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An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities

AN ASSESSMENT OF ENERGY STORAGE SYSTEMS SUITABLE FOR USE BY ELECTRIC UTILITIES

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FOREWORD

This is the final report of "An Assessment of Energy Storage Systems suitable for Use by Electric Utilities." This final report is separated into three volumes. Volume 1 contains the Executive Summary and Chapter 1, Overall Summary of Assessment. Volume 2 contains Chapters 2 through 7 and associated Appendices. The essential elements of the report appear in Volume 2. Volume 3 is a separate topical report on hydro pumped storage. Seclected material from Volume 3 is included in Volume 2.

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2. THE POTENTIAL FOR ENERGY STORAGE

2.1 INTRODUCTION

To determine the potential for the application of energy storage capacity on U.S. electric utilities, a few electric utility systems most representative of the large number of electric utilities in the U.S. were selected for analysis. The systems were selected based on statistical analysis of a large collection of utility data. The selection process included consideration of system size, geographical region, season of annual system peak load, annual system load factor, and other parameters.

Using computerized techniques consistent with electric utility practices, the load characteristics of each representative system were analyzed in order to determine on an annual, seasonal, weekly and daily basis for the electric utility industry:

- An estimate of the maximum potential amount of off-peak energy that could be available for charging energy storage devices.
- An analysis of the distribution of the off-peak energy.
- An estimate of the amount of on-peak energy that could be supported by the available off-peak energy.
- An estimate of the amount of energy storage power capacity capable of being supported by the available off-peak energy.
- A spectrum of typical duty cycles for which energy storage devices should be designed for power system application.

The results of this analysis of each representative system were weighted according to its assumed representativeness of the U.S. electric industry in order to determine overall estimates and ranges applicable for the entire industry.

2.2 REPRESENTATIVE SYSTEM SELECTION

Data for 199 privately and publicly owned systems representing about 90 percent of the total installed capacity and about 95 percent of the net energy generated in the U.S. was analyzed in order to select systems which would be most representative of the utility industry. The factors considered in the selection of these systems included average system size, season of system peak, annual system load factor, daily load shape (peak to valley load ratios), generation mix, and regional representation of the U.S. Appendix B1 contains a more detailed description of the electric utility data base and the method of utility selection.

Six systems were selected as being most representative of the electric utility industry. These systems, coded by letter designations, are shown in Table 2-1. Three summer peaking and three winter peaking companies were selected. The summer peaking systems A, B and C are representative of the southern (southeast, south central and southwest) regions of the U.S. with annual peak loads in the range of 2000 to 7000 megawatts. The winter peaking systems, A', B' and C' are representative of the northern (northeast, north central and northwest) regions with annual peak loads in the range of 600 to 2000 megawatts. Summer peaking systems A, B, and C have low, average, and high annual load factors respectively as do the winter peaking systems A', B' and C'.

Table 2-1 also shows the percentage of the electric utility industry each selected system was assumed to represent. These figures representing a percentage of the total number of systems were based on the statistical analysis described in Appendix B1. For example, System B was assumed to be representative of 70 percent of the summer peaking companies and 46 percent of all companies on a combined summer-winter basis.

The percentages shown in Table 2-1 were used to weight the results of the system analysis of each selected utility in order to develop appropriate weighted averages for the utility industry on a summer peaking, winter peaking and combined basis. In addition, a power pool (system Z) and a member company (system Y) of the pool were selected to analyze the potential effect that power pooling might have on the application of energy storage.

Table 2-1 REPRESENTATIVE U.S. ELECTRIC SYSTEMS

System	Peak Season	Annual Load Factor (Percent)	Assumed Industry Representation: Peak Season Only (Percent)	Assumed Industry Representation: Combined (Percent)
A	Summer	48	25	16
B	Summer	60	70	46
C	Summer	68	5	3
A'	Winter	55	30	10
B'	Winter	63	65	23
C'	Winter	78	5	2
Y	Summer	54	--	--
Z	Summer	61	--	--

2.3 METHOD OF ANALYSIS

The amount of off-peak energy available for charging energy storage capacity upon any electric system is contingent on the daily load variation and the amount of baseload capacity installed on the electric system. For each of the representative systems, an optimum baseload capacity level was identified that could provide the maximum amount of off-peak energy which would supply maximum on-peak energy requirements. The detailed analysis of the off-peak and corresponding on-peak energy associated with these optimum baseload capacity levels was used as a basis for determining the estimates and ranges of values for the study tasks. The results of this analysis of the representative systems are contained in Appendix B2, only the results averaged for the electric utility industry are summarized in this chapter.

The optimum baseload levels were determined by a computer analysis of a full year of hourly megawatt loads by assuming a number of baseload capacity levels ranging from 40 to 100 percent of the representative system annual peak load and determining the amounts of available off-peak energy below and the corresponding on-peak energy requirements above the specified level. To provide a realistic indication of the amount and distribution of off-peak and on-peak energy, each specified baseload capacity level was adjusted on a seasonal basis for scheduled maintenance outages. In addition, the levels were adjusted to take into account the effect of unscheduled outages that occur on a random basis over the year. Published industry figures of 5 weeks per year for scheduled maintenance and 10 percent unavailability to account for unscheduled outages of baseload capacity were used in the analysis. A more detailed description of the technique used is in Appendix B4.

Figure 2-1 illustrates how the off-peak and on-peak energy were calculated for a given assumed baseload capacity level. Representative system B average seasonal weekday and weekend load shapes are used here to represent the 8760 annual hourly loads actually used in the computer analysis. The assumed capacity level of 70 percent (of peak load) was adjusted for scheduled maintenance and unscheduled outages as shown.

The average seasonal capacity available to supply system base load requirements and charge off-peak energy storage systems after outage adjustments is shown to be about 55 percent (of peak load) in the spring, fall and winter seasons, and about 63 percent in the summer. Since system B is a summer peaking system, no maintenance was permitted on the base capacity in the summer season. Therefore, the average available base capacity for the summer season was adjusted only for unscheduled outages.

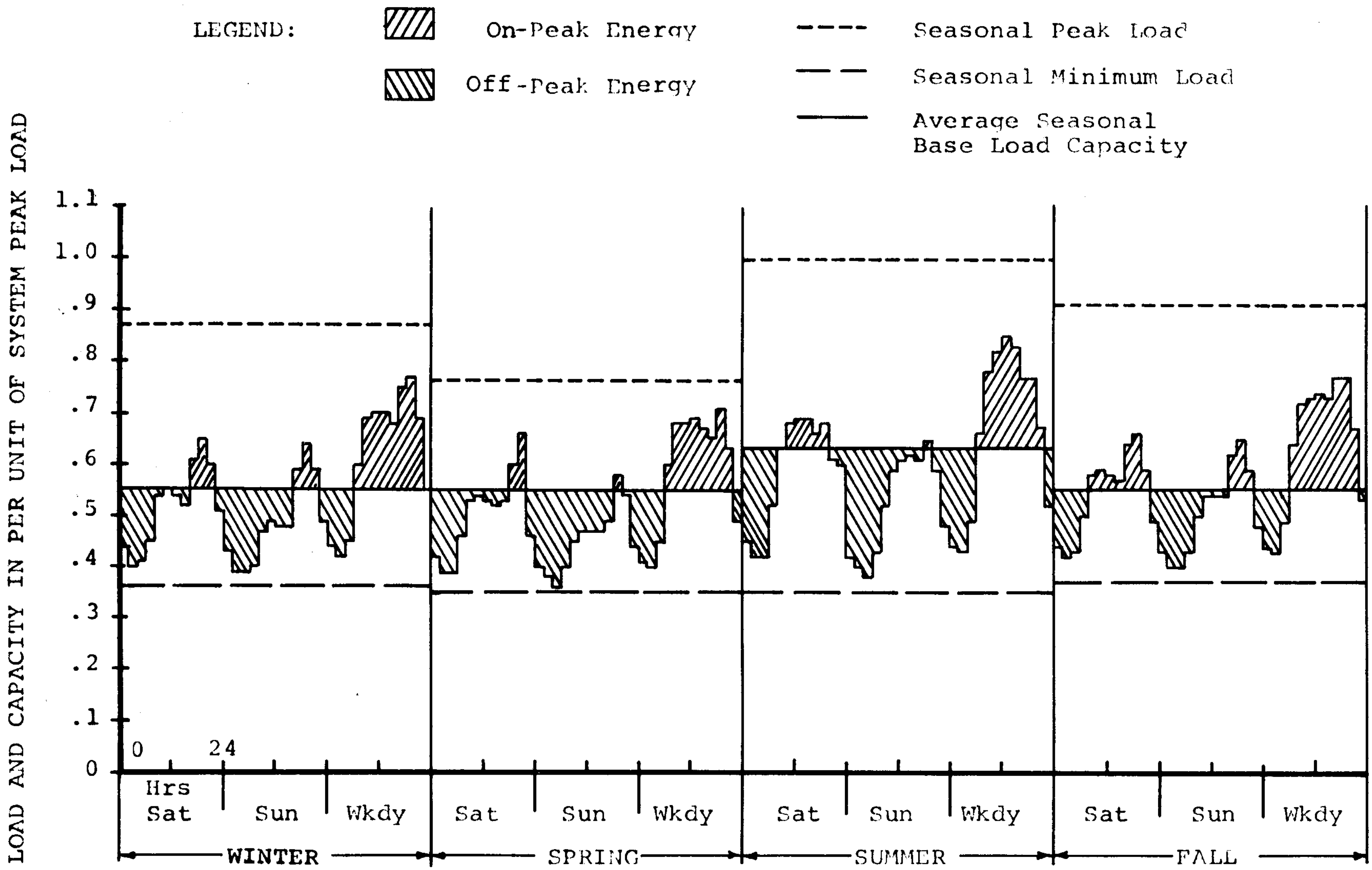


Figure 2-1 DISTRIBUTION OF OFF-PEAK AND ON-PEAK ENERGY FOR REPRESENTATIVE ELECTRIC SYSTEM B FOR THE 70% BASE LOAD CAPACITY LEVEL

The available off-peak energy calculated on a daily basis is shown by the shaded area below the adjusted capacity level and above the load requirements.
The on-peak energy requirements are shown by the shaded area above the capacity level. Figure 2-1 also shows the seasonal peak loads and the seasonal minimum loads for system B to demonstrate the extent of the variation in the system B load curve. The computer program used in this analysis is described in Appendix B3.

2.4 OFF-PEAK AND ON-PEAK ENERGY ANALYSIS

2.4.1 Maximum Theoretical Amount

For the U.S. electric utility industry, the theoretical maximum amount of on-peak energy requirements capable of being supported by the maximum available off-peak energy on an annual basis is estimated to be approximately 10 percent of the total energy produced by the industry. In terms of total energy produced by the industry for the study year 1971, this amounts to approximately 160 billion kilowatt-hours. Figure 2-2, is a summary of the results of the analysis of the off-peak and on-peak energy associated with various assumed baseload capacity levels as conducted on the representative systems, provided the basis for this estimate.

In Figure 2-2, the respective amounts of off-peak and on-peak energy associated with a specific capacity level are plotted as a function of annual system load factor. The intersection of the percent baseload capacity lines identifies points for which the annual amount of off-peak energy below the capacity level is exactly equal to the on-peak energy above the level. The curve drawn through these points of intersection identifies, for any system, an estimate of the maximum amount of on-peak energy that could be supported by off-peak energy and the required baseload capacity level. For example, for a 60 percent annual load factor system, the maximum amount of supportable on-peak energy is approximately 10 percent of total annual energy produced for load, and the associated baseload capacity level is 73 percent of peak load. From Figure 2-1, the maximum amounts of on-peak energy and associated off-peak energy were identified for each representative system, in order to determine the industry estimate of 10 percent.

This estimate of 10 percent is based on utilization of all the available off-peak energy produced by the baseload capacity at a conversion efficiency of 100 percent.

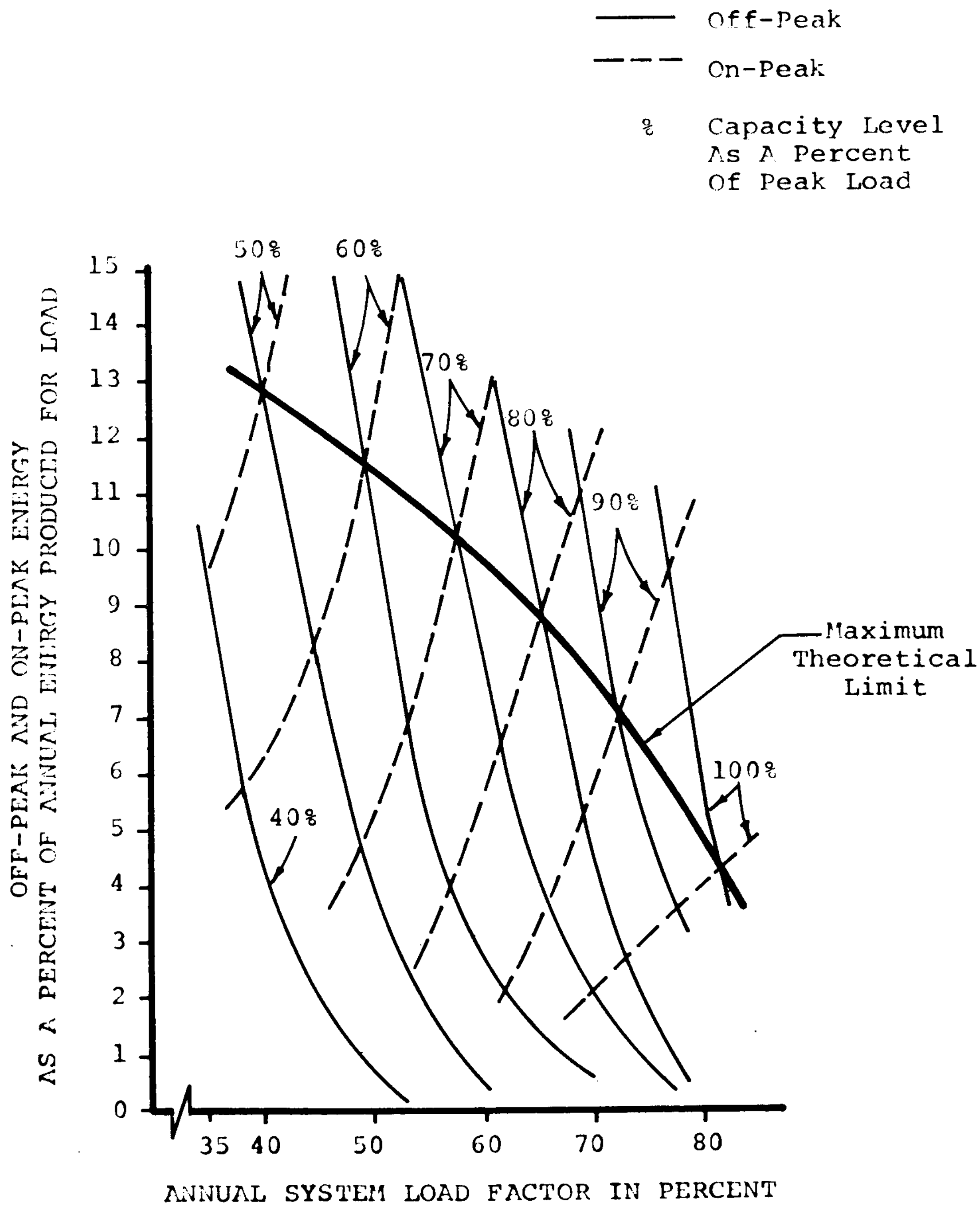


Figure 2-2 MAXIMUM ANNUAL OFF-PEAK AND ON-PEAK ENERGY LIMITS FOR U.S. ELECTRIC UTILITY SYSTEMS

2.4.2 Distribution

The available off-peak energy and on-peak energy requirements were observed to be rather evenly distributed on U.S. electric utilities over the entire year as shown in Figure 2-3.

As a percent of total annual off-peak energy, the typical seasonal, weekly and weekday distribution of off-peak energy is approximately 25, 2 and 0.2 percent (about 1 percent for five weekdays combined), respectively.
The weekly off-peak energy was found to be divided between the five weekdays and the weekend on a 55/45 percentage split. More off-peak energy was found to be available on an average Sunday than on an average Saturday.

The distribution of on-peak energy requirements as a percent of total annual on-peak energy is about 25 percent, 2 percent, and 0.35 percent on a seasonal, weekly and weekday basis respectively. The amount of on-peak energy required on a Saturday and Sunday was found to be almost negligible. The ratio of on-peak energy requirements on weekdays to the on-peak energy requirements on weekends is about 93 to 7.

There are two main reasons for the observed evenness in the distributions of off-peak and on-peak energy: (1) The utility practice of scheduling maintenance outages to fill seasonal load valleys; (2) The similarities in the cyclic nature of the daily and weekly load shapes.

The observed evenness in the distribution of both off-peak and on-peak energy implies that energy storage capacity installed on an electric system could be utilized over the entire year. The very even distribution of both off-peak and on-peak energy on a daily and weekly basis throughout the year favors the application of energy storage systems designed to operate on the daily or weekly cycle rather than the seasonal cycle. The fact that nearly one-half (45 percent) of the off-peak energy is generally available on weekends coupled with the fact that the major on-peak requirements occur on the weekdays shows the need for energy storage systems designed to operate on a weekly type cycle.

2.4.3 Practical Limits

An analysis of the frequency of occurrence of the available off-peak energy showed that approximately 30 percent of the maximum theoretical amount would be unusable for energy storage application because it does not occur on a consistent basis over the year. Table 2-2 shows the practical limits of on-peak energy that could be supplied if the theoretical maximum amounts of available off-peak energy could not be utilized. The practical upper limit of on-peak energy capable of being supplied by the

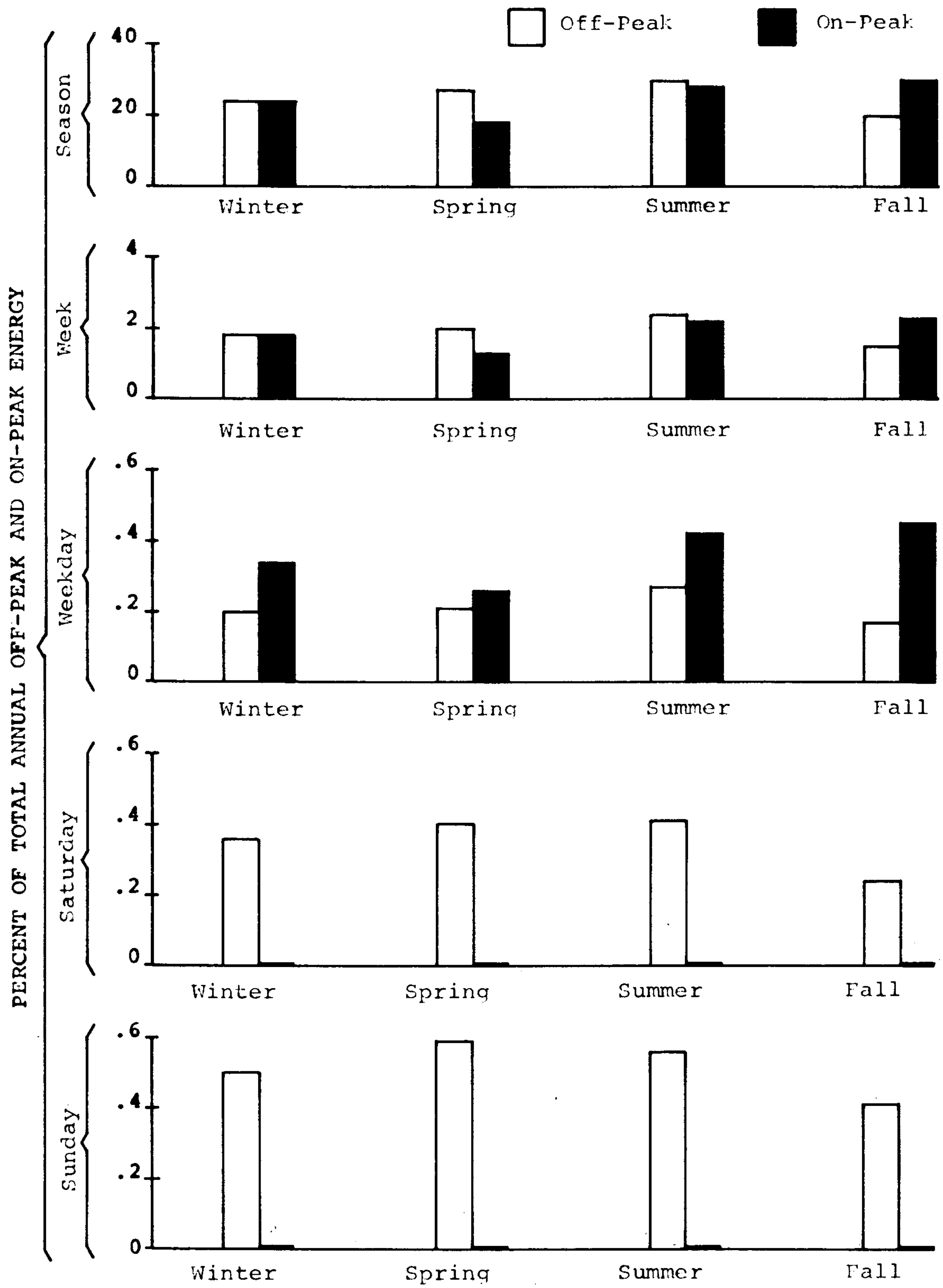


Figure 2-3 DISTRIBUTION OF OFF-PEAK AND ON-PEAK ENERGY ON U.S. ELECTRIC UTILITY SYSTEMS

Table 2-2 PRACTICAL ON-PEAK ENERGY LIMITS ON U.S. ELECTRIC UTILITIES

Efficiency of Conversion	Practical* Annual Percentage Limit (Weekly Cycle)	Practical* Annual Percentage Limit (Daily Cycle)
100%	7	4
75%	5	3
50%	3.5	2

* Percent of Total Energy Produced for Load.

off-peak energy is approximately 7 percent of total energy produced by U.S. electric utilities. In order to supply this practical limit, energy storage capacity capable of operating on a weekly cycle, would be required since the on-peak energy requirements occur primarily on weekdays and not weekends (93 percent/7 percent) whereas nearly one-half (55 percent/45 percent) of the off-peak energy is available on weekends. If one were limited to the use of energy storage capacity capable of only daily cycle operation, the practical limit would be reduced to about 4 percent of total energy produced for load.

The effect of energy storage conversion efficiency is also shown in Table 2-2. Utilization of the available off-peak energy at a lower conversion efficiency will reduce the practicallimits even further in a linear manner. For example, assuming a 75 percent conversion efficiency reduces the practical limits from 7 and 4 percent to 5 and 3 percent of respectively energy produced for load.

Figure 2-4 shows for each electric system an indication of the practical annual amount of on-peak energy that could be supplied on a consistent basis all year long on both a weekly and daily basis. In addition, the effect of a conversion efficiency of 75 percent on the practical weekly and daily cycle limits is shown.

2.5 DUTY CYCLE AND SUPPORTABLE CAPACITY ANALYSIS

2.5.1 Off-Peak and On-Peak Energy Characteristics

Figure 2-5 shows in composite form the average off-peak and on-peak energy characteristics for the U.S. electric utility systems. These characteristics, which represent weighted industry averages, were developed by computer analysis of the magnitude, duration and frequency of occurrence of both the off-peak and on-peak energy associated with the maximum baseload capacity levels of the representative systems. In this analysis, the on-peak energy requirements above, and the off-peak energy available below, the baseload capacity level identified for each representative system were analyzed in load increments of 3 percent of system annual peak (100 MW increments for a 3300 MW system). A more detailed description of the method is contained in Appendix B4; the associated computer program is described in Appendix B3; and the actual representative system profiles from which Figure 2-5 was developed are contained in Appendix B2.

With respect to the off-peak energy, the characteristics shown in Figure 2-5 are representative of that portion of the off-peak energy that would be available on a consistent basis over the 260 weekdays and 52 weekends of the year. Figure 2-5 shows, that for a typical utility, the maximum magnitude component of the off-peak energy (between the maximum baseload capacity level and load

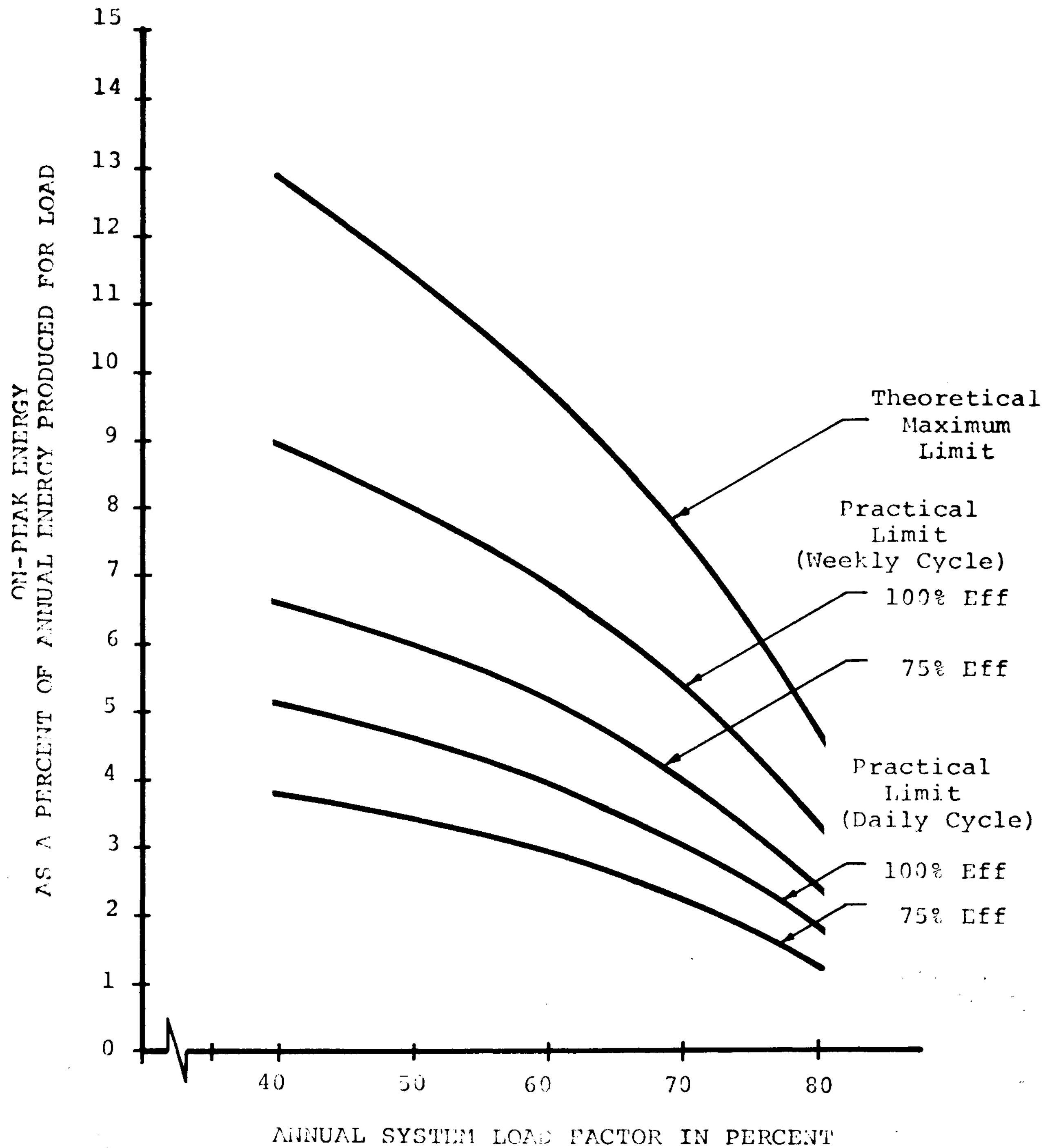
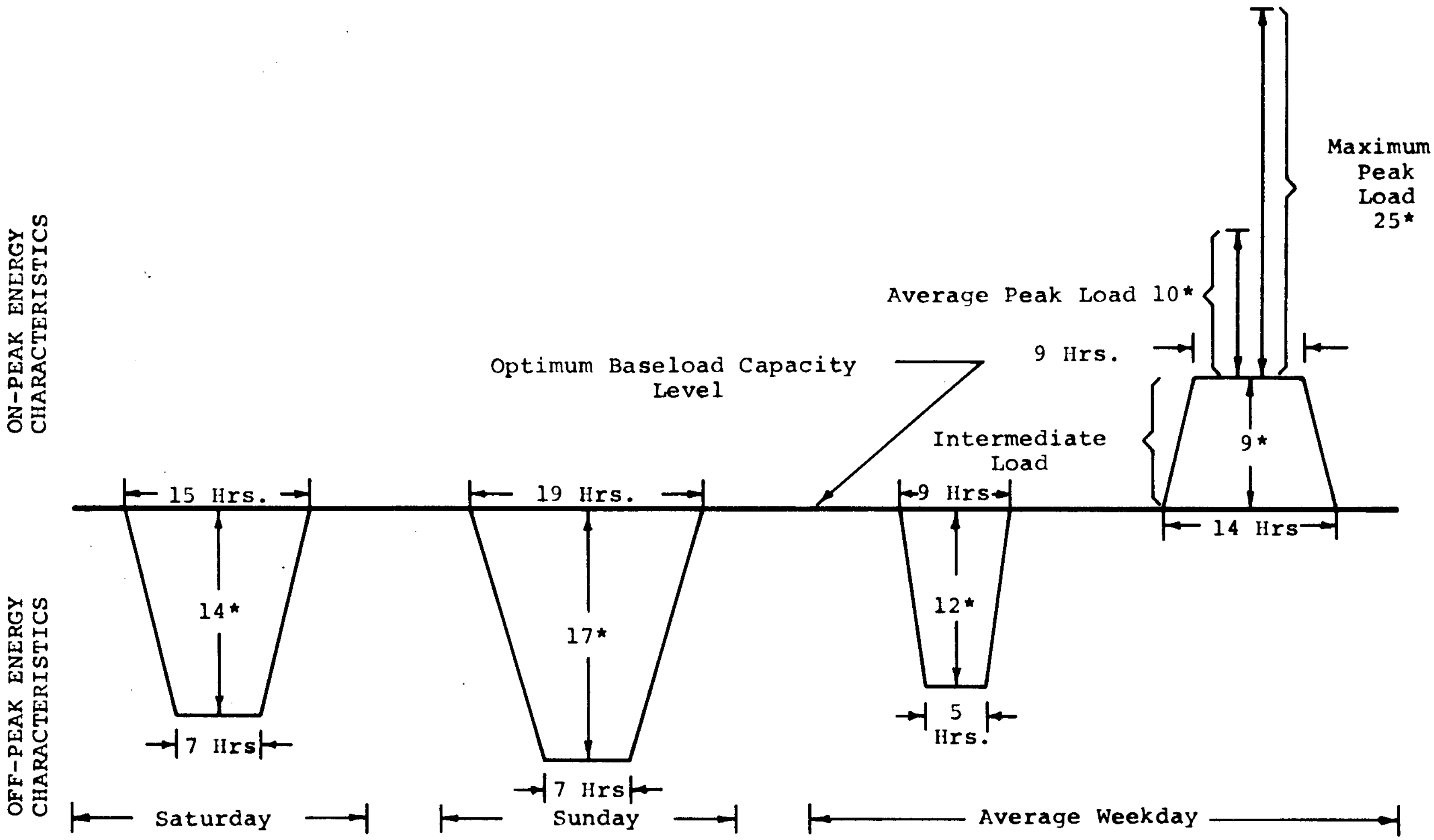


Figure 2-4 PRACTICAL LIMITS OF ON-PEAK ENERGY (INCLUDING THE EFFECT OF EFFICIENCY OF CONVERSION) CAPABLE OF BEING SUPPLIED BY THE OFF-PEAK ENERGY AVAILABLE ON U.S. ELECTRIC UTILITIES



* Magnitude as a percent of system annual peak load

Figure 2-5 OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS OF U.S. ELECTRIC SYSTEMS IN COMPOSITE FORM shape) is approximately 12, 14, 17 percent, respectively of annual peak load on an average weekday, Saturday and Sunday.

The duration components of the available off-peak energy, on the typical utility, were found to range from 5 to 9 hours on an average weekday, 7 to 15 hours on a Saturday, and 7 to 19 hours over a Sunday. For the entire weekend period, the combined duration range was observed to extend from 14 to 34 hours.

The on-peak energy requirement shown in Figure 2-5 consists of two types of loads:

1. Intermediate loads which occur consistently each weekday.

2. Peaking loads which occur in a less frequent and more random fashion each day of the year.

For a typical electric utility system as shown in Figure 2-5, the magnitude of the intermediate load above the baseload capacity level was found to be approximately 9 percent of annual system peak load. The durations of the intermediate loads were observed to fall in a range from a minimum of 9 hours to a maximum of 14 hours. Intermediate loads and associated durations contribute approximately 60 percent to the total on-peak energy requirements above the baseload capacity level; peaking loads and associated durations make up the remaining 40 percent.

Also shown in Figure 2-5, the maximum magnitude of the peaking load above the intermediate load, amounts to approximately 25 percent of annual system peak load and the average magnitude amounts to 10 percent. The peaking loads on a daily average basis are therefore approximately equivalent in magnitude to the intermediate loads.

As shown in Figure 2-6, peaking load durations measured in load increments of 3 percent of system peak ranged from 1 to 18 hours on U.S. systems. Approximately 70 percent of the peaking load durations were of 8 hours or less; durations in the range from 9 to 18 hours make up the remaining 30 percent. It should be pointed out that on only a few days of the year was more than one occurrence of the same duration observed.

Figure 2-7 provides an additional insight into the peaking load durations and the expected total annual hours of operation that would be required of peaking type capacity.
Figure 2-7 shows the numbers of days per year that peaking loads with duration of 2 hours or less, 4 hours or less, etc. were observed. The days when peaking load durations of a certain number of hours or less occurred more than once, such occurrence

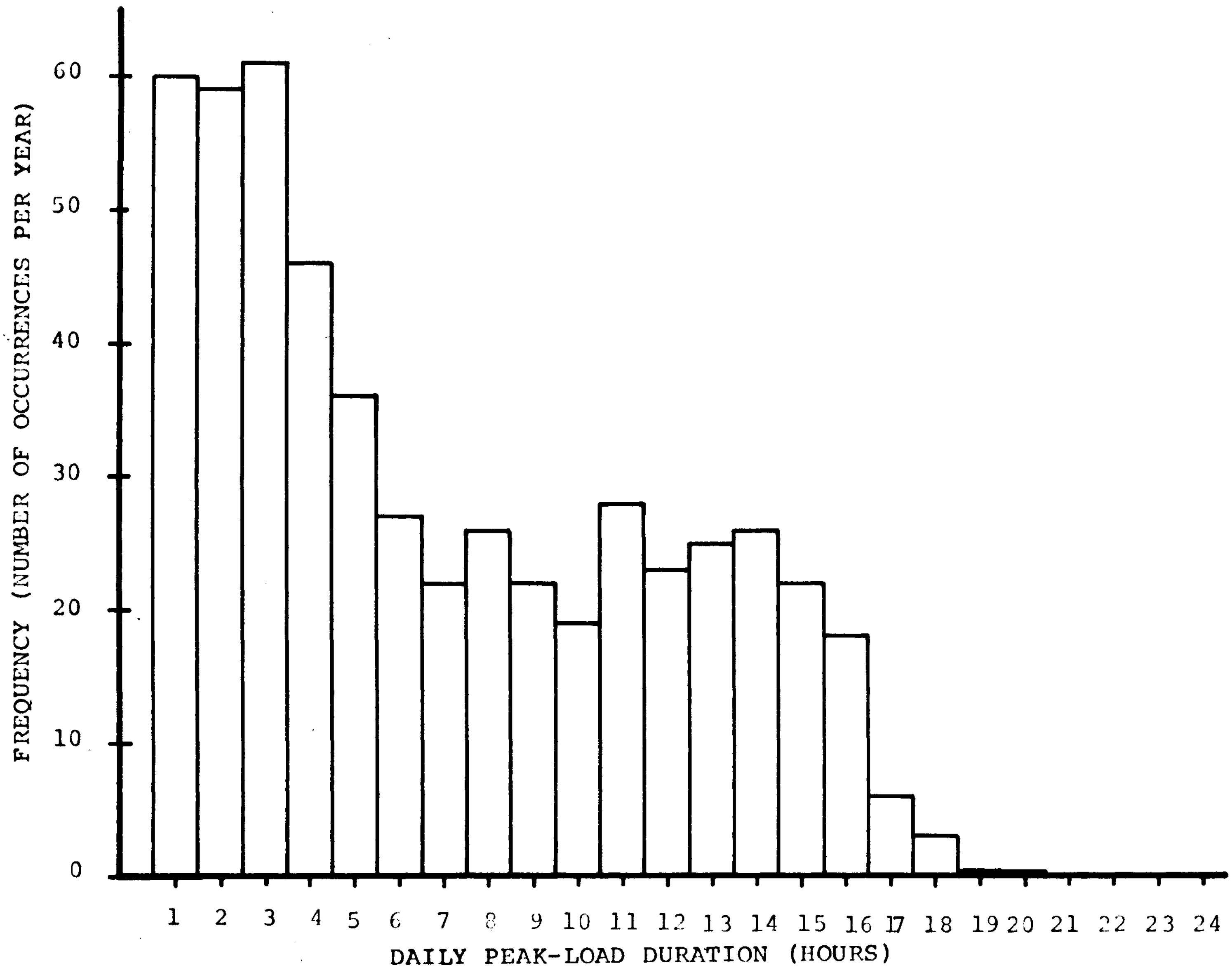


Figure 2-6 PEAKING LOAD DURATION FREQUENCY OF U.S. ELECTRIC UTILITY SYSTEMS (BASED ON MEASURING LOAD IN INCREMENTS OF 3 PERCENT OF SYSTEM ANNUAL PEAK LOAD)

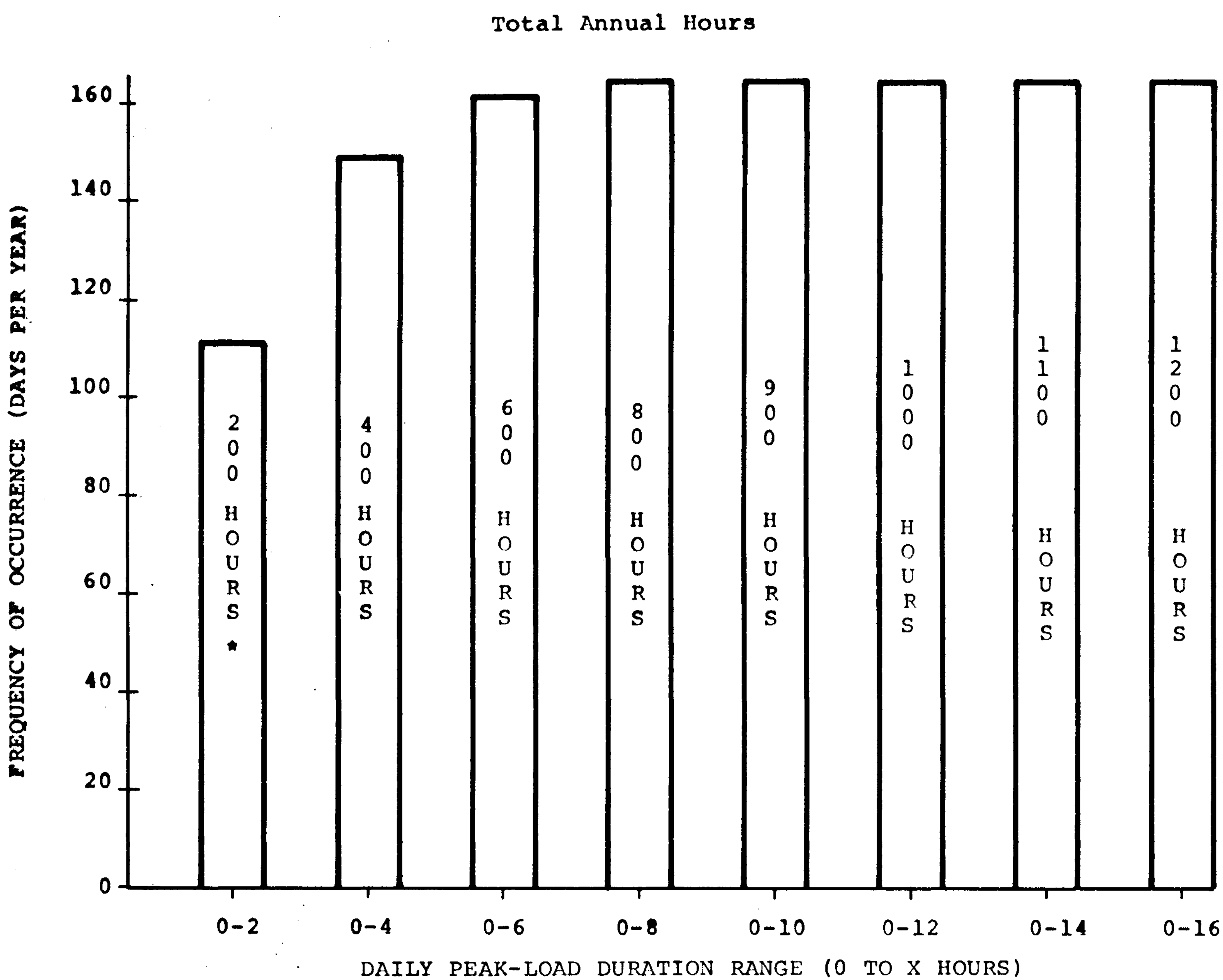


Figure 2-7 CUMULATIVE PEAKING LOAD DURATION FREQUENCY AND ANNUAL HOURS FOR U.S. ELECTRIC UTILITY SYSTEMS

was counted only once. In addition, the accumulated annual hours are shown. For example peaking loads of duration of 4 hours or less occurred approximately 150 days of the year for a annual total of approximately 400 hours. It also shows that as the duration approaches 8 hours, the number of days per year asymptotically approaches 160 which implies that peaking-duty generating capacity would be required to operate that many days per year. This analysis also shows that up to 1200 hours of annual operation would be required.

2.5.2 Duty Cycle Types

Based on the analysis of the distribution of off-peak and on-peak energy described in section 2.4.2, two types of energy storage duty cycles were identified as being most suitable to U.S. electric utility systems: the daily cycle and the weekly cycle. The daily cycle is the simplest cycle and is based on charging the energy storage capacity with the off-peak energy available on an average weekday (or any 24 hour period) and discharging that same capacity during the succeeding on-peak period.

The weekly cycle concept is simply an extension of the daily cycle to include more effective use of the off-peak energy available on the weekend to supply on-peak energy requirements for the following five consecutive weekdays. Essentially, the off-peak energy available on the weekend is allocated evenly over the five weekdays. The weekly cycle requires more storage than the daily cycle to enable longer discharge (hours) or larger power output (MW).

2.5.3 Duty Cycle Parameters

For the off-peak and on-peak energy characteristics representative of U.S. electric utility systems as previously defined in Section 2.5.1, Table 2-3 shows the ranges of duty cycle operating parameters for daily and weekly cycle energy storage devices for supplying both intermediate and peaking loads. Discharge times of 1-8 hours are shown for the peaking-duty system application and of 9-14 hours for the intermediate-duty application.

The annual hours of discharge and charging operation represent approximations based on the required daily discharge times, the available daily and weekly charge times, and the expected frequency of occurrence. Total annual discharge hours for the intermediate-duty application fall in a range from 2000 to 4000 hours; for the peaking duty application, the annual hours of operation could extend up to 1200 hours. On the charging side, total annual charging hours range from 1000-2500 hours for daily cycle devices, and 2000-4000 hours for the weekly cycle devices.

Table 2-3 RANGES OF DUTY CYCLE OPERATING PARAMETERS FOR ENERGY STORAGE DEVICES SUITABLE FOR APPLICATION ON U.S. ELECTRIC SYSTEMS

	Type of Operation			
	Intermediate Duty		Peaking Duty	
Duty Cycle Characteristics	Daily Cycle	Weekly Cycle	Daily Cycle	Weekly Cycle
Discharge Time - T_d (hours/day)	9 - 14	9 - 14	1 - 8	1 - 8
Charge Time				
Weekday - T_{cd} (hours/day)	5 - 9	5 - 9	5 - 9	5 - 9
Weekend - T_{cw} (hours/weekend)	-	14 - 34	-	14 - 34
Annual Operation				
Discharge (hours/year)	2000 - 4000	2000 - 4000	250 - 1200	250 - 1200
Charge (hours/year)	1000 - 2500	2000 - 4000	1000 - 2500	2000 - 4000
Charge/Discharge Rated Power Ratio - C/D*				
Device Efficiency 75%	1.3 - 3.7	.8 - 2.4	.1 - 2.1	.1 - 1.4
" " 50%	2.0 - 5.6	1.1 - 3.6	.2 - 3.2	.1 - 2.1
Storage Capability - S* (hours at rated discharge power)	9 - 14	24 - 34	1 - 8	3 - 19

*Based on the following relationships:

Daily Cycle

$$C/D = \frac{T_d}{T_{cd} \times e}$$

$$S = C/D \times T_{cd} \times e$$

Weekly Cycle

$$C/D = \frac{5 \times T_d}{(5 \times T_{cd} + T_{cw}) \times e}$$

$$S = C/D \times (T_{cd} + T_{cw}) \times e$$

Where e = device conversion efficiency (electric to electric)

Ranges of charge/discharge (C/D) rated power ratios and associated storage capability are also shown in Table 2-3 for energy storage devices based on conversion efficiencies of 75 and 50 percent. The C/D power ratio is the ratio of the rated charge capacity (MW) to the rated discharge power capacity (MW) that would be required to provide a specified discharge time requirement with a specified available charge time. The storage capability represents the total time in hours that an energy storage device could operate continuously at rated discharge power capacity (MW), based on starting with a full charge or full reservoir. The equation relationships from which the ranges were developed are also shown in Table 2-3; the derivation of these relationships is explained in detail in Appendix B4.

The charge/discharge (C/D) rated power ratio range shown in Table 2-3 was developed by combining maximum discharge time requirements with the minimum charge times available and vice versa. For example, to supply the intermediate load duration requirements by means of a 75 percent efficient energy storage device utilizing the charge times available on a daily basis, would require devices with C/D ratios ranging from a low of 1.3 (9 hour discharge requirement, 9 hour available charge time) to a high value of 3.7 (14 hour discharge requirement, 5 hour available charge time). Storage capability requirements of the devices range form 9 to 14 hours for C/D ratios of 1.3 and 3.7 respectively.

To supply the intermediate load duration requirements with energy storage capacity of 75 percent efficiency utilizing the charge times available on a weekly basis, C/D ratios less than those of the daily cycle would be required as shown in Table 2-3. The C/D ratios range from a low of .8 (9 hour discharge requirement, 9 hour weekday and 34 hour weekend available charge times) to 2.4 (14 hour discharge, 5 hour weekday and 14 hour weekend charge time). Storage capability requirements of energy storage devices for this application must be larger than those of the daily cycle. As shown in Table 2-3, storage capabilities range from 24 to 34 hours for devices with C/D ratios of .8 and 2.4, respectively.

Similarly, for supplying the peaking load requirements with the daily cycle, C/D ratios range from .1 ((1 hour discharge, 9 hour charge time) to 2.1 (8 hour discharge, 5 hour charge time); respective storage capabilities would range from 1 to 8 hours. For the weekly cycle the C/D limits range from .1 (1 hour discharge, 9 hour weekday and 34 weekend charge times)to 1.4 (8 hour discharge, 5 hour weekday and 14 hour weekend charge times); respective storage capabilities range from 3 to 19 hours as shown.

The effect of conversion efficiency on the C/D ratios is linear as shown in Table 2-3 when one compares the figures for the 75 percent conversion efficiency with those based on a 50 percent efficiency. C/D power ratios must increase as efficiency decreases in order to provide an equivalent amount of energy output over a fixed charge time. Storage capability requirements are essentially only time dependent and efficiency has direct effect as shown.

It should be pointed out that Table 2-3 shows the full range of duty-cycle parameters technically suitable for application on U.S. electric utilities, however many of these may not be practical or economic. Based on the results summarized in Table 2-3, weekly cycle energy storage devices appear to be more suitable for the intermediate-duty cycle application than daily cycle devices because of the limited charge time associated with the daily cycle. Similarly, it would appear that daily cycle energy storage would be more suited to the peaking-duty system application because the majority of peaking load durations were observed to be 8 hours or less. Based on this analysis, a few cycle types were selected for the economic analysis described in Chapter 5 of this report.

2.5.4 Supportable Power Capacity

Table 2-4 shows, as a function of conversion efficiency, the estimated maximum amount of energy storage discharge power capacity capable of being supported on a typical U.S. electric system by the off-peak energy available on a daily or weekly basis. These estimates are based on supplying the on-peak energy requirements with a wide range of combinations (C/D and storage capabilities) of peaking duty and intermediate-duty energy storage devices. A more detailed description of the analysis method used to determine these results is contained in Appendix B4.

For daily cycle applications, the total amount of energy storage discharge power capacity capable of being supported varies from 14 percent (about 700 MW for a 5000 MW electric system) to 10 percent of annual peak based on efficiencies of 100 and 50 percent, respectively.

For weekly cycle applications, the amount of energy storage discharge power capacity capable of being supported is approximately 40 percent greater than that of the daily cycle. The total amount was estimated to range from 20 percent at a 100 percent conversion efficiency to 14 percent at 50 percent efficiency.

Table 2-4 ESTIMATED MAXIMUM ENERGY STORAGE POWER CAPACITY CAPABLE OF BEING SUPPORTED ON A TYPICAL U.S. ELECTRIC UTILITY SYSTEM

Cycle	Conversion Efficiency (Percent)	Installed Energy Storage Power Capacity (Percent of Annual System Peak)
Daily	100	14
	75	12
	50	10
Weekly	100	20
	75	17
	50	14

2.6 FUTURE PROJECTIONS

Long range projections of future daily and weekly load shapes are not available from the electric utility industry and therefore one can only speculate on what shape they may take. Energy conservation and load management will have some effect on future load shapes, but what the effect will be is difficult to ascertain. However, it is doubtful that any of these factors will completely eliminate the daily load variations.

Future electric utility annual load factor and baseload capacity trends provides a basis for discussion of the future application of energy storage devices. Based on an analysis of annual peak load and energy forecasts for the electric utility industry for the year 1984 as provided by the National Electric Reliability Council (NERC), future annual load factors are projected to decrease from an average of 59 percent (1971) to 55 percent. In general, decreasing annual load factors tend to imply the availability of more off-peak energy.

According to the Federal Power Commission, the amount of nuclear capacity is expected to increase, from 2 percent (1971) to approximately 40 percent of the total generation capacity mix by the year 1993. The availability of low cost off-peak energy associated with nuclear baseload capacity should provide more incentive for the application of energy storage on electric power systems.

2.7 SUMMARY CONCLUSIONS

Based on an analysis of the load characteristics of electric utilities selected as being most representative of the electric utility industry, it can be concluded that use of energy storage energy storage could play a significant role in supplying future peaking and intermediate load requirements.

The analysis showed that:

- Regardless of the geographic location of the utility, or when the annual system peak load occurs, electric utilities have very similar load characteristics at the daily or weekly level.

- An optimum installed baseload capacity level, ranging from 60 to 80 percent of annual peak load, could be identified for any electric utility above which the on-peak energy requirement would be approximately equal to the available off-peak energy below that level.

The distribution of both off-peak and on-peak energy on U.S. electric systems on a seasonal, weekly and daily basis was observed to be relatively even which favors the application of energy storage systems designed to operate on a daily or weekly cycle. Energy storage devices capable of weekly cycle operation would be particularly appealing because of the fact that nearly one-half of the off-peak energy is generally available over the weekend period and over 90 percent of the on-peak energy requirements occur on weekdays (Monday through Friday).

Based on a 100 percent overall efficiency, the maximum practical amount of installed energy storage power (MW) capacity capable of being supported by the off-peak energy available on U.S. electric systems was estimated to be approximately 20 percent of annual system peak load, based on the weekly duty cycle. The maximum annual amount of on-peak energy (MWh) capable of being supplied by this capacity was estimated to be approximately 7 percent of total annual energy. (For a 5000 MW system with a 60 percent annual load factor, these figures represent 600 MW and 16 billion kWh.) Based on the daily cycle, the maximum capacity (MW) was estimated to be approximately 14 percent of annual peak load. The corresponding annual amount of energy would be approximately 4 percent.

Because U.S. electric systems possess extremely similar off-peak and on-peak energy characteristics (magnitude and duration), a spectrum of desirable energy storage duty cycle parameters can be defined, for the application of energy storage systems by electric utilities. The wide range of different combinations of duty cycle operating parameters based on both the daily and weekly cycle modes of operation for both intermediate and peaking generation applications should facilitate the application of a number of different types of energy storage technologies to U.S. electric systems. However, energy storage capable of weekly cycle operation appears to be more suitable for supplying intermediate load requirements with durations of 9 to 14 hours, while daily cycle energy storage would be more suitable for supplying peaking loads with durations up to 8 hours,

3 ENERGY STORAGE TECHNOLOGIES

There are a number of approaches to storing energy for use by electric utilities. This chapter identifies and describes the major concepts and discusses their basic characteristics and stage of development. This chapter is neither an introduction nor a definitive monograph on energy storage technologies. Rather, a portion of the information developed during this study is presented which may be of interest to the reader and is not readily available elsewhere. Because each technology is in a different level of development, each is treated differently. Costs are discussed in Chapter 4, environmental factors are discussed in Chapter 6, and research needs are summarized in Chapter 7.

A review of hydro pumped storage as the baseline technology is presented in considerable detail in a separate volume of this final report [1]. Hydro pumped storage is the only technology which is currently in commercial use, and, in light of the wealth of data available, merits a more detailed treatment. Although substantial data is presented here on the other technologies, all but hydro are developing--not mature-and a definitive treatment is outside the scope of this project. Reports on parallel projects, funded by Energy Research and Development Administration (ERDA), on compressed air storage [2] and flywheels [3] are or will be available shortly. Thermal storage systems are under active investigation [3,4,5] and have been reported elsewhere, while the subject of AC/dc power conversion has been well covered in an Electric Power Research Institute (EPRI) report [6].

Energy storage technologies may be classified or grouped in different ways. In this report, they are identified as: (1) hydro pumped storage; (2) compressed air storage; (3) flywheel (inertial) storage; (4) thermal storage; (5) battery storage; (6) chemical storage; and (7) "superconducting" magnetic storage. These may also be classified by the form of energy which is stored or by the force which is at work. Frequently, the first three storage systems, hydro, compressed air and flywheel are referred to as "mechanical storage", batteries and chemical as "chemical storage", thermal as "thermal storage" and superconducting magnets as "electromagnetic" storage [7].

In the sections which follow, each type of storage is discussed, and the major concepts and their principal limitations are identified. The last section in this chapter briefly covers the storage system/utility interface and some of its engineering problems.

3.1 HYDRO PUMPED STORAGE

This section describes conventional and underground hydro pumped storage. An expanded treatment is provided in a separate volume of this report [1].

Since hydro pumped storage is a commercial reality, an extensive library of literature exists for all of its aspects [8,9,10]. Many plants have been built and their costs and characteristics are well known. Nevertheless, there is a need for further research and study, particularly with respect to underground pumped storage. The possibility of using excavated caverns or abandoned mines as the lower reservoir in a pumped storage system opens up opportunities for use of higher heads and possibly larger capacities. It also extends the area in which hydro pumped storage might be economically developed, and at the same time has environmental advantages.

3.1.1 Description and Present Status of Development

In a hydro pumped storage system for utility use, energy is stored by pumping water from a lower to a higher elevation (Figure 3-1). The energy is recovered by passing the water from the higher to the lower elevation through a water turbine driving an electric generator. Pumping and generating can be accomplished by using separate pumps and turbines, which may be connected to a single motor-generator. The two operations can also be accomplished with a reversible pump-turbine connected to a motor-generator.

The reservoirs needed for the pumped storage operation may be natural bodies of water; reservoirs of existing hydro plants or other water storage systems; specially constructed surface reservoirs; underground caverns; or combinations of these storage possibilities. The pumping-generating plant is connected to the two reservoirs by appropriate waterways; these may be entirely underground or partially on the surface. The powerhouse itself may be either on the surface or underground. Underground powerhouse construction may be economically and environmentally desirable, even where the reservoirs are on the surface.

Plants have been built in the United States in sizes from a few megawatts to more than 1,000 MW (10,000 MWh); plants under study range to more than 2,000 MW (20,000 MWh). Differences in reservoir elevations (heads) have ranged from less than 100 feet to more than 1,200 feet; even higher heads are planned for the future. Currently, one underground pumped storage plant is in the licensing stage. In general, the plants with the smaller sizes or lower heads have been special purpose plants. With perhaps a few exceptions, the modern "pure" pumped storage plants have involved pump-turbine unit capacities of 100 MW or more, and

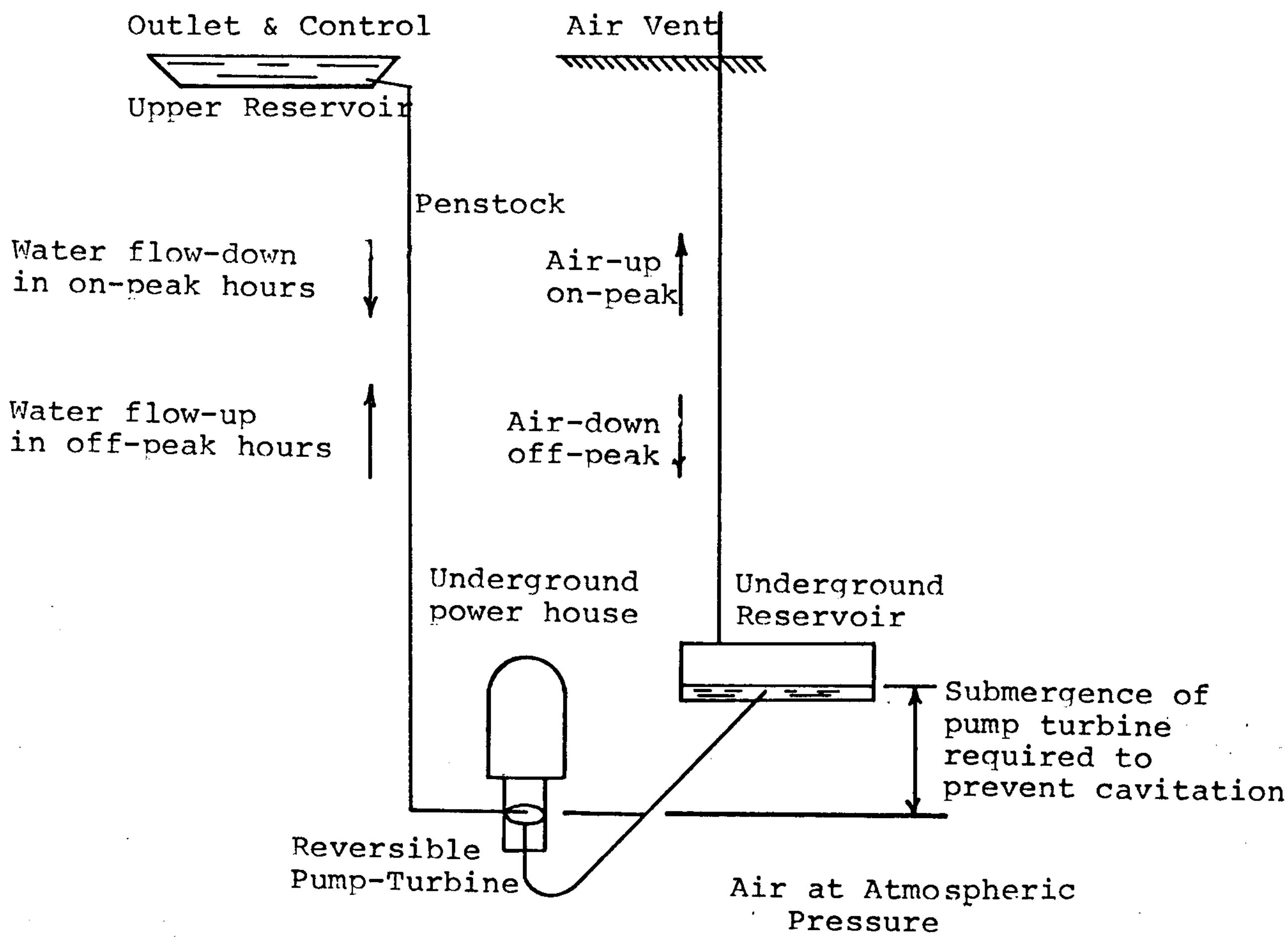


Figure 3-1 HYDRO PUMPED STORAGE

heads above 300 feet. Representative modern plants are identified in Table 3-1.

The necessity of storing relatively large volumes of water in two reservoirs, separated by several hundred feet of head, but not too far apart in distance, requires topography that is not available everywhere. However, the absence of pumped storage plants in certain areas of the country is not necessarily indicative of unfavorable topograph. Rather, it may indicate either the absence of economic need for a peaking service or, perhaps more likely, the supply of this service by conventional hydro plants.

The possibility of using underground water storage reservoirs extends the geographical area in which pumped storage can be developed and also extends the range of heads available. Within limits, the overall cost of a plant using underground storage will decrease as the head is increased. Therefore, since the head for which the usual reversible unit might be built is limited, the optimum development of underground pumped storage may involve somewhat different concepts, including the use of two plants in series, separate pump and turbine units (as used abroad for higher heads), or multistage reversible units.

The fundamental characteristics of both conventional hydro pumped storage and, hydro pumped storage with an underground storage reservoir are very similar and are discussed together wherever possible.

3.1.2 Technical Assessment

In the case of hydro pumped storage with aboveground reservoirs, there is an adequate body of information with respect to existing and potential developments, technical characteristics, and costs.

Characteristics and costs can be expressed on a per unit basis of plant capacity and related to head. During the generating portion of the operating cycle, the lower reservoir is filled and the upper reservoir is emptied. The difference in water surface elevation between the two reservoirs, or gross head, is decreased. The change in head may cover a wide range, and differences in head of 10 to 20 percent are not uncommon. As the head decreases, so does the available plant capacity. Unless there are hydraulic or electrical limitations that prevent the use of the full turbine output at higher heads the percentage change in output is even greater than the change in head, since the rate of water use, at full gate opening, also decreases as the head decreases.

During the generating portion of the cycle, the output of the plant may be controlled at some level below the available output.

Table 3-1 REPRESENTATIVE PUMPED STORAGE PROJECTS

Plant Name	Initial Operation	Plant Capacity MW(a)	Average Head feet (b)	Energy Capacity MWh
Taum Sauk	1963	350	809	2695
Yards Creek	1965	330	723	2904
Muddy Run	1967	855	386	12141
Cabin Creek	1967	280	1159	1624
Seneca (Kinzua)	1970	380	741	4256
Northfield	1972	1000	772	8500
Blenheim-Gilboa	1973	1030	1099	11948
Luddington	1973	1675	328	15075
Jocassee	1973	528	310	49632
Bear Swamp	1974	540	725	3024
Raccoon Mt.	1975	1370	968	32880

(a) Capacity may differ from amount reported by owner or by FPC in order to provide consistency in the basis of rating.

(b) Average of reported maximum and minimum heads.

It will most often be the intent to operate at or near the most efficient load point, which is for a load less than the available plant capacity at all heads. If desired, it would be possible to operate continuously at or close to the rated capacity, but with some sacrifice in efficiency. Departures from efficient loading may be required for area load regulation and to provide maximum available capacity under heavy load conditions or during shortages of other generation.

During pumping, the lower reservoir is emptied and the upper reservoir is filled; the gross head is increased. This results in a change in input to the pump-turbine unit, but generally there is a small decrease in pumping load as the head increases. This results from the much larger water quantity that can be pumped at minimum head as compared to that at maximum head. The input to the pump-turbine unit is not ordinarily under the control of the operator,since once the unit has been started as a pump, it is operated at or close to its most efficient gate opening. The average of the reported loads at maximum and minimum heads has been used for purpose of comparison to the rated output of the plant in the generating mode of operation.

Because of the opposite effects of head on the water quantities used during generation and on the quantities that can be pumped, it is possible, by selection of the pump-turbine design, to favor either one or the other. This permits a selection to be made of the ratio of pumping load to generating capacity, which is an important characteristic of any storage method.

Underground pumped storage, with one reservoir located in an excavated cavern, differs from conventional pumped storage using two surface reservoirs in a number of respects.

Since costs for a real underground system do not yet exist, they must be estimated. However, as all components of an underground pumped storage system have been constructed for other purposes, there is a valid basis for these estimates. This is covered in Chapter 4.

A powerful economic incentive exists to use higher heads and thus reduce per unit costs, particularly those of the excavated reservoir. Single-stage reversible pump-turbine design will be pushed beyond the limits of present experience to heads of 2,500 feet, or alternative unit and plant arrangements will be utilized to develop heads of 3,000 to 5,000 feet.

Since plant location depends primarily on the availability of suitable underground conditions, and to a lesser extent on surface conditions, the area in which hydro pumped storage may be constructed is extended. Particularly important is the possible availability of sites closer to load centers and to sources of pumping energy.

In the following paragraphs, specific technical characteristics are described including, unit size and head, efficiency, charge/discharge rates, reliability and availability, extent and duration of storage, turnaround time, load regulating ability, and useful life.

3.1.2.1 Size and Head A trend towards the use of large pump-turbine units is evident in planned projects calling for units with nominal capacities of 250 MW. The minimum unit size for general utility application is 100 MW. Since costs generally decrease with an increase in head, the incentive is to use heads as high as can be made available with adequate energy storage capacity. The largest single reversible unit (383 MW) constructed to date is for the relatively low head at Ludington and Raccoon Mountain. Since larger conventional hydro electric units have been built, it is likely that larger pumped storage units may be planned.

Plant size can be any multiple of unit size and generally per unit costs will decrease with an increase in plant capacity. Anywhere from two to eight units have been installed in the selected group of plants in Table 3-1; the largest in service plant contains six units for a total of 1675 MW. Total plant size is frequently limited by the available reservoir capacity or by the utility system requirements. Possible limitations to plant size for underground storage are the following:

- Limited construction access to the underground powerhouse
- The reliability of plants constructed in series (for higher heads) might indicate that individual unit size be limited
- Lower reservoir construction over long periods of time might suggest smaller units suitable with incremental increases in reservoir capacity

However, to overcome certain high fixed costs for underground plants, minimum capacity will probably be greater than 1000 MW. As for conventional pumped storage the plant size will only be limited by the upper reservoir or system requirements.

Heads that have been found economical for development, in the absence of special conditions, have been above 300 feet. In the United States, the maximum reversible unit head is 1,200 feet. Japan has a plant operating at a head over 1,600 feet. A head of 2,500 feet is probably attainable.

The development of reversible units for higher heads is probably the highest priority research and development activity related to hydro pumped storage. The use of these higher heads will depend on: (a) the extension of the head range for the single stage reversible units; (b) the use of the single stage reversible units in series with an intermediate reservoir; (c) the use of multistage reversible units, and (d) the use of separate high head turbines and multistage pumps.

3.1.2.2 Efficiency Overall efficiency (Table 3-2) is the product of the separate efficiencies of the pump, motor, transformer (used twice), generator, turbine, and waterway (used twice). There appears to be little prospect for achieving an efficiency of 80 percent since each component is now near its maximum practical limit of efficiency. Furthermore, in actual operation, variations in loading, starts and stops, station service requirements, and minor leakage and evaporation losses will reduce the overall efficiency. The efficiency range for the conventional system is 70 to 75 percent which should also be attainable for an underground system.

Conversion efficiency can be determined for existing plants, from actual data experience, by using the ratio of annual net generation to pumping energy input. A trend toward higher conversion efficiencies is evident in the past decade which showed about 66 percent conversion efficiency in 1965 and about 78 percent in 1975 (Figure 3-2). This trend is in part related to the design and construction of bigger and more efficient reversible units; but it is also related to more liberal design (i.e., lower water velocities) for the penstocks, tunnels, etc. The head losses in the water conduits can be estimated from the reported differences between gross and net heads. Although these differences are reported only for turbine operation, reasonable estimates can be made for pump operation. The combined losses are also shown in percent of gross head in Figure 3-2 for comparison with the overall efficiencies. The trend is downward, reflecting the probability that later designs have minimized losses, in recognition of relatively higher costs in recent years.

3.1.2.2 Charge/Discharge Ratio The charge/discharge ratio of a storage unit or plant can be measured as the ratio of power input (average pumping load in MW) to power output (rated capacity in MW).

The charge/discharge ratios for actual plants are tabulated in Table 3-3. There appears to be a practical limit to these ratios. The selected plants show a range from 1.0 to 1.3 with a suggested range up to 1.4. A charge to discharge ratio of 1 indicates that the pumping load is equal to the rated generating capacity; which might be considered a balanced electrical design.

Table 3-2 HYDRO PUMPED STORAGE COMPONENT EFFICIENCIES

	Representative Ranges, %	
	Low	High*
Pumping - Motor & Transformer	97.5	98.5
Pump	91.5	92.5
Water Passages	96.5	98.5
Generating - Water Passages	95.5	97.5
Turbine	89	92.5
Generator & Transformer	97.5	98.5
Allowance for Operation Under Other Than Optimum Conditions	92	98
Over-all cycle efficiency	66%	78%

*Not yet confirmed by experience.

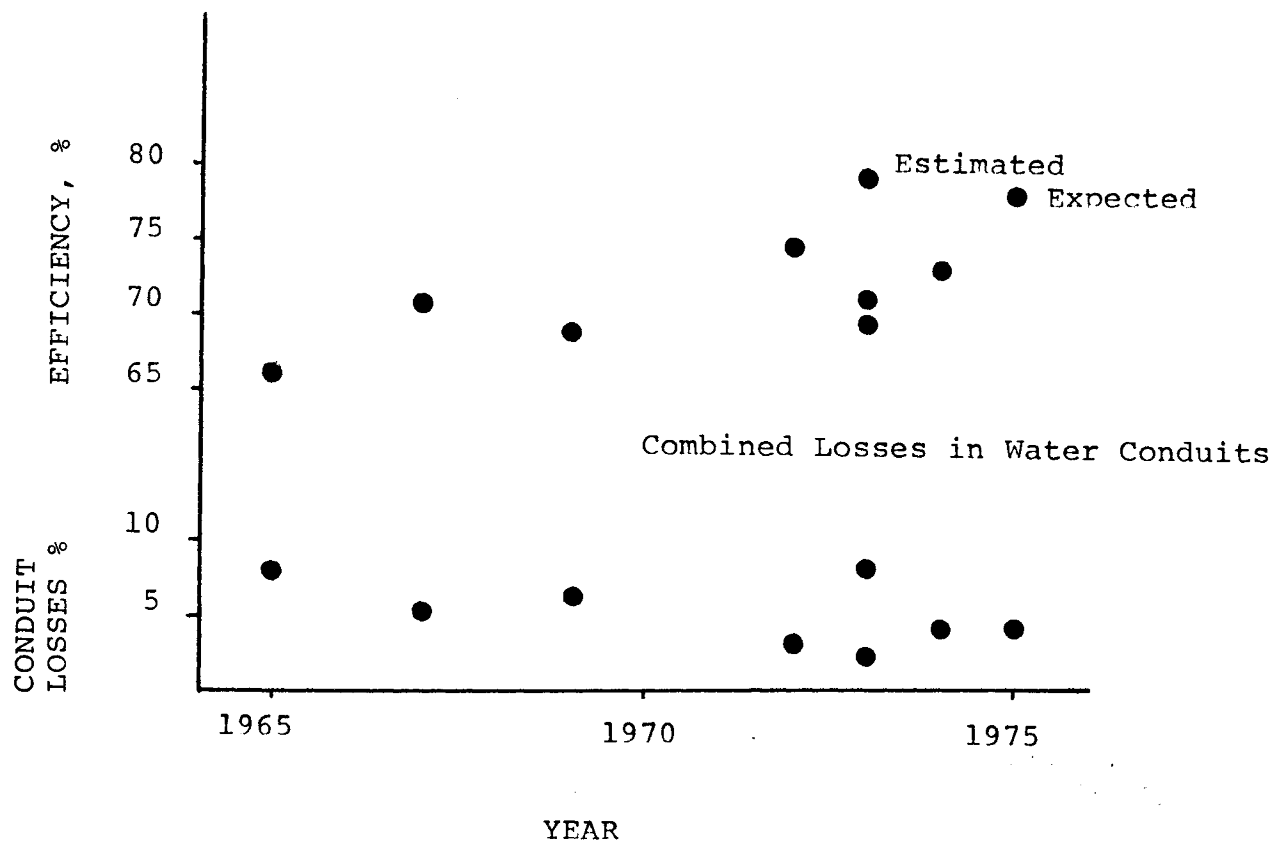


Figure 3-2 CONVERSION EFFICIENCY
VERSUS YEAR OF CONSTRUCTION

Table 3-3 CHARGE/DISCHARGE RATIO AND ENERGY STORAGE FOR REPRESENTATIVE PLANTS

Plant	Charge/Discharge Ratio Pump Load/Plant Cap.	Energy Storage KWH/KW of Plant Capacity = Hours
Taum Sauk	1.07	7.7
Yards Creek	1.30	8.8
Muddy Run	1.05	14.2
Cabin Creek	0.93	5.8
Seneca (Kinzua)	1.29	11.2
Northfield	1.00	8.5
Blenheim-Gilboa	1.13	11.6
Ludington	1.25	9.0
Jocassee	1.11	94.0
Bear Swamp	1.04	5.6
Raccoon Mountain	1.01	24.0
Suggested Range	1.0 to 1.4 (B)	(A)

(A) A variable to be determined by system conditions.

(B) Ratio controlled by selection of pump-turbine; higher ratio requires larger hydraulic and electrical equipment, hence higher costs.

A practical upper limit of about 1.35 to 1.4 gives an average motor load well in excess of the rated generating capacity, but the rate of water pumping equals the rate of water used. Conversion efficiencies are slightly lower for the higher charge/discharge ratios.

3.1.2.4 <u>Reliability and Availability</u> The following factors are reasonable assumptions for the reliability and average availability of future pumped storage units:

(1)	Forced outage rate	4 percent
(2)	Average annual maintenance, scheduled outages, and incidental unplanned outages	5 weeks/yr.
(3)	Average availability (47/52 x 0.96)	87 percent

Factors (1) and (2) are close to those used in the Mid-Atlantic Area Council (MAAC) for planning purposes and are based on operating experience of three MAAC area pumped storage plants. Factor (3) is derived from (1) and (2), and is independently confirmed by the operating availability of pumped storage as reported by the Edison Electric Institute (EEI) Prime Movers Committee. There is substantial opinion that pumped storage units will eventually show higher reliability and availability figures than these. Since conventional hydro units have an average forced outage rate below 1 percent and a maintenance time of about two or three weeks per year, there is room for improvement in the pumped storage factors. However, there is no doubt that pumped storage units are subject to more severe strains than conventional hydro units and have more opportunities for breakdowns.

3.1.2.5 <u>Extent and Duration of Energy Storage</u> The energy storages at the existing selected plants, as shown in Table 3-3, are in terms of hours of operation at rated capacity available from use of the reported energy storage. The maximum value of 94 hours at Jocassee is not typical of "pure" pumped storage as there is a substantial natural flow into its upper reservoir which also has additional purposes.

Typical storage capacities are sufficient for about 6 to 24 hours of generation at rated capacity. For a daily cycle of operation, approximately 8 to 10 hours of storage is sufficient. For larger storages, operation on a weekly basis as well as a daily cycle is inevitable. The 24 hour storage at Raccoon Mountain is close to the weekly cycle practical limit. High excavation costs, however, are likely to limit underground storage to a daily basis operation, e.g., 8 to 10 kWh per kW.

Once the water has been pumped into the upper reservoir, it can be maintained as a stored energy resource for a relatively long time. Losses from leakage and evaporation are small (under unfavorable conditions these losses are less than 5 percent per month) and may be offset by rainfall and local runoff.

The storages provided at existing plants are not necessarily indicative of those of the future. There are variables to be determined by expected future system load conditions and economic studies. There is no need to recommend a range of storage based on the presently available experience.

3.1.2.6 Turnaround Time A pumped storage plant cannot pass quickly from the pumping to the generation mode, or vice versa. A definite time interval is required due to mechanical and hydraulic inertias, for decelerating the unit in one direction, and switching and proper operation of auxiliaries. Additional time is needed for acceleration in the opposite direction. If separate turbines and pumps are utilized, as in underground storage, turnaround time can be substantially reduced, since the direction of unit rotation need not be reversed.

Limitations in control facilities or in the mechanical or electrical arrangements of the plant may prevent "turn-around" of more than one unit at a time.

Typical turn-around and starting times are:

• from pumping to full load generation	2 to 20 minutes
• from generation to pumping	5 to 40 minutes
• from shutdown to full load generation	1 to 5 minutes
• from shutdown to pumping	3 to 30 minutes

These time intervals might be applied, in series, to each unit in a plant. Under normal conditions, the successive operation of each unit may not be a real disadvantage, since changes in system load could require even longer intervals between the initial operation of each unit.

3.1.2.7 Load Regulating Ability A pumped storage plant can follow load to a limited extent, but generally the effect on efficiency and on maintenance requirements will be considered prohibitive. Nevertheless, under some conditions the advantages outweigh the penalties of such operation. At least one, and possibly two, of the selected plants do operate as load regulating units with resultant low overall efficiencies.

Of course, some gross load regulation is accomplished by the starting and stopping of the units, either as pumps or generators; but this is no more or less than can be accomplished by the starting and stopping of other energy storage systems. Because of its quick starting ability, a pumped storage unit at stand-still may, in some systems, be counted as operating reserve, in the same manner as combustion turbine capacity. It is recommended that hydro pumped storage be considered available for load regulating service only under unusual conditions, with no regulation being considered consistent with the use of the above suggested efficiency range.

3.1.2.8 Other Characteristics Some other characteristics of storage systems applicable to hydro pumped storage are:

- Maintainability - good, as evidenced by a reasonably low cost per kW per year.

- Simplicity - also good, but relative only to the complexity of a modern fossil or nuclear plant.

- Ease of expansion - poor, unless substantial expenditures are made in advance for larger reservoirs and for ultimate expansion of the plant.

- Compatibility with existing power generation - complete, as evidenced by existing operations.

3.1.2.9 Useful Life Conventional hydro plants are inherently long-life property. Many are already 50 years old and some plants that are 70 years old are still operating with original equipment. Massive structures, such as dams, dikes, and tunnels seem to have an almost indefinite life if adequately maintained.

Although pumped storage units are subject to more severe service requirements than are conventional hydro units, (reversals in direction of operation and more frequent starts and stops), maintenance and interim replacement of breaker parts, generator windings, bearings, etc. should give the pumped storage plant equipment a comparably long life. For accounting purposes, a number of pumped storage plant owners are using an average life of 70 years as compared to 80 years for hydro. Reports filed with the Federal Power Commission show a range from about 50 to 75 years for pumped storage. For tax purposes, IRS allows a life of 50 years for all hydro property.

3.1.3 Underground Pumped Storage Sites

The major structures in an underground pumped storage plant, all of which are located below ground are: the power stations, the lower reservoir, the water conduits, and the transformers. The storage of compressed air and/or water in underground caverns, 800 meters below ground level, is presently being investigated in several countries as one of the alternative methods in meeting peak power demands.

Geological feasibility depends upon suitable bedrock since underground reservoirs must be located in rock which is relatively free from residual tectonic stresses coupled with surface topography or land use conditions which permit construction of a surface reservoir. Most of the favorable formations, still pending further tests, are uniform masses of relatively undeformed granite. Although this type of rock is considered most suitable, advances made in tunneling technology enable excavation of caverns in other materials, at higher cost and risk.

Site inventory is a multi-step process; the first of which is the development of reasonably reliable contours for the top of Precambrian rock. One such investigation is a 1974 report to the Northeast Utilities Service Company, "Geological Survey of Potential Cavern Areas in New England". Another investigation underway is the cooperative program of gravimetric surveys between the U.S. Geological Survey and some state geologic agencies. These gravimetric surveys require confirmation and calibration from boring data, which are available in limited amounts. Deep borings and seismic surveys are being made in numerous locations as an attempt to locate oil, geothermal energy, etc. Unfortunately, this program has moved slowly since it has been plagued by problems in Federal research funding.

Figure 3-3, compiled by Dr. Bennett L. Smith, shows major geologic subdivisions of the United States and identifies potentially attractive areas for underground hydro pumped storage. Although it also also has the advantage of employing major units that are fairly well known geographically, it has the inherit disadvantage of including, in certain provinces, areas that are both highly favorable and those which are not. This map does, however, identify generally favorable areas for underground water storage at depth within the desired range for hydro pumped storage.

3.1.4 Combined Plant; Hydro and Compressed Air Storage

In combining the underground hydro pumped storage plant and the compressed air storage plant, cost reductions due to better

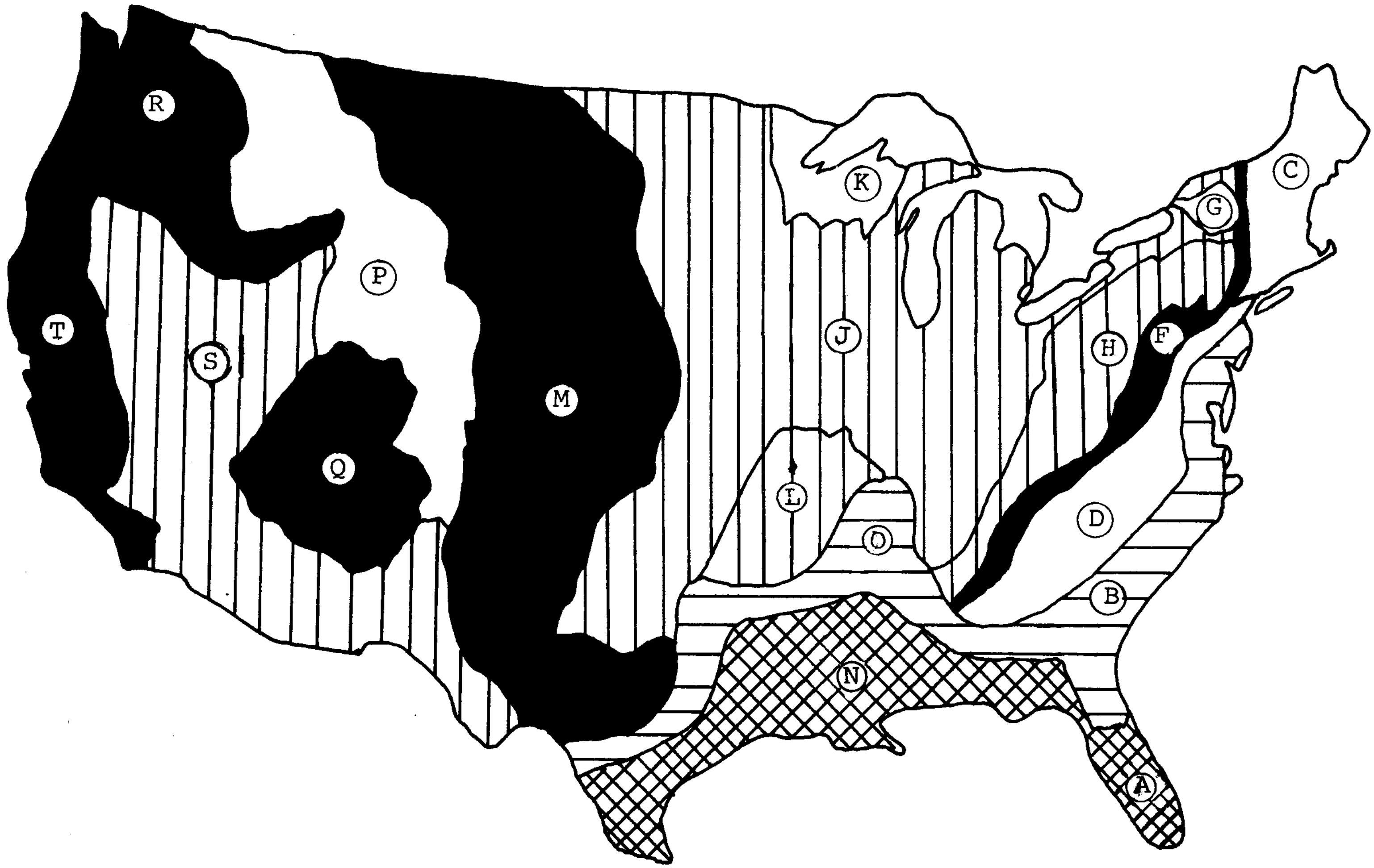


Figure 3-3 CONVENTIONAL MAJOR GEOLOGIC SUBDIVISIONS OF THE UNITED STATES (Sheet 1 of 3)

Figure 3-3 CONVENTIONAL MAJOR GEOLOGIC SUBDIVISIONS OF THE UNITED STATES (Sheet 2 of 3)

Legion

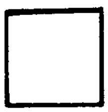
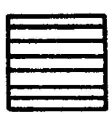
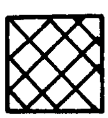
	I	Many widely distributed occurrences of competent rock.
	II	Competent rock occurs but the best targets are limited in geographic distribution.
	III	Suitable bodies exist but are relatively quite limited geographically.
	IV	Suitable rock undobtedly occurs but is concealed beneath unsuitable materials.
	V	Suitable rock too deep.

Figure 3-3 CONVENTIONAL MAJOR GEOLOGIC SUBDIVISIONS OF THE UNITED STATES (Sheet 3 of 3)

	Area	Rating (From Previous Page)
A.	ATLANTIC COASTAL PLAIN Outer Part	V
B.	ATLANTIC COASTAL PLAIN Inner Part	IV
C.	NEW ENDLAND	I
D.	PIEDMONT AND BLUE RIDGE	I
E.	TRIASSIC LOWLANDS	III
F.	RIDGE AND VALLEY PROVINCE	III
G.	ADIRONDACKS	I
H.	APPALACHIAN PLATEAU	II
J.	INTERIOR PLAINS	II
K.	CANADIAN SHIELD	I
L.	OZARK HIGHLANDS	I
M.	THE GREAT PLAINS	III
N.	GULF COASTAL PLAIN Outer Part	V
O.	GULF COASTAL PLAIN Inner Part	IV
P.	ROCKY MOUNTAINS	I
Q.	COLORADO PLATEAU	III
R.	COLUMBIA PLATEAU	III
S.	BASIN AND RANGE PROVINCE	II
T.	PACIFIC COAST REGION	III

integration of equipment and system optimization are potentially possible.

A brief description of the two systems individually, with the emphasis on the combination aspects, and the advantages and possible problems of such, follows. The combined plant concept is presently the subject of a patent application by E. S. Loane of the GPU Service Corporation.

As shown in Figure 3-1, a separate underground hydro pumped storage consists of the following principal elements:

- Upper reservoir - with suitable outlet and control structures
- Vertical conduit or penstock - with branches
- Excavated underground powerhouse - with one or more generating units. Each of these may be connected to either a reversible pump-turbine or to a separate pump and turbine on a single shaft. The powerhouse has all the necessary auxiliaries and is connected to the surface by one or more additional air shafts (not shown) for access and electric transmission
- Excavated lower reservoir - with suitable draft tubes for connection to the hydraulic units. In order to provide the required positive head on the turbines and pumps, or pump-turbine combination, the lower reservoir would normally be located above the level of the underground powerhouse. For a high-head installation, such as would usually be contemplated, the required submergence on the pumps may be in the order of 200 ft
- Vent shaft to the surface - to permit movement of air to and from the lower reservoir

Such a facility normally operates as a generating plant during the heavy load hours of the day. Water from the surface reservoir passes through the penstock and turbines to the excavated lower reservoir, and its energy drives the electric generators. Air is forced out of the lower reservoir and exhausts to the atmosphere.

During the off-peak or light load nighttime hours, the flow is reversed. The electrical units are operated as motors to drive the pumps, and water is taken from the lower excavated reservoir and delivered to the surface reservoir. Air is drawn down the vent shaft and replaces the water in the lower reservoir.

Compressed air energy storage requires underground storage of air because the required volume cannot otherwise be provided at comparable cost. The underground air storage may operate at variable pressure or at an essentially constant pressure maintained hydraulically. The constant pressure method makes more effective use of the underground storage volume.

As shown in Figure 3-4, a constant pressure air storage scheme consists of the following principal elements:

- Surface reservoir - for water with suitable outlet and control structures
- Vertical conduit - connects to underside of excavated reservoir
- Air shaft - connects to the surface
- Surface installation of parts of a combustion turbine generating plant - compressor and clutch; generator-motor, combustion-turbine and clutch, fuel storage; and suitable valves, heat exchangers, and auxiliaries

Such a facility also normally operates as a generating plant during the heavy load hours of the day. Compressed air is drawn from storage, passed through a heat exchanger, and mixed with fuel in combustion chambers. The hot pressured gas then drives one or more combustion-turbines and exhausts through heat recovery equipment (which heats the air from storage) to the atmosphere. The combustion-turbine drives an electric generator, which is at that time uncoupled from the compressor. As the air is withdrawn from storage an essentially constant pressure is maintained by the hydraulic system which delivers water to the lower reservoir.

During the off-peak or light load nighttime hours, the air and water flows are reversed. The electric units are operated as motors to drive the compressors, and air is delivered (with intercooling and aftercooling) to the underground storage. The compressed air displaces the water, which is returned to the surface reservoir.

From the foregoing it is evident that the water and air flows in both plants are in the same directions, during both on-peak and off-peak hours. This suggests the combination of plants with no change in facilities other than that the air in the underground reservoir of the hydro plant will now have to be under pressure. This can be arranged without serious detriment to either plant.

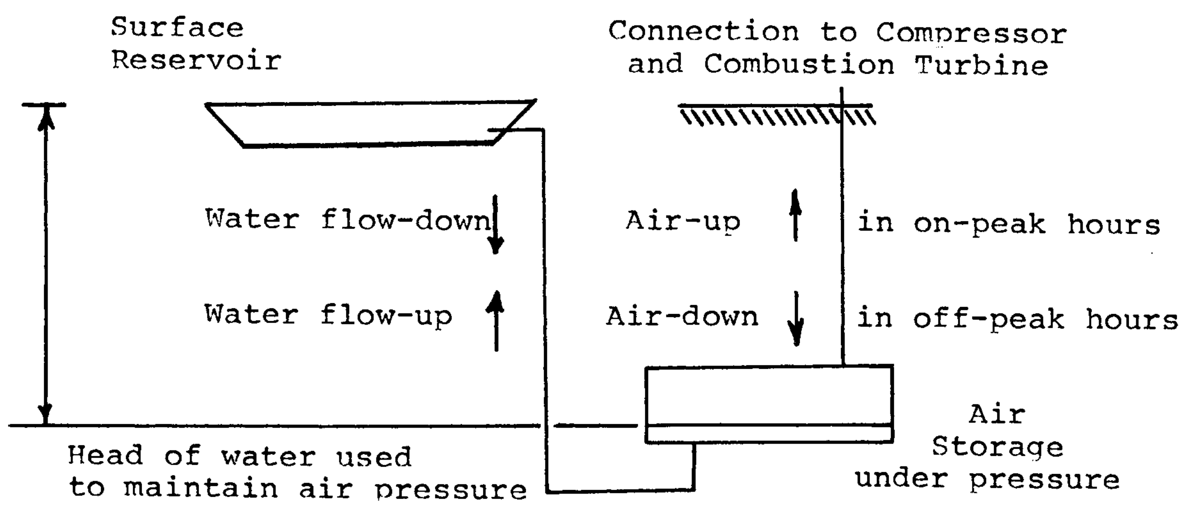


Figure 3-4 AIR STORAGE

Figure 3-5 shows the relative elevation of the underground reservoir for the separate hydro pumped storage and combined plants.

For the separate plant, as noted earlier, the underground reservoir must be above the underground powerhouse in order to provide a large positive tailwater pressure on the turbine and a high positive suction head on the pump. This is necessary to avoid cavitation and to assure satisfactory operation of the high head hydraulic units.

For the combined plant, if the surface of the water is pressurized, the reservoir can be lowered and still provide the positive head on the hydraulic units, Consequently, there is the opportunity for storing the compressed air needed for the air storage generation. It may be that the desired air pressure is higher than is needed to provide the desired hydraulic condition; but this is of little consequence, since compensation can be provided by lowering the entire underground excavation (both powerhouse and reservoir), in order to maintain the intended net head on the pump-turbines.

Possible problems might arise in the plant operation. Operation of the pumps, turbines and compressors of both systems must be synchronous; this can be done.

The air pressure in the lower reservoir reduces the hydraulic head of the water turbine, therefore, the air pressure must be sufficiently high to compensate for this reduced head.

3.1.5 Final Comments

- Hydro pumped storage is a well developed, mature technology
- Where suitable sites are available for two surface reservoirs, no technical obstacles exist to impede implementation
- Underground reservoirs may extend the areas where hydro pumped storage can be used
- Further development of high head equipment will be desirable for use in high head underground plants

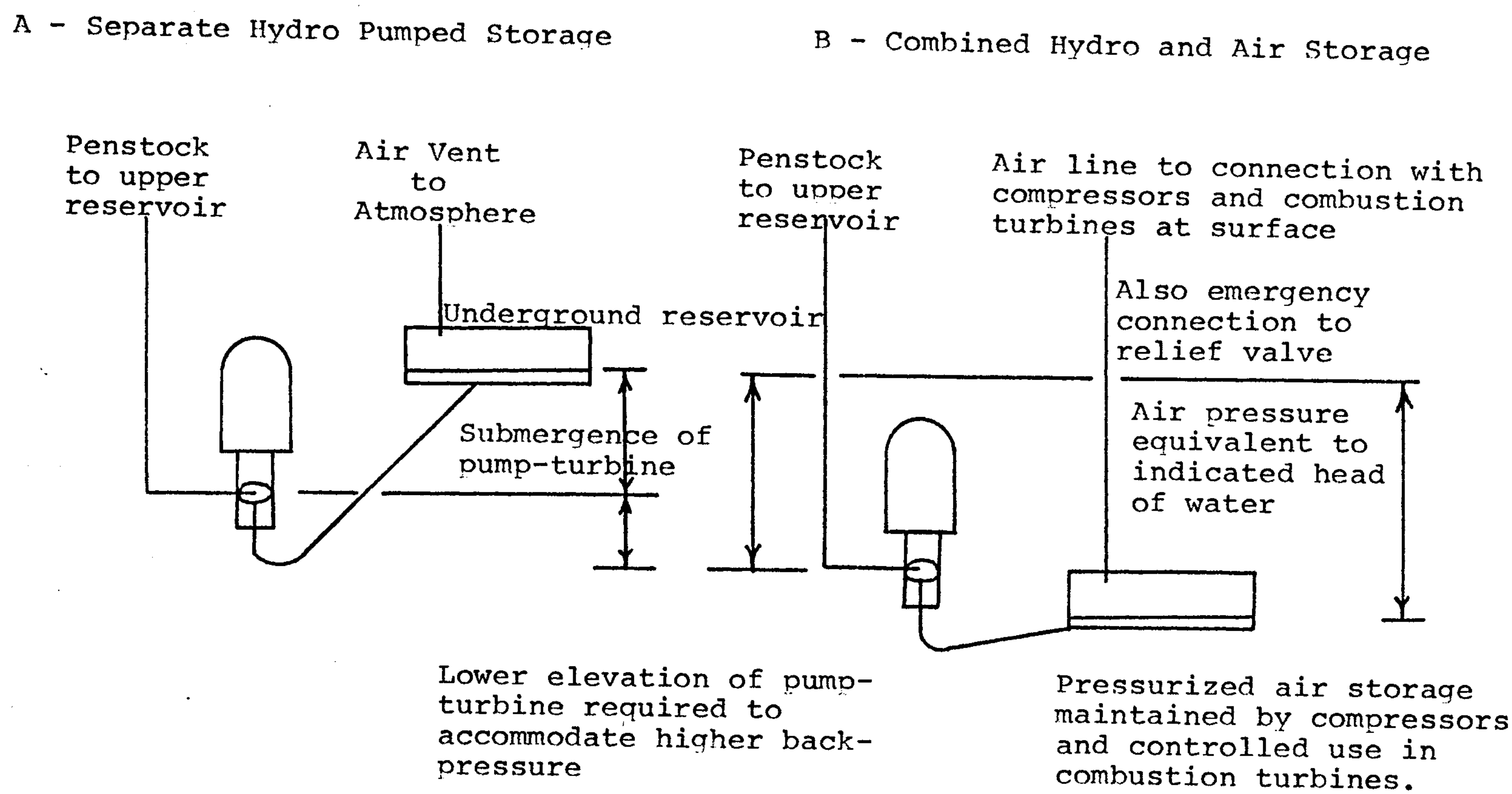


Figure 3-5 RELATIVE ELEVATIONS OF UNDERGROUND RESERVOIRS, SEPARATE & COMBINED PLANT

3.2 COMPRESSED AIR STORAGE

Compressed air storage is a fairly old concept with initial studies dating from the 1940's, and earlier [11, 12]. Although patented [13, 14] and discussed in the literature [15-23], no plant has been operational and only recently have firm plans for design and construction been implemented [24]. Thus this old concept is, in fact, an immature and developing technology with new approaches still being investigated [25]. However, the basic equipment and engineering are extensions of existing technology.

Recent efforts in a parallel program funded by ERDA have resulted in a comprehensive review of the entire technology [2]. The treatment here is, of necessity, brief.

3.2.1 Description and Present Status of Development

The popularity of the gas turbine (combustion turbine) for peak-shaving application stems primarily from a combination of low initial cost and quick-start capability. On the other hand, there is a disproportionate allocation of turbine shaft power to compressor operation rather than to externally usable purposes. If this requirement could be circumvented, then essentially all available turbine shaft power could be applied to a generator. The approach considered here is to perform the compression function separately; that is, store compressed air in quantities sufficient to operate the hot gas generator (burner and turbine) over a desired time interval, and subsequently operate in a "blowdown" mode during the peak demand period. This splitting of the operating cycle with an intermediate air storage is the essence of compressed air storage. Other approaches would include adiabatic compression with storage of the thermal energy of compression for later use in air heating [25].

About two-thirds of the power generated by the hot gas expansion through a turbine of a conventional installation is absorbed by the compressor. At present, a basic argument for air storage hinges upon using the utility's off-peak period electricity (supplied by baseload generation plant) to perform the air compression function. If this is done, the gas turbine fuel can then be expended solely for the purpose of developing turbine power to drive a generator for peak demand service.

Conceptually, the most obvious approach to compressed air storage is to physically separate the components to allow the compression (charge) portion of the cycle to occur independently from the combustion/expansion (discharge) process. (Charge/discharge and compression/expansion are used interchangeably herein.) Such an approach is shown schematically in Figure 3-6.

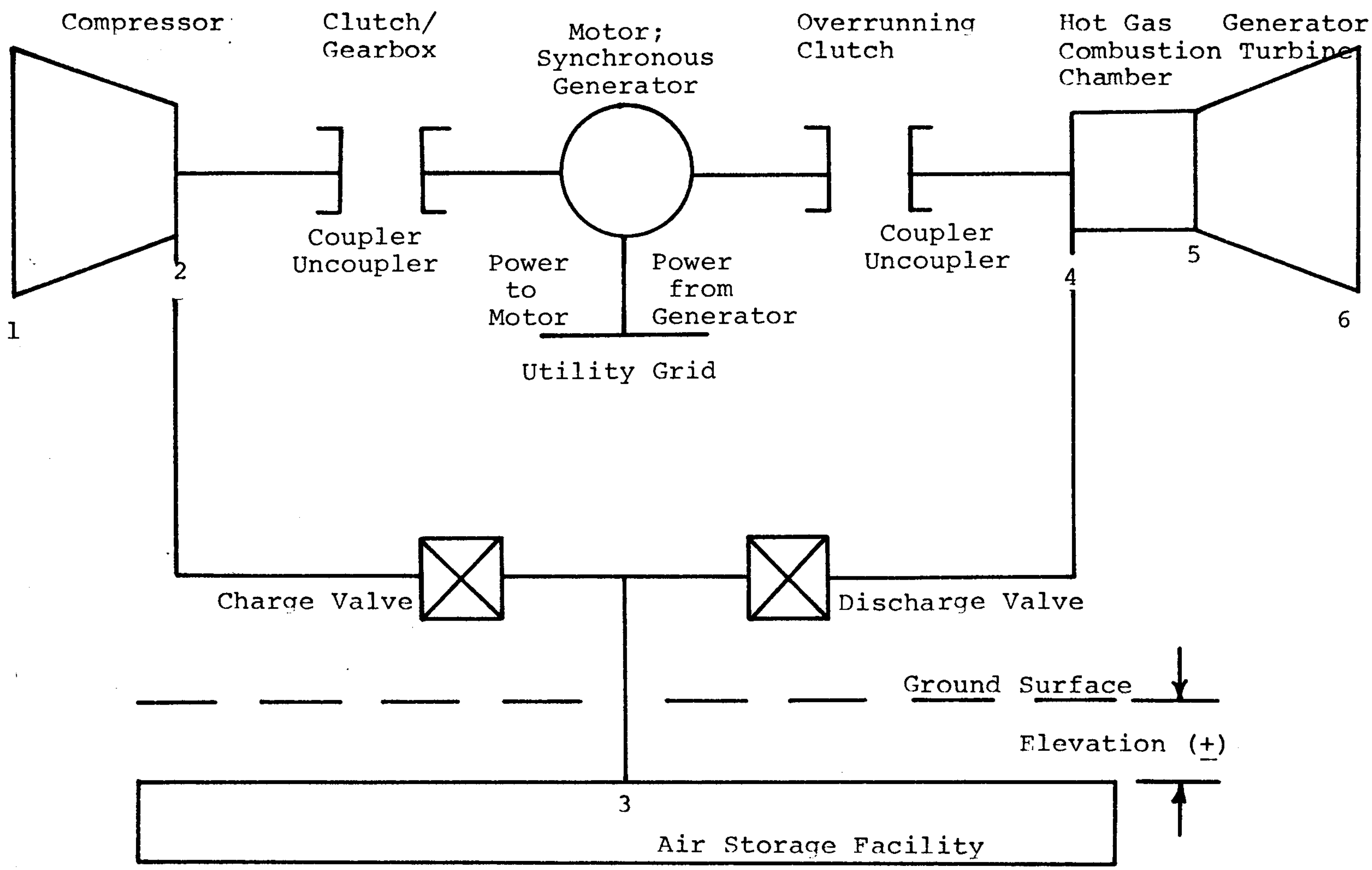


Figure 3-6 COMPRESSED AIR ENERGY STORAGE, DESIGN/OPERATING VARIABLES

3.2.1.1 Design/Operating Variables The important idea to be noted from Figure 3-6 is the split in the conventional cycle by air storage. The designer is relieved of the careful compressor/turbine matching required in the conventional machine. Further, the high through-put capability of the axial flow compressor is no longer a necessary and stringent requirement.

Because the split-cycle of the compressed air energy storage method features a blowdown discharge operation for useful power generation, the critical system design/operating variables can be readily identified. These are:

(1) Stored air temperature

(2) Air flow rate handling capability

(3) Energy addition by heating

The first variables determines how long power can be generated; the last two determine the power level available.

