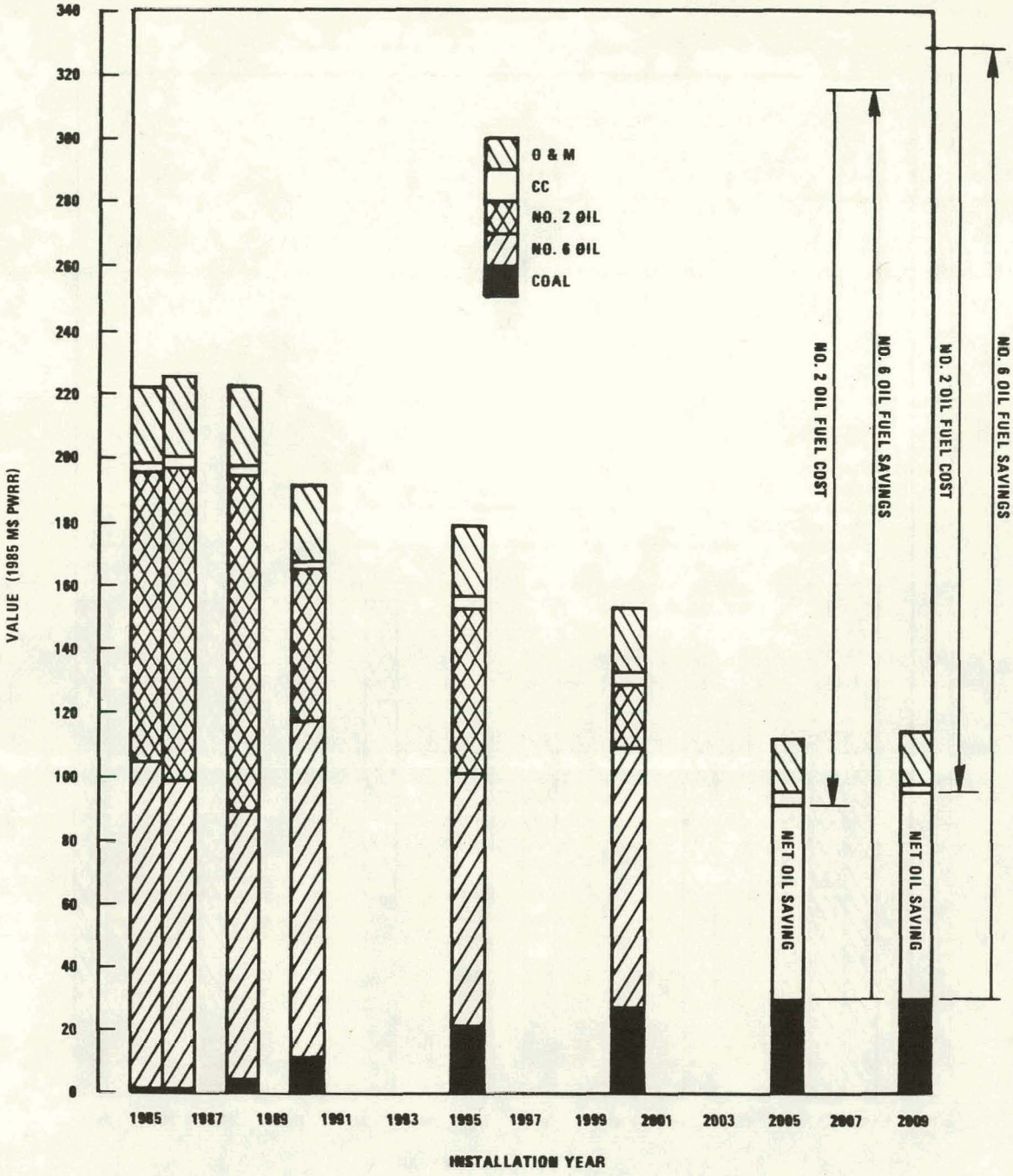

Figure C-6. 1985 M$ SOLAR PLANT FUEL VALUE DISPLACEMENT
IHR EXPERIMENT - HIGH PENETRATION

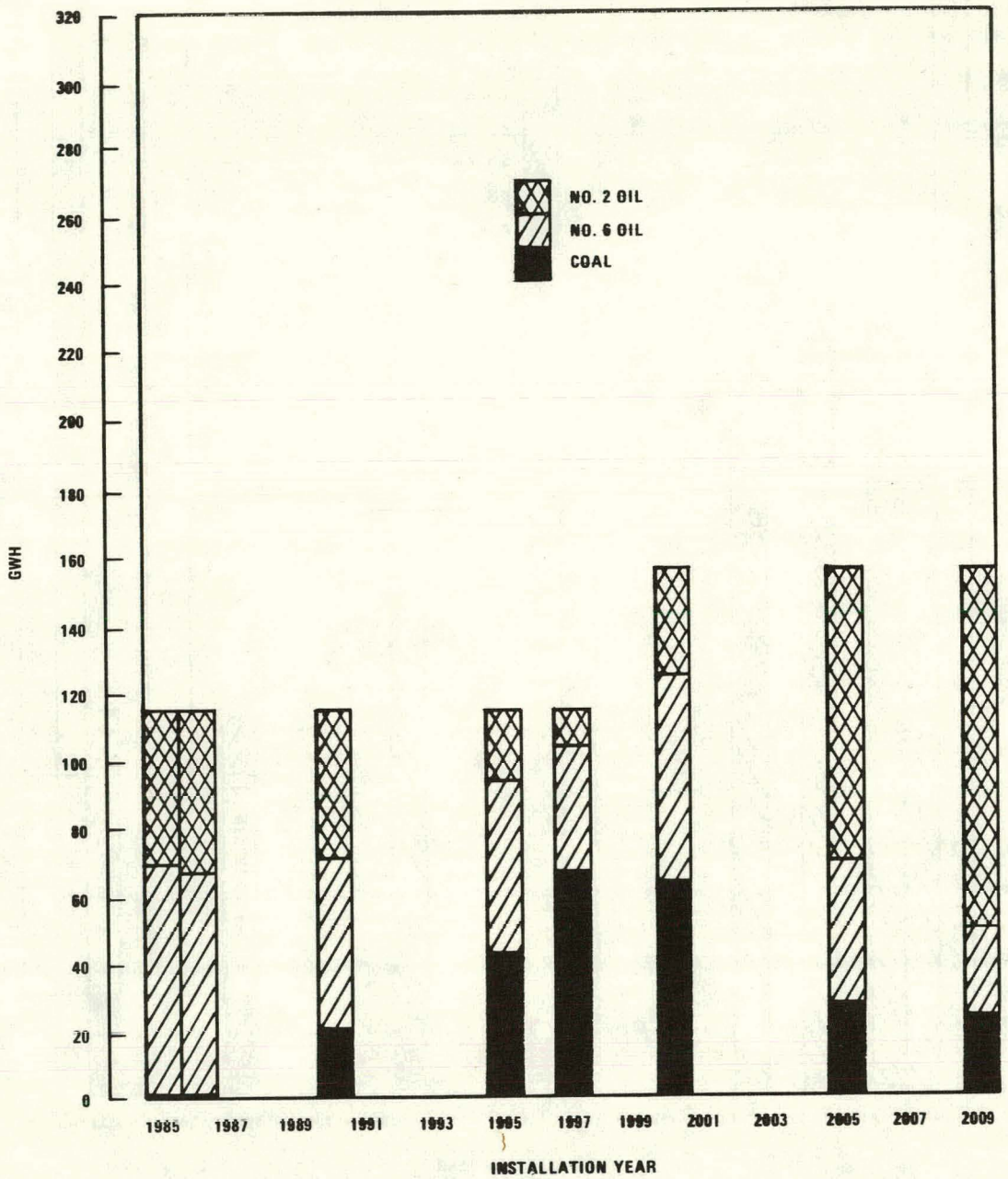

Figure C-7. 50 MW SOLAR PLANT POWER OUTPUT FUEL DISPLACEMENT COMBINATION EXPERIMENT - LOW PENETRATION

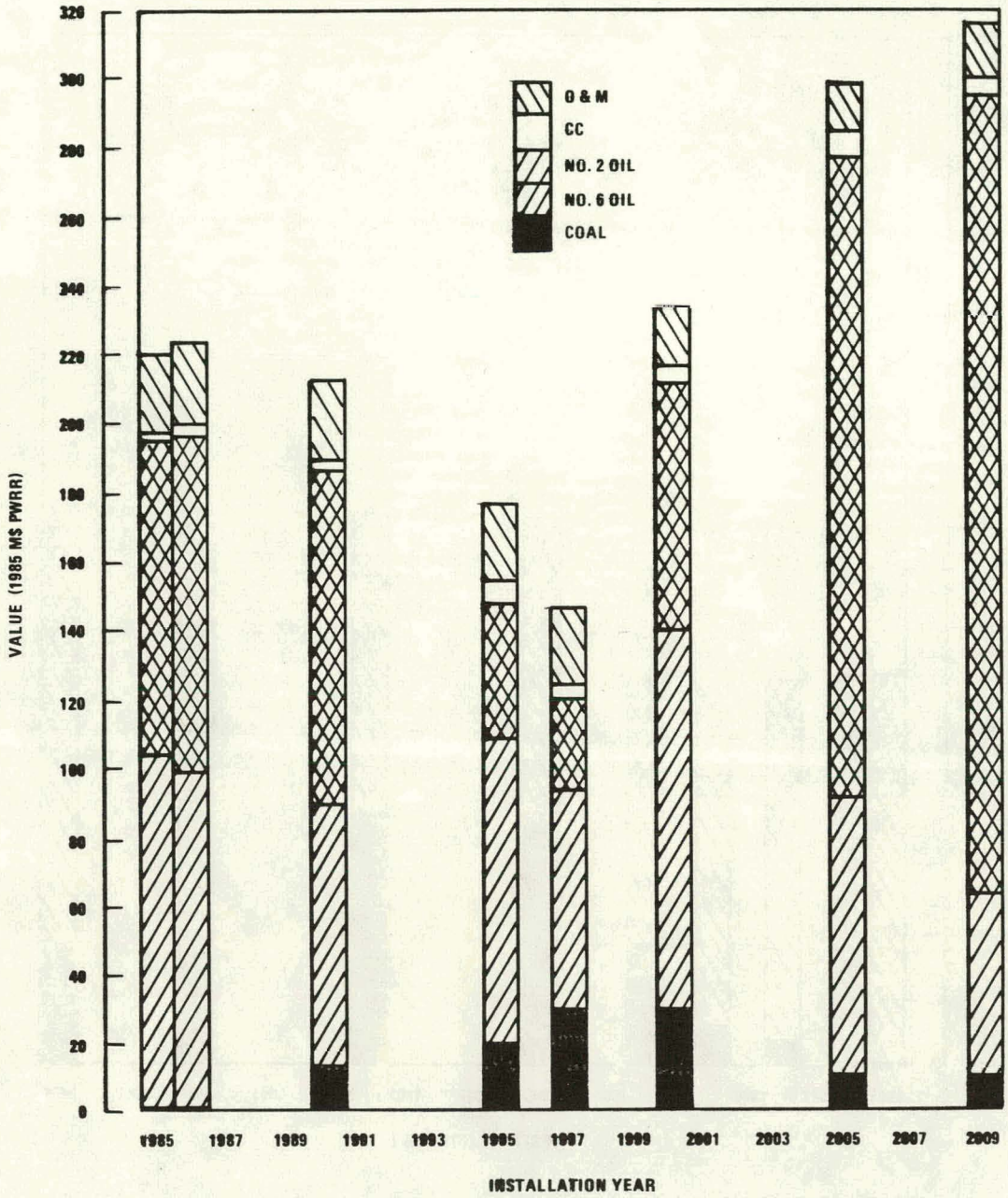

Figure C-8. 1985 M$ SOLAR PLANT POWER OUTPUT VALUE COMPONENTS COMBINATION EXPERIMENT - LOW PENETRATION

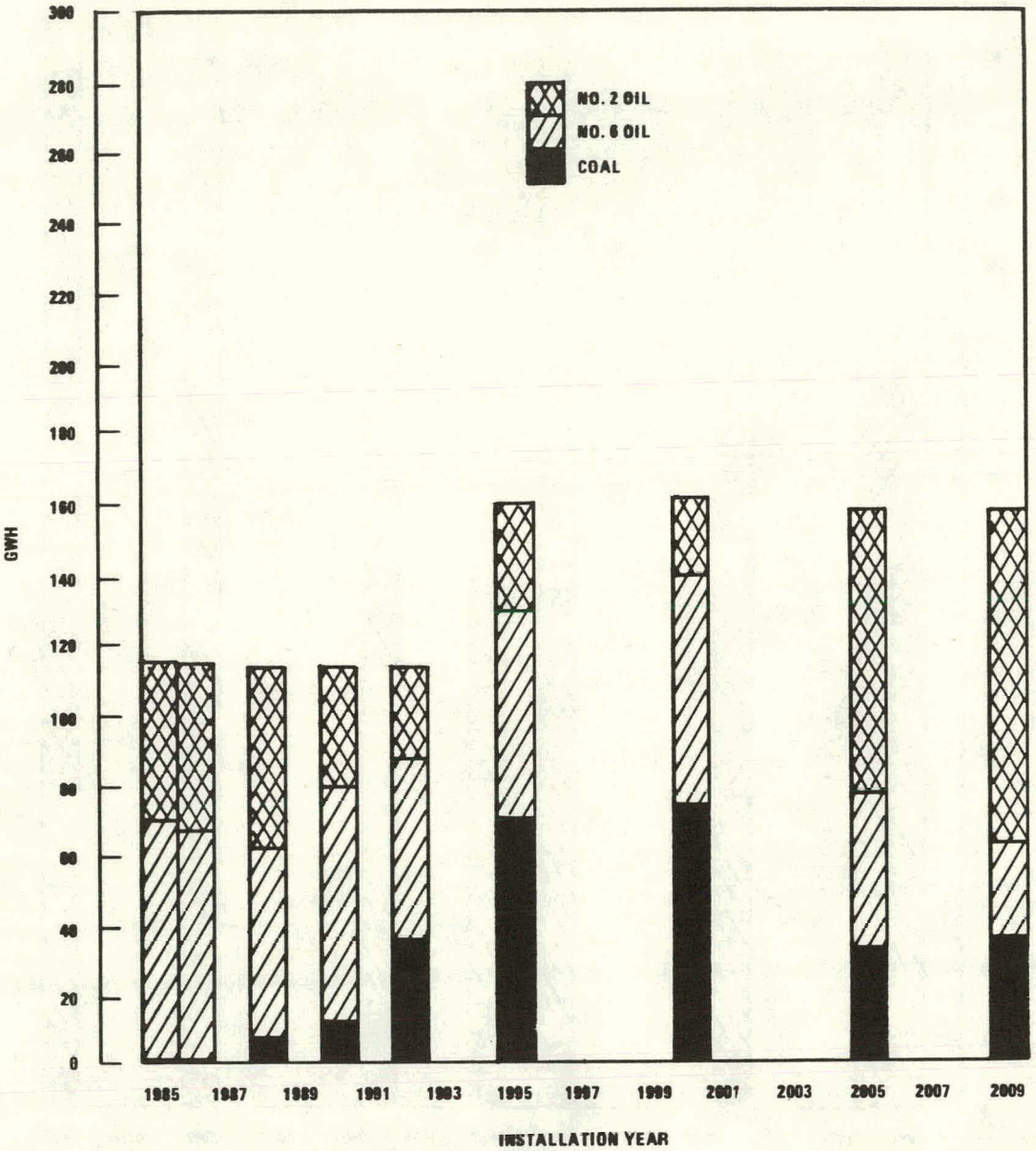

Figure C-9. 50 MW SOLAR PLANT POWER OUTPUT FUEL DISPLACEMENT COMBINATION EXPERIMENT - NOMINAL PENETRATION

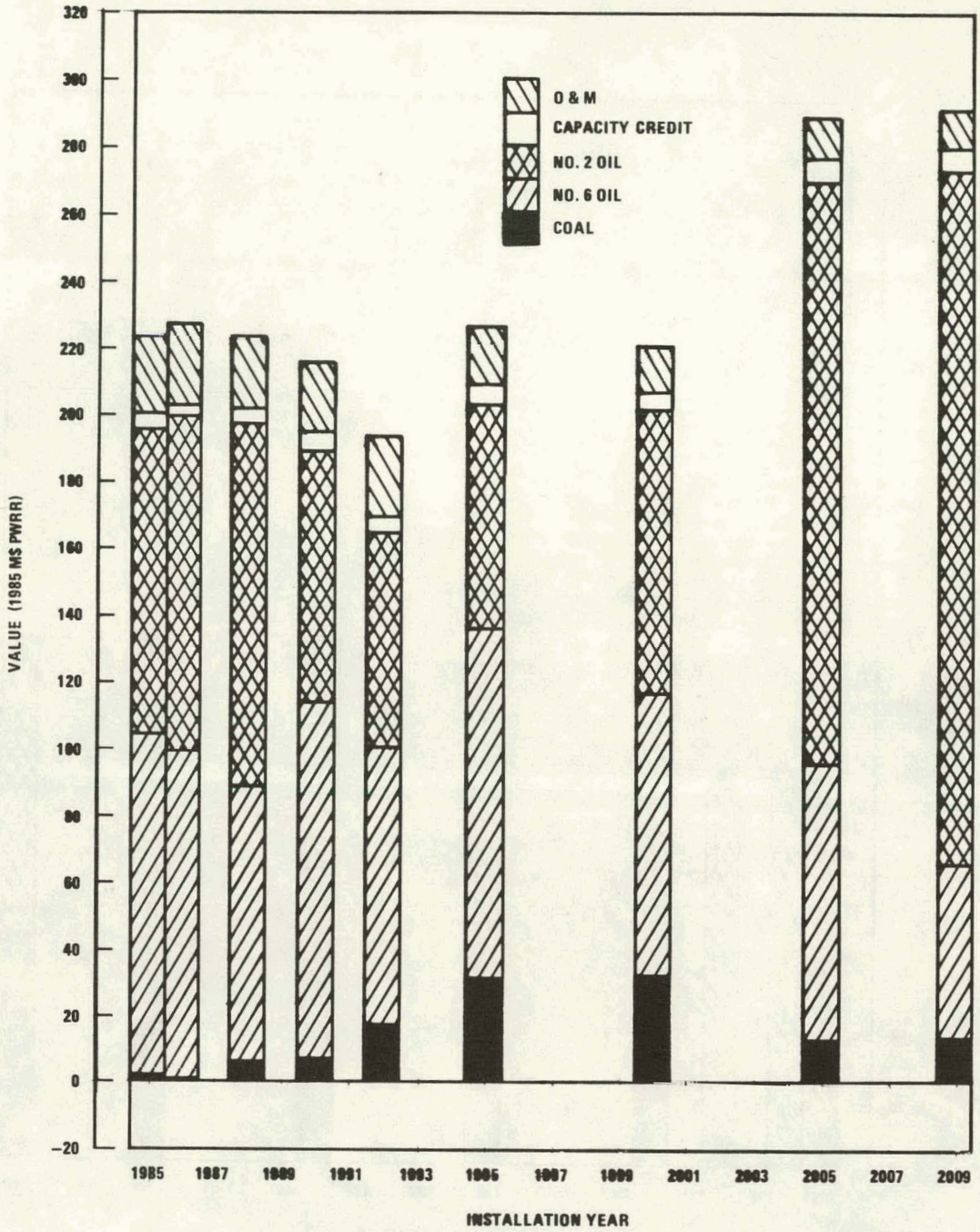

Figure C-10. 1985 M$ SOLAR PLANT POWER OUTPUT VALUE COMPONENTS COMBINATION EXPERIMENT - NOMINAL PENETRATION

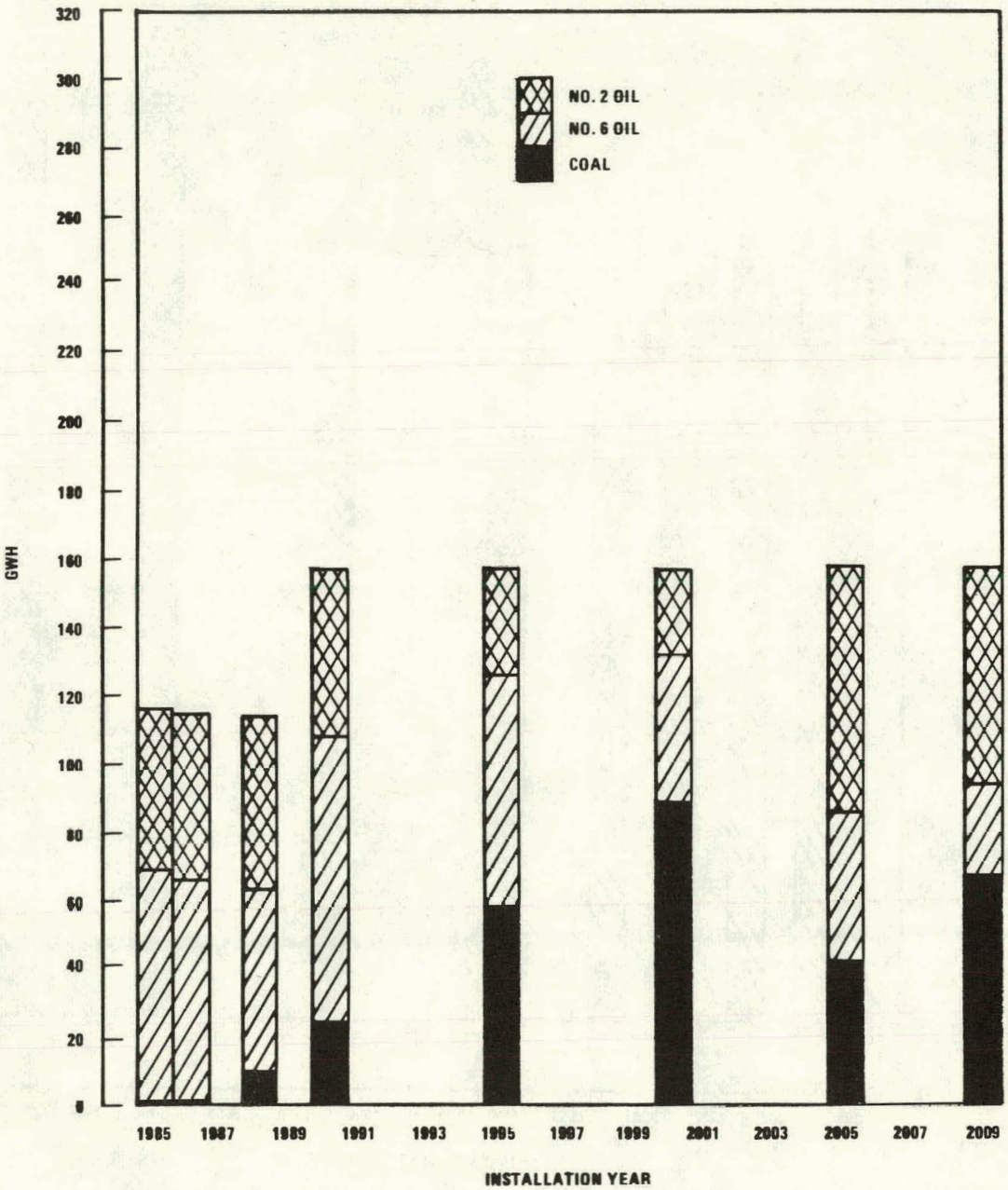

Figure C-11. 50 MW SOLAR PLANT POWER OUTPUT FUEL DISPLACEMENT COMBINATION EXPERIMENT - HIGH PENETRATION

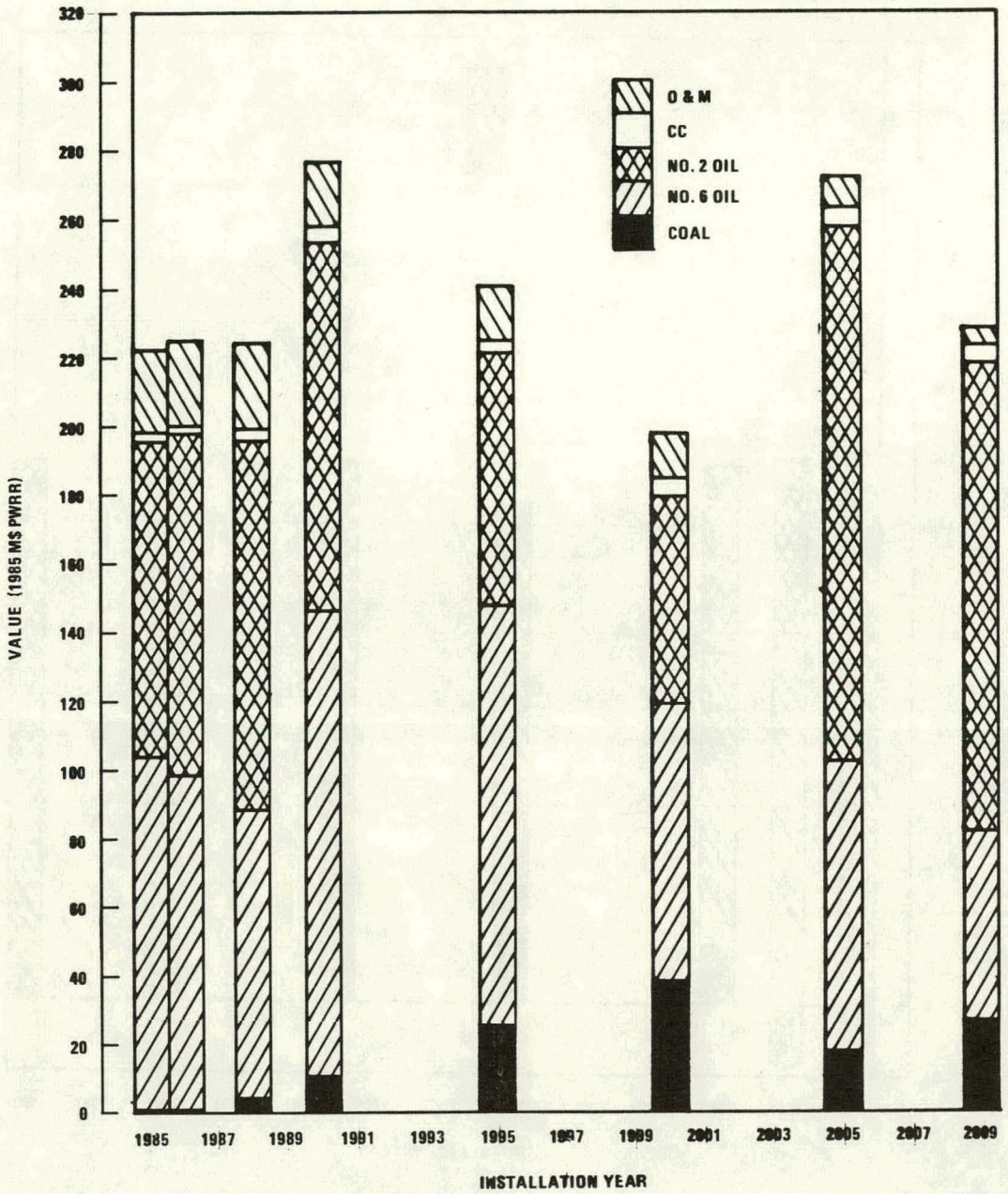

Figure C-12. 1985 M$ SOLAR PLANT POWER OUTPUT VALUE COMPONENTS COMBINATION EXPERIMENT - HIGH PENETRATION

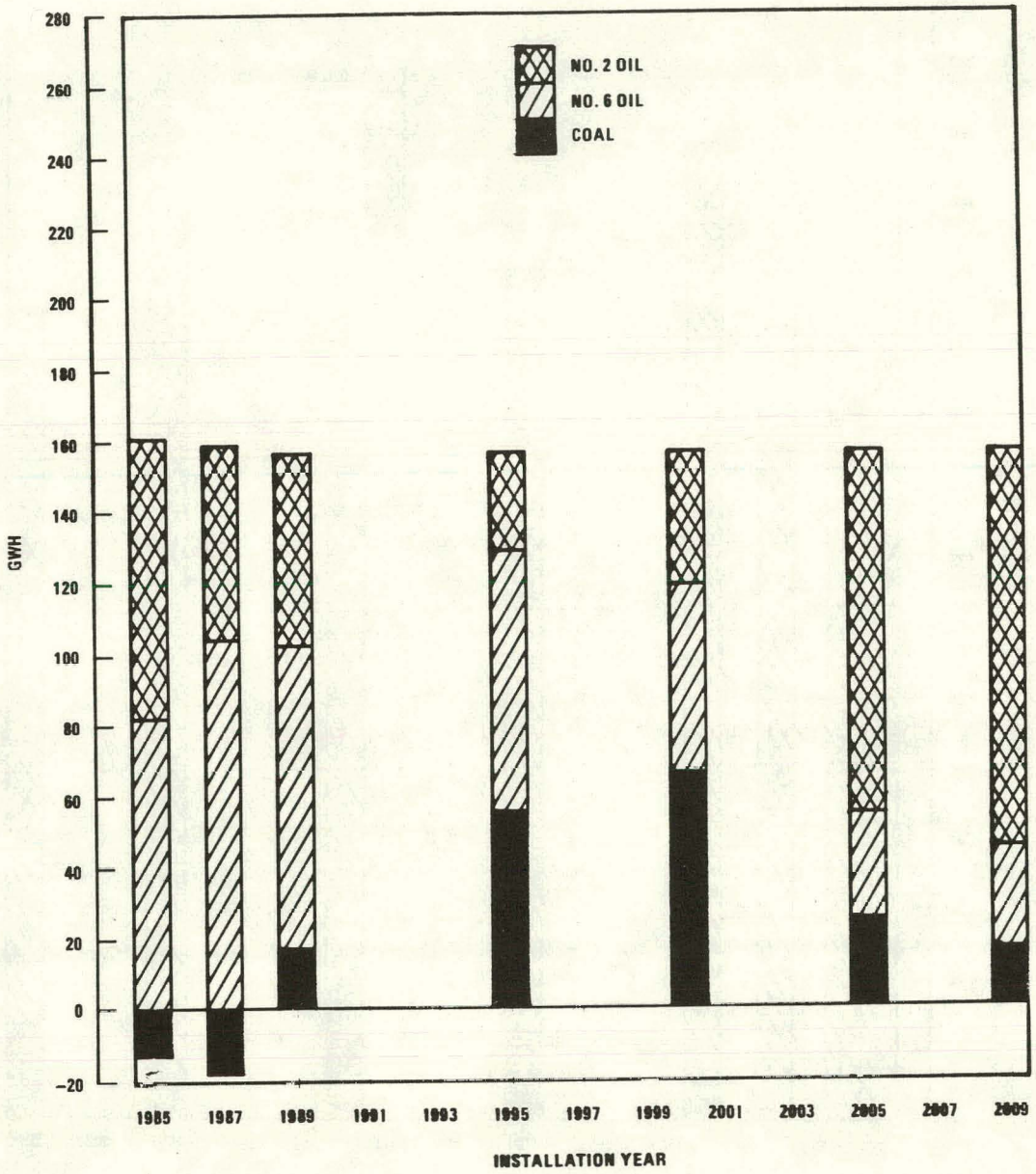

Figure C-13. 50 MW SOLAR PLANT POWER OUTPUT FUEL DISPLACEMENT ISA EXPERIMENT - LOW PENETRATION

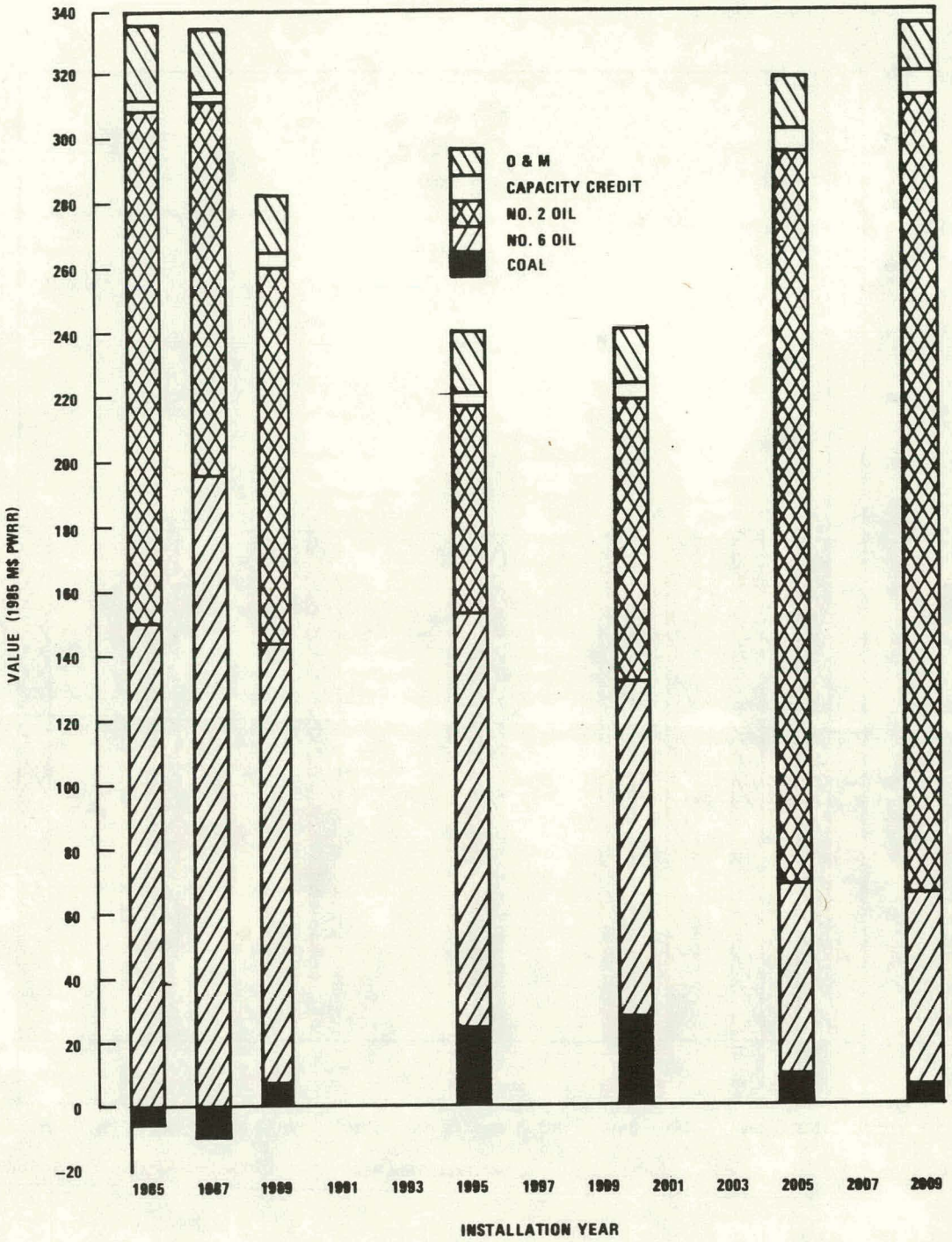

Figure C-14. 50 MW SOLAR PLANT POWER OUTPUT VALUE COMPONENTS
ISA EXPERIMENT - LOW PENETRATION

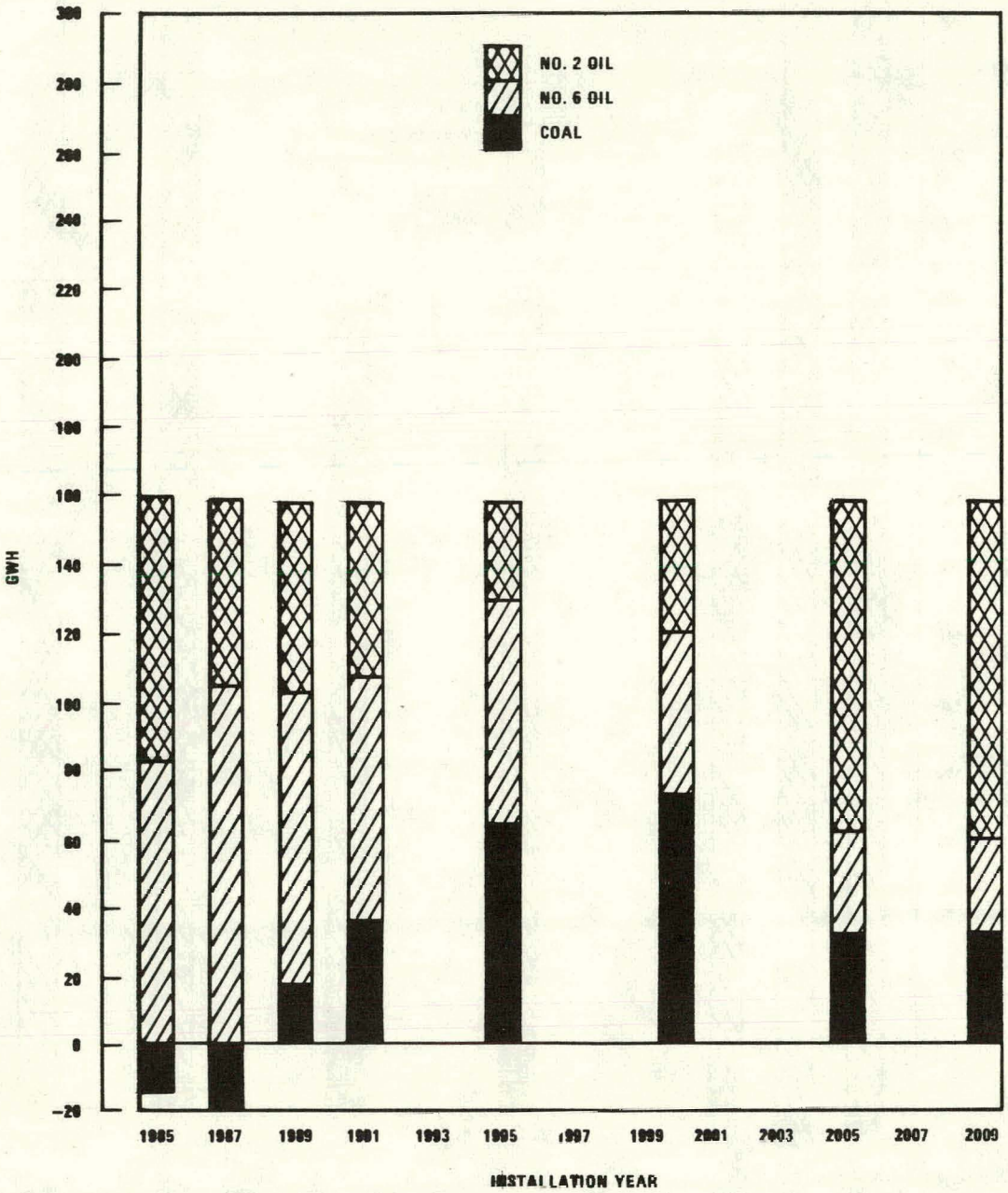

Figure C-15. 50 MW SOLAR PLANT POWER OUTPUT FUEL DISPLACEMENT ISA EXPERIMENT - NOMINAL PENETRATION

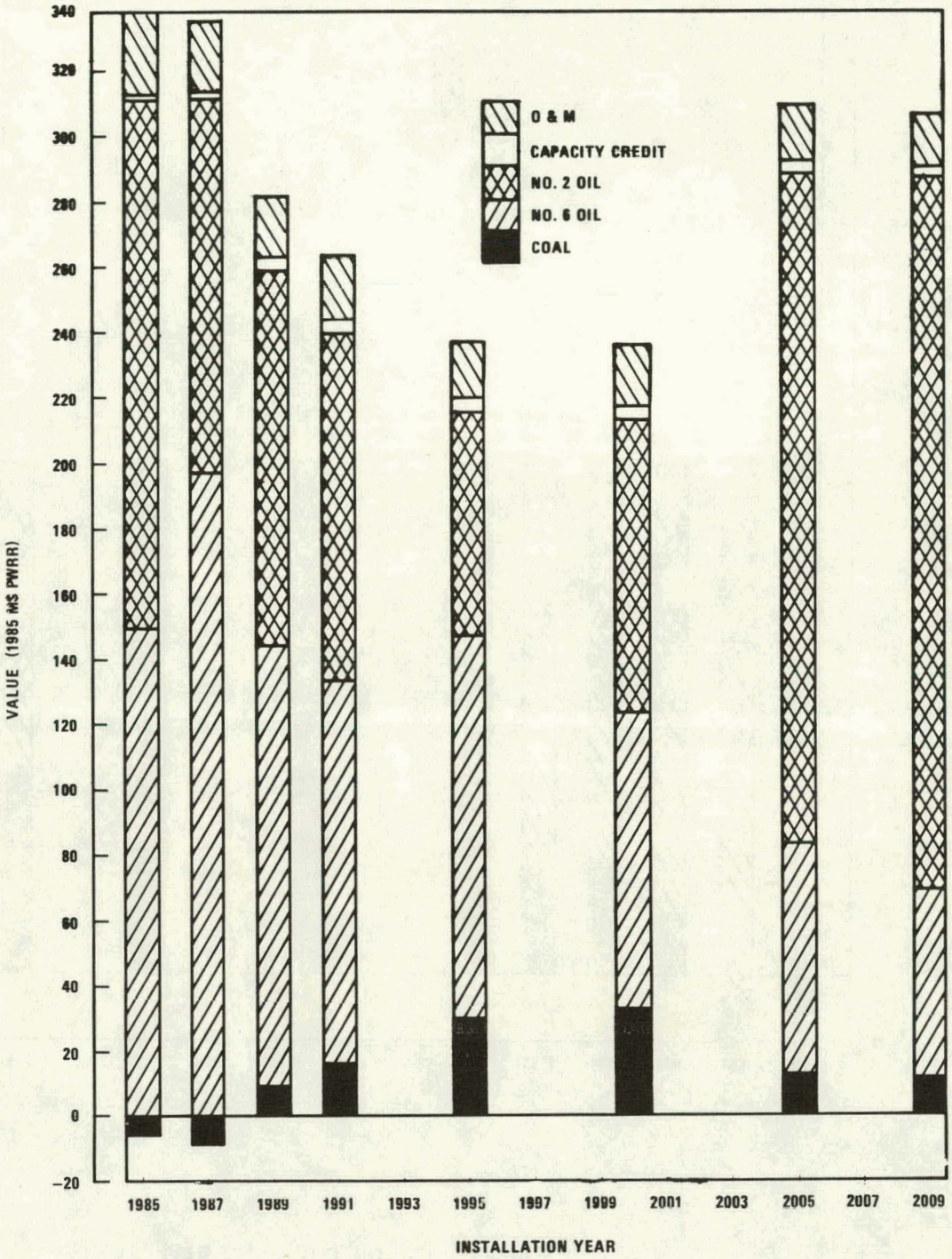

Figure C-16. 50 MW SOLAR PLANT POWER OUTPUT VALUE COMPONENT
ISA EXPERIMENT - NOMINAL PENETRATION

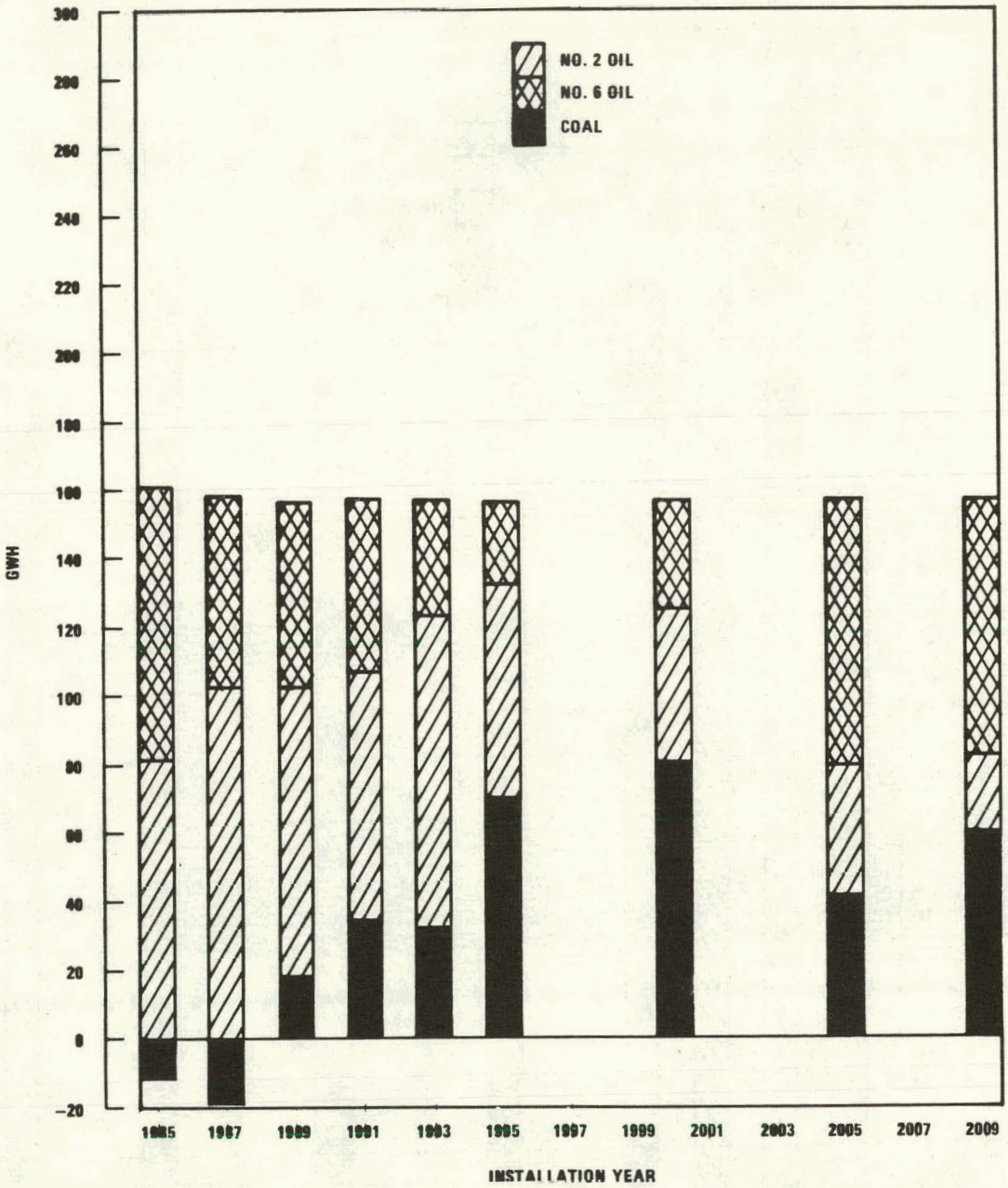

Figure C-17. 50 MW SOLAR POWER PLANT OUTPUT FUEL DISPLACEMENT ISA EXPERIMENT - HIGH PENETRATION

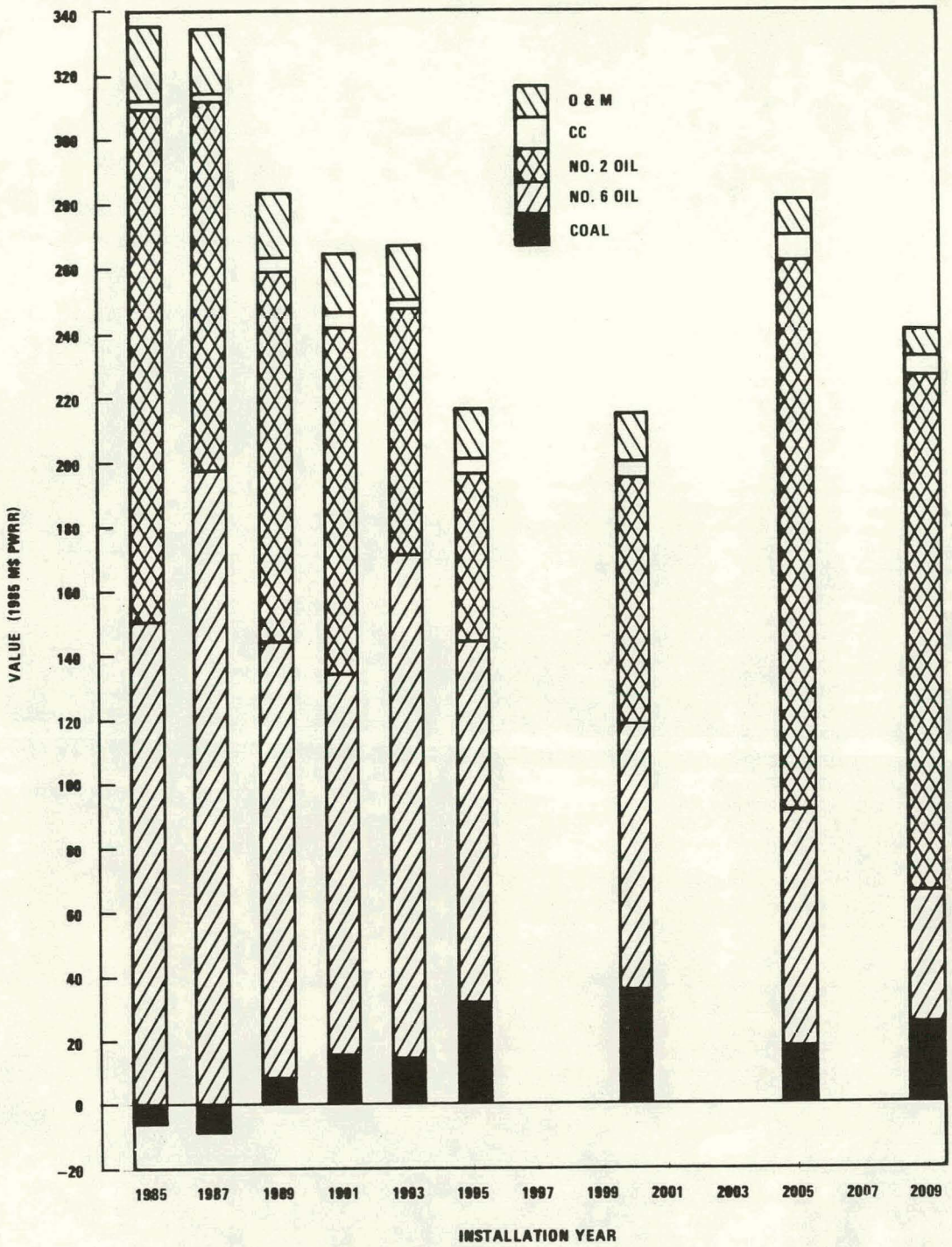

Figure C-18. 50 MW SOLAR PLANT POWER OUTPUT VALUE COMPONENTS
ISA EXPERIMENT - HIGH PENETRATION

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APPENDIX D

COST ESTIMATES

A list of tables and figures shown in this appendix follows.

Tables		Page
D-1	SERI Estimate of O&M Costs	205
D-2	Repower Plant Cost Estimates	206
D-3	Stand-Alone Plant	207
