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Underground Pumped Hydro Storage and Compressed Air Energy Storage

An Analysis of
Regional Markets and Development Potential

For
Argonne National Laboratory

By
HARZA ENGINEERING COMPANY • MARCH 1977

MASTER

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Underground Pumped Hydro Storage and Compressed Air Energy Storage

An Analysis of Regional Markets and Development Potential

by

Harza Engineering Company
150 South Wacker Drive
Chicago, Illinois 60606

March 1977

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SUMMARY LETTER

March 31, 1977

Mr. L. A. Hoornbeek
Subcontract Administrator
Argonne National Laboratory
9700 South Cass Avenue
Argonne, Illinois 60439

Attention: Dr. Joseph G. Asbury
Director, Special Project Group
Energy and Environmental Systems
Division

Subject: "Underground Pumped Hydro Storage and
Compressed Air Energy Storage"
Summary Letter

Gentlemen:

We are pleased to present our report "Underground Pumped Hydro Storage and Compressed Air Energy Storage, an Analysis of Regional Markets and Development Potential". The report documents our studies prepared under ANL Contract 31-109-38-3485 funded by the Energy Research and Development Administration. Our study has the following objectives:

1. Identification of Regional Markets - A survey of the regional markets within the continental United states to identify three regions most suitable for UPHS and CAES.
2. Regional Development Potential and Costs - A national survey with emphasis on the three selected regions to determine developmental potential and costs of UPHS and CAES.
3. Market Capture Potential - An analysis to determine cost effectiveness of UPHS and CAES and their market share in future electric systems.

4. RD&D Recommendations - Recommendations on research, development and demonstration work to realize the timely commercialization of UPHS and CAES system.

Our studies, conclusions and recommendations are given in the accompanying report and summarized in this letter.

Identification of Regional Markets

The market for energy storage projects is related to the growth of the total electric utility industry.

Total non-coincident summer peak demand on the electric utility system in the continental United States was 349 million kilowatts (kW) in 1974. The peak demand would be 657 million kW by 1985 and 1,150 million kW by 1995, based on projections of the Reliability Councils for their individual systems in 1976. The installed capacity to meet the demand after allowance for reserve needs would be 569 million kW. The total amount of peaking capacity to be installed during the 1985-1995 period could range between 90 million and 150 million kW. A large part of that peaking capacity could be supplied by UPHS and CAES provided that sufficient and timely research, development and demonstration work is first done.

A study of the electric power market of the United States was made at the regional level to identify three regions that could provide early markets for UPHS and CAES. The representative utilities or pools were identified after an evaluation of load characteristics, projected demand, existing and future generation resources and other considerations.

More detailed evaluation was made to determine the electric systems within the three different regions which would be first ready to accommodate UPHS and CAES systems. The more obvious systems so identified are: the Pennsylvania - New Jersey - Maryland Interconnection (in FPC Region I), Virginia-Carolinas Subregion (in FPC Region III), and Northern Illinois (in FPC Region IV). Other utilities or systems in the same or other regions may well be attractive candidates

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to accommodate UPHS or CAES. This is especially the case for the utility systems in ECAR (East Central Reliability Coordination Agreement). Similar analyses would be required to identify other favorable but currently less obvious utilities or systems. By 1995, most of the utilities, except for those in the Pacific Northwest, will benefit from the inclusion of UPHS or CAES in their systems.

Regional Development Potential (Geotechnical Analysis)

Generalized geotechnical studies were conducted to identify the regional development potential of UPHS and CAES projects within the continental United States. Studies were made in greater detail of FPC Regions I, III and IV after they were identified as suitable for UPHS and CAES projects with regard to market potential.

In very general terms, the geology in most of the northeastern United States and the Midwest is suitable for UPHS and CAES employing mined caverns. Most of the coastal areas are unsuitable. In a large part of the Great Northern Plains, the southwestern states, and the western states geologic conditions are less than favorable. There could be specific areas within each of the noted regions which have geology suitable for UPHS or CAES.

CAES systems can also be sited in salt domes, aquifers, and depleted oil and gas fields in addition to mined caverns. In FPC Region I, the most promising salt beds are located in north central Pennsylvania. The most promising salt domes in FPC Region III are located in southern Mississippi. In FPC Region IV, there are several areas offering potential aquifer sites for CAES projects.

The Pennsylvania - New Jersey - Maryland Interconnection appears to be most suitable for near term utilization of UPHS or CAES projects, as well as having suitable nearby geology to accommodate underground hard rock caverns for such projects. Principal load centers are located in a

geographic corridor extending from Washington, D.C. to Newark, New Jersey.

The Virginia-Carolinas Subregion of the Southeast Reliability Council appears to be among the most suitable for accommodating UPHS and CAES projects. Large granitic outcrops occur in a 50-mile by 150-mile area west and south of Richmond, Virginia, and in an extensive zone extending for 100 miles to the northwest from Charlotte, North Carolina. In addition, there are granite gneiss outcrops in central Virginia and in west central Georgia, which appear to be favorable.

In Region IV, the most favorable geology exists in northern Minnesota and northern Wisconsin where Precambrian crystalline rock occurs at or near the ground surface. The above areas are remote from the principal load centers farther to the south. The Precambrian granite is expected to be at a depth of about 2,000 feet in the northwestern tip of Illinois which would be closer to major load centers. Vertical shafts could be sunk to penetrate the overlying sedimentary rock into the Precambrian rock where powerstation caverns and underground reservoirs could be located.

There are areas in northern Illinois where aquifers are located at depths of less than 1,000 feet. Such areas present potential for siting a CAES project. In the southern part of the service area of the Commonwealth Edison Company, there exists a large aquifer. Thus, there is the possibility of a CAES Project in Region IV.

Geotechnical studies have not been conducted to the same detail for other FPC regions. It is expected that specific areas with favorable geologic conditions for UPHS and CAES could be identified by similar studies.

Regional Development Potential of UPHS and CAES Projects

Alternative concepts for UPHS and CAES projects were evaluated using present state-of-the-art and near-term

projections of technological advances. Selections were made of the concepts which appeared to be most competitive and to have the least unknowns in terms of feasibility. Capital cost estimates were prepared for each of the selected concepts.

UPHS Projects

UPHS project concepts are related to the use of different types of pump/turbines. The most economical concept using presently available machinery is a two-drop project developing 2,200 feet in each drop for a total project head of 4,400 feet. An underground powerstation would be located midway between the upper and lower reservoirs. Generating discharges from that powerstation would pass through a second drop of 2,200 feet to a lower powerstation.

Estimated investment costs of such a project with 2000 MW installation at June, 1976 price levels are as follows:

Energy Storage at Generation Rating

	<u>6 Hours</u>	<u>10 Hours</u>
FPC Region I	\$ 297/kW	\$ 353/kW
FPC Region III	271	318
FPC Region IV	337	392

Estimated costs differ from one region to another due to variations in geologic conditions and labor costs.

CAES Projects

CAES projects can incorporate a constant pressure system or a variable pressure system. They can utilize a mined cavern to hold the compressed air. Alternatively, the storage might be provided in a salt dome, an aquifer, or depleted oil or gas field.

In general, the constant pressure system appears to be superior to the variable pressure system, and would have a lower cost. A CAES system with a mined cavern is the simplest concept and appears to present the minimum technological obstacle. However, few investigations have been conducted

to determine the behavior of an underground cavern under alternating exposure to pressurized water and air.

A CAES system utilizing aquifer storage may be possible if the rock is sufficiently permeable to movement of air and has a tight cover. Permeability in the order of 1,000 millidarcies (mD) would probably provide satisfactory performance, but there are very few aquifers meeting this criterion. Instead, aquifers with 100 mD are more commonplace in many parts of the country. There is no certainty that these aquifers would be sufficiently permeable. Estimated costs for a 2,000 MW, 20,000 MWh CAES project in FPC Power Supply Region IV at June, 1976 price levels are given below:

Rock Cavern, Constant Pressure	\$325/kW
Rock Cavern, Variable Pressure	\$451/kW
Aquifer	
1,000 mD, 40 feet thick	\$333/kW
100 mD, 400 feet thick	\$344/kW
100 mD, 100 feet thick	\$466/kW

No effort was made in this study to optimize costs relative to these criteria. Capital costs of CAES are less sensitive to the amount of energy storage than capital costs of UPHS, because the cost of the storage component in a CAES system is relatively small.

Market Capture Potential

The market capture potential of UPHS and CAES systems in the continental United States is estimated at 36 million kW for the ten year period from 1985 to 1995. This amount is about 6% of the 600 million kilowatts of new generating capacity which can be expected to be required in the same period. The year 1985 is the earliest date such a UPHS or CAES project could be commissioned. The market share of UPHS and CAES could be significantly greater than 6% of total new capacity additions beyond 1995.

A large number of assumptions had to be made to perform the projections. In particular, two assumptions are of

fundamental importance. First, UPHS and CAES would maintain the margin of attractiveness over most other energy storage concepts, and over conventional peaking generation such as oil-fueled peaking steam and combustion turbines. Second, UPHS and CAES would move rapidly forward from the present state-of-the-art to large-scale commercialization through concerted effort in research, development, and demonstration. Thus, beginning from 1985, when an electric system has built up the proper percentage of base-load plants in nuclear and coal-fired steam, the UPHS and CAES concepts would then be introduced. We have assumed that the UPHS and CAES will provide a large share of the total future energy storage capacity in the electric system.

It would not be practical in this report to establish the market share between the UPHS and CAES. UPHS is technically more advanced, and appears to be economically more competitive. Thus it seems logical that UPHS might have a larger share of the market. The CAES system may be more competitive under certain circumstances, for instance it can be built in smaller increments (1,000 MW capacity or less), and consequently could be more attractive than UPHS for a smaller utility system.

Research, Development and Demonstration Needs

Both UPHS and CAES concepts have been studied and shown to hold great technological and economical promise. Because of long regulatory delays in fulfilling licensing and siting requirements and because of financial constraints, it is very unlikely that the utilities will be undertaking RD&D effort at a rate sufficient to overcome the remaining technical obstacles and commercialize UPHS and CAES systems to match the market potential. RD&D, sponsored by the government including significant financial support, is therefore essential to large-scale and timely commercialization of these concepts.

We have identified a number of key areas in which RD&D should be conducted. Aside from these recommendations, streamlining of licensing procedures will benefit all large generating projects including UPHS and CAES.

Mr. L. A. Hoornbeek
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UPHS

We recommend that development work be conducted for 20 UPHS sites. Because UPHS systems employ underground storage, such development work must be site-specific. The development work for each site should include siting studies, subsurface exploration, geotechnical investigation, conceptual project design, economic analysis, and environmental evaluation. The development work would permit these sites to be ready for licensing process and early construction when the utilities are ready to proceed with these projects.

We recommend that a commercial size (1000 MW) UPHS demonstration plant be built. Research, development, and testing associated with the demonstration project should remove uncertainties and greatly accelerate large-scale commercialization of the technology.

Certain research work in UPHS should also be conducted. They are not, however, a prerequisite to the recommended development and demonstration work.

CAES

CAES technology is less advanced and appears to be less cost competitive than UPHS. The recommended RD&D, therefore, has a lower priority than UPHS.

We recommend research, development and demonstration be initiated concurrently for CAES. However, development and demonstration should be more carefully programmed and monitored so that each technical obstacle will first be overcome before succeeding steps are undertaken.

Site-specific development work for CAES with storage in hard-rock cavern should be conducted as a part of the UPHS development work for some of the sites. In addition, site-specific development work should be conducted for at least one site each for CAES employing aquifers and salt beds.

We recommend that a commercial-size (500 MW) CAES demonstration plant be built, subject to the successive technological progress. The demonstration plant should

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employ a design and a storage medium which would be applicable in future CAES plants.

A variety of research work can be conducted in the laboratory and in field tests in existing caverns, salt beds, aquifers, and depleted oil fields. These tests could be directed towards determining the behavior of the storage medium under conditions similar to those in a CAES system.

Costs

The above RD&D program could be implemented at a cost of \$870 million in 1977 dollars. The total program would take about 10 years. It is beyond the scope of our assignment to establish the reasonableness of the RD&D program in relation to the total available funds, or the priority needs as compared with RD&D in other technologies. This program, however, represents the effort which will be required in order to permit commercialization of these systems in step with the potential market needs.

Very truly yours,

Henry H. Chen
Project Director

Enclosure: Report

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ACKNOWLEDGMENTS**

INTRODUCTION

INTRODUCTION

Authorization and Scope of Work

This report documents a study of "Underground Pumped Hydro Storage and Compressed Air Energy Storage: Analysis of Regional Markets and Development Potential," by Harza Engineering Company, Chicago, under contract No. 31-109-38-3485 to Argonne National Laboratory. This work was funded by the Advanced Physical Methods Branch of the Energy Research and Development Administration.

The contract specified the following services:

1. Identification and Description of Regional Markets for UPHS and CAES.

A market survey to identify, describe and rank electric utility markets for UPHS and CAES systems. The survey considered such regional factors as (a) size of load and load characteristics, (b) existing and future plant mix, (c) utility fuel use and fuel prices, and (d) regulatory policies and practices. Three regions were to be identified which offer the greatest apparent market potential.

2. Regional Development Potential and Costs.

A national survey to determine regional developmental potential and costs of UPHS and CAES.

Regions identified under (1) as having the greatest market potential were to be given the greatest emphasis. The survey was to utilize available data from the U.S. Geological Survey, state geological surveys, the U.S. Bureau of Mines, state mining departments, and other sources to identify regions having lowest development costs.

In estimating development costs, the analysis was to use state-of-the-art technique and cost data. A method was to be developed to rank regions according to estimated development costs and according to the quality and reliability of informa-

tion about underground geological conditions. Within specific regions, locations identified as having unusual promise were to be highlighted and described. For each of the three regions offering greatest development potential, development cost estimates were to be prepared for the system configuration judged to be most cost effective.

3. Market Capture Potential

An analysis of the cost effectiveness and competitiveness of UPHS and CAES and their market share in future electric systems.

4. Research, development, and demonstration recommendations

Identification and description of research, development, and demonstration effort which would be necessary for the successful and timely commercialization of UPHS and CAES projects.

Content of the Report

The Report contains the Summary Letter and the Main Report which consists of seven chapters with supporting tables and exhibits. Additional backup and supporting material was separately submitted to ANL.

Chapter I contains a description of the studies relating to the Identification and Description of Regional Markets for UPHS and CAES.

Chapters II, III, IV, and V contain studies related to the Regional Development Potential and Costs. Chapter II describes studies related to the geotechnical analysis. Chapter III describes studies on UPHS concepts and costs. Chapter IV describes studies on CAES concepts and costs. Chapter V describes an analysis on the regulatory climate affecting UPHS and CAES development.

Chapter VI contains an analysis of the Market Capture Potential of UPHS and CAES.

Finally Chapter VII provides recommendations on Research, Development and Demonstration of UPHS and CAES projects.

Acknowledgements

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INTRODUCTION

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CHAPTER I
**THE POWER MARKET FOR
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Chapter I

THE POWER MARKET FOR UNDERGROUND ENERGY STORAGE

Introduction

This chapter discusses studies which have been performed to identify, describe and rank the electric utility markets for UPHS and CAES systems. Consideration has been given to the regional differences in load size, load concentration, time variation of loads on daily, weekly and seasonal bases, and to the future mix of generating sources and costs.

The studies were directed toward ranking the regional markets as to relative suitability for UPHS and CAES systems. It is concluded from the studies that the utilities or groups for which underground energy storage has greatest potential usefulness are (1) the PJM Interconnection, (2) the Virginia-Carolinas Pool, and (3) Commonwealth Edison Company.

Identification of Power Market Regions

FPC Power Market Supply Regions

The continental United States was considered as comprising eight electric power supply regions corresponding to Federal Power Commission divisions, as revised January, 1969, and as shown in Exhibit I-1.

Region I, the Northeast Region, contains the nine northeastern states of Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, the District of Columbia and the major parts of Maryland and Pennsylvania.

Region II, the East Central Region, includes all of Indiana and Ohio and portions of Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Virginia, Tennessee and West Virginia.

Region III, the Southeast Region, includes all of Alabama, Florida, Georgia, North Carolina and South Carolina, with substantially all of Tennessee, along with parts of Kentucky, Mississippi, Virginia and West Virginia.

Region IV, the North Central Region, contains all of Illinois, Iowa, Upper Michigan and Wisconsin, part of Minnesota, Missouri and South Dakota.

Region V, the South Central Region, is the largest of all; it includes all of Arkansas, Kansas, Louisiana, Oklahoma and Texas, along with parts of Mississippi, Missouri and New Mexico.

Region VI, the West Central Region, includes all of Colorado, Nebraska, North Dakota, almost all of South Dakota and Wyoming, and parts of Minnesota, Montana, and New Mexico.

Region VII, the Northwest Region, contains all of Idaho, Oregon, Utah and Washington, a substantial part of Montana, and parts of California, Nevada and Wyoming.

Region VIII, the Southwest Region, comprises all of Arizona, almost all of California and Nevada, and a small portion of New Mexico.

Reliability Councils

The National Electric Reliability Council, formed in 1968 as a result of the Northeast power failure, is structured into nine geographical regions of the continental United States as follows:

ECAR - East Central Area Reliability Coordination Agreement

MAIN - Mid-America Interpool Network

MAAC - Mid-Atlantic Area Council

MARCA - Mid-Continent Area Reliability Council Agreement

NPCC - Northeast Power Coordinating Council

SERC - Southeastern Electric Reliability Council

SWPP - Southwest Power Pool

ERCOT - Electric Reliability Council of Texas

WSCC - Western Systems Coordinating Council.

Exhibit I-2 shows areas covered by the Reliability Councils. Each Reliability Council is composed up of member electric power suppliers within the geographic region. Each Reliability Council is, in turn, divided into power pools and or groups.

Relationship Between FPC Regions and Reliability Councils

Region I operates through the electrical connection of three power pools: the New England Power Exchange (NEPEX), the New York Power Pool (NYPP) and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). The NEPEX and the NYPP comprise the United States portion of the Northeast Power Coordinating Council (NPCC). The two pools NEPEX and NYPP, account for essentially complete coverage of utility capacity and requirements in New York and the six New England States, namely Maine, Vermont, New Hampshire, Massachusetts, Connecticut and Rhode Island. The PJM coordinates the bulk power supply operations of the member systems of the Mid-Atlantic Area Council (MAAC). The MAAC area includes Delaware, Washington, D.C. and parts of New Jersey, Maryland, Pennsylvania and Virginia.

The inter-system or inter-pool ties in Region II are not as strong as in Region I. There are 19 power systems incorporating a total of 26 electric utilities. The entire area is under the East Central Area Reliability Coordination Agreement (ECAR). In Region II there exists the Central Area Coordination Group (CAPCO) whose members are: The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and The Toledo Edison Company. CAPCO is more closely interconnected and coordinated than ECAR. There is also a second group (CCD) consisting of Cincinnati Gas & Electric Company, Columbus and Southern Ohio Electric Company and Dayton Power and Light Company. The CCD group has about the same degree of internal coordination as CAPCO. A third major system is the American Electric Power Company (AEP).

Region III is composed of four large subregional groups. They are the Virginia-Carolinas (VACAR) sub-area group, the Tennessee Valley (TVA) sub-area group, the Southern Companies sub-area group and the Florida sub-area group. The four groups constitute the Southeastern Electric Reliability Council (SERC). There is no major interconnection between any two of the sub-groups.

Region IV encompasses all areas of the Mid-America Interpool Network (MAIN) and part of the area of the Mid-Continent Area Reliability Coordination Agreement (MARCA). A number of pools are contained in Region IV. The three most significant ones in the MAIN area are: the Illinois-Missouri Pool (Ill-Mo), the Wisconsin-Upper Michigan Systems (WUMS) and the Iowa Pool. Commonwealth Edison Company, although not a member of any formal pool, is interconnected with a number of pools in the Region as well as with other large systems, such as the American Electric Power System to the east. Commonwealth Edison is a large power supplier, equal in size to several of the formal pools. The MARCA area has less load, covers greater territory and has more extensive conventional hydro resources than the MAIN area.

Region V has a relatively high degree of coordination between its different interconnected systems, such as the Southwest Regional Group (SWRG), the Southwest Power Pool, the South Central Electric Companies (SCEC), the Missouri-Kansas Pool (MOKAN), the New Mexico Power Pool (NMPP), the Texas Interconnected System (TIS) and the Texas Municipal Power Pool. Region V includes all areas of the Southwest Power Pool Coordination Council (SWPP) and the Electric Reliability Council of Texas (ERCOT), along with a small area of the Western Systems Coordinating Council (WSCC).