The temperature of the stored air is established by fundamental thermodynamics, the air storage facility, and the discharge characteristics of the compressor. Optimum energy storage dictates the storage of high pressure, high temperature air. However, the nature of low cost natural or man-made containers (rock caverns, salt caverns, or aquifers) and state-of-the-art of compressor technology limits the maximum storage temperatures.

The air flow rate handling capability and energy addition by heating are established with the detailed characteristics of the air storage facility and the inlet characteristic of the combustor. High air flow rates without contamination of the air by particles or liquids in the storage facility are possible if incorporated early into the design. They typically require multiple connections to the air storage facility. The inlet characteristics of the combustor usually requires a constant air pressure lower than the storage facility pressure. The reduction in pressure level may require the addition of heat to the air prior to combustion.

The thermodynamic cycle implied by Figure 3-6 is not practical with state-of-the-art equipment. The entropy/enthlpy relationship of process that is achievable with state-of-the-art equipment is shown in Figure 3-7. This process is similar to that in Figure 3-6 with the addition of facilities to treat the compressor and combustion air. Typical candidate facilities to accomplish this when connected to the basic split-cycle are:

(1) compressor interstage and/or aftercooling
(2) regenerative fuel vaporization

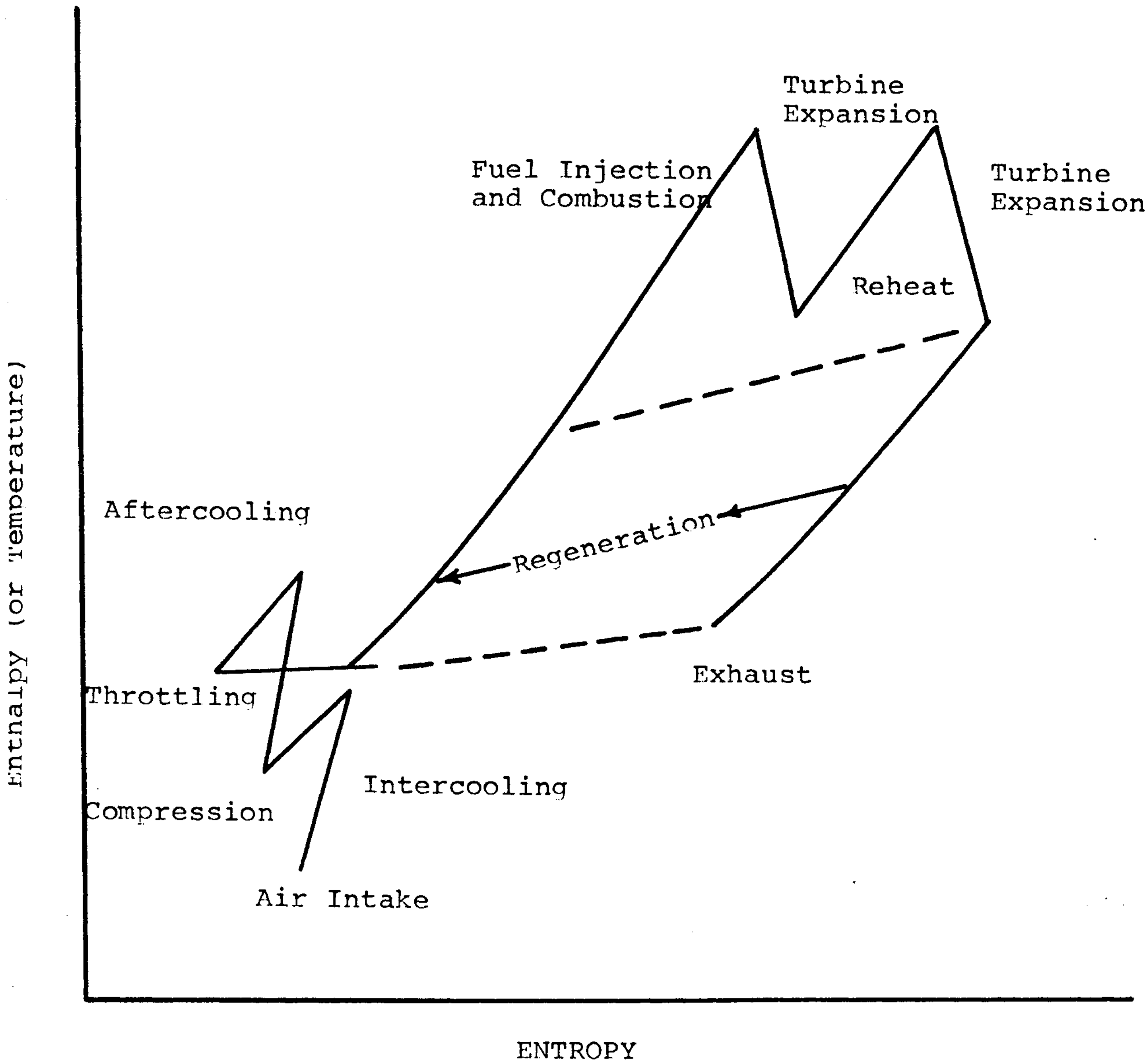


Figure 3-7 GAS TURBINE, ENTROPY/ENTHALPY RELATIONSHIP

(3) regenerative air preheating
(4) turbine interstage reheating
(5) thermal energy storage between compressor and combustor air
(6) combined cycle operation with an refired boiler

3.2.1.2 Air Compressor Subsystem Alternatives In both the industrial and aircraft-derivative gas turbines used for utility power generation, the multistage axial flow compressor has been dominant because of its high mass flow capability at moderate discharge pressure levels. However, for the split-cycle arrangement, the compressor perfcrmance requirement does not depend on a rigorous aerodynamic matching with the turbine. The air compressor subsystem alternatives are:

(1) Axial flow compressor

(2) Axial flow compressor with centrifugal boost stage

(3) Centrifugal compressor

(4) Reciprocating compressor

The first subsystem alternative is a low pressure, high mass flow approach. The other systems offer higher pressure capability, but are seriously limited in the mass flow capability.

3.2.1.3 Air Storage Facility Alternatives The air storage facility may be considered as a closed container, sited above or below ground level, with access from the compressor and to the hot gas generator. General classifications are:

(1) Fabricated pressure vessel

(2) Geological mass-integral reservoir

(3) Artificially-created reservoir

Hard rock excavation
Solution-mined cavity
Depleted oil/gas reservoir
Abandoned mines

(4) Naturally-occurring reservoir

Cave
Aquifer

The definition of an artificially-created reservoir is the intentional removal of geological material for commercial recovery and/or air storage.

During discharge, a constant volume storage facility pressure decays in proportion to the rate of mass withdrawal. This necessitates a fairly complex valving arrangement to effect simultaneous control of mass flow and pressure level at the combustor entrance. Another significant concern is that the peak-to-peak pressure levels for the full-duty cycle may be unnecessarily/undesirably high and may lead to wall material fatigue. One method of achieving constant storage facility pressure operation is by hydrostatic compensation. Figure 3-8 illustrates both a bulk water reservoir approach and natural hydrostatic compensation. Natural hydrostatic compensation results from the use of an aquifer; however, the storage pressure level is set by the inherent pressure of the aquifer. The various types of reservoirs can be multiplied by two basic options, pressure compensated or uncompensated, to yield even more approaches.

3.2.1.4 <u>Air Heating Alternatives</u> In the split-cycle concept, it is assumed that the approximately constant pressure combustion feature of the conventional gas turbine is retained. The air heating alternatives center on combustor configuration and choice of fuels. Combustor geometry of the gas turbine variety is generally one of the following:

(1) Can(s)

(2) Cannular

(3) Full annular

Fuel candidates can be grouped as follows:

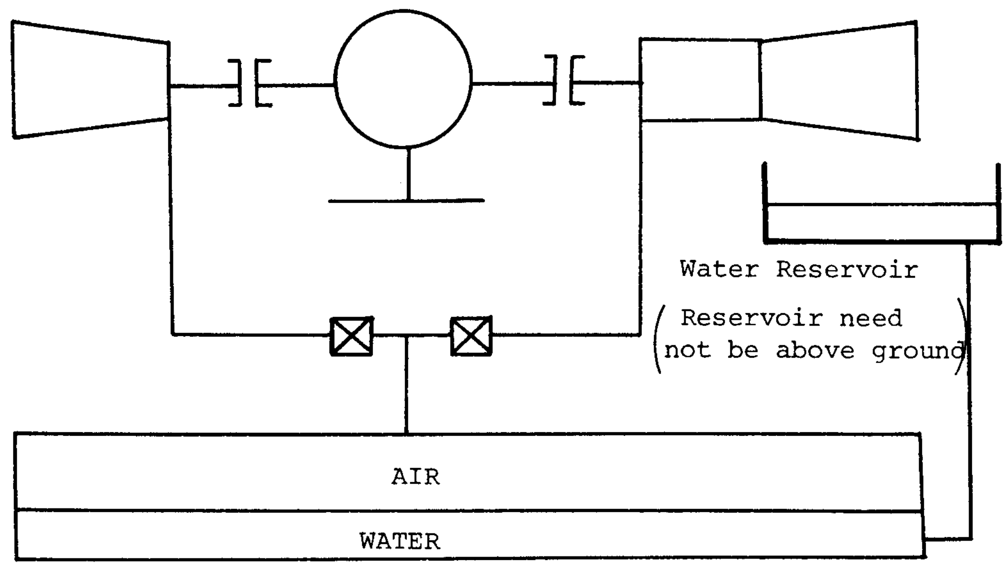
(1) Petroleum-based fuels:

Crude oil
Residual oil
Distillate oil
Kerosene and lighter fractions

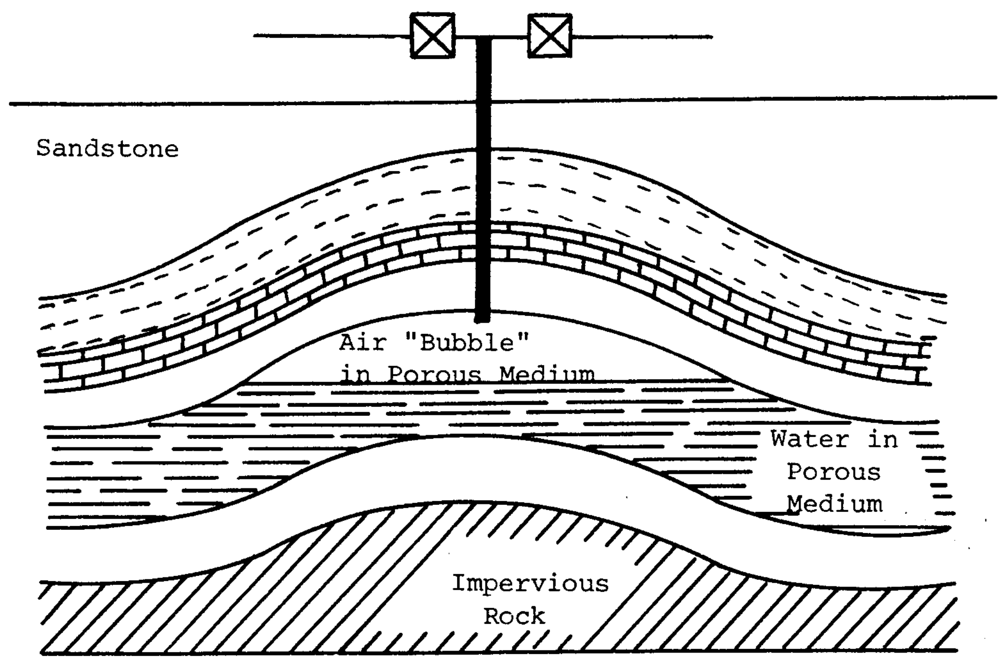
(2) Natural/synthetic gas (however processed)

(3) Hydrogen and other synthetic fuels such as methanol

(4) Other fuels (for example, fludized combustion of coal)



(A) Bulk Water Reservoir Technique



(B) Aquifer Technique

Figure 3-8 AIR STORAGE HYDROSTATIC COMPENSATION

The other major alternative is unfired operation using thermal energy storage in a pebble bed or through intermediate heat exchangers, in sensible or latent heat of various thermal energy storage materials. This approach was not considered in detail.

3.2.2 Characteristics of Storage Facilities

3.2.2.1 Potential Facility Sites Aboveground siting for a fabricated pressure vessel storage facility is straightforward because the required civil engineering technology is well known. The potential facility sites of interest are underground. These are divided into (1) mineral deposits/mines, (2) oil and gas fields/wells, (3) aquifers/wells, and (4) facilities already in use for storage purposes.

Mineral Deposits/Mines A major category of potential underground sites for compressed air energy storage is associated with mineral deposits and their exploited locations Although a cross-sectional stratigraphic map is useful for its geological details, another needed map is a contour plot of thickness of a mineral deposit.

Oil and Gas Fields/Wells A second major category of potential air storage facility sites includes oil and gas fields and their exploited locations. Their utility for this purpose arises after commercial depletion of the original material inventory.

Aquifers The third major category of geological formations having potential as air storage facilities is the water-bearing deposit or aquifer. Of prime interest are consolidated or bound aquifers.

Existing Facilities The fourth major category, the salt cavity, is the most advanced of the of underground storage categories. Salt cavities have been used for natural gas and liquid hydrocarbons and have been found to be quite satisfactory for this use.

3.2.2.2 Charging/Holding/Discharging Characteristics From the standpoint of fluid mechanics, the key aspects of an air storage facility are its charging/holding/discharging characteristics. Charging/discharging problems are concerned with the differences between free volume and porous media storage. Holding problems center on air leakage and heat losses. Methods for calculating charging and discharging times of free volume reservoirs are given in the literature for a variety of boundary conditions and assumptions. For porous media corresponding to oil/gas reservoirs and aquifers, the problems have no simple closed-form solutions and require numerical integration.

The main consequence of air leakage is a degradation in overall system performance since energy is required for air compression, but no useful turbine work is extracted from the lost air. This dual loss in efficiency is directly proportional to the air mass lost.

System chargeable heat loss (or gains) from the compressed air to the storage cavity walls during charging and holding depends upon the surface area of the cavity and the thermal conductivity of the wall material. Such losses or gains should be included in evaluating specific systems since the losses associated with a 58°F salt cavern, for example, or the gains associated with a 400°F salt dome cavity would be very significant.

As to maximum storage pressure, optimum storage pressure should at least be equal to that defined by the geostatic gradient which is about 1 psi/ft of subsurface depth. It is pointed out that less than 1.0 percent of the natural gas storage pools operate at pressures equivalent to 0.65 psi/ft or greater. Hydrofracturing data indicate fracture pressures equivalent to at least 1.0 psi/ft. For competent granite, a maximum pressure of up to three times the geostatic gradient could be used.

3.2.2.3 Potential Operating Problems Regarding the charging/discharging behavior of the two basic types of storage media, e.g., free space versus porous media storage, it should be noted that a high discharge rate requirement might not be compatible with a water-drive mechanism (e.g., aquifer) and thus pose an operational problem. Other potential problems related to the air storage facility are: (1) response of storage facility to pressure/temperature cycling, (2) fuel explosion hazards, (3) corrosion, and (4) ground control.

The response of a storage facility to pressure/temperature cycling depends upon the nature of the storage space, for example, open space versus open pore space storage. For storage cavities in solid rock, thermal diffusivity is the principal determinant of the rate of heat transferred from the stored air. Attention is called to possible deterioration of facility integrity caused by pressure/temperature cycling. With a hard rock cavity, the in-situ fracture strength of the rock formation is subject to local spalling (a form of brittle fracture) during the discharge portion of the cycle (i.e., decreasing air pressure and temperature, which vectors the thermomechanical stress gradient toward the cavity-free surface).

Specific rock properties must be considered. Elastic moduli of igneous rocks decrease with increasing temperature up to some temperature level and then become insensitive to further heating. Thermal spalling of high quartz content rock depends on thermal expansion and shear-strain behavior. The strength of a typical reservoir sandstone is reduced by increasing pore pressure or by decreasing the extent of pore compression filling the voids with fluid. Rapid temperature cycling of saturated sandstone should be avoided.

In salt cavities, thermomechanical cycling aggravates an already complex behavior under steady-state loading. Rock salt exhibits hysteresis under cyclic load, creeps inelastically, and undergoes strain hardening. Under steady load, creep is manifested by the phenomenon of convergence (cavity closure), that is, the closing of a gap between two opposite walls of a cavity. For room and pillar salt mines, this convergence has been observed to depend upon: (1) time, (2) subsurface depth of the mine, (3) extraction ratio (which is the open to pillar volume ratio), (4) size of mine, (5) height of pillars, (6) geological structure of salt, and (7) temperature humidity. The convergence has two components: (1) vertical pillar deformation caused by overburden gradient, and (2) local sag/heave of immediately adjacent strata; the dominating component is determined by the pillar spacing and the nature of the adjacent strata.

Data indicates that temperatures above 300°F produce significant increments of cavity closure at a given pressure level. The pressure difference between overburden and minimum cavity pressure should not exceed 3,000 psi. Note that if the overburden pressure gradient is assumed to be 1 psi/ft, this criterion for an unpressurized (naturally aspirated) cavity would limit the subsurface depths to 3,000 feet.

In general, a salt cavity will completely close as a result of plastic flow. Pressure and temperature combinations determine the time required to attain closure.

3.2.2.4 <u>Corrosion</u> Two kinds of corrosion problems must be considered in connection with the operation of an underground air storage facility. One arises from the inground structures such as pressure vessel or piping. The second stems from contamination of the stored air by the facility itself which appears as a corrosion problem associated with a hot gas generator turbine operation. Hot corrosion of turbine parts can occur from salt contamination of the air supply from the storage facility along with the presence of sulfur or vanadium in the fuel. The formation and condensation of sodium or vanadium sulfates on hot turbine parts can lead to catastrophic corrosion. Effective countermeasures consist of: (1) avoiding condensation of sodium or vandadium sulfates, and/or (2) providing a fuel washing facility. If the installation involves a completed well, it is likely that the casing will have been cemented. Cementing, as a galvanic corrosion control measure, is only as good as its impermeability. Additional protection can be afforded by a sacrificial metallic coating or an inorganic coating such as

Teflon, which has high dielectric strength, low water absorption, and chemical inertness. Its weakness is low abrasion resistance. A more positive measure would be cathodic protection (either in galvanic or electrolytic mode) in conjunction with a coating.

3.2.2.5 Ground Control The creation of a subsurface cavity causes a redistribution of stress in the overburden that could result in ground surface movement or subsidence. This poses a hazard to surface equipment and personnel. Significant factors contributing to subsidence above mined locations are: (1) rock profile and properties; (2) location, size, and shape of underground cavity; (3) presence of geological discontinuities; (4) presence of other openings; (5) initial stress distribution; and (6) use of artificial supports.

Subsidence can also occur above depleted (porous) oil reservoirs when the overburden pressure overcomes the support provided by the residual pore pressure and crushes the porous rock. For hard rock caverns, cavity collapse (from rock bursts or fault-associated failures), for example, may produce sufficient change in stress distribution in upper formations to result in surface subsidence.

3.2.3 Technical Characterization

Technical characterization of compressed air energy storage systems are:

(1) Power/energy range of operation

(2) Charging/discharging rates

(3) System efficiencies

(4) System scaling possibilities

(5) Manufacturing and installation considerations

(6) Operational characteristics

3.2.3.1 Power/Energy Range of Operation The power rating of the hot gas generator/turbine subsystem of a compressed air storage system would be the same as a conventional gas turbine. However, because the power to operate the compressor is not extracted from the turbine, the net power output of an air storage gas generator/turbine will be three times that of a conventional gas turbine. Since the largest conventional gas turbine is rated about 100 MW, it is concluded that power levels approaching 300 MW should be possible for a single unit gas generator/turbine operating from compressed air energy storage. Similarly, a generating station with a multiple arrangement of, say, four 250 MW hot gas generators would provide a 1,000 MW output.

3.2.3.2 Charging/Discharging Rates The charging rate of an air storage system using state-of-the-art equipment is limited by the air flow and pressure limits of single shaft compressors. Multiple compressors can be paralleled and/or seried to achieve the design air flow but will increase costs by requiring additional electric machines that are only used during charging. The discharge rate of an air storage system is a design variable that is modified by the modular nature of available equipment.

3.2.3.4 System Efficiency Two separate forms of energy are used for a compressed air storage system. Off-peak electrical energy is used to drive the compressors and fuel is combusted to heat the air expanded through the turbine. There are several different ways to define efficiency. An "energy conversion" efficiency can be defined as the efficiency of conversion of the energy input to electrical output. This is simply

$$\text{Nec} = \frac{\text{Energy Out (kWh)}}{\text{Compression Energy (kWh)} + \text{Fuel Energy (kWh)}}$$

where Nec is the energy conversion efficiency usually defined over a full cycle. For comparison with the other storage technologies, it is useful to define an energy storage 'efficiency' or figure of merit which compares the efficiency of fuel utilization in a baseload plant with the efficiency of the combined system of baseload plant and compressed air storage system. In order to do this, we define an energy storage system efficiency in terms of the fuel utilization efficiency of the baseload plus the compressed air system versus the efficiency of fuel utilization in the baseload plant.

This is best calculated by taking the compressor energy input in terms of the fuel used to produce the kWh. This efficiency is then defined as:

$$\text{Ness} = \frac{\text{HRBL}}{\text{Compressor Power Req} \times \text{HRBL} + \text{HRCAGT}}$$

where HRBL is the baseload plant heat rate and HRCAGT is the heat rate of the compressed air plant gas turbine. For typical compressed system characteristics, the efficiencies are presented in Table 3-4.

3.2.3.5 Operational Characteristics The technical characteristics of compressed air conveniently classed as operational characteristics include:

(1) Amenability to remote operation.

Table 3-4 COMPRESSED AIR ENERGY STORAGE EFFICIENCY (Figure of Merit)

Compressor Energy Requirements	Fuel Impact	Energy Conversion Efficiency η_{ec}	Energy Storage System Efficiency, η_{ess}
kWh/kWh	Btu/kWh	Percent	Percent
.6[c]	4200[b]	53%[c]	93%[c]
.6[c]	5800	43%[c]	80%[c]
.7	4200[b]	52%	86%
.7	5800	41%	74%
.8	4200[b]	49%	78%
.8	5800	40%	69%

a Baseload efficiency taken as 38% (heat rate of 9000 Btu/kWh.)

b Requires recovery of exhaust gas heat.

c These values are probably unrealistic.

(2) System response.

(3) Reliability, maintainability, and service life.

Peaking stations that feature conventional gas turbines are designed for remote operation. This capability is also anticipated for compressed air energy storage systems despite the significantly increased degree of complexity in subsystem interfaces arising from the air storage facility and the separate functioning of the compressor and hot gas generator.

With the compressor uncoupled from the turbine, the response characteristics of the hot gas generator will be quite different because of the cover inertia. The fluid mechanical lag of the air storage facility plays an important role in start-up response and stability.

The reliability, maintainability, and service life of the compressed air energy storage system may differ appreciably from that of the conventional installation, principally because of the increased number of assemblies and components. Because of the lack of operating experience, the reliability of the air storage facility is a major unknown at the present.

3.2.4 Final Comments

(1) There are no known technical barriers to devising split-cycle compression and hot gas-generation equipment from present day gas turbine technology. A multifuel capability is mandatory because of foreseen shortages of various fuels.

(2) Sites for underground air storage facilities near load centers in the U.S. exist in reasonable numbers.

(3) Some tentative guidelines applicable to the use of salt cavities (constructed by hard rock or solution-mining techniques) for air storage appear in the literature. There include a maximum pressure differential of 3,000 psi and air temperature 300°F. Guidelines for other competent rock formations also appear in the literature. Thus air storage at pressures equal to overburden pressures should be feasible; higher pressures (up to a factor of 3) can be allowed (particularly for long charge/discharge times) for competent granite caverns. Allowable wall temperatures up to 600°F have been suggested. However, the limitations posed by combined pressure and temperature cycling do not yet appear to have been adequately researched or described.

(4) Consideration experience has been amassed in underground excavation for a wide variety of construction projects. Coupled with recent advances in equipment and techniques,

construction of large air storage facilities under geologically favorable conditions could become as effective as exploiting existing facilities.

(5) No serious investigation of the use of depleted oil/gas reservoirs as as air storage facilities has actually been reported. Fire/explosion hazards may deter the utilization of these resources due to residual oil or gas in the reservoir. Further, the fluid-mechanical limitations to charging/discharging of air in porous/permeable storage facilities are not yet fully understood. Similarly, the use of reservoirs previously subjected to stimulation by various fracture treatments is not evident in the literature.

(6) Modularization of pertinent compressors, storage facilities, hot gas generators, and electrical generators are all practical, and will provide desired design flexibility.

(7) Use of existing underground space and modified conventional equipment could permit rapid introduction of compressed air systems where conditions are favorable.

3.3 THERMAL ENERGY STORAGE

Thermal energy storage (TES) is defined as the storage of energy in a form which can be utilized in a heat engine for the production of electrical power. This definition excludes those systems utilizing thermal storage in conjunction with district heating schemes or for providing comfort heating and/or cooling by utilizing off-peak electrical power. Also excluded is the utilization of thermal energy in thermochemical processes for the production of fuels.

Heat can be stored in the sensible heat of materials or in latent heat associated with a phase change. Thermal energy is stored in a material which either undergoes a change in temperature or which changes phase (solid to liquid). Of fundamental significanceis the TES material (storage medium), the range of operating temperature and the mode of heat exchange between the storage subsystem and the heat source and sink. Actual operation requires provision for thermal insulation, control of heat flows and, of course, a method of conversion from thermal energy to electrical energy.

Thermal energy storage systems can be considered to consist of a thermal storage material, a vessel for containing the TES material, and a means of transporting energy to and from storage. The options available in each of these three areas can be utilized as a frame-work for analysis of thermal storage systems. Many approaches to thermal energy storage have been treated in the literature and TES has been proposed for a wide range of applications. Specific work has been done on:

a. Hot water heating

b. Heating and cooling of buildings

c. Low temperature steam storage

d. Central station thermal storage

e. Industrial process steam

Only concepts addressing application (d) above are of interest here.

3.3.1 Description and Present Status of Development

Figure 3-9 is a simplified flow diagram depicting energy flow in a central thermal power plant. As illustrated in the figure, there are three locations for energy storage within the system. At the input, energy may be stored as fuel (in the coal pile, oil tank, or fuel rod). This requires that the entire plant must

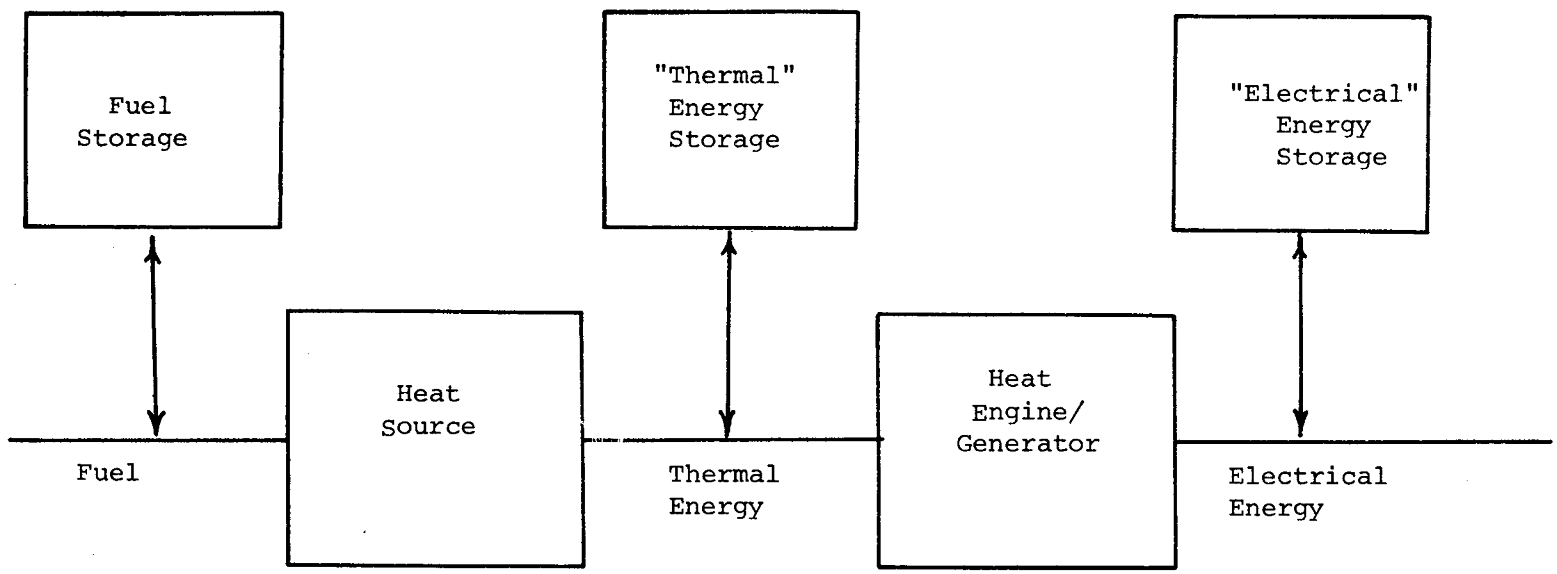


Figure 3-9 THERMAL POWER PLANT, SIMPLIFIED FLOW DIAGRAM

operate in a cyclic manner to meet varying demands. At the output, energy may be stored in an electrical form (that is, stored after it has been converted to electrical energy) by means of pumped hydro plants, batteries, or other means. With electrical energy storage, the power plant can operate at a constant load (providing energy storage capacity is sufficient) with the energy storage device acting to smooth out the fluctuations in demand. Thermal storage operates midway between fuel storage and electrical storage. In thermal storage concepts, energy is stored after conversion from the primary energy source into thermal energy. This allows the heat source (nuclear steam supply system or fossil fuel boiler) to operate at a constant load. The heat engine/generator, however, must still be designed to respond to variable loads.

Of particular interest is the coupling of a chemical energy storage system with a nuclear reactor or modern fossil unit. Here the non-storage design option is building into the unit capability for cycling operation. This is frequently difficult to do. Additionally, incremental costs of capacity may be substantially lower if peaking capacity is obtained from thermal storage, for then, the expensive steam supply costs are reduced and the incremental costs of the turbine/heat regeneration system are relatively low. For light water reactors, in particular, cycling operation is restricted by the nuclear steam supply capabilities, and here a thermal storage system could prove attractive.

3.3.1.1 Location Within Power Plant Cycle Two possible arrangements for integrating thermal storage with baseload power plants are shown in Figures 3-10 and 3-11. The separate peaking turbine (Figure 3-10) has an advantage in that it may be added to an existing plant. The throttle steam condition of the peaking turbine depends upon a trade-off between the steam rate and the cost of storage. The latter, in turn, is dependent on the storage medium and type of vessel used.

Using the stored energy to heat the feedwater, as shown in Figure 3-11 requires a modified turbine design which allows for a large variation in extraction steam flow. Throttle steam flow will be essentially constant. During peaking, feedwater heating is done by the stored thermal energy, increasing turbine through-flow and power production. The condensing plant must be sized to handle this increased flow. The storage is recharged during off-peak hours by increasing the steam extraction from the turbine.

For a nuclear power plant with turbine throttle steam saturated at 950 psia, an exhaust pressure of 2 1/2 inches Hg and feedwater temperature of 420°F, the cycle heat input may be increased by about 40 percent by using thermal storage to heat the feedwater. The non-extraction thermal efficiency will be less, so that

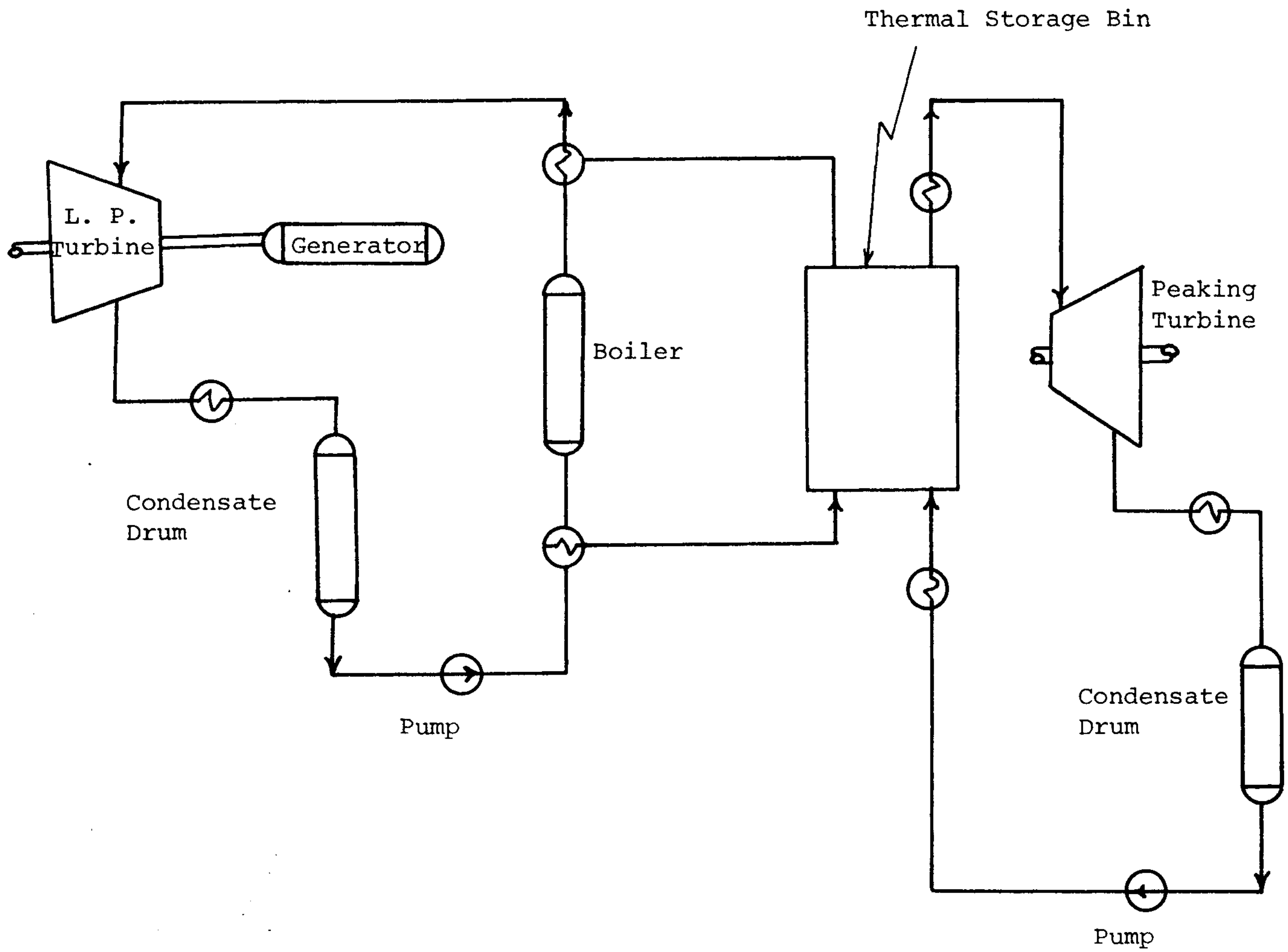


Figure 3-10 THERMAL STORAGE UNIT WITH SEPARATE PEAKING TURBINE

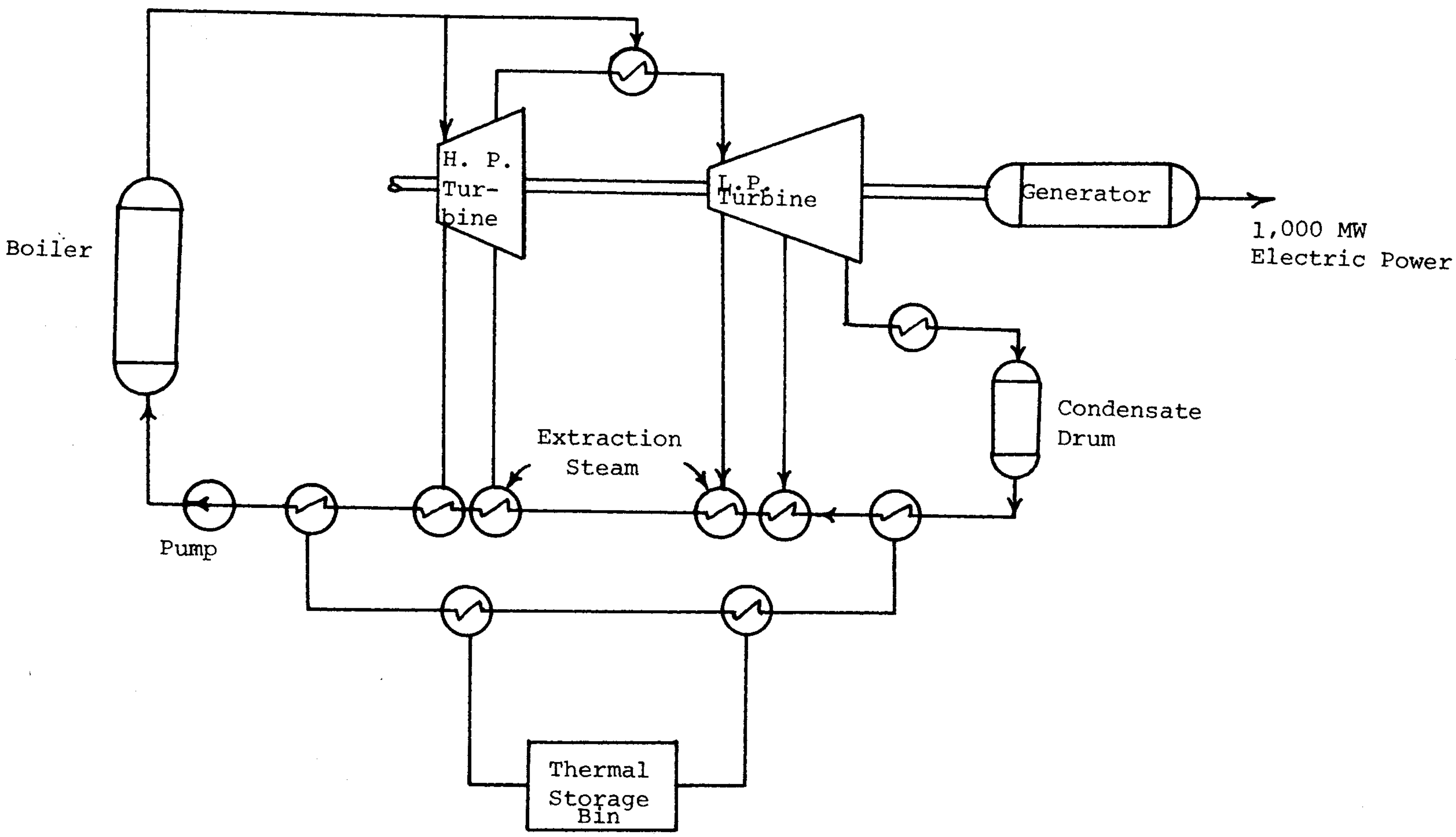


Figure 3-11 THERMAL STORAGE UNIT IN FEEDWATER STORAGE MODE

maximum peaking power will be on the order of 120 to 125 percent of the maximum non-peaking power. The incremental heat rate of the peaking power will be on the order of 160 to 180 percent of the baseload heat rate of the nuclear plant.

When designing a plant to incorporate thermal energy storage, the decision whether to employ a separate turbine or feedwater heating will depend upon a number of economic factors.

3.3.1.2 Thermal Storage Material Most thermal storage concepts can be classified as either sensible storage or phase changes storage. The difference is in the chemical structure of the material used for storing the thermal energy.

Sensible Storage Material or phase change storage. Sensible storage involves the addition, during charging, of thermal energy to a material which results in an increase in temperature of that material. The average temperature of a sensible storage material, therefore, is a measure of the degree of charge (or the energy content) of the thermal storage unit. The thermal energy contained in a sensible storage unit is given by:

$$E = MC\ (T - T_{ref})$$

where:

E = Energy content (Btu)
M = Mass of the system (lbm)
C = Specific heat of storage material (Btu/lbm°F)
T = Temperature of the system (°F)
Tref = Temperature at which the energy content is considered to be zero (°F)

Obviously, materials for utilization as sensible storage materials should have a high specific heat, and high density, and be stable over a wide temperature range. In addition, the sensible storage material must be inexpensive, readily available in large quantities, non-hazardous, stable for long periods of time, and environmentally acceptable.

The primary candidate for sensible storage material is water. Water is essentially free, abundant, nontoxic, and possesses good heat transfer properties. In addition, a vast body of engineering data and experience is available on its use. Unfortunately, water has a relatively high vapor pressure at temperatures of interest and pressure vessels for containment of hot water at these temperatures and pressures are generally expensive.

Other candidates for sensible heat storage materials in the temperature range of interest to utilities include liquid metals, molten salts, organics such as various oils, or rocks. Although the heat capacity for all of these materials is less than water, they have low vapor pressures offering potential savings in containment vessel costs.

Phase Change Material Phase change materials store energy as the latent heat of fusion between solid and liquid phases. The phase change process normally occurs at a constant temperature--an important advantage of this mode of energy storage. The energy content in a phase change energy store can be expressed as:

$$E = M [Cs (Tf - Tref) + Hf + Ce (T - Tf)]$$

where E, M, T, and Tref are as before, and:

Cs = Specific heat of solid phase (Btu/lbm°F)
Ce = Specific heat of liquid phase (Btu/lbm°F)
Hf = Latent heat of fusion of material (Btu/lb)
Tf = Melting temperature of material (°F)

The amount of mechanical energy which can be recovered from the heat store is limited by the Carnot efficiency. Some materials which may appear attractive will not yield high energy densities in actual application.

Desirable properties for heat of fusion materials include a high latent heat of fusion, high specific heat, and high density. The melting temperature must be compatible with power plant designs; thereby limiting materials for consideration to those with melting points between 500 and 1,100°F.

Many materials have been identified for use on thermal storage systems [26, 27]. A partial list of materials which may be suitable for phase change thermal storage is given in Table 3-5. These materials have melting points within the range of interest. Energy storage densities for phase change storage is generally higher than for sensible storage, but phase change materials generally possess a relatively low thermal conductivity. This complicates the problem of heat transfer and results in rather complicated (and, therefore, expensive) heat exchanger designs.

Phase change materials, like sensible storage materials, should be inexpensive, readily available, nonhazardous, stable for many cycles of charge/discharge, and environmentally acceptable.

Storage Vessel Material The purpose of the storage vessel in TES systems is to contain the storage material. The vessel can also act both as a means for insulating the storage system to reduce heat losses, and as a portion of the heat addition/removal

Table 3-5 THERMAL STORAGE MATERIALS

Formula	Melting Point (°C)	Latent Heat (cal/gm)
37 LiCl - 63 LiOH	262	104
40.3 CaCl - 59.7 $LiNO_3$	268	45.4
8.4 NaCl - 86.3 $NaNO_3$ - 5.3 Na_2SO_4	287	40.2
6.5 NaCl - 93.5 $NaNO_3$	297	41.4
7 RF - 2.5 NaF - 90.5 KNO_3	298	35.5
7.9 RBr - 16.7 NaBr - 75.4 PBr_2	309	15.8
6 KCl - 94 KNO_3	320	35.8
45.4 KBr - 31.9 LiCl - 22.7 $PbBr_2$	323	26.4
39.2 KCl - 33.6 LiCl - 27.1 $PbCl_2$	325	34.4
5.4 $BaCl_2$ - 40.9 RCl - 53.7 LiCl	337	58.5
21.3 KBr - 37.7 KCl - 34.8 LiBr - 6.1 LiCl	357	43.9
12 NaF - 40 KF - 44 LiF - 4 Mgf_2	449	162
11.5 NaF - 42 KF - 46.5 KiF	454	105
55 RbF - 45 LiF	470	63.3
37 LiF - 53 CsF	475	44.4
49 KF - 51 LiF	492	110
50 LiF - 50 KF	500	100
Ca $(NO_3)_2$	561	31.1
52 LiF - 35 NaF - 13 CaF	615	152
46 LiF - 44 NaF - 10 MgF_2	632	205
67 NaF - 33 ZnF	635	143
60 LiF - 40 NaF	652	130
60 NaCl - 50 KCl	658	99
70 NaF - 30 FeF_2	680	164
Li H	688	617
40 NaF - 60 KF	710	139
65 NaF - 23 CaF_2 - 12 MgF_2	745	137
67 LiF - 33 MgF_2	746	226

system. Since for most thermal storage systems, the cost of the storage vessel represents a substantial portion of the total storage system cost, it is important that this cost be minimized.

The primary candidate material for the storage vessel is steel. Where it is necessary for the vessel to withstand high pressure (as with water systems), vessel costs can be excessive. Alternate vessel design could reduce this cost by utilizing natural caverns (underground storage) or by utilizing alternate vessel materials (concrete or cast iron).

3.3.1.3 <u>Alternate Heat Exchanger/Storage Concepts</u> Heat must be efficiently transferred to and from storage in order to minimize temperature differences between storage and removal (which results in a loss of available energy). There are two general types of heat exchanger designs by which this heat transfer may take place--direct contact heat exchangers and indirect heat exchangers.

Direct contact heat exchangers allow the working fluid to come in intimate contact with the storage material. This can be accomplished when the working fluid and the storage material are the same fluid (as with water storage in a steam cycle) or where the working fluid and storage material are in different phases and can be kept separated (as in a rock bed storage system with high temperature gas as the working fluid). Direct contact heat exchangers are extremely efficient.

Indirect heat exchangers utilize a metal wall to separate the working fluid from the thermal storage material. The metal wall acts as a thermal impedance reducing the efficiency of heat transfer. Indirect heat exchangers can be either the conventional shell and tube type exchanger, or a fixed-bed type exchanger where the storage material remains essentially at rest with respect to tubes running through the material.

3.3.1.4 <u>Alternative Thermal Storage Concepts</u> Several concepts for the utilization of thermal energy storage for electric utilities are:

(1) Steam storage in steel vessels
(2) Feedwater storage to underground caverns
(3) Molten salt thermal-energy storage
(4) Liquid metal thermal-energy storage
(5) Thermal wells
(6) Thermal storage in fuel oil

Thermal energy storage densities for these systems are summarized in Table 3-6.

Table 3-6 THERMAL ENERGY STORAGE DENSITIES

Concept	Thermal Energy Storage Density (Btu/ft^3)	Temperature Swing (°F)
Steam Storage	10,600	420-250
Feedwater Storage	15,850	422-168
Liquid Sodium	11,690	1,000-300
Fused Salt	26,030	950-750
Fuel Oils	10,700	530-250
Metal Hydride	1,820	200
Thermal Well	2,450	340-180

Steam (Saturated Water) Thermal Energy Storage Storage of thermal energy in water-filled steel tanks utilizes off-peak steam (both at turbine inlet and extraction) to raise the temperature and pressure of the water contained in the tanks. A line diagram outlining the concept is shown in Figure 3-12. When peaking power is required, tank pressure is reduced, causing part of the water to flash to steam. The steam is then passed through a peaking turbine to generate peaking power [28-31].

The concept utilizes the sensible heat of water as the storage medium, hence "steam storage" is actually a misnomer. Steam is used to charge the accumulators and steam is withdrawn during discharge, but the difference between the charged and uncharged state is characterized by the increased temperature of the water contained in the vessels. The implementation depicted in Figure 3-12 utilizes Ruth's type of accumulators as the storage tank. Ruth accumulators are partially filled insulated steel tanks containing submerged nozzles for injection of steam. Steam entering through the nozzles gives up its latent heat to the water. The temperature and pressure of the water increases and the level of water rises somewhat, but at full charge a steam space still exists above the water surface. Opening a valve in a line leading from the steam space causes steam to flow out, reducing the vessel pressure, and allowing some water to flash to steam and lowering the temperature of the water.

Initial charging of a "cold" accumulator with high temperature steam results in throttling losses. To minimize these losses, charging at three pressure levels is used. Low pressure bleed steam is used for initial charging; higher pressure steam is utilized for topping off the energy store.

Thermal Storage in Oil Oil has certain advantages as a sensible heat storage medium. The heating and storage of the oil involves proven technology, the low vapor pressure makes for moderate storage costs, and the value of the oil is not reduced by its use as an energy storage medium. These advantages compensate for the specific heat which is about half that for water and the need for heat exchangers.

Heat from thermal storage in oil (thermal storage bin) may be integrated into the power plant in a manner shown in either Figure 3-10 or 3-11. The separate Rankine cycle plant inferred in Figure 3-10 is simple and can be sized to store all the thermal energy that is not needed during off-peak hours. When used in conjunction with a sensible heat storage medium, it has the significant disadvantage of a restricted temperature swing.

The system shown in Figure 3-11 is based on varying the amount of extraction steam drawn from the turbine to modify the electrical output of the plant. The available excess heat is stored in oil

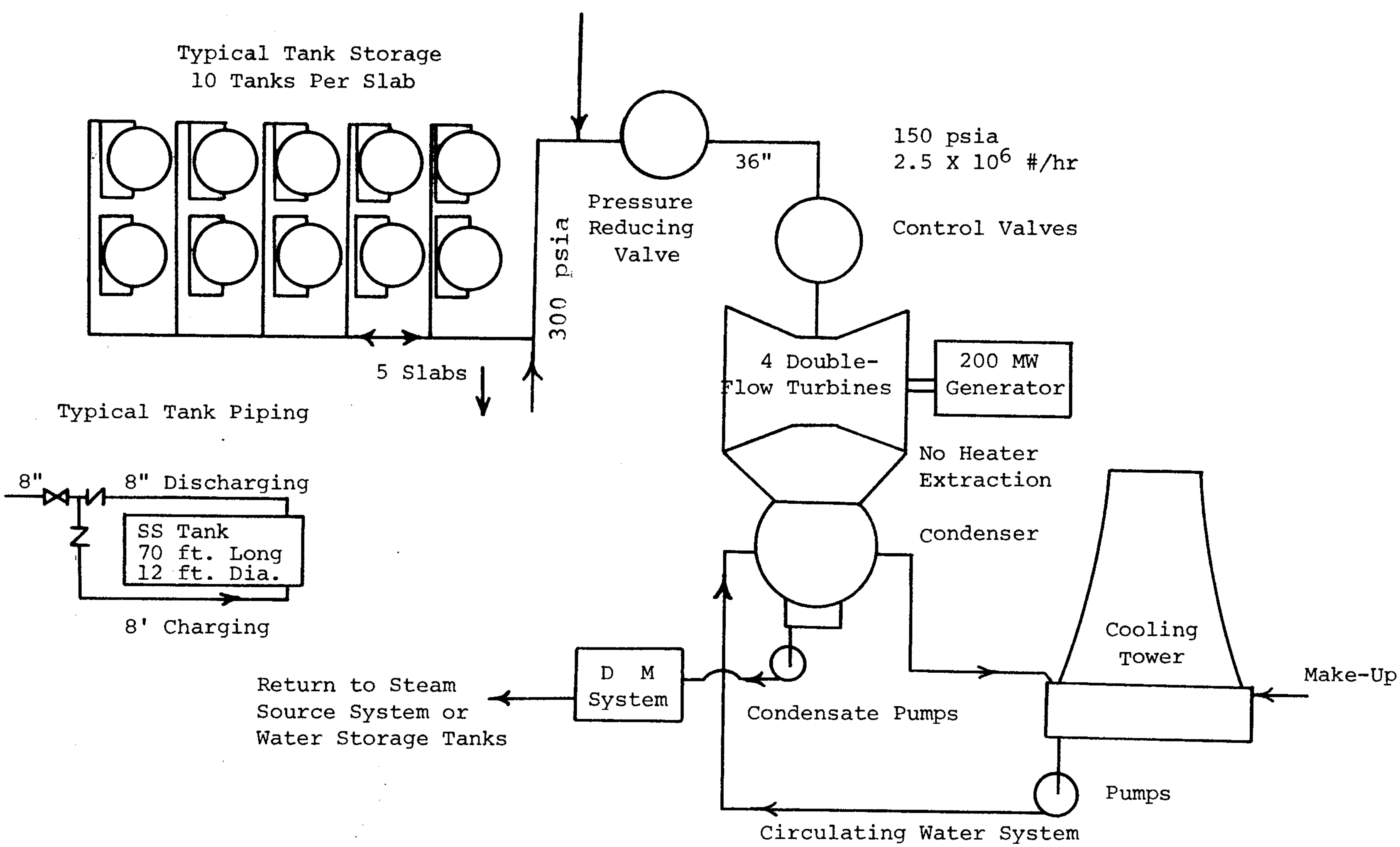


Figure 3-12 SATURATED WATER STORAGE

and recalled during periods of peak demand to heat the feedwater and thus increase turbine through-flow and power production. Between one-quarter and one-third of the normal unit output may be shifted in this manner from off-peak to on-peak periods.

The theoretical upper bound for the temperature swing in the feedwater storage mode shown in Figure 3-11 is the difference between the condensate and final feedwater temperatures. Depending on the cycle and terminal temperature differences selected, temperature swings on the order of 300°F are feasible. Although there is little or no extraction flow during peaking operation, this storage method retains the high thermodynamic efficiency of the regenerative cycle since the feedwater is heated by steam extracted previously.

The design for a hot oil energy storage system attached to a nominal 1,000 MW nuclear plant has recently been completed [32]. The indication is that this represents a near term solution with certain economic advantages over other storage systems.

The thermal storage and turbine design for the oil system is basically an extension of existing technology. The system poses leakage problems which may be overcome with proper design and fabrication.

As in the case with most storage schemes, a variety of arrangements are possible. A hybrid combination of feedwater storage at a temperature less than 212°F with hot oil used to heat this stored water up to the final feed temperature might reduce the capital investment in heat exchangers. There is an upper limit to the amount of peaking power that can be realized by cutting off all extraction. If more thermal energy is stored than can be utilized by this mode of operation, some steam may be generated from the hot oil and used to produce power either in the main turbine or a separate peaking turbine. Also in cycles which incorporate reheat, thermal energy from the hot oil may be used for this purpose.

Molten Salt Latent Heat Storage Latent heat storage in a salt material which undergoes phase change in the proper temperature range could result in lower storage volume requirements (Table 3-6).

Little experience is available on the performance of molten salts as a thermal energy storage medium although, some experimental information is available from space applications and solar energy research. Excess thermal energy available during off-peak hours is used to charge the storage bin. As the temperature of the bin approaches the melting point of the material, a change of phase occurs and the latent heat of fusion of the material is absorbed in a nearly constant-temperature process. When energy is extracted from the bin, the material freezes, giving up its latent heat.

The concept can be integrated into the power plant design by any of the methods previously discussed. The advantages of phase-change materials are their higher energy densities and the fact that heat withdrawal is at nearly constant temperature, which simplifies the control scheme for charging and discharging. The major problem is the approach toward the heat transfer into and out of the storage bin. Several basic heat transfer approaches are possible. Direct contact heat transfer can be accomplished with the use of two immersible materials [33], with a fixed bed heat exchanger [34], or with a storage system where the phase change material is contained in individual canisters and the heat transfer fluid is circulated around it (in view of fixed lead approach).

Feedwater Storage Feedwater storage in underground caverns is another process in which extraction steam is utilized during off-peak hours to heat water which is also stored in underground caverns [35]. During peak hours, the extraction steam flow is stopped, thereby providing increased power at the turbine shaft (approximately 25 percent). Also at this peak time, heated feedwater is discharged from the underground storage tank.

One scheme locates a thin-walled steel storage tank in an underground cavern. The cavern, which is man-made, is pressurized to the same pressure as the water within the tank. The steel vessel can then be designed to withstand only the pressure generated by the head of water within the tank, saving a considerable amount of steel and presumably resulting in a significant savings in cost over aboveground storage schemes.

The feedwater storage concept is similar to the steam storage concept in that both schemes utilize the sensible heat of water for the storage of thermal energy. Although the thermal energy storage density of the feedwater storage system is somewhat greater due to the greater temperature swings allowed, the average conversion efficiency is less as a result of the lower temperatures. These effects tend to cancel out, and the electrical energy storage densities are not very different. The advantage of underground storage is that storage vessel costs might be reduced. While it is true that the amount of steel required for the vessel will be considerably less than for an aboveground installation, there are added costs for field fabrication (in this case, underground) and cavern preparation. For nuclear baseload plants, additional costs for assuring containment of possibly radioactive water must also be considered.

Liquid Metal Thermal Energy Storage The use of liquid metals as a sensible heat storage medium is another process similar to storage of thermal energy in hot water, but since liquid metals have a lower vapor pressure than water, operation at a high temperature can be realized. This allows an increase in the efficiency of conversion from stored thermal energy to electrical energy. However, the thermal energy storage density of liquid sodium is less than for water due to its lower specific heat and lower density.

Liquid sodium appears to be a promising liquid metal for electric utility energy storage, and sodium-potassium mixtures are also candidates. The technology for utilizing these materials has been developed for utilization in Liquid Metal Fast Breeder Reactors (LMFBR), as well as other liquid metal-cooled reactors. Significant safety hazards are present due to the high reactivity of sodium and the sodium-potassium solutions with water. To safeguard against these hazards will add substantially to the cost of a liquid metal storage system. Because of these increased costs, it is unlikely that liquid metal storage will find application in conjunction with fossil-fired or light-water reactors. However, the application of liquid metal storage to LMFBR or gas reactors is quite possible.

Thermal Wells Utilization of thermal wells as energy storage devices involves the injection of pressurized hot water into an aquifer. The injected water will be less dense than the native groundwater due to its higher temperature, and will displace the colder water. The hot water - hot porous rock combination then acts as a thermal storage medium which can be discharged by reversing the flow of water from the charging well. Since the heat losses in a thermal storage bin increase in direct proportion to its area, while the storage capacity increases in proportion to the volume, thermal storage wells offer potential for low heat losses due to the high volume to area ratio. Approximately 75 percent of the stored heat can be recovered from a thermal well after 90 days of storage.

The utilization of the heat withdrawn from thermal wells for the generation of electricity does not yet exist as a functioning system. The requirement for high pressure aquifers which can satisfy the higher temperature steam requirements of peaking turbines limits the number of sites available for thermal well installations.

3.3.2 Technical Assessment

Steam storage, thermal storage in oil, and fused salt concepts, bracket the thermal storage field and are treated here in detail. This will provide meaningful quantitative characteristics for comparison with other nonthermal energy storage schemes. Cost estimates are developed for these systems in Chapter 4.

3.3.2.1 Steam (Saturated Water) Thermal Energy Storage Overview
The amount of steam which can be stored per unit volume is a function of the initial storage pressure, Pi, and the final pressure, Pf. Figure 3-13 shows the storage, S, in lb/ft^3 as a function of the initial pressure for a final pressure of 30 psia. In the calculations for this curve, no allowance was made for any initial steam space in the storage vessel or heat loss during discharge. The curve, therefore, represents the theoretical upper limit.

The theoretical steam rate of a non-extraction turbine with a given exhaust pressure, Pe, will vary with the throttle pressure, Pt, and throttle temperature, tt. Figure 3-14 shows the average theoretical steam rate, Rt, in lbm/kWh as a function of psi for a sliding-pressure turbine exhausting at 2.5 inches Hg Abs. The final pressure is 30 psia, as before.

The theoretical energy storage density, ED, may be calculated from:

$$ED = S/RT \quad \frac{lbs/ft^3}{lbs/kWh}$$

The theoretical energy storage density varies from 0.3 kWh/ft^3 at Pi = 100 psia to 1.5 kWh/ft^3 at Pi = 1,000 psia. This range of values is high enough to justify a design study of this method of energy storage.

The steam storage concept represents an energy storage scheme which can be developed utilizing present day technology. The system is not without problems, however. The primary disadvantage of this concept is the high cost of the storage vessel. The possibility of reducing this cost via alternate vessel materials and/or designs, therefore, merits further study. Several possibilities have been identified, including storage in pressurized underground caverns (as in the feedwater storage concept) and prestressed concrete vessels.
The extent to which these concepts will reduce storage vessel costs is yet to be determined.

Design Assumptions For the purpose of this study, it was assumed that a separate peaking turbine and separate condensing plant with wet cooling towers would be used. A peaking plant of this design may be added to an existing nuclear or "must run" fossil fuel plant, providing space is available. Direct cost comparison may thus be made with combustion gas turbines and other peaking plants.

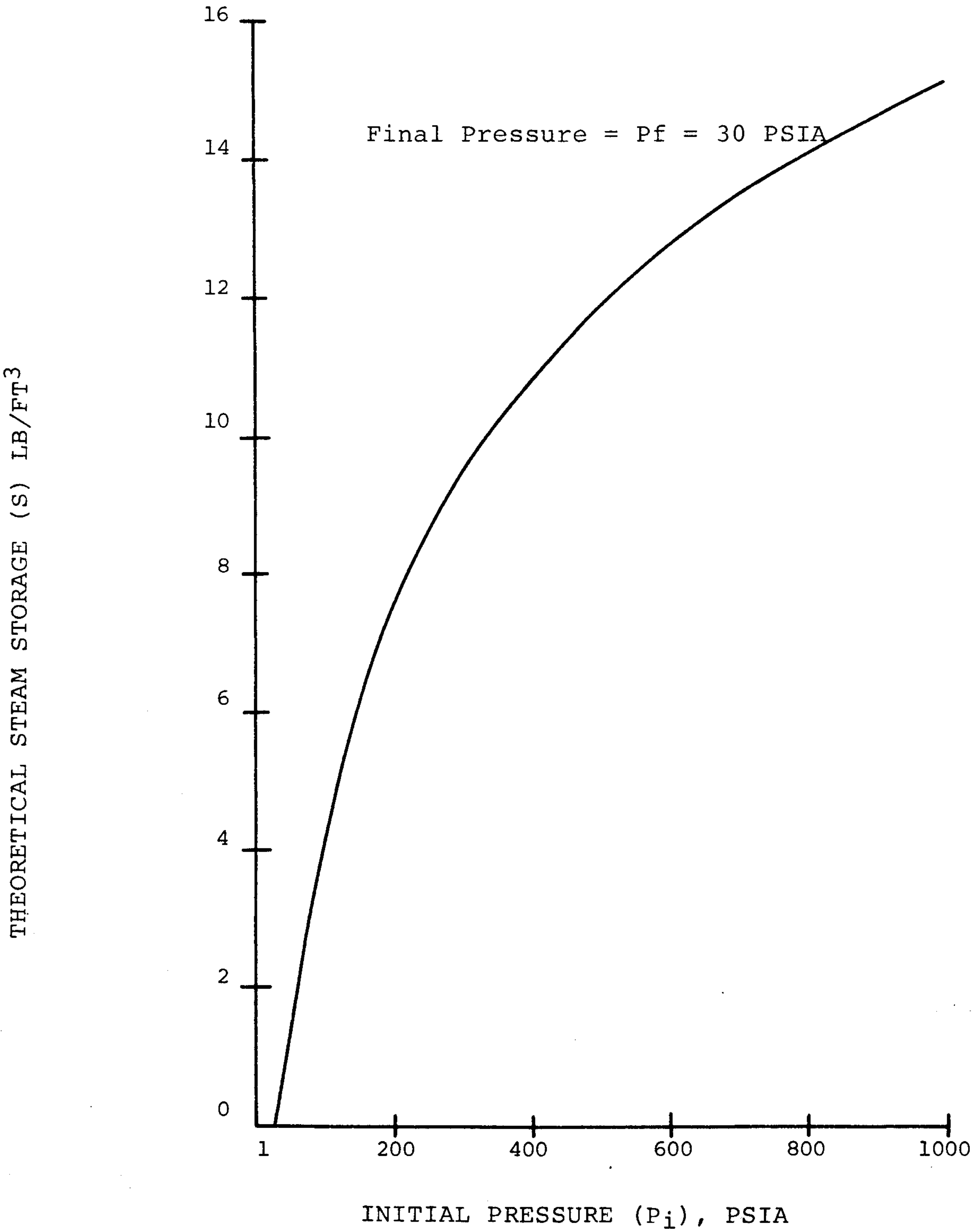


Figure 3-13 SATURATED WATER THERMAL STORAGE: STORAGE AS A FUNCTION OF PRESSURE

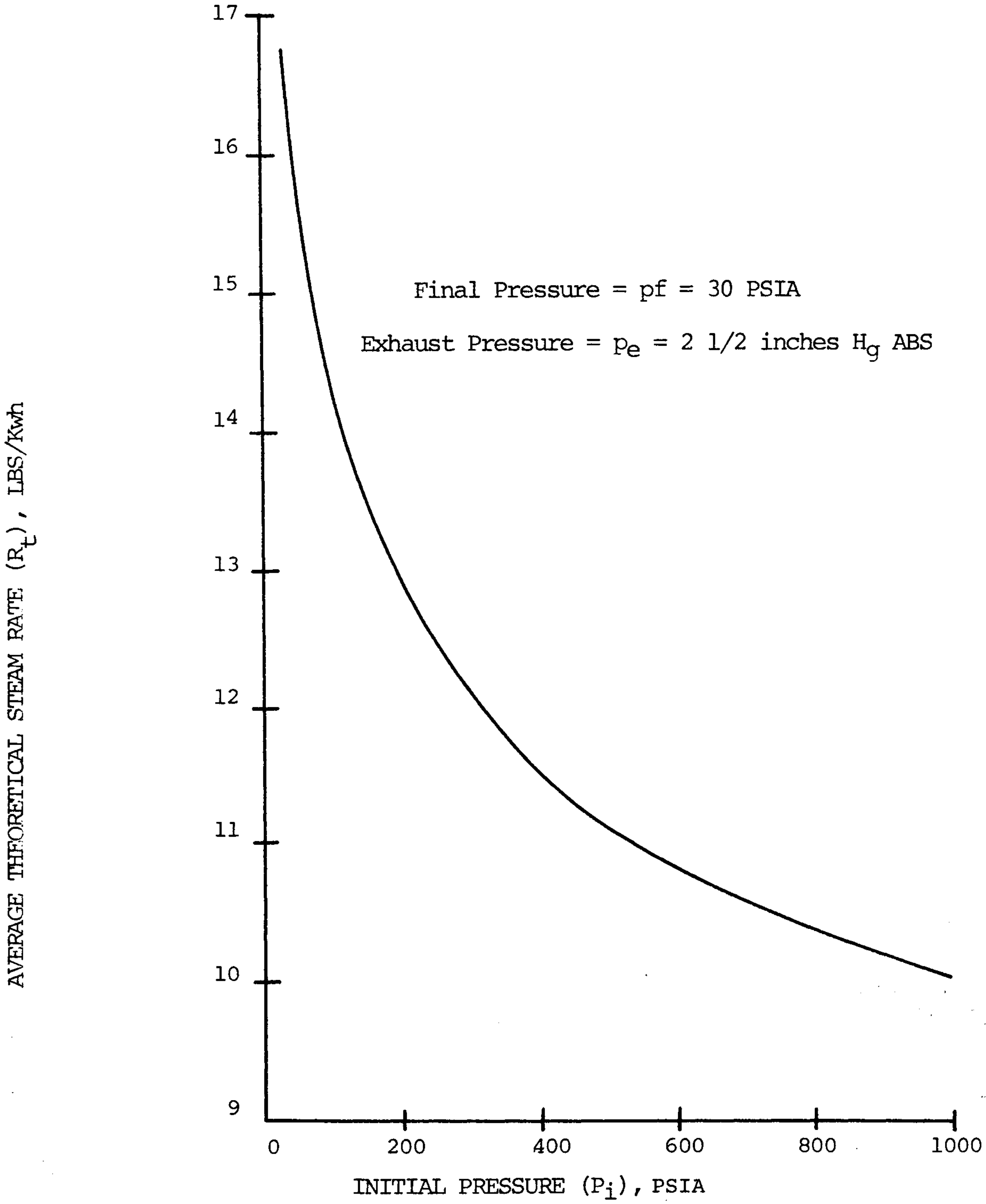


Figure 3-14 SATURATED WATER THERMAL STORAGE:
STEAM RATE AS A FUNCTION OF PRESSURE

A reduction in capital costs charged to the peaking installation could be realized when nuclear plants are initially designed to incorporate saturated water thermal storage. A suitable design of the low pressure turbines and condensing plant could accommodate the peaking steam during blowdown of the storage vessels. This would have the additional advantage if requiring no warm-up period for the turbine.

The ratio of energy stored to the cost of storage is proportional to the dimensionless energy storage number N=EpV. In terms of the energy density and initial pressure, the Gilli Number is:

$$N = \frac{18,439}{Pi} \; ED$$

For Pf = 30 psia and Pe = 2.5 inches Hg Abs, the maximum value of N is about 60 and occurs at an initial pressure between 75 and 200 psia. This is an overly simplistic optimization that ignores the capital cost of the peaking plant and storage costs such as insulation, which are not proportional to the storage pressure.

In this study, the initial pressure was chosen as 30 psia (the same as that proposed by Gilli). To avoid a continuous decay in power output, the design turbine inlet pressure was selected as 150 psia at 358°F. Throttling from the storage pressure to 150 psia occurs during the discharge of about 40 percent of the stored steam. This increases the average theoretical steam rate by about 5 percent, which was considered to be an acceptable trade-off, and eliminates the need for superheaters. This effects a considerable simplification in the system. Turbine design capacity was chosen as 200 MW and turbine design efficiency was taken as 87 percent at 150 psia, with the average over the entire discharge cycle being 85 percent.

To realize the cost advantage of shop fabrication of the storage vessels, dimensions assumed were a diameter of 12 feet and a length (or height) of 70 feet, which make the tank transportable. Accounting for initial steam space and heat loss, the steam storage capacity was taken as 90 percent of the theoretical value shown in Figure 3-13.

System Operation, Brief Description Figure 3-12 shows a diagram of a tenable system. Steam from the charging source is injected at the bottom of the storage tanks. When the water in all the tanks reaches the saturation temperature corresponding to 300 psia (417°F), steam flow ceases and the charging valves are closed.

Prior to the production of peaking power, the turbine must be warmed up. This takes about half an hour, and can be done using steam from the charging source. When peaking power is needed, all storage tank valves are opened and the turbine is loaded. Capacity will hold approximately constant until about 40 percent of the stored steam is used, and then begins to fall. The design final pressure of 30 psia need not be reached if the demand for peaking power does not require it.

The condensing plant is of standard design, utilizing a shell-and-tube condenser supplied with cooling water from a wet cooling tower. Dry cooling towers could be used with a corresponding increase in the average steam rate.

After passing through a demineralizer, the condensate must be stored until the charging cycle begins. It is then used for make-up to the main power plant to compensate for the steam condensed in the storage vessels.

Utility Interface The enthalpy of the charging steam should be on the order of 1,200 Btu/lbm--the average enthalpy of the steam discharged, in order to maintain the mass balance. The steam supplied from light water reactors (LWR) has about this enthalpy. The actual steam rate of LWR nuclear power plants is about 12 lbm/kWh. When the turbine load can be reduced, steam can be drawn off and reduced in pressure to charge the storage vessels. The roundtrip efficiency is the ratio of the work produced per lbm of steam in the peaking plant to the work which could have been produced by the steam used for charging the storage vessels. The actual steam rate of the proposed peaking plant is about 15 lbm/kWh, giving a roundtrip efficiency of 80 percent. This is high enough to justify the use of the main steam supply as the source of charging steam in LWR nuclear plants.

3.3.2.2 Thermal Energy Storage in Oil One such system for application to a Pressure Water Reactor (PWR) nuclear plant (as proposed by Exxon [32] and General Electric) similar to Figure 3-15, uses seven stages of regenerative feedwater heating. Additional heating of the feedwater is accomplished using main steam. The drains from the four low pressure heaters cascade to the condenser. Drains from the first high pressure heater are pumped forward.

With normal extraction flow, the net turbine-generator output is 1,023 MW. When this output is not needed, extraction flow is increased, reducing power production to a minimum of 670 MW. This is accomplished by recirculating feedwater through heaters designed for this maximum flow. The recirculating feedwater gives up heat to raise the temperature of oil as it is pumped from cold oil tanks to insulated hot storage tanks.
This charging mode of operation continues until the design quantity of thermal energy is in storage. Normal operation is then resumed until the peaking power is needed.

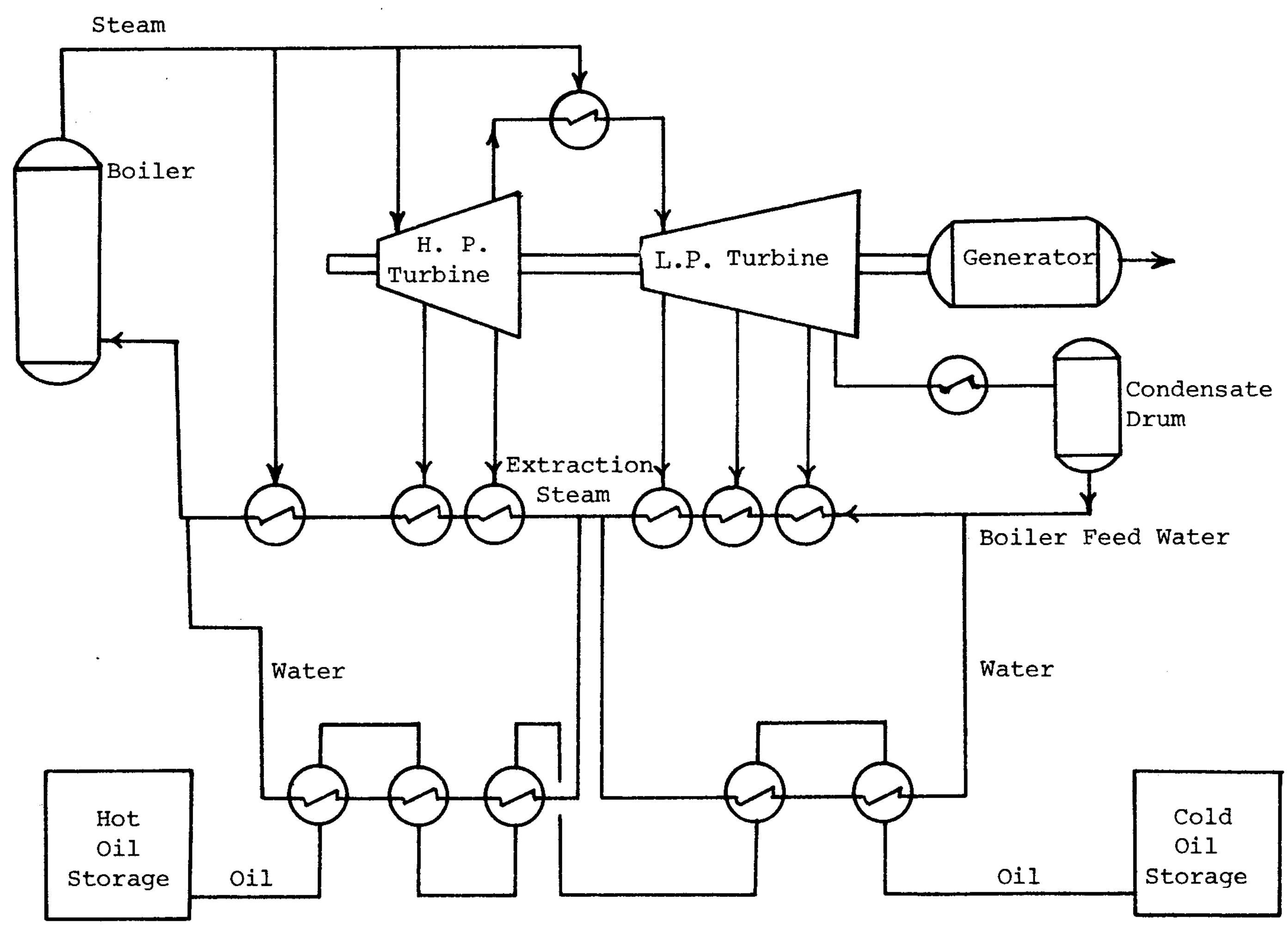


Figure 3-15 HOT OIL ENERGY STORAGE SYSTEM, SIMPLIFIED DIAGRAM

A maximum power output of 1,282 MW is achieved by reversing the direction of flow of the oil, which then transfers heat to the feedwater. The turbine is designed to be able to operate essentially nonextracting, and the condensing plant is sized to accommodate the additional exhaust flow, while maintaining a reasonable back pressure.

Leakage, which is a problem in conventional steam power cycles, is a particular concern in this concept. Precautions must be taken to avoid leaking oil into the feedwater stream. Small leaks of feedwater into the oil would not be a major problem with a PWR, but with a Boiling Water Reactor (BWR), water would radioactively contaminate the oil. Larger leaks of water into the hot oil could cause foaming and other difficulties. Means have been provided in the study design to prevent foaming in a hot oil tank and a rapid pressure rise in the heat exchanger.

The thermal storage and turbine design problems for this concept are basically an extension of existing technology. It thus provides a feasible near-term thermal energy storage system with economic factors which are promising (Chapter 4). Leakage problems exist here which are not a factor with saturated water thermal storage systems, but these are controllable with existing technology and within economic reach.

Additional development is needed to establish the optimum turbine-exchanger-oil storage integration, such as single vs. separate peaking turbine, exchanger ΔT vs. storage efficiency, and selecting the most effective oil. Further, the extent to which the oil energy storage can be integrated with the National Energy Stockpile needs to be developed, since this could have a considerable effect on the economics.

Construction of a prototype test facility, in conjunction with a fossil fuel power plant, is required to gain actual operating experience with an oil thermal energy storage system.

3.3.2.3 <u>Molten Salt Thermal Energy Storage</u> The possibility of utilizing the latent heat of fusion of material to achieve thermal energy storage is attractive in principal due to the high energy storage density per unit volume which can theoretically be achieved. Latent heats of fusion for materials suggested for utility applications will typically result in from 2 to 5 times greater energy storage density than that of the steam storage concept.

In addition, thermal energy storage using phase change materials can be charged and discharged at a fairly constant temperature level making the design of the peaking turbine (if used) considerably more straightforward and simplifying system control functions. However, the molten salt energy storage concept suffers from some severe technical problems.

Phase change materials normally posses relatively low thermal conductivities. In addition, since nearly all materials exhibit a decrease in volume during solidification, the formation of significant interface thermal resistances is probable. These problems limit the rate at which the thermal energy store can be charged and discharged.

Supercooling of the material is another problem which must be addressed. Supercooling occurs when a material does not change its phase, i.e., it remains molten even though its temperature is below the normal melting point. Heat exchanger design will be difficult since significant forces result from density changes which result from the change in phase.

A partial list of salts and salt mixtures with melting points in the range of interest is presented in Table 3-7 along with pertinent properties. Although a number of materials show promise, not one has been identified which meets all the criteria for a thermal storage material. In general, a salt mixture should have a high heat of fusion, high thermal conductivity, and high specific heat; it should be readily available at a reasonable cost, be environmentally acceptable, and non-hazardous. It must also be capable of acceptable long life, stable through many charge/discharge cycles, and compatible with its containment vessel and heat exchangers.

Variations in the design of the storage vessel and heat exchange system are possible. One system encapsulates the phase change material (PCM) in sealed tubes placed inside a pressure vessel filled with water. The vessel is then utilized in the same manner as in steam storage. The latent heat of the salt serves to increase the energy storage density of the system by increasing the "effective specific heat" of the water. A PCM occupying 10 percent by volume of the storage tank can increase the energy storage density of the system by about 15 percent assuming a temperature swing of 150°F.

Another system contains the salt in an appropriate vessel with heat addition and removal via a series of vertical tubes which contain the heat transfer fluid. This is a so-called "tube-in-shell" or "fixed bed" heat exchanger.

A molten salt thermal storage bin may be integrated into a central plant power cycle in any of the ways previously discussed. It is most advantageous to operate the bin at temperatures near the maximum cycle temperature since the electrical energy storage density depends on the efficiency of conversion from thermal to electrical energy. By operating the

Table 3-7 PHASE CHANGE MATERIAL, RELEVANT PROPERTIES (MIXTURE OF SODIUM FLUORIDE, POTASSIUM FLUORIDE, AND LITHIUM FLUORIDE)

Composition	11.5 NaF/42 KF/46.5 LiF
Melting Point	849° F
Latent Heat	190 Btu/lb
Density	137 lb/ft^3
Thermal Conductivity	1 Btu/hr ft F
Estimated Price	$1.04/lb

thermal storage bin at the highest possible temperature, the maximum conversion efficiency can be obtained.

Baseline Systems A baseline design for a molten salt storage system is shown in Figure 3-16. The storage medium for this scheme is a eutectic mixture of sodium fluoride, potassium fluoride, and lithium fluoride. Appropriate properties for the material are given in Table 3-7. This material has relatively high thermal conductivity and high latent heat, and its melting point is compatible with the temperatures available in many central power plants.

The arrangement utilized in the baseline design consists of a bank of stainless steel tubing suspended vertically in the molten salt bath as a heat exchanger. Thermal energy is added or removed via the heat exchanger by means of a fluid (assumed to be steam) circulating within the tubes. The molten salt is contained within a stainless steel-lined concrete "pool." The stainless steel liner prevents the molten salt from contacting the concrete directly.

The baseline design has been integrated with a fossil fuel steam plant as shown in Figure 3-17. The storage bin is charged using high-pressure steam during off-peak periods. When peaking power is required, the thermal storage bin acts as a steam generator for a separate peaking system.

Limitations on the rate of heat removal possible from the energy store make discharge times on the order of several hours or less impractical. Power level plants of 10 MW are of little interest to electric utilities since they are generally uneconomical. The remaining areas for consideration are:

100 MW, 1,000 MWh
100 MW, 10,000 MWh
1,000 MW, 10,000 MWh

Electrical Energy Storage Density The equivalent electrical energy density may be calculated assuming that all the energy storage capability of the material is contained in the latent heat of fusion of the material. In reality, the material will also store energy due to changes in its temperature (sensible heat), but this will tend to be offset by portions of the store which are inactive (that is, those regions which remain always solid or always liquid). The latent heat was reduced to account for the volume occupied by the heat exchanger tubes. The conversion efficiency of the peaking system was estimated to be 0.33 for the 1,000 MW unit and 0.31 for the 100 MW unit (based on a steam temperature of 750°F). The calculated equivalent electrical energy densities are:

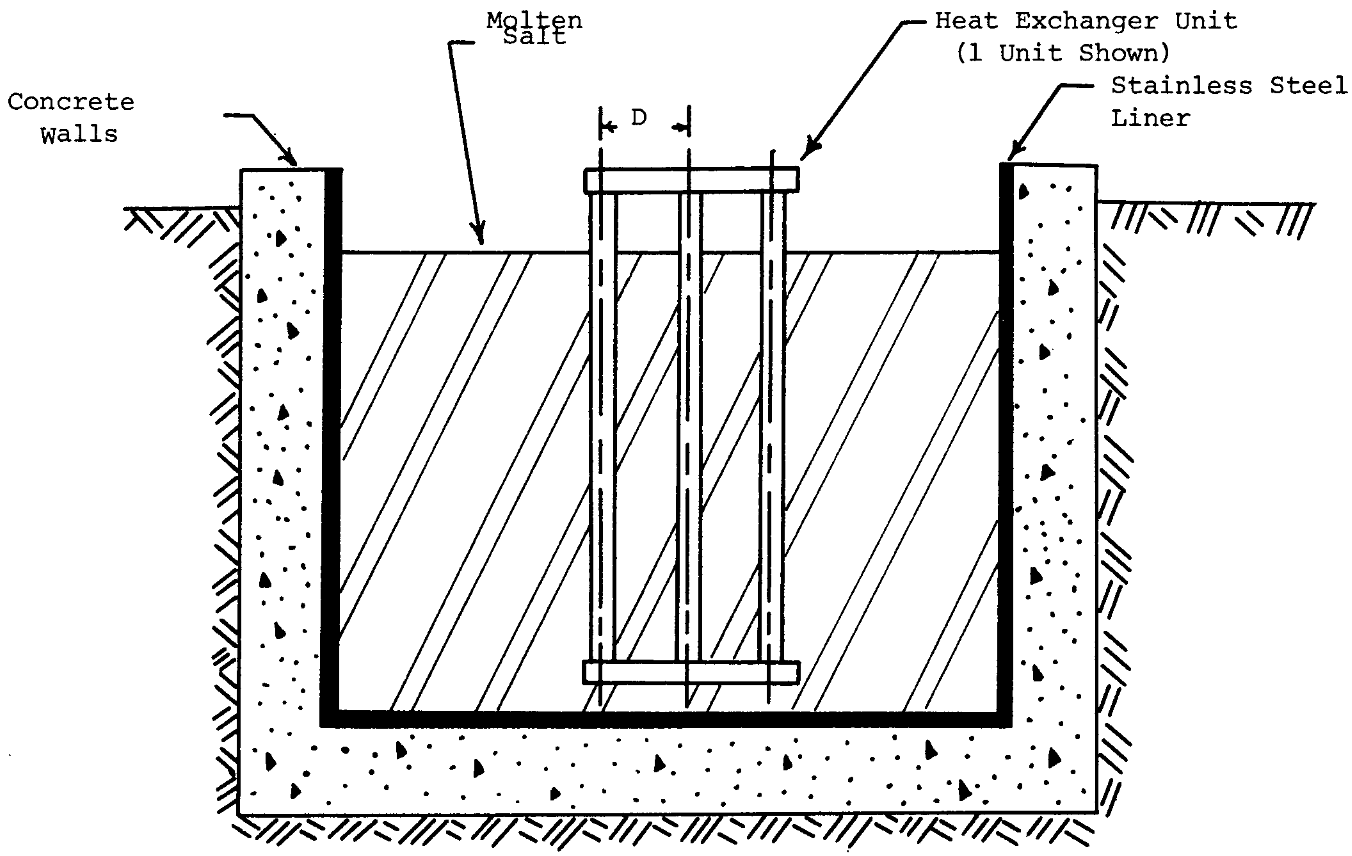


Figure 3-16 MOLTEN SALT THERMAL ENERGY STORAGE BASELINE DESIGN

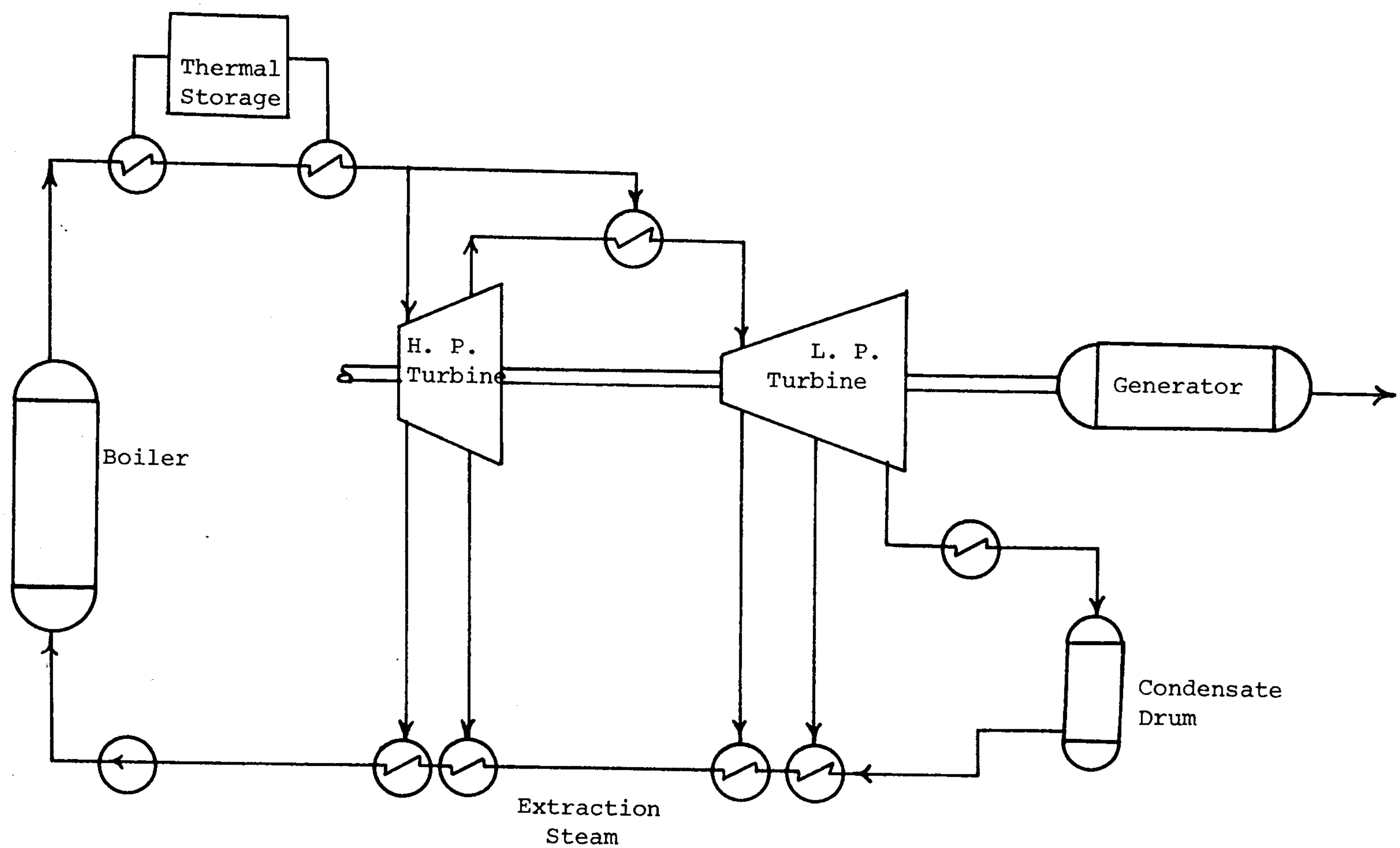


Figure 3-17 MOLTEN SALT ENERGY STORAGE; WITH FOSSIL FUEL PLANT

100 MW unit, ED = 2.1 kWh/ft^3
1,000 MW unit, ED = 2.3 kWh/ft^3

Size of Required Molten Salt Stores Based on the energy storage densities claculated above, the size of store required for each of the storage capacities are presented in Table 3-8.

Table 3-8 MOLTEN SALT STORAGE REQUIREMENTS

Power (MW)	Capacity (MWh)	Volume (m^3)	Side of Cube (m)	Wt. of Salt (kg)
100	1,000	13,300	23.7	24.5×10^6
100	10,000	133,000	51.1	245×10^6
1,000	10,000	125,000	50	230×10^6

Round Trip Efficiency Heat losses for the molten salt storage bin are about 1 percent per day. Assuming a four-day hold time (weekly cycle), the ratio of Qout to Qin will be 0.96. The calculated ratio of the efficiencies of the systems is 0.84. The round trip efficiency would be about 80 percent.

Maximum Discharge Rate The maximum discharge rate for a given molten salt energy store depends on the temperature penalty which is acceptable, conductivity of the material, and design of the heat exchanger. For the quantitative characterization of molten salt storage schemes, the discharge rate of the system was set at the power level, and this value used as a design point for estimating the costs of the heat exchanger required to satisfy this design requirement.

Maximum Charge Rate It is expected that the maximum charge rate for molten salt energy storage will be greater than the maximum discharge rate. During charging, the material in contact with the heat exchanger surfaces will be in a molten state. Thermal contact resistance between the heat exchanger surface and the material will, therefore, be greatly reduced. In addition, some convective heat transfer may take place rather than conduction alone, as is the case during discharge. The heat and mass transfer processes which are occurring are extremely complicated and a defensible estimate of the maximum charging rate will undoubtedly need to be based on experiment. Taking into consideration that the charge/discharge rate depends on geometry and on the ratio of conductivities in liquid and solid material, it is estimated that the maximum charging rate is 1.5 times the discharge rate.

Life Due to the lack of any real experience in utilizing molten salt storage systems of the sizes required for utility applications, estimates of the useful life of these systems are not available.

Heat Exchanger The heat exchanger is assumed to be fabricated from 1.5 inch schedule 40 stainless steel pipe. Preliminary heat transfer calculations have indicated that the heat flux during discharge is on the order of 300 Btu per hour per foot of pipe length. The length of pipe necessary to satisfy a given discharge rate can then be calculated. It should be noted that the heat exchanger costs are power-related costs rather than energy storage capacity-related costs.

Availability of Storage Materials Many of the proposals for utilizing molten salt thermal energy storage for utility applications have suggested that eutectic mixtures of metal fluorides be used as the storage material. The large volumes of molten salts necessary to satisfy thermal storage requirements raises the question of the availability of these materials.

The principal source of fluorine is the mineral fluorspar. The world production of fluorspar was approximately 5 million tons in 1972. A thermal energy store with a capacity of 1,000 MWh will require about 25,000 tons of the baseline metal fluoride sale, a significant portion of the world's supply. United States production in 1972, or about 250,000 tons. Thermal energy storage concepts utilizing metal fluorides could be severely limited by the availability of these materials.

3.3.3 Final Comments

Many approaches to thermal energy storage systems are possible. Three systems were selected for more detailed treatment, saturated water (steam) storage, hot oil storage and a molten salt storage concept. The first two are sensible heat storage approaches while the third is a latent heat storage system. This preliminary selection does not mean that all other approaches are not viable methods, but, rather, recognizes the limited scope of this study. It should be noted that:

- Saturated water (steam) storage has no obvious barriers to immediate application

- Hot oil storage has only a few problems which relate to heat exchange design, preventive of oil-water leaks and system integration and controls.

- Thermal storage is a fertile area for innovative engineering and other concepts, such as underground saturated water or steam storage, should be considered in follow-up studies.

- Consideration has not been given to plant availability or reliability and this would need to be addressed in a full engineering design effort.

- Licensing requirements for a nuclear power plant with a thermal energy storage system must be investigated in parallel with technical and engineering developments.

3.4 BATTERY (ELECTROCHEMICAL)

Battery energy storage is a well known form of chemical energy storage in which dc electrical energy is electrochemically converted to chemical energy during charging of the store and electrochemically converted to dc electrical energy upon discharge. Basic characteristics of direct conversion of electrical energy are an absence of mechanical (moving) components, rapid electrical response, compactness and modularity.

A large number of electrochemical systems have been investigated in recent years and systems offer prospects for development as practical storage batteries for utility application. The key characteristics of these systems have been reviewed elsewhere [37-40]. This section focuses on the battery storage system rather than just the electrochemical couples.

This section on electrochemical energy storage covers operating characteristics, the conceptual design of a battery energy storage and a brief overview of the leading candidate battery systems.

3.4.1 Description of Electrochemical Energy Storage

The basic station concept (Figure 3-18) is a series and parallel arrangement of battery modules which are composed of various arrangements of electrochemical cells. This permits in principle the building up of a battery energy storage unit to almost any arbitrary voltage and current level. Economics of dc to ac conversion (batteries are dc devices while utilities are mainly ac) place limits on dc currents and voltage.

In a battery energy storage system the chemical reactants can be stored in the battery itself, or externally in separate tanks or some hybrid combination. For the purposes of this analysis, two battery types can be identified:

(1) Static batteries which do not require auxiliary equipment other than cooling equipment.

(2) Circulating reactant systems which would resemble fairly complex chemical plants.

The basic design is a modular battery system with individual cells assembled into modules and strings reaching dc bus voltages near 1kV.

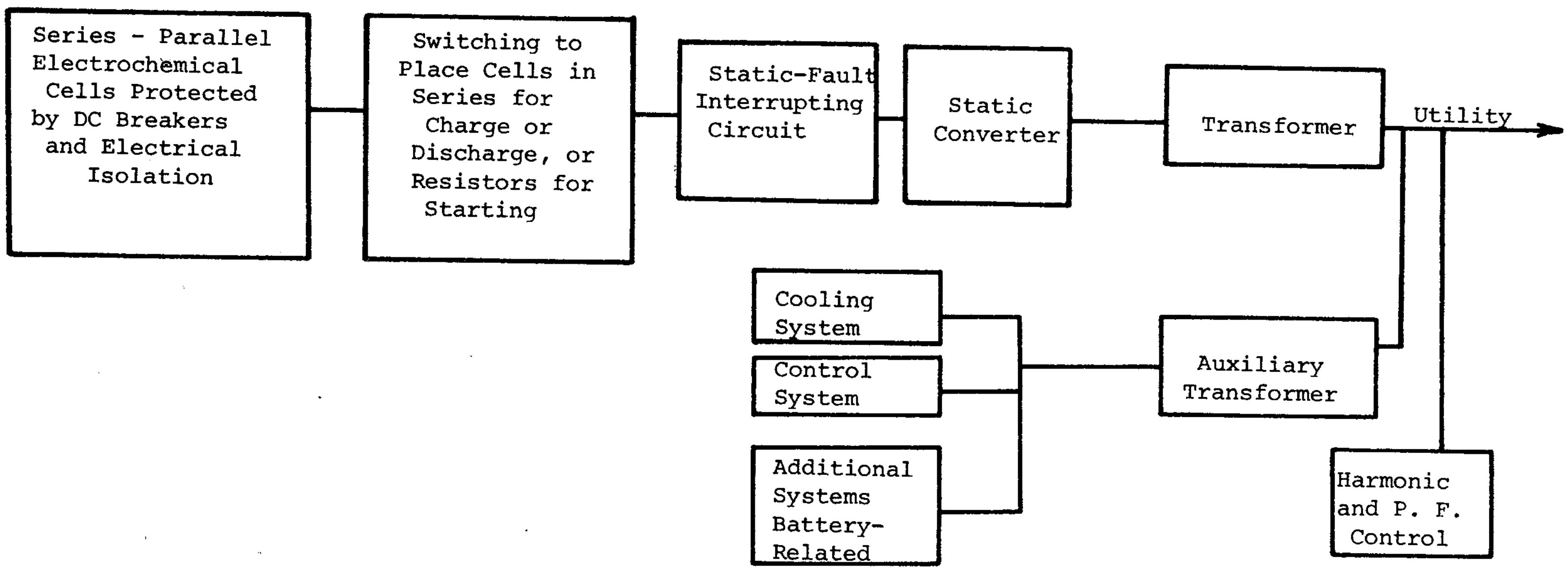


Figure 3-18 BATTERY STATION CONCEPT

3.4.2 Technical Assessment

No general description of a battery energy storage system is available in the literature although some designs for specific electrochemical cells have been developed. This section first describes battery station operating characteristics then presents some conceptual design approaches for the elements in a complete battery station. The information is largely descriptive but does show that the battery station can be constructed without major new developments except, of course, the electrochemical cells and modules. Lastly candidate electrochemical couples are discussed.

3.4.2.1 Operating Characteristics The significant operating characteristics include:

Size For batteries, cells of a few kilowatthours are the basic unit. These can be assembled into modules of almost arbitrary size. For utility use typical station sizes would be between 200 and 500 MWh based on siting at the substation level. Power and energy ratings are variable design parameters. Extremely high rates of charge and discharge tend to result in high costs of energy storage and lower efficiencies.

Efficiency Efficiencies for batteries have exceeded 80 percent on some systems under laboratory conditions. Typical line-commutated converter full load efficiencies are 95 percent (one way). Expected overall storage efficiencies lie between 65 percent and 75 percent. Efficiency can be increased by reducing the current density in the battery and increase the battery costs per unit of storage capacity. Optimum values are yet to be established and will depend on specific technologies as well as the duty cycle to be served by the battery.

Charge/Discharge Ratios Equal charge and discharge times are readily achievable. Faster charge time, with a charge to discharge ratio greater than 1, can be achieved. For lead acid batteries which cannot sustain a high charging rate, a typical ratio is approximately 1, while some advanced systems might achieve ratios on the order of 1.5 and higher if designed properly. Converter systems can be designed to handle almost any charge/discharge ratio. Standby losses result from thermal losses and self-discharge but are generally small; typically, self-discharge rates range from zero to as high as 2 to 3 percent per day.

Turnaround Time One design approach to establishing turnaround time uses motor-driven switches to reverse polarity. Another approach utilizes solid-state switching devices.

With mechanical switches, several seconds are required for changing from charge to discharge. With solid-state switching, turnaround should be possible within a cycle (1/60 of a second) for many advanced battery types and converters.

Load Regulation A battery energy storage plant can effectively follow load if coupled with a line-commutated converter. At part load there is little or no loss in efficiency of the line-commutated converter while battery efficiency increases. If forced-commutation converters are used, severe efficiency penalties result from partial loading. (Forced-commutation converters have essentially fixed losses independent of load. As load decreases, percent losses increase dramatically.)

3.4.2.2 Battery Station Concept and Design A major advantage of an electrochemical energy storage system is its ability to be located throughout the utility distribution and transmission system. By installing battery storage systems at utility substation locations, transmission costs are reduced. The basic station concept (Figure 3-18) is a series and parallel arrangement of battery modules which are composed of various arrangements of electrochemical cells. This permits in principle the building up of a battery energy storage unit to almost any arbitrary voltage and current level. Economics of dc to ac conversion (batteries are dc devices while utilities are mainly ac) place limits on dc currents and voltage. It is assumed that a sealed battery storage device can be achieved.

The proposed system is basically the same for any electrochemical couple. It consists of:

(1) Supermodules, modules and strings
(2) Support structure
(3) dc bus, breakers, and switches
(4) Power conversion equipment
(5) Auxiliary systems
(6) Control and protection system

The supermodule is a group of modules containing a large number of cells that are connected together for ease of installation. The total assumed weight of the supermodule is several tons; a rigging weight that utilizes normal crews most efficiently. Above several tons, more precautions and different techniques to manipulate the supermodule into place are necessary.

The support structure consists of a support frame that accepts the supermodules and provides all other auxiliary requirements. The frame is transportable, with a separate cooling fan and all necessary safety and performance monitors installed at the factory. The installation of the frame consists of placing it on a foundation and connecting all the control cables and dc bus. Plug-in connectors, similar to those used for gas tubing and nuclear control room wiring, allow wiring without the batteries being on-site.

The dc bus, breakers and switches must be designed to handle large short circuit currents. Switches, within and external to the module, are used to reduce the need for auxiliary starting power cable, and transformer capacity. The reduction in start-up power cable and transformer capacity is achieved by placing dc resistors parallel to the battery. During start-up, the switch internal to the support frame is opened and the dc resistors are switched across the battery. The power converter and associated dc bus are then used to heat up the units.

The auxiliary requirements for the advanced batteries are almost entirely fan loads. The size of the fan motors should not pose any electrical problem either on the auxiliary bus or to the distribution system. Other auxiliary requirements include the pumps for the cooling system and circulating electrolyte in some of the battery systems.

The control and protection system is a mixture of new and old philosophies. Computers are required to control the power conversion equipment, and to collect and process the performance data concerning the battery itself. The transformer and motors are protected by electromechanical relays.

3.4.1.7 Utility Interface The electrochemical energy storage does not have any inherent application limitations on electric utilities. However, there are engineering design details to be worked out. Safety problems associated with reactive chemicals can be solved by using either redundant enclosures or inert atmosphere systems. This may be necessary to contain the chemicals spilled by a total rupture of a battery.

Major System Components Battery Modules, Enclosures, and Buswork An electrochemical cell by itself does not have sufficient current and voltage ratings to be used without series and parallel connections. In theory, strings could be built up to any voltage by simply placing more cells in series. In the design approach considered here, a nominal terminal voltage to 1kV is assumed for all modules without any auxiliary system to control the voltage division.