D-4	CBS Solar Plant Cost Comparison	208
D-5	Operating & Maintenance Personnel Costs	209
D-6	Personnel Cost Estimates	209
D-7	Field Efficiencies for Central Receiver System	210

Figures		
D-1	Turbine Generator Efficiency Correction	211
D-2	Boiler Efficiency Correction	212

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Table D-1. SERI ESTIMATE OF O&M COSTS ($000)

	Source of Estimate	Stand-Alone			Repower		
OM 100 Operations				2390			1914
OM 110 Personnel			1046.7			570.7	
Daytime							
Shift							
Subtotal ('77)	SERI Estimate	674.2			367.6		
1978 $		775.3			422.7		
Fringe & Burden (35%)		271.4			147.9		
OM 120 Consumables	GE		1343.1			1343.1	
OM 200 Maintenance Materials				717			717
OM 210 Spare Parts			478.3			478.3	
EPGS	1/2%-yr	115.0					
Collector	1/2%-yr	245.0					
Receiver	1/2%-yr	80.3					
Storage	1/2%-yr	38.0					
OM 220 Repair Materials	50% OM 210		239.1			239.1	
OM 300 Maintenance Labor				581			430
OM 310 Scheduled			531.4			379.7	
Daytime							
Shift							
Subtotal ('77)	SERI Estimate	342.3			244.6		
1978 $		393.6			281.3		
Fringe & Burden (35%)		137.8			98.4		
OM 320 Corrective			50			50	
EPGS							
Collector							
Receiver							
Storage							
Technical Support		50			50		
TOTAL				3688			3061
1985 M$				5.9			4.9

Table D-2. 100 MWe - REPOWER - BUFFER STORAGE

(1978,K$)

	SERI Modified MM/APS (100 MW)			SERI Modified Rockwell			SERI Modified Sandia			SERI	RSA
4100 Site, Struct., Misc.			2650			2650			3793		3793
4110 Site		1200			1200			1923			
4111 Land	400			400							
4112 Yard Work	800			800							
4120 Buildings		700			700			870			
4121 Turbine Bldg.	50			50			80				
4122 Administration							30				
4123 Warehouse/Maint.	250			250			400				
4124 Control	300			300			160				
4125 Other Visitors	100			100			200				
4130 Misc. Equip.		750			750			1000			
4131 Transport & Lifting	400			400			400				
4132 Communication	50			50			100				
4133 Other	300			300			500				
4200 Turbine Plant Equip.			1400			1400			1900		1900
4210 TG & Acc.		1000			1000			600			
4220 Heat Rejection System											
4230 Condensing								1300			
4240 Feed Heating		200			200						