A number of pool entities can be identified in Region VI: the Nebraska Public Power System, the Upper Mississippi Valley Power Pool and the Rocky Mountain Power Pool (RMPP). Region VI is covered by parts of both the Mid-America Reliability Council Agreement (MARCA) and the Western Systems Coordinating Council (WSCC).

Region VII is the United States portion of the Northwest Power Pool (NWPP). Bonneville Power Administration is the major connection and coordinator of the Pool.

Region VIII, the Pacific Southwest Power Area, encompasses the California Power Pool (CALPP) whose members are the three major investor-owned utilities in California, namely Pacific Gas and Electric Company, San Diego Gas and Electric Company and Southern California Edison Company.

Regions VII and VIII comprise a major portion of the Western Systems Coordinating Council (WSCC) region which also includes the New Mexico Pool Area of Region V and the Rocky Mountain Power Area in Region VI. Most of the systems

in the WSCC region are interconnected, but the ownership of the utility systems is highly diversified.

Table I-1 lists the pools and representative utilities in the eight regions.

Utilities in Regions I, II, III and IV are strongly-interconnected within the regions and across regional lines. The interconnections permit transfer of significant amounts of power in an emergency and also permit power transfer for economic purposes. Regions V, VI, VII and VIII, while they have numerous intra-regional interconnections, have lesser interconnection capacity with other regions due to their extensive geographic coverage and relatively low load density.

Selection of Regions and Candidate Systems

This section presents an analysis which was performed, using electric utility industry load and generation data, to select regions and, subsequently, candidate utility systems for underground energy storage.

The sources of data used in this study are: the Annual Reports filed by each Regional Electric Reliability Council with the FPC in compliance with FPC Order No. 383-3, Docket No. R-362, Appendix A-1; the Form 12 reports filed before the FPC by individual utilities; current technical periodicals including Electric World, Electric Power Statistics in FPC News; and hourly load data received from several utilities through Argonne National Laboratory. An additional source of information was the 1970 National Power Survey of FPC (December 1971).

Selection of Regions

A study of the electric power market of the United States was made at the regional level to identify three regions that could provide early markets for UPHS and CAES. Consideration was given to important regional factors likely to influence utility decisions to construct UPHS and CAES facilities. The factors included existing and projected utility system load and load characteristics, and existing and projected generating plant mix.

Table I-1

LIST OF REPRESENTATIVE POOLS AND LARGE UTILITIES

<u>Regions</u>	<u>Electric Reliability Council</u>	<u>Representative Pools or Utilities</u>
I	MAAC	PJM Interconnection (PJM)
	NPCC	New York State Interconnected System (NYPP)
II	NPCC	New England Power Exchange (NEPEX)
	ECAR	American Electric Power System (AEP)
	ECAR	Alleghany Power System (APS)
	ECAR	Central Area Power Coordination Group (CAPCO)
III	ECAR	Cincinnati, Columbus, Dayton Group (CCD)
	SERC	Virginia-Carolinas Subregion (VACAR)
	SERC	Tennessee Valley Subregion (TVA)
	SERC	Southern Companies Subregion
IV	SERC	Florida Subregion
	MAIN	Commonwealth Edison Company
	MAIN	Wisconsin-Upper Michigan System (WUMS)
V	MAIN	Illinois-Missouri Pool (Ill-Mo)
	ERCOT	Texas Interconnected System (TIS)
	SWPP	Southwest Power Pool
VI	WSCC	New Mexico Power Pool (NMPP)
	MARCA	Upper Mississippi Valley Power Pool
	WSCC	Rocky Mountain Power Pool (RMPP)
VII	MARCA	Nebraska Public Power System
	WSCC	Northwest Power Pool (NWPP)
VIII	WSCC	Pacific Power & Light Company (Including regions outside the Northwest Power Pool)
	WSCC	California Power Pool (CALPP)

Regional Power Demands. Forecasts of power demand over a period from 1970 to 1990 are included in the FPC report, "The 1970 National Power Survey." The FPC periodically updates and revises such forecast. The 1976 forecasts indicated the summer peak demand for the continental United States in 1980 would be 491,808 MW, about 11.7% lower than the value estimated in the 1970 National Power Survey. The data as presented in the 1970 National Power Survey were used for preliminary comparison. Table I-2 shows annual peak demands for the years 1975, 1980 and 1990 for the eight FPC regions in percent of the annual peak demand of the continental U.S.

Table I-2

ANNUAL PEAK DEMANDS OF THE FPC REGIONS

<u>Region</u>	<u>Approximate Percent of Total Area</u>	<u>1970 Percent of Total Population</u>	<u>Percent of Total Peak Demand</u>		
			<u>1975</u>	<u>1980</u>	<u>1990</u>
I Northeast	5	25	17.5	16.7	15.5
II East Central	7	17	14.9	14.3	13.9
III Southeast	11	16	19.1	19.6	19.9
IV North Central	10	42	11.3	11.2	11.0
V South Central	23		16.6	17.4	18.2
VI West Central	16		2.5	2.5	2.5
VII Northwest	16		7.4	7.3	7.1
VIII Southwest	12		10.7	11.0	12.0
Total Continental U.S.	100	100	100.0	100.0	100.0

Note: Based on the forecasts presented in "The 1970 National Power Survey", a report by the FPC, December 1971.

Regional Load Factors. In general, the need for load-leveling or energy storage projects increases with decrease in the system load factor. Table I-3 shows summer and winter monthly load factors and season of peak demand for the eight regions as reported in the FPC Electric Power Statistics (Exhibit I-3). The winter load factors are generally higher than the summer load factors in every region. This indicates that the weekly and daily load variations during the winter are relatively less than in other season; and the winter peaking utilities are, therefore, less favorable for energy storage projects. With the exception of the Northwest Region (VII), all regions have utility systems with summer peaking demands. In Regions I, II and III, there are some winter-peaking utilities. The trend is, however, toward more winter peaking utilities as greater growth rates have been experienced in the winter than in the summer from 1974 to 1976; and such rates are generally forecast for most electric systems.

Table I-3

MONTHLY LOAD FACTORS BY THE FPC
REGIONS FOR THE YEAR 1974 ^{1/}

<u>Region</u>	<u>Season of^{2/} Peak Demand</u>	<u>Load Factors, %</u>	
		<u>June</u>	<u>December</u>
I Northeast	S and W	63	73
II East Central	S and W	71	75
III Southeast	S and W	68	70
IV North Central	S	69	81
V South Central	S	69	76
VI West Central	S and W	63	74
VII Northwest	W	73	80
VIII Southwest	S	67	74

^{1/} Computed from data in FPC Electric Power Statistics, June 1975 and December 1974.

^{2/} S - Summer, W - Winter

Future Generation Mix. The suitability of energy storage for a system is related to the primary source of energy in the system. Systems burning gas or oil to drive

steam turbines, for example, are less adaptable to storing energy than systems using nuclear energy or coal. The planned installation of future generation capacity thus serves as an index to the suitability of energy storage for a utility system. Estimates of future regional loads and the probable types and amounts of generation that will be used to meet the loads are shown in Exhibit I-4. The 1970 forecasts have been revised significantly in recent years, as will be discussed in a later section. However, the values in Exhibit I-4 indicate comparative magnitudes for different regions.

Breakdown by type of generating plants is not given in Exhibit I-4 for the years 1970 and 1980 in Regions III and V as is the case for the other Regions. A breakdown by percentage of energy generation for the different sources is available for 1990. The projected energy source distribution for electric energy generation in Region III by 1990 is 2.3% conventional hydro, 64.7% nuclear, 26.9% coal, 1.0% oil steam, 3.9% gas and 1.2% pumped storage. During the period 1970 to 1990, both large fossil-plants and nuclear generation type plants are included in projected capacity additions for base load operation.

In 1970 about 95% of energy generation in Region V was from natural gas and 5% was from coal. By 1990, the forecast for thermal generation is about 46% natural gas, 43% nuclear fuels and 10% coal. Hydroelectric capacity represented about 5% of the peak load in Region V in 1970, and it is anticipated that by 1990 the percentage of hydroelectric capacity will be less. Additions of hydroelectric capacity beyond 1970 are, for the most part, projected to be pumped storage projects.

By 1990 more than 50% of the generating capacity will be nuclear in the Northeast Region (I), the Southeast Region (III), the North Central Region (IV) and the Southwest Region (VIII). In the Northwest Region (VII) hydroelectric capacity will remain to be the most important source of generation for the period of 1976 to 1990.

Identification of Regions. Regions I, III and IV have been identified as containing utilities or power pools which will have near term demands for large energy storage projects such as UPHS or CAES systems. In these regions, there are strongly interconnected large utility systems within the regions, the generating systems will contain large blocks of

nuclear and mine-mouth coal fueled powerplants and the load profiles of the systems are generally favorable for utilizing energy storage projects.

An overview of the geology of the regions also indicates there is greater likelihood of identifying suitable geotechnical conditions and sites for UPHS and CAES systems within the regions.

The designation of the three noted regions does not exclude the possibility that there are other regions which may have need for early development of energy storage projects.

Identification of Candidate Systems

A study of the electric power markets within Regions I, III and IV was done to identify three potential candidate systems for underground energy storage. Large representative utility systems were first identified within the three regions based on the size of the system, relative ease of transmission between a stored-energy powerplant and principal load centers, load characteristics and future generation mix. The selection process does not exclude other utility systems from being considered as potential candidate systems for UPHS and CAES, but the ones identified are more obvious.

Representative large utilities were identified with regard to generating capacity size. In Region I the systems are (a) the PJM Interconnection, (b) the New York Interconnected System and (c) the New England Power Exchange. In Region III the systems are (a) the Virginia-Carolinas subregion group, (b) the Tennessee Valley subregion group, (c) the Southern Companies subregion group and (d) the Florida subregion group. In Region IV the systems are (a) Commonwealth Edison Company and (b) the Illinois-Missouri Pool. Individual members of representative large power pools in regions I, III and IV are listed in Exhibit I-5.

Table I-4 shows power demand forecasts for representative large power pools and utilities in Regions I, III and IV. The forecasts are mostly estimates made by Regional Electric Reliability Councils and filed with the Federal Power Commission as of April 1, 1976. Supplementary estimates were made in the report by considering the annual growth rate within the region where the power pool or utility was located.

Table I-4

PEAK LOADS FOR REPRESENTATIVE LARGE UTILITIES IN REGIONS I, III AND IV

Region	Utilities & Pools	Electric Reliability Council	Power Demand Forecast (MW)					
			1976	1980	1985	1990	1995	2000 ^{1/}
I	PJM Interconnection	MAAC	31,900	39,420	50,150	63,220	78,490	97,448
	New York State Interconnected System	NPCC	21,000	24,610	29,760	35,988 ^{1/}	43,519 ^{1/}	52,626
	New England Power exchange ^{2/}	NPCC	14,518	18,129	23,881	31,326 ^{1/}	41,178 ^{1/}	54,128
III	Virginia-Carolinas Subregion	SERC	25,280	33,649	46,208	61,988	82,950	111,000
	Tennessee Valley Subregion ^{2/}	SERC	24,646	30,899	39,934	47,302	56,199	66,769
	Southern Companies Subregion	SERC	19,130	26,155	37,762	54,392	79,476	116,128
	Florida Subregion	SERC	14,812	19,187	26,287	33,501	40,992	50,913
IV	Commonwealth Edison Company	MAIN	13,500	17,550	23,780	31,970	42,990	57,796
	Illinois-Missouri Pool	MAIN	10,112	12,638	16,778	22,443	30,058	40,257

Source: FPC Order 383-3, Appendix A-1

NOTE : Peak Loads are Summer Peaks unless stated otherwise.

^{1/} Estimated by assuming continuance of growth rate.

^{2/} Winter peak loads.

In Region I by 1990, the PJM Interconnection (MAAC) is projected to have the largest peak load and will be nearly as large as the combined loads of the next two pools. Principal load centers with loads over 10,000 MW, such as Washington D.C., Baltimore, Philadelphia and northern New Jersey cities (see Exhibit I-6) are along a major transmission corridor within the service area of the PJM Interconnection.

The Virginia-Carolinas subregion (VACAR) in Region III would have a peak load of 61,988 MW by 1990. Other power pools in Region III are: the Southern Companies subregion, the Tennessee Valley subregion, and the Florida subregion. Loads in Region III are less concentrated than in Region I (see Exhibit I-7). However, within the service area of the VACAR, there would be several load centers with loads between 5,000 and 10,000 MW by 1990 such as, Alexandria, Richmond-Petersburg, Norfolk-Hampton, Charlotte-Gastonia, and several other load centers with loads between 2,000 and 5,000 MW. Geotechnical analysis indicates that the Florida subregion is much less suitable for developing UPHS and CAES systems.

In Region IV, Commonwealth Edison Company would have a peak load of 31,970 MW by 1990 and the Illinois-Missouri Pool would have a load of 22,443 MW. There are also a number of principal load centers with loads over 10,000 MW (see Exhibit I-8) and several load centers with loads between 10,000 and 2,000 MW. All of the load centers are within the service area of or within a reasonable distance from the Commonwealth Edison Company and connecting utilities.

Load Characteristics. The 1975 annual load factor and weekly load factors for the first weeks of April, August and December for the representative utilities are shown in Table I-5.

The magnitude of the weekly peak load as a percentage of the annual peak load is also shown in Table I-5, along with the weekly load factor. The annual peak demands occur in the summer for all the utilities except the TVA.

In Region I, PJM with the lowest annual load factor of 59.7% appears to be the best candidate system.

Table I-5

1975 LOAD FACTORS FOR REPRESENTATIVE LARGE UTILITIES

Region	Interconnecting Pools of Utilities	Representative Utility Company	Annual Load Factor %	First Week Peak Demand % of Annual	of April Weekly Load Factor %	First Week Peak Demand % of Annual	of August Weekly Load Factor %	First Week Peak Demand % of Annual	of December Weekly Load Factor %
I	PJM interconnection	PJM	59.7	76.3	75.6	98.9	68.1	80.6	78.7
	New York State Inter- connected System	Consolidated Edison Company	51.4	66.4	70.0	82.4	70.7	70.9	72.4
	New England Power Exchange	The Connecticut Light and Power Company	62.7	84.8	73.0	90.7	68.6	95.7	71.9
III	Virginia-Carolinas Subregion	Virginia Elec- tric and Power Company ^{2/}	55.6	66.8	74.9	77.9	75.2	77.4	79.4
	Tennessee Valley Subregion	Tennessee Valley Authority	64.7	78.0	80.1	78.2	82.2	86.9	79.2
	Southern Companies Subregion	-	56.2	-	-	-	-	-	-
	Florida Subregion	-	57.2	-	-	-	-	-	-
IV	Commonwealth Edison Company	Commonwealth Company	56.0	73.0	77.5	96.2	66.2	81.1	79.2
	Illinois-Missouri Pool	Union Electric Company	51.5	54.5	80.0	86.7	67.7	66.6	78.2

Source: Weekly load factors were computed using 1975 data from FPC Form No. 12 (Schedules 14 and 15).

1/ Peak demand of the week as percent of peak demand of the year.

2/ 1974 data.

In Region III, VACAR has the lowest annual load factor at 55.6%, followed by the Southern Companies subregion group with 56.1% and the Florida subregion group with 57.2%. The Tennessee Valley subregion group has the highest annual load factor at 60.7%.

In Region IV, the Illinois-Missouri power pool has an annual load factor of 51.5%, the lowest in Region IV as well as in Regions I and III. The annual load factor for Commonwealth Edison Company is 56.0%.

Future Generation Mix. Table I-6 shows the projected generation capacity mix for the period 1975 to 1985 for representative utility systems in Regions I, III and IV. The following observations are made from an analysis of data in Table I-6.

There will be a substantial increase in nuclear capacity during the period 1975 to 1985 in every utility system. The additional nuclear capacity in utility systems ranges from 32% to 76% of the total additional generating capacity.

Results of studies by the Regional Electric Reliability Councils indicate that the trend of increasing nuclear capacity will continue for the ten years beyond 1985, as shown in Table I-7. Additions in fossil capacity are noted to be less than additions in nuclear capacity. Additions of conventional hydro and pumped storage capacity to most utility systems are either very small or none at all.

From the analysis it appears that the PJM Interconnection, the Virginia-Carolinas subregion, Commonwealth Edison and possibly utilities connecting with Commonwealth Edison are systems most suitable for accommodating underground energy storage projects. The systems have large generating capacity and are located in areas offering early markets for UPHS or CAES.

Conventional Hydroelectric and Pumped-Storage Sites

Conventional hydroelectric and pumped-storage projects could be built to meet the same needs as provided for by UPHS and CAES projects. The former projects rely on the availability of suitable topography and, in the case of conventional hydroelectric power, on adequate water supply. Most economic and environmentally acceptable conventional

Table I-6

GENERATION MIX FOR REPRESENTATIVE LARGE UTILITIES

Region	Utilities or Pools	Generating	Percentage of Total Generating Capacity					Pumped Storage
		Capability	Hydro	Nuclear	Coal	Oil Steam	Combustion Turbine	
		MW						
1975								
I	PJM Interconnection ^{1/}	39,967	1.8	10.8	36.5	27.6	20.1	3.2
	New York State Inter- connected System ^{2/}	27,028	14.9	8.7	58.2 ^{3/}	-	14.5	3.7
	New England Power Exchange ^{2/}	18,784	6.8	17.1	59.9 ^{3/}	-	7.5	8.7
III	Virginia-Carolinas Sub- region ^{2/}	32,909	7.5 ^{4/}	17.3	64.9 ^{3/}	-	8.5	1.8
	Tennessee Valley Sub- region ^{2/}	26,165	15.3	8.1	66.3 ^{3/}	-	10.1	0.2
	Southern Companies Subregion ^{2/}	23,190	12.3	-	80.3 ^{3/}	-	6.3	1.1
	Florida Subregion ^{2/}	17,675	-	7.5	70.0 ^{3/}	-	22.5	-
IV	Commonwealth Edison Co. ^{1/}	15,337	-	31.0	53.2 ^{3/}	4.5	11.3	-
	Illinois-Missouri Pool ^{2/}	10,824	3.0	-	90.6 ^{3/}	-	3.5	2.8
1985								
I	PJM Interconnection ^{1/}	63,574 ^{5/}	1.1	31.7	26.6	22.9	13.9	2.0
	New York State Inter- connected System ^{2/}	39,718	10.0	25.6	49.7 ^{3/}	-	9.8	4.9
	New England Power Exchange ^{2/}	27,673	4.6	36.2	46.4 ^{3/}	-	6.9	5.9
III	Virginia-Carolinas Sub- region ^{2/}	52,766	5.0	38.9	45.6 ^{3/}	-	4.5	6.0
	Tennessee Valley Sub- region ^{2/}	46,131	8.9 ^{4/}	43.9	38.5 ^{3/}	-	5.8	2.9
	Southern Companies Sub- region ^{2/}	42,365 ^{5/}	8.2 ^{4/}	16.0	71.2 ^{3/}	-	3.2	1.4
	Florida Subregion ^{2/}	31,378 ^{5/}	-	18.7	63.6 ^{3/}	-	17.6	-
IV	Commonwealth Edison Co. ^{1/}	27,660	-	44.8	29.5 ^{3/}	19.5	6.2	-
	Illinois-Missouri Pool ^{2/}	19,760	1.7	21.2	66.1 ^{3/}	-	9.5	1.5

Note: The generating capability shown is the net plant capability of the system at the time of the system peak load.

^{1/} From FPC Form No. 12, Schedule 1.

^{2/} From FPC order 383-3, Appendix A-1.

^{3/} Includes oil-steam. Data do not permit separation.

^{4/} Includes pumped storage. Data do not permit separation.

^{5/} Includes a small portion of undetermined fuel.

Table I-7

FUTURE GENERATING CAPACITY ADDITIONS
(1986 to 1995)

Region	Electric Reliability Council	Interconnecting Pools or Utilities	Capacity Additions MW	Percentage of Total Additions			
				Hydro ^{2/}	Nuclear	Fossil	Undetermined
I	MAAC NPCC	PJM Interconnection New England, New York, New Brunswick, Ontario ^{1/}	32,830 77,242	3 8	48 74	43 18	6 -
III	SERC	Virginia-Carolinas Subregion	39,004	11	57	32	-
		Tennessee Valley Subregion	22,100	7	93	-	-
		Southern Companies Subregion	48,691	2	29	69	-
		Florida Subregion	12,632	-	74	26	-
IV	MAIN	Commonwealth Edison Company	22,425	-	61	39	-
		Illinois-Missouri Pool	15,080	-	53	47	-

Source: FPC Order 383-3 Appendix A-i

^{1/} Represents the whole area of NPCC including New England Power Exchange, New York State Interconnected System, New Brunswick and Ontario. Data do not permit separation.^{2/} Includes pumped storage - Data do not permit separation.

hydroelectric resources have been developed in the continental United States. This is especially the case in the FPC Regions I, III and IV. Most conventional pumped-storage projects are subjected to close scrutiny for environmental impact, and they are typically opposed by special interest groups. Opportunities for developing economic, conventional pumped-storage projects close to load centers in Regions I, III and IV are diminishing yearly.