The nominal voltage of 1 kV is based on the availability of standard dc equipment, the problem of voltage division between the cells, and the problem of insulation contamination. Higher voltages would require either control devices or an extensive development program. to share the development costs. Voltage division between the cells in the battery string is influenced by the stray capacitance within the system, any differences in temperature of the cells, and slight differences in the chemical mix of the cells. Electric insulation of the connectors is required. The connectors are external to the cells and are usually in the cooling air system of many of the batteries.

Because of high operating temperatures, standard organic insulation and the usual conducting materials are not directly applicable. The standard electrical aluminum alloys 6061-T6 and 6063-T6 cannot be used because they have low tensile strengths and high elongations at these temperatures. Copper alloys are marginal because of susceptibility to formation of oxides.

Fully-insulated connections could be either formed in the field, with special high temperature insulating tapes, or be factory-formed similar to distribution high voltage plug-in connectors. With a large number of connections, the latter approach would be preferred since the manufactured costs of the connections would not be significant for most systems. The higher temperature systems may require nickel-plated copper connectors to avoid oxide formation. If the fully-insulated connectors are covered with a ceramic and then fired, the total costs for the insulated connection could be lower than the air-insulated connection.

The battery enclosure is solidly grounded. This is essential for safety considerations and aids in hot replacement of cells. If cool-down were required, it would place a severe availability limitation on the system. To avoid this, all of the battery systems are configured to allow a small bucket truck or forklift truck to lift out one cell or module once it is disconnected from the battery. If the case of the module or supermodule is not at ground potential, this would not be possible.

The normal utility practice is to have two lines of protection against electrical failures. For a fault in a certain section, the relays are set to immediately trip the circuit breakers adjacent to that section. At the same time, a trip signal, through a time delay device, is activated to trip the next breakers in series with the primary breakers. If the primary breaker clears the fault, the back-up trip signal is cancelled. If not, the next zone breakers will clear the fault. This philosophy is extended to generators in that the generator is protected by field breakers which can remove potential from the generator and standard circuit breakers. Also the leads that connect a generator to its step-up transformer, and the way it is grounded, make a single contingency failure harmless. For a fault to ground at the terminals of a generator, the fault current is from 5 to 10 amperes regardless of the size of the machine. Phase-to-phase or three-phase faults, are not possible because each phase is totally enclosed in a grounded enclosure. The main dc bus external to the battery modules is coaxial; the system will (when possible) be ungrounded or have a very high impedance ground and special relaying will be provided.

The use of a coaxial dc bus has a number of safety and economic advantages. It is highly unlikely to have a pole-to-pole fault within the coaxial bus. Unlike a normal bus that could be violated by small animals, birds, contamination, and vandals, a coaxial bus completely protects the center conductor. If the outer conductor is shorted to ground, only a very small current, which is caused by capacitive coupling of the converter ripple voltage to ground or the high resistance ground, will flow. Therefore, a single fault to ground will not constitute a failure. Also coaxial bus does not have to be braced for the short circuit forces that would be developed for a fault.

Balance of Plant - For factory-fabricated units, installation consists of providing a foundation, rigging the shipping units and batteries into place, connecting the batteries to the units, providing main and auxiliary power connections, and installing the power conditioning and control equipment.

Because all of the sensing, fire, safety, and auxiliary systems in the balance of plant required for operation of the system have been wired and checked in the factory, only a few multiconductor control cables have to be connected to a central wire location on the shipping unit. These connections can be made with multipin plug-in connectors similar to those used on gas turbine installations and railroad cars.

The power connections consist of dc bus connections and intermodule connections. Only a few connections will be required to the main bus. The intermodule connections will consist of plug-in terminals which could be removed with standard hot sticks when electrically and thermally hot. Their installation should be very quick and easy.

The ventilation system is included in the support frame. Only minor adjustment to deflecting louvers would be required during start-up.

Candidate Battery Systems A number of rechargeable battery systems are broadly suitable for utility application. Among the various battery systems, five classes of batteries are considered here as the more important candidates in terms of their prospects for technical and economic feasibility. These are:

(1) lead-acid

(2) sodium-sulfur

(3) lithium-metal-sulfide

(4) sodium-chloride and

(5) zinc-chlorine

Additionally, several redox couples have received some consideration and the zinc-bromine system is being explored as potentially attractive. Many other candidates exist but have generally been eliminated because practical approaches to building technically and economically viable batteries have not been found. Each major system is discussed in turn.

Lead-Acid Of the candidate couples, the lead-acid battery is the most developed and has been in use for nearly a century [43]. While it is now primarily used for starting, lighting and ignition in automobiles and trucks, the lead-acid battery has been used extensively for stand-by power in the twenties and thirties (and earlier) in conjunction with dc power systems and electric railroads. Today large (10,000 Ah) cells are being used for submarine power supplies and other smaller cells find application as industrial traction batteries and fork lift batteries for in-plant operations. "Load leveling" lead-acid batteries would require a somewhat different design approach, however, much of the basic technology appears applicable to utility energy storage systems.

Since the lead-acid battery is the only commercially available battery type that has been considered for utility application, it establishes a baseline against which future developments can be compared. There will be substantial differences between both the basic technology and the projected characteristics of "advanced" batteries and commercially available lead-acid batteries; these differences account for much of the current uncertainty regarding technical and economic feasibility of lead-acid batteries.

In examining the characteristics of lead-acid batteries, it is necessary to distinguish between currently available batteries, state-of-the-art batteries, and future batteries. It is only for the first two that specific, reliable estimates can be made of efficiency, life and cost. This is covered in Section 4.4 of this report. For future "advanced" lead-acid batteries, projections have been made which include 5,000 cycles for a life of 20 years, as well as, higher energy density and lower costs [44]. Achievement of projected characteristics would put "advanced" lead-acid batteries into a competitive position relative to other advanced battery systems (except for energy density and land area requirements).

Principal requirements for the lead-acid system are:

(1) adequate cooling to prevent life-shortening temperatures when the large batteries are charged and discharged at high rates, and

(2) reducing the presently substantial requirement for maintenance (principally water addition).

These requirements could be met by a circulating electrolyte-water cooled heat exchanger system to be added to each cell. This could increase the cost of the installation by 5 percent or more.

The costs for these modifications are relatively small compared to the total installation cost. New lead grid alloys might provide the additional benefit of longer service life.

Question has been raised about the adequacy of lead supplies for such a potentially large application as load-leveling. Present production of lead-acid batteries in the United States, which uses almost half of the output of primary and secondary lead, is approximately 55,000 MWh, equivalent to 550 load-leveling units of 100 MWh each. The supply of lead is projected to be adequate for the establishment of lead-acid battery load-leveling plants, at least as an interim measure until more advanced battery systems become available.

Sodium-Sulfur A class of batteries are identified as sodium-sulfur. A viable sodium-sulfur battery was first described by researchers at Ford in 1967 [45]. The key element in the high temperature sodium battery is a ceramic sodium ion conductive solid electrolyte (beta-alumina). A solid electrolyte eliminates self-discharge and provides positive separation of the electrode materials. The electrode material, and the majority of the discharge products, are liquid at the cell operating temperature (350-300°C). As liquids have no structural memory, many types of failure mechanisms are eliminated. However, corrosion of the sulfur container and the current collector must now be carefully avoided and the life of the ceramic separator must be assured. Although early work was severely hampered by the poor quality ceramic, more recent work has resulted in demonstrating that there is no inherent limit to the life of the ceramic. Much work has been done on this system at Ford, Laboratoires de Marcoussis of CGE in France, TRW, General Electric, and Chloride Silent Power in England [46, 47, 48, 49]. Dow has been investigating a variation in this system which uses sodium-conductive glass instead of beta-alumina.

The sodium-sulfur system uses inherently inexpensive material. However, purity requirements and processing costs could add significantly to the raw material costs. Specific designs for use as utility energy storage systems are in a very early state of development and much work needs to be done [50, 51].

Sodium-Chloride The sodium-chloride battery is a modification of the sodium-sulfur system. The sulfur is replaced by sodium chloroaluminate as a low melting point ionic conductor. The addition of antimony chloride results in a battery where trivalent antimony is a major active component [52]. Published literature on this system is quite limited. The work underway has been entirely restricted to the project at ESB under EPRI/ESB support [53]. The results of energy storage system design studies indicate that this battery could be quite compact and comparable to the sodium sulfur system in many aspects [54].

Lithium-Iron Sulfide Lithium-iron sulfide batteries are under development at Argonne National Laboratories and Atomics International [55,56]. The original system used liquid lithium and liquid sulfur and was analogous to the sodium-sulfur battery except that a liquid electrolyte (LiCl - KCl) was also used. Insurmountable problems developed in containing the active materials. To overcome these experimental difficulties, developers adopted solid active materials and the preferred electrode components are now a Li-Al and Li-S alloys and iron sulfide (FeS or FeS). The lower electrochemical activity of these materials has reduced the experimental difficulties but has also resulted in lower cell voltage and specific energy. This is a serious handicap for a system which uses lithium (lithium costs from $5 to 8 per pound).

Considerable progress has been made on development of prototype engineering cells and the program at Argonne is particularly large and active. Ultimate technical success does not appear to depend on breakthroughs in technology, but long cycle life and low cost are not assured.

Lithium-metal sulfide batteries are attractive relative to the lead-acid system because of their much smaller size and weight. A 100-MWh unit would occupy about 4,000 sq. ft. (compared with an estimated 50,000 sq. ft. for the lead-acid battery) although a high-bay building would be necessary. The battery would weigh about 800 tons compared to 3,500 tons for the lead-acid battery). Other advantages are operation in a sealed condition and the feasibility of using circulating air as a coolant. Maintenance may be simpler than for the lead-acid battery [57, 58].

Zinc-Chlorine - The zinc-chlorine battery system, involving storage of the chlorine as chlorine hydrate, is an aqueous-based system which has been proposed for load-leveling applications [59, 60]. Chlorine storage under pressure is not as attractive because of the requirement for drying the chlorine, and consequent disposal problems with the sulfuric acid drying agent. Although significantly-sized (1 to 2 kW) batteries have been built for demonstration purposes, little data on performance is available. When fully developed, the system should have an energy density between that of the lead-acid and the high-temperature systems. Since life would be limited by the difficulties that develop at the zinc electrode with continuous cycling at less than full depth of discharge. Overdischarge of cells could be used to increase cycle life. Because of the recirculating electrolyte, temperature control should be no problem.

In the zinc-chlorine system, the cost of reactants is low. However, the cost per kWh of storage can be kept low only if low-cost construction materials can be used. The use of these materials, in turn, depends on their ability to meet specifications for certain impurities (for example, iron in graphite), which is possible only if the materials are purchased in large quantities. Costs for the zinc-chlorine system, as for many of the other systems considered, depend strongly on whether a large-scale market for load-levelling batteries develops. Maintenance requirements are difficult to estimate in advance of commercial designs; they could be relatively high.

Redox - Redox batteries using various inorganic couples in aqeous solution, have been proposed for the load-leveling application [61, 62]. Those that use dissimilar metal couples, e.g., the iron-titanium system, are likely to be handicapped by the need for frequent reconditioning of the electrolyte because of mixing. More promising are systems that use a single metal which is stable in aqueous solution at different oxidation levels. In these, the mixing problem is minor and is significant only as reduction in overall electrical efficiency.

Of the single-metal systems, chromium or iron appear to be the most suitable. The chromium redox couple has a relatively high voltage (1.74V) and the salts are fairly soluble. Consequently, the battery is relatively compact (comparable in size to the lead-acid battery, although considerably larger than the high-temperature systems). Problems relate to the thermodynamic instability of the charged reactants with respect to water. This tends to result in reduced efficiency and chemical imbalance.

The development of redox batteries is still at a preliminary stage. Key cost-determining considerations are: the electrodes and the current densities and charge-discharge efficiencies that can be obtained from them; the rate at which the electrodes deteriorate; and in the case of dissimilar redox couples, the membrane or other barrier that separates the two halves of the cell. Much of the rest of the system--tanks, pumps, piping, and the inventory of inorganic salts, have accurately predictable costs and lifetimes. Heat generation is not a difficult problem in redox battery systems because they employ flowing electrolytes.

3.4.3 Final Comments

- No major obstacle is foreseen today with respect to the balance of plant for a battery energy storage system. Good engineering should permit timely development of all necessary components.
- Several electrochemical couples offer promise of technical feasibility.
- The major technical achievement which has not been demonstrated is long cell life. This is the key technical goal which must be pursued in research efforts.

3.5 CHEMICAL ENERGY STORAGE

Chemical energy storage is the storage of energy in the chemical potential (change in Gibbs free energy) of chemical compounds which can be made to react with a net release of energy [40]. For electric utility systems, it is the conversion of electrical energy into the chemical potential, and the subsequent recovery of the stored energy for conversion back into electricity. The definition may be relaxed to consider closed-loop chemical reaction systems which are thermally coupled to nuclear or fossil-fuel steam supply systems to achieve an energy-absorbing chemical change, followed by the release of the stored energy as thermal energy, which can then be converted to electricity in a conventional way, or, through direct electrochemical conversion, as electrical energy. Systems also exist which can effect the recovery of the stored energy at a different location. These last systems were not considered in this study.

Figure 3-19 is a generalized functional scheme of all chemical energy storage systems. However, different subsystem configurations and conversion techniques may be incorporated into different systems. Electrochemical energy storage methods utilizing batteries are a special case of chemical energy storage methods and are described in the previous section.

3.5.1 Description and Present Status, Hydrogen Energy Storage

The chemical energy storage system, other than batteries, which has received the most attention is hydrogen energy storage. This is the best known example of advanced chemical energy storage. Several approaches have been considered for each of the required subsystems--hydrogen generation from electricity, storage, and conversion to electricity. Many detailed surveys are readily available in the literature [63-65]. Each principal subsystem is treated below.

Electrolysis of water makes use of electricity as the energy input to water feedstock. It is a simple concept, the raw materials are inexpensive, and operating experience with commercial electrolyzers are available. The electrolyzers are modular and can be tailored to fit a given application.

Approaches to hydrogen storage considered here include: aboveground compressed gas, metal hydride, or liquefied hydrogen storage. Compressed gas storage is cheaper, and less energy-demanding than liquefied gas storage, although both technologies are well-developed. The cost is nearly independent of pressure over a range of a few atmospheres. Metal hydride storage systems are expected to be compact, quiet, and relatively safe devices for the storage of hydrogen. The hydrogen can probably be absorbed and desorbed at a reasonable temperature. Hydrogen release is endothermic, and, therefore, would tend to be self-quenching in the event of an accident.

In the combustion subsystems, fuel cells are a logical choice if hydrogen or simple hydrocarbons are the energy carriers. They are relatively simple devices and have no moving parts. They are also not limited by the Carnot cycle efficiency, and high operating efficiencies can be expected. The fuel cells will perform best when acid electrolytes are used (alkaline electrolytes can become carbonated if air is used and the carbon dioxide is not removed) and oxygen is the oxidant. Problems to be overcome involve reducing costs and improving life. Gas turbines are the only sufficiently well-developed alternative to fuel cells and they also operate most efficiently on hydrogen and oxygen (air).

3.5.2 Technical Assessment

Hydrogen is easily produced, stored and transmitted, and utilized to generate electricity. The combination of subsystems which leads to the lowest estimated capital costs and highest turnaround efficiencies for a hydrogen-based energy storage system, are (a) water electrolysis, (b) compressed gas storage at (750 to 1,000 psi), and (c) a fuel cell or combined cycle plant.

3.5.2.1 Hydrogen Production by Electrolysis Electrolysis is the only currently feasible direct electrochemical method for producing hydrogen from water and electricity. Devices exist for producing hydrogen for large scale industrial processes such as ammonia production and fertilizer manufacture.

Electrolyzers can be operated over a wide range of voltages and current densities. The range may depend on material limitations, such as the relative electrocatalytic activity of the electrodes, and the electrical resistivity of some of the other components. The range will also depend on the duty cycle. Lower current densities are generally needed to achieve high efficiency. Device design requires a trade-off between capital costs and efficiency.

Table 3-9 summarizes performance data for water electrolyzers. For laboratory-scale cells, electrical efficiency can be very high, on the order of 90 to 95 percent. However, in commercial, industrial application, electrolyzers are operated more typically between 50 and 80 percent (often about 60 to 70 percent).

3.5.2.2 Hydrogen Storage The major approaches to hydrogen storage include: gaseous storage, cryogenic liquid storage and storage in chemical compounds.

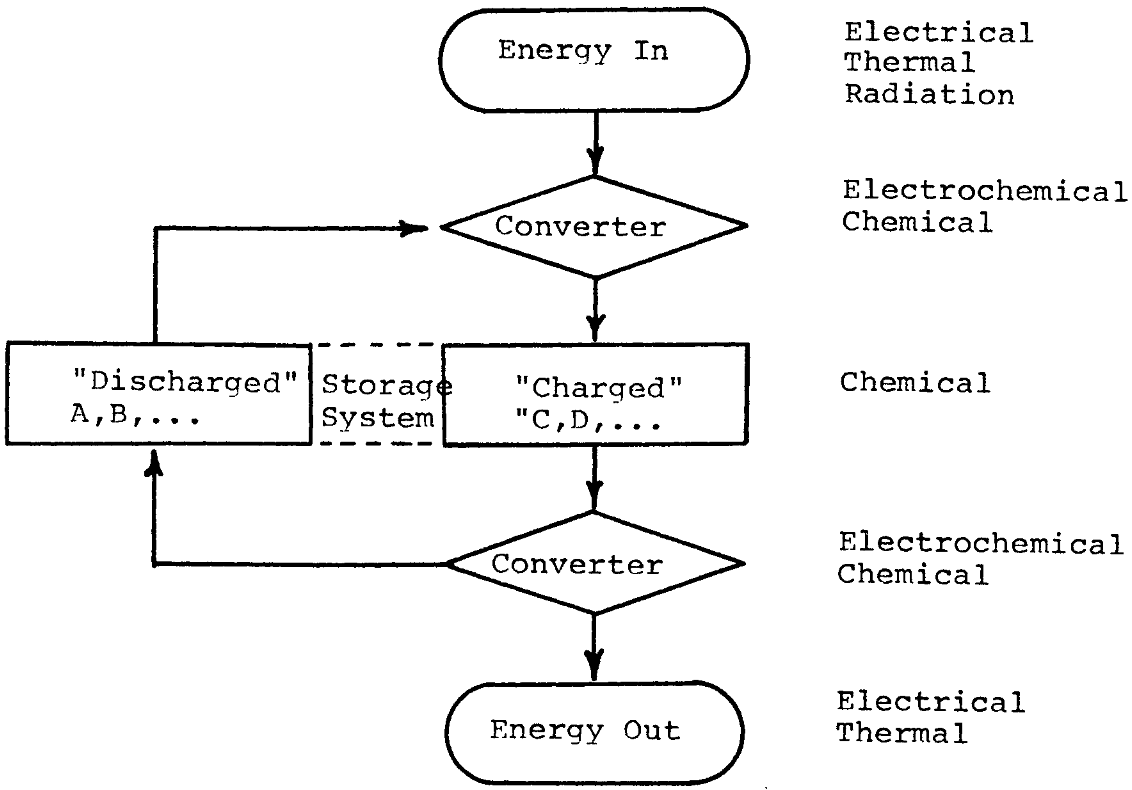


Figure 3-19 PRINCIPLE OF CHEMICAL ENERGY STORAGE SYSTEMS

Table 3-9

PERFORMANCE DATA FOR WATER ELECTROLYZERS

	Electrolyzer Type	Approximate Capacity kg/hr of H_2	Electrical Efficiency, Percent	Electrical Requirements kWhr/kg of H_2	Capital Cost, \$/KW (c)
	Ideal (NTP)	--	100	40.1	--
1966	Hypothetical	(20,000)	---	---	40
1971	Hypothetical	---	68-95	---	$<$50
1972	Hypothetical	(66,000)	63-70	53-64	~40
1973	Teledyne, Bipolar	(4,750)	---	---	88-109
1974	G.E. SPE Cells(a)	~2,000	92.5	---	~335(b)
1974	Lurgi, High Pressure	~ 800	---	---	~345(b)
1975	Brown Boveri, Bipolar	60-950	---	(53)	145-215

Data in parentheses are projected or calculated.
(a) SPE = Solid Polymer Electrolyte
(b) Installation, freight, and insurance costs included
(c) Hydrogen output equivalent

Gaseous Storage Storage of a compressed gas in pressure vessels is a known technology. A variation of this method is called "line-packing" whereby a transmission pipeline is used for storage. This method may be feasible if the transmission lines are of a type that can transport hydrogen, without leakage, and which can operate at a variable pressure of between 35 and 70 kg/cm^2 (500 and 1,000 psia). Other methods of hydrogen gas storage include storage in underground caverns or aquifers, depleted gas wells, and submerged bladder devices.

The major disadvantage of high pressure storage is the cost of the pressure vessels and the the compressor(s). Also there are unresolved questions about the occurrence of hydrogen embrittlement and fatigue cracking due to cyclic thermal and mechanical stresses as the storage vessel is filled and emptied on a regular basis. This may be overcome to some extent by adding up to 1 percent water vapor or oxygen to the gas. High strength steels are attacked, but 300 series stainless steels, pure titanium, Monel, and some aluminum alloys are suitable materials for the pressure vessels.

There is a trade-off between increasing the storage pressure (hence reducing the storage volume), and the size and cost of the compressor required to obtain the storage pressure. There is also the limitation of the mechanical properties of the materials used to fabricate the storage vessels. Regenerative compressors may offer certain advantages for hydrogen compression and transmission over conventional multistage compressors. The head coefficient for this type of compressor is an order of magnitude greater than that of conventional equipment, and one stage can replace seven to eight centrifugal stages, for example. However, the compressor efficiency is relatively low (about 50 percent), and this type of compressor at the present time, is limited to the low end of the specific speed range.

Liquid (Cryogenic) Storage Hydrogen gas may be liquified and stored in the liquid form if it is suitably refrigerated. Storage systems as large as approximately 3.5×10^6 litters (10^6 gallons) have been built and operated in connection with the space program. The advantage with liquefaction is the reduction in hydrogen storage volume by a factor of about 850 over gas storage at one atmosphere. The penalty, however, is the cost of liquefaction and insulated storage. Liquefaction costs about three or four times compression costs.

Spherical, vacuum-jacketed vessels are necessary for liquid hydrogen storage. The spherical shape is dictated by the need for vacuum insulation because of the low storage temperatures necessary. The boil-off rate from the vessel (losses) are less than 0.1 percent per day. Materials subject to hydrogen embrittlement must be avoided for the inner vessel liner. The

300 series stainless steels and aluminum alloys have been found to be acceptable. The largest practical vessel is thought to have a storage capacity of about 10^7 liters (3×10^6 gallons or about 125×10^9 Btu). The physical size of such an installation is large, and would occupy considerable land area, as well as possibly being the source of visual pollution. As an example of storage vessel size, a 16 m (52 ft) diameter vessel is required to store about 2×10^6 liters (0.5×10^6 gallons) of hydrogen.

Reducing the cost of the storage vessels can be achieved if the boil-off rate can be held at an acceptable level without the need for a vacuum-jacket insulation. Perlite is used as a filler between the inner and outer vessel jackets, but apart from a vacuum, the only gases which could be used within the inner liner are hydrogen and helium. The later is relatively expensive, and both have a high thermal conductivity in contrast to a low grade vacuum. Heat losses could be increased if either gas was used, and insulation efficiency would be reduced. However, the requirements for an energy storage system, with storage times between 5 and 10 hours, differ considerably for the liquid hydrogen tanks built for the space program. For energy storage applications, a higher boil-off rate might be tolerated, thus lowering the insulation requirements. A simpler vessel design might then result and liquefaction would not be altered, nor would the cost for the revaporization required to supply hydrogen gas to the conversion subsystem.

The restraints for storing hydrogen in the form of a slush are more stringent than for liquid storage, hence this technique is not considered to be suitable for storage of chemical energy.

Storage as Chemical Compounds Storage of hydrogen in a combined chemical form (metal hydride) is technically feasible. When hydrogen is required, the temperature and pressure of the metal hydride are adjusted in order that the hydrides might dissociate. This storage method is reversible, but the effect on cycle life of trace impurities, such as oxygen, or water vapor, on some of the compounds is not yet known.

Desirable features of a hydride storage system may be summarized as follows: (1) high retentive capacity for hydrogen, (2) low temperature for dissociation ($<100°C$), (3) high rates of absorption and desorption, (4) low heat of hydride formation, (5) low cost raw materials, (6) low weight raw materials, and (7) stability towards oxygen and water vapor to ensure long life. Some of the approaches which may be taken to obtain improved materials are: (a) alter atomic spacing to get more hydrogen into the octohedral, as well as the tetragonal interstitial sites, (b) use an alloy to modify dissociation temperature while still retaining hydrogen content, (c) use an alloy to decrease to metal-hydrogen bond strength to increase the dissociated pressure, and seek (d) an increase in the entropy of the compound to increase the metal-metal spacing, hence open the structure for more hydrogen to be continued.

3.5.2.3 Technical Characterization Summaries of the technical characteristics for the hydrogen storage subsystems and concepts are given in Table 3-10 and 3-11. Compressed gas storage is technically feasible today, and is suitable for use on a daily duty cycle.

The efficiency of compressed gas storage can be high depending upon the efficiency of compression of the oxygen and the hydrogen. Typically, compressor efficiencies of 80 percent can be achieved for oxygen and 75 percent for hydrogen. However, there is some hope for increasing the upper value. One approach would be to backpressure the electrolyzer subsystem, e.g., produce the gases under pressure electrochemically, and obviate or reduce the need for compressors. Thus efficiencies of 99 to 100 percent have been projected in the long-term. Such a high value assumes that the storage subsystem is located near the production and conversion subsystems, so that transmission losses are negligible.

A life of 20 years or more is possible. The limiting factor most probably will be the life of the seals in the compressors. These might fail after only about 5 years of continuous daily service. Until definite operating data are obtained, a safe estimate for the life of this subsystem would be 5 to 20 or more years, with the lower value referring to near-term applications.

At the present time, the iron-titanium alloy material offers the best prospects for being available in large quantities, and at a reasonable cost for metal hydride storage devices. Hence the data given in Table 3-10 refer to an iron-titanium alloy hydride storage device. Small, laboratory-scale hydride storage devices have operated for about 1,000 cycles, which is equivalent to about 3 years of operation for a daily duty cycle, large-scale storage subsystem. Maximum life has yet to be established for large-scale units. But, a conservative estimate would be 10 years. During this time period, it may be necessary to reactivate the hydride bed. Efficiencies as high as 95 percent have been measured for hydriding and dehydriding these devices.

The energy storage density for a metal hydride system will depend primarily on the hydrogen absorbing ability of the metal or alloy, its density, and the efficiency. For the iron-titanium alloy subsystem, storage density is estimated to fall in the range of 35 to 53 kWh/m^3. Just allowing for the difference in efficiency (75 versus 100 percent) would mean DE would fall to about 40 kWh/m^3. A conservative value of 35 kWh/m^3 is considered the low value.

3.5.3 Hydrogen Conversion to Electricity

Conversion of hydrogen to electric energy can be done in fuel cells and combustion devices (boilers or gas turbines). The fuel cell approach offers potential for high efficiency, with 50 percent a realistic target, and low air emissions. However, no commercial technology is available today. Future prospects are good for technology now being developed by United Technologies [66]. Readily adaptable to operation on hydrogen is the gas turbine and combined cycle plant. All of these approaches have been recently reviewed in detail [67].

3.5.4 Final Comments Listed below are the major conclusions in the analysis of Chemical Energy Storage.

1. Chemical energy storage methods are at a very early stage of development and must be considered as speculative at this time in terms of feasibility, technical characteristics, and costs.

2. Hydrogen energy storage has the potential for early implementation. Such a system would be comprised of a water electrolyzer, compressed gas storage, and a fuel cell or gas turbine. Overall efficiency falls in the range of 20 to 30 percent.

3. Chemical energy storage offers great system flexibility and can be installed in either closed-cycle or open-cycle schemes in evolutionary adaptation of existing energy resources, or provide the coupling of electric and gas resources.

4. The future of hydrogen energy storage will likely depend on improvements in the hydrogen to electricity conversion technologies where most of the inefficiencies and reduction in the capital cost of the electrolyzer currently exist.

3.6 FLYWHEEL ENERGY STORAGE

Flywheel energy storage is the storage of electrical energy as kinetic energy of a rotating mass. Most of the proposed, advanced applications of flywheel systems have been directed at eithe vehicular propulsion or electric utilities [68-69]. While special purpose applications exist [70] which are related to electric utility operation, most of the work has been on aircraft or spacecraft applications [71].

The basic design concept examined in this section incorporates a horizontal arrangement or ganged flywheels on a common shaft feeding a variable frequency field machine and a common cycloconverter. Subsystems required include bearings, vacuum systems, support structures, control systems, fire protection, and foundation-vaults. The design is a complete conceptual system for flywheel energy storage and represents a preliminary selection from the many design approaches. The flywheels are assumed to be within a readily transportable size with 10 feet taken as the nominal wheel size. Larger sizes, while possible, would pose serious shipping difficulties. Field fabricated wheels were not considered. This section describes a conceptual design of a flywheel energy storage system with a modest discussion of the subsystem design parameters. This design was generated to provide a consistent basis in defining the total system affects of various subsystem alternatives. Also a complete flywheel energy storage system, suitable for utility application, is not described in the literature.

3.6.1 Description and Present Status of Development

The state-of-the-art in flywheel energy storage systems is best summarized by stating that low energy density systems of a few kilowatt-hours capacity have been constructed and are being applied with great promise for success in transportation applications. The technology associated with those devices is not particularly advanced. Advanced, high energy density, systems have been proposed and certain critical components such as the wheel itself have been built and tested on a laboratory scale. To date, a detailed system design study in which the wheel is integrated into a total, reliable system is yet to be carried out.

Achievable energy storage in a flywheel is strictly limited by the density of the flywheel material, P, the fabricated working stress level, S, and the "shape factor", K. For flywheels, the specific energy storage is simply $E = K\ (S/P)$. Isotropic wheel shape factors are shown in Figure 3-20 and specific energy storage curves are shown in Figure 3-21. With K bounded by one (.5 for anisotropic materials), the specific energy is directly proportional to S/P.

It remains to be seen, however, if flywheel storage on utility systems can become economic. The flywheel systems currently in use, or at the detail design phase, utilize conventional materials,
low-cost fabrication processes, and relatively simple, but reliable design configurations.

Flywheels have been used by man since the beginning of civilization. The earliest use of the flywheels may have been a potter's wheel. With the advent of the industrial revolution, large flywheels became an integral part of man's daily life. Both the large Newcomen engine and the modern automobile make use of flywheels. More recent applications have included the Swiss Oerlikon transit bus, the pulsed power supply for the Princeton Plasma Laboratory, power shovel draglines, and the New York subway system.

The critical assumptions relative to the inertial energy storage system are in the area of costs and achievable stress levels rather then technical feasibility. The near-term flywheel is conceptualized with the assumptions listed in Table 3-12. The reduction from laboratory strengths is depicted in Figure 3-22. This reduction is based upon experience and good engineering practice. A lessening of these reductions would result in lower reliability and less design confidence.

Operational inertial energy storage systems consist of the following subsystems:

- Flywheel and shaft
- Bearings (and lubricants)
- Support structure
- Seals/feedthrough/couplings
- Vacuum system
- Clutch
- Speed reducer (gear box)
- Utility interface equipment - containment system and fire system

Although there is a significant degree of interdependence between these various subsystems, they are discussed separately in this section below.

Table 3-10

TECHNICAL CHARACTERISTICS OF HYDROGEN ENERGY STORAGE SYBSYSTEMS

Subsystem Alternative	Power, MW	Storage Capacity, MWhr	Efficiency %		Energy Density Kwh/m^3	
			High	Low	High	Low
(a) Compressed Gas Storage	10	100	99	75	20	14
(b) Metal Hydride	10	100	95	75	53	35

Table 3-11

TECHNICAL CHARACTERISTICS OF HYDROGEN ENERGY STORAGE CONCEPTS

Hydrogen Energy Storage Concept(a)	Power, MW	Storage Capacity, MWhr	Efficiency % High	Efficiency % Low	Energy Density kWh/M^3 High	Energy Density kWh/M^3 Low
(A)	10	100	58	28	25	17
(B)	10	100	56	28	41	27
(C)	10	100	45	23	25	17
(D)	10	100	43	23	41	27

(a) See text for concept identification details
A = electrolyzer + gas storage + fuel cell
B = electrolyzer + hydride storage + fuel cell

N_t = overall thermal efficiency, percent
D_E = energy storage density,
D_P = power density, kW/m^3

A daily duty cycle with 10 hours of discharge is assumed.

C = electrolyzer + gas storage = gas turbine
D = electrolyzer + hydride storage + gas turbine

R_c = maximum charging rate, MWhr/hr
R_d = maximum discharging rate, MWhr/hr

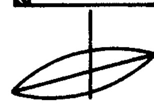
WHEEL TYPE	SHAPE	SHAPE FACTOR
CONSTANT STRESS R		1.0
CONSTANT STRESS		0.834
CONICAL DISK		0.806
FLAT DISK		0.606
THIN RIM		0.50
SHAPED BAR		0.50
RIM AND WEB		0.40
STRAIGHT ROD		0.333
DISK WITH HOLE		0.305

Figure 3-20 ISOTROPIC WHEEL SHAPE FACTORS [69]

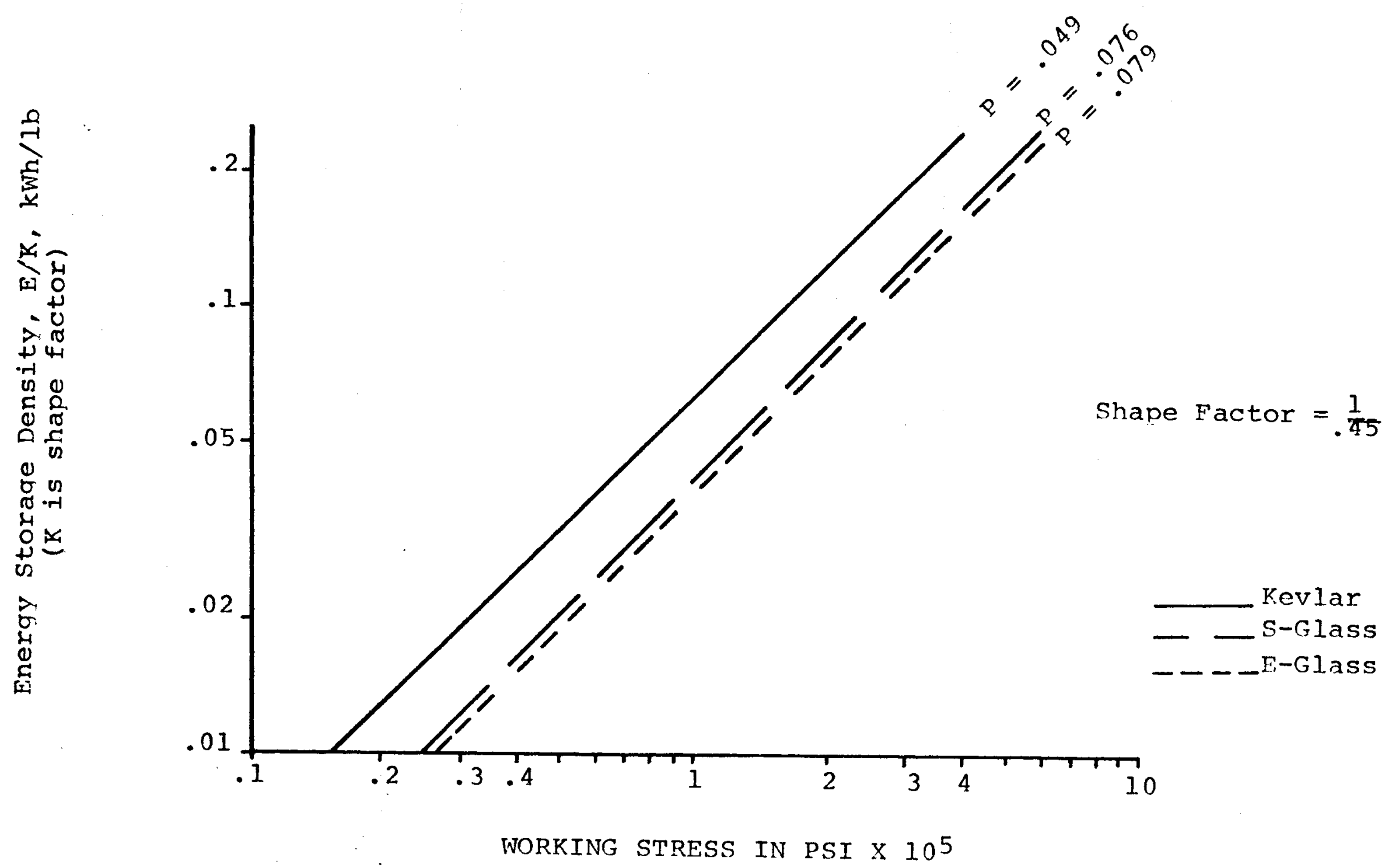


Figure 3-21 ENERGY STORAGE DENSITY VERSUS STRESS LEVEL

Table 3-12 FLYWHEEL SYSTEM ASSUMPTIONS

Assumed Maximum Parameter	Rationale	Comments
Wheel Diameter - 10 ft Wheel length - 10 ft	Ease of manufacturing Transport-clear bridges	Larger wheels would have to be assembled and balanced at the site Windage losses increase with velocity; optimum design might be smaller in diameter
Wheel speed - 10,000 rpm	Diameter/speed ratio appears compatible with near-term materials Bearing DN (bearing base in millimeters times rpm) limits will not allow higher rpm	Detailed trade-off analysis is required
Energy storage speed range = 5,000 to 10,000 rpm	2:1 speed range appears optimum with respect to power generating requirements	Trade-off of rpm range versus variable-speed transmission economics is required
Charge-discharge time = to 10 hours	Compatible with power company requirements	Detailed trade-off with economics and power company requirements is necessary

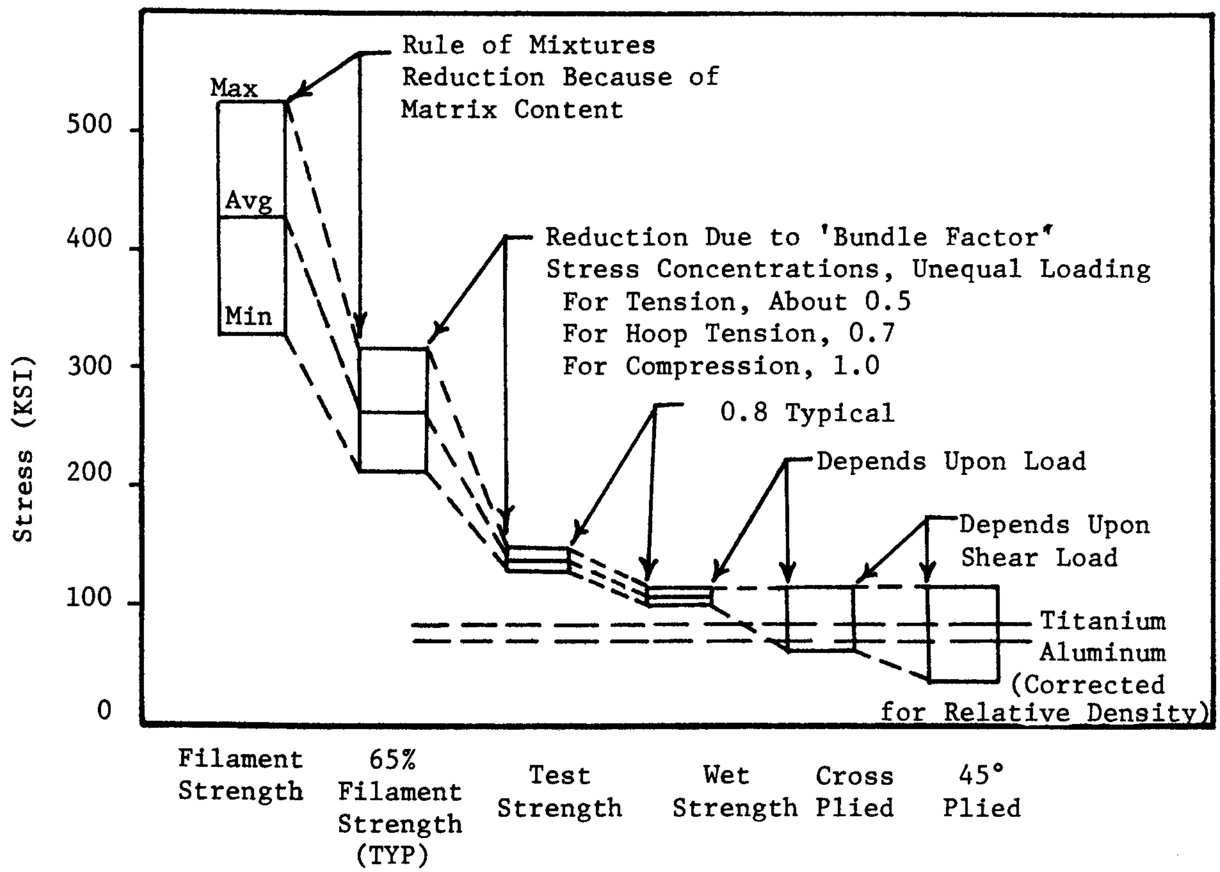


Figure 3-22 STRENGTH/BREAKING STRESS

3.6.2 Technical Assessment

3.6.2.1 Wheel Configurations Four basic advanced concept wheel are examined in this analysis: (1) constant stress, (2) brush, (3) constant thickness multirim and (4) laminated isotropic. Each configuration has its advantages and each is appropriate for specific material and time frames. Table 3-13 presents an overview of each configuration.

The constant stress wheel is ideal for metallic materials and small flywheels. Essentially a tapered disk, material utilization is increased by tapering the disk thickness with the wheel radius. For large sizes, hybrid, tapered, laminated flywheels constructed from fiber composites and metals, are required. Fabrication and non-destructive testing are expensive and difficult. If forged metals are used as the basic material, extensive machining is required. To achieve high fiber loading efficiency, substantial development work would be required.

The brush design (by David W. Rabenhorst; Applied Physics Laboratory, Johns Hopkins University) utilizes unidirectional high strength filaments in a plastic matrix (Figure 3-23). The brush-like design does not make efficient use of the swept volume, but would permit use of a fabrication technology (pultrusion) already in an advanced state of development. Individual rods are stressed unevenly unless they are tapered--an expensive procedure. Rod anchoring at the hub may be quite difficult and may cause stress concentration problems. High vacuums will be required to keep drag forces to reasonable levels.

The constant thickness multirim concept is based on the use of concentric rings of fiber composites separated by resilient (elastic) material (Figure 3-23). The concentric rings or hoops are thin enough to minimize radial shear that could result in delamination. Each ring is fabricated so the ratio of its elastic modulus to its mean density is smaller than the ring immediately around it and this should minimize disproportionate separation between the rings. Heavy filler material can be added to each ring, varying the amount of filler with radius, to increase the mean density of the inner rings and to stress each ring to its optimum level. The resilient bonding material can be a rubber-like material or, simply, a more resilient composite material. Quality assurance will be complex. This concentric ring design allows lower cost, higher performance or heavier materials to be used where optimum. Conventional fabrication procedures are applicable, but considerable development work will be required.

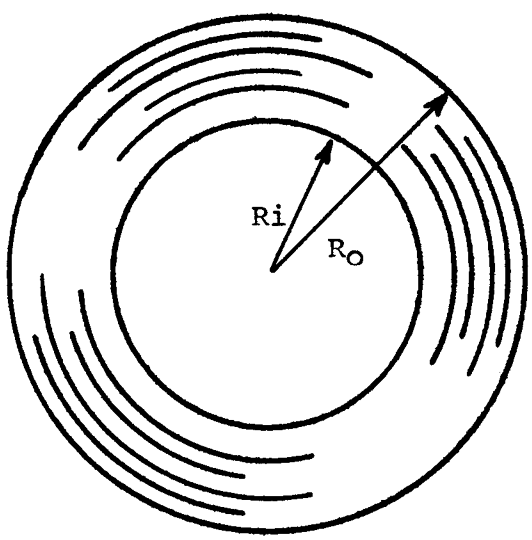
A laminated, isotropic material flywheel disk configuration would utilize sheets of high performance steels or titanium. Wheel

Table 3-13 FLYWHEEL CONFIGURATIONS

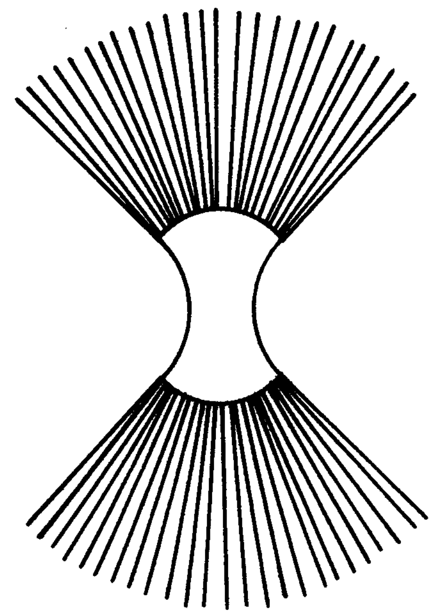
Concept	Technical Feasibility	Fabrication Cost
Constant Stress Configuration (laminated concept)	Feasible in the 1980-1985 period. Design for optimization of materials system, cost, and fail-safety are major factors influencing acceptability of concept. Large sheet materials in metals and composites are required. Difficult to tailor composites at low cost and achieve high fiber loading efficiencies. Theoretically there is a potential for a "tailored" optimized design. However, trade-offs with cost are required.	High
Brush	Where volume required is cost-effective, concept is highly feasible in 1976-1980 period. Rods occupy small portion of swept volume, adversely affecting cost and size of system. Rods are stressed unevenly, unless tapered rods are used which pose production problems. Rod anchoring at hub are complex, expensive to produce, and cause stress concentration problems. Difficult to maintain balance of flywheel due to shedding of rods. Fibers are utilized efficiently. Quality assurance (QA) techniques can be automated and incorporated as part of the pultrusion process. Failure of rods is not catastrophic. Assembly on site is simple, as is transportation.	Low

Table 3-13 FLYWHEEL CONFIGURATIONS (CONTINUED)

Concept	Technical Feasibility	Fabrication Cost
Multirim Constant Thickness	Considerable R&D is necessary Concept is feasible in 1980-1985 period. This is a sophisticated design. To optimize configuration, Different fibers must be used which increase quality assurance problems. When various fibers are used, considerable test data is required. Quality assurance is complex, resulting in low production rate. Deficiencies in fabrication difficult to rectify. The concentric ring design allows lower cost, higher performance or heavier materials to be used where optimum. Conventional filament or tape winding fabrication processes are applicable. It has high volume efficiency. Resilient rings can be incorporated between structural rings. Fracture tolerance can be incorporated in the design concept.	Moderate
Laminated Isotropic Materials	Highly feasible in 1976-1980 period. However, there are size limitations due to energy density requirements. For large flywheels, sheets must be joined. Flywheel size limited due to density of steel. Simple and fracture tolerant design. High properties of thin materials are advantageous as are low cost fabrication and assembly. Can be upgraded by substituting higher performance sheet materials.	Low



MULTIRIM



BRUSH

Figure 3-23 LAMINATED CIRCULAR BRUSH AND MULTIRIM SUPER FLYWHEEL CONCEPTS

Table 3-14 MAGNAMITE CONTINUOUS FILAMENT GRAPHITE FIBER, PROPERTIES

Fiber Type:	AS	HTS	HMS
Nominal Filament Diameter, microns	7.8-8.1	7.4-7.8	7.2-7.5
Average Density,[a] lb/in	0.0645-0.0660	0.0648-0.0663	0.067-0.0685
Weight per Unit - Length of Tow,[a] lbs/in x 10^{-6}	45-50	44-49	43-48
Ultimate Tensile Strength [a,b] x 10^3 psi	410 minimum	400 minimum	340 minimum
Modulus of Elasticity [a] x 10^6 psi	30-34	34-37	50-55

(a) Lot average values
(b) Lower values are guaranteed minimum values

SPECIFIC FIBER PROPERTIES

Fiber Type	Specific U.T.S. x 10^6 in.	Specific Modulus x 10^6 in.
AS	6.2-6.4	460-530
HTS	6.0-6.2	515-570
HMS	5.0-5.1	730-820

Table 3-15 KEVLAR 49-III, ORGANIC FIBER, SPECIFICATIONS

	Requirement	
	12-End Roving	4-End Roving
Tensile strength (package average), psi	490,000 minimum	490,000 minimum
Tensile strength (lot average), psi	500,000 minimum	500,000 minimum
Tensile modulus, psi	17.5×10^6 minimum	17.5×10^6 minimum
Weight, g/yd	0.458 ± 0.010	0.458 ± 0.010
Density, g/cc	1.45	1.45
End count	12 ± 0	4 ± 0
Fibers/end	267^{-3}_{+0}	768^{-9}_{+0}
Fiber diameter, in.	0.000463 nominal	0.000474 nominal

Kevlar 49 is a registered trademark of DuPont.

TABLE 3-16 ENERGY DENSITIES

Material Properties and Energy Characteristics	FLYWHEEL CONCEPT AND MATERIAL TYPE					
	Brush Boron Fibers	Single-Ring Graphite/Epoxy (Thornel 300)	MultiRing Steel	Disk Steel	Constant Stress Steel	MultiDisk Graphite/Epoxy with Interleaves
Ultimate Tensile Strength, F_{tu}, ksi	400	150	150	150	150	220
Material Density, lb/in^3	0.10	0.056	0.30	0.30	0.30	0.072
Energy Density, W-H/lb	40-50	60-65	6.75-7.25	5-7	12-13	40-50
Energy/Unit Swept Volume, $W\text{-}H/in^3$	0.0006-0.0010	0.10-0.4	2.0-2.2	1.5-2.0	4-4.5	3

size will be limited by the material densities, but a minimum of development work would be required.

3.6.2.2 Wheel Problem Areas Many problems can be foreseen when large flywheels are made using modern composite materials. Shape change can occur when the wheel is at rest and under the influence of gravity. This shape change is due to slow creep properties of composite materials. Depending on the details of manufacture and individual material properties, the effect could be large enough to affect wheel balance. Because of the great weight of the wheel, small dimensional changes could be serious.

For the multirim concept with an elastic material between successive rims, elastic deformation or "droop" could displace the center of mass off the spin axis causing serious start-up problems. In principle, however, once started, the system should be self-centering. Also the elastic material between successive rims must be capable of transmitting the large torques associated with speeding up or slowing down the wheel.

A major problem with composites of glass-reinforced plastic (GRP) is their low resistance to interlaminar shear compared to their tensile strength along the length of the fiber. This poses a problem in absorbing large radial forces, and it will restrict rates of acceleration and deceleration.

Related problems are the limits of the bonding properties of the materials (fiber to plastic matrix to fiber, plastic matrix to elastic material, etc.).

3.6.2.3 Candidate Materials Candidate materials for construction of energy storage wheels include high strength steels, aluminum, titanium, high strength glass fibers (E-glass, S-glass), carbon fiber, boron fiber, and new material such as Kevlar. Each of these materials has special properties which make them attractive.

The properties of single fiber strands or tows should not be used to predict the performance of hardware fabricated from composite materials. Fabricated (in situ) properties are significantly different from those measured in the laboratory. Achievable safe working stress levels are substantially below laboratory values (Figure 3-23). Achievable stress levels are lower than laboratory values due to: (1) resin volume, (2) variation in fiber properties, (3) fiber damage over winding pulleys, (4) design safety factors, (5) reduction in strength due to resin effects, and (6) the need for cross plies.

Hercules Magnamite continuous filament graphite fiber is fabricated from polyacrylonitrile (PAN) fiber precursor. The fiber is a twist-free tow containing nominally 10,000 filaments and is available in continuous lengths up to 5,000 feet without splices which is important for filament or tape would flywheel concepts. The properties of Hercules type AS and other fibers are listed in Table 3-14. Type AS, a high strength fiber (410 ksi minimum) is of particular interest in this assessment. Taking into account the variation in this fiber, fiber damage over winding pulleys and resin volume, a minimum tensile strength in the range of 150 to 200 ksi is a realistic value. Similarly for the Du Pont Kevlar-49-III fiber, the minimum specification requirement is shown as 490 ksi, in Table 3-15.

With regard to wound structures, S-901 glass, with an average tensile strength of 567 ksi, lends itself to winding; the resin selected is not as critical as for other fiber types, and a high volume percentage for fiber loading is achievable, e.g., 60 percent.
However, the density of S-901 glass is 0.090 $lb/in.^3$ as compared to 0.052 $lb/in.^3$ and 0.065 $lb/in.^3$ for Kevlar-49-III and graphite fibers, respectively.

Table 3-16 summarizes the ultimate strengths and energy densities for various flywheel configurations and material combinations. Of the concepts studied, the multirim configuration executed in metal and composite materials appears to be most promising for first-generation flywheels based on the following factors:

- Type, properties, and cost of fibers can be varied radially to optimize the flywheel
- Fiber volume in the composite can be varied radially
- Thickness of the rings can be varied radially
- As composite structures are built up to size, in contrast to machining down to size, materials and power requirements in fabrication are conserved
- Interface rings of resilient materials can be incorporated between structural composite rings
- Composite rings or complete flywheel can be encapsulated with high-performance materials, or high-performance metal strip interleaves can be used for fail-safety or to minimize influence of material and fabrication deficiencies
- Axially-mounted metal disks can be incorporated to compensate for low interlaminar properties of composites

- Composite winding technology developed for rocket cases and pressure vessel applications, and modifications of equipment developed for military uses and large filament-wound pipes will shorten the lead time

3.6.2.4 Bearings The function of the spin-axis bearings is to support the wheel/shaft assembly. The bearing system must meet the general requirements of long life and low drag losses. The bearings are an important life-critical component, and for near-term applications, represent a major maintenance item. While the design of the bearing is influenced by the entire system, the shaft, wheel configuration, and support structure (vis-a-vis stiffness and alignment) are especially critical to bearing performance.

Table 3-17 shows a matrix of the bearing subsystems that were considered. All bearing concepts are being applied to gyroscopes, with the exception of the ball-magnetic hybrid developed during the course of this study. None has been applied to large, high density designs.

The ball and roller bearing systems require a lubricant. The lubricant must meet the following requirements:

- Provide full-film lubrication under all operating conditions

- Have a low vapor pressure (this requirement is conditioned by seals and overall configurations)

- Make a minimum contribution to viscous drag losses

An overview of three major lubricant subsystems is listed in Table 3-18. The specific choice of lubricant is dependent on the type of flywheel configuration and the bearings used. A superrefined mineral oil appears best suited at this time.

3.6.2.5 Frame and Support Structure The support structure of a flywheel system exerts a critical influence on bearing life, erection costs, and system weight. In addition to manufacturing cost considerations, the flywheel frame must be light and stiff. The weight impacts the power-to-weight ratio of the system, as well as foundation costs. Stiffness has a direct influence on alignment, bearing life, and maintenance cost. An overview of frame and support structures is provided in Table 3-19.

3.6.2.6 Seals and Feedthroughs One of the major problem areas in energy storage flywheel systems (along with the wheel and support bearings) is the method by which the power is removed

Table 3-17 MATRIX OF BEARING SUBSYSTEMS

Subsystem	Concept	Advantages	Disadvantages	Conclusion
Bearings	Ball	● Relatively low drag ● Highly refined and well understood ● Relatively safe in event of failure	● Relatively short life ● Speed-load limited	Refined ball bearing-lubricant system is suitable for near-term applications
	Roller	● Relatively high load capacity ● Highly refined ● Relatively safe in event of failure	● Relatively short life ● Speed-load limited ● Higher drag than ball	Speed-load limitations make roller bearing less suitable than ball bearings
	Fluid journal pumped or self acting	● Long life ● High speed ● High load capacity	● Very high losses due to viscous drag	Not suitable because of excessive drag losses
	Gas bearing	● Long Life	● Low load capacity ● High losses ● External pressurization system required	Extensive seal research, development relative to windage losses and other system considerations necessary for successful implementation
	Magnetic bearing	● Long life ● Very high speed ● Low drag potential	● Limited capacity ● Stability requires high power consumption ● Failure can be catastrophic	Potential system. R&D is required to reduce power consumption and increase capacity
	Ball-magnetic hybrid	● Longer life than ball alone ● Possible lower power consumption than magnetic alone ● Relatively safe in event of failure	● Hybrid, while potentially better than ball or magnetic bearing alone, are the life/performance limiting subsystem for advanced wheel	Potential near or mid-term application. Compromise concept

Table 3-18 MAJOR LUBRICANT SUBSYSTEMS

Subsystems	Concept	Advantages	Disadvantages	Conclusion
Lubricant for rolling element bearings	Grease	● Low maintenance ● No auxiliary lube system ● Good lubrication in low vapor pressure forms	● High viscous drag losses ● Possible thermal problems ● No wear debris removal	Not suitable
	Oil, liquid	● May be circulated and filtered, debris removed and bearings cooled ● Generally lower drag than grease	● Drag losses can be highly variable ● Heat removal not optimum ● Auxiliary lube system required	No optimum with respect to distribution and drag losses
	Oil, mist	● Lowest possible drag losses for oil-lubricated bearings ● Optimum heat removal and distribution ● Good debris removal possibly not as good as liquid oil flush	● Minimum lubricant quantity, no reserve in event of lube system failure ● Debris removal not optimum	A well-designed oil mist system using a low vapor pressure oil appears to be best at this time

Table 3-19 FRAME AND SUPPORT SUBSYSTEMS

Subsystem	Concept	Advantages	Disadvantages	Conclusion
Frame/Support structure	Ring	● Easy assembly ● Ease of Maintenance (i.e., accessibility to life-critical components) ● Ease of alignment ● Vacuum housing nonstructural	● Complex ring and two piece vacuum housing ● Possible vacuum seal problems due to com-lex housing shape ● Possibly heavier than optimized shell configuration	Probably most cost effective in terms of maintenance and life-critical alignment
	Shell	● Simple, two-piece configuration ● Higher potential rigidity per pound than ring ● Round, flat vacuum seal	● Alignment difficult and must be disturbed to gain access--high main-tenance costs ● Vacuum housing is structural	Possible use for light, advanced system having low maintenance require-ments inside vacuum housing

from, or introduced to, the system. An overview of these subsystems is given in Table 3-20. The most simple and lightweight approach is to place the motor/generator on the spin axis inside the vacuum enclosure. This method has been proposed for spacecraft applications, but, is not suitable for efficient electric power storage systems.

The designer of terrestrial high energy density systems is thus faced with the need to conduct the rotary motion of the spin axis through the vacuum enclosure. This may be accomplished by seals on a continuous shaft passing through the vacuum wall or by means of a method of power transmission through a hermetic seal.

The specification of seals or feedthrough must consider the following requirements:

- Low power loss due to drag or friction
- Relative ease of assembly or replacement
- Long Life
- Effective sealing of 10-4 to 10-1 torr vacuum levels

Table 3-20 is an overview of several seals and feedthrough concepts.

A special coupling is required between flywheels to:

- Allow for some misalignment during installation
- Transmit torque
- Damp any oscillations that might be produced by the multiflywheel arrangement
- Decouple one flywheel from the rest of the system if it should fail

The specific design of this coupling is not final. Most of the requirements are within the capability of conventional couplings, with the exception of the decoupling features. Decoupling could be achieved by means of explosive bolts triggered by an inductive pulse.

3.6.2.7 Speed Reducer The cost of generators is a function of speed. The optimum generator speed is substantially below that of a flywheel. Since the energy stored in a flywheel varies with the square of the rotational rate, it is desirable to operate at speeds which require a speed reducing transmission. This

Table 3-20 SEALS AND FEEDTHROUGH SUBSYSTEMS

Subassembly	Concept	Advantages	Disadvantages	Conclusion
Seals and Feedthroughs	Rubbing seals	● Positive ● Relatively simple, inexpensive ● Allows a one-piece shaft, i.e., reduces number of bearings	● High friction losses ● Life is speed/size limited and is relatively short	Not suitable due to DN limitations and losses
	Labyrinth seals	● Low drag losses ● Long life, not speed limited ● One-piece shaft	● Complex, close tolerances ● Possibly not adequate in pressure regimes involved	Detailed design-analysis required to determine suitability
	Ferrofluid seals	● Positive ● Relatively low drag ● One-piece shaft	● Speed size limited ● Life not demonstrated	Promising further research required to develop and demonstrate large, long-life version
	Magnetic feed-throughs	● Positively-contained vacuum at any level ● Provides shaft damping	● Power losses (hysteresis and electro-magnetic) ● Complexity - two pieces shaft additional support bearings ● May be torque-limited ● Requires bearings on vacuum side	Probably suitable at present SOA. Complexity, costs, losses must be traded off against windage losses - vacuum pump capacity

Table 3-20 SEALS AND FEEDTHROUGH SUBSYSTEMS (CONTINUED)

Subassembly	Concept	Advantages	Disadvantages	Conclusion
Seals and feedthroughs	Mechanical feed-throughs, Harmonic drive Wobble drive	● Positive mechanically ● Positive vacuum seal	● Proliferation of bearings and single-point failure possibilities ● Never scaled to high torques	Probably not suitable due to cost, complexity, unreliability, etc.
	Self-contained (motor generator in vacuum)	● Only electric wires pass through vacuum wall	● Severely speed-limited due to motor/generator speed characteristics ● Cannot be ganged together ● Heat dissipation	Might ultimately be suitable for transportation flywheels

transmission must be efficient and should be light and reliable. The power and torque requirements for near-term applications are 1,200 hp and 16,000 lb-ft, respectively. These requirements will, of course, go up as power levels increase. Table 3-21 lists three possible speed reducer transmission concepts.

3.6.2.8 <u>Vacuum System</u> For most efficient operation, the flywheel must operate in a reduced pressure environment to reduce windage losses. The pressure is optimum with regard to system operating efficiency and installation and maintenance costs, and is a complex function of wheel aerodynamics, seal efficiency, pumping efficiency, feedthrough design, and leakage composition. In general, the type of vacuum pump and the enclosure sealing requirements will be determined by the aerodynamics of the wheel, and the sealing/feedthrough subsystem.

A clutch is necessary in the system to reduce the friction and windage losses during the no-load period of the duty cycle which will vary in from a few hours during the week to the entire weekend. The clutch may be located in side the vacuum enclosure to lower the seal losses.

The major component of costs that can be affected by further research and development is the energy density of the flywheel itself. The system will become more cost effective by lowering the material costs or by increasing the working stress levels significantly. The latter improvement could not be fully utilized until the bearing designs have a higher dynamic loading capability for high speed applications.

3.6.2.9 <u>Trade-Offs</u> An inertial energy storage system cannot be applied everywhere on typical electric utility distribution system circuits. Consideration must be given to the short circuit contributions from the system, the voltage dip starting of the device (Figure 3-24), and safety considerations. The short circuit problem can be lessened through the use of current limiting devices (Figure 3-25).

3.6.2.10 <u>Foundations</u> Economies of scale are applicable to the foundation requirements for flywheels. Mounting the flywheel shaft horizontally provides the ability to add flywheels in series and lowers the foundation requirements.

A vertical shaft requires foundation restraint for steady state and transient torques which may not be feasible or economic unless a bedrock foundation is available at the building site. The foundation has to counter the torque produced by taking power in and out of the system. This torque is related to speed and power by:

$$P = 2.26 \times 10^{-5} TW$$

Table 3-21 SPEED REDUCER SUBSYSTEMS

Concept	Advantages	Disadvantages	Conclusions
Transmission, horizontal shaft, parallel offset	● Available off the shelf for near-term applications ● 95-98 percent efficient	● Separate lubricant system required ● Relatively heavy	Best for near-term application. Design optimization required for high power applications (<1,500 hp)
Traction drive	● Variable ration (flexibility, optimum generator input speed)	● 90 percent max. efficiency ● ~100 hp SOA ● Not well suited to high inertial loads and load variations	May be applied in the future--motor/generator efficiencies must be traded against cost/complexity of vaiable speed capability
Harmonic drive	● Relatively simple ● Can also serve feedthrough function	● Limited to 500 hp ● Reduction ratio too high ● Life of flex spline at high loads and speeds is uncertain	Research and development directed at power-speed scale up may make this suitable for second generation high speed (20,000 rpm drives)

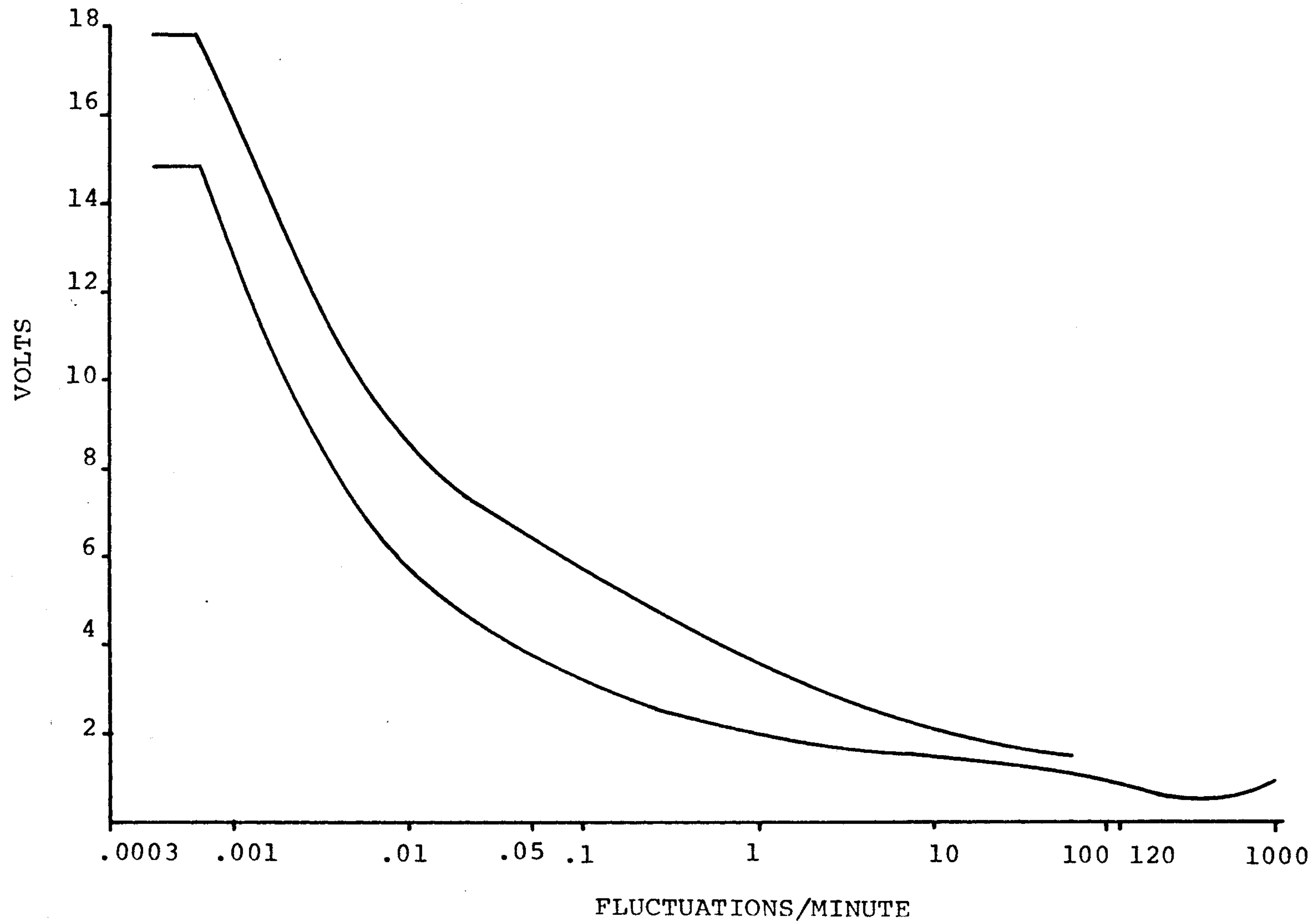


Figure 3-24 PERMISSIBLE VOLTAGE FLUCTUATIONS (120 Volt Base)

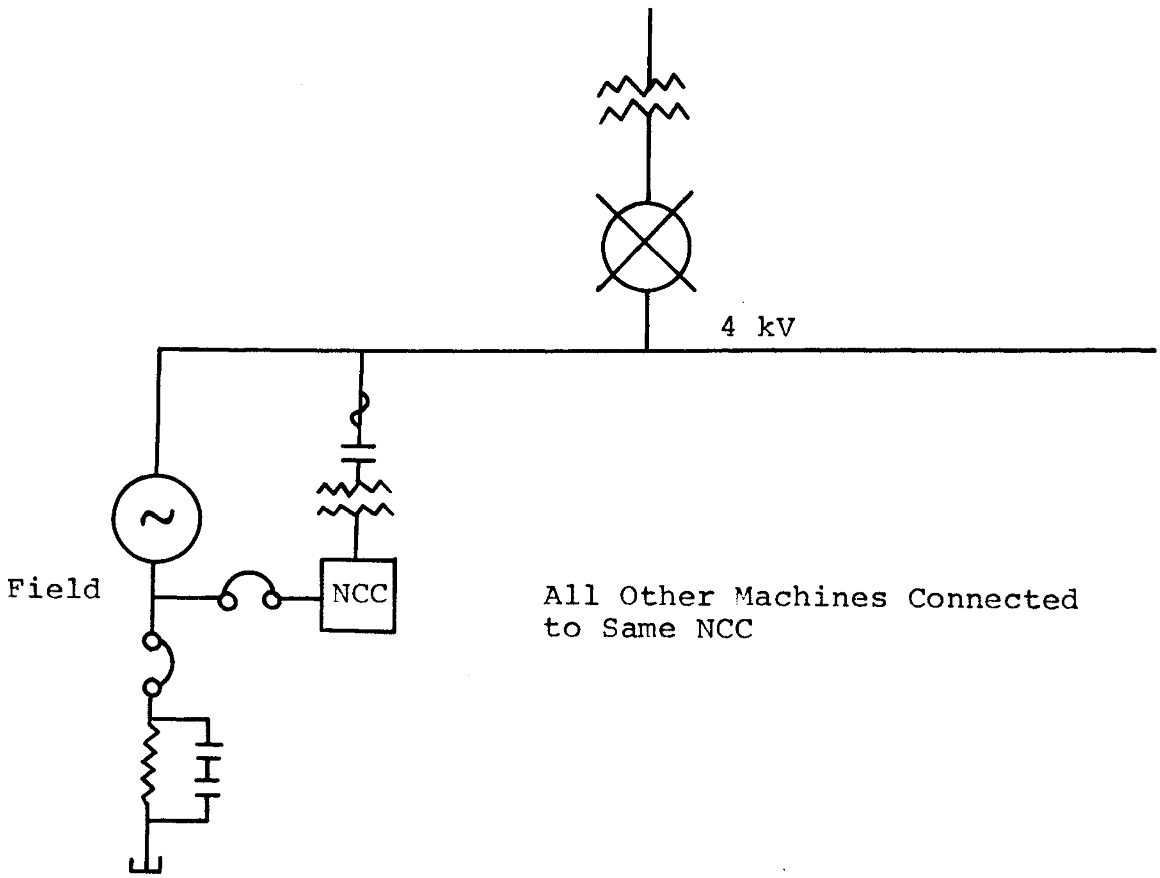


Figure 3-25 INERTIAL ENERGY STORAGE SYSTEM, ONE LINE DIAGRAM

Where T is the torque in lb - ft

W = Speed in radians per minute

P = Power in kilowatts

The transient torques are produced by switching between distribution networks.

A horizontal shaft system puts the earth under it in compression. Standard construction piles, even in marshy soil, are able to take substantial amounts of compressive loads. The reaction of the earth to the variable compressive load has been studied. All utility turbo-generators have foundations with similar loads.

The safety requirements have been designed into both the flywheel construction and its containment. For multiple ganged flywheels, the coupling between the flywheels is designed so that the failure of one flywheel will not draw energy from the remaining flywheels. The containment criteria is such that very thick walls and tamped earth surround the flywheel. The lid of the flywheel vault incorporates a water blanket for weight and fire protection.

3.6.2.11 Motor/Generator The variable frequency field (VFF) machine has been chosen for application in a flywheel energy storage system because it is the lowest cost and most reliable of the motor/generator systems that are practical. This machine combines proven technology with inherent high reliability. It can have an efficiency of approximately 90 percent.

DC machines are not considered suitable due to the commutation limits imposed by mechanical commutators and the need for a full dc to ac converter.

Field-modulated machines using the application of the synchronous flux principle are also not considered to be suitable. Standard synchronous machines, with constant speed mechanical transmissions, are also not considered to be suitable due to the extremely stringent speed control requirements imposed by the system to the constant speed transmission.

The inverter requirements for the VFF machine are the slip multiplied by the machine rating. Slip is defined as the magnitude of the difference in rotor electrical frequency and synchronous frequency divided by synchronous frequency. A 25 percent increase is made to this basic size to account for variation in the reactive power absorbed by the the field windings and some VAR control. For a 75 percent depth of discharge, a converter that is 41 percent of machine rating is required. This is substantially lower than any other approach.

3.6.2.12 Balance of Plants The balance of plant for the flywheel energy storage system will include:

- Contactors and fuses for each VFF machine
- Interconnection AC bus
- Standard protective relaying
- Control system
- Communication system for unattended operation
- Current limiting device
- Miscellaneous equipment

All of these systems are relatively standard either industrial or utility systems. The relay protection (Figure 3-26) is more typical of a generator auxiliary power system and may be more than is needed.

3.6.2.13 Installation Installation of the system requires containment vaults, support base and flywheel installation, speed reducer and clutch installation, and utility interface equipment.

The containment vaults could be installed by standard construction crews who are skilled in the placement of reinforced concrete. The support base and flywheels themselves would not be shipped together due to the potential for bearing damage by shock loading. To avoid special packaging costs, 100 flywheels would be shipped by regular carrier to insure that a special crew and cranes used during installation do not wait for special containers to make many trips between the factory and the site. The installation techniques and critical alignment necessary for a flywheel installation are very similar to those necessary for a turbine generator installation. It must be remembered that the analogy between turbine generators and flywheels is a physical one that is not dependent upon power level.
It can be assumed that the installation cost of the support base, flywheel, speed reducer, clutch, and a utility interface equipment is equal to the cost of installing 800 to 1,000 MW turbine.

3.6.3 Final Comments

The difficulties involved in transferring emerging material technologies to production status hardware, should not be underestimated.

Working stress levels in large composite wheels are yet to be measured. The major research opportunity lies in developing improved materials and fabrication procedures to achieve

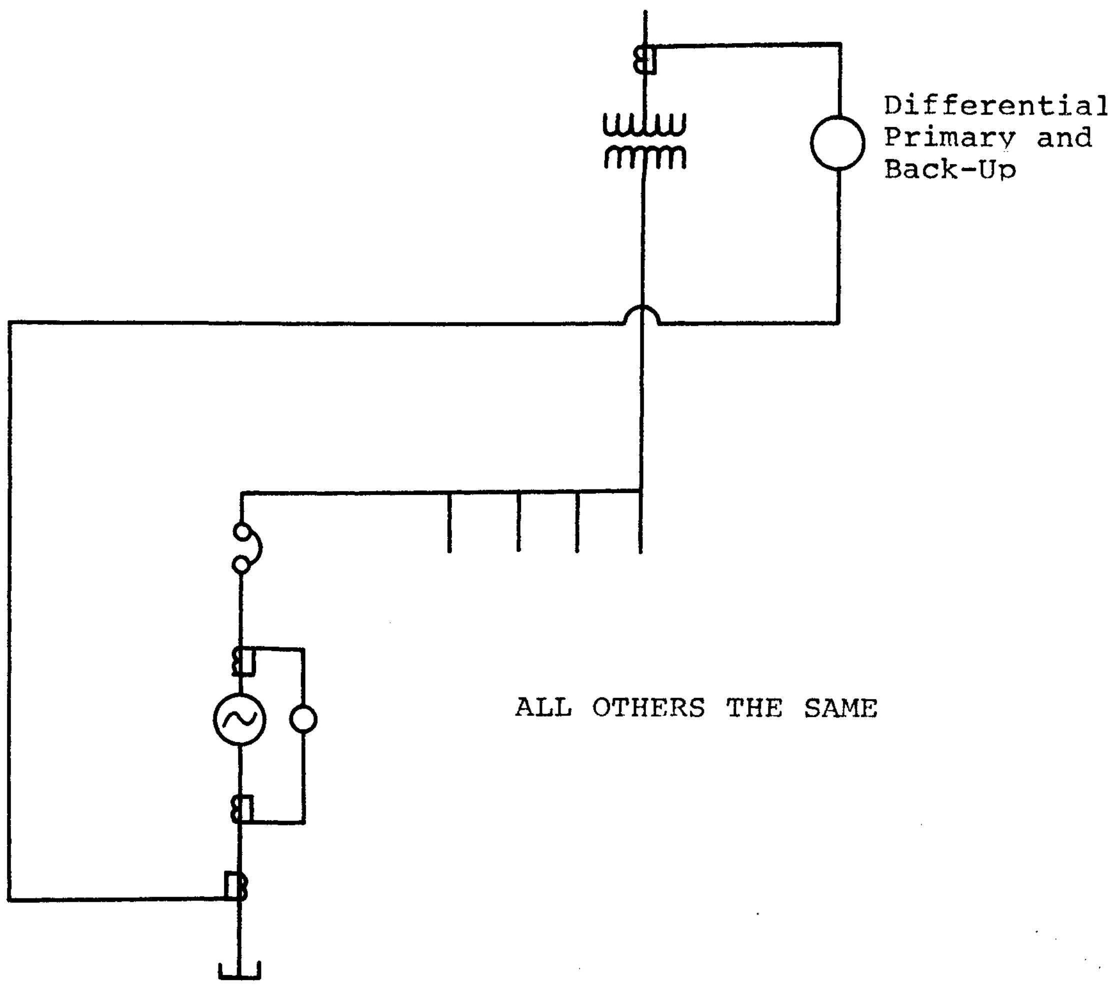


Figure 3-26 RELAY PROTECTION

significantly higher working stress levels. Fundamental improvements in the fiber properties could also occur. The potential for such improvements, perhaps doubling or tripling the currently achievable working stress levels, could make flywheel systems more attractive. Simultaneous improvements in fabrication techniques, low cost quality assurance methods, and low cost fabrication procedures could substantially improve the flywheel storage device.

Since superconducting bearings are in the first stages of development, the refrigeration requirements for the flywheel system are not yet defined. Because of the large number of bearings, any increase in energy storage due to improved superconducting bearings must be weighed against the increased costs of the balance of plant.

The two major life/cost critical subsystems requiring R&D are:

- Spin axis bearings
- Feedthrough and/or seals

High-capacity, low drag bearings must be developed through research in the following areas:

- Improved ball bearings
- Hybrid-ball/magnetic bearings
- Magnetic bearings - especially superconducting

Long life, efficient feedthroughs must be developed:

- Heavy-duty magnetic couplings
- Long-life ferrofluid seals
- Advanced low drag rubbing seals

It must be stressed that development of the wheel and the mechanical subsystems must be carried out with a systems perspective. The improvements should not be negated by increased balance of plant costs. This should not be the case by increasing the energy density of the flywheel but it could be in the area of superconducting bearings.

3.7 SUPERCONDUCTING MAGNETIC ENERGY STORAGE

A superconducting magnetic energy storage system (SMES) stores electrical energy in the magnetic field produced by a circulating current in the winding of a magnet. A simplified circuit is given in Figure 3-27. The energy stored is simply $LI^2/2$. If the magnet is superconductive, then the constant current resistance R is essentially zero. After closing the switch S, which is superconducting, current will continue to circulate obeying the simple law:

$$i = I \bullet \exp(-L/R)$$

If R is zero, the current i will always equal the initial current I. Any small resistance R in the circuit will result in any energy loss equal to i^2R and slowly discharge the stored energy.

Magnetic storage can be comparatively efficient. The energy is stored directly as electromagnetic energy, so that losses associated with conversion of potential, mechanical, chemical, or thermal energy to electrical energy and the reverse are avoided. Energy losses are, however, associated with the refrigeration power requirements and the conversion of ac to dc and the reverse process.

A SMES system has many of the same requirements as an underground pumped hydro facility. Both require a dedicated surface land area and bedrock for the storage reservoir. As the SMES system loses 10 to 20 percent of its input energy into the air from transformers, converter system and refrigeration system, cooling towers might well be required.

3.7.1 Description and Present Status of Development

Application of superconducting magnetic energy to power systems is in a very early stage of development. The proposed use of a superconducting inductor for energy storage makes use of the principle that energy can be stored in an inductor of zero resistance for, theoretically, an infinite amount of time. An inductor made from a superconducting material stabilized with a normal conductor is housed in a Dewar. The superconducting magnet is charged using off-peak energy, and during peak periods, energy is fed back to the system.

Work on superconducting systems for energy storage is being carried out at Los Alamos Scientific Laboratory and the University of Wisconsin. Much of the present effort is concentrated on small-scale work using current technology, conceptual development and cost projections.

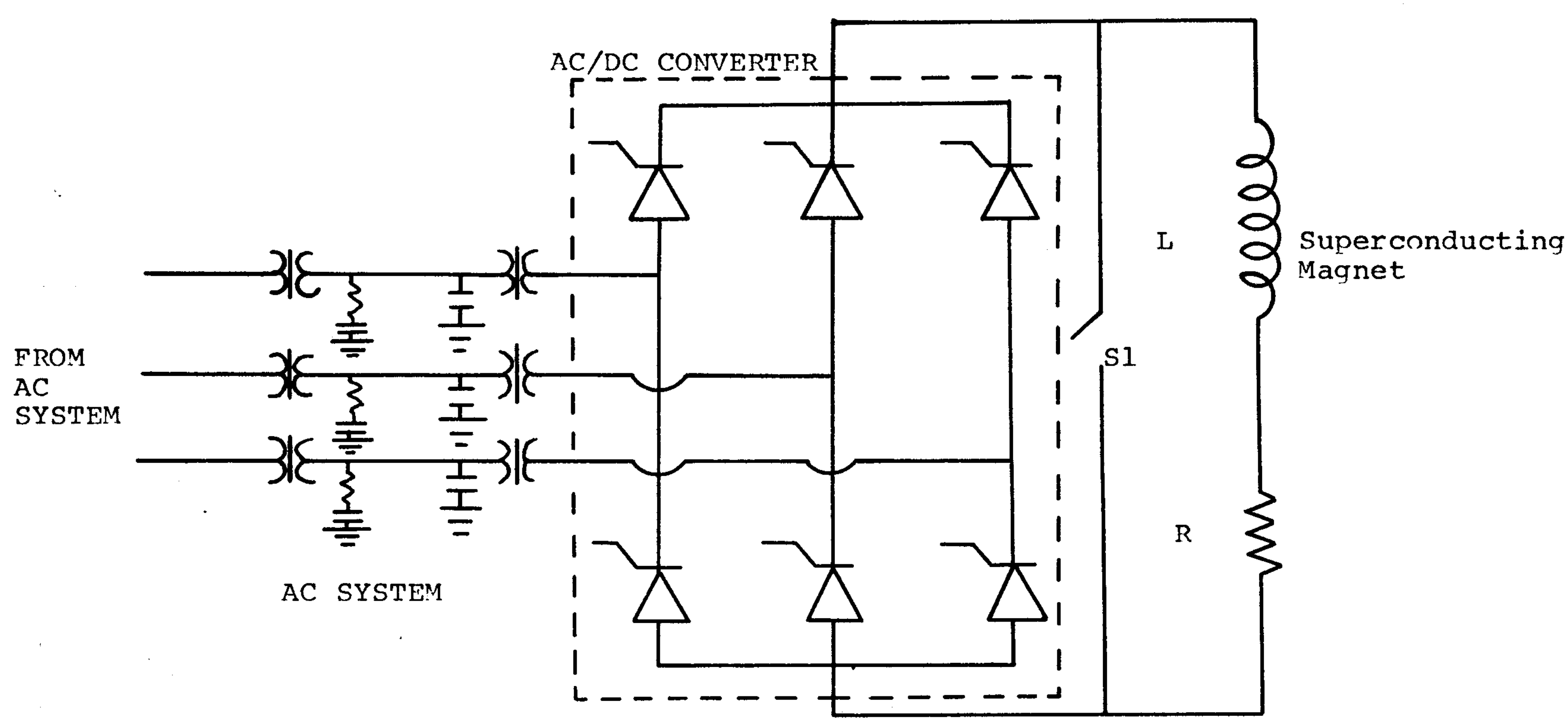


Figure 3-27 SUPERCONDUCTING MAGNETIC ENERGY STORAGE, ELECTRICAL DIAGRAM

A French group [72] has been experimenting with magnetic energy since about 1965. The most significant systems were developed for very fast discharge and were smaller in capacity by 9 orders of magnitude than the 10^7 to 10^8 MJ required to meet the demands of power networks.
Various coil configurations were investigated, and the short solenoid of circular cross section was determined to be the most favorable in terms of maximizing the stored energy per unit volume of superconduction. The purpose of the work was to study technical feasibility rather than cost. Technical aspects were considered in some detail, the economics aspects of the study being devoted to choosing the best configurations. Consequently, only relative, rather than actual cost, figures for superconductive installations were presented. Another group in France, Gayte, Girrard and Malanddin [73] have considered the various aspects of coil design for magnetic energy storage. These included studies of mechanical and thermal stresses, possible shapes and methods of construction, and the coupling of energy into and out of the coil.

At this early stage in the development of the SMES system, design details cannot be considered fixed. However, a large solenoidal magnet buried in bedrock has been taken as the base line design. This conceptual system design is not a recommendation, but rather, an approach to building a system with materials and knowledge available now. This analysis assumes the availability of a fast acting switch which may be a persistent switch, or it may be a room temperature switch on the dc side of the converters. Such a switch is essential for protection of the ac/dc conversion equipment.

3.7.2 Technical Assessment

3.7.2.1 Major Components The major components of the magnetic energy storage system are (1) the conductor, (2) the electrical converters, and (3) the mechanical support structure including the Dewar. Other required components are the utility interface and balance of plant.

3.7.2.2 Conductor Magnet Windings The basic material for fabricating conductor magnet windings is NbTi in monolithic conductor, but other design options exist including hollow conductor, cables, and braids.

For safety considerations, the system is stabilized by joining the superconductor with another material so that if a partial quench should occur the entire system will not become normal. In most systems, the stabilizer is sized to carry the full current for some period of time.

Stabilization of the superconductor in a load-leveling device involves coordination between the sizing of the stabilizer and refrigeration equipment. The quantity of stabilizer, and other conductor characteristics, such as superconductor filament size, must be chosen to allow a controlled release of the stored energy without damaging the conductor or other magnet components. The minimum refrigeration equipment is one that will make up fpr heat generated in the magnet under normal operating conditions and heat gained through the supports and insulation. If only a minimum stabilizer is used, the start-up procedure for the the SMES could require a complete cooldown phase of after even a partial quench. The assumed cooldown procedure is to flow helium, which has been cooled by either liquid cryogens or a refrigerator, through the system. The inlet temperature of the helium is slowly decreased as the magnet is cooled.

The present method used to form a stabilized superconductor is to draw a composite superconductor-stabilizer ingot through dies. This would be very difficult to do on site for a SMES located a few hundred meters below the surface of the earth. However, a preformed monolithic stabilized superconductor with a 150,000 ampere rating cannot be bent around corners.

One proposed technique for preparing the conductor for a 10,000 MWh storage device consists of fabricating twisted filament bundles of NbTi in copper or aluminum and then coating the entire composite in Al by a continuous casting technique. There are fabrication problems with this approach which would probably result in a derating of the conductor. Many problems can be foreseen. First, the casting of the aluminum must be done in place and, when considering the cast volume, one becomes concerned with the homogeneity of the resulting solidified casting. Secondly, it has been experimentally verified that NbTi conductor grain size is seriously affected by prolonged or intense heat treatment. The grain growth which occurs will tend to significantly decrease superconducting properties (such as Ic) which are vital to efficient magnet operations. Finally, to gain further mechanical stability in the conductor itself, a dilute aluminum alloy might be more desirable. However, it would be very difficult to keep the resistivity ratio of the composite cladding high enough (1000) for stable conductor operation. It appears that sections of the magnet coils might be pre-fabricated and then installed in placed.

3.7.2.3 <u>Converter</u> There are many technical questions concerning a converter for the SMES, particularly concerning the rating of the device and the interface. Most utility loading dispatching techniques are based on a constant power output from the power source. To obtain a constant power output, assuming a .5 to 1.0 per unit current range, the converter must have at least a voltage range of 1.0 to 2.0 per unit.

The interface with the utility system must provide for surge propagation within the SMES, the required major insulation resistance, and the impedance limit of line-commuted converters. Since the SMES is essentially a very large inductor, the surge propagation along a transformer winding is an appropriate analog. It is a standard practice with power transformers to construct a static shield near the first few turns to insure that the total surge voltage does not appear across these first few windings. Two of these shields would be required for the proposed SMES since neither end of the SMES will be grounded. This would be done to insure that a single failure of the insulation to ground would not result in a failure of the system. The voltage-to-ground-withstand will not be a problem due to the high dielectric strength of bubble-free liquid helium.

The only other transient voltage that can be applied to the SMES is the operating voltage. The voltage across the SMES is:

$$V(t) = Ri(t) = \frac{di(t)}{dt}$$

In the superconducting state, the resistance is equal to zero and the voltage depends upon the power flowing into or out of the SMES. However, if the device is not superconducting, or during a total or partial quench, the voltage will depend upon the resistance of the conductor.

If a large stabilizer is used, the resistance could be very low. For example, the 10,000 MWh SMES (proposed by Boom) [74] could have a resistance of 0.019 ohms. If smaller stabilizers are used, the voltage of a quench could be above the rating of the converter. Smaller stabilizers would depend on the high heat transfer capability of the superfluid helium to prevent a small local quench from spreading throughout the entire magnet. The speed of propagation of the normal region is on the order of minutes. Because of this slow propagation, the short circuit switch could be closed before the voltage on the converter exceeded its rating. Since the total mass of the support structure is proportional to the stored energy, and assuming that thermal coupling to this mass is possible, a large energy storage system may be designed to be intrinisically safe from self destruction if cold reinforcement is used.

The rating of the converter depends upon the maximum current and voltage of the SMES. If the current is 100,000 amperes or higher, many devices (greater than 20, SCR's for example) would be required in parallel. It is not realistic to assume that current can be made to divide equally enough to use all of the devices to their full rating.

3.7.2.4 Mechanical Structures An important element in the design of very large energy storage magnets is the mechanical support (reinforcement) of the superconductive windings. This reinforcement may be "cold" or "warm" depending on whether it is located within the refrigerant bath adjacent to the superconductive layers or entirely external to the Dewar, with the magnetic stresses transmitted to it in some manner through the Dewar walls. Analysis indicates that appreciable cost savings accompany the use of "warm" rather than "cold" reinforcement. Warm reinforcement may be stainless steel.

Two special problems associated with the use of rock reinforcement are results of its low tensile strength and low modulus. The former would lead to radial cracking of considerable extent -- tension cracks extending to ten times the magnetic radius. Since the modulus of rock is rather low (5×10^6 psi), it may be necessary to have some kind of an adjustable thickness separator (e.g., fluid) between the magnet windings/Dewar and the surrounding rock walls.

3.7.2.5 Balance of Plant The balance of plant consists of:

Short circuiting switch
Auxiliary power system
Control
Electrical terminations
Power transmission to surface
Refrigeration system
Gas storage

Short Circuiting Switch - A short circuiting switch is necessary to protect the converter in case of a quench of all or part of the magnet. It is likely that there will be both a superconducting persistent mode switch inside the Dewar and a fast acting switch at room temperature. The persistent switch will be used to improve the efficiency during normal operation when the SMES is not being charged or discharged. The fast acting switch would be used during emergency shutdown of the SMES, or to protect the magnet during faults or other disturbances on the ac system.

Auxiliary Power System - The auxiliary power system consists almost entirely of large motors that are used for the cryogenic refrigerators and liquefiers. Since the continued operation of these motors is essential to the operation of the plant, a number of auxiliary power transformers are also required.

The use of three transformers will greatly improve the reliability of the plant because an average time to repair a failed transformer in the size required is about six months. The impedance of the transformers are sized to allow starting of a

10,000-hp motor with all other motors running. Short circuits are limited to standard circuit breaker ratings by using current-limiting devices. The motor voltage is 6.9 kV. There is no cost penalty for a 6.9 kV over a 4-kV motor at 10 khp.

Electrical Terminations - A temperature of 1.8 K is the preferred operating temperature for the system. This results in a two-to-one increase in current density over operation at 4.5°K. This lower temperature requires additional refrigeration equipment and introduces the problems associated with superfluid helium. The dielectric properties of pure superfluid helium establishes an upper limit on the charging and discharging voltage. It will be important to determine the breakdown voltage of superfluid helium with contaminants in the system. Contaminants might consist of small metal particles; frozen gases that were absorbed by either the Dewar and stabilizer, material left in the Dewar after construction, or material which entered the helium from the refrigeration system.

In the event of a total quench, the helium may not remain in the superfluid state. In all probability, it would start to boil. The dielectric withstand of helium with bubbles in it is very low. If the coil is either charging or discharging, a turn-to-turn fault could occur. To avoid this, the SMES should be short circuited if more than a few turns become normal (the superconducting state is lost). There will be sufficient time to short circuit the SMES prior to significant helium bubble formation due to the slow speed of propagation of the normal region.

The electrical leads in and out of the SMES must have certain functional characteristics.

a. They must be electrically insulated from the support structure.

b. They must be designed to carry the maximum current even when the required flow of helium along the leads is absent.

c. Thermal cycles should not affect the performance.

To keep the refrigeration requirements and the contamination and pressure differentials to a minimum, a series of compartments may be utilized. The innermost compartment is at 1.8°k, the next compartment is at 4.5°K, and the rest of the compartments are at the various shield temperatures. To account for the increased resistance, the conductor size is increased prior to entering the next compartment.

The integrity of the dielectric insulating system within the SMES is very important to the success of the storage method. In conventional electrical equipment, a failure of the dielectric system causes only limited damage due to the interruption of the current by circuit breakers. In SMES, it may not be possible to extinguish a fault. Certainly a 100,000 ampere dc current flowing through a 2,000-3,000 henry inductor could not be extinguished without overstressing the entire insulation system and requiring extreme amounts of current interrupting equipment. If the voltage at the terminals of the SMES is reduced to zero, this will not guarantee that a fault will be extinguished. If a fault is caused by a breakdown of the helium, shorting the terminals could lower the fault current. However, if the fault resulted in or was caused by tracing on the solid insulation, the voltage generated by the changing dc current to supply the fault energy could be high enough to sustain an arc over solid insulation. Such a fault would release all of the stored energy in a part of the system without any method of limiting the damage. Such an energy release could melt the conductor locally and contaminate the system. Partial replacement of a SMES will be extremely difficult. It would require the removal of portions of the heat shields and Dewar while temporarily supporting the remainder of the systems.

Power Transmission to Surface Conventional magnetic devices cannot operate in the large dc magnetic field that exists in proximity to the SMES. The bias that the dc field would produce would saturate any normal transformer steel and render transformers, motors, and relays useless. The methods of avoiding this are to either shield the equipment with a high permeability steel or move it away from the magnetic field to a low field region. In a large plant, the power transformers, converters, refrigerators, and vacuum systems will be in a low field region at ground level.

Because of the high current to the surface, mechanical bracing is necessary for the power leads if parallel construction is used. Coaxial construction with either just a helium or a helium-solid insulation could be used to increase the dielectric strength. It could be placed on either the outer or inner coaxial conductor. The suggested material is a self-vulcanizing material, similar to the 3M seal-a-tape, that is partially overlapped with other layers. In the partial overlap areas, a corrugated Teflon section is placed between the insulating layers to allow them to move due to thermal contraction. The length of the overlap is based on the gap that is required to withstand the rated voltage when it is full of helium gas. A self-vulcanizing material was chosen to minimize the thermal contraction problems, since it will expand and contract as a cylinder instead of as a coiled spring. This type of contracting will not lead to an unwinding of the insulation or short helium gaps. The insulation would be placed on the inner surface of the outer coaxial conductor to minimize heat conduction problems.

Refrigeration System The refrigeration system must be sized to keep the magnet and the current leads to the surface below the transition temperature of the conductor. It must also have sufficient capacity to cool down the entire system from the temperature of boiling nitrogen during start-up. It is not anticipated that any helium will be vented during cool down or operation.

The size of the refrigeration system and the cooling water requirements for the system depend on the amount of refrigeration that is needed. Two systems have been chosen and the refrigeration sized according to the stated heat gains in Table 3-22 to illustrate what is involved [75]. The cooling water requirements, indicate that a cooling tower is required at the surface. The electrical power requirements, while not very large, are totally made up of large motors. During start-up a large induction motor draws six times its full load current. This large current, when added to the existing load of the other motors, will be quite substantial. This is especially important because the auxiliary power transformers will be at least a few hundred meters away in an lower dc field region. The voltage drop in a few hundred meters of 6.9 kV cable can be substantial.

The size of the room that must be magnetically shielded and ventilated is small compared to the magnet but relatively large to be lined with high permeability steel.

Gas Storage Because of the high cost of helium, it must not be vented to the atmosphere during any operating condition. It is estimated (University of Wisconsin Superconducting Energy Storage Project Report) that for 10^4 MWh of energy, assuming 100 percent depth of discharge, a storage volume of 1.63×10^8 SCF would be needed for the helium. Even at a storage pressure of 10 atmospheres and 0°C, this requires a sphere 200 meters in diameter. Liquid storage is desirable and would require 6.6×10^6 liters.

The volume of liquid nitrogen required to cool the 10^4 MWh system is 5×10^5 liters as a liquid and 1.14×10^7 SCF as a gas. This quantity is too large to be supplied from a commercial source. Storage facilities will have to be provided for the nitrogen as well as the helium.

Auxiliary systems for helium and nitrogen will include pumps to move the gases from the main Dewar to storage, vaporizers, or other safety systems for containment.

Table 3-22 REFRIGERATION SYSTEM DATA

Maximum Stored Energy Assuming 100 Percent Depth of Discharge

	10^4 MWH	10^3 M WH
Heat gain @		
1.8K, kW	8.45	1.87
11.5K, kW	28	6
75K, kW	1100	220
Refrigeration size		
length, feet	150	100
width, feet	150	100
height, feet	20	20
Cooling water, GPM	16,000	3,000
Electric power, kW	31,000	6,500

3.7.3 Problem Areas

Since operating experience with a commercially sized plant is not available, some problem areas remain. Discussion of these problem areas follows.

3.7.3.1 Quenching One problem is the quench, a superconducting-to-normal transition, at full current. One MWh is equivalent to one ton of TNT. However, several factors contribute to making a quench far less spectacular than the release of an equivalent amount of energy in an explosion. The most important factor is the much larger time over which this energy will be released.

In a large magnet, this energy release time may be increased by proper design to a period of minutes or even hours. The system may also be designed in such a way that a part of the magnet (say 5 to 10 percent of the conductor) can quench without affecting the rest of the magnet. An additional factor is the large heat capacity of the massive structure required to contain the electromagnetic forces. Experience with the present-day magnets indicates that the heat-capacity of the supports is sufficient to absorb a major fraction of the total energy (at least for cold reinforcement).

3.7.3.2 Joints Suitable methods must be devised for making zero-resistance or superconductive joints between sections of superconductor. Consider, for example, a coil having a capacity of 1,000 MWh or 3.6×10^6 MJ, and current-carrying capacity of 157,000 amperes. Any joint, with a resistance as large as 1 micro-ohm, would dissipate energy at the rate of 24 kW. Over an 8-hour period this represents a negligible loss of energy (200 kWh) in comparison with the storage capacity, but the local heating effect could result in serious consequences. For a coil inductance of 300 henries (1,000 MWh), a discharge time of eight hours (to 1/3 of the initial current) represents a circuit resistance of one hundreth of an ohm. In most large magnets, joints of less than one nano-ohm are common so this should not be a serious problem.

3.7.3.3 Coil Winding The process of coil winding with conductors capable of carrying and stabilizing currents of some 100,000 amperes, is a task of some magnitude. A 1,000 MWh machine, for example, requires about 600 km of wire. In addition to placing the superconducting wire, it is necessary, for one possible design, to cast in place a stabilizing aluminum conductor capable of carrying the full current should quenching of the NbTi superconductor take place. It is necessary to ensure that deterioration of the properties of the NbTi superconductor does not occur during the heat treatment associated with the in situ fabrication of aluminum stabilizer. In considering on-site fabrication of the stabilized superconductor, attention might well be given to the employment of continuous sputtering or vapor-deposition techniques. Such approaches could enable high current materials to be laid down and at the same time, tend to ease the problem of joint fabrication.

3.7.3.4 Magnetic Shielding The radial variation of magnetic field of a solenoidal magnetic energy storage coil with a capacity of 2.2 x 10^6 MJ and a magnetic field (at the winding site) of 10 Tesla is given in Table 3-23 [76].

It is interesting to note that even at a distance of 100 meters from the coil, an appreciable magnetic field 0.015 T exiTesla exists. Magnetic shielding may be a problem depending on the location of the coil. In designing magnetic-field shields, it must be remembered that significant constraint of the magnetic field will lower the inductance, and hence the energy storage capacity of the superconductive coil. Shield magnets will increase system costs by both the expense of their design and construction and the derating of the total system energy storage capacity.

3.7.3.5 Critical Materials There are several key materials which will play a vital role in the commercial use of SMES. Principal among these are niobium, copper, and helium.

At the present time, the projected use of niobium through the year 2000 will not cause any shortage. Most of the available Nb is currently used for basic steel products and superconductivity uses are projected to be small by comparison. After the year 2000, the situation could change drastically.

Copper, as cladding for superconducting wire and tape may be an even more serious problem in the years ahead. With costs high and reserves diminishing, the transition to aluminum may become mandatory.

The helium supply is of some concern. Unless a conservation program is reinitiated, there may not be a sufficient supply for very large magnet systems.

Raising the transition temperatures of practical superconductors and minimizing the operating forces on a large magnet system could substantially reduce costs. Reduced operating forces would be highly beneficial from a cost standpoint.

3.7.4 Final Comments

Application of superconducting magnetic energy storage to power systems is in a very early stage of development.

Table 3-23

MAGNETIC FIELD VS. DISTANCE FROM THE CENTER OF A MAGNET 30M IN DIAMETER AND HAVING AN ENERGY STORAGE CAPACITY OF 2.2 X 10^6 MJ AT 10T

Radial Distance from Center of Magnet (m)	Field (T)
0	8.74
15	9.89
20	1.91
50	1.2 x 10-1
100	1.5 x 10-2
200	1.9 x 10-3
500	1.2 x 10-4
1000	1.5 x 10-5

- Many detailed technical problems remain to be solved before these systems can be considered feasible.

- Superconducting magnetic energy storage cannot be adequately assessed at its current state of development.

- Special application may exist where a SMES may be attractive as a pulsed power supply. Of particular interest is its use in conjunction with magnet systems for controlled thermonuclear fission.

- Because of its very early stage of development, cost estimates, such as these presented in Section 4.7, should not be given much weight.