4250 Working Fluid & Acc.		200			200						
4300 Electric Plant Equip.			625			1173			400		400
4310 Switchgear		100			100						
4320 Station Suc. Equip.		100			100						
4330 Protective Equip.		25			25						
4340 Power Wiring & Acc.		100			100						
4350 Master Control (EPGS)		200			748						
4351 Hardware											
4352 Hard Design & Engr.											
4353 Soft Develop. & Test											
4360 Generator Transformer											
4370 Substation		100			100						
4400 Collector Equip.									45000		
$7/ft.^{2}			37120			52111					37674
							MM	AI	GE		
4500 Receiver Equip.			16833			42995	19864	23338	27590		19783
4510 Receiver Unit		2833			8551		3602	3478	4691	3317	
4511 Absorber				4022							
4512 Support Struct.				296							
4513 Circulation Equip.				1526							
4514 Inst. & Control				1452							
4515 Tran, Erec, Install				1315							
4520 Riser, Down, Horiz Pipe		5500			24800		11136	10800	13200	9902	
4530 Working Media		200			200		348	780	1122	634	
4540 Tower		3000			3000		2011	1890	2790	1716	
4550 Foundation											
4560 Steam Generator		4000			5144		2767	6390	5787	4211	
4570 Design Engineering		1300			1300						
4600 Thermal Storage Equip.			1338			3354	1276	2525	2765		1960
4610 Containment		162			1320		646	1071	1166		
4620 Circulation (Media)		310					229	232	250		
4630 Circulation (Steam)					724						
4640 Discharge Hx											
4650 Charging Hx											
4660 Foundation		26			91		62	102	112		
4670 Design & Engr.		500			152						
4680 Media		340			1067		339	1120	1237		
4900 Master Control (Solar)			2000								1000
SUBTOTAL			81966			103683	72810	77533	82025		66510
4800 Distrib. & Indirect			7069			12721					19833
4810 Temp. Facilities & Equip.		820			1037		2184	2326	2461	1995	
4820 Spare Parts		397			505		364	388	410	333	
4830 A&E Services		3727			7736		7536	8025	8490	6884	
4840 Construction Mgmt.		1125			2443		2487	2648	2802	2272	
4850 Startup & Checkout		1000			1000		500	500	500	500	
4860 Contingency			9105			12686	8588	9142	9669	7849	
TOTAL			102592			134910	94469	100562	106356		86345

Table D-3. 100 MWe - STAND-ALONE - 3 HR STORAGE

(1978, K$)

	AI			Martin			CE			Sandia			SERI	RSA