Within the limits of the continental United States there is, at least theoretically, a large potential for developing conventional hydroelectric plants and conventional pumped-storage plants. There is also potential for adding generating units to existing hydroelectric stations. Except in the Pacific Northwest, FPC Power Supply Region VII, such hydroelectric potential is suitable primarily for peaking operation. In Region VII both base load and peaking developments remain possible.

Throughout the country there are numerous sites for small plants that could supply energy without regard to timing, such plants contributing to reduction of fuel use without providing dependable capacity. Tidal energy of such nature may be available in Region I, on a permanent basis from American development and on a withdrawable basis from Canadian development.

In practical terms, development of most of the available hydroelectric sites is improbable for the following reasons:

- (1) Prior use of reservoir lands through residential, industrial, transportation and farming development. Such development precludes siting of a hydroelectric plant by reason of the adverse public reaction to forced relocation, the excessive cost of obtaining land, or the excessive economic cost of interfering with existing food production and manufacturing.
- (2) The reservation, by law, of certain sites for scenic or recreational purposes.
- (3) The excessive cost of hydroelectric development because of foundation conditions and physical character of the site.

Conventional Hydroelectric Plants

In 1972 the FPC published "Hydroelectric Power Resources of United States -- Developed and Undeveloped". According to the publication, conventional undeveloped hydroelectric power in the United States is 125.2 million kilowatts, with a potential average annual generation of approximately 445 billion kilowatt hours. Of the foregoing, 32.5 million kilowatts and 172.6 billion kilowatt hours (annually) are in Alaska and Hawaii. The remaining 92.7 million kilowatts of capability and 272.1 billion kilowatt hours of annual energy are in the continental United States.

More than 60% of the above noted 92.7 million kilowatts capability is in Pacific Coast drainage. In the power supply regions that are indicated herein as being most suitable for UPHS and CAES projects, the following amounts are indicated as being available:

	Capacity	Hydroelectric Percent of Continental	Potential Annual Energy Million kWh	Percent of Continental
	MW	U.S.		U.S.
PJM Area	3,444	3.7	10,037	3.7
VACAR Area	2,882	3.1	5,209	1.9
Commonwealth Edison	53	0.05	283	0.1

Practically all of the potential sites mentioned in the FPC report for the three regions identified in this report are considered as unavailable because of the problems previously noted.

Conventional Pumped-Storage

Theoretically, conventional pumped-storage can be developed in any location where there is a difference in elevation between two areas that are suitable for creation of reservoirs and sufficient water is available to provide for initial reservoir filling and water make-up. As a practical matter, the site must have certain basic characteristics relating to elevation difference, length of water conduits, size of reservoir and operating drawdown of the

reservoir if costs are to be low enough to make the site worthy of consideration.

Sites meeting required physical characteristics are abundant. A recent Federal Power Commission publication showed 155 potential sites with a total development capability of 341,000 MW available in Arizona, California, Nevada, and Utah. The Corps of Engineers published a study which showed 242 potential sites with a total development capability of 670,000 MW in the Columbia River Basin. A current study produced for a group of utilities in a state much less mountainous than the four named above identified nearly 100 conventional sites, of which 20 were, apparently, low enough in cost to deserve further consideration. Throughout the United States, the number of potential sites probably is the thousands.

In Power Supply Regions I and III there are many sites for conventional pumped-storage, some of which appear to be reasonable in cost and have minimal environmental impact. However, since a conventional pumped-storage project always requires two surface reservoirs, its environmental impact would probably exceed that of an underground pumped-storage plant. The choice between conventional and underground pumped-storage, therefore, will be partly in costs and partly in environmental impact. As the growths of population and industry put increasing pressure on land use it would be expected that underground pumped-storage will be more favorable environmentally.

Within the Commonwealth Edison area there are a few conventional pumped-storage sites, but they are either high in cost or entail serious environmental objections.

Adding Generating Capacity at Existing Powerplants

In general, older hydroelectric Powerplants were built to operate at relatively high load factors. As electrical systems grow and become predominantly thermal, hydroelectric generating units may be added to existing powerplants to provide peaking capacity.

The economics of adding units to existing powerplants depend on the physical and hydrologic characteristics of the site. If there were not specific provision made for adding units, such additions could be very expensive. Added units could create environmental problems in fluctuating river

discharge and in causing wide and rapid change of water level in the headwater reservoir and tailwater channel as the result of such discharge fluctuation.

In Power Supply Regions I and III, there are numerous hydroelectric powerplants, many of which were designed and built for peaking operation. There are also many sites at which additional units are being considered or will be considered in the future.

In Power Supply Region IV there are no conventional hydroelectric sites of any consequence suitable for adding units.

In the Pacific Northwest Power Supply Region VII there is very large potential for adding generating units to existing plants. Such is being done at the Grand Coulee and Chief Joseph Dams. It is to be expected that generating units will be added to most or all of the dams on the Columbia River downstream of the Chief Joseph Dam. Any such additions should be evaluated economically in comparison with pumped-storage and other types of generation, but it appears that a large number of additions could be made to existing powerplants before pumped-storage will be needed.

Current Activity

As of January, 1976 the Federal Power Commission was considering applications for either permits to study or licenses to build 32 conventional and pumped-storage hydroelectric powerplants. Ten permits for studying potential projects had been issued and were still in effect. Plant size ranged from 8 MW to 3,575 MW and totalled 21,132 MW. Twenty-six of the powerplants were conventional hydro, 12 were conventional pumped-storage, two were combination conventional hydro and conventional pumped-storage, and one was underground pumped-storage. Some of the conventional sites were at navigation dams along the Ohio River. They would provide energy and interruptible capacity.

Based on historical experience, some of the sites will be found not feasible for various reasons and, therefore, will not be built. Others may be found economic for later development which could be several years or even decades in the future. The large number of applications are evidence, however, of great interest in development of both conventional and pumped-storage hydroelectric projects.

GEOTECHNICAL CRITERIA
EVALUATION OF THE CONTINENTAL UNITED STATES
DEVELOPMENT POTENTIAL IN FPC REGION I
- NORTHEAST REGION
DEVELOPMENT POTENTIAL IN FPC REGION III
- SOUTHEAST REGION
DEVELOPMENT POTENTIAL IN FPC REGION IV
- NORTH CENTRAL REGION

CHAPTER II
GEOTECHNICAL ANALYSIS

Chapter II

GEOTECHNICAL ANALYSIS

Geotechnical Criteria

A study of geotechnical factors such as lithology, stratigraphy, geologic structure, hydrogeology, engineering rock properties and seismicity was made to develop a group of geotechnical criteria for evaluation of potential UPHS and CAES sites. The application of the criteria was limited by conceptual depth ranges and geometry established previously in engineering studies for UPHS and CAES sites. The geotechnical criteria, depth ranges, and geometry are shown on Exhibits II-1 and II-2.

In this study, the criteria were applied nation-wide to delineate those regions where geotechnical conditions are highly favorable for underground energy storage. Subsequent geotechnical studies involved first- and second-level ranking of regional power systems and defined specific areas where site conditions are favorable.

The geotechnical criteria were directed toward optimal construction, operation and maintenance of the major structural components of an underground energy storage system. Crystalline igneous rock or massive carbonate rock are the most favorable types of rock for mining either a UPHS system or a hydraulically-compensated, constant pressure CAES system. In the case of a variable pressure CAES system, the crystalline or carbonate rocks are also favorable.

Mention is often made in the literature of the possible use of existing mines for underground energy storage. Experience to date from underground inspections and studies indicates that use of such a facility is not generally practical. Mine workings are typically insufficient in terms of size, excavation arrangement and reservoir wall material characteristics. Furthermore, previous blasting for mineral removal often results in a chamber that is extremely difficult and costly to seal and maintain.

A massive homogeneous salt deposit is considered favorable for cavern construction because of its suitability for hydraulic mining. However, potential environmental problems

associated with water supply and salt-water disposal may serve to negate this favorable aspect. With regard to the latter problem, the Huntorf installation in Germany uses direct disposal of the mining brine solution into the North Sea.

Sandstone and carbonate rock formations are the most favorable media for compressed air storage in an aquifer. A geologic structure inhibiting vertical and lateral migration of air beyond desired storage limits and a reservoir rock possessing high rock permeability are basic geotechnical requirements. The occurrence of exposed pyrites in the storage reservoir is an undesirable situation. Oxidation of the pyrites could produce sulfur dioxide gas which would accelerate corrosion of the gas turbine machinery.

Compressed air storage in depleted oil or gas fields is potentially feasible; however, the occurrence of residual hydrocarbons is definitely an unfavorable factor as a small percentage of residual hydrocarbons mixed with the compressed air could result in a combustible mixture in the storage cavern. There is also the possibility that chemical reactions could occur under various states of pressure and temperature such that the stored air would become deficient in oxygen. Such air would be chemically unsuited for optimal gas turbine usage. For this report, air storage in depleted oil or gas fields was not studied in depth.

Evaluation of the Continental United States

A broad review of the geology of the United States was conducted to delineate areas which appeared generally suitable for underground energy storage. Geologic conditions which favorably or unfavorably effect shaft excavation and cavern siting were considered, and maps were developed showing generalized areas of the United States in which favorable and unfavorable conditions occur (Exhibit II-3). The geologic conditions which affect air storage in an aquifer were considered separately, and appropriate maps were developed showing favorable aquifer storage areas.

The generalized nature of the maps should be recognized. Within a region shown as unfavorable, limited areas probably occur which have favorable geologic conditions. Conversely, within regions shown as favorable, because geologic conditions do vary throughout the region, some areas may be unfavorable.

Geologic conditions such as great thicknesses of generally unconsolidated sediments, volcanic rocks, major aquifers, complex geologic structure and high seismicity pose significant construction problems and increased development costs. Areas in which such conditions occur are considered generally unfavorable.

Exhibit II-4 shows areas of deep, predominantly unconsolidated sediments. The deposits often contain major aquifers, provide extremely poor conditions for shaft excavation and provide no competent rock in which to excavate a cavern. In addition, geologic conditions which produce traps for aquifer storage are commonly absent.

Exhibit II-5 shows areas where volcanic rock covers large areas. Volcanic rock, due to its wide variability in both lithology and permeability, is considered unfavorable for cavern siting. A great thickness of essentially homogeneous volcanic rock would be considered favorable.

Exhibit II-6 shows areas of complex geologic structure in which geologic conditions vary widely within short distances. Although potential cavern sites may be found in the areas, detailed study of the geology in such areas is critical to site selection.

Areas of high seismic activity, where major destructive earthquakes are most likely to occur, are shown in Exhibit II-7. The exhibit also shows earthquake epicenters of Modified Mercalli Intensity VII or higher outside of the areas of high seismic activity. Although high seismic activity does not necessarily eliminate an area from consideration as a cavern site, increased costs would be associated with such a site because of the occurrence of active faults or poor rock conditions associated with fault zones.

Exhibit II-8 shows areas of extensive major faulting. Such areas are traversed by numerous faults, often with large displacements and or broken zones of considerable width. Detailed exploration would be essential prior to site selection in such areas.

Areas of massive salt beds or salt domes where a cavern might be mined hydraulically are shown in Exhibit II-9. Exhibit II-10 shows the locations of oil and gas fields, where an abandoned field may be used for air storage. Exhibit II-11 shows areas which are favorable and unfavorable for air storage in an aquifer.

Development Potential in FPC Region I - Northeast Region

Categories of Areas for UPHS Sites

Representative rocks of the three major rock groups, igneous, metamorphic and sedimentary -- are found with FPC Region I. The suitability of a particular rock type varies with the requirements of the facility being considered. UPHS, CAES constant pressure, and some CAES variable pressure schemes, require shafts and caverns in massive rock of superior quality. Other CAES variable pressure schemes are adaptable to vertical elongate caverns in highly soluble rock. CAES systems in aquifers require significantly permeable reservoir rock overlain by impermeable cap rock. The rock types found in Region I can be arbitrarily grouped according to their degree of adaptability to these systems.

For caverns in insoluble rock of superior quality, the following rock properties and rock mass characteristics are significant (partially adapted from Farquhar, 1974):

1. High strength and cohesion;
2. High degrees of homogeneity and uniformity;
3. Large subsurface volume;
4. Very low permeability;
5. High resistance to solution, weathering, scaling and slaking; and
6. High resistance to the effects of thermal and pressure cycling.

The rock units occurring in FPC Region I have been analyzed and evaluated using the above criteria as a basis. For the purposes of this study, generalized groups have been established as follows:

- a) The granitic rocks occurring as intrusive plutons most fully satisfy the criteria for cavern systems.
- b) Felsic intrusive and some types of massive metamorphic rocks (diorite, granodiorite, syenite, monzonite and granite gneiss) are slightly less favorable for caverns, but usually satisfy all or most of the above criteria.

- c) Gneisses, schists, amphibolites, serpentinites and phyllites are crystalline rocks which frequently fail to satisfy criteria of uniformity, strength and, in many cases, resistance to scaling and slaking, due to higher degrees of foliation and schistosity. Some of these rock types at local sites may be suitable for caverns on closer examination.
- d) Unconsolidated sediments and sedimentary rocks such as shale, siltstone, sandstone, conglomerate and evaporites, are grouped together as being generally unfavorable. Volcanics and metavolcanics are also included in this group.
- e) Limestones and dolomites may provide satisfactory sites and are considered as a quality group. Because of the variability of these rocks in Region I, however, a much more detailed examination is required to ascertain their subsurface occurrence and the degree to which they satisfy minimum criteria.

Generally the rock groups of Region I are of sufficient quality for shafting purposes. Unconsolidated sediments will require special treatment. The most favorable rock groups for caverns will also provide the most favorable shaft excavation conditions.

The primary factors governing the use of aquifers are permeability and air bubble confinement. Consequently, not all sedimentary rocks will be suitable for air storage reservoirs. For CAES systems in aquifers and depleted oil or gas fields, favorable rock groups include sedimentary sandstone or carbonate reef rocks for the reservoir and shale for the cap.

Potential sites for UPHS facilities are ranked below in five general categories in descending order of favorability:

<u>Category</u>	<u>Description</u>
1.	Shafts and caverns in massive granite plutons.
2.	Shafts and caverns in other massive crystalline rocks such as granite gneiss, diorite, granodiorite, monzonite or syenite.

3. Shafts through either sedimentary and or metamorphic rock; caverns in massive crystalline basement rock (Granitic basement preferred).
4. Shafts through unconsolidated sediments; caverns in massive crystalline basement rock (Granitic basement preferred).
5. Shafts through sedimentary rocks; caverns in dolomite or limestone.

The ranking is based on the assumption that the physical properties attributed to the rock material and rock mass are as usually found. The degree to which one category is more favorable than another is dependent on site specific factors.

Category 1 is assigned to a potential site with the most favorable geologic conditions.

Category 2 is assigned to a potential site with slightly less favorable geologic conditions. Site investigations may show that some granites, upon field investigation, are less favorable than the granite gneiss, granodiorite, etc., associated with Category 2 areas.

Category 3 is less favorable than Categories 1 and 2 because of a lack of detailed information on the buried basement. If granitic basement can be located within appropriate depths, a Category 3 site may prove less costly to develop than a Category 2 site due to lower shaft excavation costs.

Category 4 is considered significantly less favorable than 1, 2, or 3 because of problems associated with shafts through unconsolidated sediments and because of inadequate information on the underlying basement rocks.

Category 5 is least favorable because of the apparent absence of sufficiently thick massive carbonates at appropriate depths.

A sixth category of potential sites, wherein both shafts and caverns are in crystalline rocks such as schist, gneiss, gabbro, etc., could be added for sites located in many areas of FPC Region I. Because the engineering properties of such rock masses vary widely, significant research and exploration would be required to prove the adequacy of

the generalized rock group comprised of schist, gneiss and phyllite.

Delineation of FPC Region I for UPHS, by Categories

Areas in FPC Region I, which have been evaluated according to regional geologic factors and engineering requirements and assigned to the categories defined above, are shown in Exhibit II-12. The areas are summarized as follows:

Category 1 areas have granite cropping out at the surface. The majority of these areas are concentrated in central and eastern New England. Rock units are of late Paleozoic age and little deformed by tectonic events. Smaller granite bodies are located at the eastern edge of the Piedmont in Maryland and in southeastern New York.

Category 2 areas represent granite gneisses, syenites, monzonites, diorites and granodiorites. The four major regions meeting criteria of this category are shown as (1) western New Hampshire, (2) Rhode Island and western Massachusetts, (3) the Adirondack mountains, and (4) isolated areas in southeastern Pennsylvania, northwestern Maryland and New Jersey. Some Category 2 areas in Rhode Island and western Massachusetts are described as gneiss; preliminary local studies indicate, however, that these rocks should be suitable for caverns. More detailed studies of Category 2 areas in the Adirondacks are required to adequately evaluate specific sites because of severe deformation of the rock units. The most favorable Category 2 areas are in western New Hampshire, in Massachusetts south of Boston, and, to a lesser extent, in the granite gneisses of Maryland, southeastern Pennsylvania and northern New Jersey.

Category 3 areas occur along the edges of the Adirondack province. The indicated zone represents areas where basement rock, presumably Grenville metamorphics, are found within 2,000 feet of the surface. Although it is not known whether the basement rock is suitable for caverns, potential sites may be determined by subsurface exploration. Because of the physical characteristics of the sedimentary rocks, good excavation characteristics are expected for shafts. Other Category 3 areas may be found adjacent to plutonic rock masses in New England.

Category 4 areas are found in portions of the Atlantic Coastal Plain in Maryland, Delaware, New Jersey and New York

(Long Island). Exhibit II-12 indicates where basement rock is found within 2,000 feet of the surface. The best areas appear to be located adjacent to granite outcrops in Maryland. The sediment cover is relatively thin. Conditions exist which should result in reduced shaft costs and a good rock for the storage cavern.

There is a Category 5 area in the Appalachian Plateau of Pennsylvania and New York. Available geologic information suggests that sufficiently thick and massive limestone or dolomite is not common. Consequently, the area is not considered attractive for development of a UPHS system.

Additional factors which affect UPHS cavern site selection are included in Exhibit II-12. Relatively high seismic risk areas as defined by Hadley and Devine (1974) are shown. These areas should be avoided if equally attractive sites are available in lower risk zones. Faults representative of the larger faulted zones are also shown and should be avoided if possible. FPC Region I is geologically complex, and site studies are required to accurately determine the location and influence of faults in a particular area.

In summary, very favorable UPHS cavern sites appear to be available in FPC Region I. The most favorable areas are associated with the granites and other plutonic rocks in eastern New England and the granite gneisses in the Piedmont of southeastern Pennsylvania, northern Maryland and northern New Jersey.

Favorable Areas for CAES Sites

Constant Pressure Caverns. Geologic parameters for CAES constant pressure facilities are essentially the same as for UPHS caverns. As shown in Exhibit II-12, the most favorable sites are found in the granitic bodies of eastern New England and intrusives in the Piedmont of southeast Pennsylvania, northwest New Jersey and northern Maryland.

Variable Pressure Caverns. CAES variable pressure caverns can be excavated in massive crystalline rocks utilizing conventional mining techniques. They can also be hydraulically mined in salt domes or massive salt beds.

Areas containing crystalline rocks as required for a CAES variable-pressure cavern are the same as for UPHS and CAES constant pressure schemes as shown in Exhibit II-12.

Exhibit II-12 also shows areas underlain by bedded rock salt. The massive salt beds which appear to be the most favorable for containing CAES storage reservoirs, based on published data regarding thickness and depth, are in the north central portion of Pennsylvania, and adjacent areas in New York and extreme southwestern Pennsylvania.

Aquifer Storage. The Appalachian Plateau and the Valley and Ridge provinces are possible areas for CAES aquifer storage. However, the data available do not suggest a high potential for site development. Evaluation of sedimentary rocks underlying the Valley and Ridge and Appalachian Plateau provinces will depend on more detailed investigation. It appears likely that few appropriate sites are available. In the Valley and Ridge, the low prospective availability results from generally low permeabilities and or questionable integrity of cap rocks due to fold-induced fracturing. In the Appalachian Plateau, few rocks would be expected to have sufficiently high permeabilities. Geologic traps in this area also tend to be of the stratigraphic rather than structural type and are extremely difficult to locate.

Igneous and metamorphic rocks found over most of the remaining area of FPC Region I have permeabilities far too low for aquifer reservoir rock. Coastal Plain sediments, although frequently of high permeability, are questionable for aquifer storage because of the lack of geologic traps, the possible low strength cap rocks and the likely migration of stored air up-dip to the west. Therefore, the potential for aquifer storage appears quite limited in FPC Region I.