3.8 DEVICE UTILITY INTERFACE

In an assessment of major energy storage concepts, the interaction between an energy storage system and the utility system to which it is connected can influence the design approach adopted. This section will identify the various interface design considerations and propose specific approaches for integrating the storage system with the utility network. It is not the intent here to satisfy all possible approaches or to develop a common approach that will be acceptable to all. Rather, a "bare bones" approach is taken that can be used in a utility without substantially modifying existing equipment. A bare bones approach is one that requires the minimum amount of equipment to allow for a constant power charge and discharge of the storage system.

3.8.1 Introduction of Interface Considerations

All of the energy storage systems that have been investigated in this report can be integrated into a utility power system using modifications of existing interface technology. Proponents of technologies that require dc to ac conversion point to the high voltage direct current (HVDC) and or the uninterruptable power supply (UPS) industries. Those that use mechanical conversion point to either existing installations, dc machinery, or variable speed transmissions. It is appropriate to use interface analogies when the technologies are actually installed on utility systems. For example, extension of existing above ground pumped hydro conversion technology to very high head underground applications is valid because it is a change in parameters rather than in the application of the equipment. It is not appropriate to do this with HVDC, UPS or mechanical interface technologies without careful study.

The storage systems that require dc to ac conversion are fundamentally different in device parameters, functional operation requirements, and location in the power systems from HVDC or UPS applications. The HVDC technology has been developed and optimized to interface with a high voltage dc source that has good voltage regulation and whose short circuit current can be reduced when desired. It operates in either the inversion or rectification mode without being required to drastically change the dc voltage level. Its primary function is for bulk power transmission, and it is located on the transmission system. The UPS technology was developed to provide power for short periods of time without consideration for efficiency or system conditions that are encountered with large size converters. The storage systems do not fit any of these intentions. They are highly variable, low voltage dc sources and some of them can deliver substantial short circuit currents.

The storage systems that require mechanical conversion can be divided between the constant speed and variable speed applications. The constant speed applications of pumped hydro, compressed air, and thermal and chemical energy storage with combustion turbines utilize existing utility-based technology. They do not represent an extension or new application of utility applications. The variable speed application of flywheels can utilize techniques from other industries that have been applied on utility systems.

3.8.2 Interface Technologies

A summary of the conversion system and interface design considerations is shown in Table 3-24. The first rows indicates which conversion method was chosen, and the second row indicates the method of connecting the conversion system to the utility system. The rest of the rows indicate the potential affects of the chosen conversion technology on the utility system. Unresolved or marginal areas have been identified when a straightforward engineering approach resulted in a limiting or "weak link" area. Other approaches were disregarded because of economic, technical or practical considerations.

3.8.2.1 Conventional Rotating Equipment: Conventional rotating equipment includes those rotating electric machines that are used by utilities and large industry. They represent years of engineering and manufacturing development and years of utility operating experience. A standard utility generator can be characterized by control and production considerations, and operating capabilities. It has a number of redundant systems to control real and reactive power. Protective systems and design approaches are used to render some single contingency failures harmless and to limit the damage of other failure modes. The systems are integrated into the operating capabilities to allow automatic control of the equipment to avoid electrical stability problems and to prevent the potential damage of self excitation.

Suggested Storage System Applications: Underground and above ground pumped hydro, compressed air (for combustion turbines), and thermal energy and some chemical storage systems will be interfaced with the utility system using conventional rotating equipment. For these three technologies, no other interface method was considered. The only difference between the assumed interface and the standard utility generators would be related to the location and number of generators.

Underground pumped hydro will require some means of transmitting the power from the power house, which may be from one to two

Table 3-24 SUMMARY OF CONVERSION SYSTEM AND INTERFACE DESIGN CONSIDERATIONS

	Underground Pumped Hydro	Compressed Air	Thermal	Electro-chemical	Flywheels	SMES
Conversion Method	Standard ac machine	Standard ac machine	Standard ac machine	Static converter	Non-standard ac machine with NCC	Static converter*
Power Connection to Power System	Long ac power leads from underground power house	Standard	Standard	Converter and transformer	Standard	Multi steps of trans-formers, long power leads to surface
Impact on Existing Power System Equip-ment	Increase circuit breaker interrupting duties	Increase circuit breaker interrupting duties	Increase circuit breaker interrupting duties	Could increase capacitive switching duties	Increase circuit breaker interrupting duties	Could increase capacitive switching duties
Surge Protection Philosophy	Standard	Standard	Standard	May not be pro-tectable with surge arresters	Standard	Special shields within the magnet will be required
Failure Protection				dc fault clear-ing devices will require substantial maintenance		May not be protectable*
Effect of Depth of Discharge	None	None	Output may vary with storage temper-ature	Increases size of converter	Increases size of NCC	Increases size of converter
Site Requirements	Suitable geology	Suitable geology	Generating station	Sufficient area or none	Sufficient area or none	Suitable geology
Impact on Existing Power System Quality of Service	None	None	None	Possibility of voltage fluc-tuations and harmonic voltage injec-tion into utility system	Possibility of voltage fluc-tuations	None

*Unresolved and marginal areas.

thousand feet below the surface. This is relatively easy to accomplish with sulfur hexafluoride insulated bus or specially-designed oil filled cable that can withstand the large hydrostatic head.

The compressed air interface will vary depending on the required charge to discharge ratio. For a low ratio, a single ac machine would be used, and for a high ratio, a few machines would be required. The reason for the multi-machine approach is the limited capacity of existing air compressors. The multi-machines would be grouped together to allow the economics of a single step-up transformer. The control, protection and operating capabilities would be similar for both the single and multi-machine systems. The number of generator circuit breakers and busses will be different.

Other Storage System Applications: Other interface approaches using conventional rotating machines were considered for inertial energy storage. The approaches were the use of dc machines with a full rated converter and a standard constant speed generator with a variable speed transmission. The methods were discarded because of economic and control reasons, respectively.

3.8.2.2 Non-Conventional Rotating Equipment: Non-conventional rotating equipment includes those rotating electric machines that have been used in limited applications in other than the utility or industrial areas and special machines used in limited applications by utilities or heavy industry. Typically, these machines have had limited development and manufacturing backgrounds and little operating experience. The units that have been built are limited in size.

Suggested Storage System Applications: The only storage system that should be interfaced with the utility system using non-conventional rotating equipment is Inertial Energy Storage. The suggested approach uses a wound rotor induction machine with a naturally-commutating cycloconverter (NCC) connected to its field (variable frequency field machine). This approach has the most development, manufacturing, and field experience behind it.

A major project that uses this approach and describes its operation is a large dragline [77]. Other areas that are not discussed in the above reference are:

1) Effects of depth of discharge

2) Impact on existing power system equipment

3) Impact on existing power system quality of service

The depth of discharge of the flywheel influences the sizing of the NCC, the potential for shaft dynamics resonances, and bearing lubrication at low speeds. A seventy-five percent depth of discharge was chosen to avoid the ill effects of the latter two areas.

The impact on existing power system equipment can be in increased VAR requirements, capacitive switching requirements, and increased short circuit currents.

The naturally commutating cycloconverter has a lagging power factor at the utility system for either a lagging or leading power factor at the machine [78]. The use of shunt capacitors to correct the NCC's power factor could be used. However, sufficient VAR's can be obtained from variation of the field current magnitude of the wound rotor induction machine to supply the VAR's, thereby reducing the impact on the utility's existing system.

There is no effective control method of limiting the amount of short circuit current that can be produced by a rotating electric machine. External methods have been developed and extensively used in Europe in high power applications. The approach uses a current limiting device in parallel with an exploding link that is activated on the rate of rise of current. This could allow the limitation of both the momentary and interrupting current within the rating of most existing utility equipment. It is not appropriate for the power ratings of machines used in pumped hydro, compressed air, or thermal energy storage.

The impact on existing power system quality of service can be seen in voltage dips. The use of the variable frequency field machine avoids the limitation on voltage dips on a distribution system by using a starting resistor in conjunction with the NCC. The amount of energy that is lost by using the resistor is limited by keeping the flywheel to at least 50 percent of regular speed and only having to start the rather low mass rotor of the VFF machine.

Other Storage System Applications: Other interface approaches using non-conventional rotating equipment were considered for inertial energy storage and superconducting energy storage. Those for inertial energy storage utilized aerospace type drive systems with full rated converters. None of these systems have been built in the appropriate sizes nor is it appropriate to scale-up the sizes of existing equipment. The power rating and operating characteristics of homopolar machines makes their use inappropriate except for superconducting energy storage.

3.8.2.3 Static Conversion Equipment: Static conversion equipment includes many different types of converters and different configurations of those converters. The current fed inverters include naturally commutated, buck-boost naturally commutated, complementary and chopper-naturally commutated inverters. The voltage fed inverters include naturally commutated, phase angle control and conduction angle control force-commutated, and high frequency link inverters [79]. To this list of inverters must be added the option of using rectifiers and external switching. Also, the solid-state industry will continue to develop low cost, high rating devices which will change the relative costs of the above systems and add more systems to the list. Therefore, the system chosen for the interface should be viewed as a system for near term, bare bones application that, in all probability, will be surpassed by changes in the technology.

The area of solid-state converters is one where agreement upon application needs, operating requirements and the cost of various conversion systems does not exist. Worse yet, the equipment costs are very sensitive to storage system design assumptions, utility needs, and sales volume. For a consistent set of assumptions and some judgement as to the relative range of a specific cost estimate, none of the systems are a clear economic winner.

Suggested Storage Systems Utilizing Static Conversion Equipment: The storage systems suggested for interfacing with static conversion equipment are chemical, electrochemical, and superconducting magnetic energy storage systems. Modification of a naturally commutated inverter is suggested for some chemical and electrochemical systems, and a current-fed naturally commutated inverter for superconducting energy storage. The reason for the differences are the location and expected power rating, and the effects of the interface on the utility system equipment.

The interface design considerations of static conversion equipment on chemical and electrochemical energy storage systems are:

1) Impact on existing power system equipment

2) Surge protection

3) Failure protection

4) Effects of depth of discharge

5) Impact on existing power system quality of service

The impact on existing power system equipment can be in increasing circuit breaker capacitive switching duties, increased VAR requirements on the power system, and the injection of harmonics into the network.

A naturally commutated converter applied to chemical, electrochemical, and superconducting energy storage systems will require power factor correction capacitors to lower the amount of VAR's that it will draw from the power system. The size of the capacitor banks will depend upon the voltage range (related to the depth of discharge) and the arrangement of the converter. If there is sufficient capacitance to completely correct the power factor of the conversion system at full load and minimum power system voltage, there will be excess VAR's at light loads or normal power system voltage.

The existence of these capacitor banks will increase the capacitive switching duty of the existing circuit breakers at the station. Some of the breakers will have both their energizing and de-energizing duties increased while all of the breakers will have their energizing duties increased. If the duties exceed the ratings of the breakers, breaker damage or high overvoltages may result.

Harmonics generated by, and modified by, the conversion system are very dependent on the actual size and location of the storage system. The harmonics generated by the inverters can be limited by using shunt filters, series chokes, and high pulse number converters. Modification of the flow of the harmonics existing on the utility's system because of the shunt filters can occur. Limitation of such modifications can be effected by using series filters and harmonic transformers or by using higher pulse inverters. Generally, harmonic reduction is not a large percent of the conversion system cost.

Standard surge arresters have very limited capacitor bank discharge capability. A storage system on a 13.8 kV distribution system would be limited to using no more than 8 MVAR of power factor correction capacitors [80]. This can be resolved by allowing the modified naturally commutated inverter to be a chopper-fed naturally commutated inverter. This approach would not limit the storage system size due to the limits of a standard surge arrester.

The electrochemical energy storage system requires protection from the high dc fault currents that can be produced in commutation failures and bus faults. The existing dc circuit breakers have sufficient capability to interrupt the short circuit current from most systems but would require substantial maintenance based on the expected number of commutation failures. When more advanced converters are developed that have less sensitivity to voltage dips, dc circuit breakers will be adequate.

The depth of discharge of electrochemical storage systems is reflected in the magnitude of the dc voltage. Also, the power output from a fuel cell in the chemical storage system is reflected in the magnitude of the dc voltage. The voltage for both of these systems varies greatly. For a constant power output, the dc current varies inversely with the voltage. This inverse relationship between voltage and current imposes major constraints on the conversion equipment. Solid state devices have small time constants and are voltage sensitive. They must be sized according to the maximum current and voltage even if these two maximums do not occur simultaneously. This is further complicated by the charge to discharge rating of the storage system. For electrochemical storage systems, the charge voltage will be higher than the fully charged discharge voltage. The magnitude of the current will depend on the efficiency of the storage system and the rate of charge and discharge. Therefore, converters with a higher power rating than the charge or discharge rating of the storage system will be needed for deep discharge and expected charge-to-discharge rates of the electrochemical energy storage systems. Similar sized inverters will be needed for the fuel cell attached to a chemical energy storage system to accommodate the drop in voltage with life of the fuel cell.

The impact on the existing power system quality of service relates to the chemical energy storage system that utilizes compressed gas storage. The motors for the compressors would be relatively large compared to other motors connected to a residential distribution power system. Line starting these motors will cause voltage dips that can decrease the output of light sources and T.V. pictures. Other methods of starting motors can eliminate this problem without affecting the storage system economics.

The interface design considerations of static conversion equipment on superconducting magnetic energy storage systems are similar to those for chemical and electrochemical storage systems with the following additions:

1) fault protection

2) surge protection

3) power connection to the system

If there is a dielectric failure in the magnet, the interface must provide a means of reducing the fault voltage. If the fault is not extinguished, the magnet will destroy itself. This is no different than a failure in a large generator. However, the repair of a generator is possible while the repair of a superconducting coil a few hundred meters below the ground would be more of a rebuilding process than a repair.

There are two types of failure modes that must be considered. The first mode is a dielectric failure of the helium. For this failure mode, short circuiting the main terminals will reduce the voltage sufficiently for the helium to regain its dielectric strength. The second mode is a tracking failure on solid insulation. For this failure mode, short circuiting just the main terminals may not be sufficient. The voltage generated within the magnet from the energy being dissipated by the fault could be sufficient to sustain the arc over the insulation. The voltage generated by the decay in the magnetic field could be sufficient to sustain the arc voltage even with the terminals shorted. Current injection from ground into the magnetic to stop the fault current may be required by the converter.

The electrical insulation withstand rating between turns of the magnet and from the magnetic structure to ground depend upon the voltage surges that the interface allows to enter the magnet. This is unlike other systems where the transmitted voltage surge is equal to or lower than surges that are generated by the storage system protective devices.

Since the SMES is essentially a very large inductor, the surge propagation along a transformer winding could be used in sizing the insulation between turns. It is a standard practice with power transformers to construct a static shield near the first few turns to provide an almost linear voltage sharing across the magnet. Two of these shields would be required for the storage system.

The ratio of the transmission system voltage (to which a large superconducting energy storage system would be connected) and the corresponding storage system voltage is too large to be made in one voltage transformation. Also, such a transformer would have an intolerably high commutation impedance. Two steps of voltage transformation reduce the commutation impedance and isolate the power factor correction capacitors from the power system. This isolation reduces, if not totally eliminates, the surge arrester and capacitive switching considerations of electrochemical and chemical energy storage.

Other Approaches Using Static Conversion Equipment: Static conversion equipment, without non-conventional rotating machines, were not considered for other than the above-mentioned storage technologies.

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4. COST ESTIMATES

In this chapter, capital and operating cost estimates are developed for selected energy storage systems. These estimates are intended to provide reasonably uniform and consistent data for economic comparison of energy storage technologies which follow in Chapter 5. The material in this chapter is separated from the previous chapter to distinguish between the technology centered discussion presented there and the specific assumptions needed to make cost estimates.

For background data pertinent to cost analysis, the interested reader is referred to the literature. Special mention should be made of the comprehensive work on hydro pumped storage [1], compressed air storage [2], and flywheels [3]. Other references are cited where appropriate in the text.

It was essential to the validity of this study that a reasonable set of estimates be developed for all of the technologies and that an effort be made to levelize the optimism in these estimates. For most of the technologies, further efforts along these lines would yield some increase in precision, however, the authors believe that the estimates of this study provide a reasonable base for comparison of energy storage technologies and for judging their relative merits for future research and development efforts. Far greater effort would be needed to establish costs with sufficient accuracy for actual construction and in some cases, the information necessary to provide such a decision will not be available for a number of years.

The estimates are summarized in Table 4-1. The costs are broken down into two components; the cost related to the power output of the system, Cp, expressed in \$/kW, and the costs associated with the discharge capability of the system, Cs, expressed in \$/kWh. For a device with a discharge capability of T hours at rated power, the per unit capital cost, C, is:

$$C = Cp + Cs \bullet T$$

where C is in \$/kW. T is the number of hours which the system can discharge, from the fully charged state, at rated output i.e., a 1 kW device rated for ten hours of storage could, if fully charged initially, produce 1 kW of output for ten hours. These costs include both equipment and installation costs and an allowance for contingencies, but do not include an allowance for interest during construction.

Table 4-1 COST SUMMARY FOR SELECTED STORAGE SYSTEMS
1975 DOLLARS - NO CCIF INCLUDED

	Cp ($/kW)*	Cs ($/kWh)
Hydro Pumped Storage Conventional and Underground	90-160	2-12
Compressed Air Storage with Combustion Turbines	100-210	4-30
Thermal Storage - Water	150-250	30-70
Thermal Storage - Oil	150-250	10-15
Near-Term Lead Acid Batteries	70-80	65-110
Advanced Batteries	60-70	20-60
Flywheels	65-75	100-300
Hydrogen	500-860	6-15
SMES	50-60	30-140

*Equal change and discharge times.

Caveat: These estimates only apply to the specific design considered in this chapter

Costs can be affected substantially by the charge to discharge power ratio, C/D, which is determined by the available time for charging, Tc, and discharging, Td, the storage system. For storage systems where power conversion is accomplished with a reversible unit, costs scale with Cp. For storage systems which do not use simple reversible power units, power costs may scale in a more complicated fashion. Except where otherwise noted, equal charge and discharge times are assumed (Tc = Td), i.e., ten hours charge and ten hours of discharge at rated capacity (power required on charge is, of necessity, higher than discharge due to system inefficiencies).

Several types or classes of estimates were used here and the relative accuracy of each estimate is different. Within a specific storage system, individual subsystems are, of necessity, estimated differently. The level of accuracy of the estimates is commensurate with the level of knowledge for the technology under discussion.

Within each selected system, the estimates were developed with reference to specific design points. Judgement is then applied to extend these single point analyses to non-design point conditions. Maximum precision was not an objective; the very nature of the advanced technologies means that various parameters will inevitably change making any set of cost figures inapplicable with the passage of time.

The different types of cost estimates are listed in approximate order of increasing accuracy.

(1) Proponent estimates

(2) Parametric estimates

(3) Literature estimates

(4) Analogy estimates

(5) Manufacturer's estimates

(6) Engineering study estimates

(7) Historical data estimates

(8) Vendor (manufacturer) quotations

(9) Book prices

As a guide to the reader, each of the estimates of the various technologies is identified in Table 4-2 with respect to type, class, and accuracy. Variation in detail among the estimates

Table 4-2 QUALITATIVE CHARACTERISTICS OF COST ESTIMATES

Selected Storage Systems	Type of Estimates	Anticipated Accuracy	Class of Estimates*
Conventional Hydro Pumped Storage	7	High	R,C
Underground Hydro Pumped Storage	7,6,4	High	R,C
Compressed Air Storage	3,4,5,7	Medium	R
Thermal-Steam	5,6,8	Medium	R
Thermal-Oil	1,9,6,8	Medium	R
Thermal-Molten Salt	2,4	Low	G
Batteries Lead Acid	5,6	High	R,C
Batteries Advanced	1,2,3,6	Low-Med	R,U
Flywheels	2,4,6,9	Low(-)	R,U,G
Hydrogen	2,3,4,5	Low-Med	R,U
SMES	1,2,4	Low(-)	G,U

* (G) Guess - Insufficient Detail to Estimate Accuracy
(O) Low - Optimistic; Probable that Actual will be High
(R) Medium - Reasonable - Most Probable
(P) High - Pessimistic - Probable that Actual will be Lower
(C) Certain - Actually Confirmed by Experience; Deviations are Minimal
(U) Uncertain - Considerable Room for Error

given here are due to the fundamental differences of the technical cost elements that were considered. In particular, application of full engineering cost estimate techniques is inappropriate for advanced technologies where major cost elements are poorly defined. Addition of extra contingency factors increase the uncertainty in the estimated costs for future technologies.

4.1 HYDRO PUMPED STORAGE

Hydro pumped storage costs are best established from a review of actual records on plants built and operating, and plants under construction. In addition, detailed cost estimates have been made recently for proposed plants with underground storage reservoirs. A considerable effort was spent on analysis of hydro pumped storage systems to establish a set of baseline costs for comparison with other energy storage systems. A portion of this analysis is presented here, while more detail is presented in a report by Loane [1].

This section discusses both conventional hydro pumped storage and hydro pumped storage with one underground reservoir.

4.1.1 Conventional Hydro Pumped Storage

Construction costs for conventional hydro pumped storage were reviewed. Data was obtained from reports filed with the Federal Power Commission (FPC) and directly from plant owners. Estimated costs for future plants were confirmed from published estimates of future plant costs. A summary of these costs is presented in Table 4-3. Variations in the costs (adjusted to January 1, 1974 using the Handy-Whitman indices of costs for utility construction [4]) are due to local conditions, plant and unit size, use made of existing bodies of water, amount of storage capacity, and variations in the cost of money during construction. Separation of costs into power related costs and storage related costs permits separate analysis of the costs of reservoir construction.

A typical distribution of plant component costs, as defined by the FPC, is presented in Table 4-4. Reservoirs and dams are the largest of the listed components and are subject to the widest variation, ranging from 17 percent to 38 percent of total costs.

A different distribution using a different set of cost components, is given in Table 4-5. This table breaks out the direct, indirect, engineering and supervision costs.

Both of these distribution breakdowns are significant, the first permits separation of storage related costs from the balance of plant costs, while the second identifies the cost of money component. The cost of money component will change at a different rate than the other plant costs.

4.1.1.1 Storage Costs Energy related storage costs are represented by the costs of dams and reservoirs. The storage costs in \$/kWh, adjusted to January 1, 1974, are plotted in Figure 4-1. There are relatively wide variations in storage costs, part of which are attributable to differences in head, with an even larger part related to site differences. Storage

Table 4-3 PUMPED STORAGE COST DATA*

Plant Name	Year of Initial Operation	Capacity in MW	Capacity in Hours	Storage Cost $/KWH	Power Cost $/KW	Total Costs $/KW
Taum Sauk	1963	350	7.7	9.87	158	234
Yards Creek	1965	330	8.75	3.54	136	167
Muddy Run	1967	855	14.25	11.89	129	156
Cabin Creek	1967	280	5.85	11.45	124	191
Seneca	1969	380	11.2	6.34	186**	257
Northfield Mtn.	1972	1000	8.5	1.71	132	146.5
Blenheim-Gilboa	1973	1030	11.6	3.45	100	140
Ludington	1973	1675	9	8.44	125	201
Jocassee	1973	625	94	.69	117.5	182.5
Bear Swamp	1974	540	5.6	12.86	141	213
Racoon Mountain	1975	1370	24	1.25	87	117

* 1974 Dollars

** Adjusted to $175/kW to Eliminate Costs Associated with Downstream Discharge which Permits the Plant to Utilize the Head Created by the Lower Reservoir Dam for Generation.

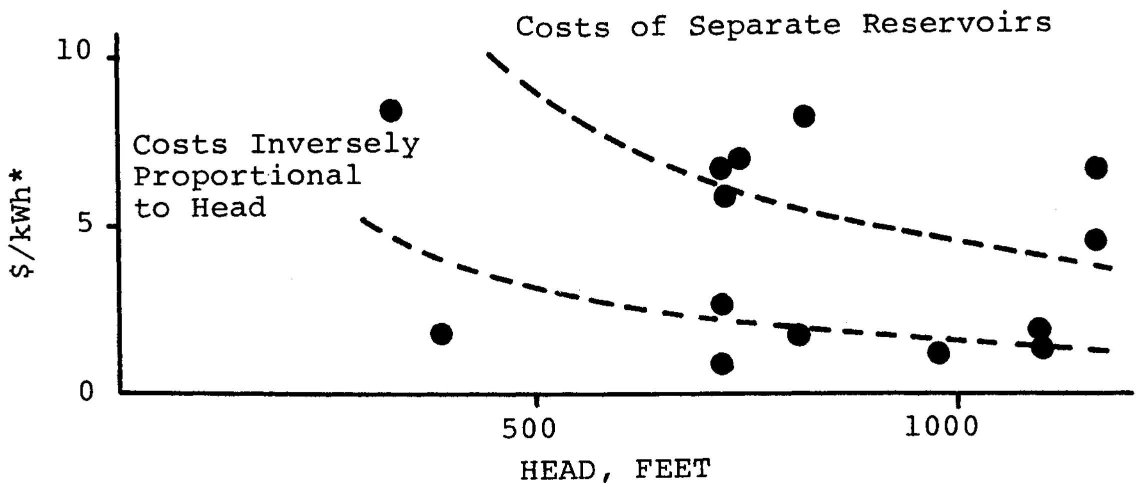
Table 4-4 TYPICAL DISTRIBUTION OF PLANT COMPONENT COSTS

Land and land rights	2%
Structures and improvements	15
Reservoirs and dams (storage costs)	28
Waterways	21
Turbines and generators	24
Accessory electrical equipment	6
Miscellaneous power plant equipment	2
Roads, railroads, and bridges	2
Total production plant*	100%

*Plant substation costs are not included

Table 4-5 TYPICAL DISTRIBUTION OF DIRECT AND INDIRECT COSTS

Direct costs	69%
Indirect construction costs	12
Engineering and supervision	8
Allowance for interest during construction	9
Other overhead costs	2
	100%



*Costs for Plants are Adjusted to 1/1/74

Figure 4-1 ENERGY STORAGE COSTS
(DAMS AND RESERVOIRS)

costs are plotted for each reservoir to compensate for the fact that several of the selected plants required construction of only a single reservoir.

It might be expected that storage costs would decrease with an increase in head, since a smaller quantity of water must be stored to produce a given amount of energy. There is some tendency in this direction, particularly if the storage cost for the highest head plant (1159 feet) is ignored. The dashed lines show a reciprocal relationship between head and energy storage costs.

Storage costs are largely determined by site conditions. Less favorable sites may be accepted to make use of higher heads. In a study of pumped storage in the Susquehanna River Basin, the costs of storage at 25 sites were analyzed. These costs, which were generally in the $3 to $7/kWh range, after adjustment to January 1, 1974 conditions, actually showed a slight tendency toward higher costs at higher heads. This rising storage cost was more than offset, however, by the decreasing cost of the balance of plant as the heads increased. Consequently, it is not safe to assume that the storage costs for surface reservoirs, in $/kWh, will always decrease with an increase in head as shown by the dashed lines in Figure 4-1.

4.1.1.2 Power Costs Balance of plant costs plotted in Figure 4-2 show less variation than storage costs. Unit cost is related to both plant size and head; unit costs decrease with increases in both size and head. The relationship that depends on size is influenced more by unit size than by the number of units in a plant, however, for the small data sample available, where the site differences are large, the plot of plant size exhibits more consistency than a plot of unit size.

The balance of plant costs depend on site differences other than head, particularly the length and nature of the water passages and whether the powerhouse is underground or on the surface. Differences also result from the designer's choice of charge/discharge ratios, water velocities in the conduits, and other options as to equipment and structures.

The extreme costs in Figure 4-2 are for Taum Sauk and Seneca and are atypical of future plant costs. These two plants have the highest total costs of the plants listed in Table 4-3. Taum Sauk was the first of the large "pure" pumped storage. Seneca involves several unusual features that added to its cost. Both are smaller in size than the plants planned for future construction. It is also reasonable to ignore Raccoon Mountain which is still under construction. The balance of plant costs for the remaining eight of the eleven selected plants fall within the approximate range of $100 to $140/kW. A range of $100 to

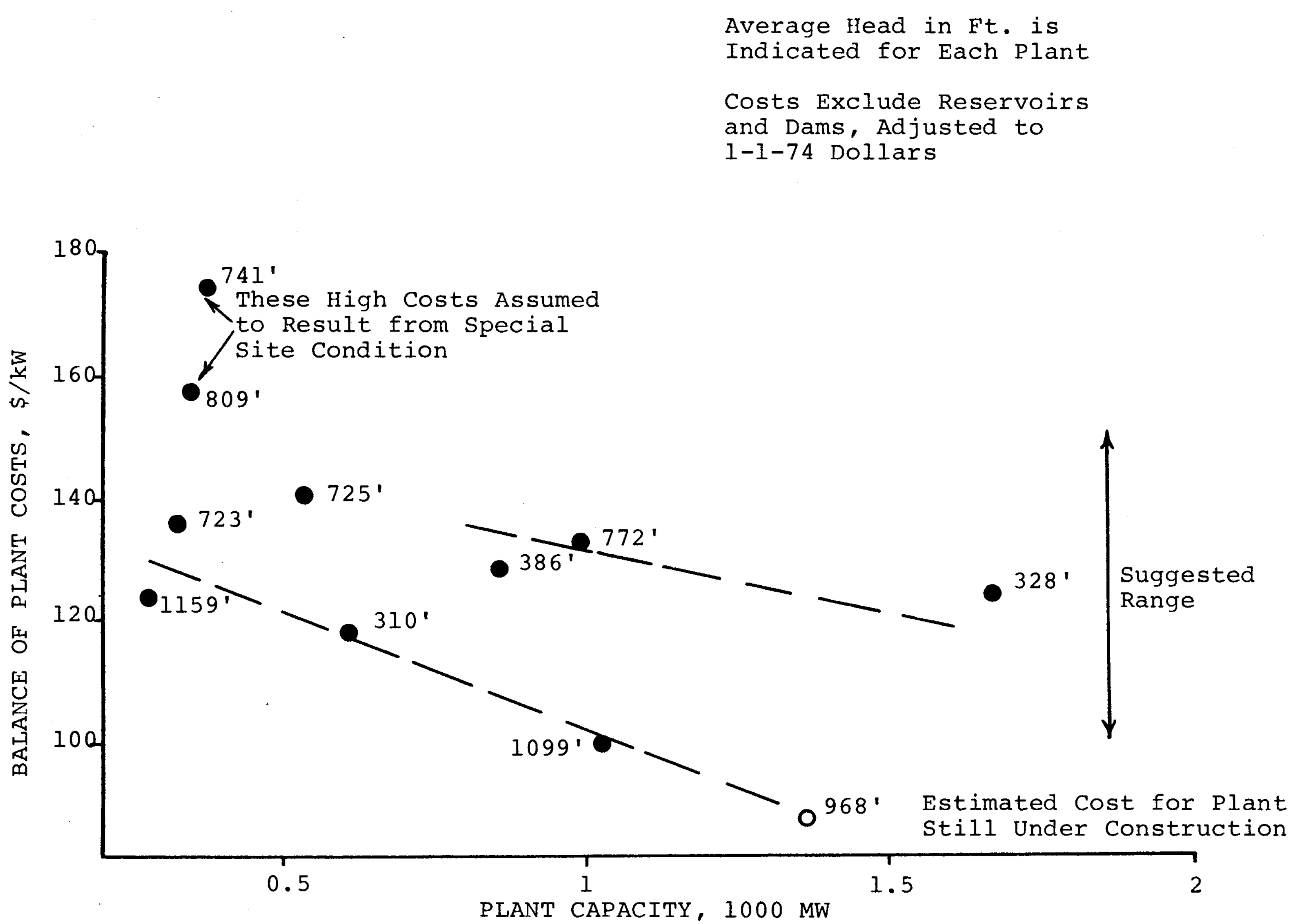


Figure 4-2 PUMPED STORAGE BALANCE OF PLANT COSTS

$150/kW is proposed for future costs (excluding storage and adjusted to January 1, 1974 cost levels). Although future plants may be built at the low range of costs under favorable conditions, it is not appropriate to assume the general availability of such conditions to justify an interest in pumped storage.

The upper extension of this range to $150/kW should be sufficient to cover any additional adjustments of older plant costs that are not provided for in the Handy-Whitman indices. A separate adjustment would be required for older plants because of increased interest rates and their effect on allowances for interest during construction. It is estimated this may be in the order of 3 to 5 percent. It is expected that new plants will have somewhat greater costs than older plants to meet environmental and recreational needs.

The choice of a charge/discharge ratio is primarily an economic decision related to site and system conditions. Where system conditions require longer hours of generation, and storage costs are high, the selection of a higher ratio may have an advantage over a larger energy storage, particularly if the storage must operate on a weekly cycle.

The charge/discharge ratio has a great effect on cost, and is an important design option. This ratio may be varied over a range from about 1.0 to 1.4. The higher ratio permits more hours of daily generation for a given pumping time and leads to slightly lower efficiencies and higher plant costs.

To increase this ratio from 1.0 to 1.4, it is ncesssary to increase the rating of the generator-motor, which will be determined by the higher pumping load, and to increase the physical size of the pump-turbine to deliver the larger quantity of water. The costs of structures and of some equipment (e.g., cranes) will also increase. At the outside, the increase in cost will be something less than 40 percent of the total plant costs applied to about 40 percent (structures, some equipment, turbines, and generators). The more likely increment is perhaps 20 percent of 40 percent. If the total plant cost is $150/kW, the estimated cost of a change in ratio from 1.0 to 1.4 is more nearly $12/kW, rather than $24/kW.

Adjustment of the cost of the selected plants to an average charge/discharge ratio would involve individual plant cost adjustments of less than about $5/kW. The suggested range of plant cost is sufficiently large to cover such adjustments.

4.1.2 Underground Hydro Pumped Storage

As for conventional pumped storage, the cost of storage and the balance of plant costs for underground hydro pumped storage are treated separately. Estimated costs for underground hydro reservoirs are derived, in part, from experience in other industries which require similar excavations.

An obvious difference between plants with underground reservoirs and those with only underground powerhouses is that relatively shorter water conduits are required for those with underground reservoirs. The long and nearly horizontal pressure and tailrace tunnels are unnecessary as is the usual surge chamber on the tailrace tunnel. These differences are very favorable to the underground reservoir.

Partially offsetting this saving in tunnel and surge chamber costs is the fact that access to the underground plant is more costly, when provided by shafts rather than by tunnels. Less obvious cost differences result from measures taken to protect the underground plant from flooding. The consequences of flooding are possibly more severe, and of much longer duration, since the whole lower reservoir may have to be emptied before restoration of operation can be accomplished. Also it is necessary to protect against full head of the project being imposed on the downstream side of the plant. These measures add to the costs for underground systems.

Another difference is in the powerhouse and equipment layout when heads exceed those that can be served by a single-stage reversible unit. For such heads, the decision may be to utilize separate turbines and pumps, a typical European practice for high head plants. In this case, there is a step increase in cost of equipment to serve the higher heads. A somewhat smaller step increase also occurs for multistage reversible units that might be substituted for separate turbines and pumps. The head at which these increases occurs is now in the range of 1,000 to perhaps 2,000 feet. Beyond the point where this increase occurs, there is little variation in equipment costs.

4.1.2.1
Adjustment of Overheads, Contingencies, and Allowances for Interest During Construction Before proceeding to estimated costs for a specific project, attention is directed to the importance of allowances made for overheads, contingencies, and interest on construction funds in these estimates. For future plants, allowances must also be made for price escalation.

The breakdown of costs for a conventional plant, shown in Table 4-5, can be rearranged in the following fashion for comparison:

Construction Costs	$81/kW	
Engineering, Supervision and Other Overheads	10/kW	(= 12.4% of 81)
Allowance for Interest During Construction	9/kW	(= 9.9% of 91)
	$100/kW	

Current estimates for underground plants show quite different allowances for the amounts to be added to construction costs. The allowance for overheads and contingencies might be 25 percent and the allowance for interest during construction might be 40 percent. If the construction cost remains at $81/kW, the use of these higher allowances results in a total estimate of $142/kW for the balance of an underground plant, as compared to $100/kW for a conventional plant.

The added provision for contingencies, about 12.5 percent, is a conservative practice, particularly where some new problems may be encountered in construction. Expert opinions will vary as to what is a reasonable allowance. Note particularly that this is not an allowance for changes in costs due to changes in labor rates or price of materials; it is entirely an allowance for unknown, but adverse factors. For hydro pumped storage the allowance for overheads and contingencies is assumed to be in the range of 20 to 25 percent of the estimated construction costs.

The allowance of 40 percent for interest is the result of the current high interest rates and extremely long construction time. (The Mt. Hope estimate used 38 percent.) Neither of these factors is reflected in the indicated interest during construction allowance (about 10 percent for conventional plants). Those plants for which the required cost data were on file with the FPC were, with one exception, completed before the period of high interest cost. Also they do not include the recent underground plants (with surface reservoirs), for which the construction time is also long. A recent estimate for such a plant, reflecting both the higher rates and longer time, showed an allowance for interest of 24 percent. In subsequent discussion of plants with underground storage, the allowance for interest will be assumed to be in the range of 25 to 40 percent of the combined construction costs plus overheads.

These assumptions mean that the combined added costs applicable to underground construction for overheads, contingencies and interest lie in the range of about 50 to 75 percent (1.20 x 1.25 = 1.5 and 1.25 x 1.40 = 1.75). These rates being much larger than the approximate 25 percent in the actual costs of constructed projects (100/81 = 1.24).

4.1.2.2 Mt. Hope Project Application has now been made by Jersey Central Power and Light Company (a General Public Utilities subsidiary) for an FPC license for a hydro pumped storage plant with an underground reservoir (the Mt. Hope Project). The application is based on a 1,000-MW plant capacity, with four reversible units operating at about 2,500 feet of head, with adequate storage for ten hours of operation. The plant is to be located in northern New Jersey at the site of an existing shaft previously used for iron ore mining.

A series of preliminary design and cost estimates for Mt. Hope were prepared by Harza Engineering Company made in 1973, based on July 1972 costs. These estimates show costs for construction of the balance of plant in the range of about $75 to $85/kW including $6/kW for land. It is considered reasonable to include this relatively high land cost as compensation for the existing mine shaft. The highest cost is for construction of an eight-unit plant (125 MW each) in four stages, this higher cost being compensated by the shorter construction time for each stage and a resulting lower interest cost (estimated for this case at only 16%). Other variations in plant description, and in assumed costs of excavation of the powerhouse cavern were considered, but major uncertainties would be involved in any comparision among them, particularly with respect to equipment costs for very high heads.

Estimates were revised in 1975, based on March 1975 costs for the purposes of the license application, but were again made on a July 1972 basis for direct comparison with the 1973 work. The cost estimated in 1975, on the basis of July 1972 costs, and considered to be directly comparable with the 1973 estimates for balance of plant is $78/kW. The cost estimated in 1975 is the result of a different plant layout and better understanding of various problems. It is very probable that the balance of plant cost would be lower for a larger plant.

If the 1975 estimate, based on 1972 costs, is stepped up to January 1, 1974, the $78/kW becomes $90/kW. The comparable estimate in the license application, based on March 1975 costs, is $113/kW, but Harza notes that costs of major equipment were very uncertain as of that date.

This estimate of balance of plant cost, adjusted to January 1, 1974 levels, of $90/kW is conservatively high. One entirely independent estimate for an underground plant with larger capacity and higher head is substantially lower. Also another recent estimate by Harza for an underground plant with surface reservoirs, is lower by about $5/kW, and this is not out of line with the $80/kW, more or less, indicated by the experience of the larger, higher head existing plants.

From the evidence of estimated costs which included, the expert opinion of Harza Engineering Company and Acres America, Inc. as to the comparability of the balance of plant costs for underground construction; and the fact that the range of high heads and large capacities underground is likely to have much less effect on costs than that encountered in existing plants, it is suggested that the construction cost for the balance of plant might lie in the range of $80 to $90/kW, as of January 1, 1974. These costs must be increased by 50 to 75 percent to cover overheads, contingencies, and interest. This results in a range of estimate costs of $120 to $160/kW in January 1974 dollars.

4.1.2.3 Underground Storage Cost The Mt. Hope estimates for construction costs of the storage reservoirs before the additions for overheads, contingencies and interest, are approximately:

	July 1972 Costs	March 1975 Costs
Upper Reservoir	$0.60/kWh	$0.85/kWh
Lower Reservoir	$2.30/kWh	$3.30/kWh

These costs, adjusted to January 1, 1974, are roughly halfway between the estimates. For comparability with existing reservoir costs, they must be increased by some factor in the 50 to 70 percent range. After such an increase, the upper surface reservoir cost, about $1.20/kWh, is in line with the lower costs for separate surface reservoirs, without consideration of the effect of the higher head available at Mt. Hope. The adjusted cost for the lower Mt. Hope reservoir is between $4 and $5/kWh.

The costs estimated for the Mt. Hope underground reservoir are for generally favorable conditions. The rock is good, there is expected to be a credit for the sale of excavated material, and labor rates and productivity are based on the expectation of a mining rather than a construction type operation. These are the major factors governing an estimate of cost for excavation of a large underground cavern, with labor rates and productivity being most important.

Costs are also greatly affected by the duration of the excavation period, as evidenced by possible wide swings in the added interest costs. As noted, even these varied from 16 percent for staged construction to 38 percent in the final estimates. It is evident that means of reducing the construction period need to be investigated.

The GPU Service Corporation and its consultants made an extensive investigation of underground excavation and mining costs. Actual costs were determined and analyzed for several large mining operations and for major cavern excavations associated with underground power plants. Estimates and advice were obtained from several recognized experts.

For mining operations, the costs adjusted to January 1, 1974 are generally in the range of $4 to $6 per cubic yard. For construction projects, with higher labor rates and lower productivity, the range is $8 to $10 per cubic yard. For Mt. Hope, the rate used, adjusted to January 1, 1974, is about $2.70 per cubic yard, this being a net cost after credit for sale of the excavated material to the operator of the existing quarry at the site.

Considering the wide range of these estimates and of the corresponding conditions applicable to as yet unknown sites, it is not unreasonable to consider a range of net costs from $3 to $10 per cubic yard. These costs must be increased by 50 to 75 percent for overheads, contingencies, and interest. The range of underground reservoir storage costs is shown in Figure 4-3. The conversion from cost per cubic yard to cost per kWh is based on a factor of 0.77 yd^3/kWh at 2,500 feet of head, including therein an allowance for 5 percent excess volume in the lower reservoir. There are, of course, some elements of cost for the lower reservoir which are not proportional to size, but these are minimal and are not included in this estimate.

The total costs for storage are shown in Figure 4-3. All the favorable elements are combined to produce the lower curve and all the unfavorable elements, to produce the upper curve. If the likely head range is about 2,500 to 4,000 feet, and excavation costs are high, plants are not likely to be built for heads in the lower portion of this range. Storage costs can then be reasonably represented by a range of $3 to $12/kWh.

4.1.3 Recommended Range of Costs

Based upon the preceding discussions, recommended cost ranges can be established for power related costs and storage related costs for both conventional and underground hydro pumped storage. A recommended range of plant construction costs, based on January 1974 dollars and including allowance for the cost of interest during construction, is presented in Table 4-6. Plant substation costs are separately identified and must be included in the power related costs of hydro pumped storage to provide comparability with other storage system cost estimates.

The substantial range in costs are not due to large uncertainties in specific cases but are due to variation in site conditions and plant design.

For comparison with other technologies, a single range of costs is used. This is done because the two hydro estimates are very

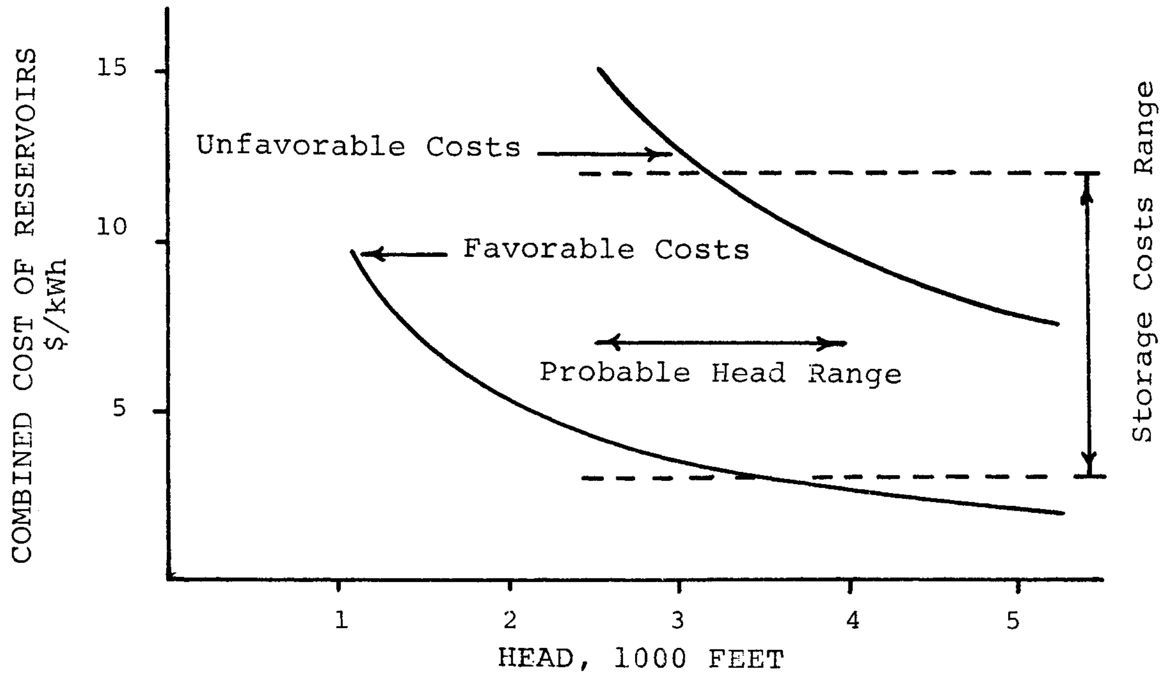


Figure 4-3 UNDERGROUND STORAGE COSTS; HYDRO PUMPED STORAGE

Table 4-6 REPRESENTATIVE PLANT CONSTRUCTION COSTS FOR HYDRO PUMPED STORAGE

	Conventional Reservoirs	Underground Lower Reservoirs
Power Related Costs	\$ 90 - \$140/kW	\$110 - \$150/kW
Storage Related Costs	\$ 2 - \$ 10/kWh	\$ 3 - \$ 12/kWh
Substation Costs	\$ 5 - \$ 10/kW	\$ 10 - \$ 15/kW

Note: In January 1975, dollars without allowance for interest during construction.

4.2 COMPRESSED AIR STORAGE

In this section, estimates for compressed air storage in underground reservoirs are developed. The equipment covered are modified conventional equipment derived from currently available compressors and combustion turbines (gas turbines). Only a split Brayton cycle is considered, with the stored air cooled to conditions tolerable to an underground reservoir. Adiabatic compressed air storage, which utilizes the thermal energy of compression, is not treated here because sufficient information was not available to permit development of a cost estimate for it.

A separate project at the General Electric Company, funded by ERDA, has recently been completed [2] and reports more detailed estimates for compressed air storage. Data available from the plant under construction in West Germany at Huntorf is insufficient to permit a cost comparison.

4.2.1 Cost Characterization in Previous Investigations

Previous investigators have described the technical features of compressed air storage and reported on various aspects of costs. The variation in aggregation of cost items makes cost comparison at the subsystem level difficult, nevertheless system level comparisons can be made.

Total system costs reported previously by various investigators are listed in Table 4-7. Within given studies where parametric variation of key design conditions was used, some trends are noticeable. The capital costs of the equipment decrease with increased storage pressure until the limits of existing high air flow compressors are reached. At this point conpressor costs increase faster than the decrease in cavern costs. The capital costs decrease for larger power rating unit sizes. Again, this reduction is limited by the sizes of the compressors that are available. The cavern type affects costs; if aquifers are available, there would not be a need for underground excavation. The potential savings of having a shallower subsurface reservoir with a hydrostatically compensated air storage are negated by the cost for a water reservoir and immersed shaft.

Table 4-7 SUMMARY OF TOTAL SYSTEM COSTS REPORTED IN PREVIOUS STUDIES OF COMPRESSED AIR

Reference	Type of Air Storage Facility	MW, MWh	Capital Cost $/kW	Year
Giramonti [5]	Mined cavern, 14 atm	(140, 140)	52.1	1968
		(140, 420)	69.1	
	Mined cavern, 50 atm	(140, 140)	50.7	
		(140, 420)	59.8	
	Mined cavern, 14 atm	(700, 700)	46.0	
		(700,2100)	56.3	
Pratt & Whitney Aircraft [6]	Mined cavern			1968
	4 atm compensated	(37, 185)	140-330	
	13.8 atm compensated	(225,1125)	80-115	
	30 atm compensated	(300,1500)	70-90	
Kalapasev [7]	Mined cavern Compensated	(250,2125)	50	1970
Olsson [8]	Mined cavern 640 psia compensated	(220,1100)	50	1971
Harboe [9]	Mined cavern 40 atm compensated	(200-250, 1600-2000)	85	1971
	Salt cavern 45 atm		75	1971
Fryer [10]	Nuclear explosive chimney	(175, 875)	65.7	1973
		(542,4336)	42.2	1973
Richert [11]	Mined cavern	(190-1900)	129	
	Mined cavern Uncompensated Compensated			

Table 4-7 (Con't) SUMMARY OF TOTAL SYSTEM COSTS REPORTED IN PREVIOUS STUDIES OF COMPRESSED AIR

Reference	Type of Air Storage Facility	MW,MWh	Capital Cost $/kW	Year
Harza Engineering[12]	Mined cavern	(190,1900)	136	1973
Harza Engineering[13]	Mined cavern	(970,9700)		
	240 psi uncompensated		167	
	415 psi uncompensated		150	
	500 psi uncompensated		145	
	415 psi compensated		202-223	
	580 psi compensated		175	
Ayers & Hoover [14]	Aquifer @ 520-ft depth	(168,00)	63	
Rogers & Larson [15]	Mined cavern	(1000,10000)		
	240 psi compensated		155	
	415 psi compensated		148	
Giramonti & Leasard [16]	Mined cavern, 40 atm	(1000,10000)	75-95	
Rudisel	Mined cavern	(--,1000)	191	
Day et al [18]	Mined cavern	(135, 350)		
	300 psi uncompensated		85	
	600 psi uncompensated		93	
	600 psi compensated		85	
Glendenning[19]	Mined cavern	(1000,8000)	99-135	1974

4.2.2 Major Subsystems

Major subsystems selected for cost analysis are:

1. Compressor subsystem
2. Hot gas generator subsystem (combustion turbine)
3. Motor-generator
4. Clutches, piping and installation

A summary of the costs for these major subsystems are presented in Table 4-8.

4.2.2.1 Compressor Subsystem Compressor costs were obtained from compressor manufacturers and should be considered as representative numbers. The costs are complete with necessary coolers and speed reducers. The major limitation at this time is the maximum horsepower achievable with a single commercial compressor. Large unit sizes will require several compressor trains unless specific development efforts to increase size and reduce unit costs occur.

For costing purposes and conservatism in the estimates, the maximum unit size considered is approximately 250 lb/sec flow. Compressors have experienced exceptionally large cost increases in recent years. Comparison of equipment estimates obtained in 1968 with current estimates indicated a price increase of 260 percent. Use of the Handy-Whitman index [4] would suggest an increase of less than 180 percent. Part of this increase must be due to functional pricing practices; large sales volumes could reduce the anticipated cost. A compressor cost range is used which covers the range from the adjusted 1968 costs to current estimates (Figure 4-4).

4.2.2.2 Hot Gas Generator Subsystem Estimates for the hot gas generator subsystem cost assume that the hot gas generator cost can be approximated as a conventional gas turbine less its compressor. It is not assumed that the compressor cost previously cited plus the hot gas generator cost is equal to that of a conventional gas turbine.

A typical installed cost for a single cycle gas turbine is \$100/kW. This includes overheads and installation as well as equipment costs less any contingency. Costs of an installed synchronous generator, including overheads, is \$50/kW. Subtracting the two and allowing \$9/kW for the balance of plant leaves the gas turbine costing \$41/kW. This is an installed cost including overhead on the single cycle gas turbine power output base. As shown in Table 4-9, the fan-compressed combination for

Table 4-8 COSTS OF COMPRESSED AIR STORAGE MAJOR SUBSYSTEMS

Subsystem	Cost Range $/kW
Compressor (High Pressure)	$50 - $85
Combustion- Turbine	$10 - $30
Motor - Generator	$35 - $50
Clutch	$ 5 - $12
Substation	$ 5 - $10

Includes installation and overheads.

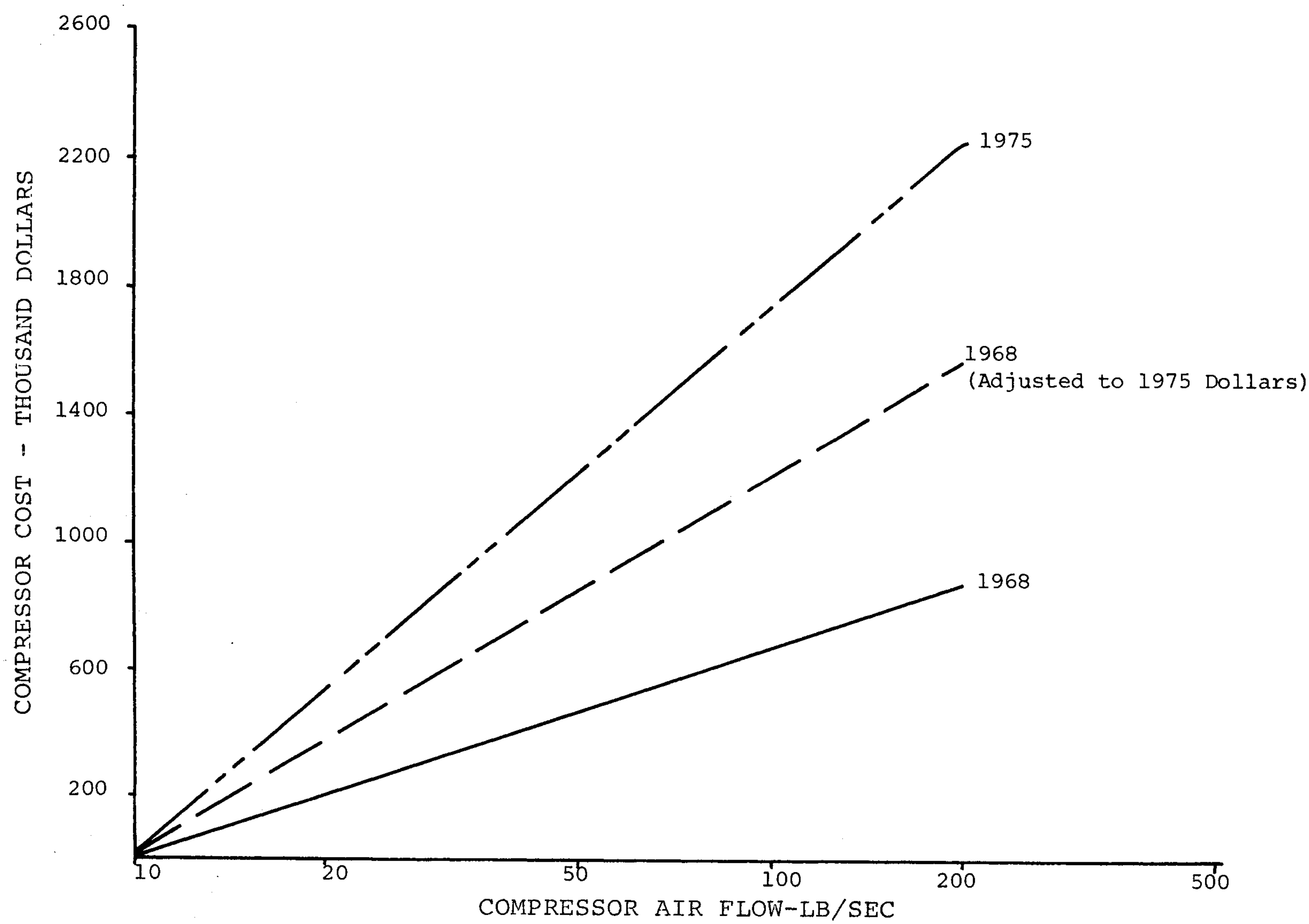


Figure 4-4 COMPRESSOR COSTS

Table 4-9 GAS TURBINE SUBSYSTEM COSTS [20]

Aviation Gas Turbine Subsystem	Subsystem Cost, Percent of Total Engine Cost*
Fan	11
Compressor	14
Plenum and Combustor	3
Turbine	20
Thrust Augmentor	5
Exhaust Nozzle	13
Shaft, bearings, and lubrication	5
External Structure	11
Controls and Balance of Plant	18

* Pratt & Whitney Aircraft Turbofan Engine.

a large gas turbine aircraft engine accounts for 25 percent of this total engine costs. Applying this reasoning to the present case, the hot gas generator will cost $31/kW.

This cost is on the basis of the normal output rating. A simple cycle combustion turbine typically delivers nearly twice as much power to the compressor as it does to the generator. Physical separation of the compressor from the turbine, with no other change in design, would permit the same turbine to drive a much larger generator (up to a factor of 3) when the compressor is disconnected.

The cost range for the combustion turbine component used in an air storage system should be from one-third of a conventional combustion turbine cost up to the full cost.
By installing a full sized combustion turbine it would be possible to operate the compressors and turbine as a conventional unit when stored air would not be available.

4.2.2.3 Motor-Generator Subsystem The motor-generator cost should be $50/kW for normal-size gas turbine generators. Larger machines will cost less (down to $35/kW). The machine could be brought up from rest by using the compressor as a turbine, simplifying the design of the generator and reducing the size of the main transformer. If the machine was made to be self-starting, an additional motor or solid-state stepping device, as used on large pumped hydro installations, would be required. Both of these approaches would increase the cost more than using the existing equipment in a dual mode.

4.2.2.4 Clutches, Piping, and Installation Remaining major subsystem costs include the necessary clutches, piping, valves, and installation. Since detailed layouts and structural requirements are not available, gross estimates were made. Clutch requirements depend heavily upon the shaft power, speed, and the charge-to-discharge ratio chosen. Costs of $5 to 10/kW are reasonable if development costs are neglected. From analogue with gas turbine installations, a cost of $20 to $30/kW is assumed for installation. This should cover any small contingencies for a control system, etc. Transformer and bus work should range from $5 to $10/kW.

4.2.3 Storage Costs

Storage costs will depend heavily upon the total volume required, the type of underground structure, and the technique used. Major candidates include salt beds, aquifers, and hard rock. Of these, the most extensive data available is for hard rock excavated caverns. Figure 4-5 provides some typical data on excavation costs.

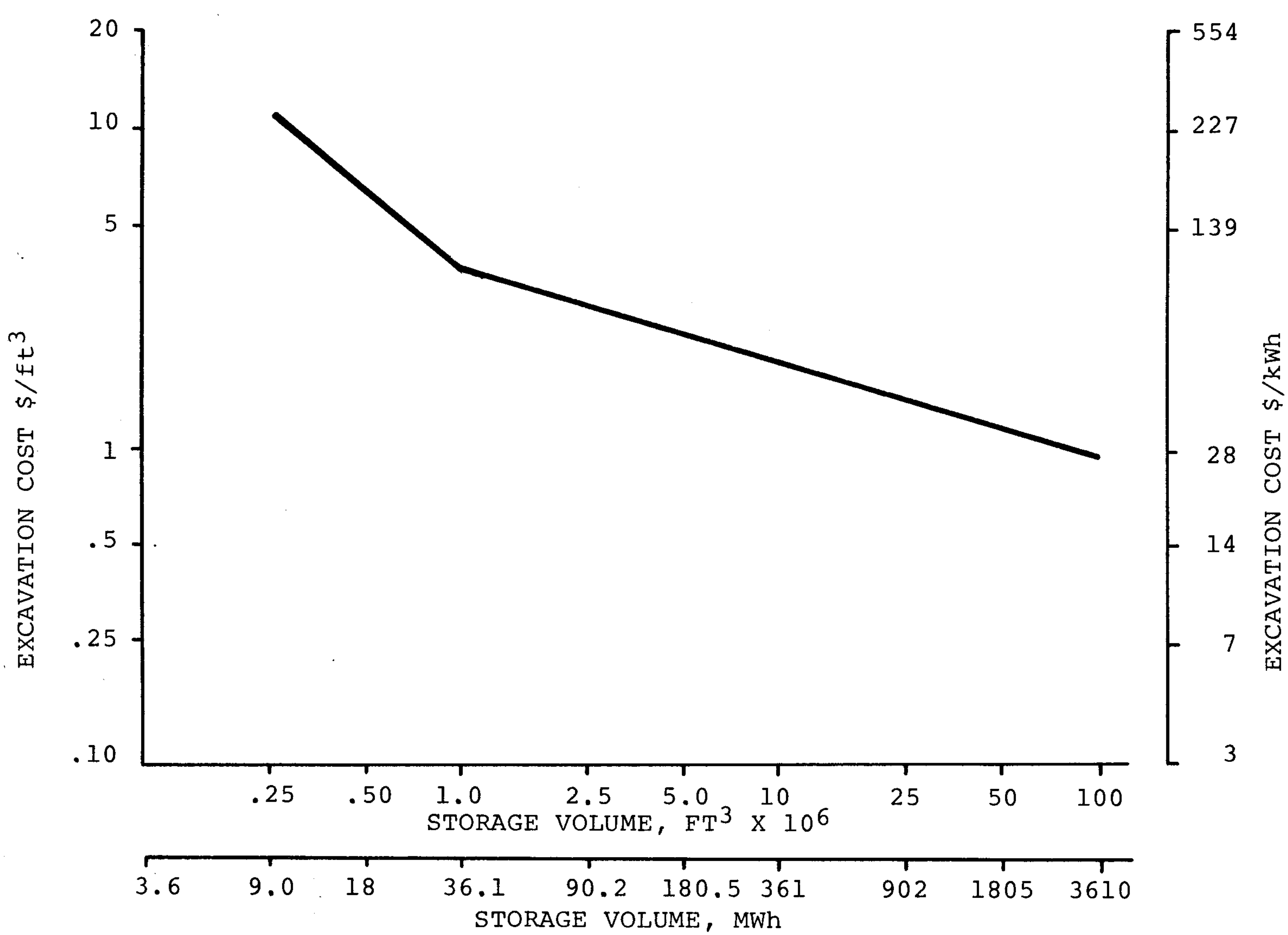


Figure 4-5 REFERENCE EXCAVATION COST CURVE FOR GRANITE AT 1500 FT. SUBSURFACE DEPTH [21]

Storage costs consist of both cavern excavation costs and air shaft costs. For large volume caverns in hard rock, excavation costs dominate shaft costs. For example, consider a combustion turbine with an inlet pressure slightly below 18 atmospheres. In this case a variable pressure cavern could be used with the pressure cycled between 18 and 50 atmospheres. This would require a maximum discharge from the compressors of 18 atmospheres. Storage costs for this configuration are shown in Figure 4-5 using a specific storage volume of 27.7 ft^3/kWh. Figure 4-5 was developed from reference data provided by United Technologies [5] and adjusted to 1975 costs. With increasing cavern volume, specific costs ($/kWh) decrease. The curve in Figure 4-5, if extrapolated to larger cavern volumes, agrees with the estimates used in the earlier discussions of underground reservoirs for hydro pumped storage. Economies of scale will dictate large size installations.

In some areas, very inexpensive storage may be available through the use of existing caverns. The potential also exists for solution mining of salt beds and the storage of air in an aquifer.

Detailed analysis would include specific estimates for piping and valving, taking into account local union practices, and credit for disposal of excavated rock (or salt or other salable minerals).

Large variations in the storage costs are possible due to specific site conditions, thus the numbers presented here should be considered as representative rather than a precise estimate. If a specific site and construction technique is chosen, the variability on the estimates will be reduced.

4.2.4 Effects of Charge/Discharge Ratios

Compressed air storage is a storage system which utilizes separate equipment for charge and discharge. As such, the charge to discharge ratio is a design variable which can, within certain limits, be controlled by the designer.

A cost function can be constructed for a compressed air storage system which explicitly allows for the dependence upon charge and discharge. (For simplicity this relationship is stated in terms of available charge and discharge times.) The charge to discharge ratio can be calculated from this relationship. If equal charge and discharge times are selected, overall plant cost will be in excess of those of conventional combustion turbines. If long charge periods are available with only very short discharge requirements, total costs could be less than that required for a conventional combustion turbine. The basic cost formula is simply:

$$Cp = (1 + Xcont)\,[Xct + Xmg + cl + Xsub + (Xcomp + Xcl) \bullet Td/Tc \bullet P/G]$$

where Cp is the power related capital cost, Xcont is the contingency in percent and Xct, Xmg, Xcl, and Xcomp, the capital cost of the combustion turbine, motor generator, clutch and compressor, respectively, all expressed in dollars per kilowatt of electrical output. Xsub is the cost associated with the substation. Properly used, the specific costs must refer to definite flow rates. Since compressor costs are substantial, the effect of the multiplier Td/Tc • P/G is significant. P/G is the ratio of kWh consumed in compression for each kWh of generation (.6 to .8). Td/Tc is the discharge time divided by the charge time.

With the use of the above cost formula, a range of installed costs for various charge to discharge times is presented in Table 4-10.

4.2.5 Recommended Range of Costs

Table 4-11 presents the recommended installed cost range to use in comparison with other technologies. As soon as better information is available, these estimates should be revised. Comprehensive studies of compressed air storage system costs should examine specific design point cost variation of individual components.

Table 4-10 EFFECT OF CHARGE TO DISCHARGE RATIOS ON POWER RELATED COSTS FOR COMPRESSED AIR

Td/Tc	C/D	Cp ($/kW)
1.25	.75 to 1.0	120 to 240
1.0	.6 to .8	107 to 180
.25	.12 to .2	80 to 145

Table 4-11 RECOMMENDED RANGE OF COSTS FOR COMPRESSED AIR STORAGE

Power Related Cost* $/kW	$100-$210
Storage Related Cost $/kWh	$ 4-$ 30

*Equal charge to discharge times.

4.3 THERMAL ENERGY STORAGE

In this section three specific approaches to thermal energy storage are addressed: a saturated water (steam) system similar to that of Gilli [21, 22, 23] a feedwater heat storage system suggested by Exxon [24], and a particular approach to storage of heat in a phase change material [25].

It is apparent that many variations and different approaches are possible for thermal energy storage. It was necessary to treat only a limited number of systems and none could be treated in sufficient detail to permit design and cost optimization. Thermal energy storage is a fertile area for innovative engineering.

A system which was not treated here, but which is under active investigation elsewhere, is saturated water storage in underground lined cavities. It is believed that such a storage system is bracketed by the two sensible heat storage systems treated here. The chief difference is the mode of storage; this is reflected in the anticipated cost for storage.

The phase change storage system concept which was examined proved to be expensive. The cost which is presented is for only one approach; other approaches are possible and might prove less expensive. These systems are in an early conceptual development stage and are not on the same basis as the saturated water and oil thermal systems.

This set of estimates collectively covers a substantial range of approaches. For each one, a simple design was costed out and then judgement was used to open the range of costs to include what should result from further design study. These cost estimates are a combination of engineering study estimates, manufacturer estimates, and engineering judgement.

The estimate for the oil system, provided by Exxon Research and Engineering, and General Electric was critically reviewed. The estimate for the saturated water (steam) system was developed from current estimates from tank, turbine, and pipe manufacturers. The oil storage system estimate was developed from manufacturers's estimates of the steam turbine, and extrapolation of existing tankage, piping, and heat exchanger costs. The variation in the latter portion of the estimate may be larger, but since it is a relatively small portion of the estimate, the total estimated cost is within 25 percent of an installed cost. The molten salt system estimate is very speculative in that it postulates a heat exchanger that has never been constructed. The estimate should be considered as a crude estimated number.

4.3.1 Thermal Steam

The basic design approach, discussed in Chapter 3, is storage of saturated water in steel tanks (Ruth Accumulators) and recovery of the energy as steam to run a separate peaking turbine. Two important details of the design that relate to unit costing of the system are the change of output power with depth of discharge and the warm-up of the turbine.

Cost estimates for a 200 MW thermal steam plant are detailed in Table 4-12. Unit pricing for both the power and energy related components were not given because they are strongly dependent upon the minimum required power output and the comparison of discharge duration to turbine warm-up time.

4.3.1.1 Power Related Costs Estimates were obtained from major turbine manufacturers for sliding pressure turbines. A sliding pressure peaking turbine was chosen because it is more economic and presents fewer control problems than switching between turbine stages at various pressures. The representative sliding pressure turbine design will have a constant power output for 40 percent of the storage energy with only a 2 percent loss in energy for throttling. The power output will then reduce at the same rate as the reduction in pressure in the Ruth accumulators. If a system that delivers a constant power output for a given length of time is required, more storage capacity or larger turbine sizes would also be required. Similarly a reduction in power output would be experienced if a turbine with some of its stages at various pressures were used instead of a sliding pressure turbine. The power output curve for such a turbine would increase initially and then fall off after a while. The second approach would be less efficient, more expensive, and present more control problems than a sliding pressure turbine.

A sliding pressure turbine would require first of a kind development with the major development effort on the valves. For 200 MW units, four exhaust ends will be required utilizing last-stage blades with lengths between 24 to 28 inches. Estimated cost, in January 1975 dollars, is $9 to $10.4 million depending upon the precise design of the last stage. Turbines larger than 200 MW should not be considered due to rapid increases in the cost of piping, valves, and, for larger size units, the last stage.

A peaking turbine must be heated up to its operating temperature prior to being loaded. This will typically take a half hour at approximately 10 percent of full steam flow. This amount of energy will be lost each time the turbine is started.

Controls for a 200 MW sliding-pressure plant, which provide for unattended operation, have been estimated at $2 million. An

Table 4-12 COST ESTIMATES FOR 200MW THERMAL STEAM SYSTEM

Power Related Cost		Millions of Dollars
Turbine including stop valves		10.5
Turbine structural and installation (includes building & cranes)		3.7
Controls (for fully automated operation)		2.1
Balance of Plant (includes condenser, cooling towers, transformer and misc.)		21.5
Overheads and Contingencies[3]		3.8
		41.6[1]
Storage Related Cost		
SS tank 12 ft. x 70 ft. with full X-ray and 3 1/2 inch mineral wool[2]	200,000	
Piping	16,000	

1 Unit Cost in \$/kW will depend on minimum power required at the end of discharge.

2 Withdrawable energy, neglecting heat loss, is 4.54 MWh for each tank.

3 These are in addition to allowances contained in each identified component.

operator at a remote location can push a button which will cause the turbine to start, come up to speed, go on line, carry load, and, if in trouble trip. The operator can push another control button and the unit will shut down.

The structural estimate for the 200 MW turbine installation is approximately $3,700,000. This includes the turbine generator building and foundation, plus the gantry crane. It is based on a volume of enclosed building space of 414,000 ft³ and a volume of 37,800 ft³ for the turbine foundation.

The condenser and cooling tower represent a large part of total plant capital costs. For the 200 MW station, the wet cooling tower would cost $4 million. Gilli has suggested that the condenser serving the peaking turbine could be cooled by water from the main condenser, however, this would raise the condenser pressure of the main turbine, causing a consequent decrease in its output. The amount of decrease depends upon the relative size of the main to peaking turbine. In the case of a substantial (200 MW) steam storage system, the decrease in output of the main turbine would be unacceptably large.

A better approach would be to size the main condenser to serve both turbines. A condenser sized for both turbines would not be very far from optimal for the main plant alone. This combined approach could result in a power related capital cost on the order of $150/kW assuming no restriction in minimum power output.

4.3.1.2 Storage Costs Storage costs were developed based on the use of stainless steel tanks as pressure vessels. These estimates are conservative and lower cost storage systems are possible.

The installed cost of stainless steel storage tanks 12 feet in diameter and 70 feet long is estimated to be $200,000. This includes full x-ray inspection and 3-1/2 inch thick mineral wool insulation. This thickness of insulation will hold the temperature of the water in the tanks to a drop of less than 10°F in a 24-hour period with an ambient temperature of 0°F. The corresponding pressure loss is less than 30 psi resulting in a decrease in steam storage of about 5 percent.

The installed tank cost works out to about $25 per cubic foot installed. The cost of piping, including insulation, hangers, fittings, and installation, has been estimated to be $16,000 per tank which adds an additional $2 per cubic foot.

For the design conditions selected, each storage tank will have a storage capacity of 68,000 pounds of steam which can produce a maximum of 4,550 kWh. The number of tanks required will depend on the daily maximal peaking load duration in hours, T. Table 4-

13 shows the number of tanks as a function of T, neglecting heat loss but including heating of a 200 MW turbine.

Less conservative approaches to pressure vessel construction and design could lower costs. These approaches include the use of: carbon steel, prestressed cast iron (field erected), prestressed concrete (field erected), and underground reservoirs in mined hard rock caverns (lined) or "geothermal" formations.

Use of carbon steel would lower costs by approximately 20 percent. In a nuclear plant, however, there would be some concern about use of carbon steel in the same loop with a stainless steel vessel. Bulk purchase of large numbers of tanks could reduce costs by 10 percent to 20 percent. Prestressed cast iron vessels are being studied in West Germany for use as pressure vessels in nuclear stations and for energy storage. Prestressed concrete pressure vessels have been designed for liquified natural gas storage and if thermal expansion problems were to be solved, it could conceivably be developed as a lower cost storage reservoir. Underground storage would require both excavation and structural work for the cavern lining, but it is not possible to estimate the costs of such a system now. Each of these should be examined more carefully.

4.3.1.3 Cost Summary The saturated water thermal storage peaking plant employs existing technology. In the 200 MW size range, the capital cost, excluding the storage system and not requiring any particular minimum power output, is estimated to be $210 per kW. This is a conservative figure including first-of-a-kind development of the turbine. If a moderately lower cost estimate is assumed, the plant would be completely competitive with modern gas turbines using fuel which costs $3 per million Btu.

Table 4-14 provides a range of cost numbers based on achieving optimum plant integration and use of less expensive pressure vessels. With carbon steel tanks and large production runs, costs would be reduced. With inexpensive tankage using innovative designs, such as prestressed concrete pressure vessels, even lower costs could be achieved.

4.3.2 Thermal Oil

The basic design approach, discussed in Section 3.3, is a feedwater heat storage scheme which substitutes the heat contained in oil for the extraction steam. This steam is usually taken from the turbine and used to produce more electrical energy. The basic cost estimates which were developed by Exxon and General Electric under contract to Exxon [25] were reviewed and found to be reasonable. A summary cost estimate for a 259 MW

Table 4-13 REQUIRED NUMBER OF SATURATED WATER TANKS

MWh Discharge	No. of Tanks	Total Installed Cost ($)
200	46	9,936,000
400	90	19,440,000
1,000	222	47,952,000
2,000	442	95,472,000

Table 4-14 STEAM (SATURATED WATER) COST ESTIMATE

Conservative[1]		Reasonable[2]		Optimistic[3]	
Turbine and Balance of Plant	Storage	Turbine and Balance of Plant	Storage	Turbine and Balance of Plant	Storage
$250/kW	$70/kWh	$200/kW	$45-50/kWh	$150/kW	$30-35/kWh

1. High degree of certainty that this cost level can be achieved.
2. Requires careful design effort and bulk purchase of storage tankage. Some reduction achieved through use of carbon steel.
3. Assumes fully integrated plant design and low cost storage vessel such as pre-stressed concrete. Technical feasibility of very low cost tanks is uncertain.

plant integrated with a 1,000 MW pressurized water reactor (PWR) is shown in Table 4-15.

4.3.2.1 Power Related Costs The key to power related costs is the design of a variable-flow extraction turbine. To investigate this, Exxon contracted with General Electric to do the preliminary design analysis for a 1,000 MW variable extraction turbine suitable for use with a standard PWR.

The specifics of the cost estimate are considered proprietary by Exxon, however, the differential costs between the power related components of both the powerhouse and oil handling facilities is $61.2 million, or $236 per kW. This is reduced $181 per kW by taking credit for the increased turbine output due to the oversized condenser and larger exhaust area. Increasing the size of the condenser and the exhaust area will result in a 23 MW increase in electrical output. This increased output at $625 per kW was credited to the storage system.

4.3.2.2 Storage Costs Unlike saturated water energy storage, energy output of the thermal oil storage system is relatively constant with depth of discharge. The sizing of the atmospheric pressure tanks is accomplished by the arithmetic addition of 3.87 kWh per barrels of oil and the heat and pumping losses. Heat and pumping losses will depend upon the distance between the station and the oil storage, and the number of tanks used for hot and cold oil storage. This distance might be a few hundred to a few thousand feet to ensure that a fire in the oil tanks would not require plant shutdown.

The cost of the insulated tankage was estimated to be $5/kWh. State-of-the-art technology and tank sizes were used and then insulated to lower the heat losses. A very simple inert gas system to exclude oxygen from the tanks and a high capacity transfer pump would be added for fire protection which completes the tankage system.

The oil for the tanks has to be a special refined product that will not break down after long exposure to the chosen operating temperature. The oil is estimated to cost $7.50 per kWh ($.69 per gallon). This investment is unlike other utility investments in that it is nondepreciating. If it is converted to an equivalent depreciating investment, the cost would be reduced to $5.50/kWh.

4.3.2.3 Cost Summary The thermal oil energy storage system utilizes existing state-of-the-art equipment with specially refined oil. When integrated with a 1,000 MW pressurized water reactor (PWR), a 259 MW, 2593 MWh storage system is estimated to be from $150 to $250/kW and $10.50 to $12.50/kWh. This is

Table 4-15 THERMAL OIL SYSTEM, COST ESTIMATES

I.	Plant Net Output			MW
	(a) Conventional Nuclear, Base Case			1,000
	(b) Nuclear + storage, Normal Operation			1,023
	(c) Nuclear + storage, Maximum Operation			1,282
	(d) Nuclear + storage, Minimum Operation			670
II.	Incremental Investment over Base Case			
	(1) kW-Dependent Facilities (259 MW)		$M	$/kW
	Powerhouse-related		23.8	
	kW-related oil facilities		37.4	
	Total, kW-dependent		61.2	236
	Less credit for 23 MW @ $625/kW		14.4	
	Net, kW-dependent		46.8	181
	(2) kWh-Dependent Facilities over Base Case (2593 MWh)		$M	$/kWh
	Oil Tankage, etc.		12.1	
	670,000 Bbl Oil at 69¢/gal		19.4	
	50¢/gal to $1/gal ($M 14-28)		31.5	12.15
	(3) Total Cost, 10-hr storage			
	Incl. oil		78.3	302
	Excl. oil		58.9	227

competitive with hydro pumped storage and considerably lower than saturated water thermal energy storage.

4.3.3 Molten Salt

The basic design approach is to store heat in solid-to-liquid phase change of a material and recover the energy as steam to run a separate peaking turbine. The most important cost detail of the storage system is the assumed heat exchanger design. Summary cost estimates for molten salt thermal energy storage systems are shown in Table 4-16.

4.3.3.1 Power Related Costs The heat exchanger is assumed to be fabricated from 1.5-inch schedule 40 stainless steel pipe. Preliminary heat transfer calculations have indicated that heat flux during discharge is on the order of 300 Btu per hour per foot of pipe length. The length of pipe necessary to satisfy a given discharge rate can then be calculated. It should be noted that the heat exchanger costs are power-related costs rather than energy storage related costs. Estimates of the cost of 1.5-inch stainless steel piping ranged from $4 to $8 per foot. Allowing $9 per foot for installation and fabrication, the installed heat exchanger could be expected to cost about $15 per foot of piping required. A reasonable range would be from $10 to $20 per foot.

Another heat exchanger design, that is not limited by the heat transfer between a pipe and material that pulls away from the pipe upon changing into the solid state, could substantially reduce the heat exchanger size and cost.

The balance of plant and turbine costs were obtained by analog from the saturated water thermal energy storage system.

4.3.3.2 Storage Related Costs Storage costs are broken into two major components, the salt mixture and the vessel. The material selected for the baseline design has an estimated price for the salt mixture of $1.04 per pound for carload quantities. Discussions with chemical processors indicate that the cost for metal fluoride mixtures could be as low as $0.33 per pound if sufficient demand for these chemicals exists. The salt mixture cost was, therefore, estimated to range from $0.33 to $1.04 per pound.

An engineering structural estimate for a concrete container was obtained for a 1,000 and 10,000 MWh storage system. Since steam from the storage will be at the same relative temperature and pressure, power output will be constant over the depth of discharge. The costs are contained in Table 4-16.

4.3.3.3 Cost Summary The molten salt thermal energy storage system extends the application of existing equipment to achieve a

Table 4-16 SUMMARY OF COST CHARACTERISTICS FOR MOLTEN SALT STORAGE

Power (MW)	Storage Capacity (MWh)	Power Related Capital Costs ($/kW)		Energy Storage Related Capital Costs ($/kWh)	
		Turbine and Balance of Plant	Heat Exchanger	Salt Mixture	Concrete Container
100	1,000	$190/kW	370-740	18-56	25-30
100	10,000	$190/kW	370-749	17-53	20-25
1000	10,000	$100/kW	340-680	17-53	20-25

higher energy density and a constant steam quality output. Its cost range of $440 to $930/kW and $37 to $86/kWh is very high. Even if the heat exchanger was free, the cost range is still $100 to $190/kW and $37 to $86/kWh.

This estimate is very crude and not suitable for comparison with other systems. It should not be used to dismiss all molten salt thermal storage systems since it only applies to one type of fixed bed storage unit.

4.3.4 Recommended Range of Costs

For comparison with other technologies, two thermal storage systems are considered, saturated water storage in above-ground pressure vessels, and feedwater heat storage in oil. The steam storage system appears more suitable for peaking applications while the thermal oil system may be suitable for intermediate applications. This difference arises from differences in costs. The steam system has lower power related costs but has higher storage costs. The oil system has higher power related costs (intermediate heat exchangers and pumps are required) but lower storage costs. They should be considered as representative of thermal storage systems in general. The recommended range of costs to use for comparisons are presented in Table 4-17.

Table 4-17 RECOMMENDED RANGE OF COSTS; THERMAL STORAGE

Cost Component	Thermal Oil	Thermal Water
Cp $/kW	150-250	150-250
Cs $/kWh	10-15	30-70

4.4 BATTERY STORAGE

Cost estimates for battery storage systems are presented in this section. These estimates were developed in three parts: battery module costs; converter and power conditioning costs; and installation costs. Battery module costs were developed, first, by a parametric estimate of energy density and selling price in Wh/lb and $/lb, and, second, by an entirely separate review of estimates made by the battery developers and potential manufacturers. Converter and power conditioning costs were developed from a combination of previous cost data and manufacturer estimates. These independent sources provide a high degree of certainty that if an adequate production level is reached the stated cost levels for the power conversion equipment will be achieved. Installation costs were developed from engineering estimates of various size storage systems using advanced and lead-acid batteries.

The method of costing that was used permits identification of anticipated cost differences between battery systems. This precision is not warranted by the state of development of the technology. Uncertainties in the battery cost estimate are large, and comparing the various battery systems in detail to establish a preference for one or another is not a valid use of the data presented here.

Because much of the data reviewed during the cost analysis is proprietary, no indication of source is given. Due to modifications to these estimates, they should be treated as those of the authors of this report. For the interested reader, review of the literature [26, 27, 28, 29, 30] is suggested.

Estimating the manufactured cost of a mass produced battery the fundamental step is the development of a careful design. This design effort must include material quality specifications and specific quality control procedures. If a detailed design cannot be made and if the component quality is not specified, then a great deal of uncertainty will exist in any cost estimate no matter how carefully it is made.

The second major step is obtaining vendor quotations of material costs in large quantities. It is best to obtain this information for various lot sizes so the effects of economies of scale can be examined. With material costs available for various lot sizes and purity requirements, major subcomponent cost estimates can be developed. This should be done by vendor requests or directly. It is preferrable to obtain reliable vendor estimates if it is expected that the components will be purchased. If subcomponents are manufactured on-site, they become just one component of the cost estimate.

From the detailed design, complete process flowsheets must now be developed. This usually requires several iterations before a final production method and flowsheet is chosen. Next, a conceptual design of equipment and plant layout must be made using the capital cost estimates of the manufacturing equipment and plant. At this point, labor requirements can be estimated.

By putting this all together, the basic cost information is developed. Now information on yield rates and equipment utilization factors are required. Plant depreciation must be calculated, overheads included, taxes calculated and return for investment included. In addition, a selling price mark-up must be established. For utility battery volumes, this could be up to 50 percent of manufactured cost. The manufactured costs are obtained from cell and material costs, subcomponent costs, labor, capital charges and overheads, and then establishing a capacity factor and production rate.

The general and administrative overheads, contingency and profit, as a percentage of material costs, are usually substantially different for manufacturing than for field construction.

The above description represents a significant effort for each system. A full analysis of battery costs is recommended for follow on programs.

4.4.1 Battery Module Cost; Candidate Systems

The capital costs of a load-leveling battery are taken to be the initial costs, excluding handlings and site preparation, including operational necessities such as insulation for high-temperature batteries. In some battery systems, the initial cost may be offset by a small credit for materials or components recovered from a battery at the end of its useful life (salvage value).

A number of rechargeable battery systems broadly suitable for the load-levelling application appear capable of ultimately meeting capital cost targets of \$20 to \$40/kWh. (All costs are expressed in 1975 dollars.) All seem capable of achieving charge-discharge efficiencies of 60 to 80 percent. However, all of these systems require considerable further research, and development and design optimization.

Although the distinction is somewhat arbitrary, five classes of battery systems are considered here as significant contenders for load-leveling:

1. Lead-Acid
2. Lithium-Metal Sulfide
3. Various Sodium-Solid Electrolyte

Systems (Sodium-Sulfur and Sodium-Chloride)

4. Redox Battery
5. Zinc-Chlorine Battery

4.4.2 Parametric Battery Cost Estimate

Actual calculated battery energy densities, based upon battery module designs developed as part of a Battery Energy Storage Test Facility Project, together with material and fabrication cost estimates, permitted a parametric estimate for each of the advanced systems: lithium-metal sulfide, sodium-sulfur, sodium-chloride and zinc-chlorine. These were compared with the results of a similar analysis for lead acid batteries. A graphical summary of this analysis is shown in Figure 4-6 where the shaded areas indicate the projections for the candidate battery technologies.

A clear distinction exists between conventional lead-acid and the advanced systems on the basis of energy density. However, the more expensive advanced batteries may prove to be competitive with the lowest cost lead-acid systems. This is a reasonable result and may permit the smooth introduction of the advanced batteries where markets currently exist for lead acid. The lower cost range for the advanced batteries is clearly below the lowest range for lead-acid. Advanced batteries, if successfully developed, should demonstrate a clear cost superiority over lead-acid.

4.4.3 Review of Manufacturer's Estimates

Most of the developers of advanced batteries and the lead-acid manufacturers make continuing cost studies. These were reviewed and the data in Table 4-18 was developed.

4.4.3.1 Lead-Acid Of the candidate systems, the clearest forecasts are for the lead-acid battery which is the only commercially established system under consideration at this writing. With proper design, and based upon present experience, it seems likely that a selling price of $40/kWh and a lifetime of 5 to 10 years could be achieved. The lifetime could be extended to more than 20 years by two renovations in which positive plates and separators were replaced. These renovations might account for about 50 percent of the initial cost, after allowance is made for the value of the scrap lead recovered. Such low cost batteries would most likely require buildings for housing the batteries, thus adding $20/kWh or more to the battery costs.

Recent cost studies by Gould, ESB, and C&D have resulted in the estimates summarized in Table 4-19. According to the manufacturer, these batteries all require buildings or some protective structure. For utility application the preferred

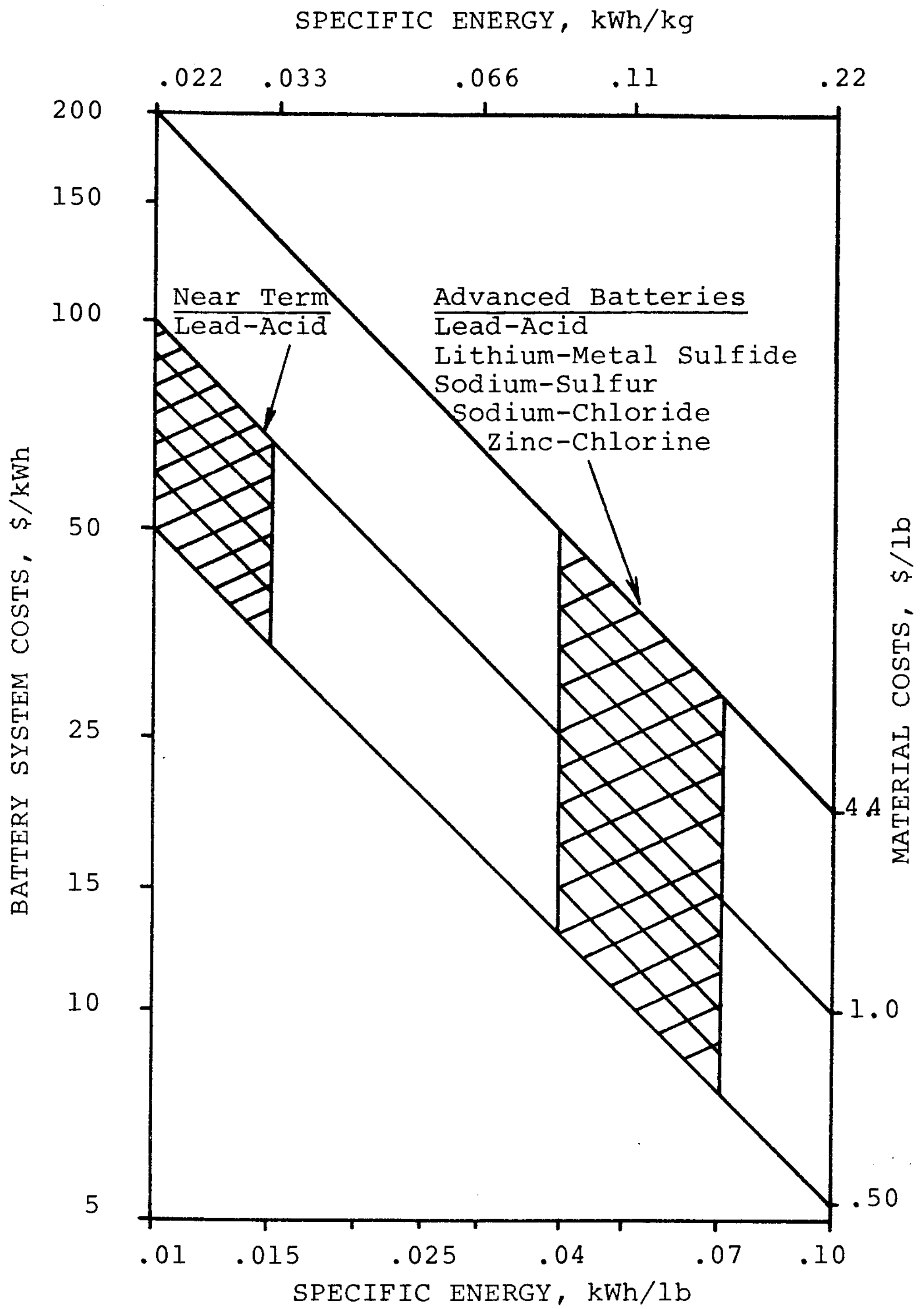


Figure 4-6 RELATIONSHIP BETWEEN BATTERY SYSTEM COSTS AND MATERIAL COSTS

Table 4-18 RESULTS OF REVIEW OF MANUFACTURER ESTIMATES OF SELECTED BATTERIES

Type	Operating Temperatures	Suggested[1] Approximate Module Cost ($/kWh)
Lead-Acid	20°-50°C	35[2]-65
Sodium-Sulfur	300°-350°C	15-25
Lithium-Metal Sulfide	400°-450°C	30-35
Sodium-Chloride	180°-210°C	15-25
Zinc-Chlorine	0°-80°C	12-30
Redox	20°-50°C	30-35[3]

1. Further studies are required before the differences in the advanced systems can be used to distinguish between them. Assumes success in R&D for advanced batteries.
2. Lower value estimate for an advanced battery module.
3. These estimates may be low and include a portion of power related costs. Highly suspect.

Table 4-19 LEAD-ACID BATTERY COST ESTIMATES

	MANUFACTURER		
	C & D	ESB	GOULD
Lead Cost ($/kWh)	22.10	19.80	13.00
Other Materials Cost ($/kWh)	11.70	14.40	10.70
Price ($/kWh)	62.90	65-70	43.30
Price/Cycle ($/kWh/Cycle)	2.51	2.60	2.47

From summary at Lead-Acid Workshop, EPRI, Palo Alto, CA, J. R. Birk. November 19, 1975 [28] approach is a weather-proof external housing rather than buildings. Further work will be required by manufacturers before the lowest achievable cost systems can be defined.

4.4.3.2 Lithium-Metal Sulfide Lithium-metal sulfide batteries are attractive, relative to the lead-acid system, due to their much smaller size and weight. According to conceptual designs, a 100 MWh unit would occupy only about 4,000 square feet (compared with an estimated 50,000 square feet for the lead-acid battery), although a high bay building would be necessary. The battery would weigh about 800 tons. Other attractive features are operation in a sealed condition, feasibilility of using circulating air as a coolant, and simpler maintenance.

A detailed estimate of the prospective manufacturing costs of the Argonne National Laboratory (ANL) lithium-metal sulfide battery indicates a factory cost of $22.72/kWh which, with general and administrative overhead at 11 percent and profit at 11 percent, gives a selling of $28/kWh [27]. Material costs amount to over $19/kWh, of which lithium and lithium salts constitute $7.40. These estimates are heavily dependent upon the availability of boron nitride separator material and suitable electrical feed-throughs at costs that reflect full-scale production for load-leveling applications, and are far below present costs. Such expectations appear reasonable, given that a high production level is realized.

The ANL cost analysis may underestimate such factors as G&A, profit, and materials wastage for manufacturing operation. Allowing for this suggests a battery cost of $30 to $35/kWh.

4.4.3.3 Sodium-Solid Electrolyte Systems The family of batteries using sodium and solid electrolyte include:

1. Sodium-beta alumina-sulfur (300°-350°C)
2. Sodium-glass fiber-sulfur (300°-350°C)
3. Sodium-beta alumina metal chloride (200°C)

These battery systems share the weight, size and low maintenance advantages of lithium-metal sulfur batteries and, at first examination, have an extra advantage in lower material costs (sodium being much less costly than lithium both per pound and per kWh).

Most groups working with these systems are developing sodium-sulfur batteries with tubular beta-alumina electrolytes. In a number of designs, individual tubes filled with sodium are immersed in a common tank that contains sulfur and the carbon current collector to form a single unit cell. Preliminary cost estimates based on this configuration indicate that material costs could be as low as $5/kWh, labor and overhead a similar amount, and the selling price less than \$20/kWh. (See Table 4-20).

Attainment of such low material costs depends strongly upon: the suitability of low cost carbon mat (at low current densities, carbon power might be used) as the cathodic current collector (other types of carbon can cost 10 to 20 times as much), and the use of aluminum, protected with a suitable coating, as the container material for the sulfur (higher costs will be incurred if a separate current collector is required). If these materials are not suitable, costs would escalate substantially.

The sodium chloride system with some antimony and a slightly lower energy density should have a lower cost of fabrication, but may have slightly higher material costs, compared to sodium sulfur. The ultimate cost of the beta alumina electrolyte may have a significant impact on the relative cost of the sodium-sulfur and sodium chloride systems.
The design capacity density (Wh/cm^2) is about a factor of 2.5 to 3 greater for the sodium-sulfur system. Thus, the resulting cost of the electrolyte may be proportionally greater for the sodium-chloride system.

4.4.3.4 Redox Systems On the basis of optimistic assumptions about the performance and lifetime of electrodes in the system, a preliminary estimate of \$30 to \$35/kWh has been made for a chromium redox battery with a storage capacity of 100 MWh [31]. This estimate places it in a zone for further consideration against the claims of other systems, but a similar price estimate has been developed for an iron titanium systems [32]. These systems were not examined in detail since they are not as developed as the other advanced batteries.

4.4.3.5 Zinc-Chlorine In the zinc-chlorine system the cost per kWh can be kept low only if low-cost materials of construction can be used. The use of these materials, in turn, may depend upon there materials meeting specifications for certain impurities (for example, iron in graphite), which is possible only if the materials are purchased in large quantities. Costs for the zinc-chlorine system, as for many of the other systems considered, thus depend strongly on whether a large-scale market for load-leveling batteries develops. For large-scale production it has been estimated that a zinc-chlorine hydrate battery might be manufactured for \$25 to \$30/kWh.

The cycle life obtained, before the battery would require rebuilding, was estimated at 1,000-2,000 cycles, however, maintenance requirements may be relatively high.

Table 4-20 SODIUM-SULFUR MATERIALS COST

Cell Costs	$ Per kWh		
Sodium (22.5¢/lb)	0.28		
Sulfur (8¢/lb)	0.21		
Beta-Alumina (25¢/lb)	0.44		
Graphite ($10/lb)	0.44		
Aluminum Sheet (63¢/lb)	0.93		
Insulating Header Material	0.18		2.48
Module Costs (Based on 62.5 kWh units)			
Steel Sheet		0.80	
Thermal Controls		0.56	
Insulation		0.24	1.60
TOTAL			4.08

4.4.4 Converter and Power Related Cost Components

The cost of a solid state converter is very dependent upon the characteristic of the storage system, the design assumptions and the volume of production. When these variables are applied to the many different possible converter types, and appropriate wider cost ranges are used in systems that require substantial development, there are no clear economic winnters. Table 4-21 shows a summary of the suggested converter costs for batteries, fuel cells, and superconducting magnetic energy storage systems.

The differences between the costs of the converter systems are attributable to additional equipment needed to complete the system and some estimates as to the advances in solid-state technology at the time the earliest converter would be needed. Lead-acid batteries are a near term storage technology that would use modified line commutated converters. These systems can suffer commutation failures on a voltage dip. Such a failure requires a static dc interrupt capability to make the maintenance and availability of the unit acceptable. Advanced batteries may not use this converter technique and could use less expensive means of dc interrupt. However, it is not expected that the more advanced converters will be available until the time period when the advanced batteries will be available.

4.4.5 Balance of Plant

Detailed estimates were developed for installation and site-related costs for several different battery module arrangements, complete in weather-proof structures. The results of these studies are presented in Figure 4-7 and include installation and foundation costs. No building costs were included but miscellaneous balance of plant items were included.

4.4.5.1 Installation Since factory fabricated units are assumed, installation will consist of providing a foundation, rigging the shipping units and batteries into place, connecting the batteries to the units, providing main and auxiliary power connections, and installing the power conditioning and control equipment.

4.4.5.2 Foundations The foundation cost estimates have assumed that the land on which the system is to be installed is flat, without extensive tree cover, and has at least a 2,000 pound per square foot load bearing capability. If the land is marshy, the costs would be double while if it is rocky, the costs would increase by 50 percent. Slab foundations that provided access aisles between the shipping units were assumed using substation concrete cost estimates as applicable. An alternate to concrete might be conventional asphaltic concrete.

Table 4-21 EXPECTED SELLING PRICE OF AC/DC CONVERTERS

Near Term Batteries	$/kW	70-80
Advanced Batteries	$/kW	60-70
Fuel Cells	$/kW	50-60
Superconductive Magnetic Energy Storage	$/kW	50-60

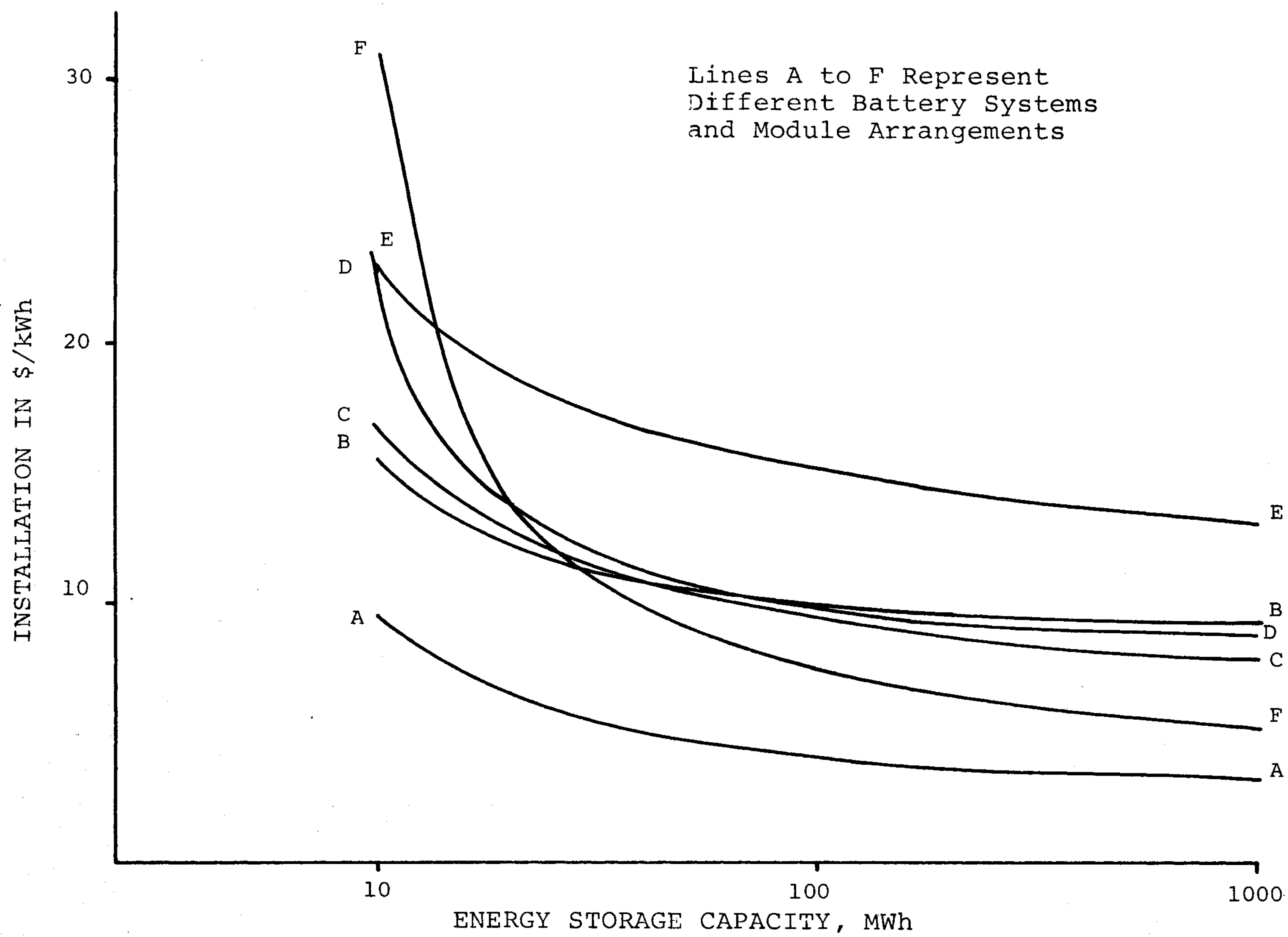


Figure 4-7 BATTERY INSTALLATION COSTS VERSUS CELL MODULE ARRANGEMENT AND STORAGE CAPACITY

An even lower cost material is LCF, a mixture of lime, cement, and flyash, with sand and/or stones. It forms a semirigid base that is installed like dirt. A 30-inch thick base of LCF is equivalent to 16 inches of portland concrete or 60 inches of asphaltic concrete, and has an installed cost of only 30 percent of that of concrete. Application of LCF required solving the settling problem associated with a semirigid substance and methods of placing the material. It has been used extensively for runways at Newark International Airport.