4100 Site, Struct., Misc			5381			3636			10715		8900			8900
4110 Site		1500			1030					3000			3000	
4111 Land				201										
4112 Yard Work				829										
4120 Buildings		2200			1592					1860			1860	
4121 Turbine Building	1386			946						800				
4122 Administration	180									300				
4123 Warehouse/Maint.	300			236						400				
4124 Control	216			410						160				
4125 Other	118									200				
4130 Misc. Equip.		1681			1014					4040			4040	
4131 Transport & Lifting	721			381										
4132 Communication	110			15										
4133 Other	850			618										
4200 Turbine Plant Equip.			19424			16975			20070		19000			19000
4210 TG & Acc.		10856			10683					11000			11000	
4220 Heat Rejection System		4215			2750									
4230 Condensing		320			525					8000			8000	
4240 Feed Heating		1655			1582									
4250 Working Fluid & Acc.		2378			1435									
4300 Electric Plant Equip.			4301			5717			6759		4000			4000
4310 Switchgear		860			932									
4320 Station Suc. Equip.		1502			800									
4330 Protective Equip.		253			225									
4340 Power Wiring & Acc.		938			1800									
4350 Master Control (EPGS)		748			600									
4351 Hardware	487													
4352 Hard Design & Engr.	185													
4353 Soft Develop. & Test	76													
4360 Generator Transformer					460									
4370 Substation					900									
4400 Collector Equip. $7/ft.^{2}			52111			45683			51319		45000			49000
										MM	AT	GE		
4500 Receiver Equip.			23305			14572			36174	18369	13688	16091		16050
4510 Receiver Unit		8551			3147					5589	3478	4691	4586	
4511 Absorber	4022			1442										
4512 Support Struct.	236			669										
4513 Circulation Equip.	1526			349										
4514 Inst. & Control	1452			81										
4515 Tran, Erec, Install	1315			605										
4520 Riser, Down, Horiz Pipe		4942			2294					6671	1747	12564	3661	
4530 Working Media		183			222					222	183	259	221	
4540 Tower		3166			2987					3120	1890	2790	2600	
4550 Foundation					769					—	—	—		
4560 Steam Generator		5144			3854					2767	6390	5787	4981	
4570 Design Engineering		1319			1300					—	—	—		