Depleted Oil and Gas Fields. Oil and gas production in FPC Region I is located in western New York and Pennsylvania. Possibilities for siting CAES facilities in oil and gas fields are limited to these areas. Depleted gas fields have been utilized for natural gas storage since 1916 in New York and 1920 in Pennsylvania. As of 1963, 61 such storage pools were active in Pennsylvania, 51 at depths between 900 and 3,000 feet (Lytle, 1963). Working gas capacities in pools above 3,000 feet depth ranged from 225 to 51,408 million cubic feet (Mcf) at storage pressures of from 53 to 1,143 psi. The higher capacities and pressures are generally found in the deeper pools. Geologically, these pools are located in stratigraphic rather than structural traps in Pennsylvanian, Mississippian, Upper Devonian and Lower Silurian rocks of the Appalachian Plateau. Comparable

information on gas storage in New York is not available. However, the prevailing geologic conditions are expected to provide possibilities similar to those found in Pennsylvania for CAES application.

Development Potential near Region I Load Centers

The second-level power-market correlation and ranking study indicated load centers and market service areas where the potential for energy storage projects appears to be great. The Pennsylvania-New Jersey-Maryland Area (PJM) in FPC Region I was favorably indicated by this ranking. Geotechnical analyses indicated that the more favorable sites would be for systems which utilize mined caverns. The principal load centers are located in a geographic corridor that extends from Washington D.C. to Newark, New Jersey. Extensive areas of granite, granodiorite, diorite and granite gneiss occur in the PJM area a short distance west of this corridor. Exhibit II-12, which indicates areas favorable for UPHS and CAES caverns, shows favorable cavern sites from Baltimore, Maryland to northern New Jersey.

Mined Caverns. The rock units in the above mentioned areas, if they possess the engineering properties commonly associated with their composition and texture, would all be equally suitable for cavern development. The characteristics of the rock mass, such as jointing, uniformity and homogeneity and size would determine the most satisfactory site for a cavern system. In the preparation of project cost estimates, the rock masses shown in Exhibit II-12 are assumed to have both shafts and caverns in high quality crystalline igneous rocks with minimal adverse geologic defects such as joints or shear zones.

Surface geologic investigations to determine the surface physical characteristics of a rock mass and the geologic conditions that effect surface engineering structures could be required to further differentiate the areas shown in Exhibit II-12. Subsurface exploration for sampling and testing of the rock material and for in-situ evaluation of the rock mass characteristics (to determine its suitability for shaft and cavern excavation and its permeability) would be required to establish geotechnical feasibility.

Salt Beds. Although potential rock cavern sites are indicated by geologic conditions where load centers are located in the eastern PJM area, potential CAES sites exist

in western Pennsylvania in bedded salt deposits; and these should not be overlooked in future studies. Cavern development should consider comparative economics between conventionally and hydraulically mined caverns.

Within the PJM market area, itself, the region most favorable for a CAES system in a salt bed appears to be in north central Pennsylvania. Southwestern Pennsylvania, another area which appears to possess potential sites for a CAES system in a salt bed is mostly outside of the PJM market area. It is noted that for this study, market potential and geologic conditions combine to favor rock cavern storage for this area.

Aquifers and Oil and Gas Fields. Potential sites for CAES systems in either aquifers or depleted oil and gas fields occur in the PJM market area. However, available geologic data and problems inherent to residual hydrocarbons in the rock do not suggest a high potential for either aquifer or oil or gas field projects.

Development Potential in FPC Region III - Southeast Region Categories of Areas for UPHS Sites

The criteria used in this report to group rock types for their favorability for conventionally mined caverns is repeated below:

1. High strength and cohesion.
2. High degrees of homogeneity and uniformity.
3. Large subsurface volume.
4. Very low permeability.
5. High resistance to solution, weathering, scaling and slaking.
6. High resistance to the effects of thermal and pressure cycling.

Other type caverns require different criteria; namely, highly soluble rock for hydraulically mined caverns, and very permeable reservoir rock overlain by a tight cap rock for aquifer and oil or gas field storage.

Using the defined geologic and engineering criteria for conventionally mined caverns, the most favorable types of rock units are granitic plutons of late Paleozoic age. Generally favorable rock types constitute large bodies of massive granite gneiss and felsic intrusives other than granite. Significantly less favorable, but with some cavern potential, are Paleozoic dolomites and limestones. Rock types that also occur but are generally considered less suitable, include schist, phyllite, gneiss, amphibolite, unconsolidated sediments, and sedimentary rocks other than carbonates.

Granitic plutons are found in the Piedmont and Blue Ridge provinces of FPC Region III. The largest granitic masses are concentrated at the edge of the Coastal Plain in Virginia and in Virginia and in west-central North Carolina. These plutons are generally late Paleozoic in age and should be largely undeformed. Other extensive granite masses are located in western Georgia and eastern Alabama near the extreme southern limit of the Piedmont province. The granites tend to be sinuous and linear, and they are likely to be more deformed by orogenic activity.

Massive metamorphic rock types, particularly granite gneiss, are concentrated along the western edge of the Blue Ridge province. Significant occurrences of granite gneiss are also found in the Piedmont, particularly in central Georgia and central Virginia. Judging by the surface distribution of these rock masses, the largest and least deformed are in the Piedmont, while those further west tend to be more elongate and sinuous.

Other rock types such as schist, phyllite, amphibolite, gneiss and meta-sediments, which are found in the Appalachian provinces, are generally less satisfactory for caverns. The metamorphosed sedimentary rocks include a major slate belt along the eastern edge of the Piedmont in North and South Carolina. A number of Triassic age rift basins, filled with continental sediments and volcanics, are located in the Piedmont north of South Carolina.

The remainder of FPC Region III consists of sediments and sedimentary rocks overlying crystalline basement. Basement rock is deeper than 2,000 feet over most of the sedimentary areas, and it is recorded at depths in excess of 25,000 feet in southern Mississippi. Relatively little is known about the characteristics of the buried basement.

East of the Appalachians, basement rocks are generally assumed to be related to rocks exposed in the Piedmont. In areas to the west, basement rocks could be related to either Blue Ridge or older, more deformed lithologies. The largest mass of known rock types beneath the Atlantic Coastal Plain are Piedmont related crystalline metamorphics and meta-sedimentary types generally unfavorable for caverns. Of particular importance to the evaluation of potential cavern sites beneath the coastal plain are the known areas of granite, adjacent to the exposed Piedmont in southern Virginia and South Carolina. Basement underlying other portions of the Coastal plain and the western plateaus are largely unknown, with the exception of a granite mass identified southwest of Nashville, Tennessee.

Sedimentary rocks in FPC Region III are widely varied. Cretaceous and Tertiary sediments of the Gulf and Atlantic Coastal Plains are essentially unconsolidated sand, gravel, silt and clay and are unsuitable for caverns. Older sediments at the base of the Gulf Coast sequence are somewhat more competent, but they are extremely deep and include rock units generally unfavorable for caverns. These deposits include clay, silt, sand, shale, carbonates and evaporites.

Potential sites for UPHS facilities are categorized below in descending order of favorability as follows:

<u>Category</u>	<u>Description</u>
1.	Shafts and caverns in granitic rock. Most favorable.
2.	Shafts and caverns in massive granite gneiss or igneous plutons other than granites.
3.	Shafts through consolidated sedimentary rock; caverns in crystalline basement rock (Granite basement preferred).
4.	Shafts through consolidated sedimentary rocks; caverns in limestone or dolomite.
5.	Shafts through unconsolidated sediments; caverns in crystalline basement rock (Granite basement preferred).

6. Shafts through unconsolidated sediments; caverns in limestone or dolomite.

The limiting assumptions that were discussed under FPC Region I apply also to the ranking of rock materials and rock masses in FPC Region III. Areas favorable for UPHS and CAES caverns and ranked according to the defined categories are shown in Exhibit II-13.

Favorable Areas for UPHS Sites

Category 1 areas would have massive granite for all underground structures and are considered as most favorable. Areas fulfilling Category 1 criteria are shown in Exhibit II-13. Within these areas, the most favorable sites will probably be in the northeast and central Piedmont areas. The granites are generally younger and less deformed than those to the south and west. Of particular note are large granitic outcrops in a 50 mile by 150 mile area west and south of Richmond, Virginia, and an extensive zone extending for 100 miles to the northwest from Charlotte, North Carolina.

Category 2 ranking would have granite gneiss from the surface to a great depth. Such areas are more limited in number in the southeast than in the northeast. Three potential areas are indicated in Exhibit II-13. These areas are located along the Tennessee-North Carolina border, in west-central Georgia and in central Virginia. The granite gneisses in Georgia and Virginia appear more favorable than those in Tennessee and North Carolina because of reported lesser degrees of deformation.

Category 1 and 2 areas are considered independent of depth criteria for the various cavern configurations, based on the assumption that favorable plutonic rocks occurring at the surface generally extend to great depth.

Category 3 has crystalline basement within 4,500 feet of the surface, overlain by consolidated sedimentary rocks. A potential area includes the upwarped crystalline basement of the Nashville Dome. Although the nature of the basement rock under Nashville is not well known, a small area to the southwest is shown as granite. The overlying sedimentary rocks in this area consist of shale, carbonates and sandstone which should present no major problems for shaft excavation.

Category 4 areas are potential areas of consolidated sedimentary rocks with limestone and dolomite at depth. They are found in the Cumberland and Interior Low Plateaus. The stratigraphic column of Paleozoic rocks in Tennessee (Wells, 1933) suggest the carbonates do not have the physical characteristics required for cavern siting. Consequently, this category is considered as having minimal potential.

Category 5 areas are limited to portions of the Atlantic Coastal Plain. These areas reflect thicknesses of unconsolidated sediments between 0 (near the western edges) and 2,000 feet (dashed line). The 2,000-foot depth is considered a practical limit of shafting technology in unconsolidated sands and gravels. These materials would possibly require costly measures for groundwater and stability control during excavation of a shaft. Coastal Plain areas underlain by granite are preferred. The highest potential for Category 5 sites in Region III is in an area of buried granite adjacent to the exposed Piedmont, east of Richmond, Virginia. The sediment cover is relatively thin in this area. Favorable basement rock is too deep in most other areas of the Atlantic and Gulf Coastal Plains to warrant consideration for UPHS.

Category 6 areas in Region III are limited to western Tennessee where Paleozoic carbonates are overlain by Gulf Coast sediments. The favorability of the carbonates for cavern storage is questionable as discussed under Category 4. When coupled with the requirement for shafting through unconsolidated, water-bearing sediments, these sites appear unfavorable.

Additional UPHS sites in the metamorphic rock units of the Piedmont and Blue Ridge provinces may be available for other power markets requiring facilities within a specific, limited area. The determination of specific sites is not within the scope of the study. Metamorphic rocks will not be discussed further.

Favorable Areas for CAES Sites

Constant Pressure Caverns. The geologic criteria for constant pressure caverns are essentially the same as for UPHS caverns. Suitable areas are shown in Exhibit II-13. Category 3 sites are eliminated in Region III as being beyond the maximum depth of proposed CAES schemes. The most favorable sites are granite plutons in Virginia and North Carolina.

Variable Pressure Caverns. Variable pressure caverns can be located in areas favorable for UPHS constant pressure cavern schemes (see Exhibit II-13), or they can be hydraulically mined in suitable salt formations. Morse (1956) lists 22 salt domes in southern Mississippi. ERDA (1976) lists 25 salt domes less than 3,000 feet deep in Mississippi and one in Alabama. These domes are possible sites for solution-mined CAES caverns. No bedded salt is found at appropriate depths in Region III.

Aquifer Storage. Available information suggests that aquifers of sufficient permeability for use in aquifer storage of air are limited to Coastal Plain sediments.

The basic problem with air storage schemes in Coastal Plain sediments is structural rather than lithologic. It is doubtful that geologic traps capable of limiting up-dip migration of stored air can be located in the unconsolidated sediments. As of 1975, the only underground LPG storage reservoir existing in Region III was in the Petal salt dome in Mississippi (ERDA, 1976), although the FPC (1974) showed storage areas in central Mississippi to the west of the Power Region. In summary, aquifer storage does not appear to have much potential in Region III.

Depleted Oil or Gas Fields. Oil or gas field CAES storage is essentially a variation of aquifer storage. Such storage is necessarily limited to areas of past and or present oil or gas production. Production in FPC Region III is primarily in two areas of southern Mississippi and southern Kentucky. Scattered gas pools are also found in a zone from central Mississippi to north central Kentucky. The available data suggest that CAES facilities in depleted oil and gas fields have little potential in FPC Region III.

Development Potential near Region III Load Centers

The second-level power-market analysis and ranking indicated VACAR market areas as potential areas for energy storage projects. Numerous load centers exist because of the distribution of industrial and residential development in the area from northern Virginia to eastern Alabama. For the geologic evaluation of potential UPHS and CAES, an area inclusive of Virginia, North Carolina and South Carolina is considered as the market area.

The geotechnical analysis indicates favorable geologic conditions for UPHS and CAES mined caverns (Exhibit II-13). Numerous Category 1 sites in granite are found from Virginia to Georgia. Although detailed physical characteristics of these rock masses are not known, the same assumptions made for FPC Region I are made for FPC Region III for the preparation of cost estimates, where shafts and caverns would be sited in high-quality rock. The favorable rock masses appear to be in the northeast and central Piedmont; specifically in an area south of Richmond, Virginia and northwest of Charlotte, North Carolina.

This area is too large to make an evaluation of specific rock masses. Further screening as to market areas, transmission facilities and land use patterns should be made to define areas for geologic study. Exclusive of the major power markets of the Southeast Region, the salt dome areas of southern Mississippi offer potential sites for CAES. Many studies have been made of these domes by oil and gas producers.

Potential sites for CAES systems in aquifers and depleted oil and gas fields have been discussed in the previous section.

Development Potential in FPC Region IV - North Central Region

Categories of Areas for UPHS Sites

Potential sites for UPHS facilities are ranked within three general categories:

Category

Description

1. Shafts in overburden and or Precambrian rock; caverns in Precambrian rock.
2. Shafts in overburden and or sedimentary rock; caverns in Precambrian rock.
3. Shafts in overburden and or sedimentary rock; caverns in carbonate rock.

Favorable Areas for UPHS Sites

Exhibit II-14 shows areas where each of the above noted categories are found in Region IV.

Category 1 ranking, the most favorable for UPHS site locations, requires that Precambrian rock be at the surface or immediately beneath the overburden. Shafts in Category 1 areas would penetrate Precambrian rock exclusively or overburden and Precambrian rock. Caverns would be located in Precambrian rock. Areas in which Precambrian rock is at or close to the ground surface are northern Minnesota and Wisconsin, the Sioux Uplift in southeastern South Dakota, and the Ozark Uplift in Missouri.

Category 2 ranking is assigned to areas where shafts would penetrate overburden and/or sedimentary rock and where caverns could be located in Precambrian rock. In areas where the Precambrian is relatively shallow, a portion of the shaft could be in the Precambrian. The Category 2 areas shown in Exhibit II-14 fulfill the depth requirements for one-drop and two-drop projects.

Category 3 ranking is assigned to areas where shafts would penetrate overburden and or sedimentary rock and one or both caverns would be in dolomite or limestone, of the Mammoth cave Huntor, Ottawa or Knox Megagroups.

Precambrian rock is considered to be the most favorable rock in which to place underground structures. The Precambrian is expected to be more massive, homogeneous, impermeable and resistant to abrasion and solution than the carbonate units. Of the rock types composing Precambrian rock, those of granitic or related composition are considered the most favorable. Granitic-type basement rock crops out or is found over much of an area designated as a Category 1 site. This same basement rock probably occurs under large areas of Region IV.

Carbonate units could provide a potential alternative for the siting of underground structures. Of the carbonate rocks, dolomite is preferred over limestone, because of its lower solubility. Most of the carbonate units in Illinois are limestone rather than dolomite; however, one carbonate stratigraphic unit, the Knox Dolomite Megagroup, consists predominantly of dolomite. Due to the variability of carbonate units and the potential problems commonly associated with siting structures therein, a least favorable Category 3 ranking is assigned to sites for underground structures in carbonate units.

Favorable Areas for CAES Sites

Geologic parameters and potential site categories for CAES caverns are essentially the same as for UPHS cavern. The depth criteria for CAES projects, however, differ from those for UPHS projects. The depth from the surface to the crown of the cavern for the constant pressure system would be from 2,300 to 3,500 feet for a 1,000 to 1,500 psi storage pressure range; and for a variable pressure system with the same maximum pressure range, the depth is 1,500 to 2,000 feet. A Category 4 has been added to indicate the potential of aquifer storage in Region IV. For this category compressed air would be stored directly in the pore space of a permeable rock formation. The areas to which each of the noted categories are associated for CAES projects are shown in Exhibit II-15.

Conventional mining techniques could be used to excavate rock caverns for use in either constant pressure or variable pressure storage. Hydraulic mining cannot be used due to the absence of suitable materials such as soluble salt beds or salt domes in Region IV.

Category 1 areas that have sites where shafts could be constructed in overburden and or Precambrian rock are the same as those for UPHS caverns. Category 2 areas that have sites for shafts in overburden and or sedimentary rock and caverns in Precambrian rock are located in most of the northern and western part of Region IV, outside of the Illinois Basin. Category 3 areas, with sites for shafts in overburden and/or sedimentary rock and caverns in dolomite or limestone at the required depths, are located only within the Illinois Basin.

Category 4 areas are located within and on the flanks of the Illinois Basin and in the Forest City Basin in southwestern Iowa. The outlined areas on Exhibit II-15 indicate areas where aquifers are present at necessary depths. Site studies will be required to define areas of sufficient aquifer permeability and closed geologic structure.

The oil and gas producing areas of Region IV, where potential sites might be found in depleted oil or gas fields, are limited to the Illinois Basin.

Development Potential near Region IV Load Centers

The major load center for Region IV as selected in the second-level ranking of power systems is located in northern Illinois.

Within the service area of this load center, the only potential for cavern development at the prescribed depths is in Precambrian rock. There are no dolomite or limestone formations at the required depths in which caverns could be excavated. A cavern could be excavated in the Precambrian for a one-drop pumped hydro project under most of the service area. In the southeastern portion of the area, the Precambrian is deeper than 4,500 feet.

Caverns for a two-drop pumped hydro project could be excavated in the Precambrian in the area beginning in northern Illinois along the Illinois-Wisconsin state line and extending north toward the central part of Wisconsin. In the southern part of the load center area, the Precambrian is too deep for an intermediate reservoir.

Within, approximately, the western two-thirds of the load center area, a cavern could be excavated in the Precambrian for 1) a constant pressure, hydraulically compensated CAES project with crown depth of 2,300 to 3,500 feet or 2) a variable pressure CAES project with crown depth of 1,500 to 2,000 feet.

Only the southern portion of the load center area presents the possibility of 1,000 to 1,500 psi compressed air storage in an aquifer at the required depths of 1,500 to 2,300 feet to the top of the reservoir. Storage in this area would be in the Mt. Simon aquifer. If shallower depths were considered for storage pressures as low as 500 psi, other aquifers, such as those occurring in the northern Illinois area, offer potential utilization.

Permeability values for the Mt. Simon aquifer are extremely variable, as reported in data from underground gas storage projects in Illinois; but they are generally comparatively low. Of nine values reported, only one value was larger than 200 millidarcys; five were less than 50 millidarcys.

There are no oil or gas fields located within the load center area. Hence, with regard to market potential, compressed air storage in a depleted oil or gas field is not an option in Region IV.

The maps accompanying this report present the general pattern of favorable areas for certain type projects, but they are not intended to be site specific. Extensive study and exploration will be required to appraise the feasibility of a proposed project at any specific site or localized area.

INTRODUCTION

GENERAL CONCEPT OF UPHS

SELECTION OF UPHS PLANT ARRANGEMENTS

**DESCRIPTION OF THE SELECTED UPHS
PLANT ARRANGEMENT**

CONSTRUCTION COST ESTIMATES

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CHAPTER III
UNDERGROUND PUMPED
HYDRO STORAGE

Chapter III

UNDERGROUND PUMPED HYDRO STORAGE

Introduction

This chapter discusses investigations related to the preparation of development-cost estimates for underground pumped hydro storage (UPHS). A system configuration found by analyses to be most cost-effective was selected for costing. Cost estimates were then prepared for the regions (or locations) offering the greatest development potential as well as having early UPHS markets.

General Concept of UPHS

Figure III-1 illustrates the general components of a UPHS plant. In an underground hydroelectric pumped storage system, energy is stored by pumping water from a lower underground reservoir to an upper surface reservoir. The stored energy is returned to the utility system in the form of electrical energy by flowing the water from the upper reservoir back to the lower reservoir through water turbine machinery powering electrical generators.