4.4.5.3 Rigging One of the more expensive operations during the installation of the system will be the rigging. To insure the most efficient use of the riggers, special trucks and packing of the individual battery systems is assumed.

The installation cost estimates in Figure 4-7. assume a worker of average productivity and the availability of sling points. If bolted sling points must be installed, the job will take considerably longer. Once rigging has started, it has been assumed that there will be sufficient batteries delivered to complete the entire installation. If because of factory production limitations, the operation cannot be more or less continuous, the rigging costs can increase in proportion to the time. The workers on the crane may be paid by the number of days the crane is on the job, and whether it is used 3 days per week, or 5 days per week, the cost may be the same. If the crane is used only 3 days, the workers may not be used to do other work due to union work rules.

The special trucks that were assumed would be standard open-top freight containers. The top of such a trailer is made of canvas that can be rolled back with the sides and door on the back the same as a standard box trailer. The canvas will protect the batteries from the usual dirt, contamination, and shipping hazards, while not requiring a double move or uncrating. Either a double move or uncrating could almost double the rigging costs.

4.4.5.4 Connectors It has been assumed that all of the sensing, fire, safety, and auxiliary systems required for operation of the system will have been wired and checked in the factory. Only a few multiconnector control cables must be connected to a central wire location on the shipping unit. These connections will probably be made with multi-pin plug-in connectors similar to those used on gas turbine installations and railroad cars.

The power connections consist of DC bus connections and intermodule connections. The main DC bus will require only a few connections per major module. The intermodule connections will consist of plug-in terminals. These terminals can be removed with standard hot sticks when electrically and thermally hot. Their installation should be very quick and easy.

The ventilation system is included in the support frame. Only minor adjustment of deflecting louvers would be required during start-up.

4.4.5.5 Converter Installation The installation cost of the converter will be dependent upon the type of converter selected. Most of line-commutated devices require a substantial amount of power factor correction capacitors. To keep the terminal power factor with a lead-lag range of .95, the capacitors must be switched in groups of a few MVAR. This could require substantially more installation time than other systems. The chopper-inverter system that is being used as a base line does not require any power factor correction capacitors. The installation for the system is essentially similar to the installation of one of the support frames and a number of transformers. Transformers of 10 MW or more have an essentially constant installation cost. The range of installation costs for a converter is $3 to $5/kW of converter rating.

4.4.6 Recommended Range of Costs

Based on available information, Table 4-22 indicates the recommended range of costs to be used in comparing battery systems with other technologies. Separate ranges are used to cover near-term lead-acid and advanced batteries. The range for the advanced batteries covers any breakthrough in lead-acid battery costs in the future. No distinction should be made between the various advanced battery systems.

Table 4-22 RECOMMENDED RANGE OF COSTS FOR BATTERY STORAGE SYSTEMS

Storage Costs[1]	Near Term Lead Acid	Advanced[6] Batteries
Battery Modules	\$40-\$65/kWh[2]	\$15-\$40/kWh[4]
Installation and Foundations	-	\$ 5-\$20/kWh[5]
Buildings, Installation, and Foundations	\$20-\$35/kWh[3]	-
Cooling	\$ 5-\$10/kWh	-
	\$65-\$110/kWh	\$20-\$60/kWh
Power Costs[1]		
Converter and Transformer	\$70-\$80/kW	\$60-\$70/kW

1 Contingencies and overheads included in individual cost elements.

2 From cost estimates of ESB, C&D and Gould; Battery life of 1750 to 2500 cycles.

3 J. R. Birk, Lead Acid Workshop, November 14, 1976; from estimates by Bechtel.

4 Includes cooling systems.

5 Assumes 500 MWh or more of battery modulation; weather-proof battery, no building.

6 Includes an advanced lead acid module which is suitable for outdoor installation without extensive cooling auxiliaries and site engineering.

4.5 CHEMICAL STORAGE

In this section, estimates are presented for hydrogen storage systems and individual system components. A hydrogen storage system for the near to intermediate term will consist of three main subsystems: an electrolyzer (to produce hydrogen from electricity); a hydrogen gas storage system; and a fuel cell or thermal power plant (to generate electricity from hydrogen). Of these components, only the thermal power plant, likely a gas turbine-steam turbine combined cycle plant, is used widely today. Estimates for the other components cannot be very precise.

For reference material, refer to the substantial work at Brookhaven National Laboratories (BNL) [33, 34, 35] and a recent summary on the subject of generation of electricity from hydrogen [36]. Of the many proposed methods for hydrogen production, only electrolysis of water is directly applicable to use in an electric energy storage system.

4.5.1 Electrolyzers

Electrolysis units are designed for each individual application by the manufacturer. A cost quoted for one application may be quite different from that of another, which would operate under an entirely different set of conditions (e.g., voltage, current density, temperature, pressure, load factor, electricity cost). Table 4-23 summarizes the characteristics of bipolar electrolyzers supplied by major European and U.S. manufacturers. Additional data is included on projected characteristics for advanced electrolyzers. Currently only European suppliers have the in-house manufacturing capability and experience to provide large electrolyzer systems in the ton of hydrogen per day range.

While several European suppliers manufacture large electrolyzer systems, the principal manufacturer is Lurgi. Lurgi manufactures a high pressure electrolyzer (32 atm) (pressurized systems are required to minimize evaporation losses). Projections by Lurgi for electrolyzer system performance represent the most advanced large-scale technology available in the near future.

The recent equipment selling price quoted by Lurgi is about $300/kW thermal of hydrogen with an expected 50 percent future reduction based on a doubling of current density. Lurgi cites installation costs slightly over 20 percent of current equipment costs, however, these appear to be somewhat low for the U.S.A. Installed costs for today's Lurgi electrolyzers are about $400/kW thermal of hydrogen and may decrease to $250/kW in the near future.

A cost breakdown is reported by Salzano [33] for a single 160 lb/hr unit operating at a high efficiency (80 percent

Table 4-23 BIPOLAR ELECTROLYZER COST ESTIMATES

Manufacturer	Current Technology: Cost $\$/kWh_t$ of H_2	Current Technology: Efficiency %	Current Technology: Life Years	Advanced Technology: Cost $\$/kW_t$ of H_2	Advanced Technology: Efficiency %	Advanced Technology: Life Years
Lurgi [37]	310(a)	73	10	150 to 175	75	10
Brown Boveri (Oerlikon) [38]	400(b)	73 to 67	25			
Teledyne Isotopes [39] (1 ton/day plant)	500(c)	-	-	50(d)	94	20
	No Large Systems Operating					
General Electric [40]	325(d)	94	-	\$40-85(d)	94	20
	No Large Systems Operating					

(a) $750 Nm^3/h$ plant (140 lb/hr); equipment 1.825×10^6 DM, installation 0.398×10^6 DM; 4.6 $kWh/Nm^3 H_2$ (DM = Deutsch Mark)

(b) Estimate for 452 Electrolyzers (EBK 385-70); 113,000 Nm^3/h total; $\$150 \times 10^6$ for equipment

(c) Projected cost for 1 ton/day, one-of-a-kind plant.

(d) Electrolyzer excluding rectifier and balance of plant.

efficiency), and hence, relatively low current density, in Hoganas, Sweden is as follows:

Electrolyzer unit	55%
Power supply	18%
Building	8.5%
Miscellaneous piping	1.6%
Main piping	6.2%
Other	10.7%
	100%

The installed plant cost (about $1 million, 5 years ago) corresponds to $350/kW thermal of hydrogen.

The efficiency data given on Table 4-24 represents the highest current density and, hence, (presumably) the lowest capital cost for Lurgi equipment.

Both GE And Teledyne project equipment costs for electrolysis modules of $50 to $85/kW thermal of hydrogen for advanced systems, without the rectifier. Including a rectifier and installation, a cost of $100-$200/kW thermal would appear to be achievable for advanced systems in the long run.

4.5.2 Hydrogen Storage

The approaches which have been suggested for the storage of hydrogen cover a broad range of conceptually quite dissimilar technologies and do not lend themselves readily to comparison. Storage technologies considered include: cryogenic liquid, compressed gas, and metal hydrides.

4.5.2.1 Liquid Hydrogen Liquid hydrogen storage is an acceptable and cost-effective way to store large quantities of hydrogen for long periods, or when it is used in liquid form (e.g., for rocket fuel oxidant). For electric utility use in a weekly or daily cycle, the energy requirement for liquefaction (kWh electric input/kWh of hydrogen = 2/3) is so large, and the operating problems posed by cycling of hydrogen liquifiers so serious, it may be dismissed.

4.5.2.2 Compressed Gaseous Hydrogen Compressed gas, with pressures typically around 2,400 psi as the maximum optimal pressure is an established hydrogen storage technology. This

Table 4-24 STORAGE FACILITIES, COST ESTIMATES

Equipment	Unit Capital Cost $/kWh ($/kW)	Efficiency %	Unit Capital Cost $/kWh ($/kW)	Efficiency %
Compressed Gas Tanks (2,400psi) [41]	$225-$500 ($35-75/ft^3)	100	Advances or cost reductions could occur through use of modern composites.	
Compressor $200/hp [42]			No projected advances	
14.7-2400 psi: 7 hph/1,000scf	(15)	94		
147-2400 psi: 3.6 hph/1,000scf	(7.50)	97		
Metal Hydride Tanks [43]	2.60	100(a)	---	
FeTi ($FeTiH_{1.4}$) $2.25/lb (current price)	9.0	90		
$1/lg [44]			4	90
Liquid Liquifier (Installed cost) [45]	(250) (c)	65		90(b)
Cryogenic Tank (240 tons, $$10^6$) [46]	0.1	99.75		

(a) Energy not electric

(b) Maximum theoretical efficiency

(c) Escalated from 1966 figure for 40 ton/day plant by $(1.04)^9$, and liquefier cost 70% of that for LH_2 plant with steam reforming.

method of storage is the reference technique against which new approaches must compete.

In a compressed gas system, compressors are the principal on-line (nonstorage) equipment which would be operating concurrently with the electrolyzer. As can be seen from Table 4-24, the capital cost and power requirements for compressors are a small percentage of those for electrolyzers. This percentage is reduced in both cases as the output pressure of the electrolyzer is raised. If compression was from 1 atmosphere to 2,400 psi, compressor costs and power requirements would only be 4 percent of those for current Lurgi electrolyzers. These percentages would be reduced to 2 percent for electrolyzer operation at 10 atmospheres. (The Lurgi electrolyzer shown in Table 4-23 operates at about 6 atm, and some of their units operate at even higher pressure.) An order of magnitude estimate confirmed these power requirements. Compressors affect the efficiency of the total storage system only slightly and even including installation would be a minor cost component.

Based on several quotations and a quick design effort, 2,400 psi steel cylinders with typical dimensions of 1 1/2 feet diameter by 20 feet long appear to cost on the order of $2,000 to $2,500, corresponding very roughly (in round numbers) to about $50 to $75/ft water volume equal to $325 to $500/kWh thermal of hydrogen. The cost of tanks is the dominant cost component for gaseous storage.

Installation and overhead costs are expected to add 30 percent to 50 percent to these costs. Considerable operating experience exists for pressure vessel storage of hydrogen. Pressure vessel materials at ambient temperatures are such that hydrogen embrittlement is not a problem.

4.5.2.3 Metal Hydride Storage Costs based on data from BNL for iron titanium and the associated reservoirs are shown in Table 4-24. The cost of heat exchangers is also important, but less so than the items shown. A parametric indication of the effects of the cost, for iron-titanium, tank material, and heat exchanger surface area on the BNL reference design for the hydrogen storage equipment itself, has been published [35]. The heat exchanger design now identified as optimal is indirect, incorporating circulating water tubes in the iron-titanium bed for heat addition and removal.

Interestingly enough, a parametric cost study of compressed tanks and iron-titanium storage systems indicates that costs for these two systems should be quite similar. The design claculation for 20 ft. long x 1.5 ft. diameter steel tanks at 2,400 psi gives a weight percent of hydrogen for this particular design of 1.25 percent (weight of stored hydrogen to weight of pressure vessel).

Similar data for iron-titanium ranges from 1.4 percent to 1.7 percent where the higher value is for a tertiary magnesium compound (only hydride weight is included). Since fabrication costs of good steel and the iron-titanium appear similar, expected costs should be similar. Hard data is available confirming pressure vessel data costs of $1/lb. Available data on iron titanium is approximately $2/lb. (This results in a cost ratio of $2 • (1.4 to 1.7) to $1 • 1.28). Reductions in cost of iron titanium to $1/lb through bulk purchases must be compared with compressed gas tank cost reductions to $.75 to $.80/lb through bulk purchase. This basic comparison demonstrates a slight but real edge for the equipment costs for compressed hydrogen storage over iron titanium.

Complete system costs could be substantially different but the designs of iron titanium storage systems have not yet reached the point where their costs can be distinguished from compressed hydrogen tank storage.

The most critical cost item for metal hydride systems is the cost of the hydride. Through work at BNL iron-titanium (FeTi) has been identified as the most promising host material and there appears to be considerable potential for reduction of the cost below the current $2 to $2.25 per pound. BNL has indicated that costs as low as $0.50 per pound may be achievable if FeTi can be produced directly from the Illmenites, ores in which iron and titanium occur in the desired ratio of 1:1. A discussion with International Nickel has indicated that $1 per pound may be an optimistic target. Ultimate cost for the material will depend upon what processes can be used for extraction and preparation. The applicability of the extraction process will, in turn, depend upon what impurity levels can be tolerated in the iron-titanium used. This subject has not yet been treated in detail, so projections are difficult.

4.5.3 Electrical Power Generation

Combustion turbines (simple or combined cycle) and fuel cells are intermediate and peaking generation options which merit consideration for use in electrical energy storage systems where only hydrogen (not pure oxygen) is utilized. Gas turbines are commercially available today and the introduction of first generation, acid electrolyte fuel cell powerplants comparable in capacity to gas turbines appears promising for the early 1980's.

Cost and efficiency data for gas turbines and fuel cells are presented in Tables 4-25 and 4-26. While comparatively inexpensive, simple cycle gas turbines have relatively low efficiency; currently this is a maximum of about 30 percent and rises only to 36 percent for advanced, very high temperature units. Such efficiencies make simple cycle gas turbines

Table 4-25 COMBUSTION SYSTEM, EQUIPMENT COSTS

Concept/Manufacturer	CURRENT OR NEAR-TERM TECHNOLOGY					ADVANCED TECHNOLOGY				
	Size MWe	Comb. Temp. °F	Cost $/kWe	Efficiency Percent	Life Years	Size MWe	Comb. Temp. °F	Cost $/kWe	Efficiency Percent	Life Years
Simple Cycle Gas Turbine United Technologies [47] (FT4)	25-35	1400-1900	80-105	26-30 max	25(a)	-	3000	100-120	36	-
United Technologies (FT50) [47]	87-100	1900-2300	-	32 max	-					
Combined Gas Turbine - Steam (b)		-	175(b)	40-45		-	3000	140-160	50	-
H_2/O_2 Direct Cycle	(Installed Cost)									
Rocketdyne [36]	100	1050	350	44	30	100	2000	380	51	30
Rocketdyne [36]	1000	1050	100	44	30	1000	2000	145	51	30
					(1000-2000 hours/year)					

(a) Period between overhauls is 8,000 hours for clean fuel and clean air, but currently about 2,000 hours in practice.

(b) Installation costs of $45/kWe (gas turbine - $20/kWe, Steam unit - $15/kWe, electrical and other - $10/kWe).

Table 4-26 HYDROGEN FUEL CELLS, EQUIPMENT COSTS

CONCEPT/MANUFACTURER	CURRENT OR NEAR TERM TECHNOLOGY			ADVANCED TECHNOLOGY		
	Cost $/kWe	Efficiency Percent	Life Hours	Cost $/kWe	Efficiency Percent	Cell Life Hours
H_2/Air						
FCG-1(a) [United Technologies] [36,51]	200	40	40,000	-	-	-
Acid [UT] [35,51]	225	42	10,000	225	47	40,000
Solid Polymer Electrolyte [35,51]	600	44		200	44	
Molten Carbonate [UT] [36,51] (c)	N/A requires CO_2	N/A	4,000(b)			40,000
Alkaline [36]	N/A	N/A		110	52	
H_2/O_2						
Acid [UT] [36]	160	44	10,000(b)	160	51	40,000
Solid Polymer Electrolyte [36]	270	54	20,000	Same	As	Acid
Alkaline [UT] [36]	N/A not available with commercial materials	N/A		90-160	54-60	40,000

(a) Reformer included in FCG-1 figures but in none other; figures given are FCG-1 goals. Estimates of installation costs by PSE&G are about $65/kWe; those of UT are slightly lower.

(b) Small cell or test cell basis.

(c) Not practical for pure hydrogen systems unless substantial CO_2 available.

unattractive for use in energy storage systems. The acid electrolyte fuel cell is the most promising near-term electrochemical concept. For both near term and advanced technology, the acid electrolyte fuel cell and combined cycle units appear comparable in efficiency. The electrolyzer rectifier and the fuel cell inverter could be combined for some cost reduction for a complete system. Given the uncertainties in capital costs for acid electrolyte fuel cells and advanced hydrogen burning gas turbines (in combined cycle units), one cannot at this time realistically distinguish between the installed capital costs for energy storage systems using these two electrical power generation options.

The advantages for the fuel cell and the reasons for electric utility interest have been well documented. Principal among them is their minimal environmental impact, low emissions (including noise), and the absence of a need for cooling water. These advantages would carry over to energy storage systems using hydrogen. The high efficiency at partial load and excellent load-following capability would also be advantageous. However, since rapid cold starts do not appear possible, an efficient means of maintaining the fuel cell at a standby temperature is required.

Gas turbines can be easily designed to burn hydrogen and its use would reduce some (but not all, e.g., NOx) emissions. The use of a clean fuel would further tend to enhance life, although effects from air contaminants would still persist in practice. Cooling water requirements and emissions (including noise) would penalize the combined cycle system in comparison to the fuel cell, although acoustic emissions can be reduced. While gas turbines have poor heat rates at partial load, they are capable in practice of rapid starts (on the order of 8 to 10 minutes from a cold condition to full load). Bringing the steam portion of the system on line would require more time.

4.5.4 Recommended Range of Costs

As an example of the capital cost and efficiency potential for this concept, simple estimates are developed from the summary data of Table 4-27 incorporating near-term and advanced technology. Combined cycle units and acid electrolyte fuel cells were indicated as highly competitive, on both a capital cost and efficiency basis in both the near- and long-term; combined cycle units will be arbitrarily assumed. Simple cycle gas turbines are eliminated due to their low efficiency, resulting in low overall system efficiency, and larger, more costly electrolyzer and hydrogen storage installations. Compressed gas storage will be considered because costs are better known and it would appear to be a strong candidate even in the long-term.

Table 4-27 MAJOR SUBSYSTEMS, COST SUMMARY*

Subsystem	Near Term	Intermediate Term
Electrolyzer Subsystem		
Electrolyzer modules plus Auxiliaries and Rectifiers	$300-$350/kWt	$100-$200/kWt
Installation for Electrolyzers 20 to 50% of equipment cost	60- 175/kWt	20- 100/kWt
Total	$360-$525/kWt	$120-$300/kWt
Compressed Hydrogen Storage Subsystem		
Steel Tanks (2400 psi 1-1/2 ft. dia x 20 ft. length)	$2.25-$5.00/kWht	$2.25-$500/kWht
Tank Installation	.75- 2.50/kWht	.75- 2.50/kWht
Total	$3.00-$7.50/kWht	$3.00-$7.50/kWht
Compressor	7.50-$15.00/kWt	7.50-$15.00/kWt
Combined Cycle Plant or Fuel Cell (Installed)	$225/kWe	$225/kWe

Note: kWt = kilowatts of thermal energy in hydrogen produced.

kWht = kilowatthour of thermal energy in hydrogen produced.

*Includes overheads and contingencies
In January 1975 dollars.

To examine the effect on capital costs of the system efficiency, storage capacity, and charge to discharge ratio, the following approximate cost algorithm can be used.

$$C(\$/kW) = Cp + \frac{Cel + Ccomp}{Egt} \bullet \frac{Td}{Tc} + \frac{Cst}{Egt} \bullet T$$

where C is the total capital costs, Cp is the capital cost of the combined cycle unit (or fuel cell), Cst is the storage cost in dollars per kW thermal of hydrogen and Cel and Ccomp are the capital of the electrolyzer and compressor. Td/Tc is the discharge time to charge time ratio. The charge to discharge ratio is related to the charge and discharge time ratio by the expression:

$$C/D = (Tc/Td)/(Eel \bullet Ecomp \bullet Egt)$$

where Eel and Ecomp are properly defined in relation to the energy output in weight of hydrogen. The effect of charge and discharge times on power related costs is presented in Table 4-28.

The recommended range of costs to be used in comparison with other technologies are presented in Table 4-29.

TABLE 4-28 EFFECT OF CHARGE AND DISCHARGE TIMES ON POWER RELATED COSTS FOR HYDROGEN STORAGE

Td/Tc	C/p	Cp ($/kW)
1	2.34	500 to 860
.5	1.17	350 to 540
.25	.58	290 to 380

$E_{ct} = E_{el} = .9$, $E_{comp} = .95$ on basis of kWht of hydrogen.

TABLE 4-29 RECOMMENDED RANGE OF COSTS* FOR HYDROGEN STORAGE

C_p	C_s
$500-$860/kW	$6-$15/kWh

*Includes overheads and contingencies. In January 1975 dollars, equal charge and discharge times.

4.6 FLYWHEEL ENERGY STORAGE

The approach used here is quite simplistic and is not an attempt at a full manufacturing cost estimate for flywheel energy storage systems. For a treatment of this topic the reader is referred to a study of flywheel systems by Rockwell International [3] which focused on flywheel systems. That study is in agreement with the approach taken here, although it differs considerably in detail.

In this section cost estimates for a complete flywheel energy storage system are discussed with emphasis on realistic flywheel design stress level and costs, necessary support systems, installation, and utility interface equipment. This approach has not been followed in published papers thus making comparison of published costs with those recommended in this report difficult.

The cost of a flywheel energy storage system may be divided into four major cost components:

1. The flywheel and vacuum housing - support structure
2. The foundation-vault structure
3. Utility/device interface equipment
4. Installation, overheads and contingency

As shown in Figures 4-8 and 4-9, the system becomes more cost effective by lowering material costs or increasing working stress levels. The former will be bounded by functional pricing practices that will tend to keep the cost of a material near the cost of other materials performing the same function. The latter improvement cannot be fully utilized until bearing designs possess higher capabilities in high speed applications.

4.6.1 Flywheel Costs

The problem of assigning realistic values to cost projections of composite materials applied to flywheel design is difficult to solve without an extensive economic study. Most existing cost projections are unrealistic, assuming large markets and limited progress with conventional materials. However, while there have been a large number of experimental, exploratory commercial applications of composite materials [52], the two principal production items that have been commercialized are graphite golf club shafts and Kevlar reinforced plastic kayaks and canoes. There is no clear indication today that the application of advanced composite materials will expand beyond the category of a specialty material.

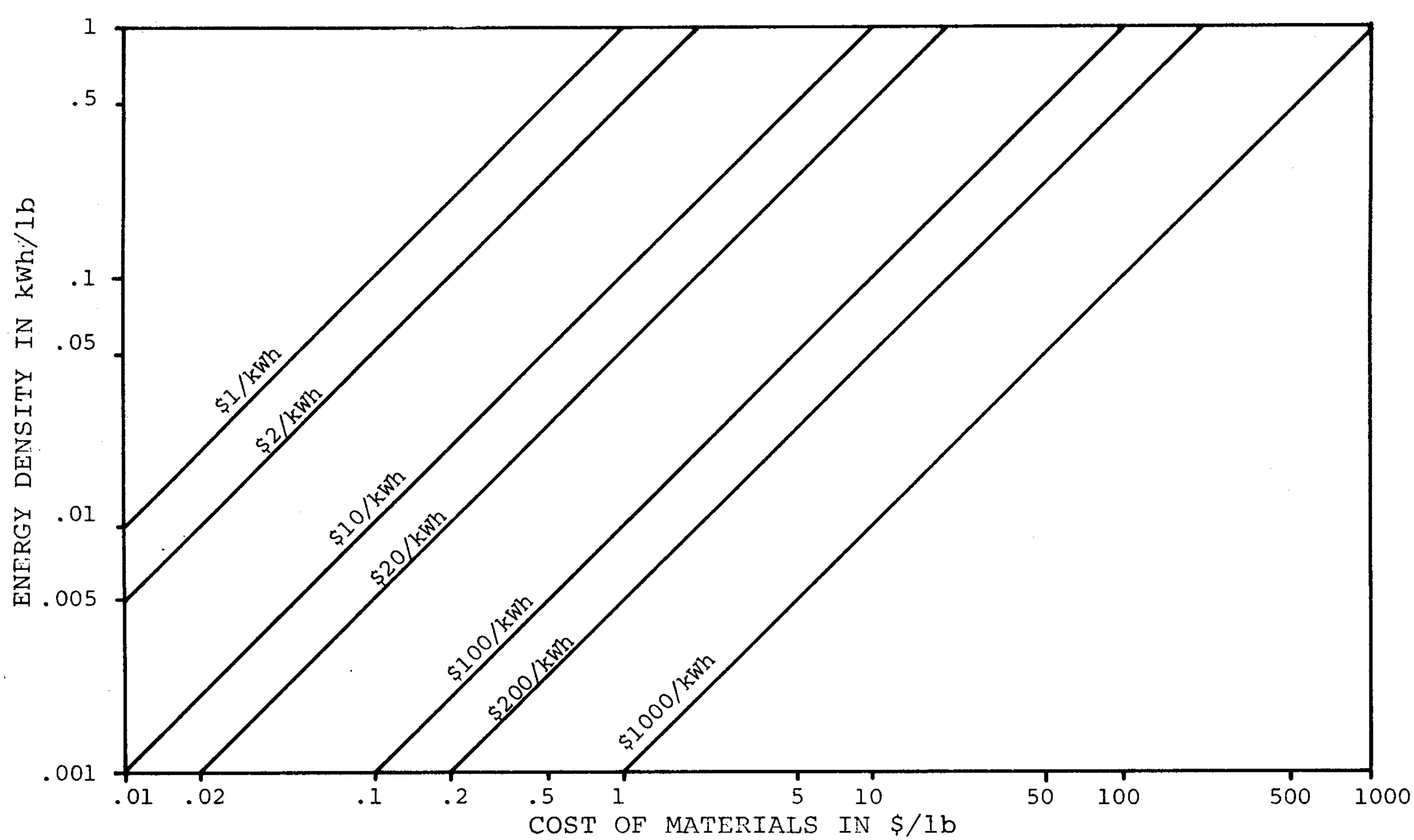


Figure 4-8 STORAGE COST VERSUS COST OF MATERIALS AND ENERGY DENSITY

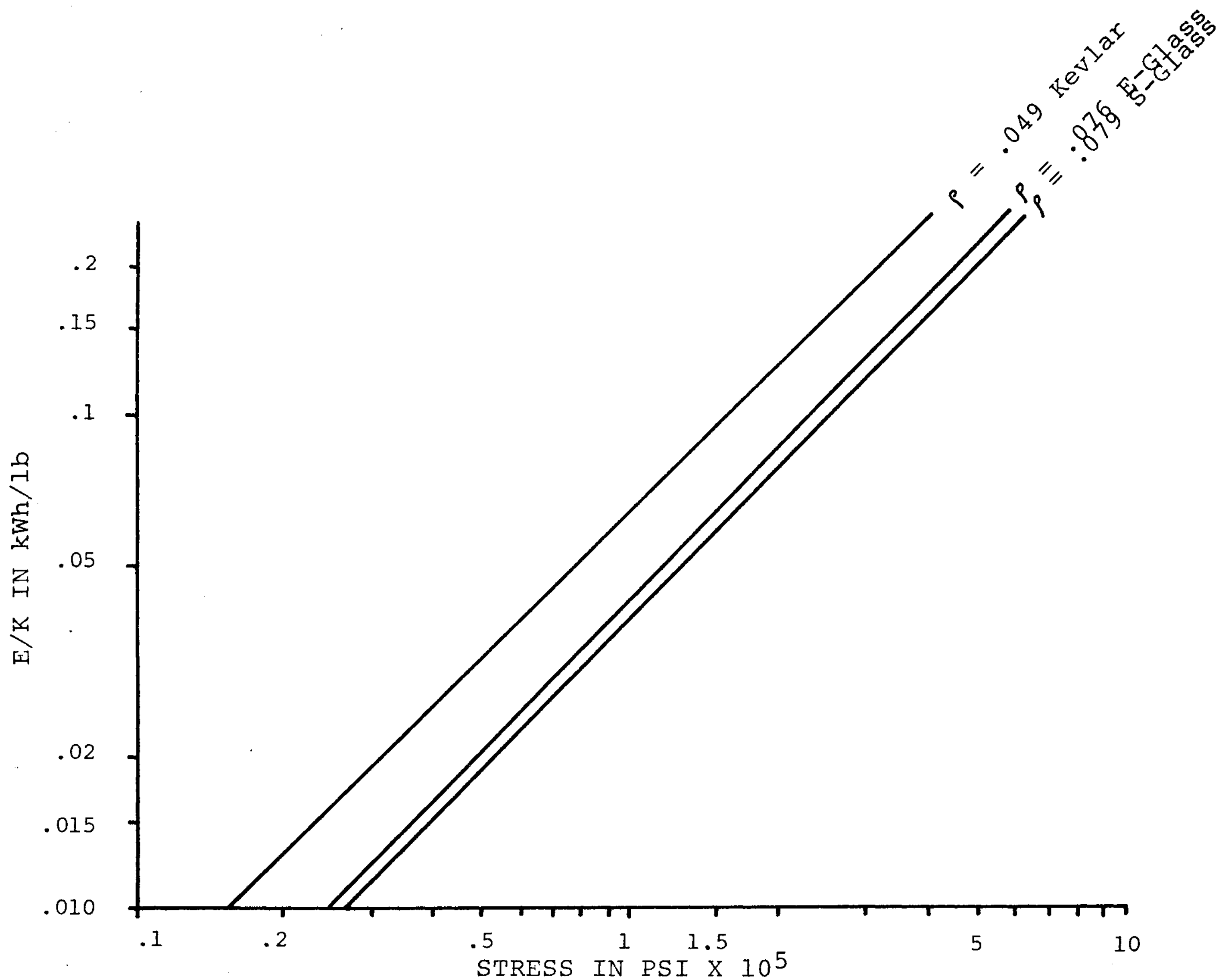


Figure 4-9 FLYWHEEL SPECIFIC ENERGY STORAGE DENSITY

It does not appear possible to accurately forecast the future cost reductions that will be achieved with composite materials as the market expands and technology improves. While there was an initial drastic reduction in the cost of advanced fibers from several hundred dollars to the present prices, there are no reliable prediction of future downward cost trends. The prices for high strength fibers may never decrease to the values of $1 to $2/lb sometimes quoted for graphite or Kevlar.

As will be seen in the following discussion, flywheel system costs are dependent on the flywheel and vacuum housing support structure costs, and are proportional to the energy density of the wheel and fabrication costs.

The total costs involved in fabricating composite hardware and meeting performance specifications must also be taken into account. These costs include tooling, quality assurance (QA), and nondestructive testing (NDT) costs. The cost for various manufacturing processes are listed below in Table 4-30, however, these values do not include the costs of materials or of controlling these materials to high performance specifications. These requirements can double the total cost of fabrication.

Table 4-30 COST OF VARIOUS MANUFACTURING PROCESSES [53]

Process	Cost ($/kW)
Matched Metal Die Molding (preform)	0.25 - 1.00
Spray-up	0.35 - 1.00
Autoclave	0.50 - 2.50
Filament Winding	0.75 - 2.50
Pultrusion	0.35 - 1.75
Hand Lay-up	0.45 - 1.50
Injection and Transfer Molding	0.25 - 0.50

It will be noted that filament winding and autoclave or oven curing processes are necessary for multiring, constant stress or similar flywheel designs. The "pultrusion" process, referred to in Table 4-30, in which the rods require no post-curing operation, is applicable to the flywheel brush concept. The fabrication costs for the multiring flywheel are expected to be at the upper end of the range quoted (i.e., $5/lb for filament winding and the autoclave cure), and it seems likely that this should be doubled to include the high-performance specifications that will be required for flywheels (i.e., $10/lb). The cost of pultruded "brushes" is an integral part of the pultrusion process and the total cost will probably be approximately $2/lb.

Fabrication facilities are readily available for curing large flywheels designed in fiber-reinforced plastic matrices. For 10-feet-diameter flywheels, the winding equipment would not be difficult to design and construct, since more complex 74-inch-diameter rocket cases employing high-strength fibers are currently being fabricated for test purposes, (i.e., for the Trident I C4). Furthermore, while not of the quality required in flywheel energy storage systems, 9-foot-diameter pipes in glass-reinforced plastics have been produced and installed by Corban Industries, Tampa, Florida [54]. An example of the cost estimates for large facilities recently determined for NASA by the McDonnel Douglas Corporation is included as Table 4-31 [55].

An autoclave capable of accepting flywheels approximately 20 feet in size costs roughly $1.5 million and an oven, which may be acceptable for the curing and bonding operations, costs approximately $150,000. These costs are clearly not prohibitive for the predicted numbers of flywheels required. A wrapping machine is estimated to cost approximately $600,000.

The relative importance of installation costs will decrease as the wheel size increases. A substantial savings might accrue to a larger wheel size; yet, it is difficult to see how field fabrication of flywheels would be feasible. This is an option not considered during this study.

4.6.2 Vacuum Housing and Support Structure

The flywheel must be housed in a vacuum container to minimize windage losses. Bearings which support the shaft must be securely supported to prevent undue displacement from dynamic loadings. All of this requires a substantial structure and is similar to problems faced in designing the casing and support structure for large rotating machines. For a heavy wheel, turning at high speeds, even a small imbalance will produce strong non-constant bearing loads. If not sufficiently stiff, the bearing support system will permit excessive movement of the bearings and lead to accelerated wear and eventual failure.

The costs for the foundations for the flywheels will be quite excessive just to meet the structural support requirements. To these costs must be added the structure to contain this flywheel during a catastrophic breaking. The total system could, therefore, be quite massive and requires location in an area of high load bearing soil or a pile system.

Table 4-31 FIBER-REINFORCED PLASTIC STRUCTURES, CAPITAL EQUIPMENT COSTS

Item	Temperature/Pressure		Maximum Size, Ft (Meters)	Quantity	Cost (Each) $K
Autoclave	700°F (643°K)	300 psi (2067 kp)	25 ft diameter x 75 ft long (7.6 x 22.8m)	1	1500
Oven	600°F	(388°K)	20 ft x 20 ft x 75 ft (6.1m x 6.1m x 22.8m)	2	150
Refrigerator	0°F-10°F (255°K-260°K)			2	90
Layup Machine	-	-	Bed - 20 ft x 53 ft (6.1m x 16.1m)	1	1600
Wrapping Machine	-	-	5 ft x 53 ft (1.5m x 16.1m)	1	600
Braiding Machine	-	-	33.5 ft (10.2m) diameter	1	1000
Densification Press	350°F (449°K)	100 psi (689 kp)	5 ft x 7 ft (1.5m x 2.1m)	1	100
Heated Roller			Rollers - 3 ft diameter x 6 ft (0.9m x 1.8m)	1	125

4.6.3 Installation

The installation of the flywheel energy storage system can be broken down into:

1. Containment vaults
2. Support base and flywheel installation
3. Speed reducer and clutch installation

The containment vaults could be installed by standard construction crews who are skilled in the placement of reinforced concrete. For most locations, this would include the driving of a number of piles under the containment. The reinforced concrete walls and water lid could be cast cn the jobsite without significant cost penalties.

The support base and flywheels themselves would not be shipped assembled due to the potential for bearing damage by shock loading. Installation techniques and critical alignment necessary for a flywheel installation are very similar to those for a turbine generator installation. Figure 4-10 shows the cost of installing various size turbine generators and it should be noted that the analogy between turbine generators and flywheels is a physical one that is not dependent upon power levels. Therefore, we will assume that the installation cost of the support base, flywheel, speed reducer, clutch, and utility interface equipment is equal to the cost of installing a 800 to 1,000 MW turbine. This assumption is not arbitary, but represents the fact that the cost of installing the rest of the system, aside from the support base and flywheel, is within the uncertainty in the flywheel installation. Other costs are shown in Tables 4-32 and 4-33.

4.6.4 Parametric Cost Estimates

Flywheel energy storage cost estimates were developed using a combination of parametric estimates, engineering study estimates and manufacturer estimates. Two types of material were considered for costing purposes; Kevlar, a high strength, low density material, and both E- and S-glass fiberglass. Necessary overheads and contingencies are contained within material cost estimates and were explicitly included in site costs.

4.6.4.1 Wheel Costs After an extensive review of fabrication techniques and costs, a range of wheel fabrication costs were selected. The higher values in each range reflect what are the most likely values. The lower end of the range is speculative and may never be achieved. The most optimistic values assume a fabricated material cost for the Kevlar as $2/lb and a fabricated

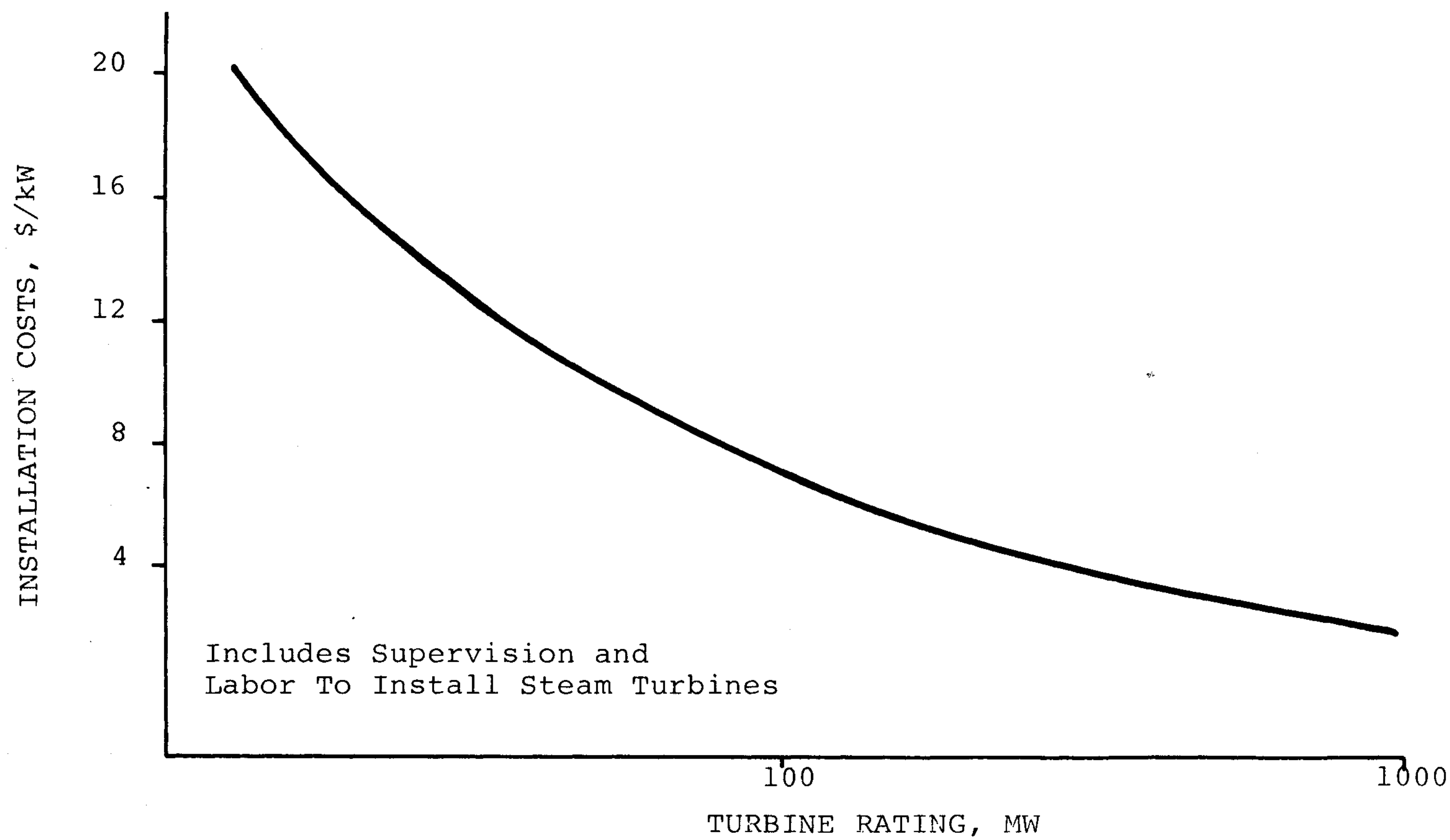


Figure 4-10 TURBINE INSTALLATION COSTS

Table 4-32 POWER RELATED AND BALANCE OF PLANT COSTS FOR FLYWHEEL STORAGE

Power Related		55-60
Variable Frequency Field Machine, $/kW		4- 6
Transformer (10-20MW Size) $/kW		5-10
Speed Reducer/Clutch Balance of Plant Costs*		5-10
Current Limiter	$ 50,000	
CO_2 and Ventilation for 10 vaults with 120 axial feet	$214,000	
Controls	$ 54,000	
Balance of Plant, Engineering, Installation and Overheads	$600,000	
Add to Vault Costs	$918,000	

* These costs are related to number of machines and size rather than the power rating of the equipment.

Table 4-33 FLYWHEEL FOUNDATION AND VAULT COSTS

Ten separate Foundations and Vaults with ten axial feet for Flywheels in each vault	$1,325,000
Foundation and Vault with 120 axial feet for Flywheels	$ 610,000
Ten separate Foundations and Vaults with 120 axial feet of flywheels in each vault	$3,835,000

material cost for E-type fiberglass as \$1/lb. Minimum wheel fabrication costs are taken as \$1/lb and range upward to \$10/lb. S-type fiberglass costs are permitted to range up to \$2/lb while Kevlar costs are permitted to range up to \$10/lb. A single wheel cost algorithm can be written:

$$\text{Cwheel } (\$/\text{kWh}) = E\ (\text{kWh/lb}) \bullet (Xm + Xf) \bullet (\$/\text{lb})$$

where Cwheel is the selling price for a fabricated wheel, E is the complete wheel energy density assuming conservative, long life design, and Xm and Xf are the material and fabrication cost estimates.

4.6.4.2 Vacuum Housing - Support Structure As in the case of the flywheel, no detailed design was developed for the vacuum housing and support structure. Typically, the mass of this system will at least equal the mass of the flywheel and would be frequently an order of magnitude larger. For this analysis, a mass ratio of one is assumed. This includes the vacuum container or can, the bearing support structure and the necessary structure to provide rigidity and transmit forces to the foundation. A mass ratio of one will probably prove optimistic. Costs for this type of structure typically ran from \$1/lb to \$2/lb with the higher value more probable. A simple cost algorithm can now be constructed for the vacuum housing and support structure.

$$\text{Xvh } (\$/\text{kWh}) = E \bullet Mr \bullet Xvii$$

where Mr is the ratio of the mass of the support structure to that of the flywheel and Xvii is the assumed selling price of the vacuum structure-support housing (presumably tool steel).

4.6.4.3 Foundation - Vault The foundation for the flywheel storage system is a critical component which provides an element of safety and adequately handles and transmits torques to the earth. As with all foundation work, deep excavation should be avoided, so a shallow subsurface arrangement for horizontal shaft wheels was selected. Economies of scale were then considered, and a simple arrangement was chosen. Three different sized installations were then considered using a hypothetical 10 ft. x 10 ft. 1 MWh wheel. Based on assumed wheel energy densities, actual physical dimensions for each wheel approach were calculated from known densities. Making appropriate allowances for clearances and bearings, costs for the foundation vault are distributed over the flywheel costs on a \$/kWh basis. If Xfv the total cost of the foundation-vault and N, the number of flywheels are known, the cost contribution to the foundation-vault is simply:

$$Cfv = \frac{Cfv}{N}$$

Total storage related costs:

$$Cs = Cfv + Cvh + Cw + CI$$

where CI is an estimated installation cost.

These costs are shown in Figures 4-11 and 4-12.

In Figure 4-11 the two curves correspond to two different maximum shaft weights. The lower weight is more conservative. Actual near term wheels would probably be smaller. Bearing and shaft limits contribute to cost by limiting the weights any single shaft (one set of bearings) can support.

In an actual design, the dynamic, rather than the static bearing loading, will be the design limit. In this analysis, we have assumed the wheel to be perfectly balanced or to be self balancing.

4.6.4.4 Effects of Efficiency and Depth of Discharge The cost algorithms developed in the earlier sections are all based on gross or total stored energy. To convert to net energy, it is necessary to account for the depth of discharge and the efficiency of the storage device.

The efficiency and depth of discharge are determined by the characteristics of the power conversion equipment, which converts the rotating mechanical energy of the wheel to ac power. The basic device suitable for this application is the variable frequency field machine with a naturally commutating cycloconverter. This device permits utilization of approximately 75 percent of the energy (50 percent speed reduction from top of charge to bottom of discharge). These devices have round trip electrical efficiencies of 88 percent to 90 percent and establish the upper bound on efficiency for these devices. Practical efficiencies will be near 70 percent.

To calculate the net costs of the flywheel systems, the previous values must be scaled by the reciprocal of efficiency and depth of discharge.

$$Xnet = Xgross/(DOD \bullet e)$$

where Xnet and Xgross are the flywheel component costs on a net and gross energy basis and DOD is the depth of discharge while e is the storage efficiency.

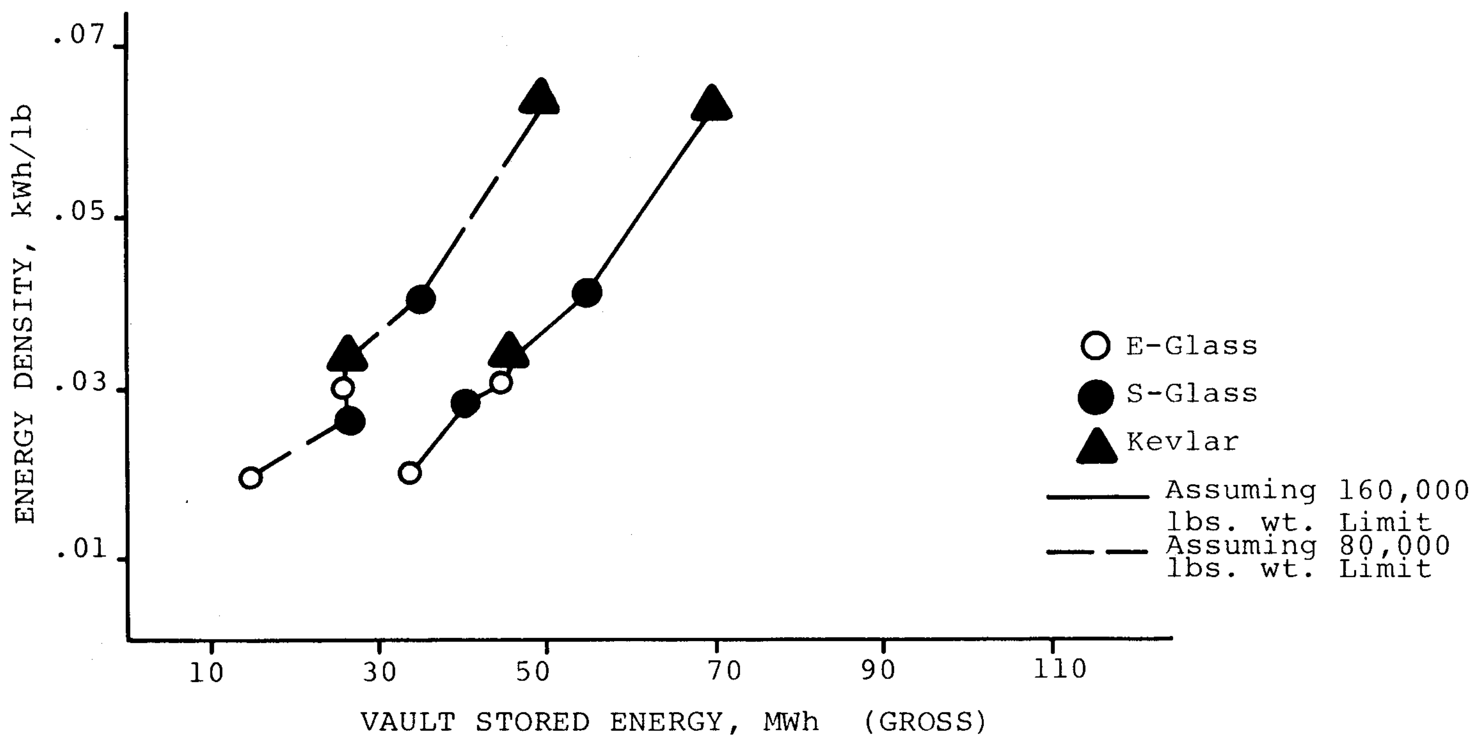


Figure 4-11 FLYWHEEL; ENERGY STORED IN VAULT VERSUS WHEEL ENERGY DENSITY

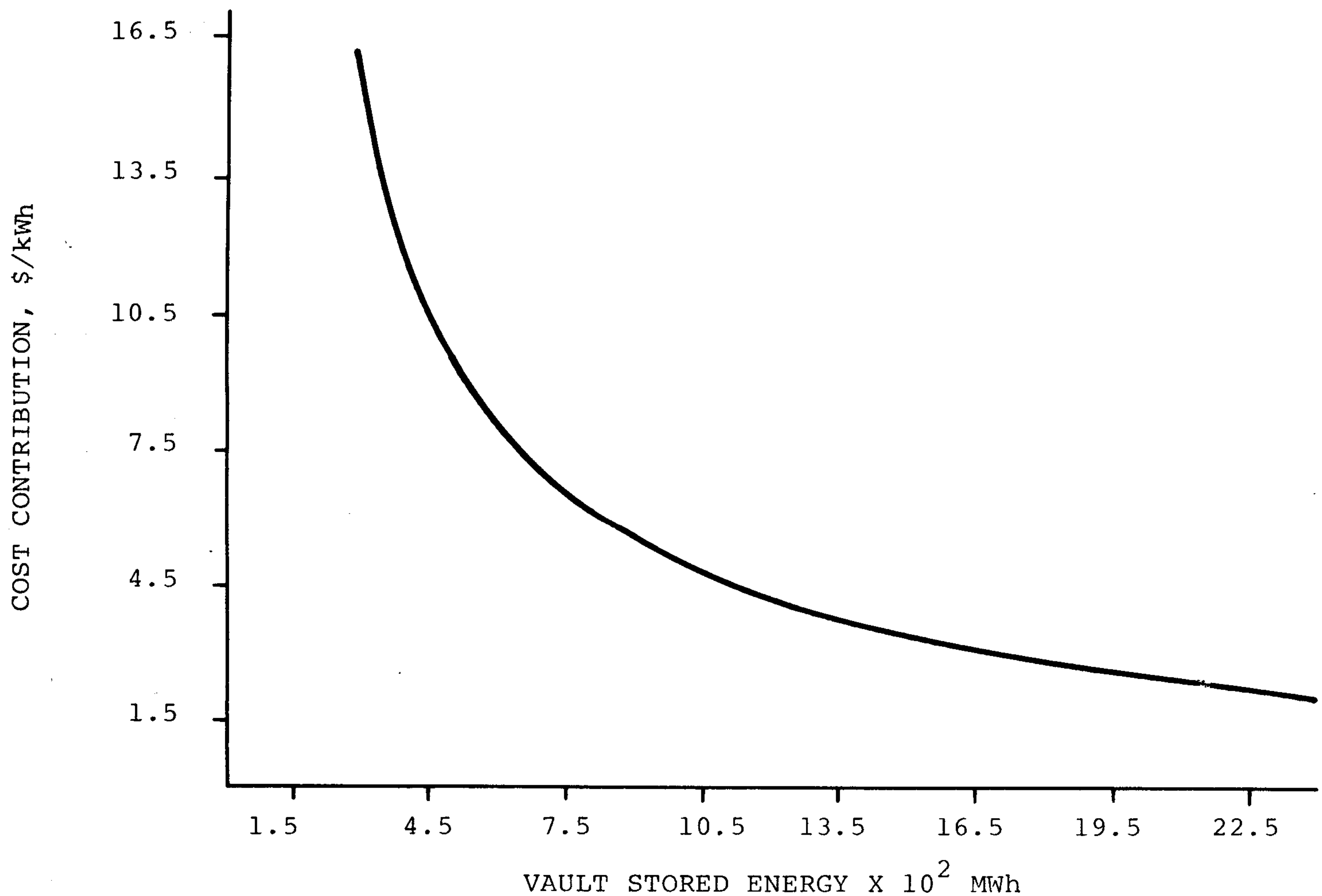


Figure 4-12 FLYWHEEL; COST CONTRIBUTION FROM FOUNDATION - VAULTS VERSUS STORED ENERGY

Table 4-34 presents results of cost calculations for the various components considered.

4.6.5 Recommended Range of Costs

Based on the preceding discussion, a recommended range of costs is presented in Table 4-35 for use in comparing the flywheel systems with other technologies. Overall, the estimates are not very reliable and need to be refined when more detailed designs are available. Particularly, little information is available on manufacturing costs of composite structures in a mature market.

In light of the lack of precision and the realization that the conservative estimates are not economic, a wide range is taken for comparison with other technologies.

Table 4-34 SUMMARY OF STORAGE RELATED COST COMPONENTS FOR FLYWHEEL SYSTEMS

	Conservative			Optimistic		
	E-Glass	S-Glass	Kelvar	E-Glass	S-Glass	Kelvar
Wheel Cost \$/kWh	1200-1900	700-1400	450-600	65-100 @X = 1 130-200 @X = 2	75-130	70-90
Vacuum Housing \$/kWh	230-390	140-280	90-120	65-100	40-65	25-30
Vault Foundation \$/kWh	13-25	10-13	8-13	8-11	6-10	6-8
Assumptions:						
Working Stress Load, , ksi	75-125	100-200	150-200	100-150	150-250	200-250
Mass Ratio, MR	1	1	1	1	1	1
Vacuum Housing Cost, VH, \$/lb	2	2	1-2	1	1	1
Shape Factor, K	.33	.33	.33	.5	.5	.5
Wheel Cost, X_w, \$/lb	10	10	10	1-2	2	3
Bearing Weight Limit, lb	80,000	80,000	80,000	160,000	160,000	160,000
Efficiency		70%			70%	
Depth of Discharge		75%			75%	

Table 4-35 RECOMMENDED RATE OF COSTS* FOR FLYWHEEL STORAGE

Storage Costs:	C_S, \$/kWh	100-300
Power Costs:	C_p, \$/kW	65-75

* In January 1975 dollars. Includes contingencies and overhead in individual component costs.

4.7 SUPERCONDUCTING MAGNETIC ENERGY STORAGE

As discussed in Section 3.7, the concept of storing energy in a superconducting magnet is in a very early stage of development. Currently, insufficient information exists to provide a good cost estimate for this system. Order of magnitude estimates, however, are possible. In estimating costs for futuristic devices which will be several orders of magnitude larger in size than previously constructed systems, considerable uncertainty will always exist and truly detailed cost estimates are not justified.

In the superconducting magnetic storage systems, two approaches are possible in treating the cost estimates. First, an attempt at using scaling laws should be made, and secondly, a conceptual design of a full scale system should be developed and costed. Both approaches will result in estimates with large uncertainties (100 percent to 200 percent) and can only be considered general estimates. This is particularly true for superconducting magnets, where manufacturing, assembly, and installation steps have not been adequately conceptualized. Cost estimates developed early in conceptual design phases of projects which cannot be costed by analogy (no known analog), are very suspect.

4.7.1 Previous Estimates

Major programs in the United States on superconducting magnetic energy storage systems are underway at the University of Wisconsin [58, 59, 60] and the Los Alamos Scientific Laboratory [61, 62, 63]. These two projects represent a substantial effort to examine the prospects for magnetic energy storage and project the cost of large, high capacity devices. The Los Alamos estimates are based upon scaling from conventional configurations, while the Wisconsin estimates are parametric and based on estimates of material requirements, fabrication, and assembly in dollars per pound. Table 4-36 summarizes the best estimates of these two groups for large magnets. Smaller magnets are not economic and are not considered here. The storage costs in Table 4-36 are calculated from the proponent estimates after adjustment for depth of discharge and efficiency.

In Table 4-36 the first column is the total energy stored in the magnet. All of this energy cannot be recovered since the current in the magnet cannot be permitted to drop to zero. The recoverable energy is reduced by the allowable depth of discharge and by the device efficiency. Costs on a per unit output basis are higher than on a gross stored energy basis. The data in Table 4-36 has not been corrected for neglected cost items or contingencies. The last column reflects a 20 percent to 40 percent compound construction interest factor which accounts for the allowances for interest during construction. The adjusted

Table 4-36 SUMMARY OF ADJUSTED COST DATA OF PREVIOUS INVESTIGATIONS OF SUPERCONDUCTING MAGNETS

Gross Storage Capacity MWh	Estimated Gross Cost $ Millions	Adjusted (1) Net Capacity MWh	Adjusted Storage (1) Cost $/kWh
10,000 [58]	505	7210 - 8640	$58-70
10,587 [59]	300	7630 - 9150	$32-38
10,833 [62]	641	7820 - 9360	$68-82

Notes: (1) Adjusted to account for depth of discharge and efficiency minimum proponent estimate is now approximately \$30/kWh excluding allowance for interest during construction.

4.7.2 Conservative Estimate

With the former points in mind, a more conservative estimate can be developed based on the solenoid design investigated by both University of Wisconsin and Los Alamos but using different material costs. This estimate is detailed in Table 4-37 in the format used by the University of Wisconsin. The costs in Table 4-37 differ from earlier cost estimates and are higher. It is not clear that these estimates are more accurate, but they are certainly not overly pessimistic.

Many additional components do not appear to have been included in cost estimates of previous work. No serious attempt has been made to cost out additional items since they would add more capital expense to an already expensive device and their detail design has not been developed. Missing cost components include: storage dewars, land costs, site improvements, magnet shield for refrigeration, magnetic shield ring, power lead to surface, building required to house operating personnel, fire control equipment, dewatering equipment, a superconducting persistant switch, piping for both cooling water for the refrigeration and the helium, control system, cooling towers, and cathodic protection.

4.7.3 Cost Elements - Caveat

Analysis of the cost estimates developed to date leads to the conclusions enumerated below:

(1) Superconductor material and fabrication costs are not well known. The enormous quantity of continuous conductors required leads to a belief that cost goals are based on factory fabrication of typical equipment today. They may not be applicable to the high quality control required for the proposed conductors. Additionally, fabrication in place, underground, will require very special crews; factory fabrication costs are not applicable.

(2) Adequate designs have not been developed for the Dewar and support structure. The mass of material required for these components is enormous and fabrication costs of \$1/lb as used by the University of Wisconsin are not appropriate. Large bridge and steel-work costs are more typically \$2/lb which is standard for above ground construction efforts.

Table 4-37 MODIFIED COST ESTIMATE FOR 10,000 MWh (GROSS) SUPERCONDUCTING MAGNET)

		($) Millions		
Material Costs				
Al 36 x 10^6kg at $2.2/kg (For Conductor)		79.2		
Ti N6 .71 x 10^6kg at $33 /kg		23.4		
Al 20 x 10^6kg at $2.2/kg (For Structures)		59.5		
Epoxy Fiberglass 20 x 10^6kg at $2.2/kg		48.4		
	Subtotal		210.5	
Insulation Electrical Thermal		Unknown		
Fabrication Costs				
Conductor 36 x 10^6kg at $2.2/kg		79.2		
Epoxy Fiberglass Support Struts 20 x 10^6kg at $2.2/kg		48.4		
	Subtotal		127.6	
Refrigeration		13.0	13.0	
Labor for Assembly at 50% of above costs (not including Dewar assembly)		145.0	145.0	
Supervision at 30% of Direct Labor		43.5	43.5	
Assembly of Dewar (from Al) includes supervision 36 x 10^6kg at $4.4/kg		160.0	160.0	
Rock Excavation and Wall Preparation		25.0	25.0	
Helium		8.0	8.0	
	Subtotal			732.6
Engineering at 12% of 732.6		87.9		87.9
Contingency - Unknown - 20%		164.0		164.0
TOTAL Materials, Assembly, Labor and Engineering				984.5

Storage Cost $/kWh

Gross Storage Capacity	Estimated Gross Cost	Adjusted Net Capacity	Adjusted Storage Cost
10,000 MWh	984.5	7,210-8,640	114-136

(3) Recent studies by the University of Wisconsin have resulted in the lowest estimate of Table 4-36. This reduction results primarily from a major change in design concept and the required mass of aluminum for structural material. Aluminum requirements were reduced from more than 20 million kilograms to 1.7 million kilograms. Also reduced was the mass of epoxy fiberglass support struts. The validity of this lower estimate is questionable since it assumes an extremely thin vacuum wall. Detailed designs of the device structural requirements are not available, so these estimates should be handled carefully.

(4) Thermal insulation costs do not appear to be adequate. As yet, this is an unknown area.

(6) Excavation costs are minor.

(7) Large contingency factors should be used since a reasonable amount of detail is not available.

(8) A long fabrication and construction period is anticipated.

(9) The whole question of magnetic field suppression and also of general costs has not been adequately treated.

4.7.4 Recommended Range of Cost Estimates

Based on the adjusted cost estimates of Table 4-36 and the modified estimates of Table 4-37 a range of costs for the storage system is given in Table 4-38. Power conditioning cost estimates were developed from data supplied by manufacturers and are added to the storage costs. The tremendous range in the storage costs indicates that these estimates should not be used to justify research on these systems and should be given very little weight.

In this particular technology, it is important to place some probability on achieving the lower cost range. The lowest estimate is from the University of Wisconsin which includes a reduced structural mass for the dewar. Since inadequate detail is available to support the low value, little weight should be given to it.

Table 4-38 RECOMMENDED RANGE OF COSTS FOR SUPERCONDUCTING MAGNETIC ENERGY STORAGE SYSTEMS

Power Related Costs	C_p	\$50/kW
Storage Related Costs	C_s	\$30-\$136/kWh

Costs are essentially in January 1975 dollars and only valid for large (10,000 MWH gross) size systems. (Small units will cost much more.) Includes overheads and contingencies.

4.8 OPERATING AND MAINTENANCE COSTS (O&M)

With the rather singular exception of hydro pumped storage, available data is very scanty and does not permit accurate projection of operating and maintenance costs. Table 4-39 summarizes the best estimates on operating and maintenance costs which should be used in comparing the technologies with respect to their economic competitiveness. Additional data is available for hydro pumped storage.

4.8.1 Hydro Pumped Storage

Through actual operating experience on existing pumped storage plants, O&M expenses have been found to average about $1.60/kW/year, after adjustment to January 1, 1974 wage levels. Adjusted averages for six large plants with more than 3 years of operating experience have ranged from $1.14 to $2.52/kW/year.

This expense data is obtained from FPC publications and from company form 1 reports filed with the FPC. All reported expenses have been adjusted to January 1, 1974 wage levels by using a Bureau of Labor Statistics record of hourly earnings for transportation and public utility workers. Expenses per kW are also influenced by the capacity used in their derivation. To make this as consistent as possible, the capacity has been based 80 percent on capacity at minimum and 20 percent on capacity at maximum head, except where the owner rates the plant at minimum head capability.

The average expenses for each of the six plants with more than 3 years of operation are arranged in Table 4-40 in order of increasing total expense. These are followed by the records of four plants with less than three years of operation.

The four short records have been given no weight in determination of the recommended average O&M expenses. The longer records show that operation expenses, after adjustment to January 1, 1974 wage levels, are fairly constant over time. Consequently, the operation expenses for the four recently completed plants may be representative of future experience; and if so, they tend to confirm the experience of the older plants. Records also indicate that maintenance expenses vary widely from year to year and are likely to be subsequently higher than those experienced in the first year or two of operation.

The record for Kinzua has been given less than full weight in the determination of the recommended average, based upon its short record and known but unusual maintenance requirements. Yards Creek and Kinzua are both operated in the General Public Utilities System. It is believed that the Yards Creek experience

Table 4-39 RECOMMENDED OPERATING AND MAINTENANCE EXPENSES TO BE USED IN COMPARISONS OF ENERGY STORAGE TECHNOLOGIES

	OPERATING AND MAINTENANCE EXPENSE	
	FIXED	VARIABLE
	$/kW/yr	mills/kWh
Hydro Pumped Storage	1.6	-
Compressed Air Storage with Combustion Turbines	-	5.3
Thermal Energy Storage	3.2	.2
Battery Storage	-	2.7
Flywheels	-	5.3
Hydrogen Storage	-	2.7
Superconducting Magnetic Energy Storage	1.6	.2

Table 4-40 OPERATING COST EXPERIENCE OF HYDRO PUMPED STORAGE PLANTS

Plant	Years Of Operation	Capacity MW	Adjusted Annual Expenses, $kW/Year		
			Operation	Maintenance	Total
Yards Creek	9	330	0.36	0.78	1.14
Cabin Creek	7	280	0.97	0.41	1.38
Taum Sauk	11	350	0.28	1.25	1.53
Smith Mt.	9	440	0.56	1.00	1.56
Muddy Run	7	856	0.66	1.15	1.81
Kinzua (Seneca)	4	380	1.09	1.43	2.52
Average (6 plants, unweighted)			0.67	1.00	1.67
Average (without Kinzua)			0.59	0.92	1.51
Blenheim-Giloboa	1	1,030	0.19	0.12	0.31
Jocassee	1	312	0.52	0.07	0.59
Luddington	1	1,675	0.35	0.46	0.81
Northfield	2	1,000	0.86	0.32	1.18

is more likely to be typical of future pumped storage plant operations than is the Kinzua experience.

Records of expenses for two publicly owned plants were also available for 1970 and 1971 from published FPC data. These data, arranged in the same order as in the above table, are as follows:

Salina	2	130	0.32	0.43	0.75
San Luis	2	424	0.75	0.57	1.32

Because these records are short and for early years of operation, they also have been given no weight in the determination of the recommended average.

Included in the list of six plants is Smith Mt., which is not a pure pumped storage, because it combines reversible units with a conventional hydro installation. Nevertheless, it was considered to be a useful supplement to the relatively few data otherwise available.

Because the amounts involved are small, there is no need to consider separately the average expenses for operation and for maintenance; however, several comments on these expenses are in order:

1. Adjusted operation expenses for each plant have been found to be fairly constant over time.
2. Operation expense can be considered to be a fixed expense, i.e., independent of the amount of duration of annual generation.
3. Operation expenses, per unit of capacity, might be expected to decrease with an increase in plant size; but such relation to size is not yet evident in the above data. Other differences among plants and company practices overshadow such a size relationship, if any exists.
4. Adjusted maintenance expenses vary widely from year to year (from about $.10 to almost $4/kW).
5. Maintenance expenses are in part related to the amount of annual generation, and to this extent might be treated as a variable expense. The probable division between the fixed and variable portions has not been determined; and due to the relatively small amount of this expense, such a determination is not essential to the comparisons with other systems.
6. Maintenance expenses can be expected to decrease after correction of design and construction deficiencies during the early years of operation; however, this trend is presently revealed in the record of only one plant.

In the determination of the reported operation expenses, there has been excluded for several plants the expenses reported as "Water for Power" and "Rents", (Account 536 and 540). However, the amounts involved, on a per kW, per year basis, appear to be large only for the Northfield plant. The excluded amounts are believed to represent primarily the payments for use of an existing lower reservoir. Such payments are properly included in the economic evaluation of any specific installation, but they are not indicative of probable O&M expenses at other sites.

4.8.2 Compressed Air Storage and Combustion Turbines

There may be an increase in maintenance costs for the combustion turbine if substantial particulate contamination is present in the compressed air available from storage. Due to lack of data, no advantage or disadvantage is assumed relative to conventional gas turbine installation (an appropriate representative value is 5.3 mills/kWh).

4.8.3 Thermal Energy Storage

Maintenance costs for a thermal storage plant will probably be about the same as those for a fossil fired steam plant of the same power rating. The storage vessels should require considerably less maintenance than a conventional boiler, this should compensate for higher maintenance costs for the peaking turbine.

A representative value of $3.2/kW/yr for the fixed portion of the operating and maintenance expense and a value of .2 mills/kWh for the variable portion should be used in economic comparisons.

4.8.4 Battery Storage

In principal, sealed battery storage systems should have low operating and maintenance costs. An operating and maintenance expense half that of a gas turbine is assumed for comparisons. This would typically be 2.7 mills/kWh. Since unattended operation is expected, the fixed portion of the expense should be negligible.

4.8.5 Flywheel Storage

In principal, flywheel storage systems should be capable of unattended operation. Maintenance of bearing and lubrication systems will be considerable. For comparison purposes, it should be assumed that operating and maintenance costs will be equal to those experienced by gas turbines (5.3 mills/kWh). For a fully mature technology, these costs could be lower, however, due to small unit size and anticipated short life of the bearing systems, a conservative estimate is used here.

4.8.6 Hydrogen Storage

Maintenance expenses will be associated primarily with the electrolyzer compressors and fuel cell or combined cycle plant. Use of hydrogen should substantially reduce combustion turbine operating and maintenance costs. For comparison purposes a maintenance cost half that of a conventional gas turbine system is assumed. The net effort is, however, quite small.

4.8.7 Superconducting Magnetic Energy Storage

This technology is so futuristic that estimating operating and maintenance requirements is really questionable. It is expected that the facility will be manned and the refrigeration systems will require regular maintenance. For comparisons with other technologies, a value equal to a conventional steam plant should be assumed.

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5. ECONOMIC COMPETITIVENESS OF ENERGY STORAGE

5.1 INTRODUCTION

In this chapter, the relative economic competitiveness of selected energy storage systems is evaluated. The objectives of such economic evaluations are: (1) to determine breakeven capital costs for energy storage technologies as peaking and intermediate duty generation, and (2) to identify the sensitivity of breakeven cost to variations in operating hours, efficiency and expected life of energy storage systems as well as changes in fossil fuel costs and the cost of off-peak energy for charging. Consideration is also given to transmission and distribution capital cost savings which result from locating energy storage technologies at dispersed locations such as substations.

Finally, this section identifies attractive and unattractive energy storage technologies on the basis of economic competitiveness.

5.2 METHOD OF ANALYSIS

The widely accepted methodology for economic comparison in the utility industry is the present worth (time value of cost) evaluation. This method calculates and compares the present worth of all annual revenue requirements for the step-by-step capital expenditures of alternative plans of utility plant additions. It provides a consistent means for evaluating relative economic status on a long-term basis. The application of the present worth methodlogy is equally valid for comparing two conventional or two "developing" technologies as well as for comparing one "developing" to one conventional technology. In the first place, a "developing" technology would not be considered for commercial application until it has become a "proven" technology. In the second place, the uncertainties may lie in some of the assumptions used but not in the methodology used for economic evaluation. To provide additional sensitivity analysis, reasonable variations in economic parameters, such as rate of inflation and rate of return, may be tested in the present worth evaluation. This test was not included in this study and it was felt that such tests would be better made by individual utilities for their own studies using variations in economic parameters more appropriate for their systems.

Break-even economic costs (1975 dollars) for selected energy storage systems are calculated by equating the present worth of all annual costs of the conventional generation to that of the energy storage system. The comparison is performed over the range of energy storage system duty cyles identified in Chapter 2 as being typical for U.S. electric utility systems for the peaking and intermediate mode of generation operation. The break-even costs represent the maximum installed capital cost for which the energy storage systems would be economically competitive with conventional intermediate and peaking generation over a long range time period.

5.2.1 Economic Data Base

The economic data base used in the economic analysis for both the energy storage system technologies and the conventional generation technologies is shown in Table 5-1. Hydro pumped storage, compressed air storage, thermal (steam or oil) energy storage, and lead-acid batteries are near-term storage technologies which either exist today or which may be commercially available by 1985. Intermediate-term storage technologies include advanced batteries, chemical (hydrogen) storage, and flywheels. These systems are expected to be commercially available in the 1985 to 2000 period. Storage technology expected to be available beyond the year 2000 are considered to be long-term; superconducting magnetic energy storage (SMES) systems fall in this category. The conventional generation technologies used for comparison with the energy storage systems include simple cycle gas turbines for the peaking application and combined cycle units for the intermediate application.

The average expected life of the energy storage systems range from a low of about 5 years for near-term lead-acid battery systems to 50 years for hydro pumped storage systems. The energy storage system life estimates are reflected in the economic analysis through the annual carrying charges and the present worth calculations. The levelized annual carrying charges for the technologies shown in Table 5-1 are expressed as a percent of total capital cost. The components of these carrying charges and the associated financial assumptions are defined in Appendix B5, Economic Assumptions and Sample Calculations.

Ranges of energy storage system efficiencies are identified in terms of overall electric energy output to electric energy input. Near-term energy storage system efficiencies range from about 60 to 75 percent. Longer term efficiencies are estimated to approach 85 percent for flywheels and SMES systems. However, the chemical (hydrogen) storage system overall efficiency is not expected to exceed about 50 percent.

Operation and maintenance (O&M) costs include both variable cost and fixed cost components as appropriate to the technology. Variable costs are generally a function of the number of hours of operation. Fixed costs are a function of annual charges associated with maintaining the in-service availability of the equipment.

Table 5-1 ASSUMPTIONS FOR ENERGY STORAGE SYSTEMS AND CONVENTIONAL GENERATION USED IN BREAK-EVEN ECONOMIC ANALYSIS CALCULATIONS

Generation Technology	Expected Life (Years)	Annual Carrying Charges [a] Percent	Overall Efficiency Percent	1975 Operation and Maintenance Costs: Fixed Costs ($/kW/Year)	1975 Operation and Maintenance Costs: Variable Costs (mills/kWh)	1975 Installed Capital Cost ($/kW)
ENERGY STORAGE SYSTEMS:						
NEAR-TERM (Present to 1985):						
Hydro Pumped Storage	50	21	70-75	1.6 [g]	-	-
Compressed Air	25	18	5,400 to 4,200 [b]	-	5.3 [h]	-
Thermal, steam	25	16	65-75	3.2 [i]	0.2 [i]	-
Thermal, oil	25	16	65-75	3.2 [i]	0.2 [i]	-
Batteries, lead-acid	5-10 [c]	27-19	60-75	-	2.7 [j]	-
INTERMEDIATE-TERM (1985-2000):						
Advanced Batteries	25 [c]	15	70-80	-	2.7 [j]	-
Chemical (H_2) Storage	25	15	40-50	-	2.7 [j]	-
Flywheels	25	15	70-85	-	5.3 [h]	-
LONG-TERM (Beyond 2000):						
Superconducting Magnetic Energy Storage (SMES)	25	22	70-85	1.6 [k]	-	-
CONVENTIONAL GENERATION:						
Gas turbine [b]	25	15	12,100 to 11,000 [f]	-	5.3	100 [l]
Combined Cycle [e]	25	15	8,900 to 8,100 [f]	-	4.1	225 [m]

TABLE 5-1 ASSUMPTIONS FOR ENERGY STROAGE SYSTEMS AND CONVENTIONAL GENERATION USED IN BREAK-EVEN ECONOMIC ANALYSIS CALCULATIONS (CONT'D)

(a) Expressed as a percent of total capital (power and storage) cost and includes rate of return, depreciation and taxes. This also includes adjustment for interest accumulated construction. (See Appendix B5) No salvage value was assumed except for salvage of 25% of storage costs for lead-acid bateries.

(b) Heat rate, Btu/kWh. Corresponding compressed air pumping requirements from 80 to 58 kWh (in) per 100 kWh (out).

(c) Assuming approximately 200 cycles per year, or 1,000 to 2,000 cycles for near-term and 5,000 cycles for advanced bateries.

(d) Unit size of 100 to 300 megawatts.

(e) Based on 255 MW unit with gas turbine 175 MW and fossil steam turbine 80 MW.

(f) Heat rate, Btu/kWh. Near-term to intermediate-term heat rates.

(g) Based on typical data from existing operational installations.

(h) Costs assumed similar to conventional simple cycle gas turbines.

(i) Costs assumed similar to conventional steam peaking units.

(j) Costs assumed to be about half of conventional simple cycle gas turbine installations.

(k) Costs assumed to be similar to hydro pumped storage installations.

(m) Average industry 1975 capital costs are about $225/kW for the combined cycle unit. Costs include equipment and installation. If cooling towers are required, the capital costs would increasd by about $20/kW.

Annual maintenance requirements for energy storage systems with respect to frequency and duration of outages are not expected to exceed those of conventional generator unit requirements. In some cases, due to modular construction, energy storage system maintenance requirements may even have a lesser impact than conventional generation on overall system operations. However, due to the lack of utility operating experience for the selected energy storage systems, excluding pumped hydro, in terms of forced outages and maintenance outages, the reliability of the various storage systems was assumed to be similar to each other and to the conventional peaking and intermediate generation technologies. No economic penalty or credit for the energy storage technologies was included in the economic calculations.

The installed capital costs for the conventional generation technologies are average industry 1975 costs which include equipment and installation. The combined cycle unit costs are for an installation with once-through cooling.

5.2.2 Break-even Economics

The economic competitiveness of the selected energy storage systems was determined based on a comparison with conventional generation technologies for peaking and intermediate generation application on electric utility systems. This economic competitiveness is described in terms of break-even capital costs for energy storage systems on a $/kW basis. To determine the break-even cost, the present worth values of all future annual revenue requirements, including fixed and variable operating costs (operation, maintenance, and fuel), of both the conventional generation and the energy storage system, were calculated over the study period and equated.

The break-even economic calculations were performed on a unit capacity (kW) basis and a time period between 25 and 50 years into the future. Time periods were selected to match multiples of the expected life of the various technologies being compared. The study period for pumped hydro covers a 50-year period. The study period for all other energy storage systems covers 25 years. The study periods for the near-term energy storage technologies begin in 1980, the intermediate-term technologies in 1990, and the long-term technology in the year 2000.

To make the results of the break-even economics applicable to the electric utility industry in general, the break-even calculations were performed over a range of estimates for the economic variables which should encompass the greater part of the electric utility industry today and in the future. The generation technology assumptions of Table 5-1, together with the economic assumptions of Table 5-2, describe the range of parameters over which the break-even costs were calculated. Within these ranges, economic sensitivity analyses were also performed to determine

Table 5-2 ASSUMPTIONS FOR UTILITY SYSTEM OPERATIONS USED IN THE BREAK-EVEN ECONOMIC CALCULATIONS FOR ENERGY STORAGE SYSTEMS VS. CONVENTIONAL GENERATION

OPERATING PARAMETERS	RANGE	VALUE ASSUMED AS TYPICAL
Annual Generation Operating Time		
Peaking Application	Up to 2,000 Hrs.	1,000 Hrs.
Intermediate Application	2,000-4,000 Hrs.	3,000 Hrs.
Fossil Fuel Cost (1975)		
Gas Turbines and Combined Cycle Units	\$1.50-\$2.50/10^6Btu	\$2.50/10^6Btu
Installed Capital Cost (1975)		
Gas Turbine	\$75-\$150/kW	\$100/kW
Combined Cycle	\$175-\$275/kW	\$225/kW
Escalation Rates (Percent/Year)		
Capital (installed) cost	6 percent/yr.	6 percent/yr.
Operation/Maintenance cost	6 percent/yr.	6 percent/yr.
Fossil Fuel Cost	6 percent/yr.	6 percent/yr.
Levelized Incremental Cost of Off-Peak Energy		
Mix of generation (for charging energy storage systems)	5-30 mills/kWh	20 mills/kWh

those economic variables which might have the greatest impact on break-even economic costs for the energy storage systems for the peaking and intermediate mode of generation operation.

Fossil fuel costs (1975) were assumed to range from $1.50/MBtu to $2.50/MBtu in the study. In each case a 6 percent annual escalation of fossil fuel cost was assumed over the study period.

The average incremental cost of off-peak energy on a utility system is a function of the mix of generation units used for charging energy storage systems. This incremental cost of off-peak energy generally ranges today anywhere from 2 to 3 mills/kWh for individual nuclear units up to about 10 to 20 mills/kWh for the mix of base-capacity generation units. For any given electric utility system with the greater use of nuclear baseload capacity, it is anticipated that incremental off-peak energy costs will decrease in the future. Because the levelized incremental cost of off-peak energy for charging energy storage systems in the future could decrease, remain the same, or increase, depending on the utility's generation expansion capacity program, levelized incremental off-peak energy costs from 30 to 5 mills/kWh were evaluated in the break-even cost calculations.

The basic methodology for the economic comparison is detailed in Appendix B5 which contains a sample long range expansion calculation for the 1975 break-even capital cost of the lead-acid battery compared to the gas turbine in a peaking application for a given set of assumptions. This expansion study covers a 25 year period beginning in 1980. The battery expected life over the study period varies from 5 to 10 years. Five-year batteries were assumed to be installed in 1980, and 10-year batteries in 1985 and 1995. For this peaking application, the annual hours of operation are assumed to be about 1000 hours. Included in the sample calculation was a 6 percent per year rate of escalation for capital, operation and maintenance, and fossil fuel cost for the gas turbine. The method is flexible enough so that any rate of escalation could be used for each of these factors.

Breakeven (1975) capital costs for batteries, pumped hydro, compressed air, thermal, chemical, flywheel, and superconducting magnetic energy storage systems were calculated based on the method used in Appendix B5. For the intermediate mode of generation, the energy storage technologies were compared with the combined cycle unit with appropriate changes in the factors and terms of the economic calculations. The results of these analyses are described in the following sections for the typical daily and weekly cycles which may be required of energy storage systems on U.S. electric utility systems.

5.3 BREAK-EVEN COSTS FOR ENERGY STORAGE SYSTEMS

5.3.1 Peaking-Duty Operation

For the peaking application, the break-even installed capital costs (1975) of the energy storage systems were determined based on a comparison with the simple cycle gas turbine with a \$100/kW installed cost. Table 5-3 summarizes the 1975 break-even capital costs for the near-term, intermediate-term, and long-term energy storage technologies. These break-even costs were calculated for 400, 1000 and 2000 hours of annual peaking duty operation. On the basis of assuming 200 days of operation a year, energy storage devices of 2, 5 and 10 hours storage capability would be suitable to serve annual peaking requirements of 400, 1000 and 2000 hours, respectively.
These storage systems cover the range of typical storage systems applicable to U.S. electric utilities for the peaking mode of generation as identified in Chapter 2.

In Table 5-3, the lower value of the range corresponds to the break-even cost for the combination of economic assumptions from Tables 5-1 and 5-2 that would result in a minimum break-even cost for a given energy storage technology. Similarly, the upper value of the break-even cost range is based on that combination of economic assumptions that would result in a maximum break-even cost for a given energy storage system design for the peaking application. For example, for the thermal oil energy storage system for 1,000 hours of annual operation, the 1975 break-even cost of about \$100/kW is based on a 65 percent energy storage system efficiency, \$1.50/MBtu for gas turbine 1975 fossil fuel cost, a 30 mill/kWh levelized incremental cost of off-peak energy, gas turbine full load heat rate of 12,100 Btu/kWh, and a 6 percent per year escalation rate for capital, operation and maintenance, and fossil fuel costs. The higher value break-even cost of \$400/kW is based on a 75 percent energy storage efficiency, \$2.50/MBtu for gas turbine 1975 fossil fuel cost, and a 5 mill/kWh levelized incremental cost of off-peak energy with all other factors similar to the minimum value break-even cost calculation.

The range of break-even costs reflects the effect of increasing energy storage system efficiency, and a ten-fold increase in the ratio of the levelized incremental cost of on-peak energy to off-peak energy. That is, the ratio of levelized incremental cost of on-peak to off-peak energy for the lower range break-even cost calculation is in the order of two, and this ratio increases to about 15 to 20 for the upper range calculation of break-even costs.

Table 5-3 indicates that as the operating hours increase the range of break-even costs also increases for each of the energy storage technologies. The thermal oil and thermal steam systems

Table 5-3 RANGE OF 1975 BREAK-EVEN CAPITAL COSTS FOR ENERGY STORAGE SYSTEMS VS. GAS TURBINE[a], PEAKING APPLICATION

	Range [b] of 1975 Energy Storage System Break-even Costs ($/kW)			Range [c] of 1975 Projected Energy Storage System Costs ($/kW)		
	Annual Hours of Operation [d]			Daily Cycle Peaking Duty Device [e]		
ENERGY STORAGE TECHNOLOGY	400 Hours (2Hr.-Device)	1,000 Hours (5Hr.-Device)	2,000 Hours (10Hr.-Device)	2 Hour Discharge Dev.	5 Hour Discharge Dev.	10 Hour Discharge Dev.
Near Term (Present-1985):						
Pumped Hydro Storage	110-210	170-430	260-780	90-190	100-220	110-280
Thermal,Oil	70-200	100-400	140-760	170-280	200-325	250-400
Thermal,Steam	70-200	100-400	140-760	210-390	300-600	450-950
Compressed Air	80-160	80-260	80-440	90-210	120-330	150-520
Battery,Lead-Acid	50-140	50-270	50-480	270-420	500-800	750-1250
Intermediate-Term (1985-2000):						
Advanced Batteries	140-240	210-440	310-790	100-190	160-370	300-700
Chemical (H_2) Storage	110-230	120-430	130-760	340-490	460-780	590-1200
Flywheels	130-230	180-410	250-730	260-680	560-1600	1100-3100
Long-Term(Beyond 2000):						
Superconducting Magnets (SMES)	110-160	190-310	320-570	110-340	200-760	370-1500

a) Gas turbine 1975 installed capital cost assumed to be $100/kW.
b) Based on the data in Tables 5-1 and 5-2, including the range of energy storage system efficiencies, 5 to 30 mills/kWh levelized incremental cost of off-peak energy, 1975 fossil fuel costs of $1.50 to $2.50 per million Btu and 6 percent escalation per year for capital, fossil fuel, and operation maintenance costs.
c) Based on the minimum and maximum power and storage cost combinations for the energy storage systems as shown in Table 4-1 and the cost equations of Chapter 4 for compressed air and hydrogen storage.
d) Annual hours of operation assume 2, 5, and 10-hour devices, each operating about 200 days per year.
e) For the daily cycle peaking duty energy storage system, charge to discharge power ratios are about 0.5, 1.0, and 1.5 for a 2, 5, 10-hour device, respectively. Associated system storage capability requirements are the same as the discharge hours.

have similar operating characteristics and therefore their ranges of break-even costs are the same. The compressed air system break-even costs are low due to the need for fossil fuel in its operation. The relative low break-even costs for the lead-acid battery are due primarily to the shorter expected life of 5 to 10 years as compared to 25 years or more for the other energy storage systems. The intermediate-term advanced batteries with an improved life of about 25 years, or 5,000 cycles, have break-even costs comparable to the other intermediate-term energy storage technologies. Energy storage systems with installed capital costs either below or within the approximate ranges of Table 5-3 should prove to be economically attractive for the peaking generation mode of operation on electric utility systems. Table 5-4 indicates the 1975 break-even capital costs of the energy storage systems for the peaking application for the assumed typical conditions of Table 5-2. The incremental levelized on-peak to off-peak energy cost ratio in Table 5-4 is in the order of four.

5.3.2 Intermediate-Duty Operation

For the intermediate application, the break-even installed capital costs (1975) of the energy storage systems are determined based on a comparison with the combined cycle unit with a $225/kW installed cost. Table 5-5 summarizes the 1975 break-even capital costs for the near-term, intermediate-term, and long-term energy storage technologies for the intermediate application. These break-even costs were calculated for 2500, 3000 and 4000 hours of intermediate-duty operation. Assuming 250-260 days of operation per year, energy storage systems capable of providing 10, 12 and 15 hours of daily discharge would operate 2,500, 3,000 and 4,000 hours, respectively. These energy storage systems cover the approximate range of typical storage systems applicable to the U.S. electric utilities for the intermediate mode of generation as identified in Chapter 2.

The lower and upper values of break-even costs correspond to that combination of economic assumptions from Tables 5-1 and 5-2 that would result in minimum and maximum break-even costs for a given energy storage system intermediate application type. The range of break-even costs for the intermediate application reflect increasing storage system efficiencies and to a ten-fold increase in the ratio of the levelized incremental cost of on-peak to off-peak energy similar to the peaking application. However, because the combined cycle has a better heat rate than the gas turbine, the ratio of levelized incremental cost of onpeak to off-peak energy for the lower range break-even cost is in the order of 1 to 1.5, and increases to 10 to 15 for the upper range break-even cost.

Table 5-5 indicates that as the operating hours increase, the range of break-even costs also increase, except for the lower

Table 5-4 TYPICAL 1975 BREAK-EVEN CAPITAL COSTS FOR ENERGY STORAGE SYSTEMS, PEAKING AND INTERMEDIATE GENERATION MODE OF OPERATION

ENERGY STORAGE TECHNOLOGY	Energy Storage System Break-even Capital Cost in $/kW (1975)					
	Peaking Application[a]			Intermediate Application[b]		
	400 Hour (2Hr.-Device)	1,000 Hour (5Hr.-Device)	2,000 Hour (10Hr.-Device)	2,500 Hour (10Hr.-Device)	3,000 Hour (12Hr.-Device)	4,000 Hour (15Hr.-Device)
Near-Term(Present-1985):						
Pumped Hydro Storage	190	360	640	650	740	920
Thermal, Oil	160	320	580	570	650	810
Thermal, Steam	160	320	580	570	650	810
Compressed Air	140	230	370	320	350	400
Battery, Lead-Acid	100	180	310	300	340	410
Intermediate-Term (1985-2000):						
Advanced Batteries	210	390	670	680	780	960
Chemical (H_2) Storage	200	350	590	590	660	810
Flywheels	200	350	610	610	680	840
Long-Term(Beyond 2000)						
Superconducting Magnets (SMES)	150	290	530	560	640	810

a) Typical data assumptions of Table 5-2, the $100/kW gas turbine, and energy storage efficiencies of 75 percent except 50 percent for the chemical storage system, and 4,200 Btu/kWh and 58 kWh per 100 kWh pumping requirements for compressed air.
b) Same as (a) except comparison with the combined cycle unit at $225/kW.

Table 5-5 RANGE OF 1975 BREAK-EVEN CAPITAL COSTS FOR ENERGY STORAGE SYSTEMS VS. COMBINED CYCLE UNITS[a], INTERMEDIATE APPLICATION

	Range [b] 1975 Energy Storage Break-even Costs ($/kW)			Range [c] of Projected Energy Storage System Costs ($/kW)		
	Annual Hours of Operation [d]			Weekly Cycle Intermediate Duty Device [e]		
ENERGY STORAGE TECHNOLOGY	2,500 Hours (10Hr.-Device)	3,000 Hours (12Hr.-Device)	4,000 Hours (15Hr.-Device)	10-Hour Discharge Dev.	12-Hour Discharge Dev.	15-Hour Discharge Dev.
Near-Term (Present-1985):						
Pumped Hydro Storage	270-830	280-950	310-1210	150-500	160-560	175-670
Thermal, Oil	110-800	90-920	70-1170	430-670	480-750	570-880
Thermal, Steam	110-800	90-920	70-1170	990-2200	1100-2600	1400-3200
Compressed Air	40-410	0-460	-40-540	200-1000	230-1200	280-1500
Battery, Lead-Acid	20-500	0-580	-40-730	1900-3200	2200-3800	2800-4700
Intermediate-Term (1985-2000):						
Advanced Batteries	330-830	350-950	390-1190	630-1750	580-1900	940-2500
Chemical (H_2) Storage	100-800	70-920	20-1150	600-1100	670-1300	780-1600
Flywheels	250-750	250-860	260-1070	2900-8500	3400-10000	4300-13000
Long-Term (Beyond 2000):						
Superconducting Magnetic Energy Storage (SMES)	350-610	400-710	480-900	900-4000	1000-4700	1300-6000

a) Combined cycle 1975 installed capital cost assumed to be $225/kW.
b) Based on the data of Tables 5-1 and 5-2, including the range of energy storage system efficiencies, 5 to 30 mills/kWh levelized incremental cost of off-peak energy, 1975 fossil fuel costs of $1.50 to $2.50 per million Btu, and a 6 percent escalation per year for capital, fossil fuel, and operation and maintenance costs.

Table 5-5 RANGE OF 1975 BREAK-EVEN CAPITAL COSTS FOR ENERGY STORAGE SYSTEMS VS. COMBINED CYCLE UNITS, INTERMEDIATE APPLICATION (CONT'D)

c) Projected costs are based on the maximum and minimum power and storage cost combinations for the energy storage systems as shown in Table 6.8-1 and the cost equations of Chapter VI for compressed air and hydrogen storage. Projected costs for the 10-hour energy storage device are based on a charge to discharge, C/D, power ratio of 1.0 and a 28-hour storage capability requirement; the 12-hr. device on a 1.2 C/D ratio and a 33-hour storage requirement; and the 15-hour device on a 1.5 C/D ratio and 42 hours of storage.

d) Annual hours of operation assume 10, 12, and 15 hour devices each operating about 260 days per year.

e) For the weekly cycle intermediate duty storage system charge to discharge power ratios are in the range of about 0.7 to 1.5. Typical system storage capability requirements range from 24 to 32 hours for a 10-hour device, from 25 to 38 hours for a 12-hour device, and from 42 to 48 hours for a 15-hour device.

range values of thermal storage, compressed air, lead-acid batteries, and chemical storage. The lower break-even costs for these storage systems show a slight decrease for increasing hours of operation. The combination of economic variables used in the break-even calculation at the low range, namely the 30 mill/kWh incremental cost of off-peak energy, and the $1.50/MBtu cost of fossil fuel, is such that the cost of operation for the thermal, compressed air, lead-acid battery, and chemical storage systems increases faster than the operating costs for the combined cycle unit. As the ratio of the levelized incremental cost of on-peak to off-peak energy increases from about 2 in the lower break-even cost calculation, the break-even costs for these energy storage technologies also increase compared to the combined cycle unit with increasing annual hours of operation. Again, the near-term battery with expected life of 5 to 10 years, and the compressed air system which depends on the direct use of fossil fuel, have break-even costs lower than the other near-term energy storage technologies. Energy storage systems with installed capital costs either below or within these approximate ranges should prove to be economically attractive for the intermediate generation mode of operation on electric utility systems.

Table 5-4 identifies 1975 break-even capital costs for energy storage systems for the intermediate application for the assumed typical set of conditions of Table 5-2, and a corresponding levelized incremental on-peak to off-peak energy cost ratio of about three.

5.3.3 Dispersed Generation Network Savings

Dispersing generation throughout an electric utility system closer to the load could result in reducing or delaying the need for new transmission and distribution network facilities. Transmission and distribution system network savings in terms of $/kW of generation output can be identified for those energy storage systems which can be located at dispersed system locations, such as substations, close to the load centers. The location of the dispersed generation on the utility system will determine the extent of these savings. Physical size characteristics and space requirements of an energy storage system will dictate its possible locations. Because of the many variations in utility system configurations and planning and operating practices, only an estimate of the order of magnitude of transmission and distribution savings is possible. More precise savings estimates should be calculated for individual utilities based on a long range generation, transmission, and distribution system expansion study, with and without integrated energy storage systems.

Of the four near-term energy storage technologies, it appears that only lead-acid battery systems might be suitable for dispersed siting on electric utility systems. Pumped hyro, compressed air, and thermal storage are site- require;limited. These systems require; require large physical storage capability, and as in the case of thermal storage, are associated with a central generating station location. Of the intermediate and long range energy storage systems, only advanced batteries and, possibly, flywheel systems may be feasible for dispersed installation.

Figure 5-1 identifies the average investment, expressed in 1975 dollars, per kilowatt of generation added for transmission and distribution network facilities for a few urban and rural utilities with a mix of overhead and underground construction. The lower value of the range would correspond to rural systems with little or no underground construction and the upper value to urban systems with substantial amounts of underground transmission and distribution facilities. The investments in transmission and distribution facilities are based on average investments over a period of 7 to 10 years for each system considered. Substation investments were assumed to be equally split between transmission and distribution-supplied substations. Distribution investments were also assumed to be equally split between the newer, or higher voltage distribution system and the lower voltage distribution systems supplied by subtransmission. The investment in transmission and distribution facilities includes only utility plant in service and excludes those distribution accounts such as line transformers, services, meters, installations on customer premises, leased property on customer premises, and street lighting and signal systems, which would be required to serve customers either with or without dispersed energy storage systems.

Actual detailed transmission and distribution savings resulting from a delay or a reduction in facilities would occur at various intervals over a long period of time based on utilities service reliability criteria. Moreover, some transmission and distribution reinforcements may be required for charging purposes under certain special system conditions. Therefore, it was assumed that only 50 percent of the average investments of Figure 5-1 would be counted for determining transmission and distribution savings in connection with energy storage systems.

To determine additional break-even costs from transmission and distribution savings, the present worth of the annual revenue requirements for the transmission and distribution facilities, depending on location, were credited to the appropriate energy storage system in the generation break-even calculations of Appendix B5. An assumed transmission and distribution operation and maintenance cost of about 2 percent of the transmission and distribution investment was also included. An equivalent investment credit on a per kilowatt of energy storage capacity basis was thereby determined for an energy storage system which

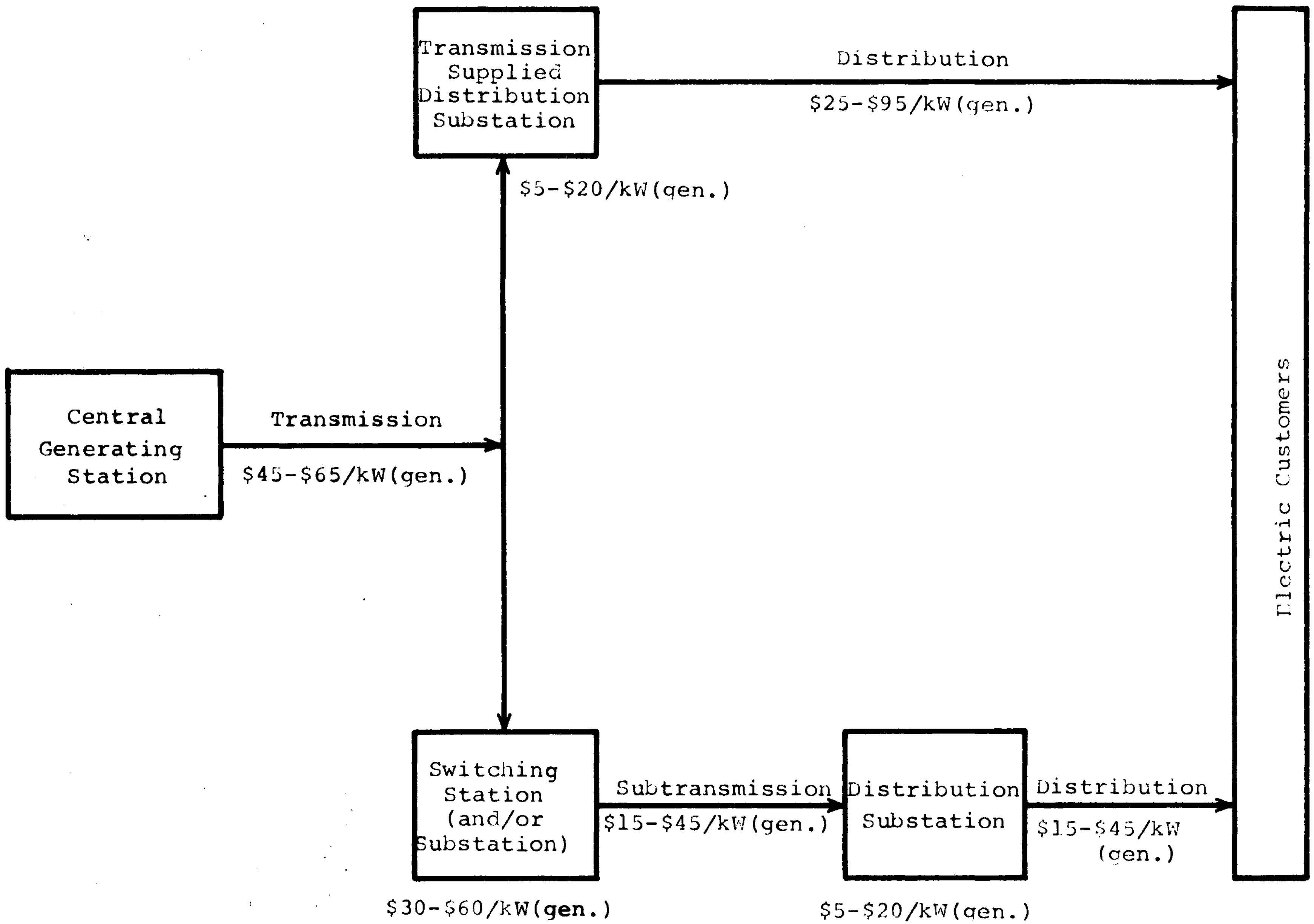


Figure 5-1 AVERAGE TRANSMISSION AND DISTRIBUTION SYSTEM UTILITY PLANT INVESTMENT (1975$) PER KILOWATT OF SYSTEM GENERATION CAPACITY ADDED

was derived from the transmission and distribution investment savings.

The resulting additional transmission and distribution break-even cost credits for the near-term lead-acid battery are shown in Figure 5-2. Depending on the installation location of the dispersed lead-acid battery system, additional transmission and distribution 1975 break-even cost credits for the lead-acid battery could vary from $15 to $75 per kilowatt of battery capacity. These transmission and distribution break-even cost credits can be added to the 1975 break-even costs of Tables 5-3, 5-4, and 5-5 for the lead-acid battery. For example, for a lead-acid battery system located on the low voltage side of a transmission supplied distribution substation transformer, an average of about $20/kW of energy storage capacity could be added to the battery 1975 capital costs. It should also be noted that the transmission and distribution break-even cost credits would be different from those of Figure 5-2 for other energy storage technologies.

5.4 BREAK-EVEN COST SENSITIVITY ANALYSIS

An economic sensitivity analysis was performed to determine the effect of incremental charges in key economic variables on the energy storage system break-even capital costs for the peaking and intermediate modes of generation operation. The effects on the energy storage system break-even capital costs were evaluated for variations in the following parameters: fossil fuel costs and off-peak charging energy costs, annual hours of operation, efficiency and capital cost of conventional generation. In addition, the effect of improvement in battery life on the battery break-even capital costs was determined.