4600 Thermal Storage Equip.			12086			3896			19179	4336	10389	11415		7600
4610 Containment		4356			649					1892	3137	3416		
4620 Circulation (Media)					310					229				
4630 Circulation (Steam)		724									232	250		
4640 Discharge Hx														
4650 Charging Hx														
4660 Foundation		300			104					181	300	329		
4670 Design & Engr.		306			800					-	-			
4680 Media		6400			2034					2034	6720	7420		
4900 Master Control (Solar)						1023								1000
SUBTOTAL			116608			91502			144216	99605	100977	104406		105550
4800 Distrib. & Indirect			15211			11300			21279	29514	29371	30831		31151
4810 Temp. Facilities & Equip.		1166			915			1442		3058	2664	3142	3167	
4820 Spare Parts		556			439			667		498	505	522	528	
4830 A&E Services		9675			6873			13935		10316	10415	10807	10924	
4840 Construction Mgmt.		2814			2073			4235		3404	3437	3566	3605	
4850 Startup & Checkout		1000			1000			1000		500	500	500	500	
4860 Contingency			13430			10074			17189	11738	11850	12294	12427	
TOTAL			151840			118016			190959	129119	130348	135237		136701

Table D-4. CBS SOLAR PLANT COST COMPARISON
1978 M$, 100 MWe PLANT

	Improved Stand-Alone		Improved Repowering		Barstow Repowering	
4100 Site, Structure, Misc.		8.9		3.8		4.1
4110 Site	3.0		1.9		2.2	
4120 Buildings	1.9		0.9		0.9	
4130 Misc. Equipment	4.0		1.0		1.0	
4200 Turbine Plant Equip.		19.0		1.9		1.9
4300 Electric Plant Equip.		4.0		0.4		0.4
4400 Collector Equip. $7/ft^2		49.0		37.7		44.1
4500 Receiver Equip.		16.1		19.8		18.8
4510 Receiver Unit	4.6		3.3		11.2	
4520 Riser, Downcomer, Horiz. Pipe	3.7	9.9		6.0		
4530 Working Media	0.2		0.6			
4540 Tower	2.6		1.7		1.6	
4560 Steam Generator	5.0		4.2			
4600 Thermal Storage Equip.		7.6		2.0		0.0
4900 Master Control		1.0		1.0		1.0
4800 Distributables & Indirects		31.1		19.8		20.8
Total Capital Investment		136.7		86.4		91.1
Interest During Construction (15%)		20.5		13.0		13.7
Total Capitalization (1978)		157.3		99.4		104.8
Total Capitalization (1985) (Escalated at 7%)		252.6		159.6		168.2
OM 100 Operations		2.4		1.9		1.9
OM 200 Maintenance Materials		0.7		0.7		0.7
OM 300 Maintenance Labor		0.6		0.4		0.4
Total Yearly O&M		3.7		3.0		3.0