Another UPHS arrangement can consist of two powerstations in series (two drops) to develop the total head differential between the upper and lower reservoirs, as shown in Figure III-2. In this case an intermediate reservoir is required. The total head differential between the upper and lower reservoirs may be 4,000 feet or more.

The major components of an UPHS powerstation are: (a) an upper reservoir, (b) a lower underground reservoir, (c) an underground powerstation, (d) connecting waterways, and (e) access and service shafts, as shown in Figure III-1.

Upper Reservoir

The upper reservoir can be an existing body of water or an artificial lake formed by dikes and dams. An artificial lake can be formed by damming a stream and forming a lake in a natural drainage system or by building a completely off-stream reservoir.

ONE-DROP PROJECT

TWO-DROP PROJECT

GENERAL CONCEPT OF A
TWO-DROP UPHS PROJECT
· ARGONNE NATIONAL LABORATORY

Lower Reservoir

The lower reservoir is created by excavating a cavern in competent rock. Caverns with dimensions approximately fifty feet wide by seventy-five feet high would be excavated in a grid pattern to provide the total storage capacity. The lower reservoir cavern would be unlined or unsupported in order to be cost competitive.

Powerstation

The powerstation would be built in a cavern to house the pumping/generating equipment and associated control and service facilities.

Pump/Turbines

Reversible pump/turbine machines are normally employed to perform the dual functions of generating and pumping in a pumped-storage project. The machines are classified as reversible since they rotate in one direction to generate power and in the opposite direction to pump water. A separate pump and turbine could be employed, but such is usually more costly.

Most reversible pump/turbines are single-stage units involving a single pressure stage to extract energy from the water during generation and to supply necessary energy to raise the water from the lower reservoir to the upper reservoir while pumping. The current maximum head for single-stage pump/turbines is 2,035 feet. Units built by Toshiba for the Bajina Basta Power Company in Yugoslavia have a capacity of 315 MW. Units larger than 200 MW at heads greater than 1,640 feet are becoming numerous. It is considered that single-stage units operating at 2,200 feet are available.

Multi-stage pump/turbines consist of two or more pump/turbine runners in series in a single casing. Each pump/turbine runner and associated water passage is referred to as a "stage". Until recently only one multi-stage reversible pump/turbine unit was in operation. Now, reversible pump/turbines rated at about 80 MW and 3,100 feet head are being manufactured and put into operation. The latter units do not have adjustable wicket gates, and they will generate only at one load. Other machines are in early stages of design. The most advanced design is for one rated 328 MW at

3,190 feet head which will have adjustable wicket gates. Other designs are projected for heads as high as 4,000 feet.

Generator/Motors

The electrical component of a hydroelectric generating unit is called a "generator/motor" to distinguish it from the "motor-generators" that have been in use for years in AC-DC conversion or AC frequency-changing service.

Generator/motors are started in the generation mode in the same manner as any conventional hydroelectric generator.

Generator/motors can be started in the pumping direction by several methods. The static, variable-frequency, converter-inverter method currently represents the most advanced technology and is usually preferred.

Interconnecting Waterways, Access and Service Shafts

Shafts are required to conduct water between the upper reservoir and the lower reservoir during project operation. The number of shafts for the interconnecting waterways is related to the number of units. The shafts are vertical for most of their lengths, with short horizontal sections.

Shafts are required for other purposes. Shafts are needed for lowering equipment from the surface to the powerstation, to provide personnel access by means of elevators and stairwells, to provide ventilation and to house high-voltage busses and control cables. One shaft may be utilized for more than one purpose.

In addition, there would be shafts to provide ventilation to the lower reservoir. Finally, extra shafts may be required strictly for construction purposes.

Selection of UPHS Plant Arrangements

Alternative plant arrangements for UPHS were investigated. Alternatives were necessary, considering the relationship between the allowable operating head on the pump/turbine and the total head available at the site. As discussed previously, the candidate plant arrangements are:

- a. A one-drop project
- b. A two-drop project

Previous studies have generally indicated that the ideal total head in a UPHS system is between 4,000 and 5,000 feet. Since present technology limits the maximum head on a single-stage reversible pump/turbine to about 2,200 feet, a two-drop project, with each drop developing 2,200 feet of head for a total of 4,000 feet of head was considered suitable for obtaining the indicated economic head differential and was, thus a viable candidate for further study.

In addition, present trends indicate that the maximum head for large, multi-stage, regulating, reversible pump/turbines could be about 3,000 feet. Therefore, a one-drop project with a total head of 3,000 feet was also considered for further study.

A preliminary comparison was made between a 4,400-foot, two-drop project, a 2,200-foot, one-drop project and a 3,000-foot, one-drop project, with the results as shown in Figure III-3. The Figure shows that the 4,400-foot, two-drop project has the least cost, significantly so if the energy storage is in excess of 8 hours. On this basis, the two-drop project was selected for the present study.

Description of the Selected UPHS Plant Arrangement

The selected two-drop UPHS project is briefly described below and illustrated in Exhibits III-1 and III-2. The project would consist of two powerstations in series with each containing four units rated at 250 MW. When operating in the generating mode, the project would produce 2,000 MW of power. Energy storage would be equivalent to 20,000 MWh or ten hours of generation. The hydraulic head developed in each of the two drops would be 2,200 feet, for a total of 4,400 feet.

The UPHS project could be modified in terms of total kW capacity or kWh energy storage to suit the needs of an individual utility. The selected unit size and operating head are considered to be within the realm of present technology. The physical sizes of the tunnels and shafts and other structures are also well within present technology.

A specific site for a project has not been chosen, but it is assumed that it would be in favorable rock as described in Chapter II.

A water supply source would be required. It is expected that about 3 cubic feet per second or more of long-term average flow would be needed for make-up water. The initial filling of the reservoirs would depend upon the plant rating, head and construction schedule; but it would be the equivalent of 8 to 10 cfs for one year.

The two-drop project would consist of the following major elements:

- a) Upper, intermediate and lower reservoirs
- b) High-head and low-head conduits
- c) Upper and lower powerstations, including equipment
- d) Access and service shafts, including equipment

Upper, Intermediate and Lower Reservoirs

A total of three reservoirs would be required. The upper and lower reservoirs would each contain sufficient storage to permit generation at 2,000 MW for 10 hours. Additional storage for intake submergence, dead storage, and make-up would be provided. A reservoir volume for a 4,400-foot project corresponding to 20,000 MWh contains the equivalent of 5,200 acre-feet. The intermediate reservoir would be much smaller, being approximately 120 acre-feet.

Upper Reservoir and Intake. The upper reservoir could be constructed by diking a depression or by enclosing an area within a ring dike. A ring dike was selected for this study for cost estimating purposes because it permits more latitude in site selection. The cost of the ring dike was estimated for a flat surface. It is assumed that the dike would be about 80 feet high, allowing for 60 feet of live storage drawdown, 10 feet of dead storage at the bottom and 10 feet of freeboard at the top. The dike shells would be constructed of rockfill obtained from excavation of the underground reservoir, and the dike would have an impervious core.

The upper reservoir would contain about 5,600 acre-feet of usable storage. The surface reservoir area would be about 100 acres at the assumed drawdown of 60 feet. The upper reservoir intake would be designed to provide transition between the high water velocities in the conduits and

the low velocities in the reservoir. The hydraulic contraction or expansion losses would thus be reduced for economical project operation, and the water velocity at the intake trashrack would be low. For a 2000-MW plant four units are planned in each powerstation. There would be two such intakes in both the upper and intermediate reservoirs, with each intake serving two units.

Intermediate Reservoir. A two-drop project would be provided with a small intermediate reservoir having sufficient storage volume to regulate differences in flow between the two powerstations, especially during startup and shutdown. The intermediate reservoir would have a free water surface exposed to the atmosphere. The intermediate reservoir would be connected to the draft-tube side of the upper powerstation and the water conduit intakes on the high-head side of the lower powerstation.

Lower Reservoir. The lower reservoir would be a cavern mined in competent rock consisting of a grid of tunnels. For this study the tunnels are assumed to have vertical walls, flat invert, and a semi-cylindrical roof. The shape of the tunnels would be designed for the type and characteristics of the surrounding rock for a specific project site. The tunnel cross-section would be 50 feet wide by 75 feet high and the center to center spacing for the tunnels would be not less than 200 feet in one direction and not less than 300 feet in a perpendicular direction. The cumulative length of the tunnels for a 5,200 acre-feet volume is slightly over 12 miles, and the gross area occupied at the above spacing is about 200 acres.

High-head and Low-head Conduits

High-head conduits would connect each powerstation with its upper reservoir, and low-head conduits would connect each powerstation with its lower reservoir.

Two high-head conduits would be needed for each powerstation. Each high-head conduit would consist of a vertical shaft and two penstock conduits serving two units. The vertical shaft would extend from each upper intake via a vertical bend to a manifold in which each high-head conduit divides into penstock conduits. The conduits would be lined with concrete. Near the powerstation, steel lining would be provided to prevent leakage and to withstand internal hydraulic pressure.

There would be one low-head conduit for each pumping/-generating unit. The low-head conduits provide sufficient distance between the powerstation and the intermediate (or lower reservoir) for satisfactory rock stress distribution and water flow geometry. The conduits would be lined with concrete. Near the powerstation steel lining would be provided.

Powerstations

The two-drop powerstations would be built in underground caverns about 530 feet long, 70 feet wide and 160 feet high. Each powerstation would consist of four unit bays and one erection and service bay. Exhibits III-1 and III-2 show conceptual plans and sections of a typical powerstation.

A unit bay would be about 95 feet long and contains a 250-MW pumping/generating unit, guard valve, generator bus, circuit breaker, main power transformer and associated equipment.

The service and erection bay would be about 150 feet long and contains an area for unit erection, service and control equipment including heating, ventilating and air conditioning equipment, small shops, storage and offices. The service and erection bay would be located at one end of the powerstation. There would be an additional area on the opposite end of the powerstation to provide space for other necessary service equipment. Access to the surface would be provided from each end of the powerstation via elevators and stairwells in vertical shafts.

Pump/Turbines and Valves

There would be four reversible pump/turbines installed in each powerstation. The pump/turbine unit is assumed to be a Francis type with vertical shaft and adjustable wicket gates. For a 250 MW unit, the rating as a turbine would be 342,000 horsepower at minimum head. As a pump, maximum discharge consistent with the turbine rating would be obtained. It is estimated that a discharge rate of 1,400 cfs per unit can be obtained under 2,250 feet of total head, requiring a power input of approximately 303 MW per unit.

Minimum head occurs when the upper reservoir is at the minimum level and the lower reservoir is full. The center-line of the pump/turbine would be set about 260 feet below

minimum tailwater. The deep setting would reduce possible cavitation, allow use of a higher rotating speed and provide minimum dimensions. Each pump/turbine would be provided with a spherical type inlet valve at the high-head side of the spiral case to permit normal and emergency shut-off.

Generator/Motors and Starting Equipment

Each of the generator/motors would be direct-connected to a pump/turbine. The generator/motor would have a vertical shaft, be reversible, and be rated at 23-kV, 263 MVA and 0.95 power factor as a generator. As a motor, maximum power input would be approximately 320 MVA, requiring a 60°C temperature rise rating of approximately 279 MW at the highest obtainable power factor permitted by system conditions.

Transformers, Breakers and High-voltage Bus

The transformer would be placed in the same unit bay as the generator/motor. The high-tension voltage would be that of the transmission system to which the UPHS plant is tied; and for this study it is assumed to be 345-kV or 500-kV. The transformers would be connected to a surface switchyard by means of SF₆ or other suitable high-voltage bus.

A low-voltage breaker and phase-reversal switch would be provided between the generator/motor and the transformer.

Shafts

Shafts would be provided from the surface to the powerstations and to the intermediate and lower reservoirs.

Powerstation Shafts. An equipment access containing a hoist would be provided to lower the powerstation equipment. The inside diameter of the shaft would be about 20 feet. Incoming air would also be brought in through this shaft. The same shaft would serve both powerstations.

A separate shaft, also estimated at 20 feet diameter, would be required for regular personnel access, high-voltage bus and exhaust air. Elevator landings would be provided at about 100 feet spacings with stairways to provide access to the bus for inspection and maintenance. The same shaft would serve both powerstations.

Ventilation Shafts. A ventilation shaft would be provided to maintain the intermediate and lower reservoirs at essentially atmospheric pressure.

Construction Cost Estimates

Construction cost estimates have been prepared for the three areas, Regions I, III, and IV, being studied. The estimates have been prepared at June, 1976 price levels with regional differences in construction labor costs being considered. The Engineering News Record labor rates for construction were used as the bases for pricing. Costs of material and equipment were considered to be the same in all three regions. A composite labor cost for Philadelphia (Region I) is 5 percent higher than for the Chicago area (Region IV), while the corresponding composite labor cost for Atlanta (Region III) is 79 percent of the Chicago area rate.

The UPHS project described herein can be built in any of the three geographical areas mentioned with only minor differences in construction methods and design features to suit particular geologic conditions.

Construction

Shaft construction methods considered applicable for selected areas of Regions I and III are based on granitic type rocks existing between the surface and the lower reservoir. Shaft construction in Region IV is different in that the upper portion of shafts will penetrate sandstones and limestones of varying thicknesses, depths and water content. Some of the beds can be expected to be highly water bearing. Thus, in all three Regions, the conventional drill, blast, and line method could be used for shaft construction where hard rock exists. In Region IV, shaft construction through rock containing water-bearing beds is based on using large diameter drilling and mud-filled holes. In such construction, steel liners would be sunk through the drilling mud to seat on the granite, following which the perimeter around the liner would be concreted.

Construction of other caverns and facilities and equipment installation are similar in all three regions.

Construction Cost Estimates

The investment costs of a 2,000 MW, 20,000 MWh UPHS project at June, 1976 price levels are given below for the three regions investigated:

<u>Region</u>	<u>Estimated Cost In Millions of Dollars</u>	<u>Cost in Dollars per Kilowatt</u>
I	706	353
III	638	319
IV	784	392

Estimated costs by major project elements are shown in Exhibits III-3, III-4 and III-5 for Regions I, III, and IV, respectively. The estimated construction costs include all direct and indirect costs for land, material, labor, equipment, engineering, contractor's and owner's overhead and contingencies. They do not include transmission ties to the owner's system, nor do they include escalation. The estimated costs are generalized and subject to revision based on specific information applicable to a given site.

Variations of Project Construction Costs

Project costs per kilowatt vary with the quantity of energy storage and the size of a project. Figure III-4 illustrates the variation of cost with energy storage hours, and it is applicable to the cost estimates noted herein for Regions I, III, and IV. The cost variation with installed capacity for a two-drop, 4,400-foot head project is given below.

COST VARIATION WITH INSTALLED CAPACITY

<u>Generating Capacity MW</u>	<u>Cost as a Percent of a 2,000 MW 20,000 MWh Project</u>
1,000 MW, 10,000 MWh	120
2,000 MW, 20,000 MWh	100
3,000 MW, 30,000 MWh	94

Project and Construction Schedules

The total elapsed time from initiation of the study of a specific site to project commissioning is approximately twelve years, assuming no lapse between phases. The first six years are required for planning studies, drilling and subsurface investigations, preparing the FPC license application (which includes the Environmental Impact Report), the evaluation by FPC (which includes preparing the Environmental Impact Statement), other state and local applications and approvals, detailed engineering design and required specification of major equipment. Construction is estimated to require about six years. Exhibit III-6 shows a total project schedule and Exhibit III-7 shows a disbursement schedule for the cost estimate for Region I. Overall project schedules are expected to be similar for projects in the three different regions.

Efficiency

The efficiency of an UPHS project is the ratio of the electrical energy output to the electrical energy input, all in terms of kWh. The average efficiency of a UPHS project is approximately 78%, based on the following individual efficiencies.

Generating

Hydraulic	98%
Pump/Turbine	92%
Generator and Transformer	<u>98%</u>
Subtotal generating	88.3%

Pumping

Hydraulic	98%
Pump/Turbine	92%
Motor and Transformer	<u>98%</u>
Subtotal pumping	88.3%
Total cycling:	78%

GENERAL

CONSTANT PRESSURE SYSTEM

VARIABLE PRESSURE SYSTEM

DESIGN AND PLANT ARRANGEMENT

COST AND CONSTRUCTION SCHEDULE ESTIMATES

PERFORMANCE CHARACTERISTICS

IMPLEMENTATION SCHEDULE

CHAPTER IV
COMPRESSED AIR
ENERGY STORAGE

Chapter IV

COMPRESSED AIR ENERGY STORAGE

General

Two concepts for compressed air energy storage (CAES) powerstations were studied: constant pressure storage and variable pressure storage. These are shown schematically in Figure IV-1. Pictorial diagrams of alternative arrangements of these two basic concepts are shown in Exhibits IV-1 through IV-4.

Consideration was given to the time frame in which a large compressed air storage plant might be constructed in the United States, which is expected to be several years into the future. In the interim, there may be significant developments occurring in high pressure combustion technology and the application of constant pressure or variable pressure air expanders to compressed air storage power generation. The use of high pressure expanders could alleviate the need for throttling high pressure air through a valve to the gas turbine machinery. In concept, use of an air expander is preferable to throttling by valve in a variable pressure system because significant power can be generated from the pressure differential that exists between the cavern air and the turbine inlet. However, for purposes of this study, we have assumed use of an air expander in the constant pressure system and throttling by valve in the variable pressure system.

Constant Pressure System

The constant pressure system (CP) as shown in Exhibit IV-1 would utilize an excavated cavern for storing air; water from a surface reservoir would provide hydrostatic compensation to maintain the constant pressure. The underground cavern reservoir would be located at a depth below the ground surface equal to the selected system operating pressure in feet of water head. For this study, maximum storage pressure is assumed to be 1,000 psi.

It is projected that pump/turbine units will be available for use with hydrostatic heads up to 2,200 feet. This corresponds to a maximum system pressure of approximately 1,000 psi. Thus, the pressures and hydrostatic heads selected for the CAES and UPHS systems in this study are comparable.

1. Variable pressure system is shown.

2. Asterisk items * when added convert the variable pressure concept to constant pressure system.

COMPRESSED AIR ENERGY STORAGE CONCEPT

It can be noted that in terms of total CAES system cost, a minimum dollar per kilowatt value occurs at a pressure of about 400 psi, although such cost is not far different from that for a 1,000 psi system. The lower 400 psi storage pressure could be obtained safely at a reservoir depth of 600 feet. Thus, assuming no adverse effects on local groundwater, the 600 foot reservoir depth enhances the use of aquifers with suitable permeability and porosity characteristics.

The CAES system shown in Exhibit IV-4 can be considered a constant pressure system, assuming use of an aquifer with high permeability, a large storage cavity, ample well capacity and moderate air injection and withdrawal rates. The air is stored in the water bearing aquifer which is pressurized by a naturally occurring hydraulic gradient. This type of storage requires special geologic conditions: (1) an aquifer having rather high permeability and porosity and (2) a cap rock to hold the air cavity developed in the aquifer.

System Characteristics

A 1,000 psi constant pressure system using an excavated storage cavern as shown in Exhibit IV-1 would operate with a 2,300-foot high water column acting between the water reservoir on the surface and the underground cavern. The water column would maintain a near constant pressure in the underground cavern. Air temperature would also remain essentially constant, thus simplifying control of the air to the power train machinery.

Starting with compressing, air would leave the final stages of compression and be cooled to approximately 100°F to increase air density and, consequently, stored mass in the storage cavern. At the lower temperature evaporation of the compensating water would also be significantly reduced. No provision would be made for controlling the relative humidity of the air as it is assumed the air would become saturated while in contact with the water in storage. As a consequence of not controlling the humidity, the total aftercooling load is reduced because of the limited latent heat load. Capital and operating costs would, therefore, be lower than for a system where moisture removal is required, as for example, in an aquifer storage system where the air bubble portion of the aquifer must be maintained dry.

The 100°F air exiting the storage cavern would be heated regeneratively in order to produce significant power

output at the air expander without developing exhaust temperatures that might cause blade icing. Regenerative heating has the additional advantage of utilizing waste heat which might otherwise be rejected uneconomically to the atmosphere. The air expander part of the power train will produce constant power output over the generating portion of the CP cycle.

Particle entrainment of sand, dust and other materials in the air leaving the cavern could result in problems of erosion and material build-up on the turbine blading. Hence, some air filtering would be provided. All of the filtering equipment would be located in the process air plant. With an excavated cavern and water compensated cycle, problems involving particle entrainment are expected to be minimal; they are expected to be more severe with aquifer storage.