The effects of unit variations in the economic parameters were determined over the long range study period based on the break-even economic calculation method described in Appendix B5. Relatively wide ranges of sensitivity can exist per unit change in an economic variable, depending on the assumed economic and generation technology operating conditions. Therefore, the sensitivity analyses were performed for unit variations in the operating parameters assumed as being typical in Table 5-2. In other words, sensitivity analyses were performed for small unit variations in the economic parameters which could affect or could be applied to the typical 1975 break-even costs of the energy storage systems shown in Table 5-4. The results of the energy storage system 1975 break-even capital cost sensitivity analyses are summarized in Tables 5-6 and 5-7 for the peaking and intermediate generation modes, respectively, and are discussed in the following sections.

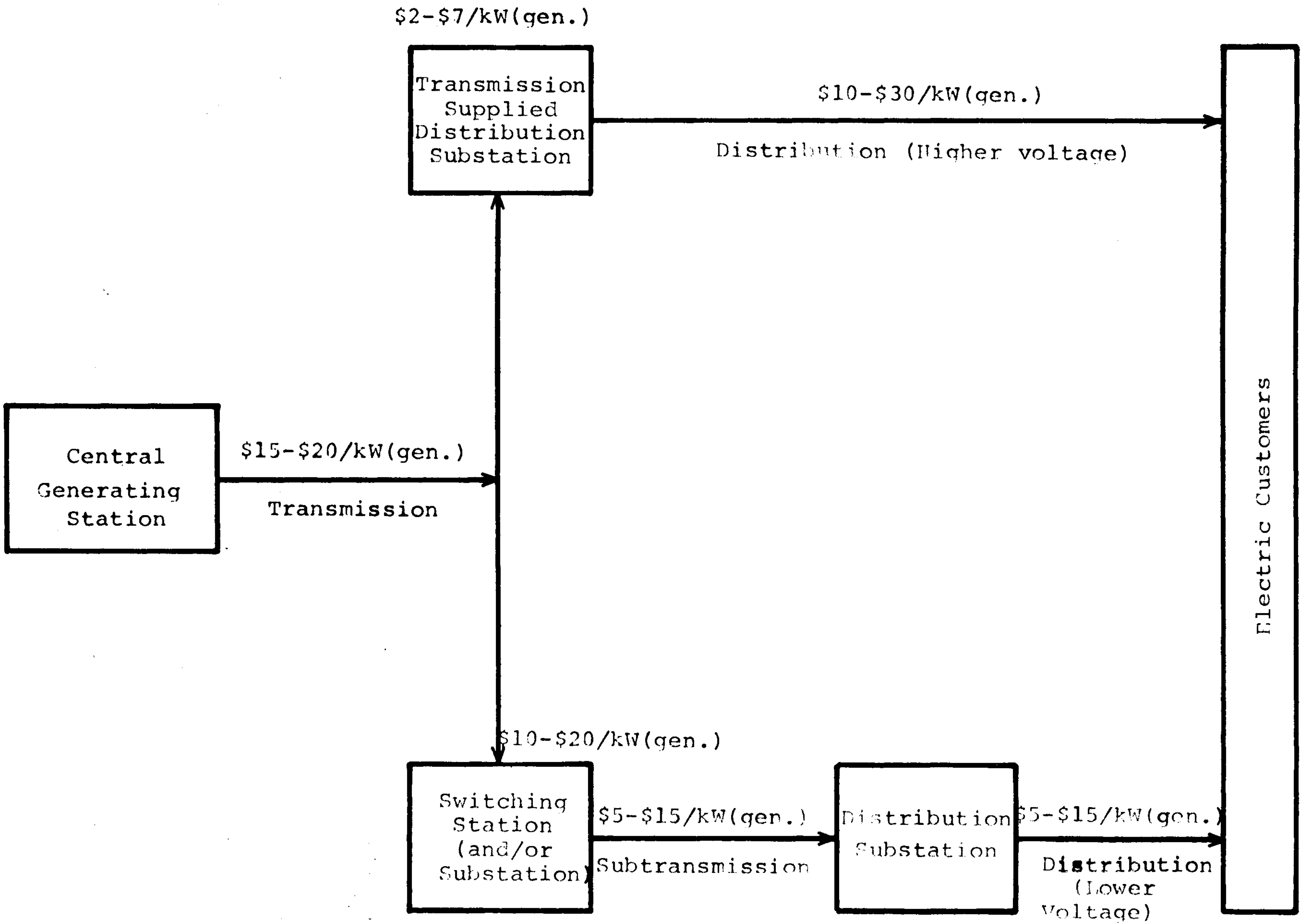


Figure 5-2 ESTIMATED TRANSMISSION AND DISTRIBUTION SYSTEM INVESTMENT SAVING CREDITS FOR 1975 BREAK-EVEN CAPITAL COST DETERMINATION FOR DISPERSED LEAD-ACID BATTERY INSTALLATIONS ON ELECTRIC UTILITY SYSTEMS

Table 5-6 ENERGY STORAGE SYSTEM 1975 BREAK-EVEN CAPITAL COST SENSITIVITY ANALYSIS, PEAKING APPLICATION[a]

	Energy Storage System 1975 Break-even Capital Cost Sensitivity in $/kW						
	Economic Parameters and Unit Changes in Parameters[b]						
	1975 Fossil Fuel Cost ($\$/10^6$Btu)	Escalation Rate (Percent/Year)	Levelized Incremental Off-Peak Energy Cost (mills/kWh)	Annual Operation (Hours)	Conventional Gen. Full Load Heat Rate (Btu/kWh)	Energy Storage Efficiency Percent	Conventional Unit Capital Cost ($/kW)
ENERGY STORAGE TECHNOLOGY	$\$0.50/10^6$Btu Increase	1 Percent/Year Increase	1 mill/kWh Decrease	100 Hours/Yr Increase	1,000Btu/kWh Decrease	1 Percent Increase	$10 Increase
Near-Term (Present-1985):							
Pumped Hydro Storage	65	80	5	30	-25	1	9
Thermal, Oil	65	55	6	25	-25	2	9
Thermal, Steam	65	55	6	25	-25	2	9
Compressed Air	5	30	2	10	-20	2	8
Battery, Lead-Acid	35	30	3	15	-15	1	5
Intermediate-Term (1985-2000):							
Advanced Batteries	65	90	4	30	-30	1	10
Chemical (H_2) Storage	65	90	6	25	-30	3	10
Flywheels	65	90	4	25	-30	1	10
Long-Term (Beyond 2000):							
Superconducting Magnets (SMES)	45	90	1	25	-20	0.5	7

a) Energy storage system compared to $100/kW gas turbine.
b) Changes in parameters are for indicated variations about the following general operation conditions: fossil fuel cost of $\$2.50/10^6$Btu, 1,000 hours of annual operation, 20 mills/kWh levelized incremental cost of off-peak energy, 6 percent escalation per year for capital, O&M, and fossil fuel costs, near-term gas turbine heat rate of 12,100 Btu/kWh and an intermediate and long-term heat rate of 11,000Btu/kWh, and energy storage efficiency of 75 percent, except 50 percent for chemical storage and a 4,200Btu/kWh heat rate for combustion turbines associated with compressed air storage.

Table 5-7 ENERGY STORAGE SYSTEM 1975 BREAK-EVEN COST SENSITIVITY ANALYSIS INTERMEDIATE APPLICATION[a]

	Energy Storage System 1975 Break-even Capital Cost Sensitivity in $/kW						
	Economic Parameters and Unit Changes in Parameters[b]						
	1975 Fossil Fuel Cost ($/$10^6$Btu)	Fossil Fuel Escalation Rate (Percent/Year)	Levelized Incremental Off-Peak Energy Cost (mills/kWh)	Annual Operation (Hours)	Conventional Gen. Full Load Heat Rate (Btu/kWh)	Energy Storage Efficiency Percent	Conventional Unit Capital Cost ($/kW)
ENERGY STORAGE TECHNOLOGY	$0.50/$10^6$Btu Increase	1 Percent/Year Increase	1 mill/kWh Decrease	100 Hours/Year Increase	1,000Btu/kWh Decrease	1 Percent Increase	$25 Increase
Near-Term (Present-1985):							
Pumped Hydro Storage	140	175	15	20	-80	4	23
Thermal, Oil	160	130	20	20	-90	6	25
Thermal, Steam	160	130	20	20	-90	6	25
Compressed Air	65	55	6	6	- 5	6	20
Battery, Lead-Acid	80	65	10	7	-45	3	13
Intermediate-Term (1985-2000)							
Advanced Batteries	145	205	10	20	-90	3	25
Chemical (H_2) Storage	145	205	15	15	-90	8	25
Flywheels	145	205	10	15	-90	3	25
Long Term (Beyond 2000):							
Superconducting Magnets (SMES)	100	200	5	15	-60	1	17

a) Energy storage system compared to a $225/kW combined cycle unit.

b) Changes in parameters are for indicated variations about the following gneeral operation condition: fossil fuel cost of $2.50/$10^6$Btu,3,000 hours of annual operation, 20 mills/kWh levelized incremental cost of off-peak energy, 6 percent escalation per year for capital, O&M and fossil fuel costs, near-term combined cycle heat rate of 8,900Btu/kWh and intermediate to long-term heat rate of 8,100Btu/kWh, and energy storage system efficiency of 75 percent, except 50 percent for chemical storage and a 4,200Btu/kWh heat rate for combustion turbines associated with compressed air storage.

5.4.1 Fossil Fuel and Off-Peak Energy Costs

If the 1975 cost of fossil fuel increases by $0.50/MBtu with no change in escalation rate, then over the long term study period an additional $30 to $70/kW can be justified for the capital cost of energy storage systems compared to the gas turbine for the peaking application based on 1,000 hours of annual operation. For the same unit change in fossil fuel cost, anywhere from $55 to $160/kW could be justified for the energy storage systems compared to the combined cycle unit for the intermediate mode of generation operation at about 3,000 hours per year. Thus, for any increase in fossil fuel costs, the associated increases in 1975, break-even capital costs for the intermediate application are about double the corresponding increases for the peaking application.

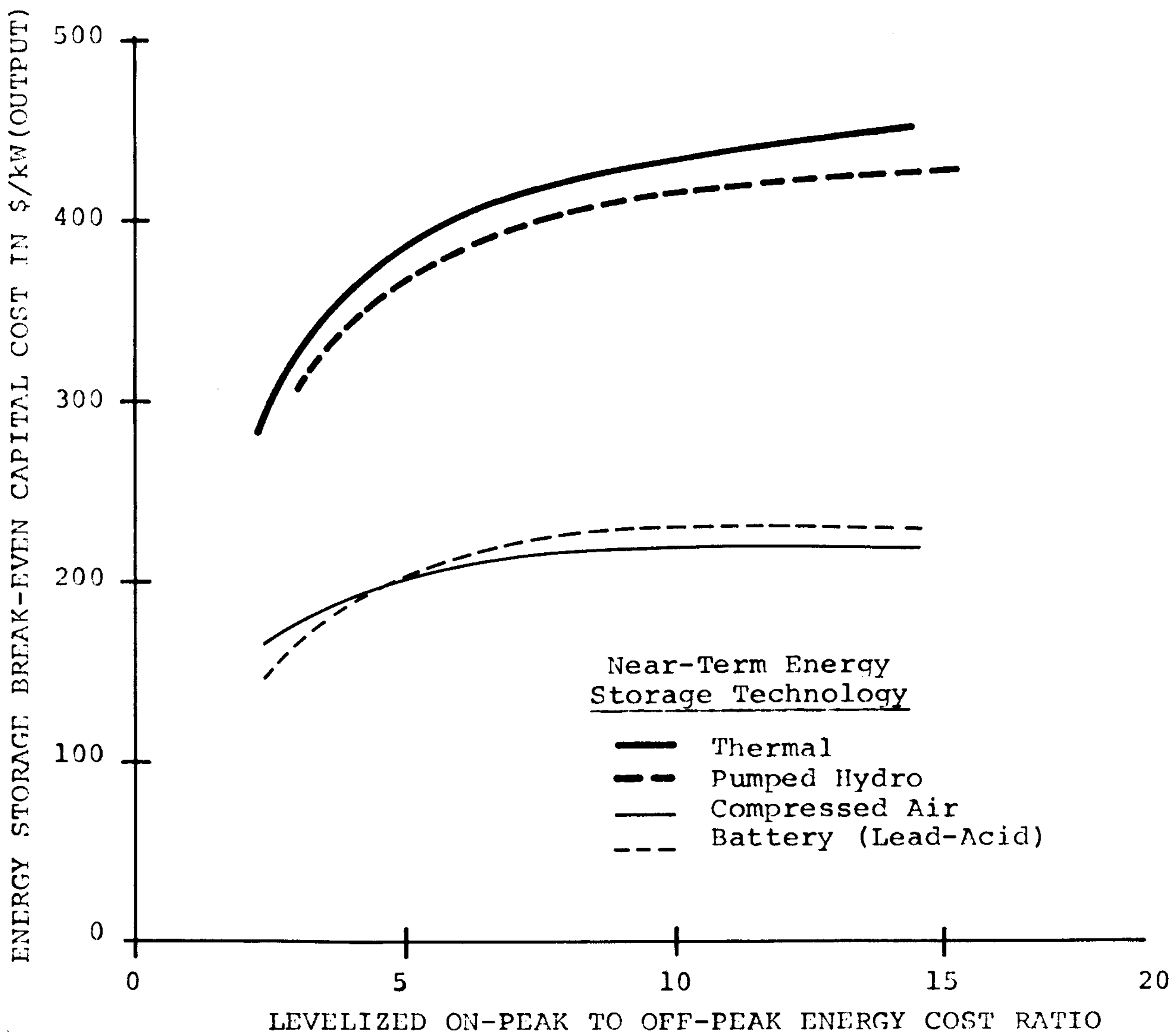
The unit increases in the fossil fuel annual escalation rate over the period of study is not a linear relationship. However, a one percent per year increase in the assumed fossil fuel escalation rate will increase energy storage system 1975 breakeven capital costs in the range from $25 to $80/kW for the peaking application and from $45 to $205/kW for the intermediate application. Again, the unit break-even cost increases for the intermediate application are about double the increases for the peaking application.

For a 1 mill/kWh decrease in the levelized incremental cost of off-peak energy assumed over the study period, additional energy storage system break-even capital cost increases from $1 to $7/kW could be justified for the peaking application; from $5 to $20/kW could be justified for the intermediate application. Thus the justified increases in energy storage system break-even costs for the intermediate application are about three times the justified increases for the peaking application.

Figures 5-3 and 5-4 show the energy storage system 1975 break-even capital costs as a function of the ratio of the levelized incremental on-peak to off-peak energy costs for each of the near-term technologies for the peaking and intermediate generation modes. The lower energy cost ratios of Figures 5-3 and 5-4 correspond to off-peak energy costs of 30 mills/kWh and the upper energy cost ratios correspond to 5 mill/kWh off-peak energy.

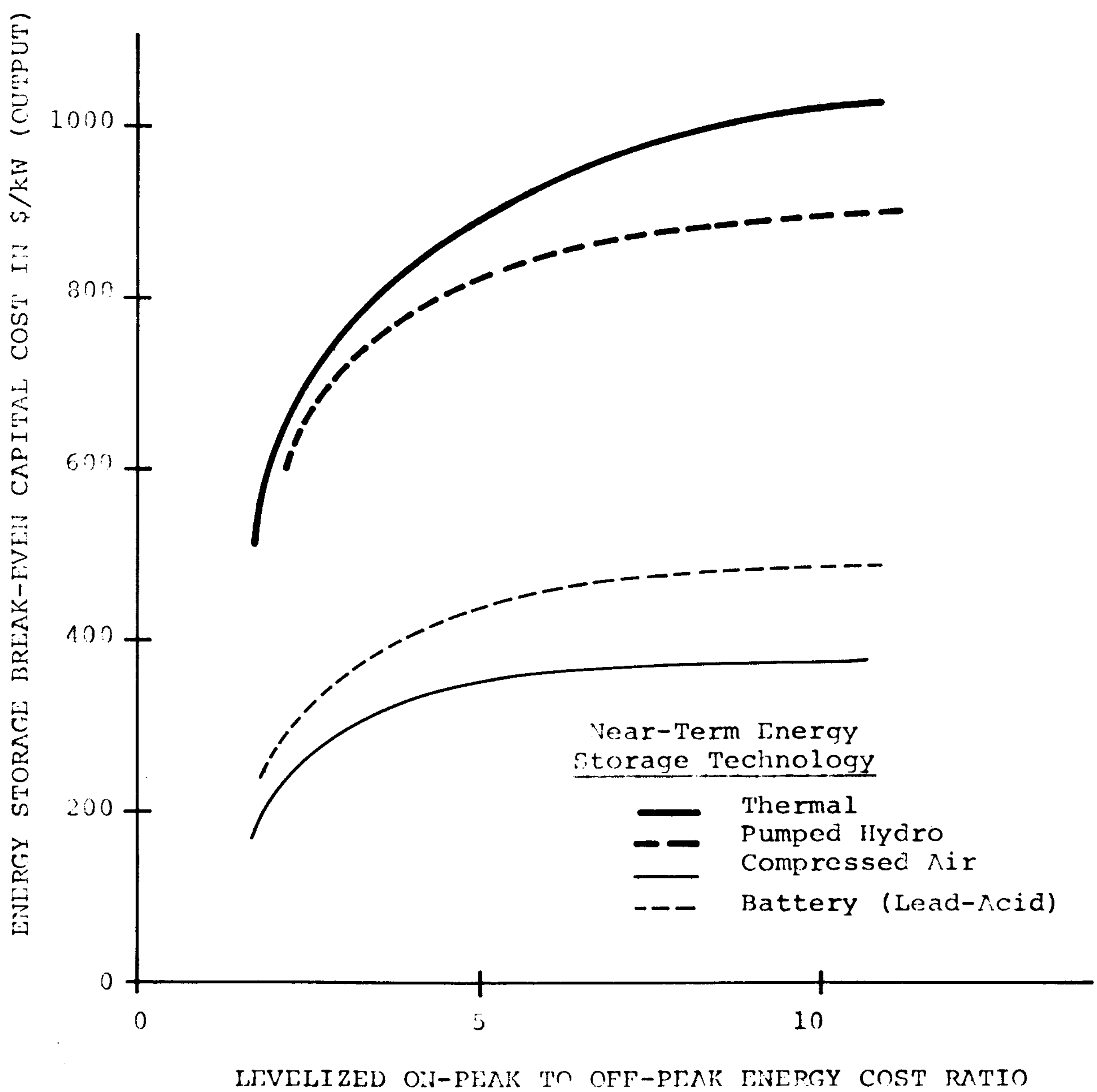
5.4.2 Annual Operation

For a 100-hour increase in the annual hours of operation, the energy storage system break-even capital costs are larger for the peaking application than for the intermediate application primarily due to the higher operation and maintenance costs and heat rates of the gas turbine compared to the combined cycle unit as shown in Tables 5-6 and 5-7. Incremental break-even capital



Gas Turbine: $100/kW Cost, 12,100Btu/kWh Heat Rate,
1,000 Hours Annual Operation
Fossil Fuel Cost: $2.50/10^{6}Btu (1975)
Escalation: 6% per year for Capital, O&M, and Fossil Fuel
Energy Storage: 75% Efficiency, 4,200Btu/kWh Heat Rate
for Compressed Air
Levelized Incremental Off-Peak Energy: 5 to 30 mills/kWh

Figure 5-3 NEAR-TERM ENERGY STORAGE SYSTEM 1975 BREAK-EVEN CAPITAL COST VS. THE LEVELIZED ON-PEAK TO OFF-PEAK ENERGY COST RATIO, PEAKING APPLICATION



Combined Cycle: $225/kW Cost, 8,900Btu/kWh Heat Rate, 3,000 Hours Annual Operation
Fossil Fuel Cost: $2.50/10^{6}Btu (1975)
Escalation: 6% per year for Capital, O&M, and Fossil Fuel
Energy Storage: 75% Efficiency, 4,200 Btu/kWh Heat Rate for Compressed Air
Levelized Incremental Off-Peak Energy: 5 to 30 mills/kWh

Figure 5-4 NEAR-TERM ENERGY STORAGE SYSTEM 1975 BREAK-EVEN CAPITAL COST VS. THE LEVELIZED ON-PEAK TO OFF-PEAK ENERGY COST RATIO, INTERMEDIATE APPLICATION costs per 100 hours of annual operation vary from $10 to $30/kW for the peaking application and from $5 to $20/kW for the intermediate application.

5.4.3 System Efficiency

Table 5-6 shows that a decrease of 1,000 Btu/kWh in the full load heat rate of the gas turbine over the period of study would result in a reduction of the justified 1975 break-even capital costs for the energy storage systems from $15 to $30/kW. Similarly in Table 5-7, for the intermediate application, a reduction of 1,000 Btu/kWh in the combined cycle full load heat rate would reduce the justified 1975 break-even capital costs of the energy storage systems from $45 to $90/kW.

Improvements in battery efficiency of 1 percent will increase the battery break-even capital costs from $1 to $3/kW for the peaking and intermediate generation modes, respectively. Improvements in energy storage system efficiency are worth about three times more for the intermediate application than for the peaking application.

5.4.4 Improved Battery Life

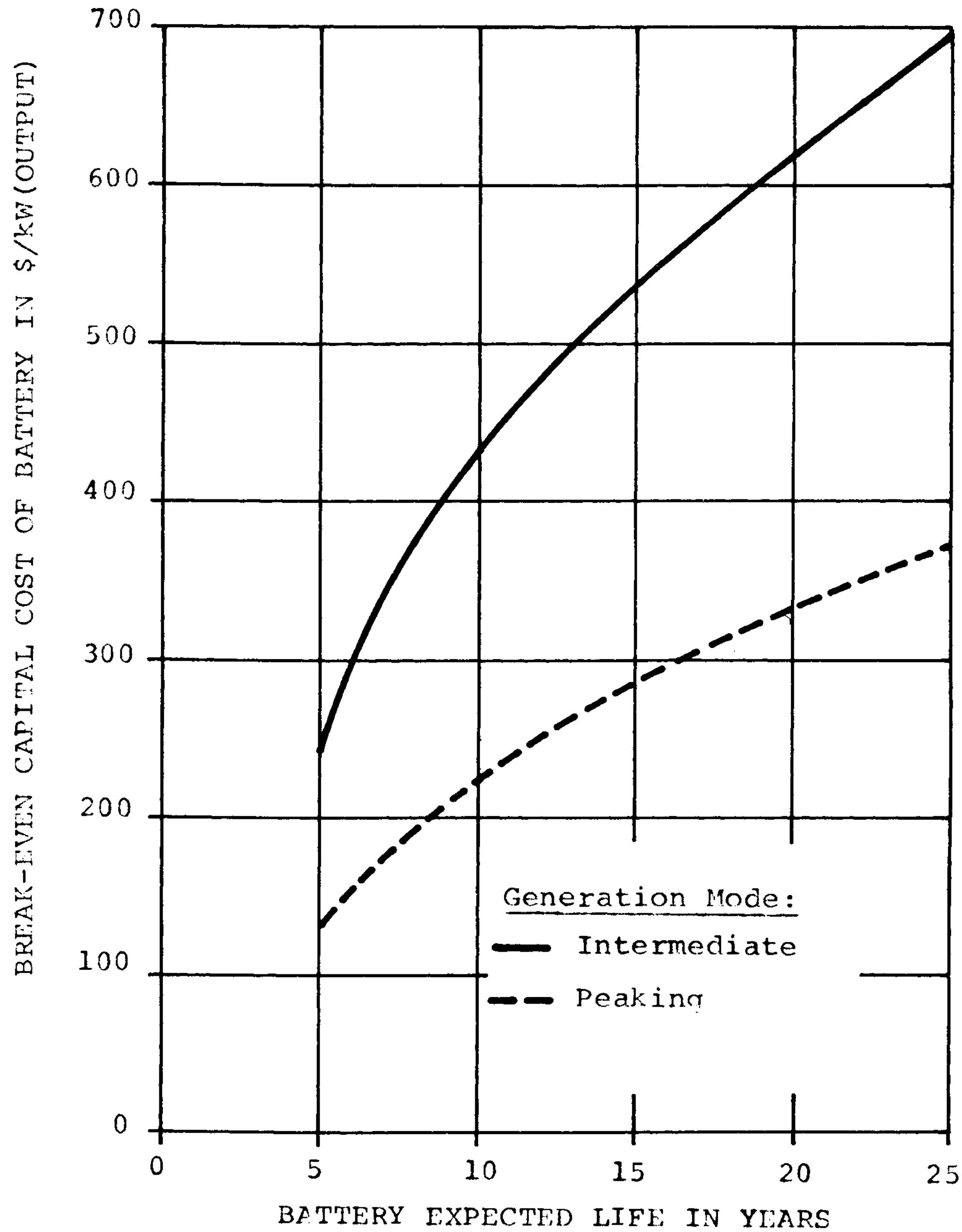
Of the energy storage technologies considered, only battery systems are projected to show substantial improvements in expected life and efficiency from the near to the intermediate-term time frames. Figures 5-5 and 5-6 show the sensitivity of the break-even cost of the battery to its expected life and efficiency. The improvement in battery life is not a linear relationship, however, an additional $10 to $20/kW in battery break-even capital costs could be justified for a one year improvement in expected battery life for the peaking and intermediate generationmodes, respectively.

5.4.5 Capital Cost of Conventional Generation

Tables 5-6 and 5-7 also show the effect on the break-even capital costs of each energy storage technology of a $10/kW and $25/kW change in the capital costs of gas turbines and combined cycle units, respectively. The effect is linear and these values can be applied directly to any of the break-even capital costs previously described.

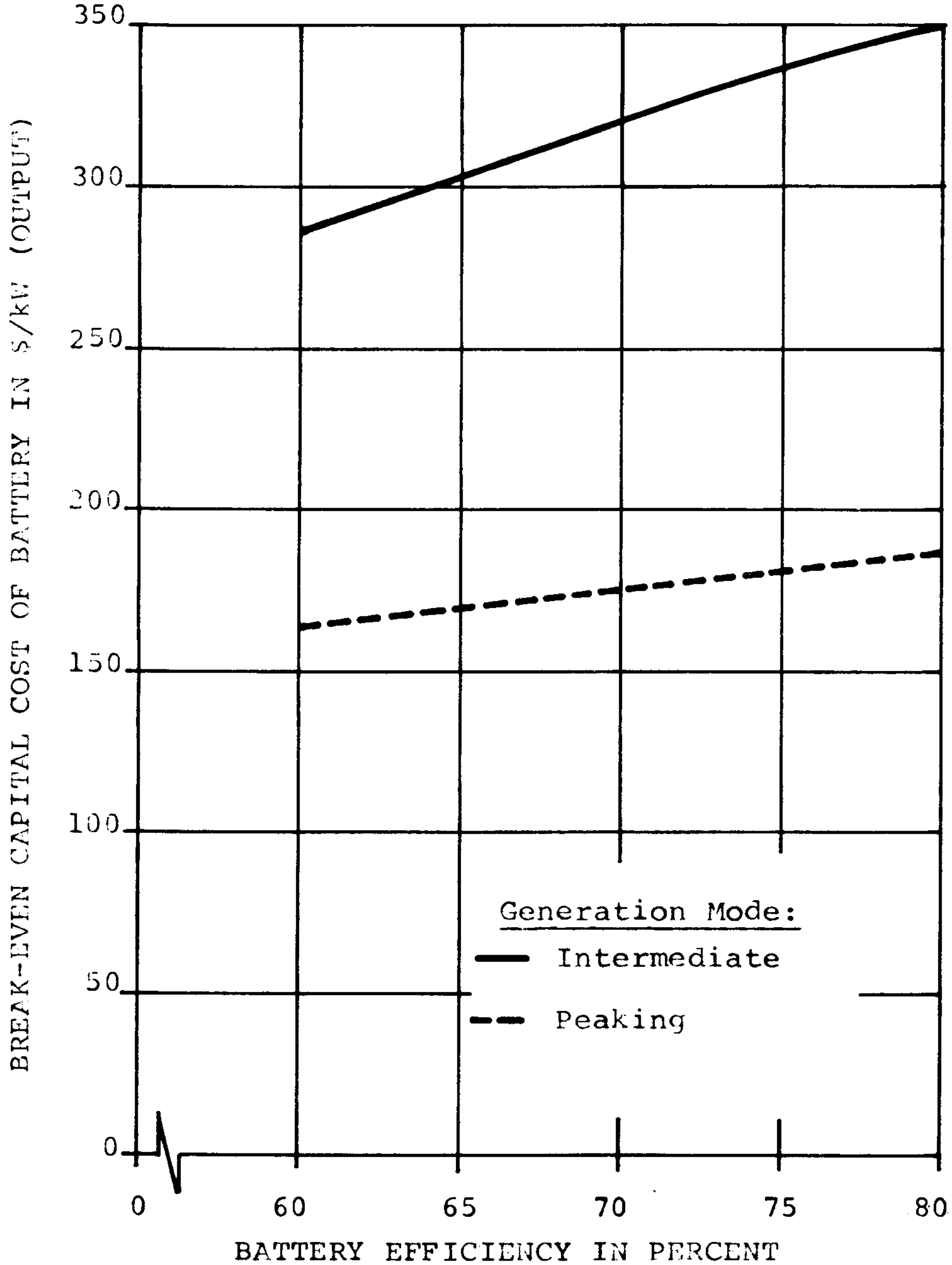
5.5 RELATIVE COMPETITIVENESS OF SELECTED ENERGY STORAGE SYSTEMS

The relative economic competitiveness of the selected energy storage systems was determined by comparing the 1975 break-even capital costs with the projected installed capital costs of the systems selected for specific peaking and intermediate duty applications. The projected costs for the peaking and intermediate system applications are shown in Tables 5-3 and 5-5,



Gas Turbine: $100/kW Cost, 12,100Btu/kWh Heat Rate,
1,000 Hours Annual Operation
Combined Cycle: $225/kW Cost, 8,900Btu/kWh Heat Rate,
3,000 Hours Annual Operation
Battery: 75% Efficiency
Fossil Fuel Cost: $2.50/10^{6}Btu (1975)
Escalation: 6% per year for Capital, O&M, and Fossil Fuel
Levelized Incremental Cost of Off-Peak Energy: 20 mills/kWh

Figure 5-5 SENSITIVITY OF THE BREAK-EVEN CAPITAL COST OF THE BATTERY TO ITS EXPECTED LIFE



Gas Turbine: $100/kW Cost, 12,100Btu/kWh Heat Rate, 1,000 Hours Annual Operation
Combined Cycle: $225/kW Cost, 8,900Btu/kWh Heat Rate, 3,000 Hours Annual Operation
Battery: 5, 10, and 10 years Life
Fossil Fuel Cost: $\$2.50/10^6$Btu (1975)
Escalation: 6% per year for Capital, O&M, and Fossil Fuel
Levelized Incremental Cost of Off-Peak Energy: 20 mills/kWh

Figure 5-6 SENSITIVITY OF THE BREAK-EVEN CAPITAL COST OF THE BATTERY TO ITS EFFICIENCY respectively for comparison with the 1975 break-even capital costs.

5.5.1 Peaking Generation Mode of Operation

Table 5-3 shows the range of projected installed capital costs in $/kW for the 2, 5, and 10-hour daily cycle peaking duty storage systems. The lower values of the projected cost ranges are based on the lower power and storage costs for the respective energy storage technologies of Table 4-1 of Chapter 4. The higher projected costs are based on a combination of the higher power and storage costs of Table 4-1 .

The relative economic competitiveness of the storage systems over the range of peaking duty applications is summarized in Table 5-8. Pumped hydro storage and advanced battery systems appear to be economically attractive over the range of 2 to 10-hour storage systems. Thermal oil, thermal steam, compressed air, chemical (hydrogen), and superconducting magnetic energy storage systems could be acceptable for particular peaking applications. Superconducting magnetic energy storage has some potential for the shorter discharge times. Hydrogen has some attractiveness primarily for the longer daily discharge times of 5 to 10-hours. Lead-acid battery and flywheel systems appear to be economically unattractive for the peaking application because of the relatively low expected life of the battery and the relatively high storage cost for the battery and particularly, the flywheel system. Even if the transmission and distribution break-even capital cost credits of Figure 5-2 are added to the break-even capital costs of Table 5-3 for these systems, lead acid batteries and flywheels continue to be generally unattractive for the peaking duty generation mode.

5.5.2 Intermediate Generation Mode of Operation

Table 5-5 shows the range of projected energy storage system installed costs in $/kW for the weekly cycle storage systems capable of providing 10, 12 and 15 hours of intermediate duty operation each day. Storage capability (hours at full discharge power capacity) was assumed to be 28, 33 and 42 hours respectively; associated charge/discharge (C/D) power ratios were assumed to be 1.0, 1.2 and 1.5. The lower and higher values of the projected costs correspond to the lower and higher power and storage costs of Table 4-1 of Chapter 4, respectively, for each energy storage technology. The projected costs for the weekly cycle intermediate duty devices are quite high compared to those of Table 5-3 because of the substantial increase in the storage capability required for weekly duty cycle devices compared to daily cycle devices.

The relative economic competitiveness of the storage systems over the range of the intermediate duty applications is also

Table 5-8 RELATIVE ECONOMIC COMPETITIVENESS OF ENERGY STORAGE SYSTEMS FOR ELECTRIC UTILITY APPLICATION

Energy Storage Technology	Energy Storage System Relative Economic Competitiveness[a]					
	Peaking Application Daily Duty Cycle			Intermediate Application Weekly Duty Cycle		
	400 Hours (2Hr.-Dev.)	1,000 Hours (5Hr.-Dev.)	2,000 Hours (10 Hr.-Dev.)	2,500 Hours (10,Hr.-Dev.)	3,000 Hours (12Hr.-Dev.)	4,000 Hours (15,Hr.-Dev.)
Near-Term (Present to 1985):						
Pumped Hydro Storage	Attractive[b]	Attractive	Attractive	Attractive	Attractive	Attractive
Thermal, Oil	Some Appl.[c]	Some Appl.	Some Appl.	Some Appl.	Some Appl.	Some Appl.
Thermal, Steam	Unattractive[d]	Some Appl.	Some Appl.	Unattractive	Unattractive	Unattractive
Compressed Air	Some Appl.	Some Appl.	Some Appl.	Some Appl.	Some Appl.	Some Appl.
Battery, Lead-Acid	Unattractive	Unattractive	Unattractive	Unattractive	Unattractive	Unattractive
Intermediate-Term (1985-2000):						
Advanced Batteries	Attractive	Attractive	Attractive	Some Appl.	Some Appl.	Some Appl.
Chemical (H_2) Storage	Unattractive	Unattractive	Some Appl.	Some Appl.	Some Appl.	Some Appl.
Flywheels	Unattractive	Unattractive	Unattractive	Unattractive	Unattractive	Unattractive
Long-Term (Beyond 2000):						
Superconducting Magnetic Energy Storage (SMES)	Some Appl.	Some Appl.	Some Appl.	Unattractive	Unattractive	Unattractive

a) Based on a comparison of break-even capital costs and projected installed capital costs for energy storage systems of Tables 5-3 and 5-5 for the peaking and intermediate generation modes, respectively.
b) Attractive refers to economic attractiveness in that the break-even costs are generally higher than the projected installed capital costs.
c) Some application refers to the fact that there is some overlap in the break-even and projected installation capital costs and therefore, application on electric utility systems may be possible for particular conditions.
d) Unattractive means that the projected costs are higher than the justified break-even capital costs.

summarized in Table 5-8. Pumped hydro storage appears to be economically attractive over the full range of intermediate duty requirements. Thermal oil, compressed air, advanced batteries, and chemical storage systems could be acceptable for particular intermediate duty applications on electric utility systems. Thermal steam, lead-acid batteries, flywheels, and superconducting magnetic energy storage systems appear to be economically unattractive for the intermediate generation mode because of the relatively high storage costs.

6 ENVIRONMENTAL AND SAFETY FACTORS

This section contains a discussion of environmental and safety issues and impacts that would be associated with construction and operation of energy storage systems. Since, for the most part, these are advanced systems for which actual operating sites and experience do not exist, most of the environmental effects and safety factors mentioned here are generic and might apply regardless of the eventual location of the plant. Potential adverse environmental effects and safety considerations from both construction and operation activities are discussed, as well as measures to be taken, where appropriate, to mitigate impacts.

It should be noted that the environmental and safety aspects of new operations are receiving ever-increasing public attention, and new laws and regulations are continuously promulgated. Hence the type of environmental report which will eventually be required, and the various environmental and safety regulations to which these facilities will have to conform, must necessarily be expected to change. Such requirements will also be strongly dependent on eventual site locations for the discussed energy storage systems and the construction difficulties associated with them. It must be emphasized that environmental impacts common to all construction projects (dust, noise, increased truck traffic, etc.) are not considered here. These would be treated in a complete assessment.

This section is not intended to be an environmental impact statement, but a qualitative guideline identifying some of the factors which must be dealt with in such a statement. An impact statement is essentially a document presenting the results of a systematic study of all the potential effects of a proposed activity on its environment. The statement (42 USC 4341) as stated in NEPA shall include:

1. A detailed description of the proposed action including information and technical data adequate to permit a careful assessment of environmental impact.

2. Discussion of the probable impact on the environment, including any impact on ecological systems and any direct or indirect consequences that may result from the action.

3. Any adverse environmental effects that cannot be avoided.

4. Alternatives to the proposed action that might avoid some or all of the adverse environmental effects, including analysis of costs and environmental impacts of these alternatives.

5. An assessment of the cumulative, long-term effects of a proposed action including its relationship to short-term use of the environment versus the environment's long-term productivity.

6. Any irreversible or irretrievable commitment of resources that might result from a proposed action or which would curtail beneficial use of the environment.

The assessment of the energy storage systems discussed includes mention of significant impacts on the environment. This is not to be confused with or considered an Environmental Impact Statement, which is a formal and quite extensive document.

The principal factors impacted by the energy storage schemes are:

Factor	In Compliance With
Air	Clean Air Act 1970, Public Law 91-604
Water	Federal Water Pollution Control Act 1972, Public Law 92-500 Safe Drinking Water Act 1974, Public Law 93-523
Land Use	State and Local Regulations
Noise	Noise Control Act 1972, Public Law 92-574
Safety	Occupational Safety and Health Act 1970, Public Law 91-596

While environmental impacts may vary in each of the systems discussed, energy storage systems, in general, show positive environmental aspects. By placing storage systems, where possible, close to load centers, the need for additional transmission and distribution circuits may be reduced. Utilizing energy storage systems for load leveling will allow utilities to use more efficient base load generation, nuclear and large fossil fuel plants, to meet peak demand periods. Thus energy storage offers a trade-off in environmental impacts.

The attendant environmental and safety considerations for each major area of technology are discussed in the following sections.

6.1 HYDRO PUMPED STORAGE

6.1.1 Conventional Systems

6.1.1.1 Environmental Concerns Due to environmental objections, some proposed pumped storage projects have been delayed for extended periods and some may never be built. These projects have attracted the attention of the general public. On the other hand, a number of plants have been built, or are planned to meet the evident need for this type of capacity within environmental requirements. Other sites appear to be suitable for development, however, their environmental acceptability must be weighed as each one is presented for licensing to the Federal Power Commission (FPC).

Environmental impact reports are now required as a part of every FPC license application. These reports require consideration of energy conservation, load flattening, and the possibility of no plant as an alternative to the proposed pumped storage.

The environmental impact of a proposed pumped storage project must be considered relative to the impact of other plants that can provide the same service. It does not necessarily follow, that a site is unacceptable because its development as a pumped storage site has certain adverse environmental impacts. Rather its acceptability must be measured in relation to other sites, to other types of capacity, and to the benefits of the proposed development.

Because of the diverse conditions existing at sites suitable for pumped storage development, it is difficult to generalize as to the importance of various environmental impacts and as to methods and cost of minimizing adverse effects. It is possible, however, to list the environmental factors, the basis of objections made against pumped storage, the possibilities of minimizing or eliminating some objectionable conditions, and the positive benefits of pumped storage. Environmental factors that are involved in a comparative assessment of sites are outlined in Table 6-1.

Objections to pumped storage may put some of the environmental factors in a different context. Many of these objections can be overcome at reasonable cost, while others cannot. In general, the objections include:

1. The use of land areas for reservoirs, which could otherwise be used for agriculture, recreation or left as wilderness. Because of the relatively small reservoirs and the nature of the sites, displacement of population is generally not a major factor.

2. The use of land for required transmission.

3. The use of land for construction purposes.

4. Temporary noise, dust, traffic, people problems, etc., during construction.

5. The aesthetics of structures such as dikes, transmission towers, and penstocks.

6. Displacement of wildlife and damage to fish.

7. The aesthetics and safety of fluctuating water surfaces.

Table 6-1 ENVIRONMENTAL FACTORS FOR SITE ASSESSMENT

I. WATER RESOURCES DISRUPTION

A. Hydrology

1. Surface Water
   a. Drainage
   b. Steam Flow
   c. Evaporation

B. Quality

1. Surface Water
   a. Sediment
   b. Turbidity
   c. Dissolved Oxygen
   d. Temperature

C. Plants and Animals

1. Plants
   a. Habitat
   b. Unique Flora

2. Animals
   a. Resident
   b. Migratory
   c. Rare and Endangered Species

D. Wetlands

II. LAND RESOURCES DISRUPTION

A. Plants

1. Habitat

2. Unique Flora

3. Timberlands (ecological impact)

B. Animals

1. Rare and Endangered Species

2. Resident Species

3. Migratory Species

C. Aesthetics

1. Scenic Land Forms

2. Unique Physical Features

3. Land and Vegetative Patterns

4. Water

III. SOCIAL RESOURCES DISRUPTION

A. Private Developments

1. Residences (including vacation homes)

2. Farms

3. Commercial

B. Public Developments

1. Utilities

2. Transportation
   a. Highways and Roads
   b. Railroads

3. Facilities
   a. Schools
   b. Cemeteries
   c. Other

4. Public Plans
   a. Regional, State & Local Plans
   b. National & State Forests & Parks

5. Other
   a. Archaeological Sites
   b. Historical Sites

C. Recreation

1. Water Related
   a. Swimming
   b. Boating
   c. Fishing

2. Land Related
   a. Hunting
   b. Hiking & Camping
   c. Other

8. Effects of exposed reservoir areas on water temperatures.

9. Possible increased energy use due to cycle efficiency.

10. Relative irreversibility of the effects on the project.

11. Soil disposal.

There is not much that can be done about some of these considerations beyond selection of a site for which these impacts are small. For example, there will always be objections on the basis of land use; overcoming objections from one segment of the population only leads to objections from others with different interests. Also the irreversible effects of the project, must be given whatever weight is appropriate.

Some of the undesirable conditions experienced during construction can probably be minimized by additional costs. Aesthetic objections can be eased by landscaping or screening the outside slopes of dikes and downstream slopes of dams, placing waterways and powerhouses underground (usually an economic decision, if site conditions are favorable), and careful routing of transmission lines to minimize their impact.

Aesthetic and safety problems due to fluctuating water surface elevations may be minimized by maintaining the elevation with the construction of low auxiliary dams, in shallow areas of the reservoir that would be exposed by drawdown. The resulting small ponds are then better suited for recreation uses. Although this involves additional cost (at Muddy Run such an auxiliary dam represented less than 1 percent of the project costs), if it offsets objections to a project, it should be considered. Aesthetic objections also tend to be countered by adequate provisions for recreation, including a visitors' center, suitable landscaping and other amenities.

Harm to fish is another site related factor. The extent of the problem is quite different for a plant located on a major river or a natural lake as contrasted to one developed on a very small drainage area. Plant operation may cause either thermal or environmental shock to the inhabiting fish.

When a project is to be located upon an existing major body of water, it is desirable that fish be prevented from passing through the plant or that it be conclusively demonstrated that such passage is not seriously harmful. In situations such as this, by-pass valves can be used to prevent fish from passing through the plant.

When a plant is to be located in a small drainage area, where a pre-plant fish population is non-existent, plant construction may create a more suitable fish habitat. Although some fish may be damaged through plant operation (possibly missing the by-pass valves) a net increase in fish population resulting from plant construction is possible.

Allegations of increased energy use due to cycle efficiency is often an unjustified objection to pumped storage. A pumped storage plant supplied with pumping energy from incremental loading of an efficient base-load unit, i.e., units that would otherwise be only partially loaded during off-peak hours, produces its energy at a heat rate of about 12,000 to 14,000 Btu/kWh. This is the range of heat rates for combustion turbines that could supply the same amount and quality of peaking service. It is also the same, or even better, range of performance than can be expected from fossil-fired cycling units, either older units adapted to this service or new units designed for the service. In cycling service, such units have much higher heat rates than are usually mentioned as a basis of their design. These arguments apply to all storage systems with comparable efficiencies. The argument favorable to pumped storage, as any storage system that can be based on heat rate, is further reinforced by consideration of the types of fuel utilized by the system and saved by its operation. In general, a more abundant fuel will be substituted for one that is scarce or more costly. This, of course, is one of the major positive impacts of all energy storage.

Other direct benefits of pumped storage, additional to the benefits and economies in its use for power, may include substantial contributions to recreational uses such as camping, picknicking, fishing, hiking, and where auxiliary ponds are provided, boating and swimming.

Another potential water supply use is the delivery of make-up for a closed cooling system of an associated thermal plant. Also where the pumped storage is located on a relatively small drainage area, the plant operation can increase the quantity and quality (except for temperature) of low flows by releases from storage, these being generally required by the license or by State permits. Under the same site conditions, the storage will also provide some flood control benefits.

Even the addition of heat to the water, resulting from the dissipation of the losses involved in the operating cycle, may not be all bad, for this may assure some open water for waterflow use during the winter season.

It is obvious that the benefits as well as the adverse environmental impacts are site related and can be evaluated only for specific conditions.

6.1.1.2 <u>Safety</u> Since operating experience with pumped storage is available, safety problems are known and adequate protection against structural failures and adverse occurrences have been developed. The principal problem areas are as follows:

1. Safety during construction - closely regulated by various state and federal agencies.

2. Dam safety - subject to state and federal requirements for design, construction and periodic inspection.

3. Powerhouse flooding, particularly for an underground powerhouse, has occurred and protection is obtained only by conservative design, special unwatering arrangements, and care in operation.

4. Water surface fluctuation - rapidly varying water surface elevations may be a hazard, if reservoirs are open to public use.

5. Operating hazards, which are common to work performed near high voltage equipment, or moving mechanical equipment.

In most cases, such safety problems should not prevent construction or operation of a pumped storage plant.

6.1.2 Underground Systems

6.1.2.1 Environmental Concerns Nearly all those possible adverse effects previously mentioned for conventional pumped storage with two surface reservoirs are reduced when one reservoir is underground. Two new factors, however, may need consideration. One is the disposal of excavated rock, assuming it cannot be sold as rapidly as it is produced, or be fully utilized in dams or dikes required for the surface reservoir. The other is the introduction of heat into a smaller volume of water and the resulting higher equilibrium temperature for the hydraulic system. This may increase the temperature of water discharged from the surface reservoir; and if the discharge is to a small stream, or otherwise exceeds the thermal rise limits specified in Federal regulations, may prove objectionable. The heating is due to system losses, approximately 40 percent of the daily generation, which must to be carried away, to a large extent, by the water returned each day to the surface reservoir.

6.1.2.2 Safety Safety problems may be increased due to the underground construction and operation, unless great care is taken to require safe designs and practices. Assuming proper design of the underground reservoir system, there is no inherently greater risk of flooding the underground powerhouse than there would be for a structure with surface reservoirs. However, flooding has far more serious consequences in terms of long durations of plant shutdown, because there is no place to which water can drain, and pumping to dewater the plant may take a long time. This is a possibility that should be recognized in design and some means of minimizing the impact of flooding should be considered.

Another condition peculiar to underground storage is the possibility that the underground storage cavern can be accidentally subjected to the full hydrostatic head. This is not a problem for the cavern, but it is a serious matter with respect to all structures and equipment that would normally be subject only to the back pressure associated with normal water surface elevations in the cavern. The plant design must either allow for this condition or make its occurrence impossible. In either case, additional cost probably will be involved to prevent possible excess pressures.

The other safety problems of conventional pumped storage operation remain, although some may be reduced in extent by the use of one rather than two surface reservoirs.

6.2 COMPRESSED AIR ENERGY STORAGE

6.2.1 Environmental Concerns

Four categories of environmental concerns relevant to compressed air systems are:

1. Acceptable land use policy (including general aesthetics)
2. Water quality assurance
3. Air pollution control
4. Noise abatement

Each of these categories is addressed below with regard to relevance to existing and or proposed regulations, and likely problems to be encountered in implementing compressed air systems.

6.2.1.1 Acceptable Land Use Other than local and regional planning and local zoning requirements, there are no uniform regulations governing suitability of surface land use for compressed air systems. From an aesthetic viewpoint, the above ground equipment can be satisfactorily enclosed in a modular housing or a field erectable shelter.

With regard to the subsurface air storage facility, the principal concern is assurance against surface subsidence. Other surface impacts of importance resulting from air leakage include water runoff, blistering and blowouts. The underground facility must remain within the boundaries of surface property unless arrangements are made with adjacent property owners.

6.2.1.2 Water Quality It is necessary to prevent the deterioration of water quality. Existing regulations governing well completion practices are compatible with compressed air storage facility siting requirements the need to avail contaminating water supply strata is compatible with the air storage facility requirement for isolation to prevent leakage of stored air. Simply stated, compressed air storage uses confined aquifers, this is not the form of most aquifers used as water supplies.

6.2.1.3 Air Pollution Control Conventional burner design centers around effecting locally stoichiometric combustion in the immediate vicinity of the fuel injectors followed by mixing with diluent air to obtain the desired exit temperature profile. To decrease NOx concentrations, water injection into the combustion chamber to lower the flame temperature is commonly used. The availability of a water supply for this purpose has a potential impact on site selection and the economics of overall costs.

6.2.1.4 Noise Abatement Whether a noise problem exists for the machinery of the compressed air energy storage station depends upon the exposure of people to the noise (staff and site neighbors), regulations of governing such exposure, land zoning mix surrounding the station, and the noise source itself.

Under the Occupational Safety and Health Act of 1970 (OSHA) rules, there are maximum allowable occupational noise exposure levels governed by a time-weighted standard covering continuous noise from 90 to 115 db.

- An exposure to continuous noise greater than 115 dbA for any length of time is not allowed.
- An 8-hr (out of 24) exposure is the maximum continuous period allowed at 90 db and is decreased in proportion to db down to 15-min at 115 db.

The noise exposure levels are somewhat analogous to that of a conventional gas turbine installation although there is a variation as to the sources due to the split in operational time.

During air storage facility charging, the basic noise sources are the synchronous motor, gear box, compressor, and the aboveground air piping to the storage facility. During discharge the noise sources are the air piping from the storage facility to the burner, the hot gas generator, the turbine exhaust duct, and the synchronous generator. Ancillary equipment provisions for noise abatement are expensive and add to the installation.

6.2.2 Safety

In addition to the hazard sources normally associated with a conventional combustion turbine peaking station (i.e., electrical equipment, rotating machinery, fuel storage, high temperature components) there are the additional hazards posed by large quantities of high pressure gas with its attendant complex of interlocked control and shutoff valves and overpressure protection devices.

The combination and concentration of individual hazard sources require a systems safety analysis. Installations near load centers or in areas of high seismic damage probability, must recognize the remote possibility of a seismic induced cavern failure, surface subsidence, and subsequent fuel tank damage occurring in short time succession.

An intuitive scan of the various types of potential air storage facilities for possible fire and explosion hazards suggests some difficulties beyond the injection of lubricant by the compressor into the storage components. These potential difficulties are associated with the following kinds of storage facilities:

1. abandoned coal mines
2. depleted oil wells
3. depleted gas wells

The potential common problem of abandoned coal mines and depleted gas wells is the accumulation of significant quantities of methane. A potential hazard may occur during the compressed air charging process in which the flammability zone may be penetrated. Although ignition sources may not be present, it may be appropriate to assure minimum residence time within the flammability zone by continuous monitoring and readjustment of stored gas composition.

6.3 THERMAL ENERGY STORAGE

6.3.1 Steam

6.3.1.1 Environmental Concerns When steam storage is integrated with nuclear plants, the safety and environmental concerns associated with the possibility of the storage of water containing radioactive fission products must be addressed. In pressurized water reactors (PWR), the working steam is isolated from the primary coolant loop by the steam generator. The utilization of steam storage with PWR's is, therefore, feasible. In boiling water reactors (BWR), however, the only separation between fission products and the working steam is the fuel cladding. A flaw in this cladding could potentially release fission products to the cooling water which, in turn, could be transferred to the storage vessels. Since the storage tanks will be located outside the containment buildings, this would be an undesirable situation. It is, therefore, felt that a steam storage system integrated with a BWR would not be acceptable without an intermediate heat exchanger loop.

6.3.1.2 Safety The steam storage concept utilizes pressurized water at 300 psi. This presents no serious safety hazard since the technology for the safe handling of high-pressure steam is well developed. The utilization of the steam storage concept in conjunction with fossil fired plants, presents no special safety or environmental hazards.

6.3.2 Hot Oil

6.3.2.1 Environmental Concerns A unique environmental concern is likely to be containment in case of a pipe or tank rupture. Here again existing codes and regulations specify diking and other safety measures which provide containment and designs to minimize the potential for environmental impact outside of the station proper.

6.3.2.2 Safety For thermal storage in organic fluids or oils the major problem is the potential fire hazard associated with large storage tanks. Properly designed storage tanks normally do not present serious fire hazards and current codes and regulations insure safe operation.

6.3.3 Molten Salt

6.3.3.1 Environmental Concerns and Safety A slight vapor pressure will exist above the melt in molten salt storage systems. Due to this vapor, it may be necessary for the melt to be sealed during operation, which will present difficulties when maintenance is necessary. Other safety and environmental concerns include reliable containment of the high temperature material and the prevention and/or control of working fluid leaks into the molten salts. It appears that these concerns can be met with available technology.

6.4 ELECTROCHEMICAL (BATTERY) ENERGY STORAGE

With the exception of potential fire hazards, there appear to be no major safety hazards associated with any of the battery systems. Safety features and detection devices will be built into each battery system. With the exception of a little waste heat, electrochemical energy storage systems do not pollute. Noise will be negligible and result from the power can be located in small buildings or vandal-proof, weather-resistant enclosures. Visual pollution (aesthetics) is also thought to be negligible.

Problems, if they were to arise in a battery system, would be related to cell failure and penetration. These problems, the release of corrosive products, excess heat and toxic vapors, would be unlikely in view of the safety-related instrumentation being proposed for initial battery systems. In order to reduce the chances of serious fires if cell failure occurs, an inert gas blanket may surround the cells. Lithium and sodium vapors, i.e., chlorine or hydrogen gas, are prevented from entering the work area around the battery system by being vented directly to the outside environment. A separate ventilation system, incorporating filters, is envisaged.

The outside surfaces of the battery modules will be maintained at a low temperature to prevent burns to plant personnel. Batteries operating at elevated temperatures, will require thermal insulation. These battery modules will be fitted with safety interlocks, to prevent access while the electrodes or electrolytes are molten.

With battery systems incorporating circulating electrolytes, the circulatory system and the holding tanks must be designed to minimize or prevent the electrolytes, which may contain strong mineral acids, from escaping and affecting either personnel or equipment.

Some safety and environmental aspects for individual battery systems are given below.

6.4.1 Lead Dioxide - Lead Batteries

6.4.1.1 Environmental Concerns Low-temperature operation will diminish the requirements for thermal insulation. Battery cases made of high impact plastic materials and fixtures are earthquake resistant; therefore, the chances of acid spillage or leakage are small. Gelled electrolytes and sealed cell construction could reduce the chances of leakage and with suitable charge control, acid mist (due to carryover from the gas(es) being evolved) can be eliminated. There are many difficulties encountered with these options to reduce gassing and their implementation is not possible for first generation technology. Although lead dust is a toxic material, it is not present in an operating battery installation. Battery manufacturers are conversant with precautions against lead poisoning in cell and battery manufacture.

6.4.1.2 Safety Safety is not anticipated to be a problem with lead acid storage batteries, since small storage systems using conventional stationary batteries for standby power and submarine applications have been in existence for many years with a good safety record. Voltage control on charging, and the prevention of cell reversal prevents excessive gas generation (hydrogen and oxygen); therefore, the chances of a combustible or explosive mixture being formed is remote. This is especially true for sealed batteries where the active materials and materials of construction are carefully selected to reduce gas evolution during overcharging, or through parasitic reactions such as grid corrosion. These materials can also mean short life (e.g., Pb-Ca grids).

6.4.2 Zinc-Chlorine Hydrate Batteries

6.4.2.1 Environmental Concerns Environmental concerns for lead dioxide-lead battery energy storage installations are also applicable to zinc-chlorine hydrate systems. There will be a slightly higher level of noise produced from the pumps required for the heat exchanger and electrolyte circulation. The heat exchanger will also discharge some low grade heat; however, little heat is expected to be rejected from the cell during operation. In fact, refrigeration is not needed during standby or during discharge. During discharge, the resistive heat generated is compensated to some extent by the endothermic nature of the chlorine hydrate decomposition reaction.

6.4.2.2 Safety When zinc-chlorine hydrate batteries are in the fully discharged state, no free chlorine is present. In the fully charged state, the chlorine is present in combined form as chlorine hydrate, a relatively innocuous material. It is only during the charging and discharging processes that some free chlorine may exist at the electrode surfaces or in solution in the electrolyte. A safety hazard could exist if this relatively small amount of chlorine were to leak from the battery. Dangerous illnesses can occur if one is exposed to 40 to 60 parts per million by volume for one-half hour. Fortunately the odor of chlorine is strong enough that it can be identified before toxic levels are encountered. It is also a gas which may be detected by suitable sensors in an unattended location. If an accident were to occur, and the chlorine hydrate store were to warm up (e.g., a heat exchanger malfunction), the decomposition of the hydrate is slow enough that any escaping chlorine gas can easily be dissipated in a well ventilated area. Toxic accumulations are only a remote possibility. There are no flammable materials in the battery which, operates at atmospheric pressure and near ambient temperatures.

6.4.3 Sodium-Sulfur Batteries

6.4.3.1 Environmental Concerns and Safety Potential safety hazards exist for sodium-sulfur batteries. Sodium is highly reactive with oxygen and water vapor, and hydrogen is released from the latter. Sulfur also readily reacts with oxygen giving SO_2 which, in the presence of water, results in an acidic product. Sulfur attacks some ferrous materials, in particular iron, at temperatures in excess of 450°C. Both anode and cathode reactants are in the liquid state when a cell is in operation. A general safety philosophy is thus to enforce operating procedures and install interlocks which will not permit personnel to have access to cells while one or both reactants are liquid. The cells should be surrounded by an inert gas, at least while one of the reactants is liquid. The battery modules should be designed such that failure of a single cell is not catastrophic to the remaining cells in a submodule. Also the module enclosure should be designed so that in the event of a cell or submodule failure no reactants escape, and the module is cooled as rapidly as possible to solidify the reactants.

In the event of loss of coolant circulation, the rate of cell temperature rise will be approximately 0.5°C per minute. This rate is slow enough to be detected by the safety instrumentation, permit shutdown and to allow the installation to cool down. The gas circulation system through the modules should be kept separate from the conventional room ventilation system. Any SO_2 resulting from small cell leaks or any particulate matter or other gases resulting from catastrophic cell failure will not affect the working area. For systems where the batteries are essentially exposed to the environment, emissions will only occur in the event of a catastrophic failure.

6.4.4 Sodium-Metal Chloride Batteries

6.4.4.1 Environmental Concerns Sodium-sulfur environmental concerns will be similar to those for the systems already described. The cell temperature under normal operating conditions will be about 200°C. Insulation surrounding the battery will prevent the exterior battery housing temperature from reaching this high.

6.4.4.2 Safety As with the zinc-chlorine hydrate battery, there is a remote possibility of some chlorine discharge from sodium-metal chloride batteries. If the cutoff voltage control on charging were to malfunction, it could result in an overcharge causing the cell potential to increase to that of chlorine evolution. If not released, chlorine gas could pressurize the cells to the point of rupture. This is not likely to occur since the cells are designed with about a 20 percent excess coulombic capacity on charge. Apart from safety reasons, overcharging is to be avoided because efficiency would be lowered and current collector materials may degrade.

If for some reason the cells cool down, and have to be reheated, there are no adverse effects on performance or safety. The modules will be shipped in the discharged state, sealed, and pressurized with an inert gas to minimize safety hazards associated with handling.

During operation, an inert gas atmosphere is maintained outside the modules and normal precautions are taken for the operation of high power electrical systems. This prevents the release of acidic products, excess heat and toxic vapors by preventing catastrophic cell failure. Module cases will be electrically grounded. A protective fire wall will be provided around the battery compartment housing, and voltage, current, pressure and chlorine sensors will be incorporated to indicate off-design performance.

6.4.5 Lithium-Metal Sulfide Batteries

6.4.5.1 Environmental Concerns and Safety Safety requirements for lithium-metal sulfide batteries are similar to those for sodium-sulfur battery systems. However, the potential of catastrophic failure appears to be significantly smaller than that for the sodium battery systems. With the lithium metal sulfide battery both of the electrodes are solids and less reactive with air. The compartments containing each module should include sensors for lithium vapors and provide for an inert gas blanket.

6.5 CHEMICAL ENERGY STORAGE

6.5.1 Environmental Concerns

In general, there will be little adverse effect on the environment if chemical energy storage systems are installed. Although the safety record to date is good for the bulk handling of hydrogen, oxygen, and hydrogen-rich gases, safety in the operation of these systems is yet to be demonstrated.

Little environmental impact is anticipated from the installation of an electrolysis subsystem. There will be a small amount of noise generated by the power conditioning and ancillary equipment, such as pumps. Some low grade heat will be dispersed by natural convection from the electrolyte heat exchangers.

Hydrogen gas has been stored in special vessels or pipes at high pressures up to 170 kg/cm² (2400 psia). Although compression is required to accomplish this form of storage, the method offers the advantage of storing the gas close to a load center, hence reducing transmission costs if the hydrogen source is also close by. The gas can also be dispatched from storage at any desired pressure below the storage pressure, eliminating the need for a "send-out" compressor. High pressure storage subsystems if underground, do not pose any visual problem, however, regulations concerning the construction and siting of pressure vessels exist, and may preclude siting such subsystems near load centers.

The environmental influences of a hydride storage subsystem will be similar to those for a water electrolysis subsystem. If done conventionally, there will be little or no emissions except from the compression equipment, if. Electrochemical compression reduces such emissions. Water circulation will suffice to remove heat during hydriding. There is an opportunity of constructing a closed coolant system because the waste heat rejected by hydriding could be utilized during the endothermic dehydriding reaction. If the combustion subsystem is a combined cycle plant, emission, primarily consisting of NOx, to the atmosphere will occur. primarily consisting of NOx. Noise will also result from the gas turbine portion of the system but will be silenced by the use of a fired or unfired heat recovery boiler.

6.5.2 Safety

Since hydrogen is non-toxic, the primary safety hazards are fire and explosion. Hydrogen handling techniques and safety practices are well established, and the safety record with water electrolyzers is good. Electrolyzers are characterized by low temperature operation (100°C) but can operate at pressures up to 32 atmospheres. Care will have to be exercised with the compressed gas subsystem which may operate at pressures in excess of 1000 psig, but safety is not a problem and most commercial units operate unattended.

Removal of impurities in the product gases is important from both a safety (e.g., hydrogen in oxygen and oxygen in hydrogen) and a performance viewpoint. Some subsystem equipment, such as electrolyzers and fuel cells, exhibit decreased performance as a result of inhibition of the desired reaction by impurities (e.g., chlorides) which aggravate or instigate corrosion problems.

Hydride storage systems may be inherently safer than compressed gas systems because hydrogen is present in combined form; with only a small proportion of the hydrogen in the form of a relatively low pressure gas (1 to 10 atmospheres) at any given time. The dehydriding reaction is endothermic, hence large storage tanks, if ruptured, can be self-quenching, especially if the heat source is disconnected and the hydride bed is divided into compartments internally.

Hydrogen is a very mobile gas, and care is needed to prevent leakage. However, the high mobility (buoyancy) favors rapid dispersal of the gas in a well ventilated system, and concentrations leading to an explosive mixture are unlikely to build up. Tests in which the iron-titanium hydride material was ejected into air and/or water, with and without the presence of an ignition source, indicate that no acute or unusual safety hazards exist.

Some of the various chemical schemes for hydrogen production produce reactants which are toxic. For example, consider a thermochemical method involving an iron chloride cycle, and designed to produce 144,000 metric tons/year (160,000 tons/year) of hydrogen. Even if the yield was 99.9 percent, about 63,000 metric tons/year (70,000 tons/year) of chlorine plus hydrochloric acid would be lost to the environment. Trying to prevent this loss would probably be more expensive than producing the reagents for the production schemes.

6.6 FLYWHEEL ENERGY STORAGE

6.6.1 Environmental Concerns

Noise, effluents, and land requirements are the only items of major environmental concern. The noise from this system will be equivalent to that of ten large motors, however, sound deadening baffles can be placed in exhaust hoods to meet the necessary sound ordinances. No effluents of any kind are anticipated during normal operation, and only CO_2 during emergency conditions. Land area requirements may be minimized by locating the facility along transmission line right of ways.

6.6.2 Safety

In the event of system failure the main safety concern is the damage or injury caused by wheel disintegration or escape. Safety requirements for the system would be designed into the wheel construction and its containment.

The most critical flywheel failure is when the shaft shears and the wheel, with all of its stored energy, tries to leave its vault. The vault lid must have enough mass to take a direct wheel hit (after shaft shearing) and prevent the wheel from escaping. After the initial blow to the lid, the flywheel will bounce around inside the vault dissipating its energy but probably hitting the lid numerous times. The lid could be designed as a concrete box filled with water with a screen like network of reinforcing bars in the concrete. The initial strike against the lid will crack the concrete and release the pool of water which will act as a damping agent, a thermal stabilizer and fire retardant. Lubricant or epoxy matrix fires can occur by the sudden release of the wheel's energy. However, these fires will be extinguished by the pool of water and a CO_2 system. Since the flywheels are inside separate vacuum enclosures the pool of water will only affect the flywheel it is above; therefore, two different systems will be required. One, floods the entire vault in case of a major catastrophe, the other, connected individually to the vacuum enclosures would, when activated by flywheel disintegration, prevent epoxy matrix fires and help drain the energy from the wheel through additional viscous drag.

A summary of major catastrophic failure modes is listed in Table 6-2.

6.7 SUPERCONDUCTING MAGNETIC ENERGY STORAGE

6.7.1 Environmental Concerns

A superconducting magnetic energy storage (SMES) station consists of both aboveground and sub-surface installations.

The ventilation equipment, power conversion devices, refrigeration system, and cryogen and gas storage vessels are located at surface level. Also at or near ground level is a guard or shielded magnetic ring. Depending upon the depth at which the storage magnet is buried, and the design of the shield magnet, an enclosed area may be required above the centerline of the solenoid.

Due to the tremendous weight of the magnet, sites must be of suitable bedrock composition. Suitable bedrock are granites, dolomites, sandstones, limestones, etc., which have compressive strengths of 30,000 psi or greater, and tensile strengths of about 1,000 psi.

The major environmental impacts would be on land requirements for example, exclusion area requirements due to the magnetic field and the aboveground placement of cryogen storage tanks. Cooling tower or once through cooling system operation for heat dissipation and evaporation of water must also be considered for environmental impacts on land requirements.

Table 6-2 SUMMARY OF MAJOR CATASTROPHIC FLYWHEEL FAILURE MODES

Potential Catastrophic Failure Mode	Primary Effects	Secondary Effects	Potential Safeguards
Wheel Disintegration	Sudden Release of Stored Energy Transferred to Container, Building, etc.	Destruction of Vacuum Container-Implosion	Tamped Earth Bunkers with lids of concrete and clay or Water Tanks
		Heavy Building Damage Hazard Potential Over a Considerable Radius	A brush-type Wheel Minimizes this Hazard; Development of Composite Wheels
		Domino Effect on Other Wheels in Array	Domino Effect Minimized by breakaway Couplings and Common Vacuum System; Windage Automatically Stops Array in Event of Vacuum Failure
Bearing Failure	Conversion of Kinetic Energy into Heat at Bearings over a Period of Minutes to Hours. Total Destruction of Bearings	Extreme Heat; fire Hazard	Fire Hazard Minimized by CO_2 Flood Provisions of H_2O Deluge from Water tank lid
		Damage to Trunnions	
		Shaft Breakage	Temperature Rise Monitors and Shutoff Provisions; Backfill of Vacuum Enclosure with CO_2 would be a Good Brake
Implosion or Fast Vacuum Leak	Collapse of Vacuum Enclosure. Relatively Rapid Pressure Rise.	Damage to Wheel from Enclosure	Wheels will Stop Quickly due to Pressure Loss
		Damage to System by Shock Wave	Best Prevented by Periodic Inspection

6.7.2 Safety

Safe limits of magnetic field exposure to humans and animals have not yet been established. It may turn out that the limit will be imposed by non-physiological constraints such as freedom to carry watches and ferromagnetic objects of various kinds. Strong magnetic fields may not be appreciably reduced by burying the installation. Biological effects are unknown at this time.

Catastrophic loss of superfluid helium must be a consideration for the later stages of development of a SMES system. Helium is a non-toxic gas.

Currents in excess of 100,000 amps, and energy stored in the magnetic field equivalent to approximately 10,000 tons of TNT for a 10,000 MWh system mandate a high order of reliability for all components of the system to meet stringent safety requirements.

6.8 COMPARISON OF ENERGY STORAGE SYSTEMS

The preceding sections provide qualitative discussion of many factors which are unique to the selected storage systems. To provide a qualitative comparison of the selected storage systems, Figure 6-1 and 6-2 were prepared. Table 6-3 identifies the principal impact areas and Figures 6-1 and 6-2 use a severity index to indicate some variations in potential impact. Only a detailed, site specific, analysis can produce a true comparison. The effective ranking in Figures 6-1 and 6-2 should be used for general guidance only.

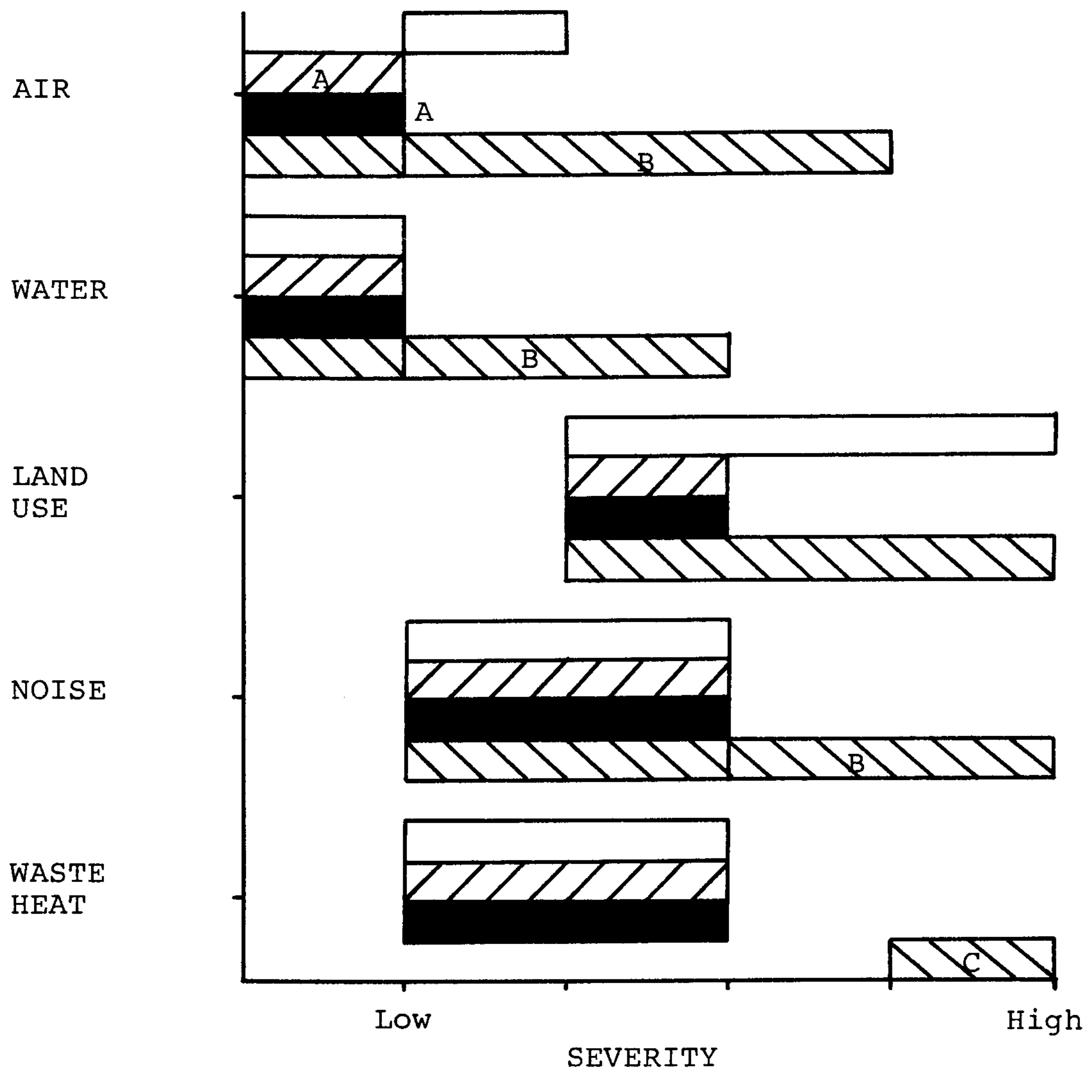
All of the storage systems considered should be able to meet current and planned environmental regulations through appropriate design effort. At this stage of development it is difficult to distinguish between the considered systems, however, some real differences do exist. For the most part the quantitative differences can be identified as total thermal enrichment resulting from use of the storage systems and land area requirements.

Prior to commercial installations, full environmental impact statements will be required. At this time, most of the distinctions which can be drawn are subjective.

Table 6-3 MAJOR FACTS TO BE CONSIDERED IN ENVIRONMENT ASSESSMENT

	Air	Water	Land Use	Noise	Biological	Occupation, Safety and Health (6)
Hydro Pumped Storage	Water Vapor	Heat	Water Reservoirs	Pumps and Turbines	Entrainments and Impingement on Fish and Fish Larvae	Protection against flooding of Powerhouse and Against Dam or Waterway Failure
Compressed Air Storage with Combustion	Heat, NO_x, CO, CO_2 Hydrocarbons	- (4)	Combustion Turbine Water Reservoirs Compensated Storage	Compressors and Combustion Turbines	- (4)	Protection Against Oil Fires (5)
Thermal Storage	Heat	Heat	Tank Farm Power Plant Cooling Towers	Steam Turbines	- (4)	Protection Against Oil Fires (5)
Lead Acid	Heat, H_2, SO_2, Acid Mist	- (4)	Low Profile Structure	Fans, Pumps, Power Conditioning	- (4)	Personal Protection Against Acid Required. Fire and Explosion Hazards
Advanced Batteries (2)	Heat (1)	- (4)	Low Profile Outside Equipment	" "	- (4)	Various Types of Fire Hazards
Flywheels	Heat	- (4)	Subsurface	Motors and Generators Power Conditioning	- (4)	Containment of Flywheel or Fragments if Catastrophic Failures
Hydrogen	Heat, O_2	- (3) Heat	Low Profile Structures Outside Equipment and Tank Farm	Fans, Pumps, Power Conditioning Equipment	- (4)	Protection Against Fires and Explosion Hazard Required
SMES	Heat, HO_2	Heat	Low Profile Equipment Tank Farm Exclusion Arc	Refrigeration System Power Conditioning Equipment	Effects of Magnetic Fields	Protection Against Magnetic Field Required (7)

1. All Systems Should Be Designed to Meet Environmental Regulations.
2. Sealed System. No Air Emissions Anticipated.
3. If Combined Cycle Plant is Used.
4. No Special Non-Negligible Effects Identified.
5. If a Combustible Oil Used.
6. Only Unusual or Non-Standard Items Identified.
7. Exclusion Area May be Requested to Unknown Magnetic Field Effects.



Lead Acid Batteries
Advanced Batteries
Flywheel
Hydrogen

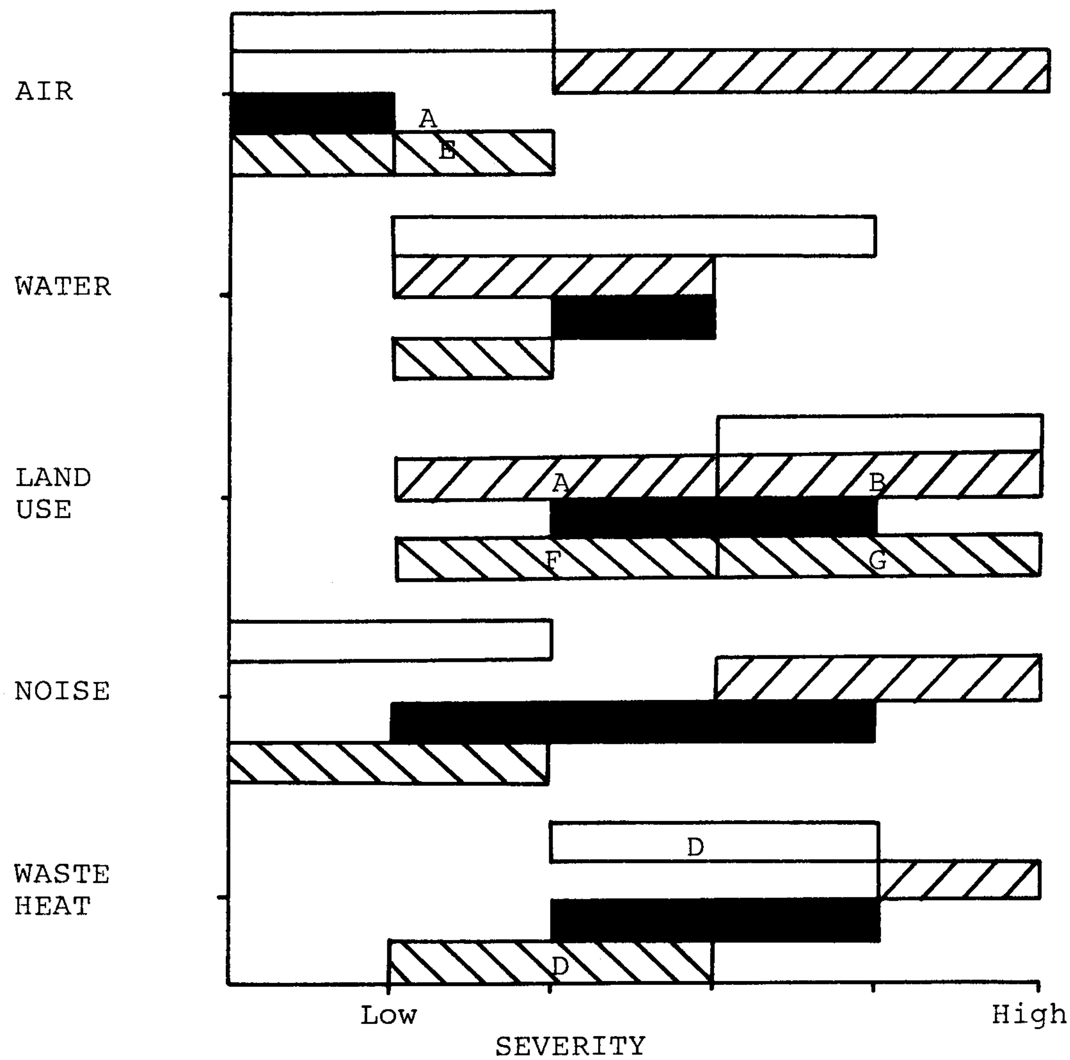
Notes

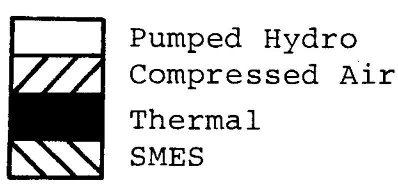
A. Sealed System Does Not Include Heat Rejected To Air

B. If Combined Cycle Plant Used for Hydrogen Combustion

C. Low Thermal Efficiency

Figure 6-1 COMPARISON OF DISPERSED STORAGE SYSTEMS BY PRINCIPAL IMPACT AREAS





Notes

D. Primary Cooling With Water

E. If Helium Released to Atmosphere

F. Does Not Include Underground Space

G. Exclusion Area Required to Magnetic Field Effects

Figure 6-2 COMPARISON OF CENTRAL STATION STORAGE SYSTEMS BY PRINCIPAL IMPACT AREAS

7. RESEARCH AND DEVELOPMENT

This section reviews and summarizes key areas for future research and development, engineering, and demonstration for energy storage systems suitable for use by electric utilities.

Sources of research, development, engineering, and demonstration funds in the United States include manufacturers, electric utilities, the Electric Power Research Institute (EPRI), and various government agencies such as the Energy Research and Development Administration (ERDA). To achieve commercialization of energy storage technologies, substantial investment by manufacturers will be required. Participation by these other sources will be necessary and appropriate through the varying development stages depending on the status of the technology and the risk in advancing a commercially successful technology.

Fully mature technologies benefit from improved performance, reduced manufacturing and construction costs, and changes which expand the market or increase site availability. Developments of this type will frequently be undertaken by manufacturers to ensure a competitive advantage. More generic research and development, aimed at longer range or higher risk goals will not necessarily be pursued by either the manufacturer or individual utilities on their own initiative because of the large amount of money involved, the lengthy period before a return on investment is obtained, and the substantial risk incurred.

Among the various energy storage technologies under serious consideration, only conventional hydro pumped storage is a commercial reality. Currently, demonstration, or first of a kind plants, are planned for compressed air storage with combustion turbines, underground reservoir hydro pumped storage and advanced batteries (Table 7-1). Virtually all of the other technologies considered are under investigation or being developed by at least one organization (government, private industry, or electric utility).

Demonstration of several different attractive technologies is possible. Identified in Table 7-2 are those technologies which could be successfully demonstrated in the near-term (before 1985). For these technologies and the others identified in earlier chapters of this report, barriers to commercial development remain (Table 7-3). For technologies which are essentially state-of-the-art, the major barrier is lack of existing plants.
For systems where substantial research is required, the major barrier is simply lack of a commercial product. Examined in detail, key areas for research and development can be identified

Table 7-1 CURRENT PLANNED DEMONSTRATION OR FIRST-OF-A-KIND PLANT

Type of Plant	Construction Started	Expected Service Date
Conventional Hydro Pumped Storage	In Use Today	In Use Today
Compressed Air Storage Nordwest Deutsche Draftwerke Huntorf, West Germany 290 MW, 580 MWh	1975	1977
Battery Energy Storage Test* Facility 1-3 MW 10-30 MWh USA	1977	1979
Underground Reservoir Hydro Pumped Storage Jersey Central Power and Light New Jersey, USA	1982**	1992**

*The BEST facility will be used for testing prototype modules of batteries under advanced D&E for utility energy storage.

**"These dates are determined by the system need for the Mt. Hope capacity as evidenced by the statement in Exh. 0 of Jersey Central's application for an FPC License -

'The current forecast of Applicant's load and capacity is such that the Mt. Hope Project should be operational in 1992. Because Project construction is estimated to require eight to ten years, construction should begin in 1982.'"

Table 7-2 ATTRACTIVE TECHNOLOGIES WHERE NEAR-TERM DEMONSTRATIONS ARE POSSIBLE

- Underground Reservoir Hydro Pumped Storage
- Compressed Air Storage with Combustion Turbines
    - Salt Caverns
    - Aquifers
    - Hard Rock Caverns
- Thermal Storage
    - Saturated Water (Steam)
    - Oil
- Battery Storage Systems
    - Prototype Modules of Advanced Batteries and State-of-Art Lead-Acid Battery Energy Storage Test Facility
- Hydrogen Storage

Table 7-3 MAJOR BARRIERS TO COMMERCIAL SUCCESS

Conventional Hydro Pumped Storage	Commercial Now, Delays in Licensing
Underground Reservoir Hydro Pumped Storage	Lack of First Plant, Construction Lead Time, Construction Cost Uncertainty, Site Availability Delay in Regulatory Approval
Compressed Air Storage with Combustion Turbine	Lack of First Plant, Uncertain availability of Oil, Construction Cost Uncertainty, Site Availability Possible Need for Regulatory Approval
Thermal Storage in Water and Oil	Lack of First Modern Plant, Regulatory Hurdles, Containment Costs
Lead-Acid Batteries	Cost, Lack of First Modern Plant, Life
Advanced Batteries	Lack of Commercial Product; Life and Cost Uncertainty
Flywheels	Lack of Commercial Product, Cost
Hydrogen	Lack of Commercial Product, Cost, Efficiency
Superconducting Magnetic Energy Storage	Lack of Commercial Product; Cost Uncertainty; Site Availability; Uncertain environmental site requirements

for each technology. An exhaustive listing of specific research and development requirements would fill a book. Table 7-4 identifies key problem areas for each storage system.

A brief discussion of each approach to energy storage permits some identification of problem areas. This is not an exhaustive listing of research opportunities, but rather, an indication of where advances could result, making the technology more attractive for utility application.

7.1 HYDRO PUMPED STORAGE

Conventional hydro pumped storage is in commercial use today. Underground hydro pumped storage plants are being planned and designed for service in the late 1980's and early 1990's. There are, however, important opportunities for research and development related to hydro pumped storage. Some of the appropriate areas of investigation will have wider areas of application than just pumped storage.

Research and development opportunities are divided into equipment improvements, reduction of environmental impact, cost reduction, and increase of site availability.

Specific work toward improvements in plant equipment would be beneficial. Particular objectives include:

1. Extension of head range for single-lift, reversible pump-turbine units.

2. Development of multistage reversible pump turbines for high head applications (including underground).

3. Development of larger unit sizes (investigation of metal fatigue and structural integrity in water could lead to removal or mitigation of structural and mechanical limitations on unit size).

Specific work on cost reductions would focus on the many related factors of equipment costs, reservoir costs, and consttuction time. Among the many areas for cost improvement are the following:

1. Reduction of tunnel and other underground excavation costs.

2. Optimization of construction procedure.

Table 7-4 KEY AREAS FOR RESEARCH AND DEVELOPMENT

Technology	Major R&D Opportunities
Hydro Pumped Storage	Increased Head and Size of Reversible Pump Turbines (There is No Need for Such Work on Separate Pumps and Turbines). Site Availability as Affected by Environmental Considerations (as Contrasted to Topographic or Geological Factors).
Compressed Air with Combustion Turbines	Compressor Throughput Rates. Compressor Costs. Thermal-Physical Properties of Caverns. Cavern Construction Costs. Air Heating Schemes. Improved Heat Rate. Higher Pressure Turbomachinery.
Thermal Storage	First of Kind Turbine Development. Controls. Pressure Vessel Cost. Oil to Water Heat Exchanger Design and Reliability. Long Term Oil Stability. Licensing Requirements.
Lead Acid Batteries	Life. Cost.
Advanced Batteries	Basic Cell and Battery Design. Life. Materials Stability. Low Cost Fabrication and Manufacturing Techniques. Energy Density.
Hydrogen	Low Cost, High Current Density Electrolyzer. Improved Efficiency for Combined Cycle Plant or Fuel Cell. System Design. Storage System Selection and Cost Effective Design and Fabrication.
Flywheels	Wheel Design. Fabrication Techniques and Cost. Cost Effective Vacuum Housing and Support Structure Development. Material Costs. Energy Density (Working Stress Level).
Superconducting Magnetic Inductors	Conductor Fabrication. Higher Temperature Superconductors. Dewar and Support Structure Fabrication. Cost. Conductor Conceptual Development.

3. Reduction in overall construction lead time and licensing delays.

Reduction of adverse environmental impact would improve availability of sites for hydro pumped storage. Specific work in this area would include:

1. Development of fish repulsion devices and modifications of water intake designs to keep fish away from water turbines.

2. Further investigations of effect on fish life cycles of fluctuating water levels, effluent discharge/dispersion patterns, and inadvertent passage of fish through plant.

Lack of general public acceptance has greatly restricted hydro pumped storage and investigations into the cause of adverse public reaction could led to identification of selection criteria which would identify an unacceptable site early in the planning stage. A major study or inventory of sites could identify possible attractive sties and, together with site selection criteria, could aid in determining acceptable sites. Investigations to permit early identification of suitable sites and to attain favorable public reaction could reduce the objections sometimes encountered in siting of hydro pumped storage, when the planning is not shared with the public sector.

For underground reservoirs and powerhouse construction, studies of rock mechanics and of locked-in stresses, as they affect limiting depths and location of suitable sites, are appropriate. Further studies of risks inherent in underground construction and how they should be factored into the costs of the plant would be beneficial.

7.2 COMPRESSED AIR STORAGE

Compressed air storage with combustion turbines has received the majority of attention in investigations of air storage systems. Much fundatmental development work could be directed at examination of possible thermodynamic cycles and older approaches to using compressed air storage concepts. A major area deserving further investigation is the search for approaches which remove or minimize the need for the combustion of fuel for oil heating. Efforts to develop combustionless air storage systems are quite appropriate for intermediate-term applications.

The first commercial installation in Huntorf, Federal Republic of Germany is scheduled for a 1977 service date. This system will use a solution minded salt cavern for the air storage. Major areas of research and development opportunity include compressor design studies, "hot" compressor development, new turbine designs which permit high pressure arrangements, high pressure heat exchangers, improved heat rates for combustion turbines, consideration of combined cycle operation, and underground reservoir thermo-physical properties.

Reservoir studies should cover salt beds, aquifers, and hard rock caverns. Major interest lies in the thermal properties of storage reservoirs, rates of air withdrawal, and contamination of air containment with its resulting turbine corrosion. Valving and clutch design also merit attention.

Specific research on the air heating subsystem should include:

1. Procedures for reducing air emissions from combustion turbine and combined cycle operations.

2. Higher efficiency turbine development and the application of combined cycle plants

3. Coal combustion techniques

4. Synthetic fuels such as hydrogen or methanol

5. Integration with coal gasification or liquefication plant.
6. Thermal storage systems

Specific research in compressor technology will seek to increase compressor unit sizes (single shaft). High temperature compressor operation, in conjunction with a thermal energy storage system, could eliminate the need for combustion turbines and simple air turbines could be used.

Site-related suties are important. Specific work could be done on:

1. Costs of underground construction

2. Salt cavity stability under thermal and pressure cycling

3. Rock cavity or cavern stability

4. Aquifer stability, movement of air pockets in porous structures

5. Charge/discharge rate characteristics of porous media and aquifer storage

6. Air storage modeling studies which simulate operation, thermal and pressure cycling, and which examine transient and stability phenomena. Analytical, computer modeling, and experimental verification are included.

Heat storage or new air turbine configurations deserve special consideration as second generation devices. Heat storage can be on the air storage side of the compressor where a pebble bed heat exchanger might be the logical avenue of investigation. Heat could also be extracted from the compressor and stored in the sensible heat of oil or water. Recovery of heat is difficult if transfer must be to air. Large heat exchanger surface areas are usually required. Use of two or more stages of air compression and heat storage could permit thermal storage at moderate temperatures using conventional compressors. This would avoid existing limitations on compressor pressure ratios and operating temperatures.

7.3 THERMAL

Research and development efforts on thermal energy storage systems fall into two very distinct time frames for utility application. The near-term effort is primarily a development or first of a kind engineering effort with some critical experimental verification required. Intermediate-term systems which would combine storage with phase change material (molten salts) would require substantial research efforts before commercialization would be feasible.

Major emphasis should be placed on the near-term systems, with first consideration given to heat storage in water and oil as part of nuclear power plants. Detailed design studies are appropriate and the need may exist for support of demonstration or first of a kind plants. Specific design studies would also answer the question of system reliability which cannot now be addressed.

7.3.1 Saturated Water (Steam)

Research and development efforts should focus on the choice of turbine configurations, nuclear safety, equipment reliability, and identification of potential operating problems. Low cost design concepts for field fabricated pressure vessels capable of withstanding both pressure and temperature cycling could reduce overall costs.

Further design and cost studies of special approaches to pressure vessel design and construction is necessary. The straightforward approach of using stainless steel vessels is conservative and ensures long life. Other materials may prove suitable; carbon steel is one possible approach. Both factory fabrication and field erection techniques, using a whole range of materials including steels, cast iron, concrete, and, perhaps, composites, deserve examination. If costs for the pressure vessels could be dramatically reduced without diminution of ability to comply with safety and licensing requirements, it would greatly improve the attractiveness of this system. Consideration of underground storage in lined rock cavities is also appropriate.

Detailed design studies are not currently available, but are an essential step. A perturbation of nuclear plant design in the complex regulatory environment must be treated with caution and would almost certainly represent a significant barrier to the introduction of thermal energy storage.

7.3.2 Oil

For storage systems using oil as the sorage medium, major effort should be placed on confirming long-term stability of the oils, their heat transfer properties, and the reliable design of water to oil heat exchangers. Careful consideration of fire hazards is necessary.

The thermal storage and turbine design problems for this concept are basically an extension of existing technology. It thus provides a feasible near-term solution to the thermal energy storage problem with cost factors which are promising. It poses leakage problems which are not a factor with saturated water thermal storage systems, but these are controllable with existing technology and within economic reach.

Construction of a prototype test facility, in conjunction with a fossil fuel power plant, is required to gain actual operating experience with an oil thermal energy storage system.

7.3.3 Other Sensible Heat Fluids

Other sensible heat storage fluids merit further consideration. Specifically, sensible heat storage in liquid sodium or NaK, in conjunction with an LMFBR, or gas reactor, may prove practical. Detailed design studies will become appropriate as liquid metal technologies come closer to commercial application.

7.3.4 Phase Change Material (Molten Salt)

The molten salt thermal energy storage concept requires an extensive research and development effort before practical systems can be designed. This effort would be concentrated on the two "pacing" areas of heat exchanger design and improved storage materials plus studies of metal compatibility with salt.

The high cost of the heat exchanger is a result of the large heat transfer area required to discharge the storage bin. A substantial incentive, therefore, exists for an improved design which would decrease this cost.

Although the eutectic metal fluorides considered appear technically attractive, high costs and limited availability will undoubtedly make them unsuitable for utility applications. The materials necessary in order to make phase change thermal storage economically feasible must be available in large quantities and at low cost in addition to possessing the desirable properties of high conductivity and high latent heat. An intensive search for such materials would be required if fused salt storage systems are to become practical.

7.4 ELECTROCHEMICAL (BATTERY)

The key requirements for each battery system is achievement of adequate life and low selling price. In any comprehensive program, cell performance and life must first be demonstrated or projected with adequate confidence. Battery design and cost studies should be contemplated when sufficient definition can be given to cell design points so that a complete storage system could be developed.

For any battery system, the basic problem areas are similar, and typically can be identified with:

1. Low ratio of practical to theoretical energy density

2. Loss of capacity under cycling

3. Corrosion of inactive components, such as current collectors and containers

4. Inadequate or too costly separator materials

5. Inadequate hermetic seals (feedthroughs)

6. Restricted availability and/or high cost of materials

Other specific problems can be identified for each electrochemical couple and for each different approach to using a particular couple in a battery.

7.4.1 Lead-Acid

Research and development in lead-acid batteries is divided into two categories: near-term and advanced. For the near-term, the R&D effort is geared toward desing and production engineering to apply state-of-the-art technology to utility energy storage. For advanced lead-acid batteries, R&D efforts must be concentrated on achievement of fundamental advances in the technology would lead to substantial improvements in energy density and life, as well as cost reduction.

Major problems include poor utilization of active materials, low energy density, shedding of active material corrosion and growth of the electrodes. and loss of capacity with cycling. Much detailed work would be required to identify failure mechanisms and remedy the life problem. Related design considerations include excessive plate temperatures during operation, electrolyte stratification, and the potential need for cooling and electrolyte circulation during normal operations.

7.4.2 Advanced Batteries

The major research programs aimed at battery development are directed at the key problem of attaining adequate life under cycling conditions, and developing inexpensive and simple fabrication procedures. Early consideration should include cost engineering studies, complete cell and module designs, and extensive cell experimental work.

A consideralbe effort in a joint ERDA, EPRI, and utility study of the feasibility of a battery energy storage test (BEST) facility has concluded that centralized testing of prototype battery cells and modules of essentially commercial scale are feasible and will permit large-scale testing of advanced batteries in the early 1980's. While not a true demonstration plant, this test facility will permit demonstration and proof-of-concept for the advanced battery systems prior to the time when full battery cell and module production facilities could be available, and at lower cost than would be required for a full scale demonstration.

7.5 CHEMICAL ENERGY STORAGE

7.5.1 Chemical Storage

Chemical energy storage systems addressed in this study were limited primarily to systems with electric input which requires use of electrochemical converters. Chemical systems which utilize thermal input have not been considered in detail. They have been considered as elements in a synthetic fuels or chemical heat pipe development program. It is possible that a suitalbe low cost, high efficiency energy storage system, which does not use electrochemical converters, may be developed. To date, systems where energy is stored in chemical forms have either been fuel storage or batteries. Hydrogen storage falls between these.

7.5.2 Hydrogen Storage

Key components of a hydrogen storage system include the electrolyzer, the storage subsystem, and the fuel cell or combined cycle plant.

The inefficiencies of the fuel cell or combined cycle plant multiply the costs of both electrolyzer and storage subsystems. Every increase in efficiency reduces total costs substantially. Little hope exists for dramatic increases in efficiency (up to 80 percent) due to basic thermodynamic and kinetic constraints.

Hydrogen can effectively be stored as a compressed gas.

Development of metal hydride storage systems hinge upon understanding mechanisms which result in loss of storage capability, selection of the optimum material, purity level specifications, and low cost fabrication techniques. Metal hydride storage may offer some system-related improvements. The area where the greatest reductions in cost can occur is the electrolyzer. Here, the more optimistic projections of what is achievable are less than a third of current losses. Substantial improvements depend upon increasing current densities and operating termperatures with non-noble metal catalysts.

7.6 Flywheels

The development of large flywheel energy storage systems requires that research and development in critical areas be carried out on a broad front with a system's perspective. The pacing subsystem for a flywheel energy storage system in the near-term is the wheel itself. As wheel sizes and speed increase, the bearing and shaft components will become the pacing problems.

Specific work would be required to:

1. Conduct techno-economic forecasts on advanced composite materials to determine realistic estimates of future fiber costs.

2. Develop multirim and constant stress conceptual designs which are cost-effective and which take into account fabrication costs, materials utilization, fracture tolerance, and the life cycle.

3. Develop a computer program for analysis and optimization of composite and metallic systems for flywheels to achieve efficient material utilization. Conduct trade-offs with fabrication costs.

4. Develop automatic monitoring methods of quality assurance and nondestructive testing of fabriaction and operation of flywheels.

5. Conduct cost-effective analysis based on life cycle of hybridized multirim constant stress flywheels.

6. Develop conceptual designs of advanced composite shafts efficiently integrated with composite flywheel designs. Develop cost-competitive fabrication methods for flywheel shafts.

Two critical subsystems requiring R&D are the spin axis bearings, and the feedthrough and/or seals. High-capacity, low drag bearings must be developed through research in the following areas:

1. Improved ball bearings

2. Hybrid-ball/magnetic bearings

3. Magnetic bearings - especially superconducting

Long-life, efficient feedthroughs must be developed. Possible approaches include: heavy-duty magnetic couplings, long-life ferrofluid seals, and advanced low-drag rubbing seals.

Although the required technology development is summarized in two categories - the wheel and the mechanical subsystems - it must be stressed that this development must be carried out with a systems perspective. The improvements should not be negated by increased balance of plant costs. These costs should not be increased by increasing the energy density of the flywheel but superconducting bearing will undoubtedly mean increased costs. Any improvement must be weighed against the cost of the refrigeration and containment system of the cryogen.

7.7 SUPERCONDUCTING MAGNETIC ENERGY STORAGE SYSTEMS

Superconducting magnets for storing energy are long-term (beyond 2000) systems which may be important for applications other than bulk energy storage. Economies of scale require that the system be extremely large, but such systems pose the most difficult engineering problems. Current research is focused on the basic phenomena and a clear picture of the concept and its costs. Much research is needed before this technology can be considered for utility application. While metallic superconductors may never achieve properties suitable for high temperature operation (100°K), development of nonmetallic high temperature superconductors is a possibility; but data to support this view is inconclusive and speculative.

7.8 POWER CONVERSION

There are three basic needs for future R&D in solid-state power conversion equipment that would provide either cost savings or increased operating capability. Such topics are:

1. Verify the assumptions used in the converter and converter transformer designs.

2. Research and develop components that are true switching devices to replace the present latching devices.

3. Develop reasonable boundaries on the output waveshape requirements of converters.

There are considerations in the design of converter equipment that are based more on what has been done and than on what can be done. Two main areas are the voltage safety factor used in the solid state devices in self-commutated converters (SCC) and naturally commutated converters (NCC). The cost of a SCC is very dependent upon the safety factor that is used. Traditionally, a 2 per unit or larger safety factor has been used. In theory, a much smaller factor could be used. However, field experience with units using lower than a 2 per unit factor has not, in general, been very good.

The magnetics in any piece of conversion equipment are built conservatively. This conservatism is based upon experience with mercury arc rectifiers and is not really appropriate with solid-state NCC or with SCC. A significant portion of the cost of either converison method is for the magnetics.

All of the existing devices that are appropriate for use at high power levels are latching one-way switches. This causes the undesirable VAR requirements of NCC's and the inefficiency of SCC's. If a tru switch that can be closed and opened by control signals were developed, the converter would be significantly improved.

The harmonic output of a converter is a parameter that is not now welldefined. Each installation is studied individually and special filters are designed for that application. Considerable engineering time would be saved if some reasonable bound could be established. Experimental work is required to define acceptable limits.

7.9 SPECIAL STUDIES

In addition to specific technology research, significant additional effort is required to further define the role of energy storage, its importance and relative ecomics for electric utility systems. Far more specific analysis is required, than is appropriate for the study reported here, to permit a decision on installation of commercial equipment. Understanding must be increased with respect to the future character of electric loads throughout the county. The many small incentives and disincentives for storage should be examined. These include tranmsission and distribution savings, changes in reliability, changes in reserve requirements, operation vs. spinning reserve capacity, regulation duty and system stability. Further economic studies will be appropriate as more definition is given to the specific technologies. Such studies will require that specific electric system expansion plans be used in the comparison. Further analysis of the potential competition for available off-peak energy such as electric heating, both water and space, time-of-day pricing, load management and electric vehicles is desirable.

In the end the impact of energy storage on electric utilities will be based on decision made in the market place between the user and the manufacturer. These decisions will be affected by economics, financial resources and fuel availability, as well as the success of the current programs to install nuclear and coal-fired baseload capacity.

APPENDIX A. LAND AREA REQUIREMENTS

This appendix provides estimates of the land area requirements for the individual storage systems. Comparisons can be drawn from the data, however care should be used in such comparisons for some systems are incomplete. The land area requirements for energy storage systems vary widely and range from a completely designed battery energy storage system to the partially known requirements for superconductive magnetic energy storage. Often the land requirements for storage alone overshadow the land required for the associated additional power conditioning equipment. The area requirements per unit of storage capacity for each system is presented for comparison purposes.

A.1 HYDRO PUMPED

There are two types of hydro pumped storage systems, conventional and underground. Conventional systems have two surface reservoirs and require at least twice the land surface area as underground systems at the same head. The concept of underground systems envisions one surface and one subsurface reservoir.