BASIS FOR DISTRIBUTABLE & INDIRECT COST ESTIMATES

4810	Temporary Facilities	-	1% of 4100 through 4600, 4900
4820	Spare Parts	-	1/2% of 4200 through 4600, 4900
4830	A&E Services	-	15% of 4100 through 4300, 4500,4600, 4900
4840	Construction Management	-	5% of 4100 through 4300,4510, __, 20, 40, 50, 60;; 4610-60; 4900
4850	Startup & Checkout	-	20 person-years @ $50 k/yr
4860	Contingency	-	10% of 4500-4600

Table D-5. OPERATING & MAINTENANCE PERSONNEL COSTS (1977, $000)

	Stand-Alone	Repower
Operating	674.2	367.6
Maintenance	342.3	244.6

Table D-6. PERSONNEL COST ESTIMATES ($1977)

Category	Rate ($/yr)	Effective[a] Personnel Requirement	
		Stand-Alone	Repower
Operating			
Plant Superintendent	32000	1	1/2
Clerk	10200	1	1/2
Statistician	18100	1	1/2
Warehouseman	16400	1	1/2
Guards	12900	8	4
Plant Engineer	28800	1	1/2
Engineer (Controls/Computer)	24700	1	1/2
Computer Technician	18100	2	1
Chemist	28800	2	1
Instrument Technicians	18100	2	1
Helper	9600	1	1/2
Apprentice	9600	1	1/2
Shift Foreman	22400	4	2
Control Room Operators	20000	4	2
Asst. Control Room Operators	17600	4	3
Auxiliary Operators	12900	4	3
Maintenance			
Maintenance Supervisor	24700	1	1/2
Working Foreman	21600	2	1
Electrician	17800	1	1
Mechanics	17800	3	1 1/2
Machinist	17800	1	1/2
Welder	17800	1	1/2
Apprentices	9600	3	1 1/2
Janitor	9600	1	1/2
Heliostat Field Foreman	22400	1	1
Mechanics	17800	3	3
Control Specialits	17800	3	3

[a]It was assumed for personnel estimates that the repowered plants have two units per site, which reduces the effective personnel requirements.

Table D-7. FIELD EFFICIENCIES FOR CENTRAL RECEIVER SYSTEM[a]

[Ground coverage fraction = 0.23 (average)]

K( ) Elevation	Azimuth J( )	FF (J,K)[b]							
		0°	15°	30°	45°	60°	75°	90°	105°
10°		.5550	.5530	.5525	.5525	.5510	.5410	.5270	.5085
20°		.7020	.7006	.7000	.6993	.6915	.6785	.6610	.6405
30°		.7980	.7950	.7900	.7865	.7740	.7570	.7380	.7125
40°		.8278	.8276	.8230	.8147	.8050	.7955	.7770	.7480
50°		.8422	.8410	.8368	.8295	.8192	.8065	.7945	.7700
60°		.8495	.8480	.8440	.8381	.8305	.8211	.8112	.7875
70°		.8503	.8484	.8458	.8422	.8369	.8298	.8205	.8000
80°		.8444	.8426	.8410	.8388	.8352	.8297	.8230	.8025
90°		.8325	.8310	.8287	.8260	.8240	.8212	.8171	.7966

[a]Reflects commercial system design presented in the MDAC Central Receiver Solar Thermal Power System Preliminary Design Report, October 1977.

[b]FF (J,K) is product of cosine times blocking and shadowing efficiencies for the field at azimuth J and elevation K.

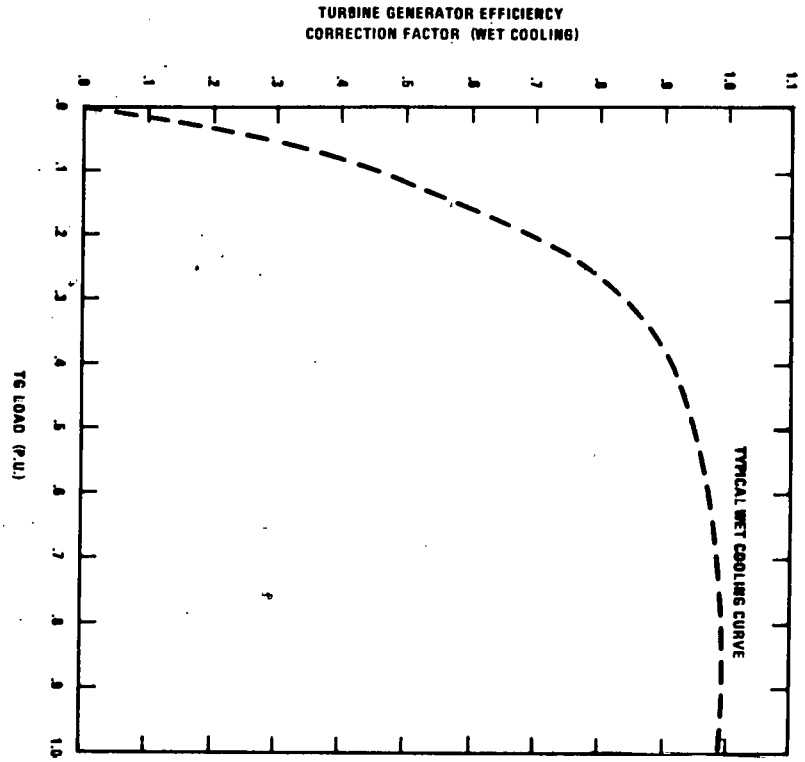

Figure D-1. TURBINE GENERATOR EFFICIENCY CORRECTION

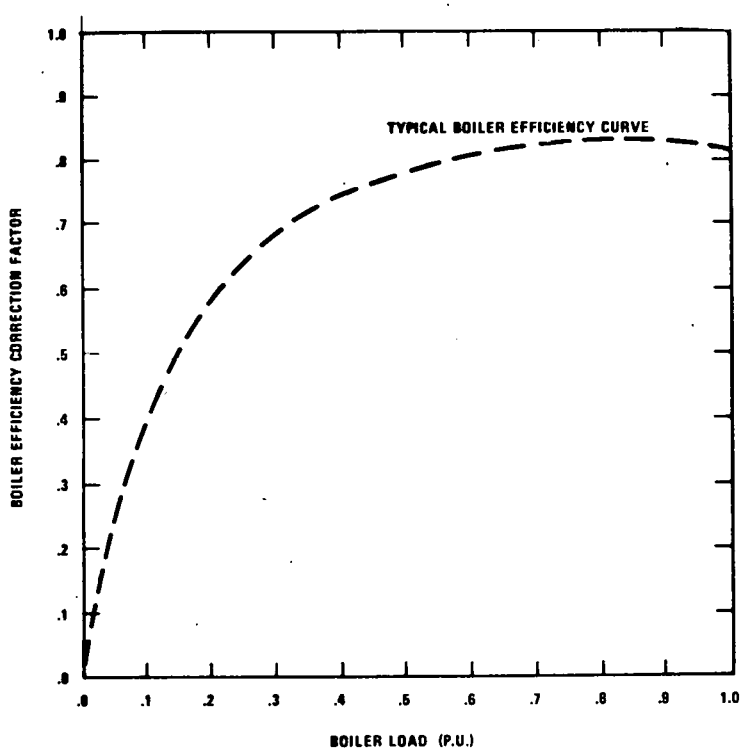

Figure D-2. BOILER EFFICIENCY CORRECTION

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APPENDIX E

ESTIMATION OF A SOLAR-THERMAL REPOWERING MARKET

Two initial criteria were stipulated as being necessary to the feasibility of solar-thermal repowering: a) to be repowerable, a unit must be in an area receiving at least 200 $kWh/M^2/yr$ direct insolation; b) to be repowerable, a unit must be a gas or oil fired steam unit. With the application of the first criterion, ten states are seen to have acceptable insolation: Arizona, California, Colorado, Kansas, Nevada, New Mexico, Oklahoma, Texas, Utah, and Wyoming. Application of the second criterion eliminates Wyoming. Plants meeting these criteria are identified in Tables E-1 through E-12 [1].

These plants comprise a total capacity of 76,143 MWe, with over 80% occurring in Texas and California.

Since insolation is not uniform across states, the next step was to screen out those plants in unacceptable insolation areas--those in northern California, northwestern Nevada and eastern Kansas, Oklahoma and Texas (see Figure E-1). Insolation screening reduced the potential market by 2/3 to 26,823 MW.

The PNM Market Survey [2] was then used to further reduce the potential market by screening out those plants which, because of age, heat rate or other reasons, utilities would definitely not repower. The PNM survey was also used to impose percentage repowering constraints on many units because of reported land availability. Units over 200 MW were not covered in the PNM survey, so no screening could be imposed upon them at this step. The PNM survey reduced the potential market to 11,918 MW from 26,823 MW.

The next step was the removal of California coastal plants [3]. These sites were deemed <u>not</u> potentially repowerable because of land availability and cost along the coast, and problems arising from coastal fog and the effects of salt spray on equipment. Removal of coastal plants reduced the potential market to 8,726 MW from 11,918 MW.

The final step was to assume that because of the inverse relationship between solar plant value and penetration, no system would repower beyond a given percentage. Two percentages of penetration per system were assumed--10 and 20%. The 20% criteria reduced the market to 6,298 MW from 8,726 MW. The 10% criteria reduced the market to 3,908 MW. Figure E-2 shows the reduction in the repowering "market" as a function of these criteria.

REFERENCES

1. The Mitre Corporation: Solar-Thermal Repowering. Originally from Inventory of Power Plants in the United States, DOE/RA-001, 1977.

2. Public Service Company of New Mexico, Technical and Economic Assessment of Solar Hybrid Repowering.

3. DOE/EIA-0033/1, Steam-Electric Plant Construction Cost and Annual Production Expenses, 1978.

Table E-1. GENERATING CAPACITY - TEXAS STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
1,2	Houston Lighting & Power Co	P H Robinson	2,316[b]	2,316	14	0	2,330
1,2	Houston Lighting & Power Co	Cedar Bayou	2,280	4,596	0	0	2,280
1	Gulf States Utilities Co	Sabine	2,050	6,648	0	0	2,050
1	Texas Util: Texas Elec Service Co	Handley	1,434[b]	8,080	0	0	1,434
1	Texas Util: Texas Power & Light Co	Tradinghouse Creek					
1	Houston Lighting & Power Co	W A Parish	1,256	10,716	14	0	1,270
1	Texas Util: Texas Power & Light Co	Valley	1,176[b]	11,892	0	0	1,176
1	Texas Util: Dallas Power & Light Co	Mountain Creek	990	12,882	0	0	990
1	Texas Util: Dallas Power & Light Co	Lake Hubbard	928	13,810	0	0	928
1	San Antonio Public Service Bd	V H Braunig	894[b]	14,704	0	0	894
1	San Antonio Public Service Bd	U W Sommers	892	15,596	0	0	892
-	Texas Util: Texas Elec Service Co	Morgan Creek	845	16,441	0	0	845
1,2	Houston Lighting & Power Co	Sam Bertron	826[b]	17,267	41	0	867
1	Houston Lighting & Power Co	Greens Bayou	822	18,089	396	0	1,218
1	Cen & SW: Southwestern Elec Power Co	Wilkes	808	18,897	0	0	808
1	Texas Util: Texas Power & Light Co	De Cordova	775	19,672	0	0	775
1	Austin Electric Dept	Decker	752	20,424	0	0	752
1	Texas Util: Dallas Power & Light Co	North Lake	709[b]	21,133	0	0	709
1	Texas Util: Texas Elec Service Co	Eagle Mountain	707	21,840	0	0	707
1	Texas Util: Texas Power & Light Co	Stryker Creek	704	22,544	0	0	704

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Code Key

1 : Eliminated because of inadequate insolation (2000 kWh/M^2/yr)
2 : Eliminated because of coastal location
3 : Eliminated because of lack of available land
4 : Repowering potential partially constrained due to limited land availability
5 : Eliminated because of utility disinterest
- : Not eliminated