The storage of air in an aquifer is also, substantially, a constant pressure process. For the system as shown in Exhibit IV-4, numerous wells would be drilled on the surface in a grid pattern that followed the aquifer. Well size and quantity would depend on the characteristics such as permeability, porosity, thickness, and lateral extent of the aquifer. A permeability of less than 500 millidarcys may not allow the required air injection and withdrawal rates, with a given number of wells, that are necessary for daily compressed air storage cycling. Porosity should be at least 20 percent.

Preparation of an aquifer for air storage would involve injection and circulation of warm, dry air into a previously developed air cavity in the aquifer to dry that portion of the aquifer, thus removing entrapped water and increasing the effective permeability of the structure for air. Any reentry of water into the porous structure, such as in the form of moisture laden air would adversely affect aquifer storage operation. Thus, it is considered necessary to provide for continuous removal of moisture from the air to a level of ten percent relative humidity using refrigeration equipment, before injecting it into the aquifer. The stored air "bubble" would be sufficiently great in size to maintain a large separation distance between the wellpipe inlet and the aquifer air-water interface.

It is assumed that there will be greater particle entrainment in the air flowing from an aquifer than from a rock cavern. The particles would come from the elastic motions of the porous aquifer structure itself, and mineral residues associated with the drying and material weathering of the aquifer. Thus, the air processing plant for aquifer-

stored air would be more complex than one servicing an excavated rock cavern. A similar situation would not exist in a hydraulically compensated rock cavern because of water washing action in the cavern reservoir.

Variable Pressure System

The second type of compressed air storage concept considered is illustrated in Exhibits IV-2 and IV-3. The system would operate on a variable pressure (VP) cycle with stored air pressure varying between maximum and minimum operating limits. For this study it was assumed that an excavated cavern was used for storage and the minimum air storage pressure was 650 psi. The temperature drop associated with cavern air expansion from 1,000 psi to 650 psi should not produce freezing temperatures in the air storage cavern. The underground reservoir would be located at a depth below the ground surface such that the material above the cavern ceiling would be sufficient to contain the internal air storage pressure with a safety factor of 1.5.

In the compressing mode, atmospheric air would be filtered and compressed through several stages of machinery to the required storage pressure. The first stages of compression would be accomplished using axial compressor equipment. Centrifugal compressor machinery would be used for intermediate and final stage compressing. The air would be intercooled between stages of compression and aftercooled before being injected into the storage volume.

In the generating mode, air leaving the storage volume would be directed to the air process plant where it would be filtered and possibly heated. Additional processes such as water washing may be found necessary, depending on accumulated operating experience, and they could be added as required. The air would then enter a manifold system where motor-operated valving would regulate the air flow to air expander machinery or throttling valves. From there, the air would enter the turbine combustors. The combustion gases would expand through the gas turbines, pass through the regenerator and exit to the atmosphere.

System Characteristics

Two forms of variable pressure air storage were considered: Storage in a hard rock cavern and storage in a salt deposit. As in the constant pressure system, air would be stored at about 100°F. Expansion of the air in the cavern during power generation would lead to a lowered cavern air temperature.

Assuming that the air initially had a high relative humidity, water would precipitate out of the cooling air and collect in the bottom of the cavern. The water could become a significant volume after numerous cycles of operation, and some means would have to be provided for its removal from the cavern. If left in the salt formation cavern, it could also have deleterious effects on the surrounding containment surfaces and combustion machinery.

Refrigeration equipment would be used for aftercooling at the final stages of compression. Because air temperature would be lowered below optimum storage temperature, reheating the air to 100°F would follow the aftercooling process. Reheat energy could be obtained from one of the intercooling exchangers or the condenser section of the refrigeration machinery.

In the generating mode, air would be discharged from the storage reservoir under a varying pressure. Unless some provision were made for outlet control, air flow rate to the turbines would be variable, which is not conducive to proper turbine operation. Throttling from the air discharge pressure to a level corresponding to turbine inlet pressure would produce a moderate lowering of temperature and a loss of potential air energy. It can be recognized that in the variable pressure system, pressure and temperature of the cavern air flowing to an expander would be continually decreasing. Further study is required to determine if an air expander can be satisfactorily added to the power train of a variable pressure system to produce power throughout the generating phase, augmenting turbine shaft power and reducing overall turbine fuel consumption.

Design and Plant Arrangement

Plant site improvements would consist of roads, roadway lighting, road signs, a perimeter chain link fence with gate house(s), drainage grading and culverts, auxiliary buildings and utilities. Where applicable, buildings would be complemented by surfaced parking areas and landscaping. Utilities would include water, sewage and electricity. Potable water would be obtained from public supplies if possible; otherwise, a deep well would be used with subsequent treatment, as required.

Where municipal sewage service was not available, a sewage treatment system would be built on the site. The treatment plant could include laboratory, control house, sludge treatment or other processes necessary to meet state health requirements.

A switchyard would be located in the vicinity of the powerhouse building. The yard would contain transformers, breakers, disconnect devices and other conventional components necessary for connecting the power plant to the electrical transmission system.

A fuel treatment and storage plant would be located on the site. It is assumed that the bulk of fuel consumed by the plant combustion equipment would be No. 5 or No. 6 residual fuel oil. These fuels would require some treatment for removal of sodium, vanadium and other harmful metal elements. It would also be necessary to supply sufficient heat energy to the fuels to maintain them at a flowing consistency throughout the year. There would be some light oil (No. 2 distillate) stored on the plant site for special service in the combustion equipment. Clean-up treatment for this latter type fuel would be minimal.

Fuel storage would be provided through use of several large capacity welded steel tanks. Each tank would be situated within a surrounding earth fill dike which would contain accidental oil spills or the results of a tank rupture. Pumps and associated piping would convey the fuel oil to the powerhouse building. Because of the large volume of fuel oil required to support an installation of this size, it is anticipated that the fuel supply would be obtained from both railway tank car and pipeline sources. The fuel storage area would be serviced by a railroad spur; the rail line would also go to the power plant building for transporting the compressor-generating machinery.

Selection and arrangement of cooling equipment would be site specific. If sufficient surface water of suitable quality were available for use, a wet-cooling, induced draft system would be preferred. Natural draft tower cooling would provide an alternate method of cooling. Where water is in short supply, dry cooling would be used. The cooling system would contain pumps, pipings, exchangers, ponds and other components necessary for proper functioning of the system.

Constant Pressure System - Hydraulically Compensated

The underground storage cavern as depicted in Exhibit IV-1 would be excavated in competent rock. The excavation would comprise a system of interconnected tunnels approximately 50 feet wide by 75 feet high. For the storage of 20,000 MWh, the tunnels would have a total volume of about 2.6 million cubic yards. For a 2,000 MW plant, a 13-foot diameter water shaft with concrete liner would connect the storage cavern to a surface reservoir. The active volume of the surface reservoir would be equal to the 1,600 acre-feet of air storage volume.

Design of the surface reservoir would depend on site conditions such as geology, topography and soil foundation characteristics. A reservoir covering 60 acres with 30 feet of drawdown would be adequate. An intake structure with trashracks would be provided at the entrance to the water shaft to prevent the flow of water between the upper reservoir and underground storage cavern, when necessary for maintenance and to minimize trash entrance into the storage cavern.

The aboveground plant would be connected to the storage cavern by a 5-foot diameter, concrete and steel lined air shaft. The upper section of the air shaft would be a grouted pressure casing. Consideration was given to the use of manifolding several smaller diameter pipe lines to the upper portion of the pressure casing. The pipe lines would be routed to the air processing plant, as required. The air processing plant would contain separate systems to service individual compressing-generating units in the powerstation building. It would also contain acoustical structures for sound control of the compressor air inlets and the turbine exhausts.

The powerstation building would be a concrete and steel-framed metal paneled structure containing erection and repair areas, shops, storage space, overhead traveling crane and operation offices. It would also contain the compressing-generating equipment. Regenerators and exhaust gas ducts would be located outside of the building.

Constant Pressure System - Aquifer

Several hundred air wells would be required for injecting air into the storage cavern and supplying air to the above-

ground plant. The wells would be drilled into the aquifer which could have a minimum depth below ground of 600 feet for a 400 psi system or approximately 1,600 feet for a 1,000 psi system. Six-inch diameter steel pipe casings would be grouted in place between the ground surface and the aquifer. These 6-inch pipes would connect to field gathering-distribution lines which would then, in turn, connect with larger manifold lines. The manifold lines would connect to the air process plant. All of the aforementioned pipelines and manifolds would be buried in trenches to provide for nearly uniform thermal conditions throughout the year.

All other features of the aboveground plant would be similar to those described previously in the section, Constant Pressure System - Hydraulically Compensated, except there would be no surface reservoir. Aquifer storage does not require artificial hydraulic compensation because in a sufficiently extensive aquifer such compensation exists naturally.

Variable Pressure System - Rock Cavern

This type of system is illustrated in Exhibit IV-2. The underground cavern for a system operating between 1,000 psi and 650 psi air pressure would have a storage volume of 8.9 million cubic yards for 20,000 MWh of generation. The volume is approximately the same as for 20,000 MWh of UPHS at 4,400 feet head. The underground excavation and air shaft details are similar to those discussed for the constant pressure, hydraulically compensated system. Consideration was given to the use of storage volumes in other than excavated rock: abandoned mines, naturally occurring voids in the earth and other appropriate structures. All are applicable for air storage use if they can:

- (1) be made relatively water and air tight,
- (2) withstand daily cycling of pressure and temperature,
- (3) accommodate the maximum storage pressure,
- (4) have sufficient volume for an economical installation.

The aboveground plant would be similar to that described for the constant pressure, hydraulically compensated system except that there would be no surface reservoir.

Variable Pressure System - Salt Formation

A compressed air storage system having an air storage cavern in a bedded salt or salt dome formation is illustrated in Exhibit IV-3. It is representative of the system presently being installed in Huntorf, West Germany. A cavern can be formed in a salt formation by either regular drill, shoot and muck mining or, as for the Huntorf installation, hydraulic (solution) mining techniques.

Drill, shoot and muck mining would required an adit or mine shaft access. After completion of the storage cavern by "room and pillar" or other suitable construction mining methods, construction entrances into the cavern would be blocked off to withstand the internal air storage pressure. Salt would be removed from the mine in dry, solid form for subsequent disposal.

Hydraulic mining of the cavern would have some advantages and some disadvantages. One advantage is that the initial shaft entering the salt formation could be fitted with a pressure casing and used for ducting the air into and out of the cavern. Another advantage is that cavern development could proceed rapidly and require a minimum labor force. However, pumping costs, pumping machinery, a suitable water supply for hydraulic mining operations, and disposal of the saturated salt solution are potential disadvantages which need to be considered relative to a specific site.

The aboveground plant would be similar to that discussed for the constant pressure hydraulically compensated system except that a brine retention basin would be required instead of a surface water reservoir. The basin would be required to hold saturated brine removed from the developing cavern for further processing and disposal.

Cost and Construction Schedule Estimates

The investment costs of a 2,000 MW, 2,000 MWh CAES installation in Power Supply Region IV at June, 1976 price levels are given below:

<u>Systems</u>	<u>Cost in Dollars per Kilowatt</u>
Rock Cavern, Constant Pressure	325
Rock Cavern, Variable Pressure	451
Aquifer	
1,000 mD, 40 feet thick	333
100 mD, 400 feet thick	344
100 mD, 100 feet thick	466

Equipment and construction costs are summarized in Exhibits IV-5, IV-6, and IV-7. Costs are based on June, 1976 cost levels without escalation. In the case of the constant pressure, aquifer storage system costs do not reflect development of the aquifer, that is, initial pressurization and drying.

Costs are relative to FPC Region IV. For FPC Region I, costs are higher and are obtained by multiplying the given costs by 1.025. For FPC Region III, costs are lower and are obtained by multiplying the given costs by 0.895.

Constant Pressure System - Hydraulically Compensated

Excavation. This system requires four major excavations:

(1) Upper reservoir, (2) Water conduit, (3) Storage cavern, and (4) Air shaft.

The storage cavern excavation considered in this study would be similar to that required by underground pumped hydro storage. Excavation rate is estimated to be 33,000 cubic yards per week average. This is a lower rate than anticipated for UPHS; and it is due to the smaller volume of excavation, fewer excavation shafts and a smaller construction plant.

Excavation of the shafts would start with drilling of the air shaft, fitting the shaft with a hoist for access to the underground workings and then raise-shafting the water conduit. Next, the underground cavern would be opened for production type excavation while excavation of the main hoisting shaft (water conduit) continued. This procedure would expedite the excavation schedule as shown in Exhibit IV-8.

Rock excavated from the underground reservoir would be used to construct the upper reservoir embankments. Excess rock could be stockpiled adjacent to the embankments. The cost estimate considers that an asphalt liner would be used for water containment, although other lining could be adopted.

Actual location of the project and the time required for construction of the upper dike and reservoir could dictate use of a higher proportion of aboveground excavation materials in the reservoir structures to accelerate the construction program and allow time for filling the reservoir before operation. This alternative should not materially change the estimated project cost.

Aboveground Plant. The cost estimate for the aboveground portion of the plant is based on a 1,000-acre plant site.

The site would include the surface reservoir and sufficient area to cover the extent of the underground cavern. An allowance of \$2,500 per acre has been used for land costs. The number of generating units installed would vary with the unit size as supplied by the equipment manufacturer. In terms of present day designs, size could range from 135 MW to 300 MW per unit. Cost of the combustion machinery for 2,000 MW of generation has been estimated at \$107/kW, which cost is used in Exhibits IV-5, 6 and 7. The units would be rated for 10 hours generating, 8 hours compressing. Compressor load exceeds generator rating by 23%, which sets the size and cost of the generator/motor.

Auxiliary compressing equipment includes multi-stage centrifugal compressors, gear box increasers, and drive motors for accomplishing the required compressing in 8 hours. The composite power train for the auxiliary compressors is estimated to require 89 MW of driving power per gas turbine machine producing 200 MW output power. Costs reflect current manufacturer's estimates where off-the-shelf hardware is not yet available.

Cooling equipment costs are based on the use of wet cooling and induced draft cooling tower equipment. This is considered the lowest cost for the subject installation. Natural draft cooling towers are applicable to this type of installation. However, the capital cost is much higher than the type of system estimated. Dry cooling would result in far higher equipment costs.

The fuel treatment system would be sized for a full-load fuel usage rate in the combustion machinery of approximately 800 GPM. Fuel storage costs are based on storage of a three and one-half month fuel supply at the site.

The air manifold piping cost has been estimated for a 40-inch diameter steel pipe manifold and 18-inch diameter distribution piping, which provide velocities of approximately 17 feet per second with acceptable pressure drop. Piping wall thickness was computed for 1,000 psi internal pressure with no allowance for corrosion. The piping and manifolds would be coated, wrapped and buried with cathodic protection. Pipe fittings would be of forged steel; piping design would be in accordance with applicable ASME codes.

The power plant building cost estimate includes foundation, structural steel, siding, roofing, all utilities, heating, ventilation and air conditioning, acoustical treatment and overhead crane.

The process air plant cost includes the cost of an open structural steel frame with galvanized steel railings, stairs and open grating flooring. Cost also includes a system of high pressure air filters. No allowance has been made for air washers, dryers or other type process equipment.

Constant Pressure System - Aquifer

Costs for this type of system are summarized in Exhibit IV-6. Sub-surface work consists of drilling from the surface down into the aquifer stratum and installing and sealing steel well casing. However, because of the many wells required to obtain sufficient air flow into and out of the aquifer, total civil cost is not significantly different from that for a hard rock cavern. The cost summaries in Exhibit VI-6 are for a depth of 2,200 feet to the top of aquifer and show the effect of utilizing greater aquifer penetration in a less permeable aquifer. In the case of the greater penetration, the casing would be grouted down all the way from the surface to the upper portion of the aquifer. The drill hole would extend deep into the aquifer below the bottom of the casing and be gravel-packed up to the well casing. Costs for drilling the wells have been estimated at 34 dollars per linear foot of depth for the 100 millidarcy, 100 foot thick aquifer and 45 dollars per linear foot for the other two aquifers studied.

Aboveground Plant. The cost estimate for this type of plant is similar in most respects to that given for the hydraulically compensated system. There are two notable exceptions - a higher air manifold piping cost and a higher process air plant cost. The increased costs result from the many wells installed for access into the aquifer and greater air cooling and filtering requirements, respectively. It can also be noted that site improvements for this system are higher than the other two systems studies. The increase results from gravel surfaced service roads in the well areas.

The costs estimated in Exhibit IV-6 show the effect of different aquifer permeabilities. The more permeable the aquifer, the lower the aquifer development cost. Thus, the first column in Exhibit IV-6 reflects costs for a relatively thin aquifer stratum with good permeability. The second column is for a thicker stratum, much less permeable, and requiring more wells than associated with the first column. The third column shows the effects of a very deep, less

permeable aquifer. By utilizing greater penetration into the aquifer stratum, it is estimated that the same air flow per well can be obtained in this latter case as in a more permeable but thinner aquifer. The overall cost is increased, however.

Variable Pressure System - Rock Cavern

Cost for this system are summarized in Exhibit IV-7.

Excavation. The variable pressure storage system requires two major excavations:

1. Storage cavern.
2. Air shaft.

To excavate the cavern within three years, approximately, it has been assumed that two hoisting shafts in addition to the 5-foot ID air shaft would be used. Tunnels leading to the hoisting shafts would be plugged with concrete after completion of the excavation.

Aboveground Plant. Most electrical-mechanical costs for this type system are similar to those for the constant pressure, hydraulically compensated system. The increased process air plant cost reflects additional air filtering and refrigeration machinery. There is also a difference in generating unit costs resulting from the use of more gas turbine machinery in the variable pressure system as compared to the constant pressure system. Machinery for the latter are assumed to be coupled to air expander machines which produce additional power for electrical power generation.

Variable Pressure System - Salt Formation

Based on geotechnical analyses, the siting of a compressed air storage powerstation in a salt formation is restricted, in general, to areas of Michigan, western Pennsylvania and eastern Ohio, Texas, Louisiana and Mississippi. None of these areas exhibited sufficient market potential for compressed air storage as to require further study. Therefore, cost estimates have not been made for siting of this type powerstation.

Selection of System Configuration - CAES

Examination of the cost summaries, Exhibits IV-5, IV-6 and IV-7, gives indication of a hydraulically compensated constant pressure system as having the lowest installed cost in dollars per kilowatt; the variable pressure system is noted to have the highest installed cost. Consideration of the latter cannot be disregarded in terms of cost alone. A variable pressure system can be sited in the same type geologic formation as a constant pressure system. Where there is no possibility of constructing a surface reservoir as required for system operation, the variable pressure system becomes a viable alternative for energy storage. Aquifer storage requires a special type geology which may be available where there is no competent rock for cavern excavation or salt beds for hydraulic mining.

FPC Region I. As discussed in Chapters I and II, this region is characterized by competent rock in and around those utility service areas where energy storage exhibits significant potential. Thus, it would seem reasonable to suggest that the hydraulically compensated, constant pressure storage system as shown in Exhibit IV-1 is the best candidate system for this region. The system would have an installed investment cost of approximately \$333/kW. However, if topography of the surface area, environmental constraints or land use limitations prevented siting of a constant pressure system, consideration could be given to siting of a variable pressure powerstation at the higher cost of \$462/kW. Aquifer or salt formation storage does not appear practical in this region.

FPC Region III. The major geologic characteristics of the region vary markedly between localities, and in all probability potential sites could be found which meet the particular requirements for the four different storage schemes shown in Exhibits IV-1 through IV-4. However, as the market potential is located in the Virginia-Carolinas sub-region, it is most likely that the competent rock formations in this area would provide suitable sites for a hydraulically compensated, constant pressure storage system. There is no evidence of any large, suitable water-bearing aquifer or salt formation existing in this area of the region. Hence, such systems can be rejected from further consideration. The variable pressure system using a cavern excavated in rock is an alternate choice for this region. The region is also characterized by a widely dispersed population and

industrial community which indicates greater flexibility in locating the powerstation and its surface reservoir. The compressed air storage system most suited for this region appears to be the hydraulically compensated, constant pressure system as shown in Exhibit IV-1.

FPC Region IV. With regard to compressed air storage, this region contains both competent rock and large water-bearing aquifers. The competent rock is located in the northern part of the region; the aquifers are in the southern part. Geologically suitable formations exist for either aquifer or rock cavern storage within the area where market potential is high. Thus, selection of a candidate system will involve consideration of topography, environmental and land use restrictions, risk assessment and costs.

Whichever storage system is selected, it would operate at constant pressure, being either a hydraulically compensated system as shown in Exhibit IV-1 or an aquifer storage system as shown in Exhibit IV-4.

Performance Characteristics

The constant pressure systems shown in Exhibits IV-1 and IV-4 are considered, for convenience in this study, to operate at the same 1,000 psi air storage pressure. Additionally, they would have the same compressing and generating periods and use the same type compressing/generating machinery. The notable difference between the two systems regarding performance is cooling and drying of the compressed air as discussed previously. Specific performance data is given below.