A.1.1 Conventional

For a conventional hydro pumped storage system of 1000 MW and 10,000 MWh, the head might vary between 300 and 10000 feet. As shown in Figure A-1, the area required per reservoir varies as the head varies. The following table indicates the land area requirements for different depth reservoirs. Figure A-1 assumes a vertical sided reservoir, turbine efficiencies of 89 percent, and a 20 percent land surplus. The total area required for a complete pumped hydro facility could be as much as three to five times larger than that required for d just the reservoir.

Reservoir Depth (feet)	Land Area Requirements (Acres) @ 300 foot head	@ 1000 foot head
100	400	130
50	800	290
25	1600	540

A.1.2 Underground

For an underground energy storage system of 1000 MW and 10,000 MWh capacity, the head might vary between 2500 and 4000 feet. For these heads, from the curves of Figure A-1, the land area requirements vary as follows:

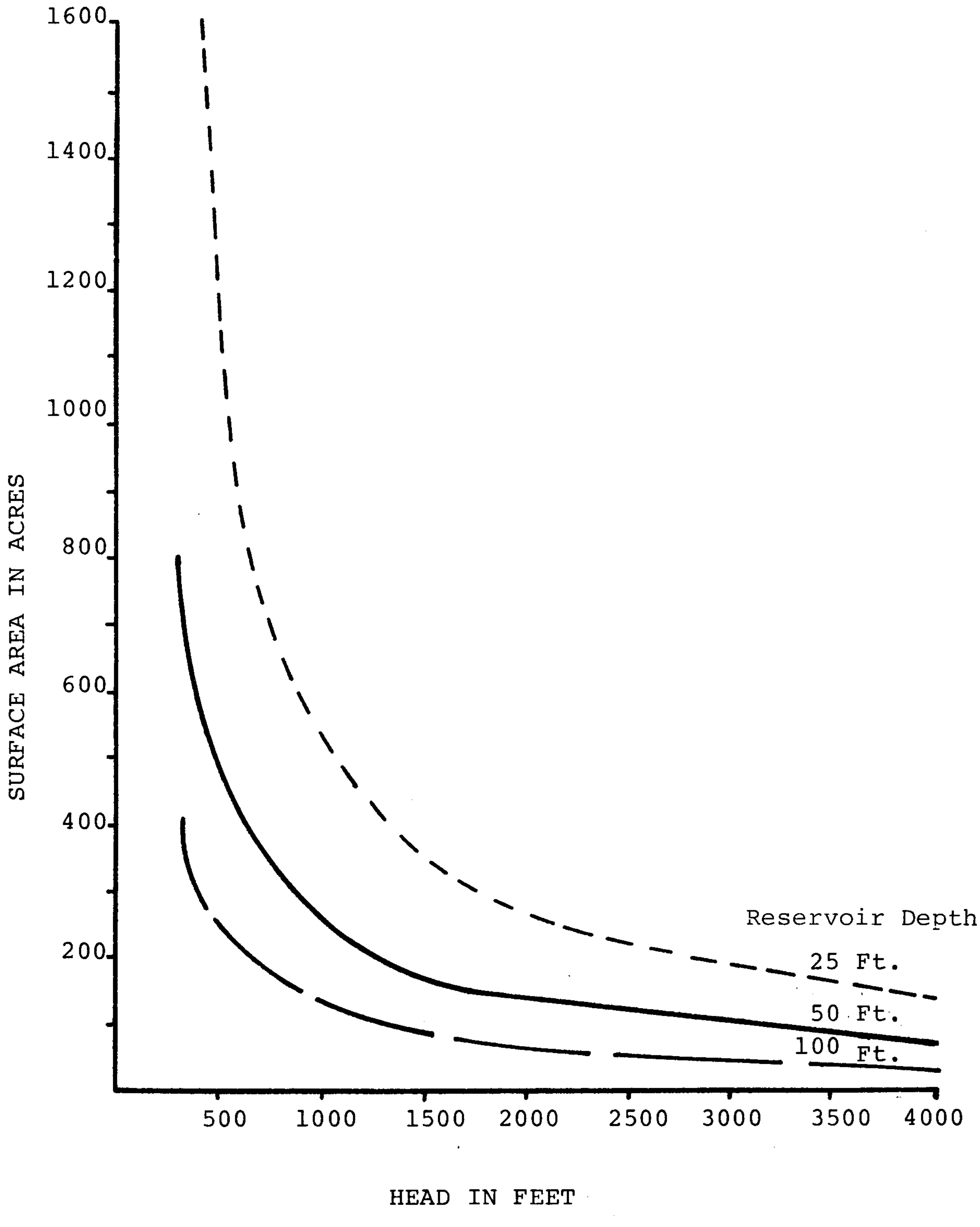


Figure A-1 HYDRO PUMPED STORAGE SURFACE AREA VS. HEAD

Reservoir Depth (feet)	Land Area Requirements (Acres) @ 2500 foot head	@ 4000 foot head
100	50	40
50	110	90
25	210	160

A.2 COMPRESSED AIR

The compressed air energy storage system is basically underground. The only surface land area requirements are for the gas turbines and the reservoir for hydrostatic pressure compensation of the air storage, if one is used. A 1000 MW system would require ten 100 MW turbines with a 30-day fuel supply with dikes for possible leakage containment. The land area requirements for such a system would be between eight and ten acres.

The land area requirements for an upper reservoir used with a hydrostatic pressure compensated 10,000 MWh air storage system as shown in Figure A-2 are as follows:

Storage Pressure (atm)	Reservoir Depth (feet)	Surface Area (Acres)
20	75	22
	50	34
	25	68
50	75	9
	50	14
	25	28
100	75	5
	50	7
	25	14

Therefore, the total land area requirements vary from 5 to 68 acres for the hydrostatic pressure compensated storage system plus the gas turbines land area requirement.

A.3 THERMAL

The land area requirements were considered for three thermal energy storage systems, steam, oil and molten salt. The land area for the associated electrical equipment is insignificant compared to the land required for the storage of the energy.

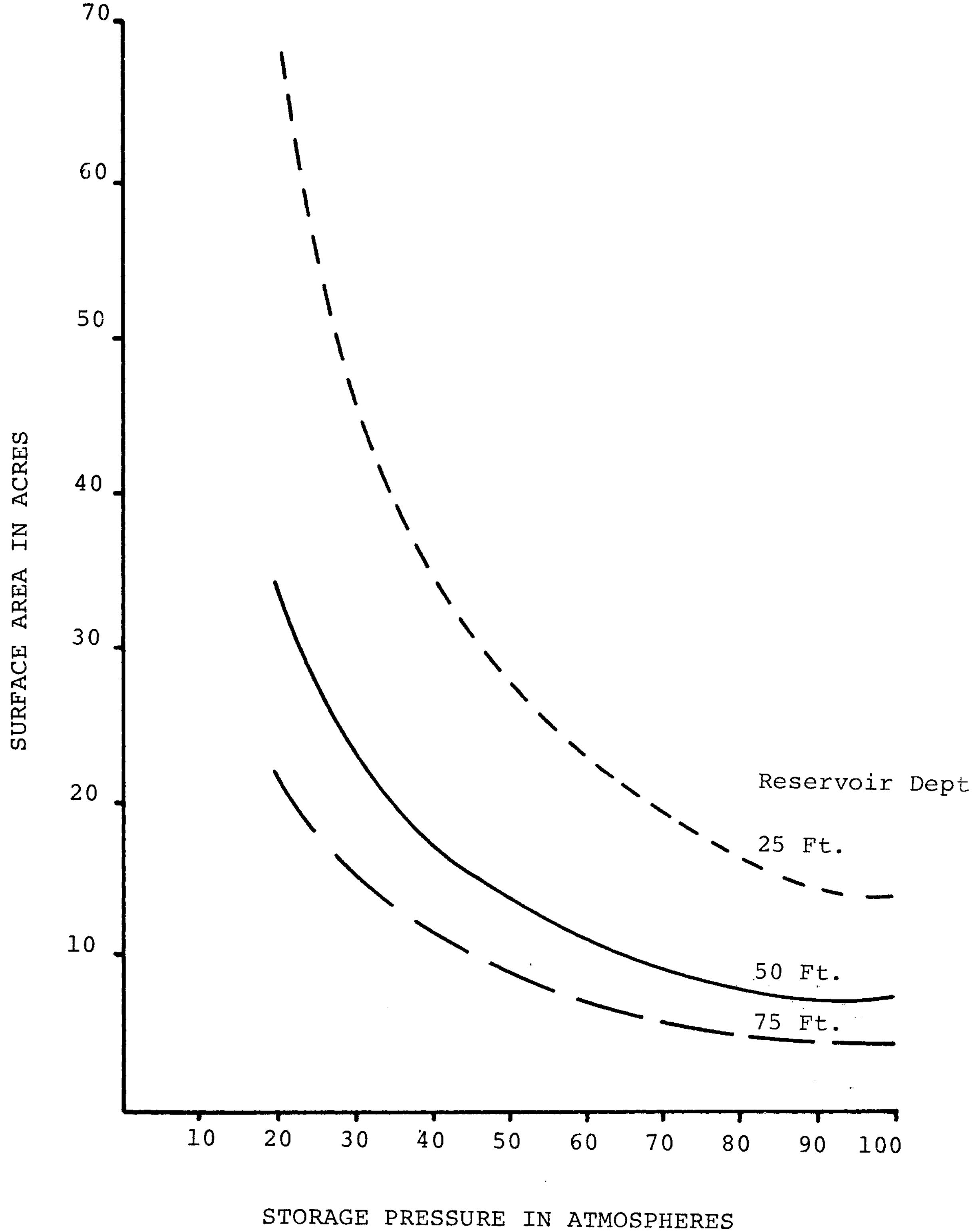


Figure A-2 COMPRESSED AIR ENERGY STORAGE
10,000 MWh SYSTEM

A.3.1 Steam

For a capacity of 200 MW and 2000 MWH, a steam energy storage system would consist of 440 tanks which are seventy feet high and twelve feet in diameter. The total land area requirement for the 440 tanks is 5.2 acres which includes access to all the tanks via a twenty-foot road and a six foot clearance between tanks (Figure A-3).

The land area requirements could be reduced as much as 1.7 acres (from 5.2 to 3.5 acres) by reducing the (six-foot) clearance between tanks to one foot.

A.3.2 Oil

The hot oil energy storage system of 2600 MWh consists of two 411,000 Bbl hot oil tanks which are each 240 feet in diameter and 52 feet high, and two 353,000 Bbl cold oil tanks which are each 220 feet in diameter and 54 feet high. Sufficient containment for possible tank leaks is required. Six-foot high dikes along the perimeter of the land are required to contain the hot oil. For four tanks, and assuming the two hot tanks are full, 21.2 acres would be required to contain the oil in these two tanks. (Figure A-4). If we consider only one tank leak at a time, then the containment area is reduced to 11.5 acres. Therefore, if we reduce the size of the tanks and increase the number of the smaller tanks, the containment required will be reduced until the tankage land area requirement exceeds it. However, this reduces safety and reliability. Also, a possible additional reduction would be to utilize the empty tank during a leak condition. This would require a quick discharging of the leaking tank before possible contamination from the oil outside the leaking tank. It would also eliminate any area required for leakage. Therefore, the land required would only be that of the tanks or 2.64 acres. Tanks could also be placed subsurface or underground.

A.3.3 Molten Salt

The molten salt energy storage system land area requirements vary according to the depth of the container for the molten salt. The following table shows the land requirements for six and twelve meter deep containers (Figure 3-16):

Power/Capacity (MW/MWh)	Volume (m^3)	Depth (m)	Land Area (Acres)
100/1000	13,300	6	.54
		12	.27
100/10,000	133,000	6	5.4
		12	2.7
100/10,000	125,000	6	5.1

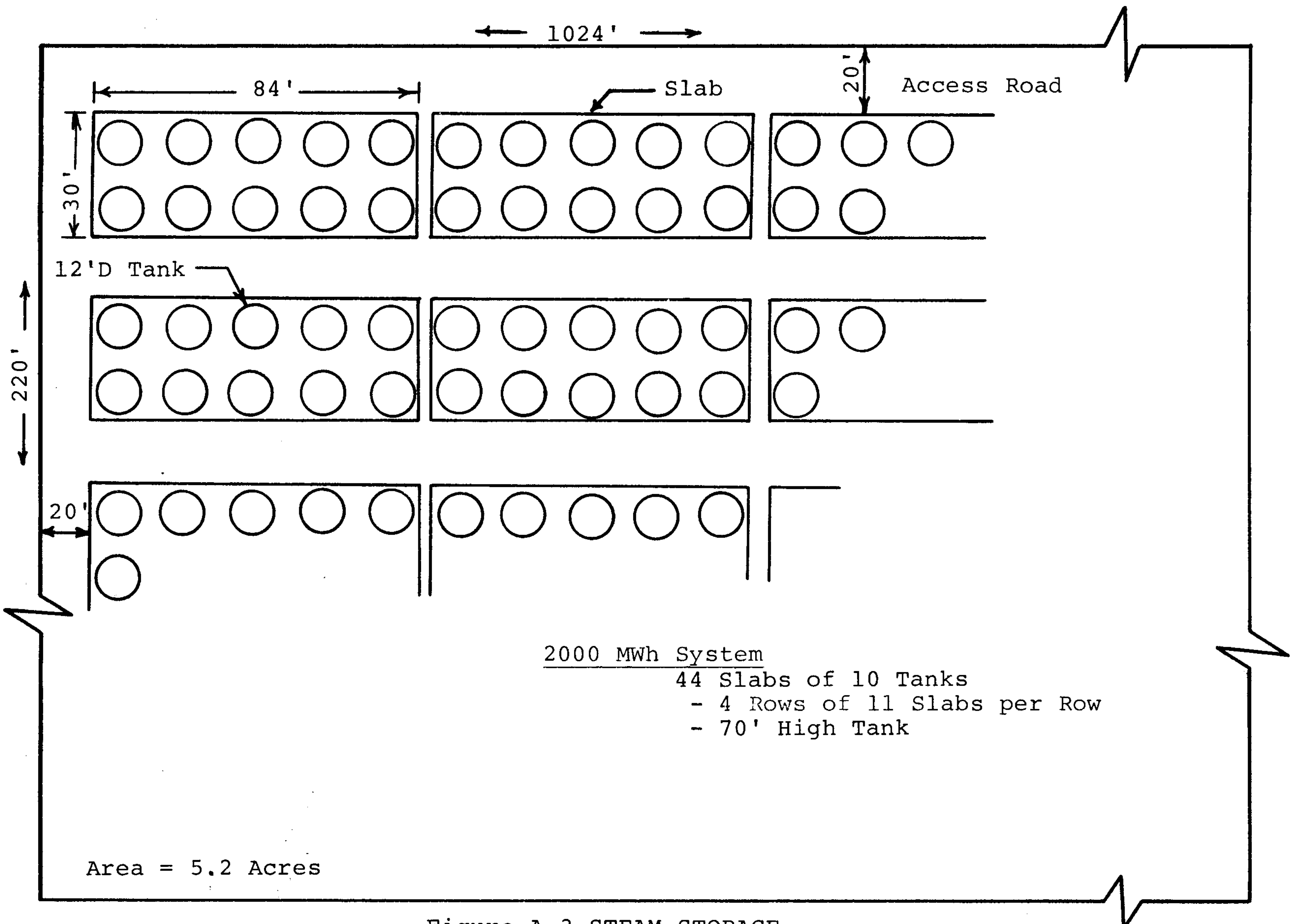


Figure A-3 STEAM STORAGE SYSTEM

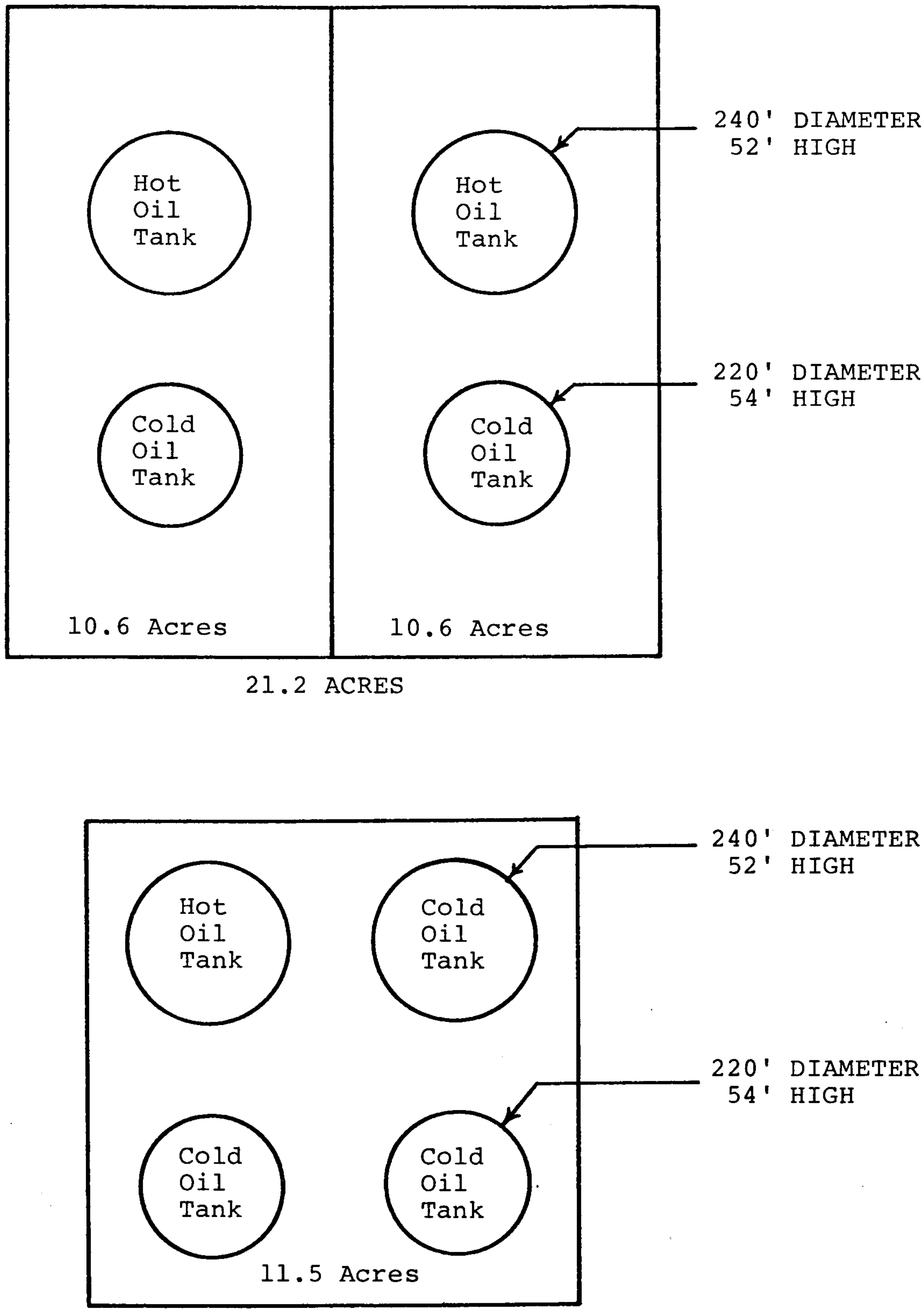


Figure A-4 OIL STORAGE SYSTEMS

A.4 ELECTROCHEMICAL (BATTERY)

There are many types of battery systems being developed. The land area requirements are discussed as two categories, lead-acid and advanced. The land area requirements will be divided into two categories, lead-acid and advanced. This is primarily due to the availability of a complete conceptual design of a lead acid facility.

A.4.1 Lead Acid

A baseline 20 MW, 200 MWh nominal demonstration plant consisting of an operating building, switchyard, cell manufacturing building, tanks, roads and parking requires a land area of 7.4 acres (Figure A-5). This requirement is for the specific battery design proposed for the Bechtel study by Gould, Inc., and may vary for other lead-acid battery design configurations.

A.4.2 Advanced

Of the advanced battery energy storage systems, two representative systems were chosen; lead acid and the sodium chloride. Diagrams of the land area required for the batteries alone are included (Figures A-6 and A-7). The advanced lead acid battery storage of 50 MW and 500 MWh would require four slabs of 320 x 350 feet just for the batteries (10.3 acres). Each slab has 200 rows of 50 modules per row and 12 cells per module. A sodium chloride battery energy storage system (ESB design) of 100 MW, 1000 MWh capacity requires two 210 x 255 foot slabs for the batteries only. Each slab has thirty groups of 400 modules with 12 cells per module. The land area requirement for the two slabs is 2.5 acres. Inverter/converter equipment could add as much as another acre.

Also other advanced battery systems and their land area requirements are as follows:

Battery 100 MW 1000 MWh	Land Area Requirements Batteries Only (Acres)
Sodium Sulfur (TRW Design)	11.0
Lithium Sulfur (AI Design)	10.0
Lithium-Aluminum/Iron-Sulfide (Argonne National Laboratories Design)	4.8

All of the above layouts were developed using battery module data from the Battery Energy Storage Test (BEST) Facility Project Team Technical Report EPRI 255, ERDA 31-109-38-2962, August 1975.

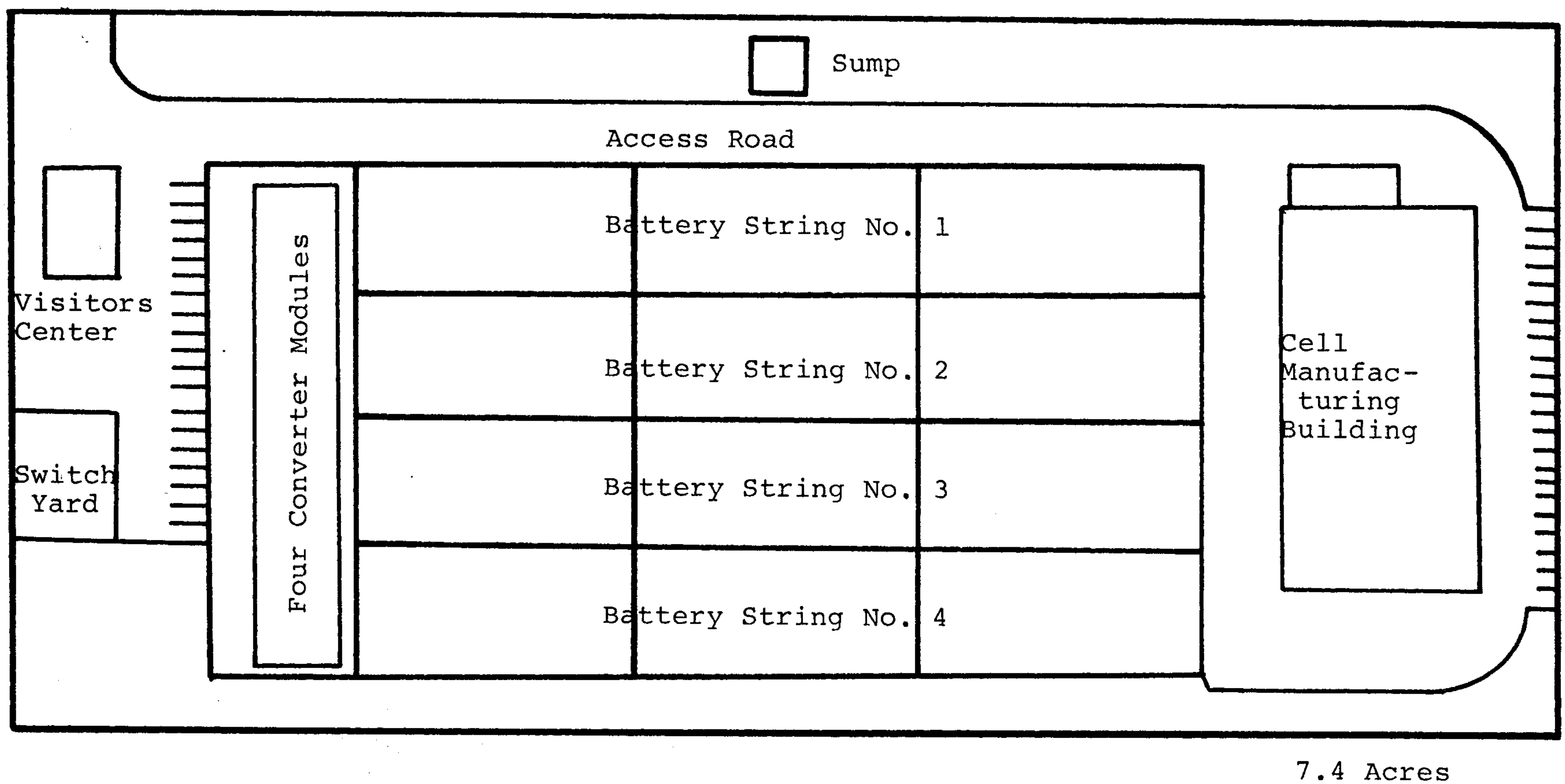


Figure A-5 LEAD ACID BATTERY
20 MW, 200 MWh DEMONSTRATION PLANT

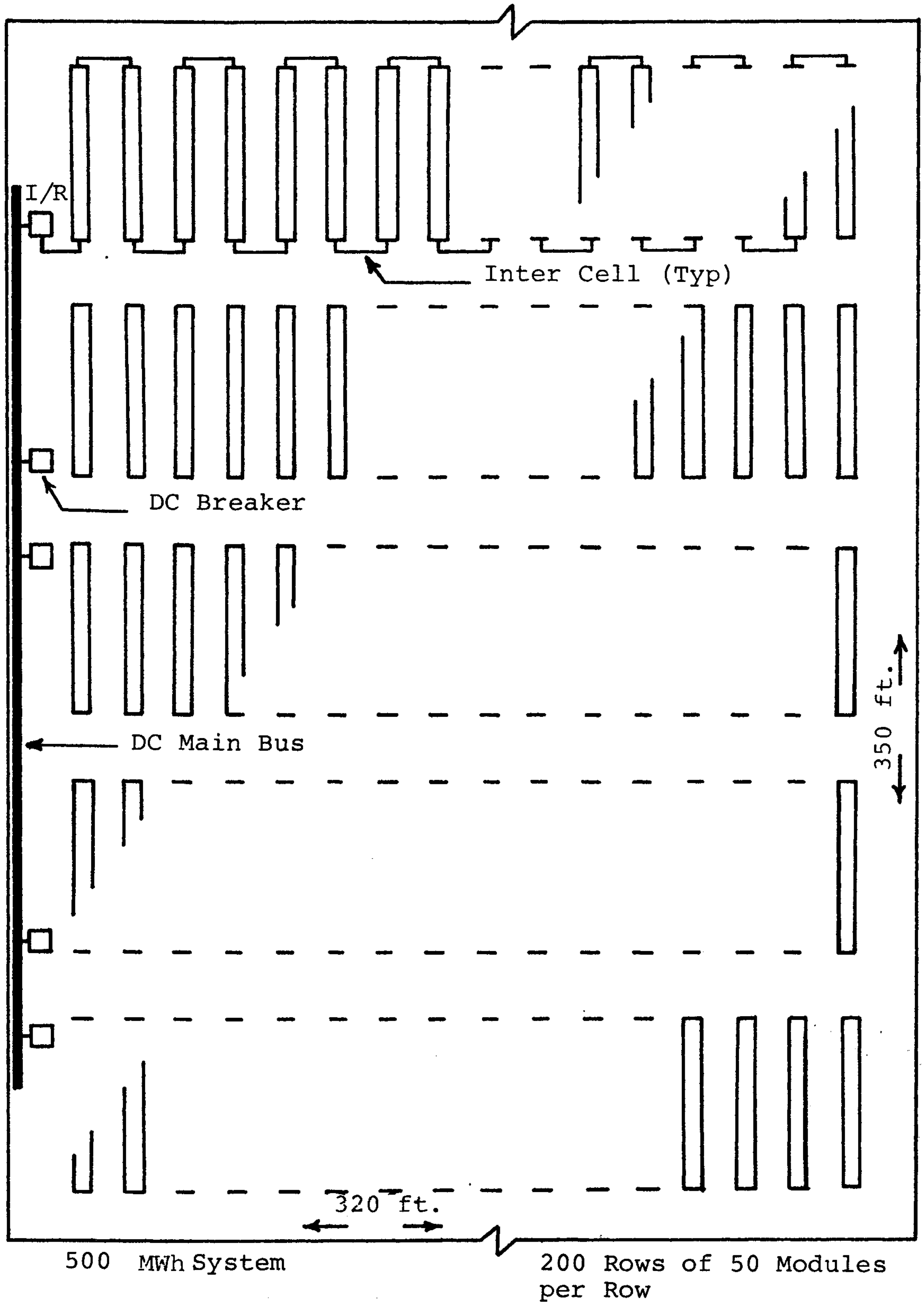


Figure A-6 ADVANCED LEAD ACID BATTERY ENERGY STORAGE SYSTEM

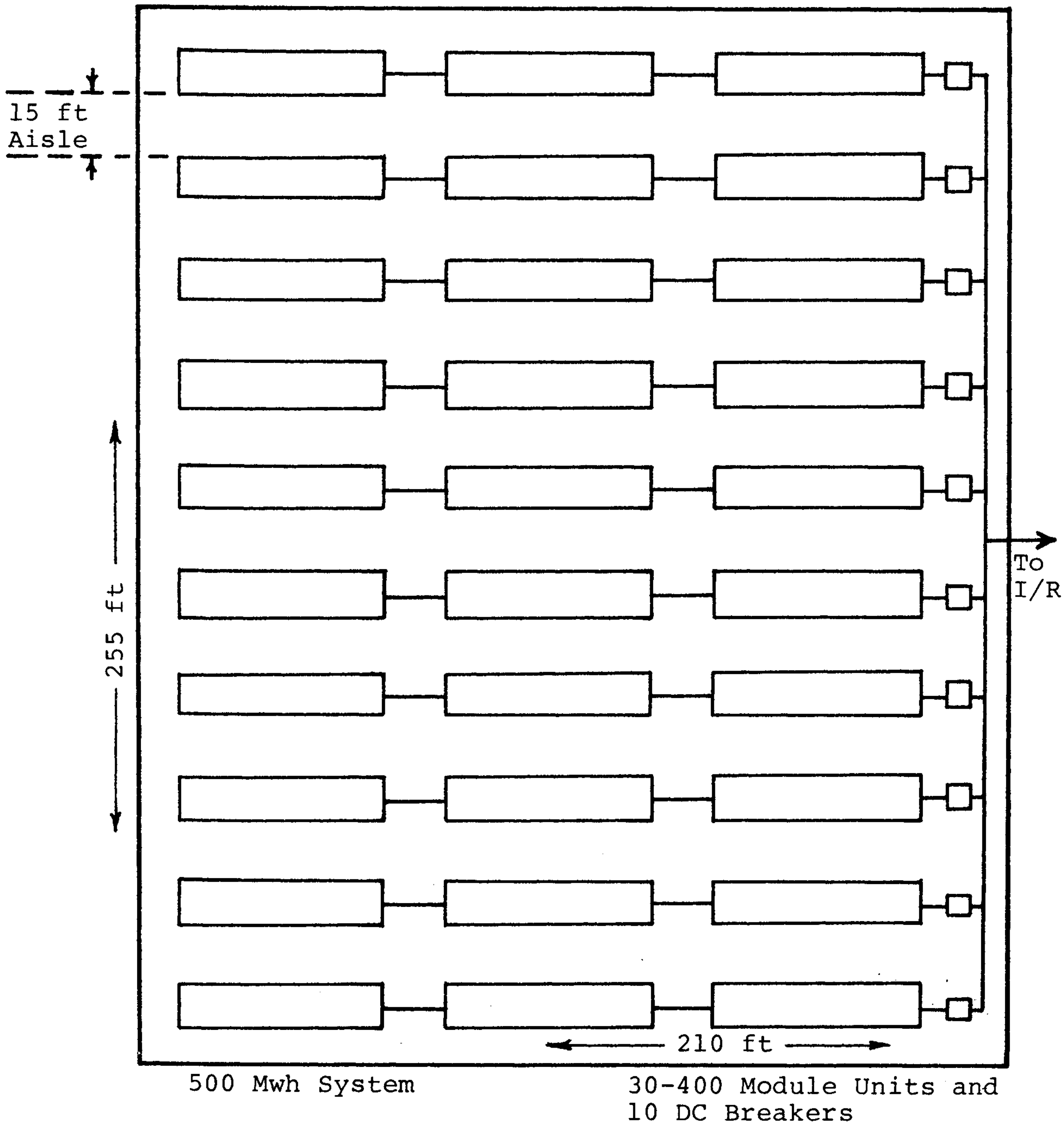


Figure A-7 SODIUM/CHLORIDE BATTERY ENERGY STORAGE SYSTEM

A.5 CHEMICAL

For a 53.7 MWh hydrogen energy storage system, 3000 pounds of hydrogen are stored in high pressure cylinders. The system includes 20 modules of five tanks which are 1.5 feet in diameter and 20 feet long. These cylinders are placed in either the horizontal or vertical positions. The horizontal position requires 12,000 square feet or .28 acres, the vertical position 2640 square feet or .067 acres. (Figures A-8 and A-9).

Land area requirements have been calculated for complete storage systems of 50 MW, 500 MWh and 200 MWh, 2000 MWh.
This includes the electrolyzer, dimineralization (DM) plant and oxygen storage. The land areas are 19 and 28 acres, respectively. (Figures A-10 and A-11).

A.6 FLYWHEEL

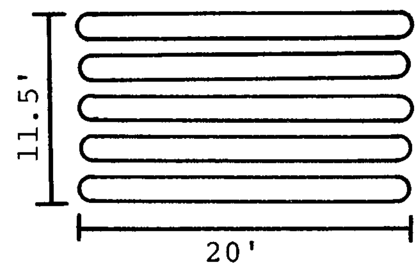
Flywheel energy storage systems differ by flywheel sizes and materials. Two foundation/vaults of 115 x 155 x 15 feet high require a land area of 155 x 370 feet or 1.3 acres (Figure A-12) to house the flywheels. Included in the land area is a twenty-foot wide access road to the flywheels. The land area required for the connection of the flywheel storage to a utility system is insignificant, at worst, it might raise the 1.3 to 1.5 acres depending on the capacity of the flywheel system and the associated transformer required. The capacities of the systems considered for the specified vault size are:

Flywheel Material	MWh Range
E - Glass	160 - 560
S - Glass	160 - 690
Kevlar	160 - 890

A.7 SUPERCONDUCTING MAGNETIC ENERGY STORAGE (SMES)

The total land area requirements for the SMES is indeterminable due to the uncertainty of the exclusion area for magnetic field effects. The land area could be substantial. The refrigeration equipment will take up less than an acre; however, the tankage requirements for cryogenic storage is tremendous. For a 10,000 MWh system a storage volume of 1.63×10^8 SCF would be needed for the helium. At a storage pressure of 10 atmospheres and 0°C, this would require a sphere 196 meters in diameter or at least a land area of 9.5 acres if it can be physically built. Also the nitrogen would require storage of almost equal size therby doubling the land area requirements at the very least. The basic system is so futuristic that the land requirements estimates should be considered crude.

Single Module



Single Module Data

5 Tanks
  1.5' Dia. X 20' Long
Capacity:
  30 lb H_2/Tank
  150 lb H_2/Module
Land Area: 230 ft^2/Module
Land Requirement: 1.53 ft^2/lb H_2

20 Module Layout Data

Capacity: 3000 lb H_2
Land Area: 12,000 ft^2 (96' X 125')
Land Requirement: 4 ft^2/lb H_2

20 Module Layout

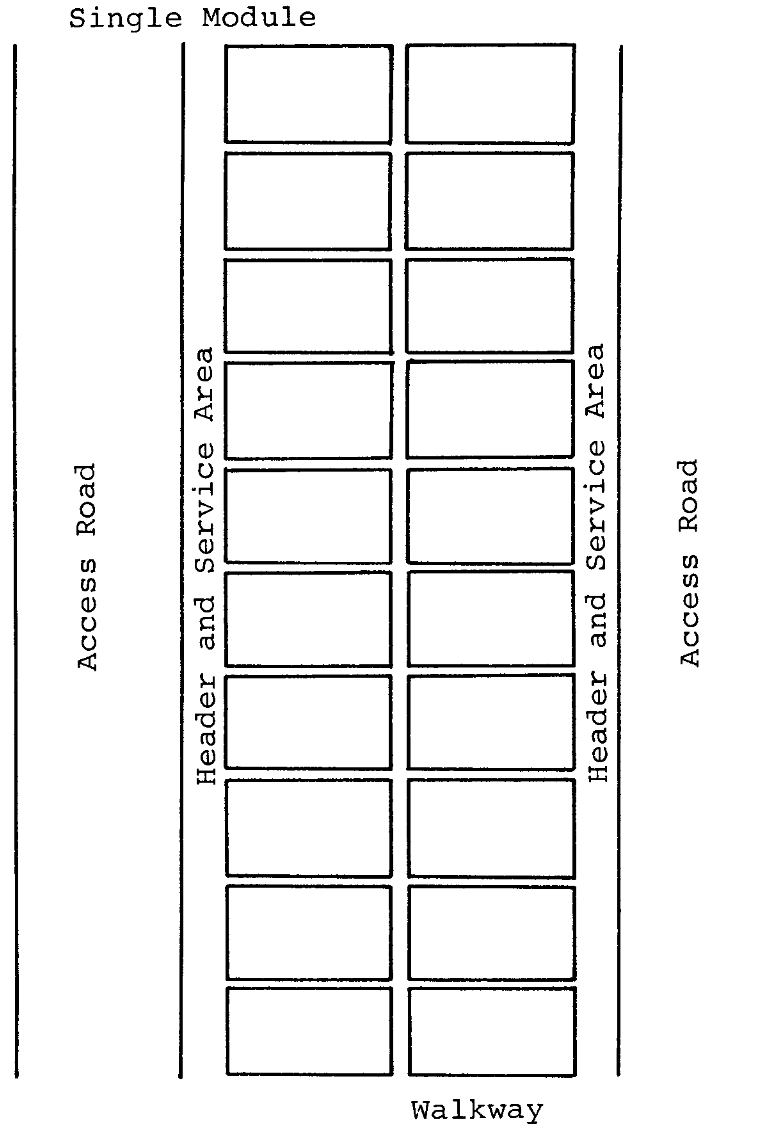
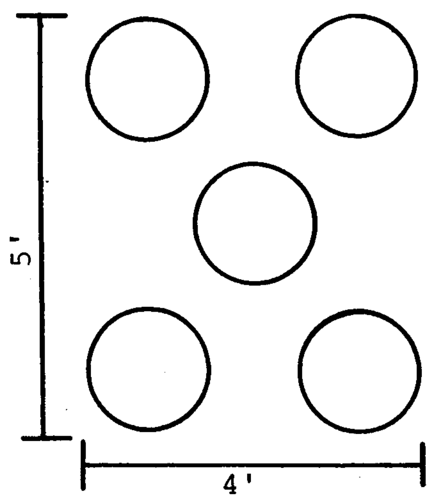


Figure A-8 LAYOUT OF HIGH PRESSURE CYLINDERS FOR HYDROGEN STORAGE - HORIZONTAL POSITION

Single Module



Single Module Data

5 Tanks
1.5' Dia. X 20' Long
Capacity:
30 lb H_2/Tank
150 lb H_2/Module
Land Area: 20 ft^2/Module
Land Requirement: 0.13 ft^2/lb H_2

20 Module Layout Data

Capacity: 3000 lb H_2
Land Area: 2640 ft^2 (60' X 44')
Land Requirement: 0.88 ft^2/lb H_2

20 Module Layout

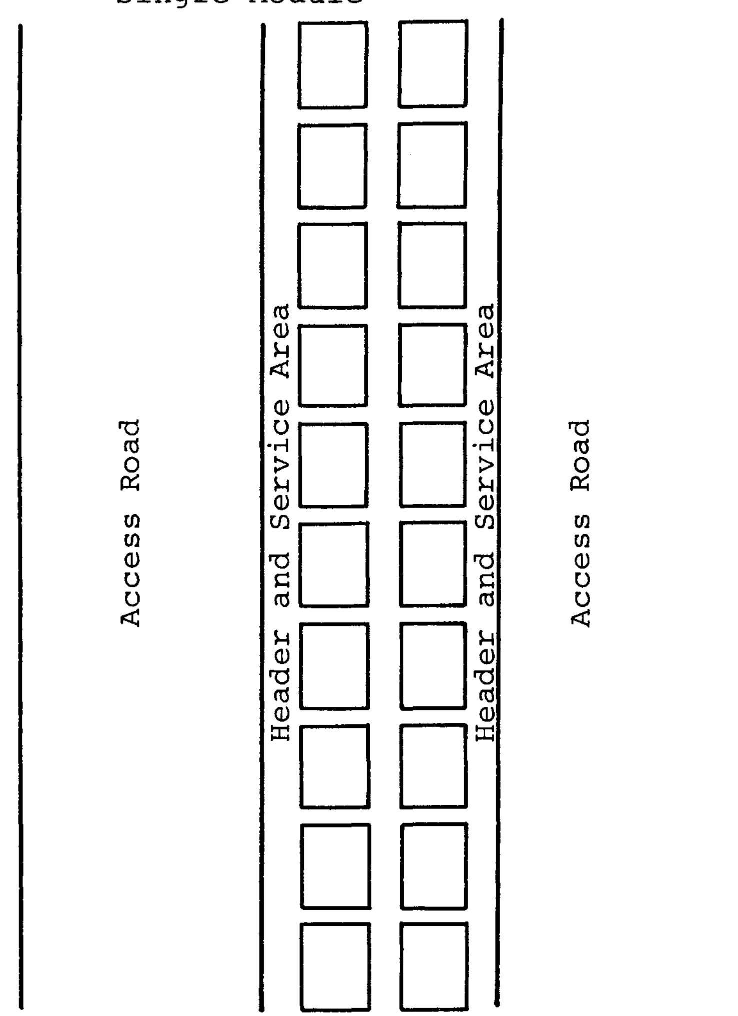
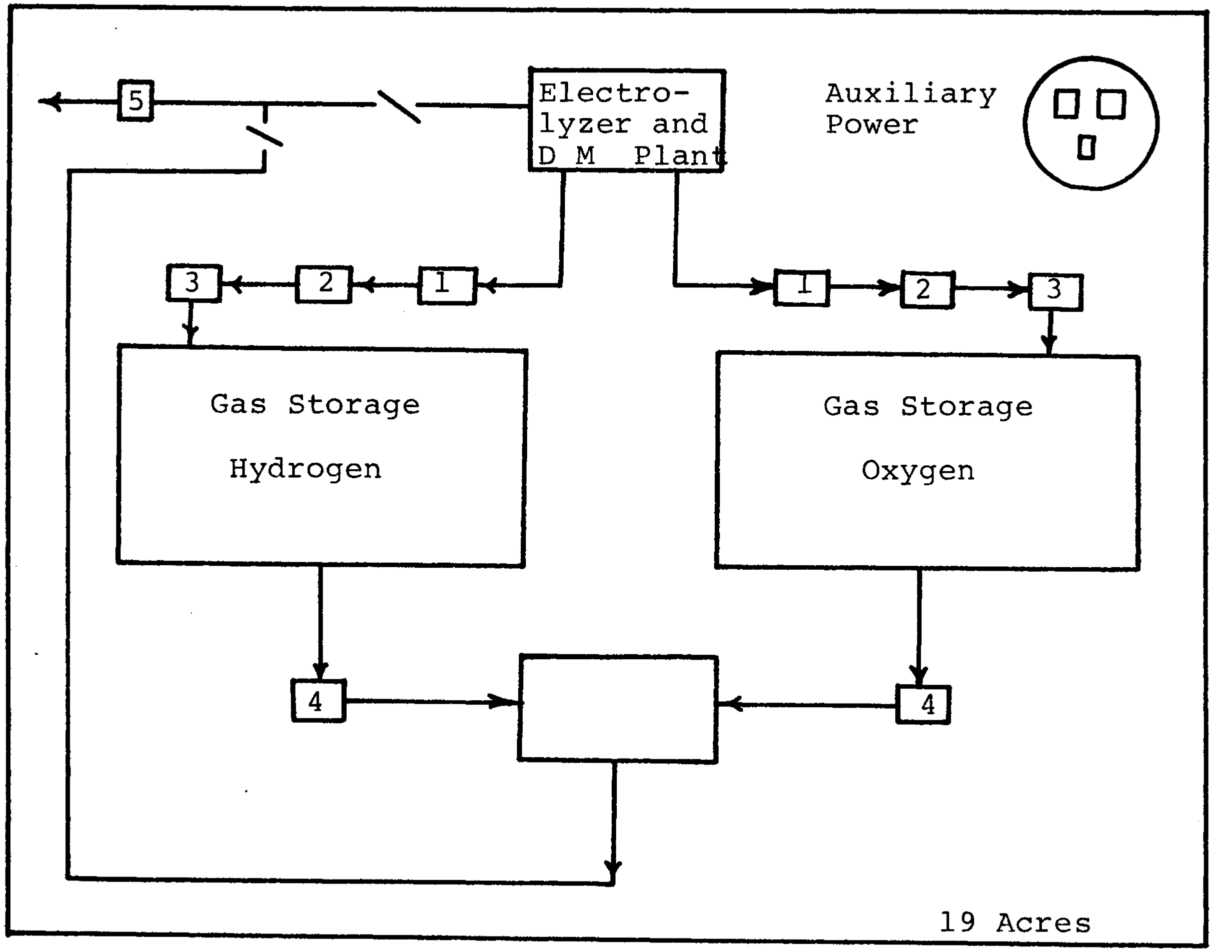


Figure A-9 LAYOUT OF HIGH PRESSURE CYLINDERS FOR HYDROGEN STORAGE - VERTICAL POSITION

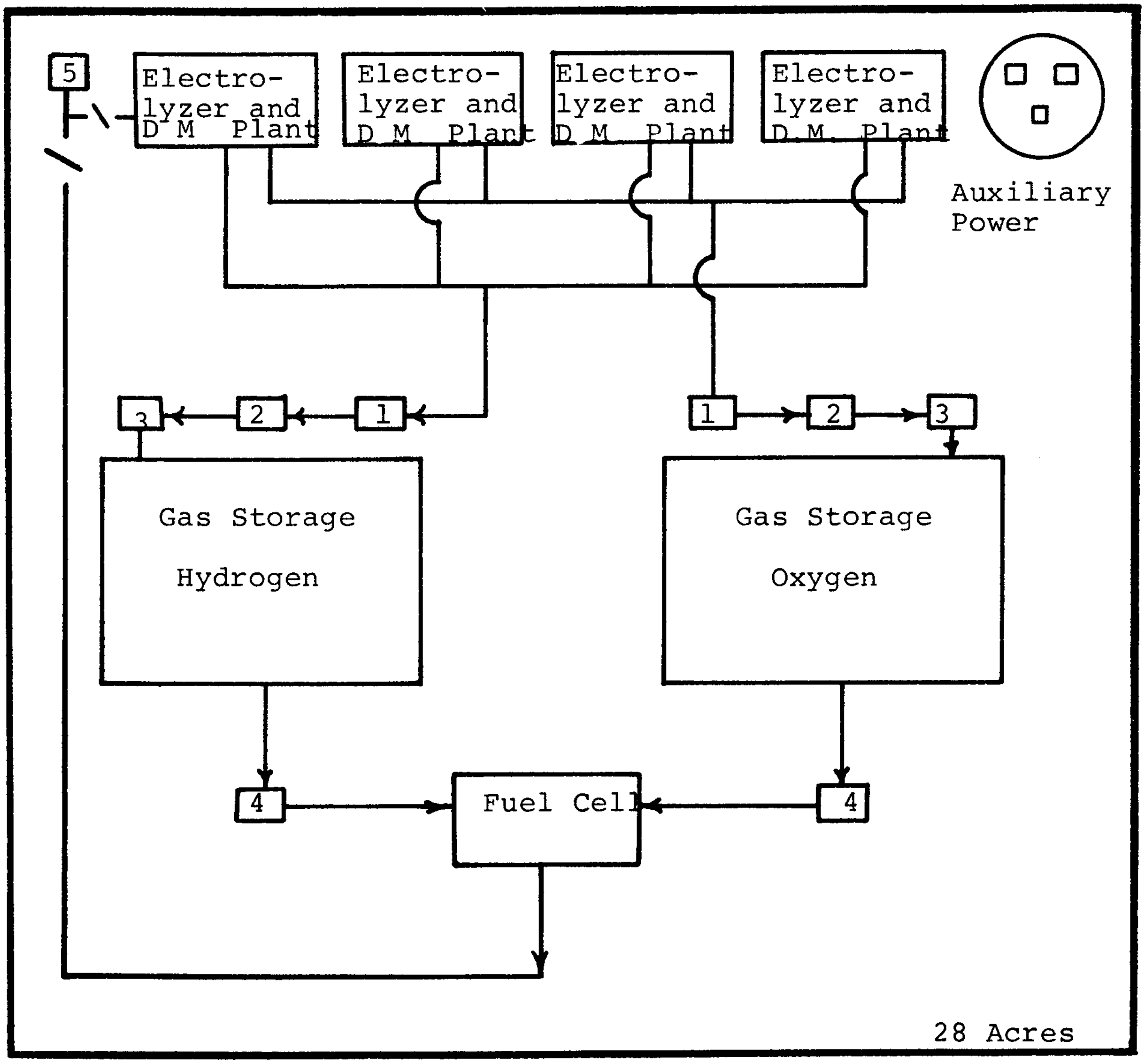


1100 ft

1 Cooler
2 Dryer
3 Compressor

4 Heater
5 Incoming Supply,
Filter and Converter

Figure A-10 FUEL CELL
50 MW



1100 ft

1 Cooler
2 Dryer
3 Compressor
4 Heater
5 Incoming Supply, Filter and Converter

Figure A-11. FUEL CELL
200 MW

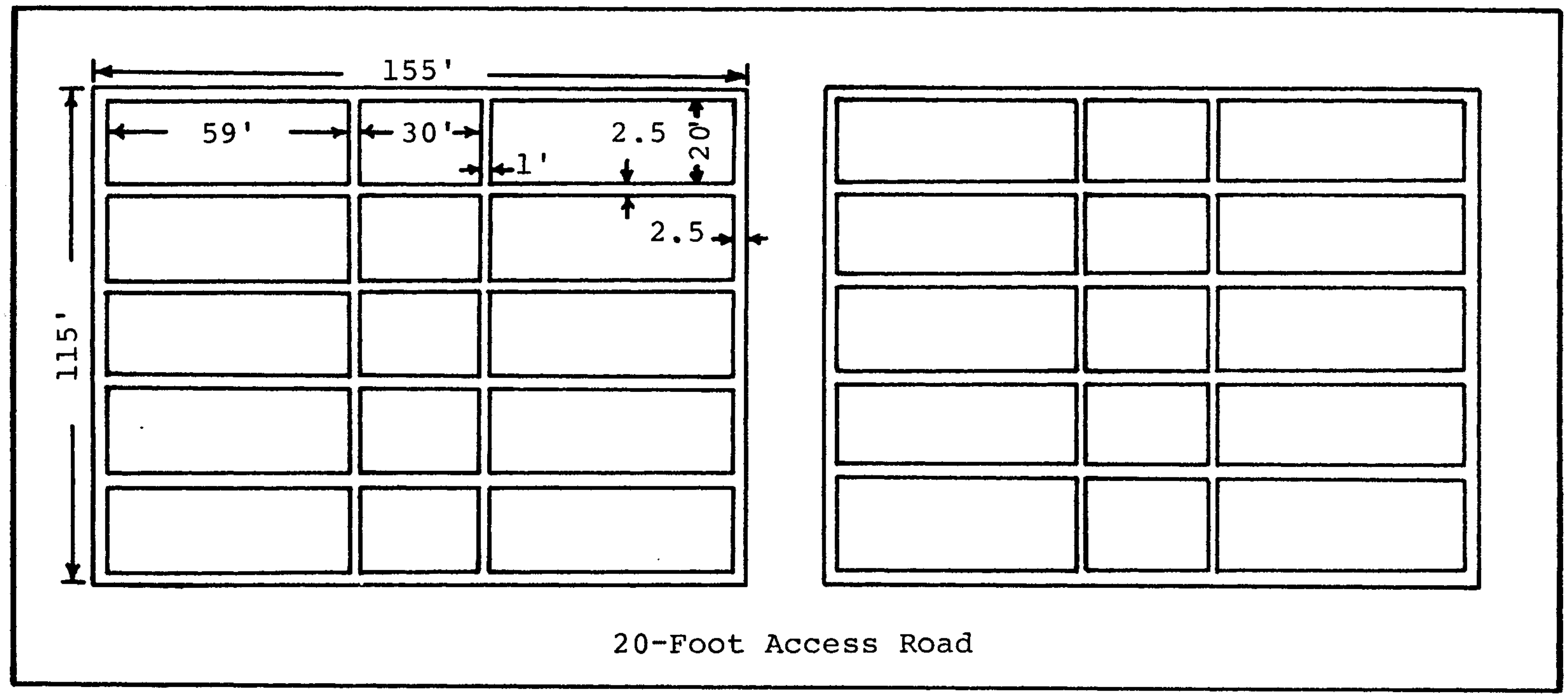


Figure A-12 FLYWHEEL FOUNDATION/VAULTS

A.8 CONCLUSIONS

Figure A-13 is a summary taken of the land requirements for the energy storage system previously discussed. Although not all the systems include the same equipment, Table A-1 and Figure A-13 do offer a comparison for the land area requirements of the systems on that basis.

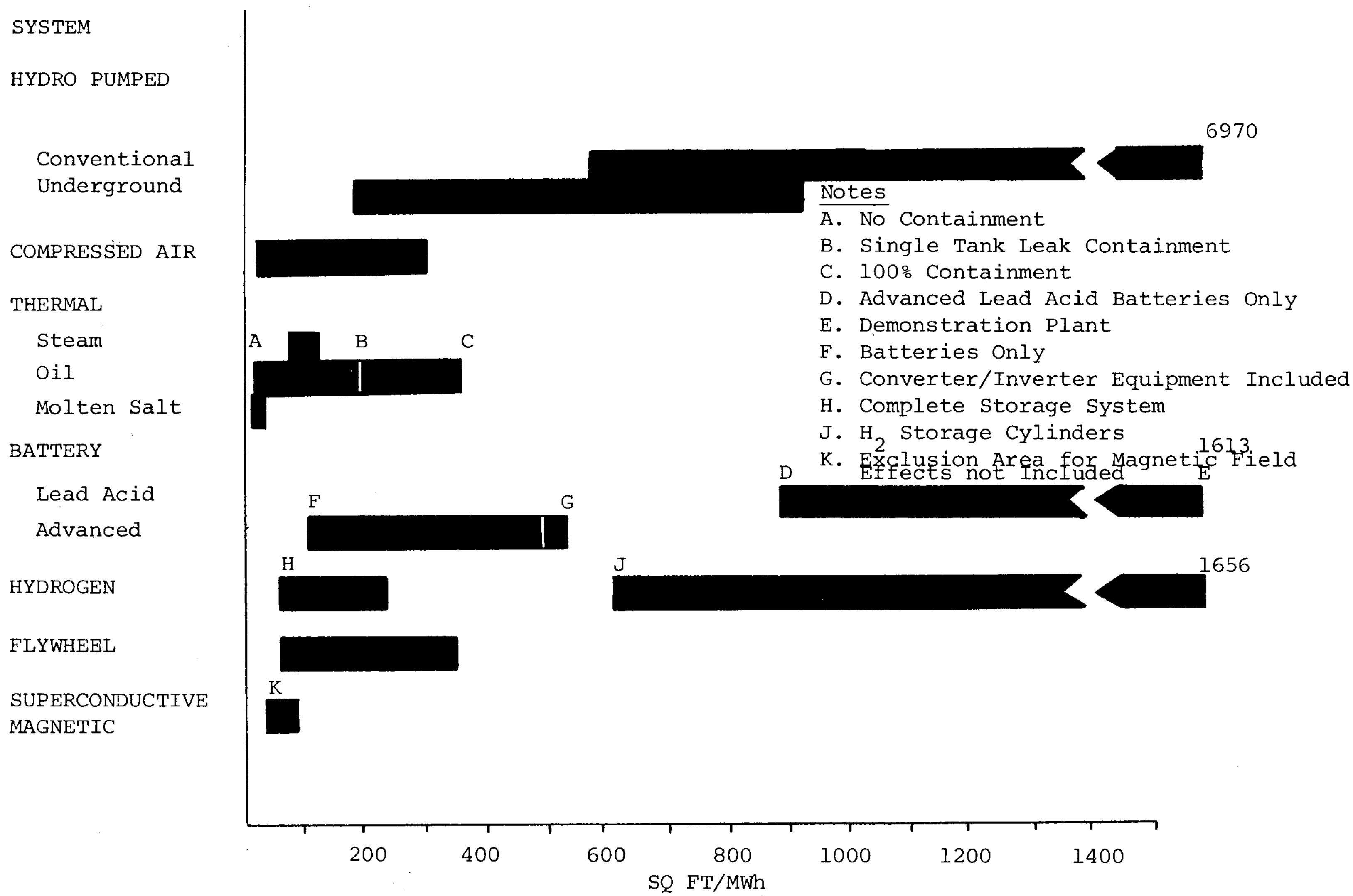


Figure A-13 LAND REQUIREMENTS

Table A-1 LAND AREA REQUIREMENT

System	Sqft/MWh
Hydro Pumped	
Conventional	570 to 6970
Underground	175 to 915
Compressed Air	22 to 300
Thermal	
Steam	76 to 113
Oil	19(A) to 192(B) to 355(C)
Molten Salt	11 to 24
Battery	
Lead Acid	896(A) to 1613(E)
Advanced	109(E) to 479(G)
Hydrogen	54(H) to 227/610(J) to 1656
Flywheel	64 to 354
Superconductive Magnetic	41(K) to 83

Notes

A. No Containment
B. Single Tank Leak Containment
C. 100% Containment
D. Advanced Lead Acid Batteries Only
E. Demonstration Plant
F. Batteries Only
G. Converter/Inverter Equipment Included
H. Complete Storage System
J. H2 Storage Cylinders
K. Exclusion Area for Magnetic Field Effects not Included

B1 ELECTRIC UTILITY DATA BASE DESCRIPTION AND METHOD OF UTILITY SELECTION

B1.1 INTRODUCTION

In this appendix, the collection and analysis of United States electric utility industry system load and generation data to determine representative system characteristics are described. These analyses included evaluations of (1) average system size according to peak load, peak load seasons and annual energy produced for load, (2) average annual load factors, (3) valley to peak load ratios, and (4) capacity mix of generating units.

Based on these analyses, electric utility systems were selected as being most representative of the industry. These representative utility systems were subsequently used to determine the amount of off-peak energy available for charging energy storage systems, the distribution of this off-peak energy over the calendar year, the typical utility system duty cycle power and energy requirements for energy storage systems, and the competitive economics of energy storage systems with each other and with the more conventional forms of electric power peaking and intermediate generation as described in Chapters 2 and 5.

B1.2 U.S. ELECTRIC UTILITY DATA BASE ANALYSIS

B1.2.1 Data Base Description

The year 1971 was selected as the base data year because it was the most current year for which consistent load and generation data as well as annual hourly system load data for U.S. electric utility systems were available at the time the study wwas initiated.

The electric utility system data base consists of load and generation characteristics of 199 privately and publicly owned electric systems. A part of the data base is listed in Table B1-1. [1-11]. Complementing this data base is annual hourly load data for about 150 individual utilities and/or pools which was made available on a confidential basis by the Edison Electric Institute. [12]

Although the data base of 199 systems consists of less than 10% of the utilities in the U.S., it represents about 90% of the total installed capacity of 367,000 megawatts and about 97% of the 1.6 billion megawatt-hours of net energy generated in the 1971. For the most part the data-base is comprised of privately owned systems having annual electric operating revenues of $2.5

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 1 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10^3)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10^3)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.): Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
ALABAMA: Alabama Power Co.	A01	0278325	T	60.2	04342	S	23051095	04097	066.0	032.8	001.2	000.0	SERC
ARIZONA: Arizona Public Service Co.	A04	0117399	T	55.1	01410	S	06816583	01540	097.2	000.3	002.5	000.0	WSCC
Tucson Gas & Electric Co.	A06	0050924	T	62.4	00570	S	03115756	00640	099.5	000.0	000.5	000.0	WSCC
ARKANSAS: Arkansas-Missouri Power Co.	A07	0027077	T	56.2	00223	S	01097855	00036	097.2	002.8	000.0	000.0	SWPP
Arkansas Power & Light Co.	A08	0166063	T	53.0	02535	S	11769498	02370	092.8	002.9	004.3	000.0	SWPP
CALIFORNIA: Pacific Gas & Electric Co.	C01	0791457	T	63.9	09704	S	54338611	09577	073.1	026.3	000.0	006.6	WSCC
San Diego Gas & Electric Co.	C02	0120320	T	57.2	01451	W	07271160	01719	079.5	000.0	015.5	005.0	WSCC
Southern California Edison Co.	C03	0802434	T	62.7	09350	S	51399129	11704	083.0	009.6	004.5	002.9	WSCC
COLORADO: Home Light & Power Co.	C04	0005815	T	57.1	00065	W	00325298	00000	000.0	000.0	000.0	000.0	WSCC
Public Service Co. of Colorado	C05	0146563	T	63.2	01538	W	08518989	01846	079.5	019.6	000.9	000.0	WSCC
Western Colorado Power Co.	C06	0004178	T	60.6	00040	W	00213282	00034	064.7	035.3	000.0	000.0	WSCC
CONNECTICUT: Connecticut Light & Power Co.	C07	0178698	T	61.8	01672	W	09044118	02099	066.9	005.8	010.6	016.7	NPCC
Hartford Electric Light Co.	C09	0106785	T	62.9	00885	S	04876830	01184	060.4	000.8	023.2	015.6	NPCC
United Illuminating Co.	C11	0081089	T	62.8	00804	S	04424277	01031	098.0	000.0	002.0	000.0	NPCC
DELAWARE: Delmarva Power & Light Co.	D01	0104742	T	64.5	01090	S	06161043	01281	088.1	000.0	011.9	000.0	MAAC
DISTRICT OF COLUMBIA: Potomac Electric Power Co.	D02	0251845	T	50.9	03045	S	13575711	04165	091.9	000.0	008.1	000.0	MAAC
FLORIDA: Florida Power Corp.	F01	0176540	T	60.2	02077	S	10960887	02292	088.0	000.0	012.0	000.0	SERC
Florida Power & Light Co.	F02	0484830	T	59.2	05378	S	27883891	06105	084.9	000.0	015.1	000.0	SERC
Gulf Power Co.	F04	0057684	T	55.2	00842	S	04071508	00969	096.0	000.0	004.0	000.0	SERC

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 2OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10³)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10³)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.) Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
Tampa Electric Co.	F05	0101375	T	62.2	01257	S	06846350	01725	098.0	000.0	002.0	000.0	SERC
GEORGIA: Georgia Power Co.	G01	0422595	T	61.8	06337	S	34489276	05546	085.9	007.8	000.0	006.3	SERC
Savannah Electric & Power Co.	G02	0029916	T	60.3	00339	S	01793669	00393	082.2	000.0	017.8	000.0	SERC
HAWAII: Hawaiian Electric Co., Inc.	H01	0093355	T	68.7	00821	W	04581279	00977	097.3	000.0	002.7	000.0	WSCC
IDAHO: Idaho Power Co.	I01	0081810	T	62.0	01381	S	07500487	01296	000.0	099.5	000.5	000.0	WSCC
ILLINOIS: Central-Illinois Light Co.	I02	0056859	T	54.2	00719	S	03414823	00840	096.2	000.0	003.8	000.0	MAIN
Central Illinois Public Service Co.	I03	0107562	T	58.2	01252	S	06379751	01178	100.0	000.0	000.0	000.0	MAIN
Commonwealth Edison Co.	I04	0989560	T	54.4	10943	S	52148209	11993	072.3	000.0	015.6	012.1	MAIN
Illinois Power Co.	I06	0159175	T	55.9	01974	S	09658264	02198	091.9	000.1	008.0	000.0	MAIN
Mt. Carmel Public Utility	I07	0001958	T	53.7	00018	S	00084674	00018	100.0	000.0	000.0	000.0	MAIN
Sherrard Power System	I08	0002315	T	48.8	00022	S	00093651	00000	000.0	000.0	000.0	000.0	MAIN
INDIANA: Indiana & Michigan Electric Co.	I13	0184356	T	61.6	03018	W	16291399	01805	096.4	000.6	003.0	000.0	ECAR
Indianapolis Power & Light Co.	I14	0107760	T	55.3	01390	S	06727402	01572	100.0	000.0	000.0	000.0	ECAR
Northern Indiana Public Service Co.	I15	0132136	T	68.5	01544	S	09269085	01386	093.1	000.7	006.2	000.0	ECAR
Public Service Co. of Indiana, Inc.	I16	0190579	T	62.4	02372	S	12950867	02655	093.3	002.1	004.6	000.0	ECAR
South Indiana Gas & Electric Co.	I17	0034639	T	50.7	00467	S	02071948	00495	095.2	000.0	004.8	000.0	ECAR
IOWA: Interstate Power Co.	I18	0052267	T	61.2	00465	S	02492920	00592	098.0	000.2	001.8	000.0	MARCA
Iowa Electric Light & Power Co.	I19	0055055	T	58.0	00661	S	03358409	00575	091.3	000.3	008.4	000.0	MARCA
Iowa-Illinois Gas & Electric Co.	I20	0052101	T	53.1	00620	S	02885720	00597	064.2	000.3	035.5	000.0	MARCA

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 3 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10³)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10³)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.): Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
Iowa Power & Light Co.	I21	0063549	T	48.4	00754	S	03197812	00579	078.6	000.0	021.4	000.0	MARCA
Iowa Public Service Co.	I22	0047059	T	52.2	00438	S	02002970	00440	084.5	000.0	015.5	000.0	MARCA
Iowa Southern Utilities Co.	I23	0025529	T	50.6	00263	S	01168505	00279	096.1	000.0	003.9	000.0	MARCA
KANSAS:													
Central Kansas Power Co., Inc.	K01	0007139	T	53.6	00093	S	00437601	00085	074.1	000.0	025.9	000.0	SWPP
Central Telephone & Utilities Corp.	K02	0038691	T	59.8	00420	S	02202431	00475	088.6	000.0	011.4	000.0	SWPP
Kansas Gas & Electric Co.	K03	0071150	T	51.0	01079	S	04818341	01168	099.7	000.0	000.3	000.0	SWPP
Kansas Power & Light Co.	K04	0074522	T	50.0	01129	S	04951729	01395	099.9	000.0	000.1	000.0	SWPP
KENTUCKY:													
Kentucky Power Co.	K05	0035878	T	67.0	00428	S	02511506	01080	100.0	000.0	000.0	000.0	ECAR
Kentucky Utilities Co.	K06	0095697	T	60.1	01150	S	06076384	01190	093.2	002.4	004.4	000.0	ECAR
Louisville Gas & Electric Co.	K07	0089434	T	55.8	01271	S	06212749	01557	087.7	005.0	007.3	000.0	ECAR
LOUISIANA:													
Central Louisiana Electric Co., Inc.	L01	0043209	T	52.0	00648	S	02981398	00931	099.0	000.0	001.0	000.0	SWPP
Gulf States Utilities Co.	L02	0193937	T	68.2	03285	S	19653018	04101	100.0	000.0	000.0	000.0	SWPP
Louisiana Power & Light Co.	L03	0153643	T	58.5	02096	S	10741161	02654	099.0	000.0	001.0	000.0	SWPP
New Orleans Public Service Inc.	L04	0073963	T	54.1	00837	S	03966677	01250	098.7	000.0	001.3	000.0	SWPP
MAINE:													
Bangor Hydro-Electric Co.	M01	0016675	T	73.9	00148	W	00960394	00124	046.0	026.6	027.4	000.0	NPCC
Central Maine Power Co.	M02	0080949	T	61.6	00783	W	04225193	00744	053.6	039.7	006.7	000.0	NPCC
Maine Public Service Co.	M04	000901[illegible]	T	52.0	00078	W	00359252	00038	060.5	005.3	034.2	000.0	NPCC
MARYLAND:													
Baltimore Gas & Electric Co.	M06	0274587	T	58.7	02605	S	13397424	02806	080.1	000.0	019.9	000.0	MAAC
Potomac Edison Co.	M09	0079615	T	68.6	01009	W	06063444	00889	099.0	001.0	000.0	000.0	ECAR

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 4 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10³)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10³)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.) Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
MASSACHUSETTS:													
Boston Edison Co.	M12	0246436	T	59.9	01877	S	09851883	02048	085.8	000.0	014.2	000.0	NPCC
Boston Gas Co.	M13	0002479	T	68.0	00017	S	00101266	00000	000.0	000.0	000.0	000.0	NPCC
Brockton Edison Co.	M14	0025425	T	54.0	00231	W	01093446	00020	100.0	000.0	000.0	000.0	NPCC
Cambridge Electric Light Co.	M15	0019230	T	56.4	00175	S	00864022	00115	080.0	000.0	020.0	000.0	NPCC
Fall River Electric Light Co.	M17	0016463	T	65.7	00149	W	00855029	00014	100.0	000.0	000.0	000.0	NPCC
Fitchburg Gas & Electric Light Co.	M18	0008363	T	60.0	00060	W	00310788	00061	100.0	000.0	000.0	000.0	NPCC
Holyoke Water Power Co.	M20	0012685	T	62.1	00086	S	00468924	00207	087.0	013.0	000.0	000.0	NPCC
Nantucket Gas & Electric Co.	M23	0001190	T	51.3	00006	W	00026963	00008	000.0	000.0	100.0	000.0	NPCC
New Bedford Gas & Edison Light Co.	M24	0045367	T	59.7	00326	W	01706838	00112	090.1	000.0	009.9	000.0	NPCC
Western Massachusetts Electric Co.	M26	0070019	T	63.1	00589	W	03257524	00596	035.4	018.0	025.6	021.0	NPCC
New England Electric System	M48	0301185	T	59.5	02777	W	14474279	02508	073.1	021.8	005.1	000.0	NPCC
MICHIGAN:													
Consumers Power Co.	M29	0364230	T	67.0	03667	W	21522356	03828	070.1	003.0	011.8	016.1	ECAR
Detroit Edison Co.	M30	0585324	T	63.7	05986	S	33396690	07010	090.3	000.0	009.7	000.0	ECAR
Edison Sault Electric Co.	M31	0005353	T	63.9	00068	W	00380640	00038	000.0	084.2	015.8	000.0	ECAR
Michigan Power Co.	M32	0006823	T	66.3	00075	W	00435133	00003	000.0	100.0	000.0	000.0	ECAR
Upper Peninsula Power Co.	M34	0014945	T	62.8	00108	W	00594138	00065	072.3	021.5	006.2	000.0	MAIN
MINNESOTA:													
Minnesota Power & Light Co.	M35	0060682	T	79.0	00602	W	04165564	00511	079.3	020.7	000.0	000.0	MARCA
Northern States Power Co.	M36	0317871	T	58.8	03292	S	16946998	03260	073.4	000.6	008.5	017.5	MARCA
MISSISSIPPI:													
Mississippi Power Co.	M37	0063247	T	57.4	00966	S	04894587	00966	089.0	000.0	011.0	000.0	SERC

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 5 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10^3)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (KWhrs x 10^3)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.): Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
Mississippi Power & Light Co.	M38	0094636	T	53.0	01343	S	06246040	02002	099.5	000.0	000.5	000.0	SWPP
MISSOURI:													
Empire District Electric Co.	M39	0033020	T	61.0	00299	S	01597736	0032.6	096.0	004.0	000.0	000.0	SWPP
Kansas City Power & Light Co.	M40	0128947	T	48.2	01574	S	06641310	01675	100.0	000.0	000.0	000.0	SWPP
Missouri Edison Co.	M41	0008492	T	58.0	00110	S	00558888	00000	000.0	000.0	000.0	000.0	SWPP
Missouri Power & Light Co.	M42	0029462	T	52.8	00362	S	01679611	00051	066.7	000.0	033.3	000.0	SWPP
Missouri Public Service Co.	M43	0038634	T	45.0	00390	S	01536469	00551	099.6	000.4	000.0	000.0	SWPP
Missouri Utilities Co.	M44	0012466	T	41.7	00135	S	00493144	00031	000.0	000.0	100.0	000.0	SWPP
St. Joseph Light Power Co.	M45	0015960	T	49.2	00188	S	00808002	00222	100.0	000.0	000.0	000.0	SWPP
Union Electric Co.	M46	0304488	T	52.6	04228	S	19484441	04603	084.6	014.8	000.6	000.0	MAIN
MONTANA:													
Montana Power Co.	M47	0057714	T	67.0	00873	W	05123812	00769	032.0	067.6	000.4	000.0	WSCC
NEVADA:													
Nevada Power Co.	N01	0042323	T	53.7	00718	S	03405681	00637	094.5	000.0	005.5	000.0	WSCC
Sierra Pacific Power Co.	N02	0034131	T	61.4	00379	W	02038000	00457	077.9	002.6	019.5	000.0	WSCC
NEW HAMPSHIRE:													
Concord Electric Co.	N03	0004533	T	56.4	00044	W	00217468	00000	000.0	000.0	000.0	000.0	NPCC
Exeter & Hampton Electric Co.	N05	0004546	T	54.0	00041	W	00193835	00000	000.0	000.0	000.0	000.0	NPCC
Public Service Co. of New Hampshire	N07	0080126	T	57.2	00806	W	04039970	00855	081.4	005.6	013.0	000.0	NPCC
NEW JERSEY:													
Atlantic City Electric Co.	N08	0095406	T	57.6	00829	S	04187667	00921	080.0	000.0	020.0	000.0	MAAC
Jersey Central Power & Light Co.	N09	0140402	T	53.4	01452	S	06881105	01881	039.4	008.8	018.6	033.2	MAAC
N.J. Power & Light Co.	N28	0051826	T	63.3	00488	W	02705042	00151	084.8	000.0	015.2	000.0	MAAC
Public Service Electric & Gas Co.	N10	0614637	T	54.0	05925	S	28055190	07483	073.0	002.2	024.8	000.0	MAAC

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 6 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10³)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10³)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.) Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
NEW MEXICO:													
New Mexico Electric Service Co.	N12	0006132	T	77.4	00069	S	00468785	00120	098.3	000.0	001.7	000.0	WSCC
Public Service Co. of New Mexico	N13	0041674	T	63.1	00459	S	02534279	00542	100.0	000.0	000.0	000.0	WSCC
NEW YORK:													
Central Hudson Gas & Electric Corp.	N14	0064881	T	65.0	00550	S	03162296	00592	083.6	007.9	008.5	000.0	NPCC
Consolidated Edison Co. of New York, Inc.	N15	1117573	T	52.8	07719	S	36218739	08904	077.7	000.0	022.3	000.0	NPCC
Long Island Lighting Co.	N16	0262269	T	54.7	02405	S	11479088	02924	074.7	000.0	025.3	000.0	NPCC
New York State Electric & Gas Corp.	N18	0176574	T	63.8	01556	W	08696297	01406	096.3	002.8	000.9	000.0	NPCC
Niagara Mohawk Power Corp.	N19	0440327	T	69.1	04551	W	27544914	04107	058.3	017.8	009.0	014.9	NPCC
Orange & Rockland Utilities Inc.	N20	0055515	T	55.7	00524	S	02570549	00635	081.4	006.9	011.7	000.0	NPCC
Rochester Gas & Electric Corp.	N21	0110063	T	68.3	00790	S	04380613	00973	047.0	005.4	004.4	043.2	NPCC
NORTH CAROLINA:													
Carolina Power & Light Co.	N22	0255643	T	63.1	03795	S	20963536	04394	066.5	004.8	012.7	016.0	SERC
Duke Power Co.	N23	0451541	T	68.2	06622	S	39575576	07080	079.8	014.2	006.0	000.0	SERC
Nantahala Power & Light Co.	N24	0005290	T	62.4	00076	W	00415516	00100	000.0	100.0	000.0	000.0	SERC
NORTH DAKOTA:													
Montana-Dakota Utilities Co.	N26	0025190	T	63.1	00185	W	01022599	00216	092.6	000.0	007.4	000.0	MARCA
Otter Tail Power Co.	N27	0037874	T	56.3	00264	W	01302016	00239	089.1	001.7	009.2	000.0	MARCA
OHIO:													
Cincinnati Gas & Electric Co.	O01	0187996	T	59.3	02093	S	10882441	02387	084.7	015.3	000.0	000.0	ECAR
Cleveland Electric Illuminating Co.	O02	0266575	T	61.8	02792	S	15114965	03235	090.4	009.4	000.2	000.0	ECAR
Columbus & Southern Ohio Electric Co.	O03	0118875	T	55.2	01419	S	06862192	01477	080.2	000.0	019.8	000.0	ECAR
Dayton Power & Light Co.	O04	0133764	T	58.5	01501	S	07693081	01717	086.7	000.0	013.3	000.0	ECAR
Ohio Edison Co.	O05	0267481	T	66.1	02880	S	16671213	03252	099.9	000.0	000.1	000.0	ECAR

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 7 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10³)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10³)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.): Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
Ohio Power Co.	U06	0289887	T	77.4	04305	S	29191891	05962	099.9	000.0	000.1	000.0	ECAR
Toledo Edison Co.	U08	0101702	T	64.8	01054	S	05983009	01048	091.5	000.0	008.5	000.0	ECAR
OKLAHOMA: Oklahoma Gas & Electric Co.	U09	0156030	T	47.9	02360	S	09902654	02442	097.1	000.0	002.9	000.0	SWPP
Public Service Co. of Oklahoma	U10	0121212	T	48.6	01610	S	06854350	01726	098.7	000.0	001.3	000.0	SWPP
OREGON: California-Pacific Utilities Co.	U11	0012396	T	58.8	00163	W	00840061	00019	036.8	021.1	042.1	000.0	WSCC
Pacific Power & Light Co.	U12	0171679	T	69.2	02613	W	15837969	01546	033.6	066.3	000.1	000.0	WSCC
Portland General Electric Co.	U13	0104919	T	58.7	02056	W	10558000	00736	009.8	089.8	000.4	000.0	WSCC
PENNSYLVANIA: Duquesne Light Co.	P02	0193047	T	64.5	02015	S	11383103	02335	096.1	000.0	000.0	003.9	ECAR
Metropolitan Edison Co.	P04	0138109	T	65.9	01271	W	07336133	01339	082.4	001.0	016.6	000.0	MAAC
Pennsylvania Electric Co.	P05	0176754	T	64.3	01629	W	09176332	01855	091.3	006.7	002.0	000.0	MAAC
Pennsylvania Power Co.	P06	0042450	T	70.0	00465	S	02850495	00547	099.6	000.0	000.4	000.0	ECAR
Pennsylvania Power & Light Co.	P07	0298578	T	62.1	03294	W	17919228	03420	080.0	004.2	015.8	000.0	MAAC
Philadelphia Electric Co.	P08	0503008	T	58.1	04922	S	25045250	06367	057.3	021.9	020.2	000.6	MAAC
U.G.I. Corp.	P12	0012806	T	59.3	00101	W	00524931	00108	100.0	000.0	000.0	000.0	MAAC
West Penn Power Co.	P13	0154817	T	67.0	01868	W	10963665	02465	098.0	002.0	000.0	000.0	ECAR
RHODE ISLAND: Blackstone Valley Electric Co.	R01	0023752	T	63.7	00186	W	01034356	00029	096.6	003.4	000.0	000.0	NPCC
Newport Electric Co.	R03	0008716	T	61.8	00072	W	00389667	00027	048.1	051.9	000.0	000.0	NPCC
SOUTH CAROLINA: Lockhart Power Co.	S01	0002751	T	65.9	00047	S	00271589	00017	029.4	070.6	000.0	000.0	SERC
South Carolina Electric & Gas Co.	S02	0115660	T	58.8	01729	S	08856168	02395	083.0	010.5	006.5	000.0	SERC

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 8 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10³)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10³)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.): Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
Black Hills Power & Light Co.	S03	0013106	T	62.0	00112	W	00611470	00132	090.2	000.7	009.1	000.0	WSCC
Northwestern Public Service Co.	S04	0014000	T	47.6	00144	S	00600445	00082	033.0	000.0	067.0	000.0	MARCA
TEXAS:													
Central Power & Light Co.	T01	0123017	T	59.5	01654	S	08656933	02034	099.9	000.1	000.0	000.0	ERCOT
Dallas Power & Light Co.	T03	0124832	T	48.7	02056	S	08769223	02636	100.0	000.0	000.0	000.0	ERCOT
El Paso Electric Co.	T04	0038919	T	60.1	00501	S	02661782	00637	100.0	000.0	000.0	000.0	WSCC
Houston Lighting & Power Co.	T05	0317794	T	64.0	05530	S	30888019	06325	097.1	000.0	002.9	000.0	ERCOT
Southwestern Electric Power Co.	T06	0099287	T	50.3	01517	S	06753695	01265	096.2	000.0	003.8	000.0	SWPP
Southwestern Electric Service Co.	T07	0007594	T	43.3	00110	S	00417321	00017	076.5	000.0	023.5	000.0	ERCOT
Southwestern Public Service Co.	T08	0096973	T	61.5	01597	S	08603678	01868	096.4	000.0	003.6	000.0	SWPP
Texas Electric Service Co.	T09	0172037	T	57.1	02612	S	13093635	03039	100.0	000.0	000.0	000.0	ERCOT
Texas Power & Light Co.	T10	0189364	T	47.4	03224	S	13514485	03475	099.7	000.0	000.3	000.0	ERCOT
West Texas Utilities Co.	T11	0044270	T	60.2	00560	S	02953045	00723	098.6	000.0	001.4	000.0	ERCOT
TENNESSEE:													
Kingsport Power Co.	T12	0010608	T	53.9	00191	W	00899543	00000	000.0	000.0	000.0	000.0	SERC
UTAH:													
Utah Power & Light Co.	U01	0097439	T	66.1	01271	S	07362515	01402	087.6	011.4	001.0	000.0	WSCC
VERMONT:													
Central Vermont Public Service Corp.	V01	0031570	T	54.5	00314	W	01499098	00094	004.3	042.5	053.2	000.0	NPCC
Green Mountain Power Corp.	V02	0016701	T	57.3	00195	W	00978798	00051	000.0	049.0	051.0	000.0	NPCC
VIRGINIA:													
Virginia Electric & Power Co.	V08	0390370	T	57.5	05295	S	26705347	05189	083.5	006.3	010.2	000.0	SERC
WASHINGTON:													
Puget Sound Power & Light Co.	W01	0094101	T	54.5	01850	W	08832575	00398	021.6	077.6	000.8	000.0	WSCC
Washington Water Power Co.	W02	0052578	T	62.6	00934	W	05133821	00821	000.0	100.0	000.0	000.0	WSCC

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 9 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10³)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10³)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.): Fossil or Steam	Generation Capacity Mix: Hydro and Pumped Storage	Generation Capacity Mix: Gas Turbines and Diesels	Generation Capacity Mix: Nuclear	NERC Membership
WEST VIRGINIA:													
Appalachian Power Co.	W03	0228134	T	66.1	03333	W	19298594	03527	082.4	017.6	000.0	000.0	ECAR
Monangahela Power Co.	W04	0087236	T	71.8	00943	W	05931168	01357	100.0	000.0	000.0	000.0	ECAR
Wheeling Electric Co.	W06	0017338	T	74.3	00228	W	01484198	00000	000.0	000.0	000.0	000.0	ECAR
WISCONSIN:													
Consolidated Water Power Co.	W07	0002941	T	50.7	00052	S	00231079	00021	000.0	100.0	000.0	000.0	MARCA
Lake Superior Dist. Power Co.	W08	0011131	T	64.3	00100	W	00565982	00128	071.9	010.9	017.2	000.0	MARCA
Madison Gas & Electric Co.	W09	0023869	T	54.3	00283	S	01346140	00266	074.4	000.0	025.6	000.0	MAIN
Wisconsin-Michigan Power Co.	W14	0039431	T	68.5	00358	W	02148215	00320	000.0	019.4	003.1	077.5	MAIN
Northwestern Wisconsin Electric Co.	W11	0001331	T	57.5	00011	W	00055427	00011	000.0	018.2	081.8	000.0	MARCA
Wisconsin Electric Power Co.	W13	0219237	T	57.8	02831	S	14334145	02801	088.0	000.0	003.1	008.9	MAIN
Wisconsin Power & Light Co.	W15	0080307	T	62.6	00853	S	04670081	00920	084.8	004.3	010.9	000.0	MAIN
Wisconsin Public Service Corp.	W16	0074102	T	66.2	00714	S	04142761	00788	082.9	007.0	010.1	000.0	MAIN

End of List of Privately Owned Electric Systems

Publicly Owned Electric Systems Follow

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 10 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10^3)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (kWhrs x 10^3)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.): Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
Salt River Project Agricultural Improvement & Power District (Arizona)	X01	0085286	M	53.9	01147	S	05418734	00653	080.9	011.0	008.1	000.0	WSCC
City of Los Angeles, Department of Water & Power, Power System (Calif.)	X02	0228124	M	59.3	03430	S	17803097	03607	079.5	020.5	000.0	000.0	WSCC
Sacramento Municipal Utility District	X03	0047675	M	43.9	01020	S	03919704	00597	000.0	100.0	000.0	000.0	WSCC
City of Colorado Springs, Department of Public Utilities (Colo.)	X04	0016051	M	57.1	00217	W	01086341	00219	097.3	002.7	000.0	000.0	WSCC
Jacksonville, Electric Authority (Fla.)	X05	0068873	M	56.6	00898	S	04453721	01095	090.8	000.0	009.2	000.0	SERC
Orlando Utilities Commission (Fla.)	X06	0029352	M	54.0	00313	S	01479942	00436	091.3	000.0	008.7	000.0	SERC
City of Tallahassee (Fla.)	X07	0015443	M	50.4	00160	S	00707695	00234	082.5	000.0	017.5	000.0	SERC
Board of Public Utilities of Kansas City	X08	0021212	M	53.4	00325	S	01520085	00512	096.5	000.0	003.5	000.0	SWPP
City of Detroit, Public Lighting Commission	X09	0016659	M	63.6	00119	S	00661335	00174	100.0	000.0	000.0	000.0	ECAR
City of Lansing, Board of Water & Light (Mich.)	X10	0023359	M	63.0	00302	S	01669576	00469	099.8	000.2	000.0	000.0	ECAR
Nebraska Public Power District (Columbus)	X11	0054350	M	45.8	01161	S	04662887	00411	090.7	008.3	001.0	000.0	MARCA
Omaha Public Power District	X12	0059199	M	49.6	00913	S	03970265	00838	100.0	000.0	000.0	000.0	MARCA
Port Authority of the State of New York	X13	0100380	M	82.2	00858	W	06178654	03102	000.0	100.0	000.0	000.0	NPCC
The South Carolina Public Service Authority	X14	0033499	M	68.0	00622	S	03430207	00766	079.4	017.6	003.0	000.0	SERC
The Utility Fund, City of Austin	X15	0034773	M	47.3	00541	S	02243090	00862	100.0	000.0	000.0	000.0	ERCOT
Lower Colorado River Authority (Texas)	X16	0019031	M	53.4	00568	S	02656871	00534	062.2	037.8	000.0	000.0	ERCOT
City Public Service Board of San Antonio	X17	0066024	M	47.4	01274	S	05306822	01876	099.9	000.1	000.0	000.0	ERCOT
Public Utility District #2 of Grant County (Washington)	X18	0026709	M	60.7	00170	SW	00903742	01620	000.0	100.0	000.0	000.0	WSCC
City of Seattle, Department of Lighting	X19	0056372	M	57.3	01380	W	06927066	01241	004.1	095.9	000.0	000.0	WSCC

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 11 OF 12)

Company Name	Company ID. Code	Annual Electric Operating Revenues ($ x 10³)	Type of Owner	Annual Load Factor (%)	System Peak Load (MW)	Peak Season	Total Net Energy For Load (MWhrs x 10³)	Total System Capacity (MW)	Generation Capacity Mix (% of Total System Cap.) Fossil or Steam	Hydro and Pumped Storage	Gas Turbines and Diesels	Nuclear	NERC Membership
City of Tacoma, Department of Public Utilities, Light Division	X20	0028475	M	63.1	00776	W	04285832	00719	008.2	091.8	000.0	000.0	WSCC
Public Utility District #1 Snohomish County (Washington)	X22	0022776	M	54.4	00683	W	03259062	00000	000.0	000.0	000.0	000.0	WSCC
Bonneville Power Administration	Y01	0152728	F	78.9	05855	W	40461427	09720	100.0	000.0	000.0	000.0	WSCC
Tennessee Valley Authority	Y02	0598035	F	63.8	16745	W	93521786	19829	076.3	021.8	001.9	000.0	SERC
Pick-Sloan Missouri Basin Program Integrated Power System-USBR	Y03	0075060	F	58.0	00711	W	03614254	02298	000.0	100.0	000.0	000.0	MARCA
Central Valley Project -USBR	Y06	0028207	F	42.2	00227	S	00840573	01090	000.0	100.0	000.0	000.0	WSCC
Colorado River Storage Project-USBR	Y07	0030026	F	51.1	00092	S	00410811	01262	000.0	100.0	000.0	000.0	WSCC
Western Farmers Electric Cooperative (Okla.)	Z08	0007317	C	56.0	00237	S	01162481	00279	098.6	000.0	001.4	000.0	SWPP
City of Independence, Power & Light Dept. (Mo.)	Z10	0008890	M	37.3	00139	S	00453927	00161	077.6	000.0	022.4	000.0	SWPP
City Utilities of Springfield (Mo.)	Z13	0011343	M	44.3	00235	S	00914706	00275	093.5	000.0	006.5	000.0	SWPP
Minnkota Power Cooperative Inc. (N. Dak.)	Z15	0010126	C	52.7	00199	W	00918299	00300	092.7	000.0	007.3	000.0	MARCA
Rural Cooperative Power Association (Minn.)	Z17	0009758	C	54.7	00178	W	00852556	00064	070.3	000.0	029.7	000.0	MARCA
City of Lakeland, Department of Electric & Water Utilities (Fla.)	Z21	0013570	M	53.8	00147	S	00691271	00274	085.8	000.0	014.2	000.0	SERC
Incorporated Village of Freeport (N.Y.)	Z22	0003757	M	51.6	00033	S	00147334	00034	000.0	000.0	100.0	000.0	NPCC
Colorado Ute Electric Association Inc.	Z24	0008207	C	52.0	00137	W	00622971	00201	098.5	000.5	001.0	000.0	WSCC
Eugene Water & Electric Board (Oregon)	Z25	0012776	M	53.2	00345	W	01610117	00137	018.2	081.8	000.0	000.0	WSCC
Corn Belt Power Cooperative (Iowa)	Z26	0006235	C	55.7	00107	W	00524669	00106	076.4	000.0	023.6	000.0	MARCA

Table B1-1 1971 U.S. ELECTRIC UTILITY SYSTEM LOAD AND GENERATION DATA BASE (SHEET 12 OF 12)

Notes:

1. Types of ownership:
   - T - private
   - M - municipal
   - F - Federal power agency
   - C - cooperative

2. Peak season:
   - S - summer
   - W - winter

3. National Electric Reliability Council (NERC) regional councils:
   - ECAR - East Central Area Reliability Coordination Agreement
   - ERCOT - Electric Reliability Council of Texas
   - MAAC - Mid-Atlantic Area Council
   - MAIN - Mid-America Interpool Network
   - MARCA - Mid-Continent Area Reliability Coordination Agreement
   - NPCC - Northeast Power Coordinating Council
   - SERC - Southeastern Electric Reliability Council
   - SWPP - Southwest Power Pool
   - WSCC - Western Systems Coordinating Council

million or more, and publicly owned systems with operating revenue of $50 million or more. Of the 199 systems, 163 are privately owned, 26 are municipals, 5 are Federal power agencies and 5 are cooperatives.

The type of load and generation data shown in Table B1-1 is identified by the headings of the attached data forms. The load data consists of annual system load factors, system peak loads, peak season, and total net annual energy produced for load. The generation data includes the installed capacity for each system and its percentage generation mix according to the four general categories: fossil or steam, hydro and pumped storage, gas turbine and diesels, and nuclear. In most cases the total system capacity represents the net generating capability of generating stations owned and operated by the individual utility, as well as the utility's share of generation jointly-owned with one or more other systems. This total system capacity does not necessarily represent the individual utility's system reserve capability because firm purchases from other companies are not included in the capacity figures.

Table B1-1 includes information as to utility 1971 annual electric operating revenues; type of ownership (private or public); National Electric Reliability Council (NERC) membership (or an assigned NERC region according to the general area in which the utility operates); and a company ID code for computer processing.

The primary sources of system load and generation characteristics from which the 1971 data base was developed are:

a) Federal Power Commission (FPC)
b) Edison Electric Institute (EEI)
c) National Electric Reliability Council (NERC) and its nine regional councils
d) Rural Electrication Administration (REA)

B1.2.2 Load Characteristics

B1.2.2.1 Average System Size Table B1-2 shows the results of the statistical analysis to determine average utility system size in terms of peak load and annual system energy produced for load [13]. Of the 199 systems, 65% are summer peaking systems and 35% winter peaking.

The average size system in terms of peak load is about 1500 megawatts. The average summer peaking system is about 600 megawatts larger than the average winter peaking system. However the system with the largest peak in the data base is a winter peaking system, the Tennessee Valley Authority. The largest summer peaking system is the Commonwealth Edison Company in Illinois with a 1971 peak of about 10,900 megawatts. The systems

Table B1-2 AVERAGE U.S. ELECTRIC UTILITY SYSTEM SIZE - 1971 DATA BASE

	All Systems	Summer Peaking Systems	Winter Peaking Systems
Number of Systems	199	129	70
System Grouping by Load (MW):			
0 - 1,000	115	65	50
1,001 - 5,000	71	53	18
5,001 - 10,000	11	10	1
10,001 and beyond	2	1	1
System Peak Load (MW):			
Average	1,500	1,700	1,100
Minimum	6	17	6
Maximum	16,700	10,900	16,700
System Grouping by Energy (MWhrs x 10^3):			
0 - 1,000	48	22	26
1,001 - 5,000	67	47	20
5,001 - 10,000	40	27	13
10,001 and beyond	44	33	11
System Annual Energy Produced for Load (MWhrs x 10^3):			
Average	7,900	8,700	6,400
Minimum	27	85	27
Maximum	93,500	54,300	93,500

with the smallest peak loads are the Boston Gas Co. (Mass.), a summer peaking system with a 17 MW load, and the Nantucket Gas & Electric Co. (Mass.), a winter peaking system with a 6 MW load.

The average size system in terms of system annual energy produced for load considering all 199 systems is about 7,900 GWhrs. The annual energy of the average summer peaking system is about 2,300 GWhrs. greater than the average winter peaking system. However, once again the system with the largest amount of annual energy is a winter peaking system, the Tennessee Valley Authority. The summer peaking system with the largest amount of annual energy generated for load is the Pacific Gas and Electric Co. in California. The winter and summer peaking system with the smallest amount of annual energy are the Nantucket Gas & Electric Co. (Mass.) with 27,000 MWhrs. and the Mt. Carmel Public Utility (Ill.) with 85,000 MWhrs.

B1.2.2.2 Annual System Load Factors The annual system load factors of the 199 systems in the 1971 data base were analyzed to determine their range. Table B1-3 summarizes the results of this analysis. The annual load factors are expressed in percent and are defined as the percentage ratio of net annual energy for load to the product of annual peak load (one hour integrated peak demand) and annual hours.

The annual load factors were found to range about 45 percentage points from a low of about 37% to a high of about 82%. The range of the annual load factors for the summer peaking companies was 9 percentage points more than the winter peaking companies. In general the annual load factors for the winter peaking companies are higher than the summer peaking companies, because of more extremely weather sensitive loads in the summer.

The average annual load factor for all systems, Summer peaking system alone and Winter peaking systems alone, are shown in Table B1-3. In addition these industry averages were also calculated on both an annual peak load and energy basis in order to take into consideration the effect of relative system sizes. On a weighted (peak load or energy) basis, the average system load factors were found to be a few percentage points higher than on an unweighted basis. For summer peaking systems, on a weighted basis, the average annual load factor is 59%.
On a similar weighted basis, the average annual load factor for winter peaking systems is 65%.

The 1971 annual load factor analysis also showed that the sample data of annual load factors very closely represented a normal distribution. The frequency distribution of the annual load factors for the 1971 utility data base is shown in Figure B1-1. Also shown on this figure are separate distributions for the winter and summer peaking system. The figure shows the wider annual load factor range for summer peaking systems compared to the winter peaking systems. The peak load weighted average

Table B1-3 ELECTRIC UTILITY ANNUAL LOAD FACTOR ANALYSIS - 1971 DATA BASE

Description	Systems	Summer Peaking Systems	Winter Peaking Systems
Number of Systems	199	129	70
Annual Load Factors (%):			
Range	45	40	31
Minimum Value	37	37	51
Maximum Value	82	77	82
Average			
1) Unweighted	59 ± 7.3*	57 ± 7.0*	62 ± 6.5*
2) Weighted (Peak Load)	60 ± 6.8*	59 ± 6.2*	65 ± 6.1*
3) Weighted (Annual Energy)	61 ± 6.8*	59 ± 6.2*	65 ± 6.3*
Median	59	57	62

* Plus and minus one standard deviation.

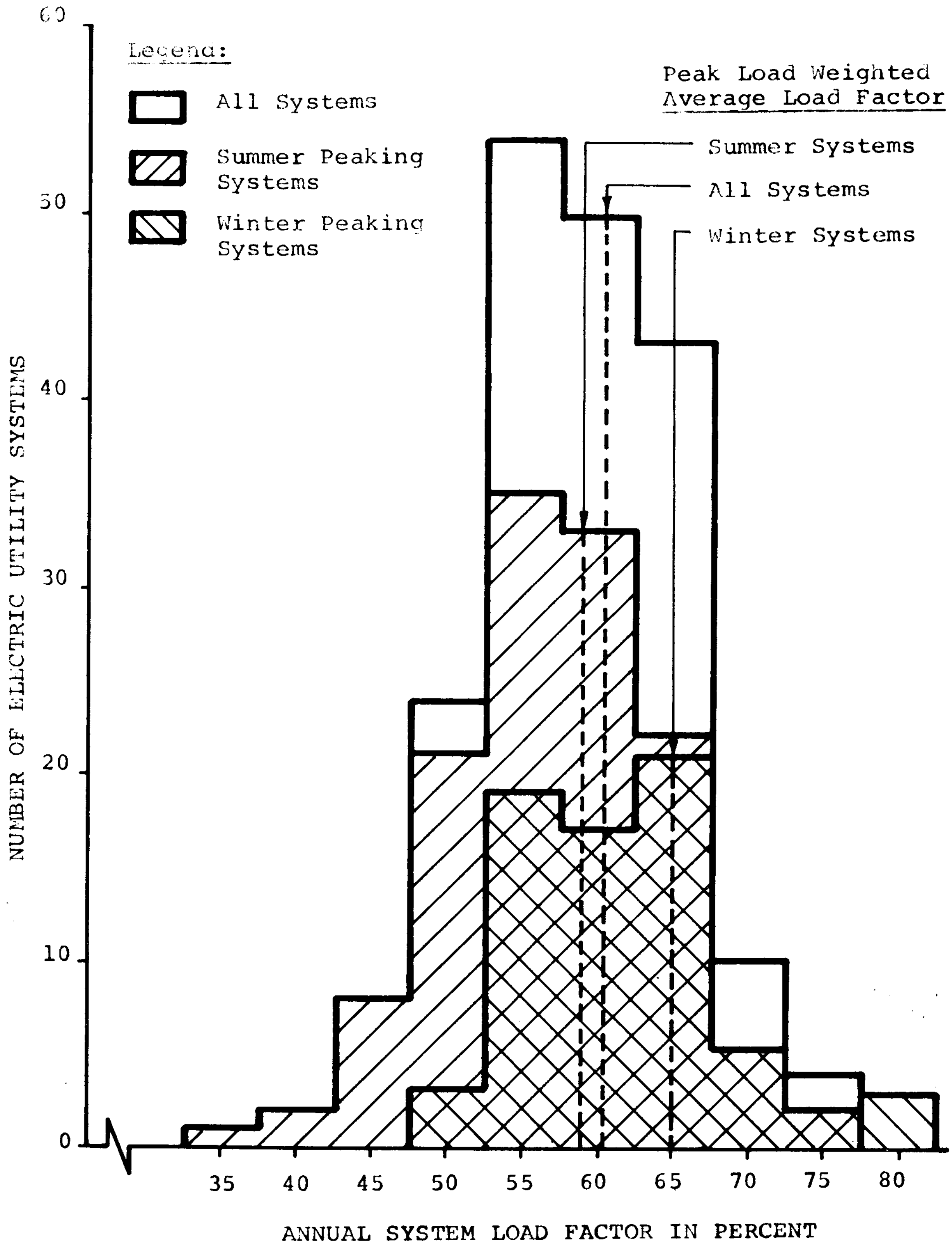


Figure B1-1 FREQUENCY DISTRIBUTION OF ELECTRIC UTILITY 1971 ANNUAL SYSTEM LOAD FACTORS annual load factors for all systems, summer peaking systems, and winter peaking systems are also identified.

Figure B1-2 shows the cumulative frequency annual system load factor distribution. Approximately 140 or 70% of the 199 systems were found to have annual load factors between 50 and 65%, 20% had load factors below 50% and only 10% had load factors above 65%. About half of the systems have annual load factors above and below 55%. Figure B1-3 shows the energy distribution for the 1971 utility data base according to annual system load factor for all systems, summer peaking systems, and winter peaking systems. About 70 percent of the total energy generated in the U.S. is supplied by summer peaking systems.

B1.2.2.3 <u>Valley to Peak Load Ratios</u> A valley to peak load ratio analysis was performed to verify that the selected representative systems were typical of the U.S. electric utility industry as far as load curves or shapes are concerned. From the annual hourly load data of approximately 100 utility systems for which such data was available, average annual weekday, Saturday and Sunday hourly load curves were developed for each system and used to determine valley to peak load ratios for average Saturdays, Sundays and weekdays. The results of this electric utility analysis are shown in Table B1-4.

Table B1-4 indicates that the variation in daily load shape is greater on a weekday than on an average Saturday or Sunday since the valley to peak load ratio for an average weekday is less than that of Saturday or Sunday. The average valley to peak load ratios for winter peaking systems are higher than the summer peaking systems. A comparison of the peak to peak load ratios also shows that Saturday peak loads are generally higher than Sunday peaks. The minimum to maximum annual load ratio indicates that the lowest annual system load is generally in the order of about 30 percent of the system annual peak load.

B1.2.3 <u>Generation Data</u> The generation capacity was categorized into four general types as follows: conventional steam units; hydro and/or pumped storage, gas turbines and/or diesels, and nuclear units.
Only 18 of the 199 utilities reported nuclear capacity on their system, about half of the utilities reported having hydro and/or pumped storage units, about 85 percent of the utilities reported having some conventional steam capacity, and about 2/3 of utilities included gas turbines and/or diesels in their capacity mix. The average generation capacity mix of the 1971 utility data base on a percentage basis was as follows: Conventional steam, 80%; hydro and/or pumped storage, 11%; gas turbines and/or diesels, 7%; and nuclear, 2%.