Table E-2. GENERATING CAPACITY - TEXAS STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
-	Texas Util: Texas Elec Service Co	Permian Basin	703	23,247	0	0	703
1	Cen & SW: Central Power & Light Co	Barney M Davis	676	23,923	0	0	676
1	Texas Util: Texas Elec Service Co	Graham	635	24,558	0	0	635
1	Austin Electric Dept	Holly Street	626[b]	25,184	0	0	626
1	Lower Colorado River Authority	Sim Gideon	623	25,807	0	0	623
1	Houston Lighting & Power Co	Webster	615	26,422	14	0	629
1,2	Cen & SW: Central Power & Light Co	Nueces Bay	596	27,018	0	0	596
1	Cen & SW: Central Power & Light Co	Lon C Hill	574	27,592	0	0	574
1	Cen & SW: Central Power & Light Co	Victoria	554	28,146	0	0	554
1	Gulf States Utilities Company	Lewis Creek	542[b]	28,688	0	0	542
1	Cen & SW: Southwestern Elec Power Co	Knox Lee	497	29,185	0	0	497
-	Southwestern Public Service Co	Jones	496	29,681	0	0	496
1	San Antonio Public Service Bd	W B Tuttle	495	30,176	0	0	495
-	Southwestern Public Service Co	Nichols	476	30,652	0	0	476
1	Gulf States Utilities Company	Neches	453	31,105	0	0	453
1	Lower Colorado River Authority	T C Ferguson	446	31,551	0	0	446
-	Southwestern Public Service Co	Plant X	434	31,985	0	0	434
1	Texas Util: Texas Power & Light Co	Trinidad	412	32,397	0	0	412
1	Brazos Elec Pwr Coop Inc	R W Miller	388	32,785	0	0	388

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-3. GENERATING CAPACITY - TEXAS STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
-	Cen & SW: West Texas Utilities Co	Fort Phantom	357	33,142	0	0	357
1	Texas Util: Dallas Power & Light Co	Parkdale	341	33,483	0	0	341
1,2	Houston Lighting & Power Co	Deepwater	335	33,818	0	0	335
1	City of Garland	Ray Olinger	335[b]	34,153	0	0	335
1	Houston Lighting & Power Co	T H Wharton	323	34,476	946	0	1,269
1	Texas Util: Texas Power & Light Co	Lake Creek	316	34,792	0	0	316
-	El Paso Electric Company	Newman	267	35,059	0	290	557
1	Cen & SW: Central Power & Light Co	E S Juslin	261	35,320	0	0	261
1	Cen & SW: West Texas Utilities Co	Paint Creek	242	35,562	0	0	242
1	San Antonio Public Service Bd	Leon Creek	229	35,791	0	0	229
1	Texas Util: Dallas Power & Light Co	Dallas	224	36,015	0	0	224
1	Cen & SW: Central Power & Light Co	La Palma	219	36,234	49	0	268
1	Houston Lighting & Power Co	Hiram Clarke	210	36,444	84	0	294
1	Denton Municipal Utilities	Denton	190	36,634	0	0	190
1	Cen & SW: Central Power & Light Co	J L Bates	189	36,823	0	0	189
4	Cen & SW: Central Power & Light Co	Laredo	178	37,001	0	0	178
1	San Antonio Public Service Bd	Mission Road	164	37,165	0	0	164
1	Texas Util: Texas Power & Light Co	Collin	156	37,321	0	0	156
-	Cen & SW: West Texas Utilities Co	Rio Pecos	137	37,458	0	5	142

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-4. GENERATING CAPACITY - TEXAS STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
1	City of Bryan	Bryan	126	37,584	22	0	148
1	Austin Electric Dept	Seaholm	125	37,709	0	0	125
1	Texas Util: Texas Elec Service Co	North Main	116	37,825	0	0	116
1	Texas Util: Texas Power & Light Co	River Crest	113	37,938	0	0	113
1	City of Bryan	Dansby	105	38,043	0	0	105
4	Cen & SW: West Texas Utilities Co	San Angelo	101	38,144	0	33	134
1	City of Garland	C E Newman	90	38,234	0	0	90
1	Greenville Electric Dept (TX)	Greenville	85	38,319	0	15	100
-	Cen & SW: West Texas Utilities Co	Oak Creek	82	38,401	0	0	82
3	City of Lubbock Power & Light	Plant 2	82	38,483	0	0	82
4	Southwestern Public Service Co	Denver City	80	38,563	0	0	80
1	Brazus Elec Power Coop Inc	North Texas	76	38,639	0	0	76
-	Medina Electric Coop Inc	Pearsall	75	38,714	0	0	75
-	Southwestern Public Service Co	Moore County	68	38,782	0	0	68
-	Southwestern Public Service Co	East Plant	62	38,844	0	0	62
1	Lower Colorado River Authority	Comal	60	38,904	0	0	60
4	Cen & SW: West Texas Utilities Co	Concho	53	38,957	0	0	53
1	Houston Lighting & Power Co	Gable Street	53	39,010	0	0	53
-	City of Lubbock Power & Light	Holly Ave	98	39,060	52	0	102

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-5. GENERATING CAPACITY - TEXAS STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
-	Cen & SW: West Texas Utilities Co	Lake Pauline	45	39,105	0	0	45
1	Cen & SW: Southwestern Elec Power Co	Lone Star	44	39,149	0	4,815	4,859
-	Southwestern Public Service Co	Riverview	35	39,184	0	0	35
4	Cen & SW: West Texas Utilities Co	Abilene	27	39,211	0	0	27
3	Texas Util: Texas Elec Service Co	Wichita Falls	26[b]	39,237	0	0	26
1	South Texas Elec Coop Inc	Sam Rayburn	25	39,262	0	24	49
1	Houston Lighting & Power Co	Champion	19	39,281	0	0	19

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-6. GENERATING CAPACITY - CALIFORNIA STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
1,2	Pacific Gas & Electric Comapny	Potrero	318	20,090	183	268	769
3	Southern California Edison Company	Redondo Beach No. 1	270[b]	20,360	0	0	270
3	San Diego Gas & Electric Company	Silver Gate	247	20,607	0	0	247
3	Imperial Irrigation District	El Centro	190	20,797	0	0	190
3	Southern California Edison Company	Long Beach	180	20,977	0	455	635
-	City of Pasadena Wtr & Pwr Dept	Broadway	171	21,148	0	0	171
4	Southern California Edison Company	Highgrove	170	21,318	0	0	170
4	Pacific Gas & Electric Company	Kern	166	21,484	0	0	166
3	Glendale Public Service Dept	Grayson	164	21,648	54	121	339
-	Southern California Edison Company	Cool Water	147	21,795	0	0	147
4	Southern California Edison Company	San Bernardino	130	21,925	0	0	130
1,2	Pacific Gas & Electric Company	Humbult Bay	102	22,027	0	0	102
3	Burbank Public Service Department	Olive	99	22,126	137	0	236
3	San Diego Gas & Electric Company	Station B	93	22,219	0	0	93
1	Pacific Gas & Electric Company	Oleum Steam	80	22,299	0	0	80
4	Burbank Public Service Department	Magnolia	70	22,369	0	0	70
-	City of Pasadena Wtr & Pwr Dept	Glenarm	65	22,434	52	0	117
1	Pacific Gas & Electric Company	Martinez	40	22,474	0	0	40
1	Pacific Gas & Electric Company	Avon Steam	40	22,514	0	0	40

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-7. GENERATING CAPACITY - CALIFORNIA STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
1,2	Pacific Gas & Electric Company	Moss Landing	2,177[b]	2,177	0	0	2,177
1,2	Pacific Gas & Electric Company	Pittsburg	2,027[b]	4,204	0	0	2,027
2	Southern California Edison Company	Alamitos	1,982[b]	6,186	121	0	2,103
2,5	Los Angeles Dept of Water & Power	Haynes	1,606	7,792	0	0	1,606
2	Southern California Edison Company	Ormond Beach	1,556	9,348	0	0	1,556
2,3	Southern California Edison Company	Redondo Beach No. 2	1,309	10,657	0	0	1,309
1	Pacific Gas & Electric Company	Contra Costa	1,277	11,934	0	0	1,277
2,3	Pacific Gas & Electric Company	Morro Bay	1,056[b]	12,990	0	0	1,056
2,3	Southern California Edison Company	El Segundo	996[b]	13,986	0	0	996
4	Southern California Edison Company	Etiwanda	912[b]	14,898	121	0	1,033
2,4	San Diego Gas & Electric Company	Encina	909[b]	15,807	20	0	929
2	Southern California Edison Company	Huntington Beach	872	16,679	121	0	993
2,4	San Diego Gas & Electric Company	South Bay	714	17,393	150	0	864
2,5	Los Angeles Dept of Water & Power	Scattergood	635	18,028	0	0	635
4	Los Angeles Dept of Water & Power	Valley	548	18,576	0	0	548
2	Southern California Edison Company	Mandalay	436	19,012	121	0	557
2,5	Los Angeles Dept of Water & Power	Harbor	388	19,400	80	0	468
1,2	Pacific Gas & Electric Company	Hunters Point	372	19,772	61	0	433

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-8. GENERATING CAPACITY - OKLAHOMA STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
1	Oklahoma Gas & Electric Co	Seminole	1,701	1,701	19	0	1,720
1	Cen & SW: Public Serv Co of Oklahoma	Riverside	946[b]	2,647	0	3	949
1	Oklahoma Gas & Electric Co	Horseshoe Lake	697	3,344	0	222	919
1	Cen & SW: Public Serv Co of Oklahoma	Northeastern	643	3,987	0	0	643
1	Oklahoma Gas & Electric Co	Mustang	511[b]	4,498	74	1	586
5	Cen & SW: Public Serv Co of Oklahoma	Southwestern	483	4,981	0	6	489
1	Cen & SW: Public Serv Co of Oklahoma	Tulsa	475	5,456	0	8	483
4	Western Farmers Elec Coop (OK)	Mooreland	326	5,782	0	0	326
1	Oklahoma Gas & Electric Co	Muskugee	196	5,978	0	0	196
-	Western Farmers Elec Coop (OK)	Anadarko	84	6,062	0	314	399
1	Cen & SW: Public Serv Co of Oklahoma	Weleetka	83	6,145	180	0	263
1	Oklahoma Gas & Electric Co	Arbuckle	74	6,219	0	1	75
1	Grand River Dam Authority	Chouteau	56	6,275	0	0	56
1	Oklahoma Gas & Electric Co	Belle Isle	55	6,330	8	0	63
1	Oklahoma Gas & Electric Co	Osage	40[b]	6,370	0	0	40

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-9. GENERATING CAPACITY - KANSAS STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
1	Kansas Power & Light Co	Lawrence	614	614	0	0	614
1	Kansas Gas & Electric Co	Gordon Evans	540[b]	1,154	0	0	540
1	Kansas Gas & Electric Co	Murray Gill	349	1,503	0	0	349
1	Kansas Power & Light Co	Tecumseh	348[b]	1,851	54	0	402
-	Kansas Power & Light Co	Hutchinson	258	2,109	303	0	561
1	Kansas City Bd of Pub Util (KS)	Quindaro No. 3	240	2,349	0	0	240
-	Central Telephone & Util Corp (KS)	Judson Large	180[b]	2,529	0	0	180
1	Kansas City Bd of Pub Util (KS)	KAW	161	2,690	0	0	161
1	Empire District Electric Co	Riverton	136	2,826	0	0	136
-	Central Telephone & Util Corp (KS)	Mullergren	120	2,946	0	0	120
-	Sunflower Electric Coop (KS)	Garden City	119	3,065	71	0	190
1	Kansas City Bd of Pub Util (KS)	Quindaro No. 2	95	3,160	125	0	220
1	Kansas Gas & Electric Co	Ripley	87[b]	3,247	0	0	87
1	Coffeyville Mun Lt Dept	Coffeyville	81	3,328	0	0	81
1	Kansas Gas & Electric CC	Neosho	74	3,402	0	0	74
-	Central Telephone & Util Corp (KS)	Cimarron River	50	3,452	0	0	50
1	Winfield Mun Light & Power Plt	Winfield	45	3,497	11	0	56
1	City of Wellington (KS)	Wellington	34	3,531	0	0	34
1	Kansas Power & Light CC	Abilene	34	3,565	78	0	112
1	McPherson Board of Public Util	Plant No. 2	32	3,597	66	0	98
1	McPherson Board of Public Util	Plant No. 1	26	3,623	0	0	26
1	Ottawa Water & Light Dept (KS)	Ottawa	7	3,638	0	0	7