Heat Rate

The heat rates for the candidate CAES constant pressure systems have been estimated based on a complete cycle of operation of the plant. The following paragraphs illustrate their development.

Constant Pressure System - Hydraulically Compensated

Compression of the hydraulically compensated, constant pressure storage cavern over a period of eight hours would be with a power input of 2,574 MW for nine sets of compressors and auxiliary boosters. Auxiliary equipment such as fans, pumps and heaters would require an additional 32 MW and the total energy input is 20,848 MWh.

The air stored in eight hours is sufficient to provide for 10 hours of power generation at a rated capacity of 2,088 MW. Corresponding oil consumption amounts to an equivalent of 70,140 million Btu. Auxiliary power input for fuel pumps, heating and miscellaneous equipment accounts for an equivalent 561 million Btu. The equivalent heat rate is therefore:

3,359 Btu/kWh of fuel plus 1.0076 kWh off-peak electrical energy/kWh generated. Using 9,500 Btu per kWh as the incremental off-peak heat rate, the gross heat rate is 12,932 Btu per kWh.

Constant Pressure System - Aquifer

The aquifer system would require approximately 75 MW of auxiliary equipment power during compressing. Total input compressing period energy is 21,192 MWh.

The equivalent heat rate for the aquifer system is therefore:

3,359 Btu/kWh of fuel plus 1.024 kWh off-peak electrical energy/kWh. Using 9,500 Btu per kWh as the incremental off-peak heat rate, the gross heat rate is 13,088 Btu per kWh.

Variable Pressure System - Rock Cavern

Compression of the variable pressure storage cavern over a period of eight hours would be with a power input of 2,574 MW for the ten sets of compressors and auxiliary boosters. Auxiliary equipment such as fans, pumps and heaters would require an additional 75 MW of power. The total load power input is thus 2,649 MW and the total energy input is 21,192 MWh.

The air stored in eight hours is sufficient to provide for 10 hours of power generation at a rated capacity of 2,000 MW. Corresponding oil consumption amounts to an equivalent of 79,120 million Btu. Auxiliary power input accounts for an equivalent 561 million Btu. The equivalent heat rate is therefore:

3,956 Btu/kWh of fuel plus 1.069 kWh off-peak electrical energy/kWh generated. Using 9,500 Btu per kWh as the incremental off-peak heat rate, the gross heat rate is 14,112 Btu per kWh.

Implementation Schedule

Exhibit IV-8 is a schedule of the time required for siting of a hydraulically compensated, constant pressure system. The schedule considers the period from initial study and site selection to the first units being placed "on-line". The ten and one-half year period includes an allowance for the time required for environmental and state siting permits. It is expected that detailed design and contract document work would begin prior to final agency approval in order to expedite construction of the installation.

Initial construction would start with the air shaft. Material from the shaft and the other excavations would be used in construction of the upper reservoir and site improvements. It would be necessary to finish the air shaft excavation before starting work on the underground reservoir. Thus the critical path appears to be: permits, shaft and reservoir excavation.

Equipment purchase is scheduled so that equipment can be installed and operational testing can be started immediately after completion of the lower reservoir. This would involve first filling the upper reservoir with water and surcharging the lower reservoir with air. Then the system would be pressurized. The period scheduled for operational testing follows the first cavern pressurizing.

Exhibit IV-9 is a schedule for the constant pressure system using aquifer storage. The schedule is developed on the same basis as discussed for the hydraulically compensated system. The time required for total siting is estimated at nine and one-half years. This is one year less than the compensated system because no major underground excavation is required. By comparison, the total project time is five and one-half years longer than that required for installation of the Huntorf CAES project in West Germany and much of this time can probably be attributed to environmental, licensing and permit requirements. The drilling of the air wells and installation of the field piping would require less than two years assuming a properly manned work force. An aquifer development program would begin after auxiliary compressor and refrigeration equipment was in place. Warm, dry air would be circulated through the air volume in the aquifer to develop proper aquifer characteristics. The program would be completed in the ninth year of the project in time to perform operational testing.

**THE FEDERAL REGULATORY AGENCIES FOR CONSTRUCTION
LICENSES**

STATE REGULATORY AGENCIES

REGULATORY CLIMATE ON PROJECT CONTRUCTION

ECONOMIC ASPECTS

FINANCIAL ASPECTS

**CHAPTER V
REGULATORY CLIMATE**

Chapter V

REGULATORY CLIMATE

An assessment was made of the regulatory climate that influences utility's decisions regarding construction of UPHS and possibly CAES projects. Decisions favoring one type of generation project over another are generally based on analyses of relative economic, financial and public reaction factors, tempered by governmental regulations affecting the criteria which enter into the analyses. Regulations governing construction of project at a specific site can increase a utility's risks in overcommitting financial resources.

The Federal Regulatory Agencies for Construction Licenses

Utilities are regulated by various federal, state, and local agencies. The Federal Power Commission (FPC) is authorized to issue or deny licenses to develop hydroelectric projects on streams affecting interstate commerce. The FPC also sets rates for interstate sale or exchange of electricity and for wholesale marketing to distributors.

The Nuclear Regulatory Commission (NRC) corresponds to the FPC in granting licenses to build nuclear powerplants, but it is not empowered to set rates for marketing.

The Environmental Protection Agency (EPA) rules on the environmental impact of major projects and influences the FPC and the NRC in their decisions regarding utility license applications. Other federal and state agencies participate in the review of license applications. For example, in the case of hydroelectric projects, the Department of the Interior, Department of the Army Corps of Engineers and numerous other agencies pass judgment on the merits of a project for which a utility makes license application.

Regulations exist concerning the requirements for license application, and procedures are established as to the actions on the part of the regulating agencies to review and analyze an application and for the participation of other governmental agencies and the general public. Because of the numerous agencies involved, the time required

to process a license application normally extends over several years. An FPC license for a hydroelectric project takes about three years to process, assuming no delays or minimal opposition.

A UPHS project may or may not be subject to FPC jurisdiction as to acquiring a license, depending on circumstances regarding the site. However, the law governing licensing of hydroelectric projects has generally been broadly interpreted so that in recent years all hydroelectric projects on or off navigable streams have been required to obtain an FPC license.

A CAES project, on the other hand, does not appear to require acquisition of an FPC license. At the present time, this type project is not under the jurisdiction of any single federal or state agency. Because of the large size of a CAES project and the impact it can have on an electric utility and the industry, in general, it is anticipated that any proposed CAES project will be closely scrutinized by the FPC, EPA, Corps of Engineers, various state regulatory commissions, state environmental agencies and other interested agencies. Thus, it would be prudent at this time to assume that the utilities will need some form of license and or permit for building a CAES project. In fact, the first CAES project might serve as a test case for rules and regulations governing the construction and operation of such projects.

Finally, various interest groups and environmental advocates may, by extensive legal maneuvering including court actions, prevent the construction of CAES projects which they believe should not be built on grounds of potential adverse environmental impact. Litigation may take several years and may continue even after approval is granted by an appropriate regulatory agency as evidenced by recent actions regarding the Seabrook nuclear plant in New Hampshire.

No licensing laws such as mentioned above govern the construction of fossil-fueled powerplants. Coal-fired steamplants requiring cooling water from rivers, lakes and oceans fall under air and water pollution regulations of state and federal (EPA) agencies; and they are thus subject to certain agency approvals, resulting in delays and revisions. This is also true for construction of gas turbine powerplants.

State Regulatory Agencies

Regulation at the state level is divided into two major areas. First, the states are gradually increasing their influence over the utilities in their siting of power projects by (a) enacting powerplant siting laws, and (b) creating departments or agencies of energy and environmental resources. Proceedings under state laws can be as lengthy as federal proceedings. Siting laws will most probably exist in all states within a few more years due to the environmental concerns and pressures for land use planning. Many states, such as Illinois, have rules governing injection of fluids underground.

Secondly, state public utility commissions set revenue levels and tariff structures for the sale of electricity, which affect the terms under which utilities can obtain financing. Each state has its own commission and associated regulations for evaluating the adequacy of a utility's revenues and earnings. The rules and regulations change according to the regulatory climate and, in general, to the individual commissioners who are appointed or elected, depending on the laws of a state.

Regulatory Climate on Project Construction

The late 1960's and early 1970's witnessed innumerable delays and cancellations of major power projects due to a need to meet the requirements of the National Environmental Policy Act of 1969 and court rulings resulting from the legal opposition of special interest groups. Gradually, however, there seems to be evolving an ability on the part of the utilities to comply with the intent and letter of environmental law and a better understanding by some regulatory agencies of the difficulties of a utility in complying with restrictive interpretations of the law. New procedures and methods may now be developing that would eventually streamline the procedures of applying for and processing license applications. Some siting laws, while as yet untested indicate further improvement in the expediting of the licensing process. UPHS and CAES projects will have an impact on local land, water, and air; and they can be expected to require a minimum of three years for the licensing phase.

Economic Aspects

Utilities normally appraise the relative economic merits of a project on a least-cost basis regarding their

financial status. As such, rules and regulations governing their return on investment are usually the most important economic considerations. The utilities endeavor to minimize necessary revenue requirements in meeting a given load level while achieving allowed rates of return on investments and equity. Under such procedures, the utilities include all taxes as costs. Taxes are, in reality, a transfer of funds from the public to government through the utilities. This tends to create a monetary bias in favor of projects with low capital costs such as a gas turbine powerplant, which has the lowest capital cost of all alternative generating sources. In this context, regulatory reform might be considered to enable utilities to analyze the relative economics of projects at state and federal levels. Such considerations would include quantifying economic factors such as better utilization of human resources, utilization of indigenous and renewable resources, and conservation of limited resources.

Financial Aspects

The more important elements considered in assessing the financial well-being of an electric utility are: (1) its ability to obtain adequate revenues to cover its operating expenses and payment of debts and (2) to provide adequate and allowable return to its investors. In the decision making process, utilities must evaluate the financial impact of alternative types of projects. This type of evaluation is heavily weighted by the short-term impact, and it differs from the economic analysis referred to previously.

Because of a quadrupling of fuel oil prices and other inflationary events occurring over the past several years, the utilities have had continuous and substantial cost increases in new plant construction and operation. In seeking to maintain their financial balance, they have expressed concern about inadequate rate relief due to (1) regulatory delays and (2) regulations inadequate in accounting for inflation. For several years state regulatory agencies generally did not act favorably toward the utilities' frequent requests for substantial rate increases.

Many rate regulators do not recognize the need for the utilities to raise substantial new capital to build new projects, to have substantially higher working capital for new construction of capital-intensive projects and to have

capital to equip old projects with recently required pollution abatement facilities. High inflation rates and extended periods of construction compound the difficulties of a utility when projects not in operation are inadequately factored in the rate base.

The financial strength of many utilities has deteriorated in the recent past. Bond ratings have decreased, the cost of new money has increased and the ability of utilities to raise equity and debt money has been adversely affected.

During the past two years, regulatory agencies have responded more favorably to many of the utilities' requests for rate increases by:

- . allowing higher returns on total investments and on equity,
- . permitting automatic fuel adjustments,
- . including, in part, construction work in progress (CWIP) in the rate base with, in some cases, compensating disallowances of interest during construction.

Exhibit V-1 shows current regulatory commission practices by states. Note the large emphasis on original cost rate base, depreciation of which does not provide adequate funds for replacement by new facilities at inflated costs.

Recent rate adjustments have generally helped the utilities. An informative indicator is that of the price index of electric utility stocks. The market prices of utility stocks have returned to near their book values. A return toward book value means a utility's ability to raise new equity funds is enhanced.

On a long term-basis, a utility's financial condition depends on the effects of inflation and the relationship between revenues and the costs of owning, operating and building facilities.

Some reform in the regulation of utilities which might improve a utility's position and ultimately benefit the consumer through lower rates is in order. Reform in regulatory practices is beyond the scope of this study. However, regulation should encourage utilities to develop projects

which would be beneficial on a long-term basis. It is to be recognized that such projects invariably require a long construction time and large investment. Projects which have minimum environmental impact and which lessen U.S. dependence on foreign oil could be categorized and encouraged through tax and other incentives. The following allowances might be considered:

- (1) Providing a suitably large investment credit to UPHS projects,
- (2) Allowing CWIP in the utility's rate base,
- (3) Capitalizing AFUDC in the CWIP,
- (4) Expensing and allowing research and development expenditures in operating costs.

INTRODUCTION

ATTRACTIVENESS OF UPHS AND CAES SYSTEM

SYSTEM GENERATION MIX

MARKET CAPTURE POTENTIAL OF UPHS AND CAES

CHAPTER VI
MARKET CAPTURE POTENTIAL

Chapter VI

MARKET CAPTURE POTENTIAL

Introduction

This chapter presents studies which have been performed to estimate the market capture potential of UPHS and CAES technologies in nine Regional Reliability Councils. Consideration has been given to the attractiveness of UPHS and CAES systems versus other means of meeting peaking capacity, and to the future mix of generation sources. The potential power market for UPHS and CAES is projected to be about 36 million kW by the year 1995. The market potential would double by 2000 and possibly triple by 2005.

Attractiveness of UPHS and CAES Systems

Energy storage systems such as UPHS and CAES are attractive in meeting future peaking capacity requirements. Conventional peaking capacities have been oil or gas fueled combustion turbines and steam plants. With increasing cost and shortage, and government regulations limiting the use of such fuels for electric generation, these plants are in many cases no longer practical peaking options in the future. It has been demonstrated in many specific cases that the energy storage systems such as UPHS at the present day estimate of capital costs are already economically more attractive than combustion turbines and oil-fueled steam plants.

There are two other conventional peaking alternatives. First, redevelopment or expansion of existing, conventional hydroelectric plants is a practical and probably economical means of adding peaking capacity. Meaningful increments of such peaking capacity are limited to the Pacific Northwest. Second, coal-fueled cycling steam plants are serious contenders in the intermediate peaking range. However, unit capital costs of such plants are higher than those of UPHS and CAES systems.

Studies by various investigators of alternative energy storage systems have identified UPHS to be among the most attractive and technologically most advanced. Possibly thermal storage and CAES are the only other systems that

would be competitive with UPHS. Conventional hydro pumped storage is limited in potential applications because of siting problems.

The present study confirms that UPHS would be generally more attractive than CAES. Investment costs would be about equal, while CAES would have a higher energy production cost since it would still consume fuel oil during the generation cycle. However, such conclusions might not necessarily apply to specific cases. There are geographical areas where UPHS cannot be sited, whereas a CAES system would be. CAES systems can be built in smaller blocks (500 MW) than UPHS systems, which would tend to favor the CAES system in a smaller utility.

System Generation Mix

A future electrical system would ideally consist of large nuclear and coal plants on base load, older coal-steam plants for intermediate duty, and low cost energy storage plants for peaking and intermediate duty. Existing oil-fired powerplants might be relegated to the role of reserve capacity. Hydroelectric plants would mostly operate on peaking duty during adverse water supply conditions. Such a generation mix would be most cost effective and would minimize use of petroleum. Table VI-1 shows an ideal generation mix for an electric system having an annual load factor of 60 percent.

Table VI-1

IDEAL GENERATION MIX

<u>Type of Generating Capacity</u>	<u>Percent of Total Capacity</u>
1. Base-load Nuclear and Coal Steam	60-65
2. Intermediate-Load Coal Steam	15-10
3. Oil-fueled Steam	5
4. Combustion Turbine	5
5. UPHS and CAES	10
6. Other Energy Storage	5
TOTAL	100

Naturally, the ideal generation mix will depend on the shape of the load curve, relative capital and energy costs of the different types of generation as well as the development of the system over time. A detailed analysis on a system by system basis would be impractical for this present study. Consequently, the above mix has been adopted on a Reliability Council basis in order to provide an estimate of the potential UPHS and CAES installations.

Market Capture Potential of UPHS and CAES

Each Regional Reliability Council was analyzed to determine the potential market for UPHS and CAES.

Each Reliability Council has been assumed to be a single system, and with the growth in the system, the generation mix will gradually evolve to the ideal status as indicated in Table VI-1.

The starting points are the projections of future demand and generating capacity by the Reliability Councils as filed with the Federal Power Commission in 1976. In general, these projections extend to 1995, although all are not available through 1995. It is assumed that with the emphasis in oil and gas savings, and with the advancement in technology and demonstration of economy of UPHS and CAES, these projected additions in generating capacity will be adjusted to include a significant amount of UPHS and CAES projects. For this purpose, UPHS and CAES projects are considered to be potentially available beginning from 1985. On this basis, the potential market for UPHS and CAES has been estimated for years 1995 and 2005 and are shown in Table VI-2.

Table VI-2

MARKET CAPTURE POTENTIAL BY RELIABILITY COUNCIL AREAS

(Million kW)

Reliability Council	1995		2005	
	Peak Demand	UPHS and CAES Capacity	Peak Demand	UPHS and CAES Capacity
ECAR	177	15	323	35
ERCOT	82	0	147	0
MAAC	78	3	145	10
MAIN	102	13	177	21
MARCA	48	2	92	6
NPCC	80	0	148	6
SERC	260	3	440	6
SWPP	142	0	332	0
WSCC	181	0	366	6
Total Continental				
U.S.	1,150	36	2,170	90

It is seen that some of the Reliability Councils might not accomodate UPHS or CAES over the next 30 years. The WSCC has a very large proportion of its present capacity in hydroelectric plants. The natural path of expansion for that system would be the addition of base-load capacity and expansion of existing hydroelectric plants. The ERCOT system has a very large share of its present capacity in oil or gas-fired steam plants. The general direction of system growth should therefore be towards addition of nuclear or coal fired base plants.

Projections of new capacity for each Reliability Council are discussed below. New capacity additions has been estimated for the periods 1985 through 1995 and 1995 through 2005. Estimates of new capacity take into account load factors, generating facilities already operating or committed for construction by 1985, and regional resources.

Exhibit VI-1 shows annual and monthly load factors occurring in 1976 for the Reliability Council electrical

systems. Future annual peak demands and planned generation mix as reported by the Regional Reliability Councils are presented in Exhibit VI-2 and Exhibit VI-3, respectively.

Market Capture Potential in ECAR

Estimate of power market of UPHS and CAES in ECAR (FPC Region II) for the period 1985 through 1995 is shown in Exhibit VI-4. ECAR has a large amount of generating capacity in coal-fired steam plants. Thus, it will be very favorable to introduce UPHS and CAES projects into ECAR. Market capture potential of UPHS and CAES is estimated to be 15 million kW by 1995 and 35 million kW by 2005.

Market Capture Potential in ERCOT

Estimate of power market potential in ERCOT (FPC Region V) is shown in Exhibit VI-5. ERCOT has a large amount of generating capacity in oil-fired steam plants. The market for UPHS and CAES in this area is therefore limited because low cost base load capacity will not be developed sufficiently to provide off-peak charging energy to energy storage projects. There would be little market potential for UPHS and CAES in ERCOT by 1995 and 2005.

Market Capture Potential in MAAC

Exhibit VI-6 shows estimate of market capture potential of UPHS and CAES in MAAC service area (FPC Region I). Potential 1995 peaking capacity in MAAC could include about 3 million kW of UPHS and CAES systems; and the potential capacity could increase up to 10 million kW by 2005.

The base-load generating capacity in MAAC is predominantly coal and nuclear; of the total 1975 generating capacity 37 percent was coal and 10 percent nuclear (see Exhibit VI-3). It is projected that nuclear and coal generating capacity will be two-thirds of the total capacity by 1995. Therefore it is very favorable for introducing UPHS and CAES projects into the MAAC system.

Market Capture Potential in MAIN

Estimate of market capture potential in MAIN (FPC Region IV) is shown in Exhibit VI-7. It is projected that MAIN could accommodate up to 13 million kW of UPHS and CAES capacity by 1995. MAIN has a large amount of coal-fired

steam, about 75 percent of the 1975 generating capacity. It is expected that more than 50 percent of the total generating capacity will be coal-fired steam and 41 percent nuclear by 1995. The potential capacity of UPHS and CAES is estimated at 21 million kW by 2005.

Market Capture Potential in MARCA

Exhibit VI-8 shows estimate of market capture potential of UPHS and CAES in MARCA (FPC Region IV and VI). MARCA has about 50 percent of generating capacity in coal-fired steam plants. It is estimated that the coal-fired steam generating capacity will be more than 50 percent and the nuclear capacity will reach 30 percent by 1995. It appears favorable for MARCA to have energy storage projects.

There are development possibilities of surface pumped storage projects in the area, but siting problems might hamper realization of these projects. Market potential for UPHS and CAES is estimated at 2 million kW by 1995 and 6 million kW by 2005.