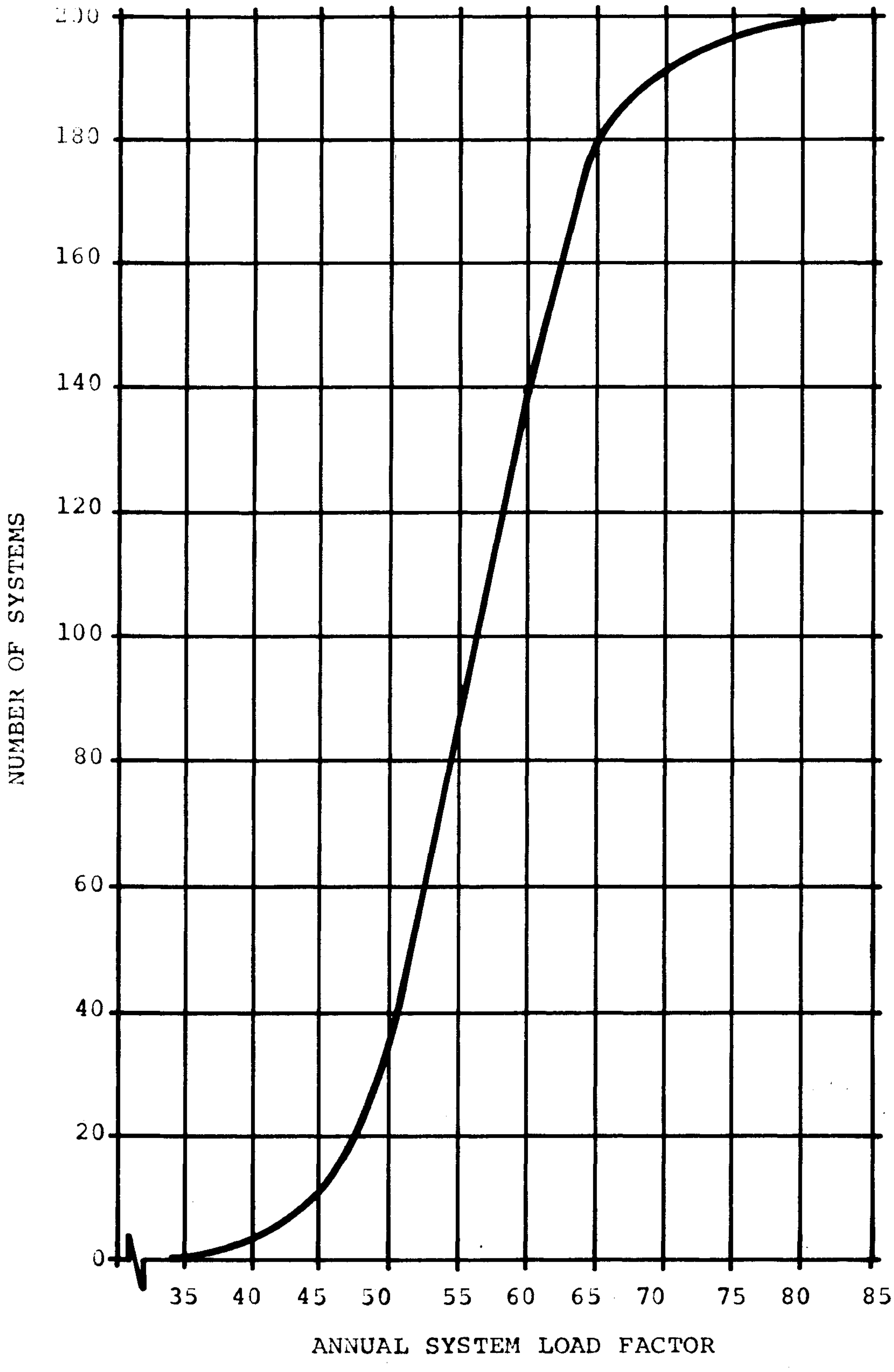


Figure B1-2 CUMULATIVE FREQUENCY DISTRIBUTION OF ELECTRIC UTILITIES 1971 ANNUAL SYSTEM LOAD FACTORS

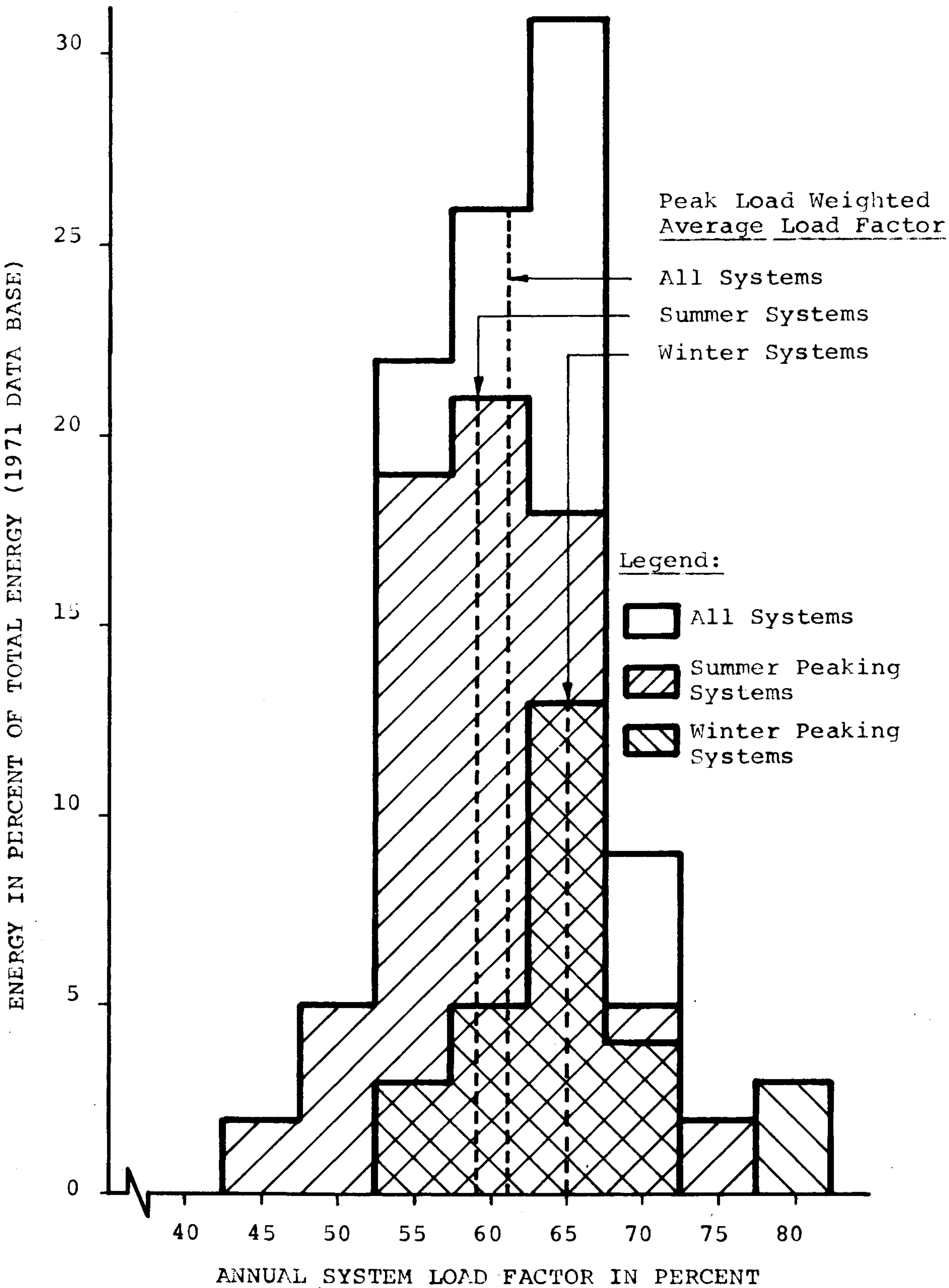


Figure B1-3 FREQUENCY DISTRIBUTION OF ELECTRIC UTILITY 1971 SYSTEM ENERGY PRODUCED FOR LOAD VS. 1971 ANNUAL SYSTEM LOAD FACTOR

Table B1-4 ELECTRIC UTILITY VALLEY TO PEAK LOAD RATIO ANALYSIS (1971 EEI SYSTEM HOURLY LOAD DATA BASE)

Description	Load Ratios in Percent		
	All Systems	Summer Peaking Systems	Winter Peaking Systems
Number of Systems	102[a]	79	23
I Valley/Peak Load Ratio			
Average Weekday	59 ± 7*	58 ± 6*	63 ± 10*
Average Saturday	66 ± 8*	65 ± 7*	69 ± 8*
Average Sunday	66 ± 7*	65 ± 6*	70 ± 9*
II Peak/Peak Load Ratio			
Saturday/Weekday	88 ± 6*	87 ± 6*	91 ± 5*
Sunday/Weekday	82 ± 6*	81 ± 6*	85 ± 6*
III Minimum/Maximum Load Ratio	30 ± 7*	29 ± 6*	34 ± 10*

*Plus and minus one standard deviation.

a) The 102 utility systems represent about 63% of the installed capacity and about 69% of the total energy generated in the U.S. in 1971.

B1.3 REPRESENTATIVE U.S. ELECTRIC UTILITY SYSTEMS

B1.3.1 Method Of Selection

The statistical analyses of both the 1971 utility data base and the 1971 EEI systems annual hourly load data base as to average system size, season of system peak, annual system load factor, valley to peak load ratio, generation mix as well as regional representation of the U.S. were used as guides to select the representative U.S. electric utility systems.

All 199 systems as listed in the 1971 utility data base were not represented as individual system in the EEI annual hourly load data base. EEI data included only 102 of the 199 individual 1971 utility data base systems. As the availability of individual system annual hourly load data was critical to assessing energy storage requirements for use on utility systems, the selection of representative systems was limited to those 102 systems of the EEI data base. This particular constraint did not have any significant effect on representative system selection.

Six systems as well as a power pool and a member company of the pool were selected as being most representative of the electric utility industry. These systems which are coded by letter designations A, B, C, A', B', C', Y and Z are shown in Table 1-5.

Three summer peaking and three winter peaking systems were selected. The summer peaking systems are representative of the southern (southeast, south central and southwest) regions of the U.S. while the winter peaking systems are representative of the northern (northeast, north central and northwest) regions. The power pool and its member company are summer peaking systems located in the eastern U.S.

With respect to system size, the three summer peaking systems, A, B and C, have annual system peak loads ranging from 2000 to 7000 megawatts compared to the summer peaking system average of 1700 megawatts. A summer peaking system of the average size did not meet several of the other requirements for system selection. The representative winter peaking systems, A', B', and C', with annual system peaks ranging from 600 to 2000 megawatts, encompass the average winter system peak of 1100 megawatts. Based on the availability of utility system and power pool annual hourly load data, a power pool with a peak load of about four times the member utility's peak load was selected.

Systems B (60 percent annual load factor) and B' (63 percent annual load factor are representative of the weighted industry average annual load factor systems of 60 and 65 percent respectively for summer and winter peaking utilities. System A (48 percent annual load factor) is about 2 standard deviations and system C (68 percent annual load factor) is about 1 1/2

Table B1-5 REPRESENTATIVE U.S. ELECTRIC SYSTEMS

System	Peak Season	Annual Load Factor (Percent)	Assumed Industry Representation: Peak Season Only (Percent)	Assumed Industry Representation: Combined (Percent)
A	Summer	48	25	16
B	Summer	60	70	46
C	Summer	68	5	3
A'	Winter	55	30	10
B'	Winter	63	65	23
C'	Winter	78	5	2
Y	Summer	54	--	--
Z	Summer	61	--	--

standard deviations from the weighted industry average summer load factor system and represent low and high load factor summer systems, respectively. Similarly, systems A' (55 percent annual load factor) and C' (78 percent annual load factor) are about 1 1/2 and 2 standard deviations from the weighted industry average winter annual load factor system and represent low and high load factor winter systems, respectively.

All of the eight representative systems' load ratios are within one standard deviation of the summer and winter peaking system utility averages of Table B1-4 except for the following deviations. System C', with a very high annual load factor of 78 percent, exceeds the winter weekday and Saturday valley to peak load ratio averages by only 1.2 and 1.4 standard deviations, respectively. Similarly, for the peak to peak load ratio analysis, system Y exceeds by 1.3 and 1.4 standard deviations, respectively, the average Saturday peak to weekday peak and the Sunday peak to weekday peak average load ratios. In addition, system C with very low Sunday loads has an average Sunday peak to weekday peak load ratio about 2.7 standard deviations below the average value of Table B1-4 for summer peaking systems.

Each system was assumed to represent a certain portion of the electric utility industry as shown in Table B1-5. The relative percentages assigned to each system were based on the statistical load factor analysis shown in Figures B1-1, B1-2, and B1-3. For example, system B was assumed to be representative of 70 percent of the summer peaking systems and 45 percent of all companies on a combined summer-winter basis.

B1.3.2 Additional System Description

Figure B1-4 shows a plot of the weekly peak loads for the eight representative U.S. electric systems. A comparison of the summer peaking systems, A, B and C, demonstrates the greater disparity in weekly peaks for system A, a system with a low (48%) annual load factor, compared to systems B and C with annual load factors of 60 and 68 percent, respectively. Similarly for the winter peaking systems, Figure B1-4 indicates the relatively low weekly peak loads for system A', a system with an annual load factor of 55 percent. The lowest weekly peaks for winter peaking systems A', B', and C' are 53, 74 and 82 percent of the individual annual peak loads respectively. This figure also shows that representative utility system Y very closely follows the weekly peaking pattern of power pool Z. This analysis indicates that the differences in weekly peak hourly loads between the peak season and the other three non-peaking seasons is the main reason why electric systems have poor system annual load factors.

Table B1-6 shows that the average percentage mix of the generating capacity of the representative systems very closely approximates the average percentage generation mix of the 1971 utility data base. None of the six representative systems A, B,

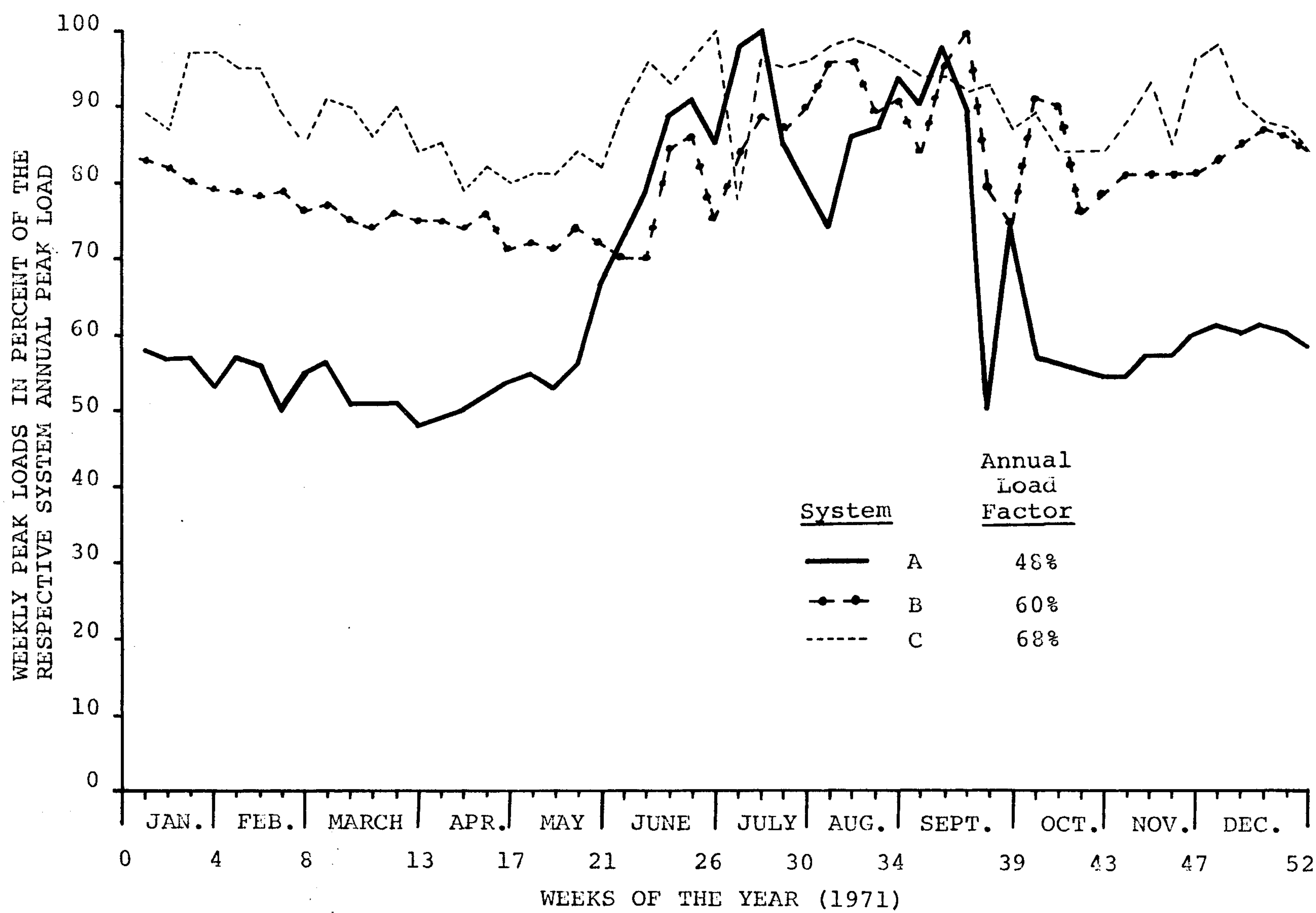


Figure B1-4 WEEKLY PEAK LOADS FOR REPRESENTATIVE U.S. ELECTRIC SYSTEMS (sheet 1 of 3)

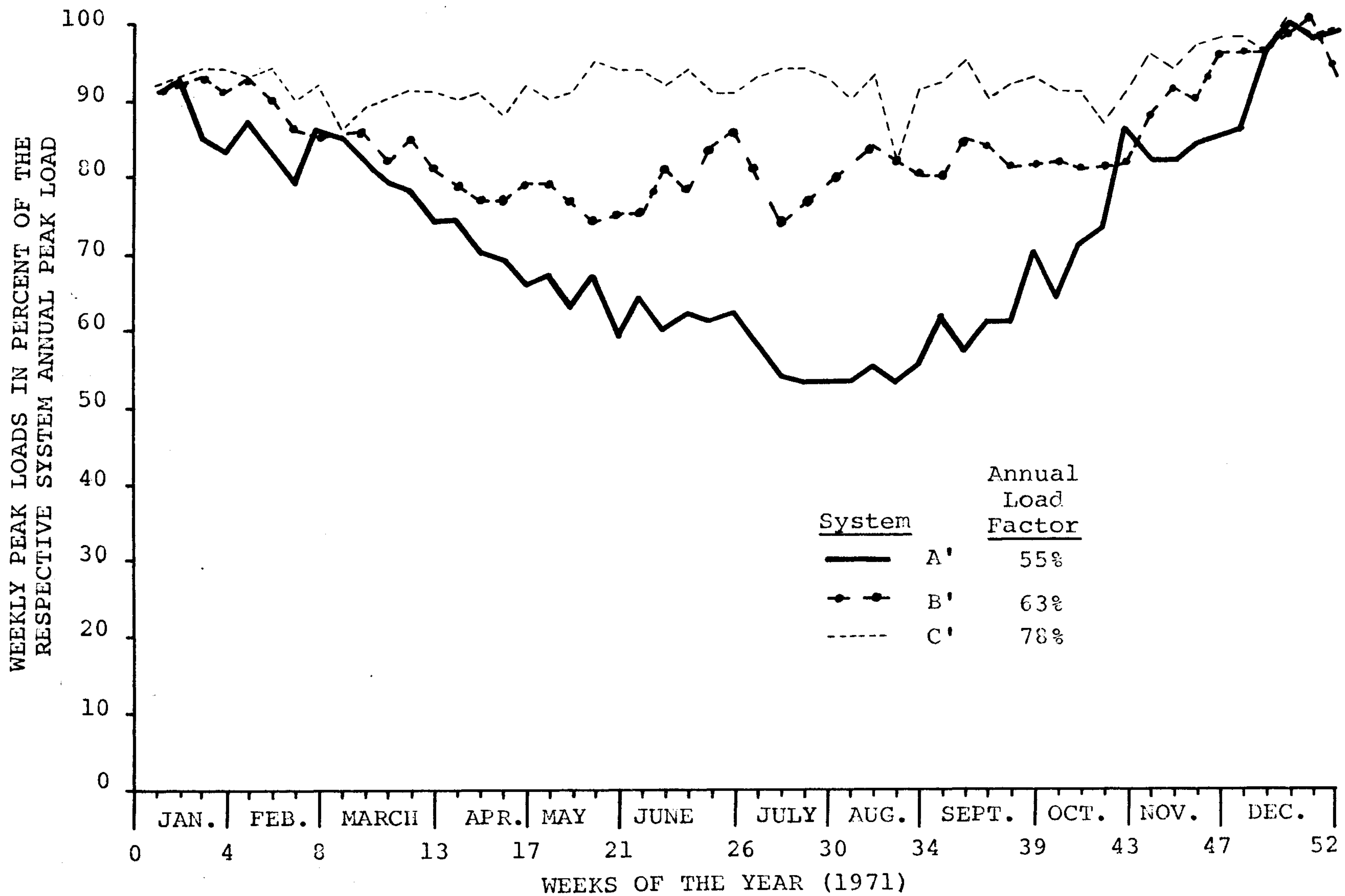


Figure B1-4 WEEKLY PEAK LOADS FOR REPRESENTATIVE U.S. ELECTRIC SYSTEMS (sheet 2 of 3)

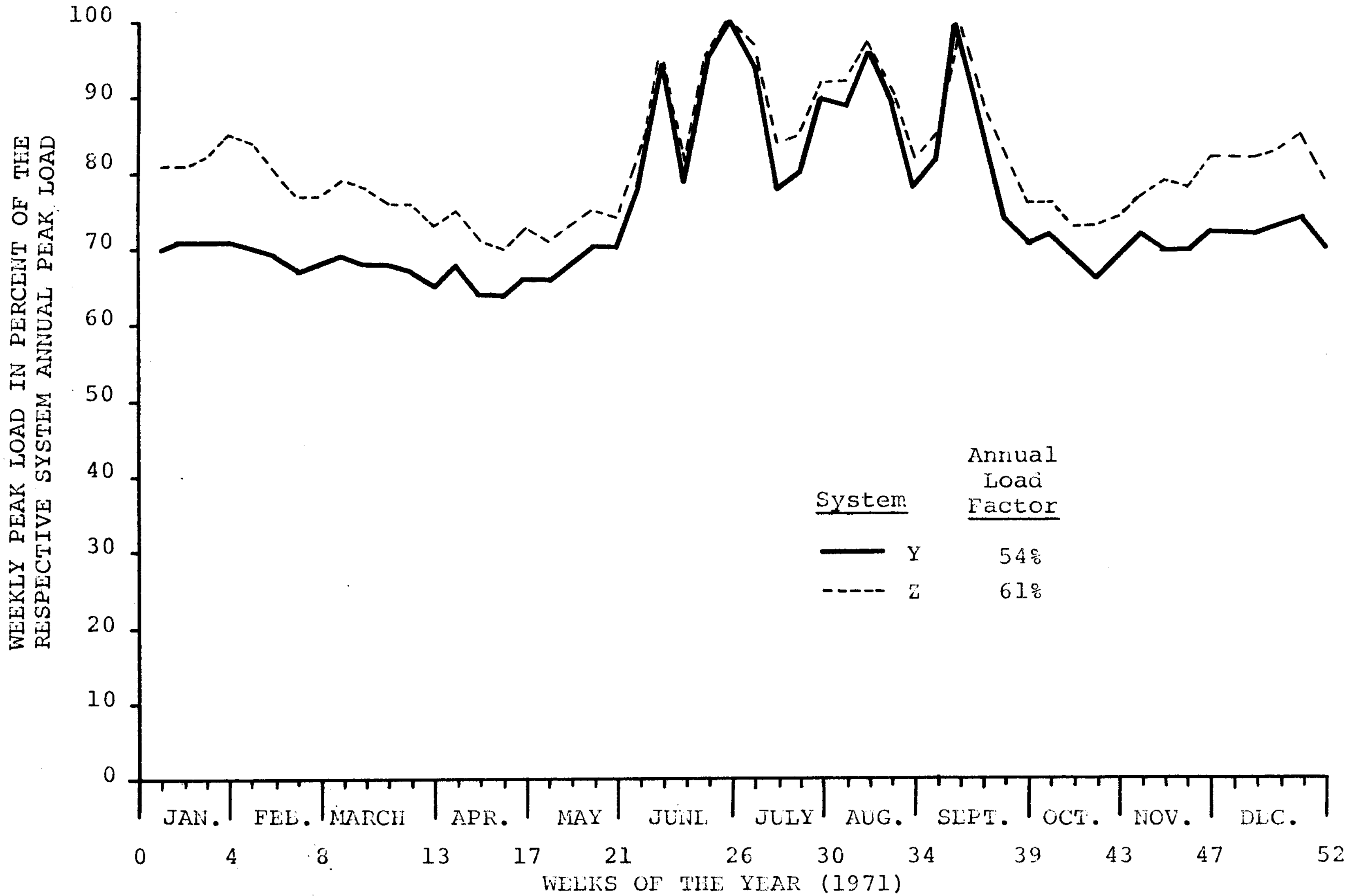


Figure B1-4 WEEKLY PEAK LOADS FOR REPRESENTATIVE U.S. ELECTRIC SYSTEMS (sheet 3 of 3)

Table B1-6 GENERATION MIX OF REPRESENTATIVE SYSTEMS AND 1971 UTILITY DATA BASE

Type Capacity	Percentage Mix			
	1971 Data Base	Systems A,B,C and A'B',C'	System Y	Power Pool Z
Conventional Steam	80	83	75	75
Hydro and/or Pumped Storage	11	14	2	3
Gas Turbines and/or Diesels	7	3	23	20
Nuclear	2	-	--	2

C and A', B', C' had any nuclear units in service in 1971. Table B1-6 also shows the percentage generation mix for the power pool Z and its member system Y.

The percentage mix of energy sales and electric customer for the representative systems are shown in Tables B1-7 and B1-8, respectively. System B sells half of its energy to commercial customers; system A', 57 percent to residential customer; and system C', 65 percent to industrial customers. In terms of number of customers, all representative systems have a substantial majority of residential customers. Although the number of industrial customers is relatively small on each system, a substantial portion of the energy sales of the representative systems is for industrial customers.

Table B1-7 PERCENTAGE MIX OF TOTAL 1971 ENERGY SALES[a] FOR REPRESENTATIVE U.S. ELECTRIC SYSTEMS

System	Residential (%)	Commercial (%)	Industrial (%)	Other[b] (%)	Sales for Resale (%)
A (48)	27	18	23	9	23
B (60)	28	50	20	2	0
C (68)	24	16	44	1	15
A' (55)	57	21	19	2	1
B' (63)	34	19	23	10	14
C' (78)	15	10	65	1	9
Y (54)	27	29	42	1	1
Z (61)	30	23	42	2	3

a) Source: FPC Publications, FPC S226 (Oct 1972) and FPC S228 (Dec 1972).

b) Other includes sales of electricity for public street and highway lighting, interdepartmental, other public authorities, and railroads and railways.

Table B1-8 PERCENTAGE MIX OF TOTAL 1971 ELECTRIC CUSTOMERS[a] FOR REPRESENTATIVE U.S. ELECTRIC SYSTEMS

System	Residential (%)	Commercial (%)	Industrial (%)	Other[b] (%)	Sales for Resale (%)
A (48)	88	10	1	1	Negligible
B (60)	85	14	1	Negligible	"
C (68)	78	21	1	"	"
A'(55)	91	9	Negligible	Negligible	Negligible
B'(63)	90	9	"	1	"
C'(78)	87	12	1	Negligible	"
Y (54)	88	11	1	Negligible	"
Z (61)	88	11	1	"	"

a) Source: FPC Publications, FPC S226 (Oct 1971) and FPC S228 (Dec 1972).

b) Other includes number of customers for public street and highway lighting, interdepartmental, other public authorities, and railroads and railways.

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12. EEI Subcommittee Report, "Ten-Year Report on Load Diversity Based on 1962-71 Load Data," Edison Electric Institute, New York, New York.

13. National Bureau of Standards Handbook 101, "A Computer Program for Statistical and Numerical Analysis," U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 20402, March, 1966.

B2 Results of the Representative Electric Utility System Analysis

Tables B2-1 through B2-5 shows for each representative system the seasonal, weekly and daily distribution of the maximum amount of available off-peak energy and the associated maximum amount of on-peak energy requirements capable of being supplied by the off-peak energy.

Tables B2-6 through B2-11 shows for each representative system the characteristics (load magnitute, duration and frequency of occurrence) of the off-peak and on-peak energy.

Tables B2-12 through B2-15 shows the weighted industry averages, on a summer peaking, winter peaking and combined summer-winter basis, of the distribution and characteristics of the off-peak and on-peak energy.

Table B2-1 MAXIMUM OFF-PEAK AND ON-PEAK ENERGY AND ASSOCIATED BASE LOAD CAPACITY LEVELS FOR THE REPRESENTATIVE ELECTRIC SYSTEMS

System	Annual Load Factor (Percent)	"Optimum" Baseload Capacity Level (Percent of System Peak)	Off-Peak and On-Peak Energy (Percent of Total Energy Produced for Load)
A	48	59	11.2
B	60	73	10.5
C	68	84	9.0
A'	55	68	11.0
B'	63	78	10.3
C'	78	96	6.0
Y	54	67	11.0
Z	61	75	10.5

Table B2-2 SEASONAL DISTRIBUTION OF OFF-PEAK AND ON-PEAK ENERGY ON REPRESENTATIVE ELECTRIC SYSTEMS

Representative System	Baseload Capacity Level (%)	Energy	Seasonal Distribution Winter (%)	Spring (%)	Summer (%)	Fall (%)
A	59	Off-Peak[1]	26	33	16	25
		On-Peak[2]	9	10	65	16
B	73	Off-Peak	21	26	34	19
		On-Peak	26	19	25	30
C	84	Off-Peak	19	26	36	19
		On-Peak	30	21	19	30
A'	67	Off-Peak	16	22	45	17
		On-Peak	41	18	2	39
B'	77	Off-Peak	30	26	25	19
		On-Peak	21	20	24	35
C'	95	Off-Peak	45	16	23	16
		On-Peak	6	30	28	37
Y	67	Off-Peak	23	27	27	23
		On-Peak	24	20	30	27
Z	76	Off-Peak	19	27	32	22
		On-Peak	30	19	24	27

1 Off-Peak Energy in Percent of Total Off-Peak Energy

2 On-Peak Energy in Percent of Total On-Peak Energy

Table B2-3 SEASONAL WEEKLY DISTRIBUTION OF OFF-PEAK ENERGY AND ON-PEAK ENERGY ON REPRESENTATIVE ELECTRIC SYSTEMS

Represen-tative System	Baseload Capacity Level (%)	Energy	Average Weekly Distribution Winter (%)	Spring (%)	Summer (%)	Fall (%)
A	59	Off-Peak[1]	2.0	2.5	1.3	1.9
		On-Peak[2]	0.7	0.7	5.0	1.3
B	73	Off-Peak	1.7	2.0	2.7	1.4
		On-Peak	2.0	1.4	1.9	2.3
C	84	Off-Peak	1.4	2.0	2.9	1.4
		On-Peak	2.3	1.6	1.5	2.4
A'	67	Off-Peak	1.2	1.7	3.5	1.3
		On-Peak	3.2	1.3	0.2	3.0
B'	77	Off-Peak	2.3	2.0	2.0	1.4
		On-Peak	1.6	1.5	1.8	2.7
C'	95	Off-Peak	3.5	1.2	1.8	1.2
		On-Peak	0.4	2.3	2.1	2.8
Y	67	Off-Peak	1.8	2.1	2.1	1.7
		On-Peak	1.8	1.5	2.3	2.1
Z	75	Off-Peak	1.5	2.1	2.5	1.7
		On-Peak	2.3	1.5	1.8	2.1

1. Off-Peak Energy in Percent of Total Off-Peak Energy

2. On-Peak Energy in Percent of Total On-Peak Energy

Table B2-4 SEASONAL DAILY DISTRIBUTION OF OFF-PEAK ENERGY ON REPRESENTATIVE ELECTRIC SYSTEMS (PERCENT OF TOTAL OFF-PEAK ENERGY)

Representative System	Baseload Capacity Level	Winter(%)			Spring(%)			Summer(%)			Fall(%)		
		Wkdy.	Sat.	Sun.	Wkdy.	Sat.	Sun.	Wkdy.	Sat.	Sun.	Wkdy.	Sat.	Sun.
A	59	.2	.4	.5	.3	.5	.6	.2	.2	.3	.2	.3	.5
B	73	.2	.3	.5	.2	.4	.6	.3	.5	.6	.2	.2	.4
C	84	.1	.3	.7	.1	.3	1.0	.3	.5	1.1	.0	.2	.8
A'	67	.2	.2	.2	.2	.3	.4	.4	.6	.7	.2	.2	.2
B'	77	.2	.5	.6	.2	.4	.6	.2	.3	.5	.1	.3	.4
C'	95	.4	.7	.7	.1	.2	.4	.2	.2	.5	.2	.2	.3
Y	67	.2	.4	.5	.2	.4	.6	.2	.4	.5	.2	.4	.5
Z	75	.1	.3	.4	.2	.4	.6	.3	.4	.6	.2	.3	.5

Table B2-5 SEASONAL DAILY DISTRIBUTION OF ON-PEAK ENERGY ON REPRESENTATIVE ELECTRIC SYSTEMS (PERCENT OF TOTAL ON-PEAK ENERGY)

Representative System	Baseload Capacity Level (%)	Winter		Spring		Summer		Fall	
		Wkdy (%)	Wkend (%)	Wkdy (%)	Wkend (%)	Wkdy (%)	Wkend (%)	Wkdy (%)	Wkend (%)
A	59	.1	.0	.1	.1	.8	.9	.2	.1
B	73	.4	.1	.3	.0	.4	.1	.5	.1
C	84	.5	.1	.3	.1	.3	.1	.5	.1
A'	67	.5	.6	.2	.1	.0	.0	.5	.6
B'	77	.3	.1	.3	.0	.4	.0	.5	.1
C'	95	.1	.0	.4	.3	.4	.2	.4	.5
Y	67	.4	.0	.3	.0	.5	.1	.4	.0
Z	75	.5	.0	.3	.0	.4	.0	.4	.0

Table B2-6 OFF-PEAK ENERGY CHARACTERISTICS OF REPRESENTATIVE ELECTRIC SYSTEMS

Representative System	Energy Characteristics	Average Weekday	Average Weekend Saturday	Sunday	Total
A	Magnitude (% of peak)	10	10	12	12
	Duration Range (hrs)	5 - 9	8 - 16	8 - 18	16-34
B	Magnitude (% of peak)	15	18	21	21
	Duration Range (hrs)	5 - 9	6 - 18	6 - 20	12-38
C	Magnitude (% of peak)	11	17	27	27
	Duration Range (hrs)	7 - 8	9 - 19	10 - 24	19-43
A'	Magnitude (% of peak)	9	12	12	12
	Duration Range (hrs)	7 - 12	10 - 15	11 - 16	21-31
B'	Magnitude (% of peak)	9	9	15	15
	Duration Range (hrs)	5 - 7	5 - 9	6 - 18	11-27
C'	Magnitude (% of peak)	6	8	11	11
	Duration Range (hrs)	6 - 9	9 - 13	10 - 20	19-33
Y	Magnitude (% of peak)	11	14	17	17
	Duration Range (hrs)	6 - 9	8 - 21	9 - 23	17-44
Z	Magnitude (% of peak)	12	17	17	17
	Duration Range (hrs)	6 - 9	7 - 19	10 - 23	17-42

Table B2-7 INTERMEDIATE LOAD MAGNITUDES AND DURATION FOR THE REPRESENTATIVE SYSTEMS

System	Magnitude (% of Peak)	Duration Range (Hours)
A	-	-
B	9	10 - 14
C	11	11 - 16
A'	-	-
B'	9	8 - 14
C'	3	14
Y	9	10 - 15
Z	9	12 - 14

Table B2-8 PEAKING LOAD MAGNITUDES FOR THE REPRESENTATIVE SYSTEMS

	Magnitude (Percent of Peak)	
System	Maximum	Average
A	46	14
B	23	9
C	12	6
A'	37	17
B'	19	8
C'	12	10
Y	27	7
Z	22	7

Table B2-9 PEAKING LOAD DURATION FREQUENCY (NUMBER OF OCCURRENCES/YEAR) ON REPRESENTATIVE ELECTRIC UTILITY SYSTEMS (BASED ON MEASURING LOAD IN INCREMENTS OF 3 PERCENT OF ANNUAL SYSTEM PEAK)

System \ Duration (hrs)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
A	46	39	40	40	48	43	43	57	52	46	79	61	87	76	35	37	8	4
B	61	51	64	47	30	14	10	11	8	7	14	9	9	1	3	0	0	0
C	33	27	14	20	30	17	25	15	11	10	18	7	5	12	8	0	0	0
A'	66	78	83	53	38	45	43	55	42	45	46	42	32	52	124	105	43	18
B'	69	88	69	50	42	36	21	19	21	10	10	14	12	28	2	1	0	0
C'	59	35	39	41	23	30	24	29	32	30	43	40	27	50	30	14	0	0
Y	26	39	37	28	25	32	23	21	17	19	19	19	25	19	5	1	0	0
Z	34	27	38	37	21	21	29	24	16	18	17	32	27	11	1	0	0	0
Weighted * Average	60	59	61	46	36	27	22	26	22	19	28	23	25	26	22	18	6	3

* Systems Y and Z not included.

Table B2-10 CUMULATIVE PEAKING LOAD DURATION FREQUENCY ON REPRESENTATIVE ELECTRIC UTILITY SYSTEMS (NUMBER DAYS/YEAR) (BASED ON MEASURING LOAD IN INCREMENTS OF 3 PERCENT OF ANNUAL SYSTEM PEAK)

System \ Duration (hrs)	0-2	0-4	0-6	0-8	0-10	0-12	0-14	0-16	0-18
A	83	148	165	171	173	175	175	175	175
B	109	140	145	145	145	145	145	145	145
C	60	90	121	130	132	132	132	132	132
A'	130	178	183	185	185	185	185	185	185
B'	135	163	184	186	186	186	186	186	186
C'	88	141	174	185	191	192	192	192	192
Y	65	118	144	148	149	149	149	149	149
Z	61	115	137	144	145	145	145	145	145
Weighted * Average	111	149	160	163	164	164	164	164	164

* Systems Y and Z not included

Table B2-11 CUMULATIVE ANNUAL HOURS OF PEAKING LOAD DURATION ON REPRESENTATIVE ELECTRIC UTILITY SYSTEMS (BASED ON MEASURING LOAD IN INCREMENTS OF 3 PERCENT OF ANNUAL SYSTEM PEAK)

System \ Duration (hrs)	0-2	0-4	0-6	0-8	0-10	0-12	0-14	0-16
A	122	378	630	947	1206	1489	1738	1822
B	160	382	494	556	600	663	673	676
C	87	205	415	620	701	833	888	907
A'	207	502	771	1127	1399	1685	1936	2236
B'	221	428	722	885	1018	1147	1264	1268
C'	122	364	630	926	1297	1736	2049	2175
Y	104	303	538	688	845	956	1013	1021
Z	88	316	493	734	889	1110	1230	1231
Weighted * Average	170	399	597	763	893	1040	1145	1196

* System Y and Z not included.

Table B2-12 DISTRIBUTION OF OFF-PEAK ENERGY ON ELECTRIC SYSTEMS

Distribution Period	Peak Season	Distribution and Standard Deviation of Off-Peak Energy in Percent of Total Annual Off-Peak Energy: Winter	Spring	Summer	Fall
Season	Summer	22 ± 2.3	28 ± 3.1	30 ± 8.1	21 ± 2.7
	Winter	27 ± 7.8	24 ± 2.7	31 ± 9.5	18 ± 1.1
	Combined	24 ± 5.2	27 ± 3.3	30 ± 8.5	20 ± 2.4
Week	Summer	1.7 ± 0.2	2.1 ± 0.2	2.3 ± 0.6	1.6 ± 0.2
	Winter	2.1 ± 0.6	1.8 ± 0.2	2.4 ± 0.8	1.4 ± 0.1
	Combined	1.8 ± 0.4	2.0 ± 0.2	2.4 ± 0.6	1.5 ± 0.2
Weekday	Summer	0.19 ± 0.03	0.23 ± 0.02	0.28 ± 0.07	0.18 ± 0.03
	Winter	0.23 ± 0.06	0.19 ± 0.02	0.28 ± 0.11	0.16 ± 0.01
	Combined	0.20 ± 0.03	0.21 ± 0.04	0.27 ± 0.07	0.17 ± 0.05
Saturday	Summer	0.31 ± 0.04	0.38 ± 0.06	0.39 ± 0.11	0.26 ± 0.05
	Winter	0.40 ± 0.13	0.36 ± 0.06	0.40 ± 0.13	0.23 ± 0.03
	Combined	0.36 ± 0.11	0.40 ± 0.06	0.41 ± 0.14	0.24 ± 0.05
Sunday	Summer	0.48 ± 0.05	0.59 ± 0.09	0.55 ± 0.20	0.43 ± 0.09
	Winter	0.51 ± 0.10	0.51 ± 0.11	0.58 ± 0.07	0.33 ± 0.06
	Combined	0.50 ± 0.12	0.59 ± 0.10	0.56 ± 0.16	0.41 ± 0.11

Table B2-13 DISTRIBUTION OF ON-PEAK ENERGY ON U.S. ELECTRIC SYSTEMS

Distribution Period	Peak Season	Distribution and Standard Deviation of On-Peak Energy in Percent of Total Annual On-Peak Energy			
		Winter	Spring	Summer	Fall
Season (13 Weeks)	Summer	22.0 ± 7.7	16.9 ± 4.1	34.7 ± 18.0	26.5 ± 6.2
	Winter	26.3 ± 10.4	19.9 ± 2.6	17.6 ± 10.5	36.3 ± 1.9
	Combined	23.6 ± 8.9	17.9 ± 3.8	28.5 ± 17.5	30.0 ± 6.9
Week	Summer	1.7 ± .6	1.2 ± .3	2.7 ± 1.4	2.1 ± .4
	Winter	2.0 ± .8	1.5 ± .2	1.3 ± .8	2.8 ± .1
	Combined	1.8 ± .7	1.3 ± .3	2.2 ± 1.3	2.3 ± .5
Weekday	Summer	.32 ± .11	.24 ± .07	.46 ± .19	.41 ± .10
	Winter	.36 ± .11	.28 ± .04	.26 ± .15	.50 ± .02
	Combined	.34 ± .11	.26 ± .08	.42 ± .21	.45 ± .11
Saturday	Summer	Negligible			
	Winter				
	Combined				
Sunday	Summer	Negligible			
	Winter				
	Combined				

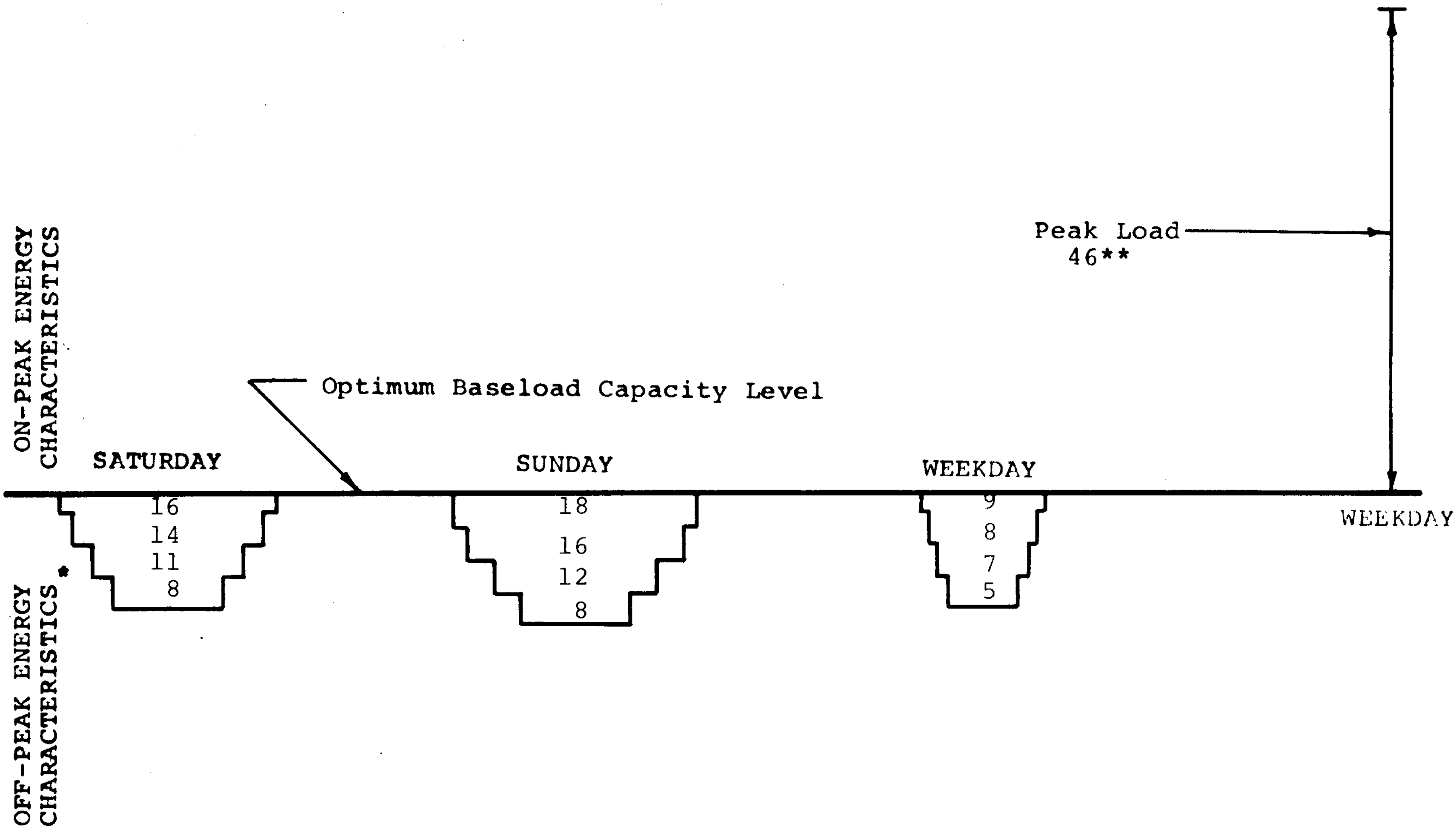
Table B2-14 OFF-PEAK ENERGY CHARACTERISTICS OF U.S. ELECTRIC SYSTEMS

Peak Season	Energy Characteristics	Average Weekday	Average Weekend: Saturday	Average Weekend: Sunday	Average Weekend: Total
Summer	Magnitude (%)	13.5±2.2	16.0±3.4	19.1±4.3	19.1±4.3
	Duration Range (hrs)				
	Maximum	8.9±0.2	17.6±0.9	19.7±1.3	37.3±2.2
	Minimum	5.1±0.5	6.7±1.0	6.7±1.2	14.1±2.4
Winter	Magnitude (%)	9.6± .9	9.9±1.4	13.9±1.5	13.9±1.5
	Duration Range (hrs)				
	Maximum	8.7±2.3	11.1±2.8	17.5±1.1	28.5±2.1
	Minimum	5.7±0.9	6.7±2.4	7.7±2.4	14.5±4.7
Combined	Magnitude (%)	11.9±2.9	13.8±4.1	17.3±4.4	17.3±4.4
	Duration Range (hrs)				
	Maximum	8.8±1.4	15.3±3.6	18.9±1.7	34.2±4.7
	Minimum	5.3±0.7	6.7±1.6	7.1±1.8	13.8±3.3

Table B2-15 ON-PEAK ENERGY CHARACTERISTICS OF U.S. ELECTRIC SYSTEMS

Peak Season	Intermediate Loads: Magnitude (Percent of Peak)	Intermediate Loads: Duration Range (Hours)
Summer	9	10 - 14
Winter	9	8 - 14
Combined	9	9 - 14

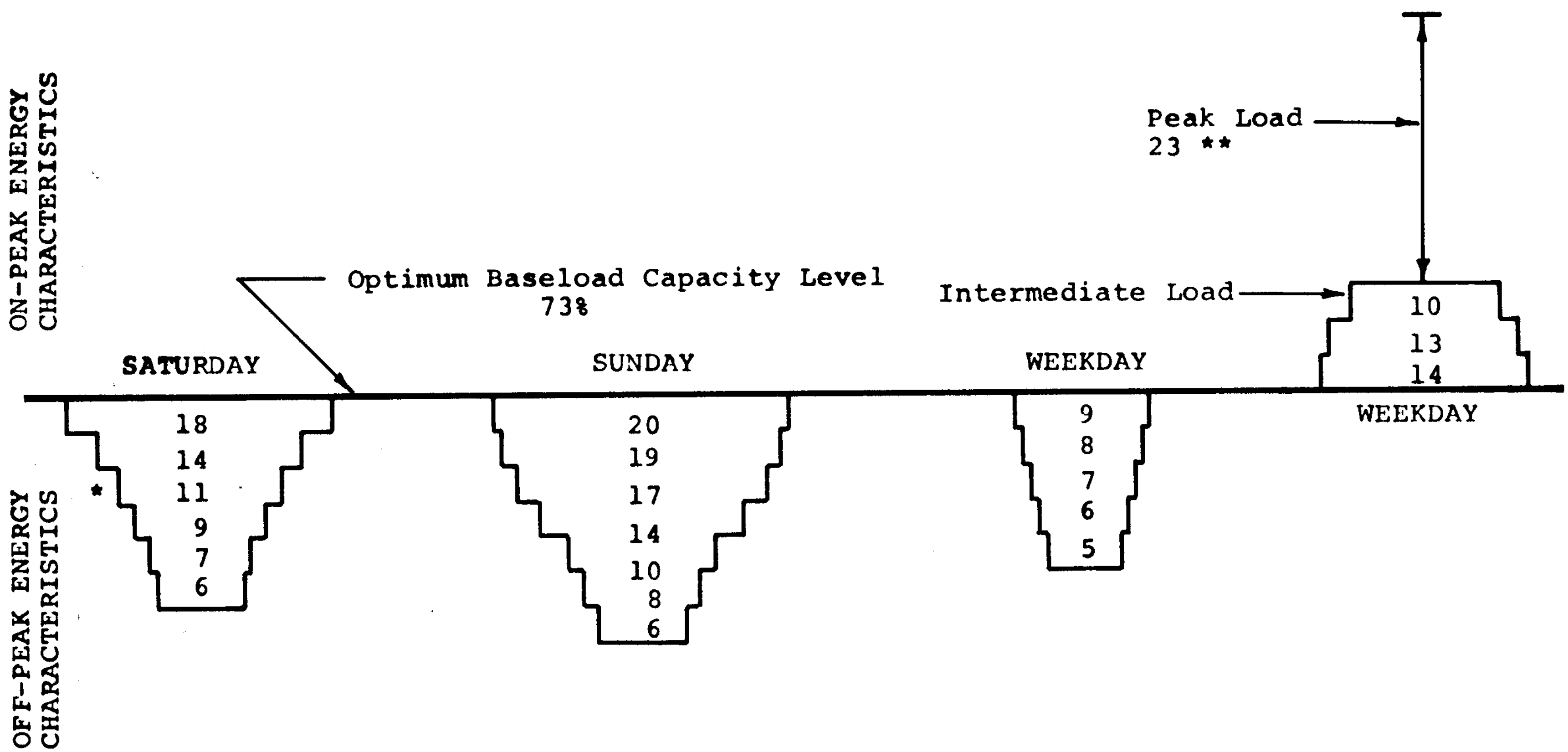
Peak Season	Peaking Loads: Magnitude (Percent of Peak): Maximum	Peaking Loads: Magnitude (Percent of Peak): Average
Summer	28.0±10.6	10.1±2.4
Winter	24.4± 8.7	10.9±4.2
Combined	26.8±10.1	10.4±3.1



* Profile step size is approximately 3 percent of system annual peak load. Duration of steps shown in hours.

** Magnitude as a percent of system annual peak load.

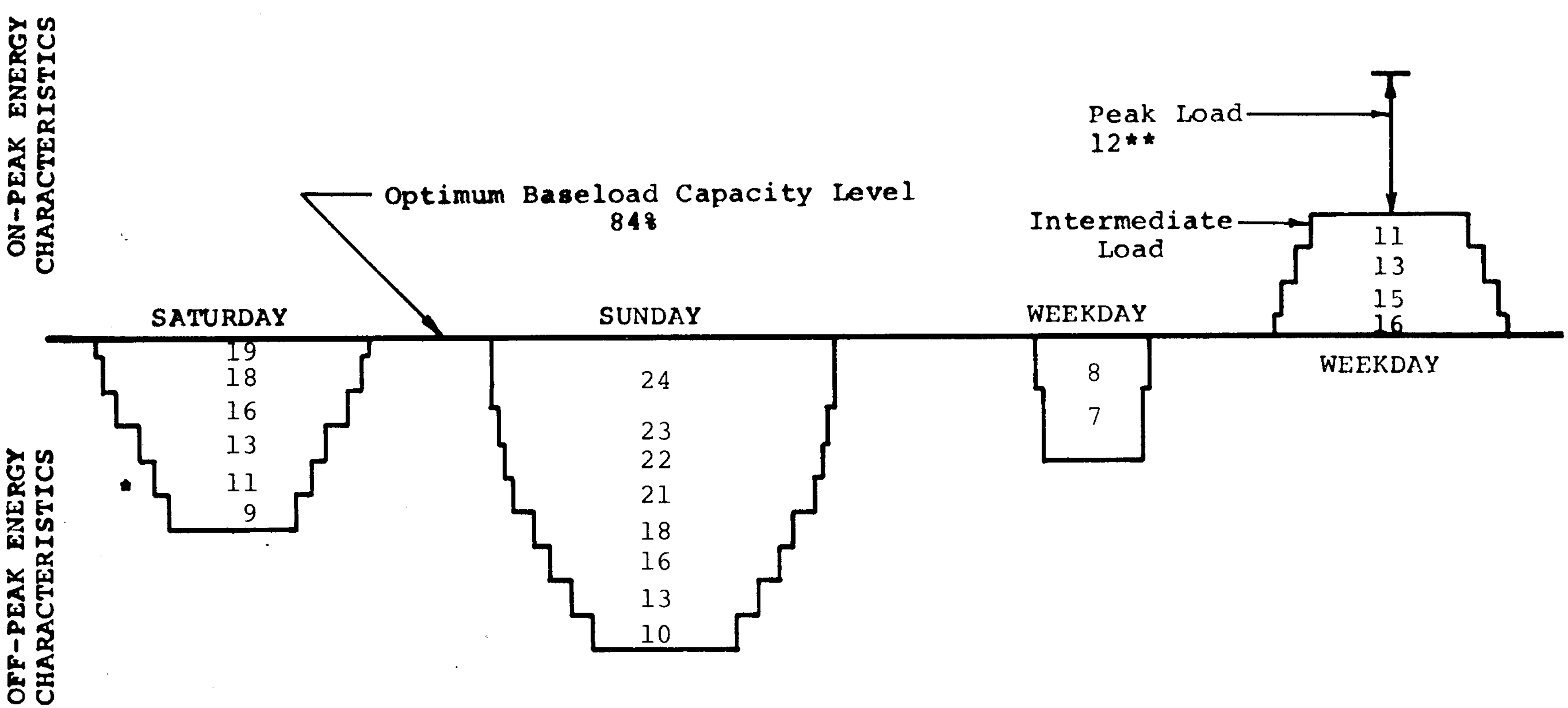
Figure B2-1 SYSTEM A OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS FOR THE 59 PERCENT CAPACITY LEVEL



* Profile step size is approximately 3 percent of system annual peak load Duration of steps shown in hours.

** Magnitude as a percent of system peak load.

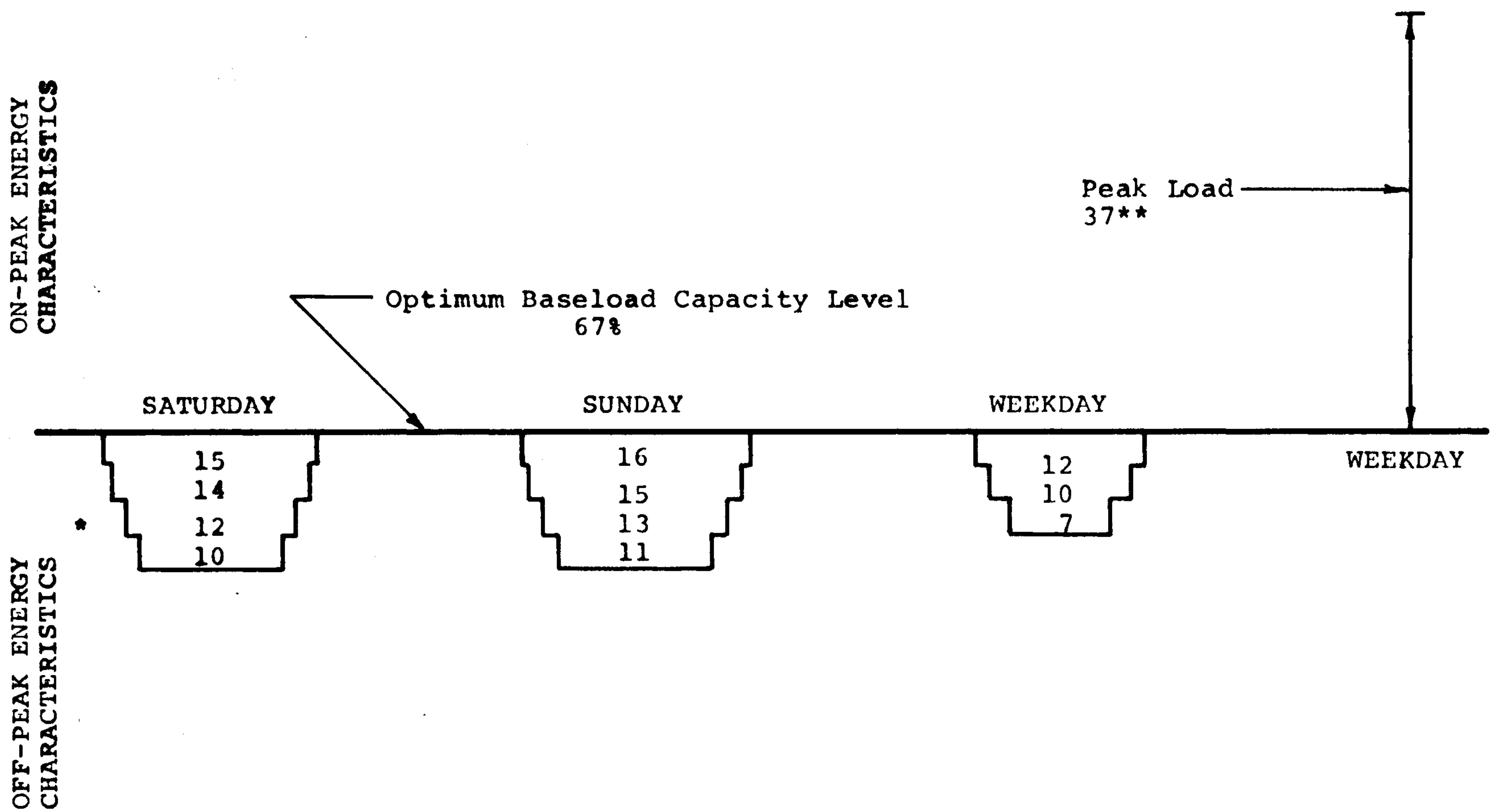
Figure B2-2 SYSTEM B OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS FOR THE 73 PERCENT CAPACITY LEVEL



* Profile step size is approximately 3 percent of system annual peak load. Duration of steps shown in hours.

** Magnitude as a percent of system peak load.

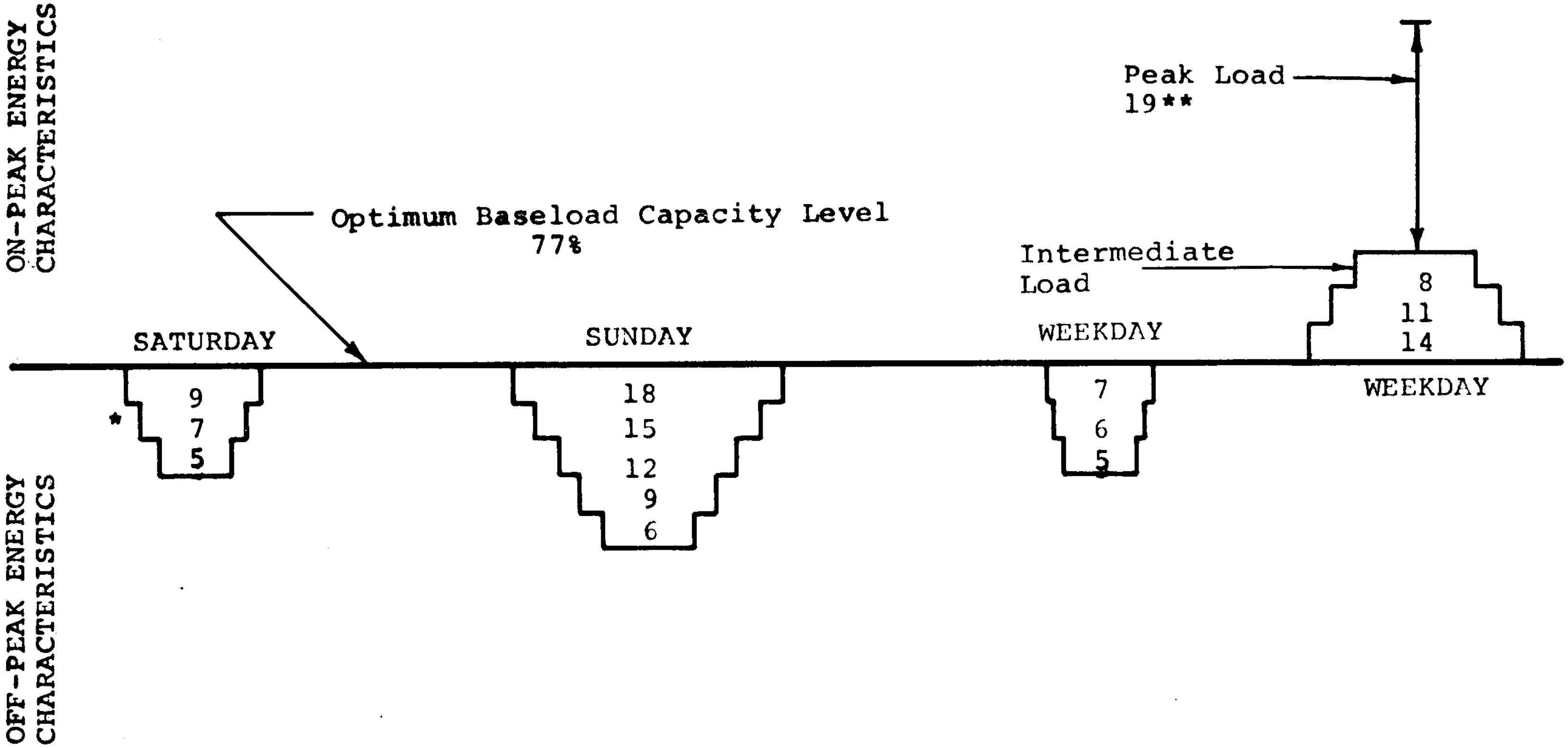
Figure B2-3 SYSTEM C OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS FOR THE 84 PERCENT CAPACITY LEVEL



* Profile step size is approximately 3 percent of system annual peak load. Duration of steps shown in hours.

** Magnitude as a percent of system peak load.

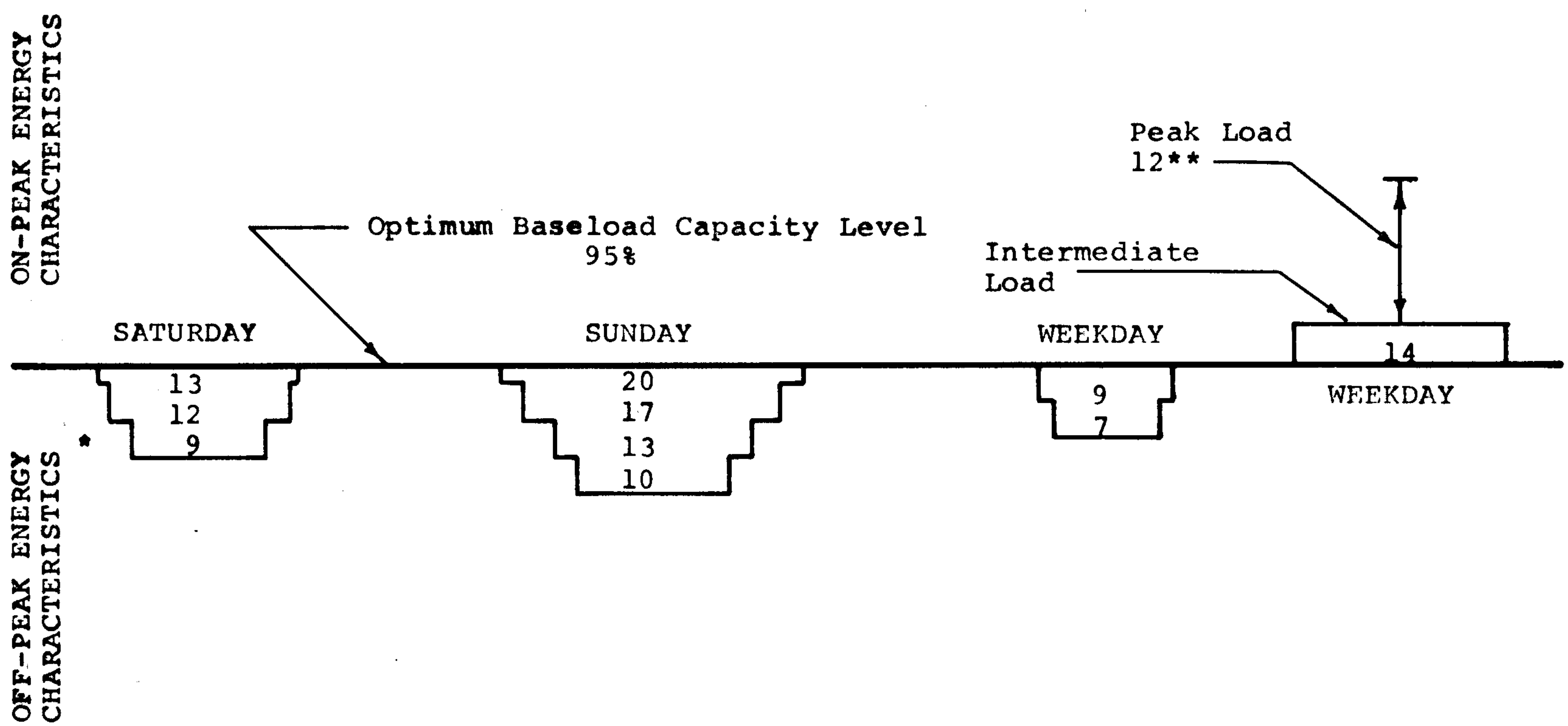
Figure B2-4 SYSTEM A' OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS FOR THE 67 PERCENT CAPACITY LEVEL



* Profile step size is approximately 3 percent of system annual peak load. Duration of steps shown in hours.

** Magnitude as a percent of system peak load.

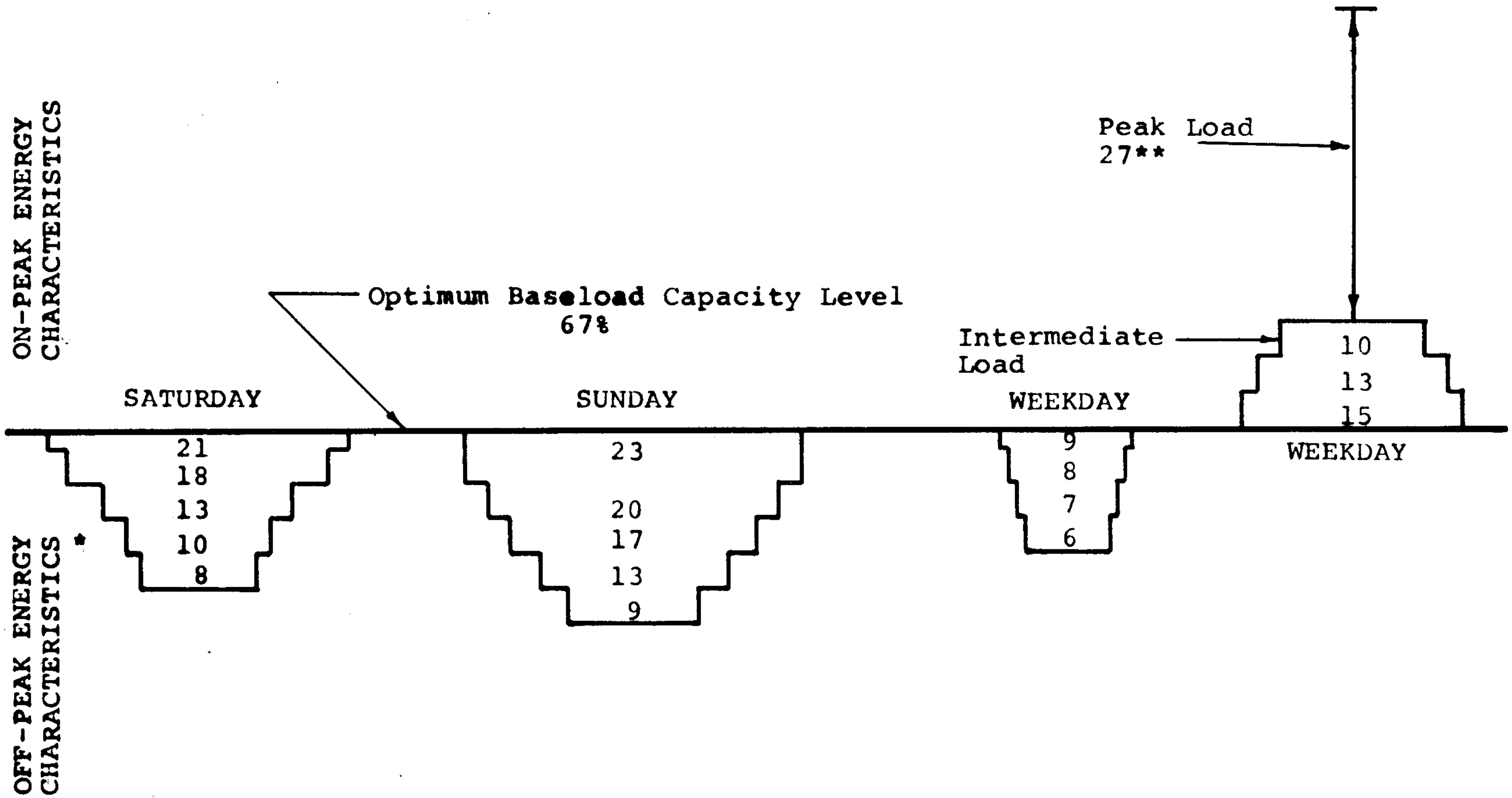
Figure B2-5 SYSTEM B' OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS FOR THE 77 PERCENT CAPACITY LEVEL



* Profile step size is approximately 3 percent of system annual peak load. Duration of steps shown in hours.

** Magnitude as a percent of system peak load.

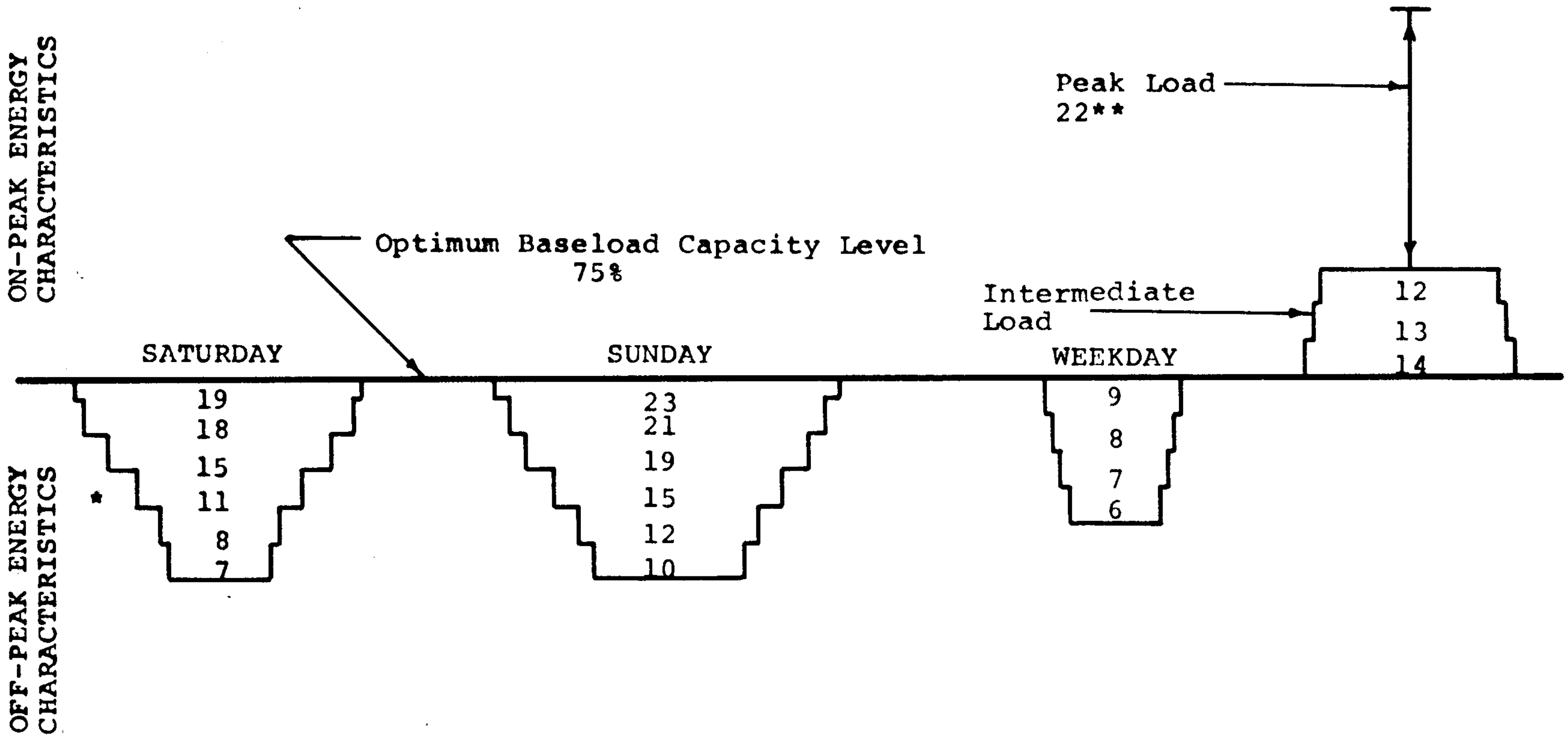
Figure B2-6 SYSTEM C' OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS FOR THE 95 PERCENT CAPACITY LEVEL



* Profile step size is approximately 3 percent of system annual peak load. Duration of steps shown in hours.

** Magnitude as a percent of system peak load.

Figure B2-7 SYSTEM Y OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS FOR THE 67 PERCENT CAPACITY LEVEL



* Profile step size is approximately 3 percent of system annual peak load. Duration of steps shown in hours.

** Magnitude as a percent of system peak load.

Figure B2-8 SYSTEM Z OFF-PEAK AND ON-PEAK ENERGY CHARACTERISTICS FOR THE 75 PERCENT CAPACITY LEVEL

B3 COMPUTER PROGRAMS

Five computer programs were used in the Energy Storage Assessment Study. One of these programs was a standard type of statistical analysis program. Two others used in the load analysis, the load duration curve and off-peak energy programs, were developed by PSE&G personnel prior to the study. Each of the three programs was modified to specifically analyze the study data or to perform additional calculations. With the fourth program, economic calculations were performed for cost estimates. The last program determines the amount of capacity and associated duty-cycle parameters of energy storage from system on-peak and off-peak load-duration input data. All programs were run on the PSE&G UNIVAC-1106 time-sharing system. A brief description of each program and how it was applied follows.

B3.1 STATISTICAL ANALYSIS PROGRAM

A basic statistical analysis computer program was used to analyze the data-base assembled for the private and public utilities for this project. A functional flowchart of the program is shown in Figure B3-1. A portion of the data-base is shown in Table B3-1.

The statistical analysis time-sharing computer program calculates thirty-four statistical measures for any given set of data, based on formulas from the National Bureau of Standards Handbook No. 101. In addition, as an option, weights can be applied to the data.

B3.2 LOAD-DURATION CURVE PROGRAM

The PSE&G load-duration program analyzes hourly load data for any given period of time and develops a load-duration curve, calculates the system load factor, and also develops average weekday, Saturday, and Sunday 24-hour sequential load shapes for that period. The original program had to be modified, with the assistance of the PSE&G Computer Systems and Services Department, to operate on the 1971 hourly load data for the 102 privately- and publicly-owned companies obtained from the Edison Electric Institute.

A functional flowchart of the system is shown in Figure B3-2. Table B3-2 shows a portion of the data-base consisting of the 1971 hourly loads for the privately-and publicly-owned companies. Example computer printouts of the average load shapes and the load-duration curve coordinates are shown in Tables B3-3 and B3-4, respectively. Figure B3-3 shows the actual computer plot of a load-duration curve.

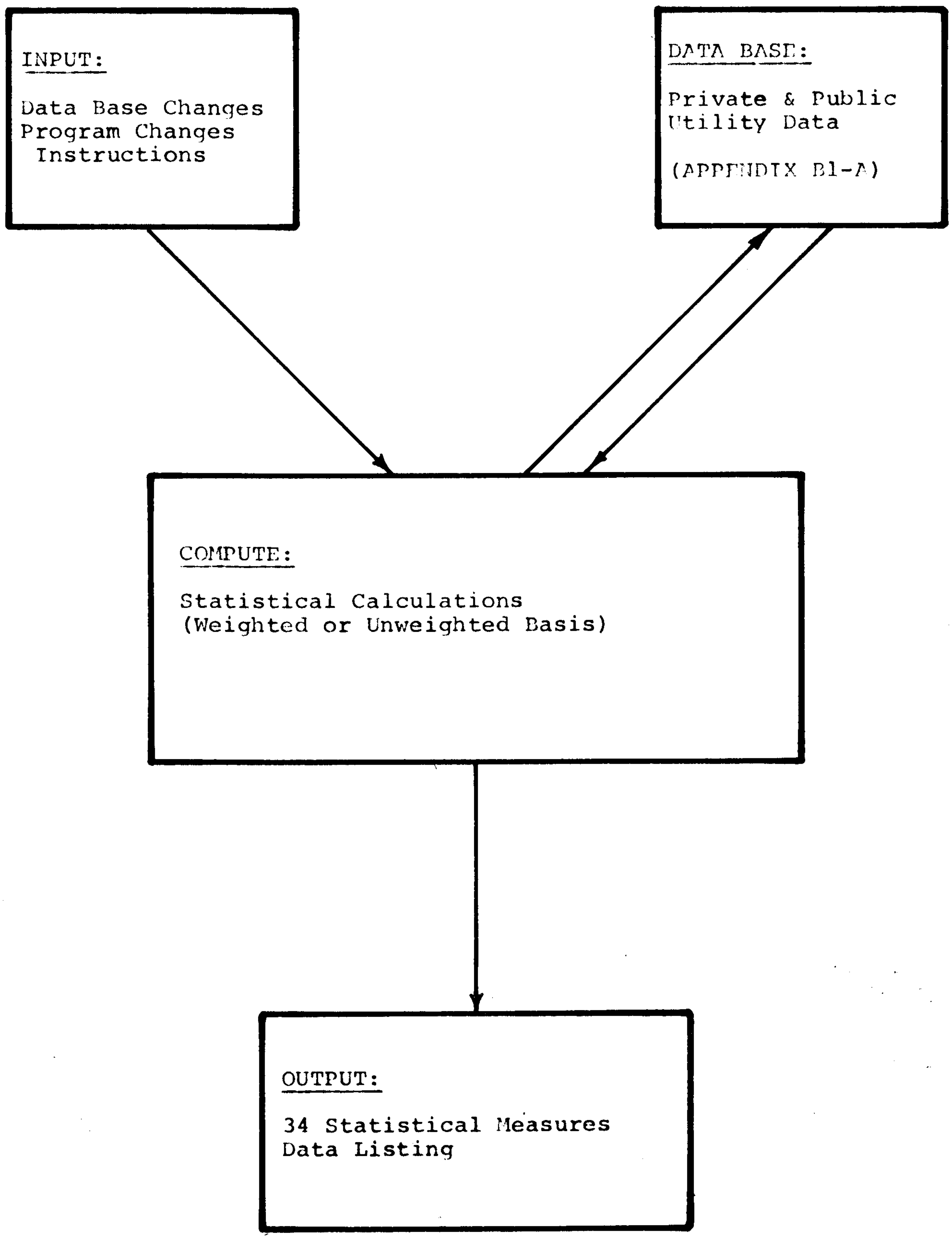


Figure B3-1 STATISTICAL ANALYSIS COMPUTER PROGRAM FUNCTIONAL FLOWCHART

Table B3-1 PRIVATE AND PUBLIC UTILITY DATA BASE COMPUTER PRINTOUT

CO.	SALES $ x 10^3	D	LF %	MW		KWH x 10^3	CAP MW	FS %	H %	GT %	N	RC	Y	C
A01	0278325	T	60.2	04342	S	23051095	04097	066.0	032.8	001.2	000.0	SERC	71	A
A04	0117399	T	55.1	01410	S	06816583	01540	097.2	000.3	002.5	000.0	WSCC	71	A
A06	0050924	T	62.4	00570	S	03115756	00640	099.5	000.0	000.5	000.0	WSCC	71	A
A07	0027077	T	56.2	00223	S	01097855	00036	097.2	002.8	000.0	000.0	SWPP	71	A
A08	0166063	T	53.0	02535	S	11769498	02370	092.8	002.9	004.3	000.0	SWPP	71	A
C01	0791457	T	64.2	09713	S	54664902	09577	073.1	026.3	000.0	006.6	WSCC	71	A
C02	0120320	T	57.2	01451	W	07271160	01719	079.5	000.0	015.0	005.0	WSCC	71	A
C03	0802434	T	62.7	09350	S	51355062	11704	083.0	009.6	004.5	002.9	WSCC	71	A
C04	0005815	T	57.1	00065	W	00325298	00000	000.0	000.0	000.0	000.0	WSCC	71	A
C05	0146563	T	63.2	01538	W	08518989	01846	079.5	019.6	000.9	000.0	WSCC	71	A
C06	0004178	T	60.6	00040	W	00213282	00034	064.7	035.3	000.0	000.0	WSCC	71	A
C07	0178698	T	61.8	01672	W	09044118	02099	066.9	005.8	010.6	016.7	NPCC	71	A
C09	0106785	T	62.9	00885	S	04876830	01184	060.4	000.8	023.2	015.6	NPCC	71	A
C11	0081089	T	62.8	00804	S	04424277	01031	098.0	000.0	002.0	000.0	NPCC	71	A
D01	0104742	T	64.5	01090	S	06161043	01281	088.1	000.0	011.9	000.0	MAAC	71	A

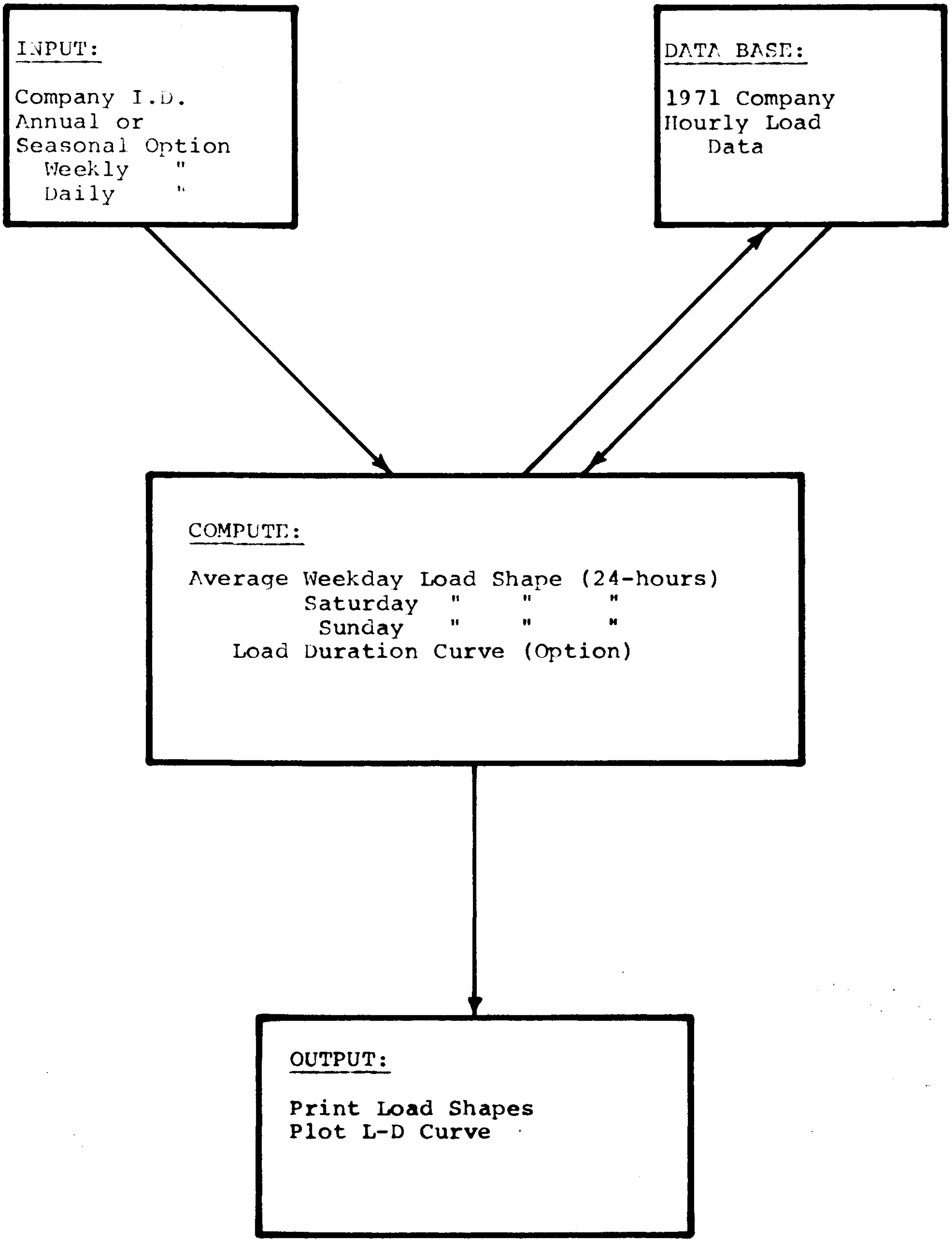


Figure B3-2 LOAD DURATION CURVE COMPUTER PROGRAM FUNCTIONAL FLOWCHART

B4.2 Off-Peak and On-Peak Energy Characteristics Analysis

To provide an indication of the characteristic features of both the available off-peak energy and the on-peak energy requirements, a computerized technique was utilized in which the loads above and the available off-peak energy below the baseload capacity level identified for each representative system were analyzed in increments of 3 percent of system annual peak. Each day the number of consecutive hours the actual load was less (or more) than the baseload capacity level was determined in these 3 percent increments. In addition, the total number of occurrences of each 3 percent increment were counted to provide and an annual frequency of occurrence. For those 3 percent load increments that occurred on a consistent basis of 260 days or 52 weekends per year, average annual durations were calculated. Those 3 percent increments that occurred less than 260 days or 52 weekends per year either represent off-peak energy that could not be counted on a consistent basis or peaking load requirements.

Based on the above described analysis, step-function (load and duration profiles of the average annual off-peak energy available and the average annual on-peak energy requirements for the baseload capacity levels were developed for each representative system by computer analysis of the actual system annual hourly load data. Figure B4-1 illustrates such a step-function profile for representative system B (summer peaking system, 60 percent annual load factor).

The profile of Figure B4-1 represents only that portion of the total available off-peak energy and on-peak energy requirements that would occur on a consistent basis over the 52 weekends and 260 weekdays of the year. The on-peak energy requirements shown are the intermediate loads which occur every weekday on system B. Those on-peak energy loads that occur less frequently on a more random basis and also contribute to the on-peak energy requirements are referred to as peaking loads and are shown for system B to range up to 23 percent of annual peak load in magnitude.

The frequency of occurrence of the more randomly occurring peaking load durations in load increments of 3 percent of system peak for the representative systems are shown in Table B2-14 of Appendix B2.

B4.3 Charge/Discharge Power Ratio and Storage Capability Relationships

B4.3.1 Charge/Discharge (C/D) Power Ratio

For any energy storage device operating over any given cyclic period, the following relationship must hold.

$$\text{ENERGY INPUT} \times e = \text{ENERGY OUTPUT}$$

If one assumes the following:

C = Rated Charge Capacity (MW)

D = Rated Discharge Capacity (MW)

T_d = Daily Discharge Time at Rated Discharge Capacity (hours/day)

T_{cd} = Daily Charge Time at Rated Charge Capacity (hours/day)

T_{cw} = Weekend Charge Time at Rated Charge Capacity (hours/weekend)

e = Device Conversion Efficiency (%) (electric to electric)

For the daily cycle mode of operation then the above relationship becomes,

$$C \times T_{cd} \times e = D \times T_d$$

The relationship between the rated charge and discharge capacity, the C/D power ratio, is then

$$\frac{C}{D} = \frac{T_d}{T_{cd} \times e}$$

Assuming the desired discharge time of 10 hours and an allowable daily charge time of 9 hours, the required rated charge capacity would be 1.5 times the rated discharge capacity for an energy storage system with a 75 percent overall efficiency.

$$\frac{C}{D} = \frac{10}{9 \times .75} = 1.5$$

To develop C/D power ratios for the weekly cycle application, the total weekly (5 weekdays) discharge requirements should be compared to the total weekly (5 weekdays and weekend) charge time availability.

$$\frac{C}{D} = \frac{5 \times T_d}{(5 \times T_{cd} + T_{cw}) \times e}$$

Assuming the desired daily discharge time of 10 hours, an allowable daily charge time of 9 hours and a weekend charge time availability of 15 hours, the required rated charge capacity would be 1.1 times the rated discharge capacity for any energy storage system with a 75 percent overall efficiency designed to operate on a weekly cycle.

$$\frac{C}{D} = \frac{5 \times 10}{(5 \times 9 + 15) \times .75} = 1.1$$

B4.3.2 Storage Capacity

The storage capability (hours at rated discharge capacity) required of an energy storage system for the daily cycle is essentially the daily discharge duration as shown in the following equation.

$$T_d = C/D \times T_{cd} \times e = S$$

Where S = Storage Capability

Using the daily cycle previously described, the required storage capability would be 10 hours.

$$S = 1.5 \times 9 \times .75 = 10 \text{ hours}$$

The storage capability must be greater for the energy storage system capable of operating on a full weekly cycle than for the daily cycle. The weekly storage capability must be large enough to hold a weekend (Saturday and Sunday) charge in addition to a weekday (Friday) charge. The following equation describes this relationship.

$$S = C/D \times (T_{cw} + T_{cd}) \times e$$

Using the weekly example given previously the required storage capability would be approximately 20 hours for the system described.

$$S = 1.1 \times (9 + 15) \times .75 = 19.8 \text{ hours}$$

B4.4 Procedure for Estimating the Amount of Supportable Capacity

To provide an estimate of the amount of energy storage power capacity that could be supported by the off-peak energy available on both the daily and weekly basis. The off-peak energy was allocated on the basis of supporting energy storage capacity with different daily discharge capabilities (hours at rated discharge power) in rated capacity increments of 3 percent of peak load (100 MW for a 3300 MW electric system). Each energy storage capacity increment would, therefore, require a different C/D power ratio and storage capability (hours at rated discharge power).

Based on the above described procedure, Table B4-2 shows maximum amount of energy storage capacity and the associated capacity components capable of being supported by the weekly cycle assuming a 100 percent conversion efficiency. Table B4-3 shows the estimate based on the daily cycle.

REFERENCES - APPENDIX B4

1. EEI Publication No. 74-57, "Report on Equipment Availability for the Ten-Year Period, 1964-1973," Edison Electric Institute, New York, New York, December 1974.

APPENDIX B5

Economic Assumptions and Sample Calculations

Table B5-1 ANNUAL CARRYING CHARGES FOR ENERGY STORAGE SYSTEMS AND CONVENTIONAL GENERATION AS A PERCENT OF CAPITAL COST

Generation Technology	Est. Avg. Life (Yrs.)	CCIF[a]	Return Percent	Depreciation Percent	Federal Income Taxes Percent	Other Taxes Percent	Total Carrying Charge[b] Percent
Energy Storage Systems:							
Hydro Pumped Storage	50	1.396	10.00	0.09	3.15	1.64	14.88
Batteries	5	1.049[d]	10.00	16.38	3.53	3.94	35.85[c]
	10	1.049[d]	10.00	6.27	2.97	2.38	21.62[c]
	20	1.049[d]	10.00	1.75	1.72	1.66	15.13[c]
	25	1.049[d]	10.00	1.02	1.48	1.54	14.04[c]
Thermal Storage	25	1.17	10.00	1.02	1.48	1.54	14.04
Compressed Air	25	1.17	10.00	1.02	2.92	1.72	15.66
Flywheel	25	1.049[d]	10.00	1.02	1.48	1.54	14.04
Magnetic Storage	25	1.396[e]	10,00	1.02	2.92	1.72	15.66
Chemical Hydrogen Storage	25	1.049[d]	10.00	1.02	1.48	1.54	14.04
Conventional Systems:							
Gas Turbine (simple cycle)	25	1.049	10.00	1.02	1.48	1.54	14.04
Combined Cycle (gas turbine/steam)	25	1.049	10.00	1.02	1.48	1.54	14.04

Table B5-1 ANNUAL CARRYING CHARGES FOR ENERGY STORAGE SYSTEMS AND CONVENTIONAL GENERATION AS A PERCENT OF CAPITAL COST (CONT'D)

a) Construction Compound Interest Factor which accounts for the cost of money during construction.
b) Based on zero salvage and excluding CCIF.
c) Total carrying charges, excluding CCIF, for lead acid batteries assuming a 25 year life for power interface equipment and 5, 10, 20 and 25 year lives for lead-acid batteries with an assumed 25% salvage for battery storage costs are estimated to be 26.1 percent, 17.9 percent, 14.1 percent, and 13.5 percent, respectively.
d) Assumed to have capital expenditure patterns similar to gas turbine installations.
e) Assumed to have capital expenditure patterns similar to hydro pumped storage installations.

Table B5-2 ANNUAL CARRYING CHARGES FOR TRANSMISSION AND DISTRIBUTION PLANT AS A PERCENT OF CAPITAL COST

Description	(Yrs.)	CCIF[a]	Return Percent	Depre-ciation Percent	Federal Income Taxes Percent	Other Taxes Percent	Total Carrying Charge[b] Percent
Transmission	50	1.06	10.00	0.4	2.2	1.6	14.2
Distribution	25	1.00	10.00	1.6	2.2	1.7	15.5
Switching Station	50	1.18	10.00	0.2	2.7	1.6	14.5
Substation	25	1.04	10.00	1.3	2.8	1.7	15.8

a) Construction Compound Interest Factor which accounts for the cost of money during construction.
b) Total carrying charges exclude CCIF. Transmission and distribution facilities are based on zero net salvage, switching station facilities assume - 10 percent net salvage, and substation facilities assume - 20 percent net salvage.

Table B5-3 FINANCIAL ASSUMPTIONS FOR ANNUAL CARRYING CHARGE CALCULATIONS FOR GENERATION TECHNOLOGIES

The carrying charges developed from the assumptions below represent the minimum revenues necessary to meet all costs incurred with the investment:

1. Weighted cost of capital - 10 percent.

2. Cost of debt - 8 percent.

3. Debt ratio - 50 percent.

4. Federal tax rate - 48 percent.

5. Investment tax credit applied at 10 percent, normalized to 33 years.

6. Full normalization to book.

7. Salvage - 0 percent.

8. Tax depreciation at Asset Depreciation Range (ADR) lives, SYD type depreciation. (22.5 years for all except Pumped Hydro at 40 years).

9. Half year convention applied in all cases, normalized to full year.

10. Allowance for funds used during construction - 8 percent.

11. Retirement dispersion - SQ.

12. Other taxes applied at 11 percent of revenue requirements. (National Average, 1968-1972).

FOR THE BATTERY VS. GAS TURBINE (6 PERCENT ESCALATION, 1,000 HOURS OPERATION)

	Assumptions for Economic Variables	Gas Turbine	Battery
1.	1975 Installed Capital Cost ($/kW)	100	Break-even cost "x"
2.	Expected Life (years)	25	5, 10, and 10
3.	Annual Carrying Charges (percent of capital cost), includes 25 percent salvage for battery storage costs.	14.04 percent	5 yr, 26.1 percent 10 yr, 17.9 percent
4.	Construction Compound Interest Factor (CCIF)	1.049	1.049
5.	O&M Costs:		
	a) Variable (mills/kWh)	5.3	2.7
	b) Fixed ($/kW/yr)	---	---
6.	Heat Rate or Efficiency:		
	Near Term	12,100Btu/kWh	75 percent
7.	Levelized incremental cost of off-peak energy	---	20 mills/kWh
8.	Annual Operation (hours)	1,000	1,000
9.	Escalation rate (percent), (Capital, O&M, fossil fuel)	6 percent	6 percent
10.	1975 Fossil Fuel Cost ($/$10^6$Btu)	2.50	---
11.	Rate of return (percent)	10 percent	10 percent
12.	Present worth factors (what $1 payable periodically is worth today)		
	a) 10 percent rate of return	D	D
	b) 3.77 percent of return (10 percent return, 6 percent escalation	A	A

GENERATION INSTALLATION PLANS

PLAN 1: BATTERY(B)
Installation of batteries with 5, 10 and 10 year life expectancies in 1980, 1985 and 1995 respectively. Battery efficiency is 75%.

PLAN 2: GAS TURBINE (GT)
Installation of gas turbine in 1980 with a life expectancy of 25 years and a heat rate of 12,100 Btu/kWh.

The following symbols are used in this example calculation for the 1975 Break-Even Costs:

PWAFRR = Present Worth of all Future Revenue Requirements
PW = Present Worth
FC = Fixed Costs
VC = Variable Costs
CC = unit Capital Cost
L = Levelized annual carring charge percent
DX = Present worth of X years of annual costs; at 10% (Standard financial tables)
O&M = Operating and Maintenance
AX = Present worth of X years
Xbe = 1975 Break-Even Cost
FFC = Fossil Fuel Cost
LL = Levelized average incremental cost of off-peak energy over 25 years.

PLAN 1: BATTERY

$$PWAFRR(B) = PWAFRR(FC) + PWAFRR(VC)$$

$$\begin{aligned} PWAFRR(FC) = &(CC\ 1980)(CCIF)(L)(D5) \\ &+ (CC\ 1985)(CCIF)(L)(D15-D5) \\ &+ (CC\ 1995)(CCIF)(L)(D25-D15) \end{aligned}$$

$$\begin{aligned} PWAFRR(FC) = &(1.06)^5(Xbe)(1.049(0.261)(3.791) \\ &+ (1.06)^{10}(Xbe)(1.049)(0.179)(7.606 - 3.791) \\ &+ (1.06)^{20}(Xbe)(1.049)(0.179)(9.077 - 7.606) \end{aligned}$$

$$PWAFRR(VC) = PWAFRR(O\&M) + PWAFRR(Charging)$$

$$PWAFRR(O\&M) = (CC\ 1980)\left(\begin{matrix}\text{Annual Hrs.}\\ \text{Operation}\end{matrix}\right)(A25)$$

$$\begin{aligned} PWAFRR(O\&M) &= (1.06)^5(2.7\text{mills/kWh})(\$1/1000\text{mills})(1000\text{hrs})(16) \\ &= \$58/kW \end{aligned}$$

$$\text{PWAFRR(Charging)} = (\text{LL})\left(\frac{1}{\text{Battery Efficiency}}\right)\left(\begin{matrix}\text{Annual hrs.}\\ \text{of}\\ \text{Operation}\end{matrix}\right)(\text{D25})$$

$$= \frac{20 \text{ mills/kWh}}{1000 \text{ mills/\$}} \; \frac{1}{.75} \; (1000 \text{ hrs.})(9.077)$$

$$= \$242/\text{kW}$$

$$\text{PWAFRR(VC)} = \$58/\text{kW} + \$242/\text{kW}$$

$$= \$300/\text{kW}$$

$$\text{PWAFRR(B)} = \$3.55\text{Xbe} + \$300/\text{kW}$$

PLAN 2: GAS TURBINE

$$\text{PWAFRR(GT)} = \text{PWAFRR(FC)} + \text{PWAFRR(VC)}$$

$$\text{PWAFRR(FC)} = (\text{CC 1980})(\text{CCIF})(\text{L})(\text{D25})$$
$$= (1.06)^5(\$100/\text{kW})(1.049)(.1404)(9.077)$$
$$= \$179/\text{kW}$$

$$\text{PWAFRR(VC)} = \text{PWAFRR(O\&M)} + \text{PWAFRR(FFC)}$$

$$\text{PWAFRR(O\&M)} = (\text{VC 1980}) \left(\begin{matrix}\text{Annual hrs}\\ \text{of Operation}\end{matrix}\right) (\text{A25})$$
$$= (1.06)^5(53 \text{ mills/kWh})(\$1/1000 \text{ mills})(1000 \text{ hrs.})(16)$$
$$= \$113/\text{kW}$$

$$\text{PWAFRR(FCC)} = (\text{CC 1980})\left(\begin{matrix}\text{Applicable}\\ \text{Heat Rate}\end{matrix}\right)\left(\begin{matrix}\text{Annual hrs.}\\ \text{of Operation}\end{matrix}\right)(\text{A25})$$
$$= (1.06)^5(2.50 \times 10^6\text{Btu})(12{,}100\text{Btu/kWh})(1000 \text{ hrs})(16)$$
$$= \$648/\text{kW}$$

$$\text{PWAFRR(VC)} = \$761/\text{kW}$$

$$\text{PWAFRR(GT)} = \$179 + \$761$$
$$= \$940/\text{kW}$$

BREAK-EVEN COST CALCULATIONS

$$\begin{aligned} \text{PWAFRR(B)} &= \text{PWAFRR(GT)} \\ \$3.55\text{Xbe} + \$300/\text{kw} &= \$940/\text{kW} \\ \text{Xbe} &= \$180/\text{kW} \end{aligned}$$

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