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-10. GENERATING CAPACITY - ARIZONA STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
-	Tucson Gas & Electric Company	Irvington	505[b]	505	73	0	578
-	Salt River Proj Agri Imp Pwr Dist	Agca Fria	391	896	192	0	583
-	Arizona Public Service Company	Saguaro	225	1,121	114	0	339
5	Arizona Public Service Company	Ocotillo	220	1,341	114	0	334
5	Arizona Public Service Company	Phoenix	117[b]	1,458	112	0	229
4	Salt River Proj Agri Imp Pwr Dist	Kyrene	109	1,567	195	0	304
3	Tucson Gas & Electric Company	De Moss Petrei	106[b]	1,673	48	0	154
-	Usbia San Carlos Project	Yucca	75	1,748	164	0	239
5	Arizona Public Service Company	Yuma Axis	75	1,823	25	0	100
-	Arizona Electric Pwr Coop Inc	Cochise B	75	1,898	30	65	170
-	Arizona Electric Pwr Coop Inc	Apache Station	75	1,973	83	0	158
3	Salt River Proj Agri Imp Pwr Dist	Crosscut	32	2,005	0	0	32
-	No. Loop		100				

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-11. GENERATING CAPACITY - NEW MEXICO STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
4	El Paso Electric Company	Rio Grande	396[b]	396	0	0	396
4	Southwestern Public Service Co	Cunningham	295[b]	661	0	0	265
-	Public Service Co of New Mexico	Reeves	175	836	0	0	175
-	Public Service Co of New Mexico	Person	126	962	0	0	126
-	New Mexico Elec Service Co	Maddox	114	1,076	66	0	180
-	Plains Elec Gen & Trans Coop, Inc	Algodones	51	1,127	0	0	51
-	Community Public Service Co	Lordsburg	46	1,173	13	0	59
-	Southwestern Public Service Co	Carlsbad	45[b]	1,218	0	0	45
3	Public Service Co of New Mexico	Prager	26	1,244	0	0	26
-	Southwestern Public Service Co	Roswell	24	1,268	0	0	24
3	Public Service Co of New Mexico	Santa Fe	12	1,280	0	0	12

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

Table E-12. GENERATING CAPACITY - NEVADA, COLORADO, AND UTAH STATIONS (MWe)

Code	Utility	Plant	Gas/Oil Steam Turbine[a]	Cumulative Total	Gas Turbine	Other	Site Total
	Nevada						
1	Sierra Pacific Power Company	Tracy	243[b]	243	0	0	243
1	Sierra Pacific Power Company	Fort Churchill	220	463	0	0	220
-	Nevada Power Company	Clark	190[b]	653	59	0	249
-	Nevada Power Company	Sunrise	82	735	68	0	150
	Colorado						
3	Public Service Co of Colorado	Zuni	115	115	0	0	115
3	Public Service Co of Colorado	Valmont	108[b]	223	66	0	174
3	City of Colorado Springs	George Birdsal	63	286	0	0	63
-	Utilities Brd of the City of Lamar	Lamar	35	321	0	2	37
-	Central Telephone & Util Corp (CO)	Pueblo New	31[b]	352	0	0	31
-	City of Colorado Springs	Drake	26	378	0	0	26
3	Public Service Co of Colorado	Alamusa	20	398	29	0	49
-	Moon Lake Electric Assn Inc	Rangley	13	411	0	0	13
4	Trinidad Mun Pwr & Lt Dept	Trinidad	8	419	0	4	12
-	Central Telephone & Util Corp (CO)	Rocky Ford	8	427	0	10	18
	Utah						
3	Utah Power & Light Company	Jordan	25[b]	25	0	0	25
-	Gadsby		66				

[a]Horizontal bars group stations by generating capacity.

[b]Site selected at random for survey and analysis.

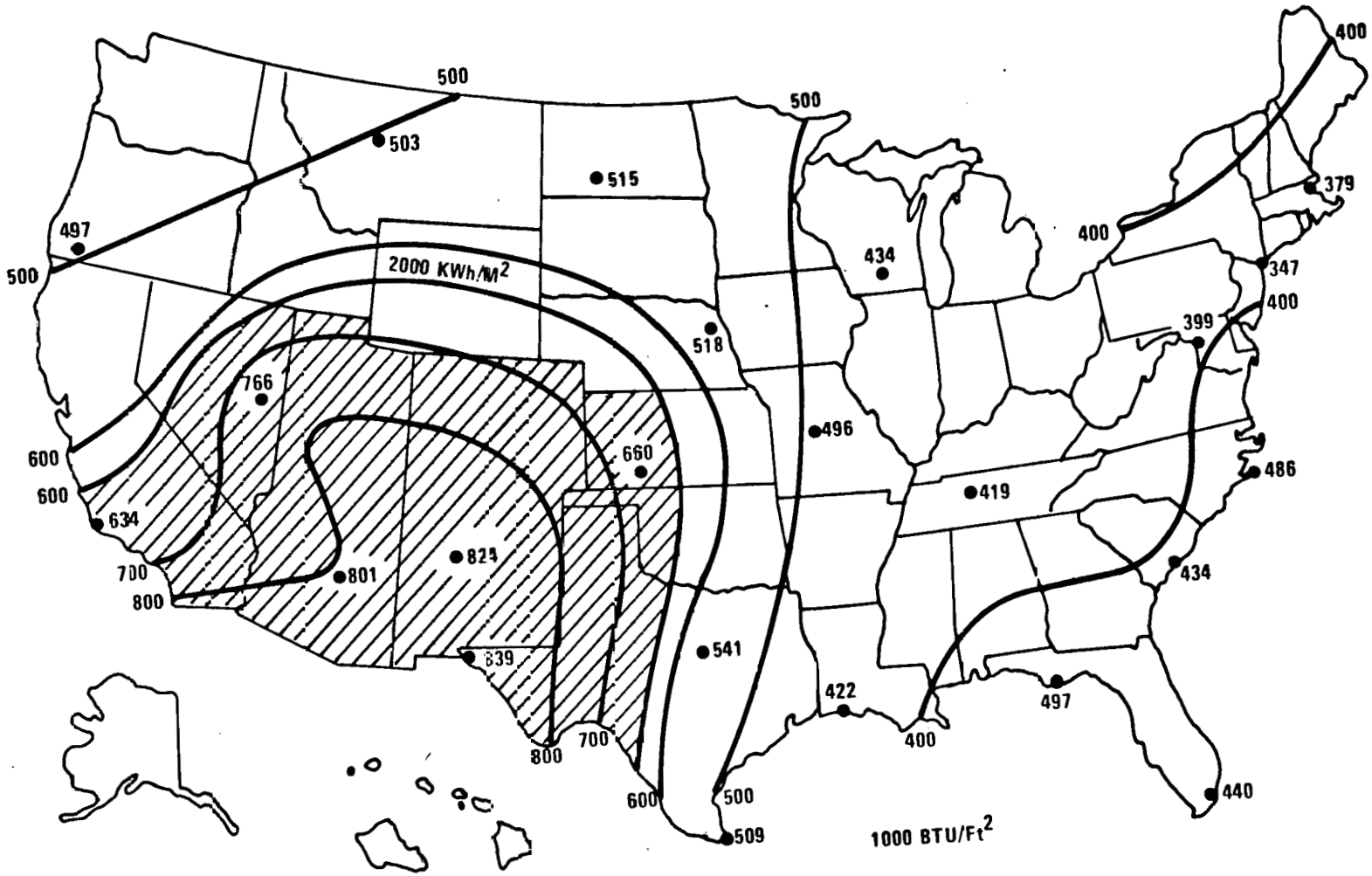

Figure E-1. AVERAGE ANNUAL DIRECT NORMAL INSOLATION (1000 Btu/ft^2) Shaded area is the region of primary interest for repowering. (Rough sketches from seasonal charts and revised SOLMET data in SAND 77-0885, "Availability of Direct, Total & Diffuse Solar Radiation for Fixed and Tracking Collectors in the USA," 1/30/78.

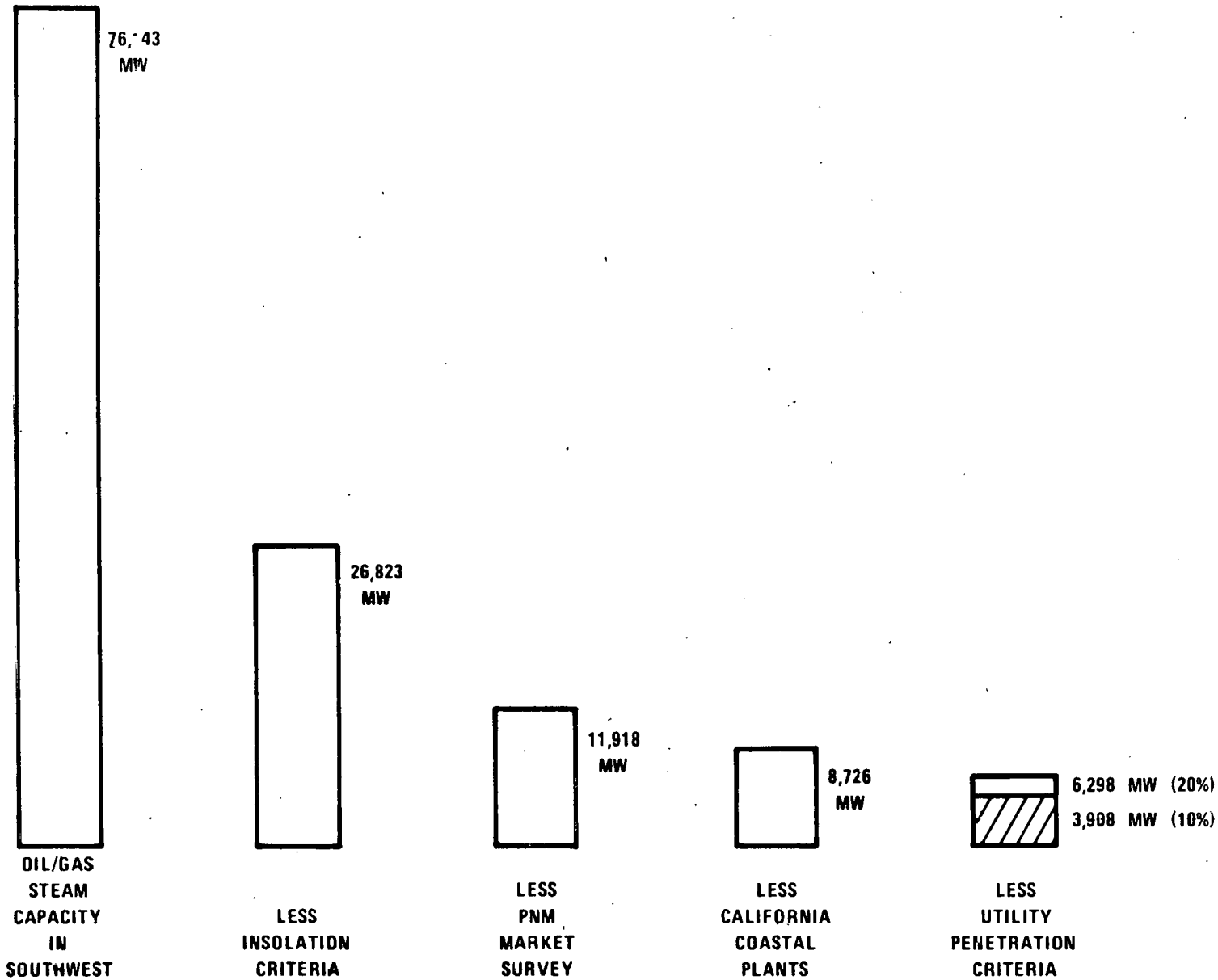

Figure E-2. REPOWERING MARKET

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This report documents the utility value analysis performed in support of the Repowering Strategy Analysis. Using standard electric utility models, the values of Improved Hybrid Repowered Plants and new 3-hr. storage coupled Improved Stand Alone Plants are determined for a modified EPRI Synthetic Utility E. The values are determined by combining a dynamic (multi-year) generation expansion analysis with a static (single-year production cost) analysis. The analysis is performed for various levels and rates of solar thermal penetration. The results indicate that numerous situations exist where the values of heliostats are greater than the cost goals which have been proposed.

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