Market Capture Potential in NPCC

Estimate of market capture potential in NPCC (FPC Region I) is shown in Exhibit VI-9. It appears that NPCC will not be ready to absorb UPHS and CAES projects before 1995. There is a large amount of generating capacity in oil-fired steam, about 58 percent of total capacity in 1975. There is also potential for surface pumped storage and conventional hydroelectric development. About 5,240 MW of pumped storage generation are in operation and 3056 MW are under application for FPC licensing (see Exhibit VI-12). Several conventional hydroelectric projects are also under application for FPC licensing (see Exhibit VI-13). However, it is estimated that there would be some potential capacity for UPHS and CAES beyond 1995. The UPHS and CAES could have a capacity of 6 million kW in 2005.

Market Capture Potential in SERC

Exhibit VI-10 shows estimate of market capture potential in SERC (FPC Region III). SERC could accommodate about 3 million kW of UPHS and CAES capacity in 1995. Capacity requirements of UPHS and CAES could increase to 6 million kW by 2005.

SERC has a large amount of generating capacity in coal-fired steam plants, about 68 percent of the total generation capacity in 1975. It is estimated that base-load coal and nuclear generating capacity will amount to 87 percent by 1995. Thus, SERC system will be favorable to accomodating large blocks of UPHS and CAES.

Market Capture Potential in SWPP

SWPP (FPC Region V) contains a very large amount of generating capacity in oil-fired steam plants, about 80 percent of the total in 1975 (see Exhibit VI-3). Low cost base-load energy will not be available for energy-storage plants during the forecast period. For this reason, it is estimated that there will be little market potential for UPHS and CAES projects by 2005.

Market Capture Potential in WSCC

Exhibit VI-11 shows estimate of market capture potential in WSCC (FPC Regions IV, V, VII and VIII). The WSCC system will not favorably accommodate UPHS and CAES projects by 1995. Pumped storage and conventional hydroelectric development potential in the WSCC areas is excellent (see Exhibits VI-12 and VI-13). The WSCC service area could, however, provide potential power market for UPHS and CAES beyond 1995. It is estimated that the UPHS and CAES capacity could be up to 6 million kW by 2005.

Summary

The total 1995 generating capacity estimated for the nine Reliability Councils is 1,370 million kW. Additions of generating capacity for the period 1985 to 1995 are 569 million kW; 36 million kW or 6 percent of the new generating capacity could be in the form of UPHS and CAES capacity. The share of UPHS and CAES in the power market beyond 1995 could be increased to a greater percentage than 6 percent of the total new capacity additions, as more Reliability Council service areas will have a generation mix favorable to accommodating UPHS and CAES capacity. Generating capacity of UPHS and CAES is estimated to be about 90 million kW by 2005.

INTRODUCTION

RD & D FOR UNDERGROUND PUMPED HYDRO STORAGE

RD & D FOR COMPRESSED AIR ENERGY STORAGE

ESTIMATED COSTS OF RD & D

CHAPTER VII

**RESEARCH, DEVELOPMENT AND
DEMONSTRATION RECOMMENDATIONS**

Chapter VII

RESEARCH, DEVELOPMENT AND DEMONSTRATION RECOMMENDATIONS

Introduction

The benefits of UPHS and CAES plants are potentially very large. The major obstacle to their commercialization on a broad scale is the utilities' concern of the reliability of capital cost estimates and long lead time. Potentially 36 million kilowatts of capacity in UPHS and CAES plants could be utilized advantageously by 1995, whereas it is unlikely that the first UPHS or CAES might become operational by 1985. Thus, decisions by utilities to proceed with these projects must be made within a few years from now, particularly for plants coming into operation prior to 1990.

This chapter presents recommendations in RD&D for UPHS and CAES which are directed towards their timely acceptance and large-scale commercialization. Obviously there are many areas of research which would directly or indirectly benefit UPHS and CAES technology. Concern is placed only on the major areas of RD&D requiring government sponsorship and funding. Omitted are those RD&D not critical to the commercialization of these technologies. Also omitted are those RD&D which would require limited amounts of funds and which could be conveniently undertaken by the private sector.

Streamlining of licensing procedure for all large generating plants is widely recognized by the utility industry as well as by federal and local government agencies as an urgent need. Providing financial inducements to projects such as UPHS and CAES which would enhance conservation of limited resources is another area of urgent need. Both areas apply to all types of major generating projects and would require legislative action at both federal and state levels. They are cited herein but are considered to be outside of specific RD&D for UPHS and CAES.

It seems appropriate to first review the current status of UPHS and CAES technology to identify the priority areas which would result in the greatest return on RD&D investment, as well as to achieve the timely commercialization of these technologies. Then recommendations and estimated costs are given.

RD&D for Underground Pumped Hydro Storage (UPHS)

Needs and Priorities

UPHS technology is well advanced. Further advancement is possible to improve performance, reduce costs, and permit applicability in a greater variety of site conditions. Prominent in the areas for further technological advancement are the development of large-capacity pump/turbines for operation at heads of 3,000 to 4,000 feet, and improvement in excavation methods of large-diameter (20 feet or more) shafts to those depths. There are, however, no technical obstacles to the construction of commercial-size UPHS. Advances in technology from RD&D would benefit practically all future UPHS projects in the country regardless of geographical area.

Large-scale commercialization appears to be several decades away if the technology is left solely to the utilities. As discussed previously, there are few incentives for the utilities to expend development money on UPHS. The exposure to large front-end investments of such projects requiring long lead times discourages them from making even the smallest amount of expenditures for siting studies.

Therefore, it is imperative that the government sponsors the initial development and demonstration work of the projects that might be constructed in the next 20 years. A large share of the costs might also have to be funded, at least initially, by the government.

UPHS Development Work

The primary development work is to obtain for the continental United States an inventory of specific sites suitable for construction of UPHS projects. This should be done for some twenty sites located in the load centers of the reliability councils which have been identified as requiring UPHS at an early date. The developmental work for each specific site should include all necessary investigations to the level sufficient to demonstrate technical and economic feasibility as well as environmental acceptance. With such developmental work, the lead times for implementation of these sites might be cut several years. It would be possible for the utilities to proceed with licensing procedures and project construction, when their concern over the risks are overcome by the information developed from the demonstration project.

It is recommended that this development work be phased over a five to seven years period. The time required for development of each site would be between three to four years.

As with most hydroelectric projects or underground work, development work is primarily site-specific, since the technological concepts are founded on existing technology. Thus, the developmental work includes the following for each site:

- a. Siting. Perform necessary studies to select the favorable site in a specific utility or load center from demand, geotechnical, economic and environmental aspects.
- b. Site-Specific Geotechnical Investigations. Perform surface and subsurface investigations including hard-rock drilling to establish geotechnical feasibility and to permit conceptual project design.
- c. Conceptual Project Design. Perform conceptual design, including general arrangement of project, location and conceptual design of principal project elements, on the basis of specific geotechnical information. Conduct necessary studies to evaluate alternative designs and select the optimum design of the project. Estimate project costs.
- d. Economic Feasibility. Perform investigations to determine project performance in the utility system in conjunction with other generating plants in the system. Compare such performance with the case where other types of projects are built in the system. Establish cost savings to the utility and determine overall economic feasibility by relating capital and operating cost requirements of the alternative types of generation.
- e. Environmental Impact. Perform all necessary studies to determine environmental impact, and establish ways to mitigate adverse impacts.
- f. Other Studies. Perform all necessary investigations to complete technical, economic, and environmental feasibility of the site for UPHS development

Conduct associated research work to enhance the technology of UPHS. Conduct associated development work for possible adaptation of the site for CAES development, if such might prove to be suitable and superior to UPHS.

UPHS Demonstration Plant

It is recommended that a commercial size UPHS demonstration plant be developed and built. Research, development, and testing associated with the demonstration project should vastly advance broad commercialization of UPHS.

The total time period of implementation from development work to construction and initial operation might be about 10 years assuming no delays. The total cost of this demonstration project would be dependent on the size of the project. The demonstration plant might initially be for an installation of 1,000 MW and 10,000 MWh, but might be designed for expansion to two or three times the initial size. The capital cost of such a demonstration plant would be about \$400 to \$500 million at the 1977 price level. The cash requirements over a 10-year period would then average to \$50 million a year.

Research in UPHS Technology

As stated previously in this Chapter, there is no single item of research work which needs to be conducted to overcome technological obstacles. There are many areas of research which might improve the economics and remove uncertainties. As a part of some of the site-specific development work or of the demonstration plant, the following research work may be conducted:

- a. Improved excavation equipment and construction techniques for excavating large-diameter deep shafts.
- b. Improved equipment and construction techniques for excavating large caverns in rock for underground storage reservoirs.
- c. Behavior of excavated underground caverns particularly stress conditions of surrounding rock.

- d. Reversible pump/turbines for higher operating head and improved efficiency.
- e. Detection from the ground surface of subsurface geotechnical conditions for creating caverns.

Furthermore, the above research work can and should also be conducted in the laboratory and in field tests separately from the recommended development and demonstration work.

RD&D for Compressed Air Energy Storage (CAES)

Needs and Priorities

CAES technology is less advanced and appears to be less cost competitive than UPHS. Consequently, recommendations in RD&D for CAES have a lower priority than for UPHS, should there be a conflict due to funding constraints.

There are several possible CAES designs employing different types of the storage medium - caverns in hard rock, aquifers, salt beds, and depleted oil and gas fields. The designs offering greater promise, wider applications and requiring less RD&D should have greater priority.

CAES systems employing hard rock caverns appear to have the least technical unknowns. Such systems would potentially also have the widest applications. However, this option would compete directly with the UPHS system as the same site might conceivably be considered for either CAES and UPHS.

The most critical question relating to technical feasibility of CAES is the stability of the air storage. The question has to be resolved for all types of storage. For aquifers, there is the additional question of feasibility of rapid injection and withdrawal of air required of a CAES system. There are other additional technical problems surrounding the technical feasibility of salt beds and depleted oil and gas fields for use in air storage.

It is recommended that research, development and demonstration be initiated concurrently, similar to the recommendations for UPHS. However, development and demonstration must be more carefully programmed and monitored so that each

technical obstacle will be overcome prior to the commitment of the succeeding larger expenditure.

CAES Development Work

The primary objective of development work for CAES, similar to that of UPHS, is to obtain for the continental United States an inventory of specific sites suitable for construction of CAES projects. The developmental work for each specific site should include all necessary investigations to the level sufficient to demonstrate technical and economic feasibility as well as environmental acceptance.

Different types of underground storage in hard rock, salt beds, and aquifers should be considered. It is recommended that development work of CAES in rock caverns be conducted where appropriate at the same site where the UPHS development work is conducted. In addition, development work should be conducted for at least two other sites with one site incorporating salt beds and another incorporating aquifers. The development work for each site includes the following:

- a. Siting
- b. Site-Specific Geotechnical Investigations
- c. Conceptual Project Design
- d. Economic Feasibility
- e. Environmental Impact

The developmental work might extend over a two to four year period for each site. The recommended time schedule is that the developmental work be conducted over a five to seven year period.

CAES Demonstration Plant

It is recommended that a commercial-size CAES demonstration plant be developed and built.

The demonstration plant might be built for an installation of 500 MW with 10 hours of storage. It might also be designed for expansion to two or four times the initial size.

Since different types of storage might pose vastly different technical problems, it is suggested that the demonstration plant incorporate a type of underground storage which could have wide applications over the entire country.

Research in CAES Technology

A large amount of research work for CAES is required to analyze the many options in alternative conceptual designs as related to alternative types of underground storage and to the present future equipment for CAES. Most of the research can and should be conducted with one or more of the site-development work described earlier. In addition, other theoretical and laboratory research efforts should be undertaken. A number of possible research areas are listed below:

- a. Improved excavation equipment and construction techniques for excavation of large caverns in rock for underground storage reservoirs.
- b. Optimum design of plant system configuration.
- c. Behavior and stability of rock exposed to air at varying pressures and temperatures.
- d. Rapid injection and withdrawal of air in an aquifer.
- e. Utilization of depleted oil and gas fields for air storage.

Item c can be further studied in field tests in existing caverns without the construction of the CAES plant itself, in advance of and separate from the development and demonstration work. Small scale field tests for items d and e might also be developed to obtain improved knowledge as to the suitability of aquifers and depleted oil and gas fields for storage of compressed air.

Estimated Costs of RD&D

A very rough estimate of costs of RD&D for UPHS and CAES is prepared for the purpose of permitting a first analysis as to the reasonableness of the recommended program. It is assumed that the program will be implemented over a ten-year period from 1978 to 1987 and estimates are made in 1977 dollars.

Table VII-1

PRELIMINARY COST ESTIMATE OF RD&D
FOR PERIOD 1977-1986

	<u>Estimated Costs in \$ Million</u>
<u>UPHS</u>	
Development Work (20 sites)	140
Demonstration Plants (1,000 MW)	<u>500</u>
Subtotal	640
<u>CAES</u>	
Development Work (Caverns, 10 sites)	20
Development Work (aquifers and salt beds, one site each)	10
Demonstration Plant (500 MW)	<u>200</u>
Subtotal	230
Total UPHS and CAES	870

The above costs do not include additional funding requirements for administration of RD&D. Further, no allowance has been provided for the research needs which would, however, be a fraction of the estimated costs for development and demonstration.

The costs would be expanded over ten to twelve years, and most of the amount would be funded in the latter half of the period.

It is beyond our scope to recommend how the funding could be accomplished. As stated before, the federal government will have to take the lead and sponsor the RD&D outlined above. Consequently, a significant share of the funds might have to be from the federal government. The utilities directly benefiting from the development and demonstration work might bear some of the costs.

EXHIBITS

FEDERAL POWER COMMISSION ELECTRIC POWER SUPPLY AREAS IN THE UNITED STATES

MAP OF THE POWER SUPPLY REGIONS

EXHIBIT I-1

ELECTRIC UTILITY GENERATING CAPACITY PEAK LOADS AND ENERGY SUPPLIED

1969 - 1975

Based on Reports by Major Systems of the United States

NOTES:

Dependable capacity, which includes net firm power purchases, is based on adverse hydro conditions.

Net assured capacity is dependable capacity less reported required reserves.

Relation between capacity and loads indicates overall condition for region although existing inter-connections may not permit full coordination throughout each region.

Dependable capacity and net assured capacity are no longer provided by FPC Form 12E-1. Net assured capacity is not available for June 1975. The line plotted for dependable capacity between December and June 1975 merely connects sets of points to provide continuity of plotting.

For further information refer to data in accompanying report.

		Percentage of Total Generating Capacity						Percentage of Total Generating Capacity					
		Generating Capacity				Combustion	Pumped	Generating Capacity				Combustion	Pumped
Region		MW	Hydro	Nuclear	Fossil	Turbine	Storage	MW	Hydro	Nuclear	Fossil	Turbine	Storage
<u>1970</u>							<u>1980</u>						
I	Northeast	62,347	9.4	7.4	75.6	5.3 ^{1/}	2.3	116,890	5.0	35.0	44.4	7.5 ^{1/}	8.1
II	East Central	55,215	-	2.0	92.0	6.0 ^{1/}	-	103,560	-	16.0	76.0	8.0 ^{1/}	-
III	Southeast	40,853						111,497					
IV	North Central	36,956	3	9	78	9	1	69,848	1	38	52	8	1
V	South Central ^{2/}	48,846	(5) ^{3/}	-	(95) ^{4/}	-	-	112,790					
VI	West Central	8,837	32.4	-	58.1	5.8	3.7	16,911	17.9	20.5	56.6	3.0	2.0
VII	Northwest	24,612	89.7	3.2	7.1	-	-	47,638	68.5	16.5	14.6	-	0.4
VIII	Southwest	35,438	25.8	1.4	70.3	2.4	0.1	69,676	16.1	25.0	53.9	3.4	1.6
<u>1990</u>													
I	Northeast	213,420	2.7	58.4	24.1	7.6 ^{1/}	7.2						
II	East Central	188,635	-	34.0	60.0	6.0 ^{1/}	-						
III	Southeast ^{2/}	219,097	(2.3)	(64.7)	(27.9)	(3.9)	(1.2)						
IV	North Central	132,207	1	59	32	8	0						
V	South Central ^{2/}	228,885	(1) ^{3/}	(43)	(56) ^{5/}								
VI	West Central	31,861	11.9	31.3	54.2	1.6	1.0						
VII	Northwest	86,792	51.1	30.9	17.1	-	0.9						
VIII	Southwest	143,950	9.3	50.4	32.1	4.6	3.6						

Source: The 1970 National Power Survey, FPC, December 1971

- 1/ Includes other sources, data do not permit separation.
2/ Figures in parentheses indicate percentage of total energy generation. Data do not permit breakdown into generating sources.
3/ Includes pumped storage, data do not permit separation.
4/ Represents 90% natural gas and 5% coal of total energy generation.
5/ Represents 46% natural gas and 10% coal of total energy generation.

INDIVIDUAL MEMBERS OF
REPRESENTATIVE LARGE POWER POOLS IN
REGIONS I, III AND IV

REGION I

PJM Interconnection

Pennsylvania Electric Company
Metropolitan Edison Company
Jersey Central Power & Light Company
Pennsylvania Power & Light Company
Luzerne Electric Division - UGI Corporation
Philadelphia Electric Company
Public Service Electric and Gas Company
Atlantic City Electric Company
Baltimore Gas and Electric Company
Potomac Electric Power Company
Delmarva Power & Light Company

New York State Interconnected System

Consolidated Edison Company of New York, Incorporated
Rochester Gas and Electric Corporation
Orange and Rockland Utilities, Incorporated
Niagara Mohawk System
New York State Electric & Gas Corporation
Long Island Lighting Company
Central Hudson Gas & Electric Corporation
Power Authority of the State of New York
Incorporated Village of Freeport
City of Jamestown, New York

New England Power Exchange

Boston Edison Company
Central Maine Power Company
Central Vermont Public Service Corporation
Eastern Utilities Associates
New England Electric System
New England Gas & Electric Association
Northeast Utilities*
Public Service Company of New Hampshire, and
United Illuminating Company

* Northeast Utilities:
Connecticut Light & Power
Hartford Electric
Western Massachusetts Electric, and
Holyoke Water Power Company

REGION III

Virginia-Carolinas Subregion

Carolina Power & Light Company
Duke Power Company
South Carolina Electric & Gas Company
South Carolina Public Service Authority
Southeastern Power Administration
Virginia Electric & Power Company
Yadkin, Incorporated

Tennessee Valley Subregion

Big Rivers Electric Corporation
Henderson Municipal Power & Light
Nanthahala Power & Light Company
Tapoco, Incorporated
Tennessee Valley Authority

Southern Companies Subregion

Alabama Electric Cooperative, Incorporated
Alabama Power Company
Crisp County Power Commission
Georgia Power Company
Gulf Power Company
Mississippi Power Company
Savannah Electric & Power Company
Southeastern Power Administration
South Mississippi Electric Power Association

Florida Subregion

Florida Power and Light Company
Florida Power Corporation
Fort Pierce Utilities Authority
Gainesville/Alachua County Regional Utilities
Jacksonville Electric Authority
Lakeland, Department of Electric & Water Utilities
Orlando Utilities Commission
Tallahassee Electric Department
Tampa Electric Company
Vero Beach Municipal Utilities

REGION IV

Commonwealth Edison Company

The Wisconsin-Upper Michigan System (WUMS)

Madison Gas and Electric Company (MGE)
Wisconsin Electric Power Company System (WE-WM) *
Wisconsin Power and Light Company (WPL)
Wisconsin Public Service Corporation (WPS)
Upper Peninsula Power Company (UPP)

*Includes its subsidiary Wisconsin-Michigan Power Company

The Illinois-Missouri Pool (Ill-Mo Pool)

Central Illinois Public Service Company (CIPS)
Illinois Power Company (IP)
Union Electric Company (UE) *

*The Union Electric System includes the Union Electric Company and its three subsidiaries, Missouri Power & Light Company, Missouri Edison Company, and Missouri Utilities Company.

REGION I

LOAD CENTERS - 1990

- OVER 10,000
- 5,000 to 10,000 MW
- ★ 2,000 to 5,000 MW

UTILITY SYSTEM

- PJM INTERCONNECTION
- NEW YORK STATE INTERCONNECTED SYSTEM
- NEW ENGLAND POWER EXCHANGE

**LOAD CENTERS AND SERVICE AREAS
OF REPRESENTATIVE UTILITY SYSTEMS**

**LOAD CENTERS AND SERVICE AREAS
OF REPRESENTATIVE UTILITY SYSTEMS**

**LOAD CENTERS AND SERVICE AREAS
OF REPRESENTATIVE UTILITY SYSTEMS**

GEOLOGIC CRITERIA COMPRESSED AIR ENERGY STORAGE (CAES)

AIR STORAGE TYPE	SURFACE STRUCTURES		SHAFT(S)	SUBSURFACE CAVERN OR RESERVOIR						FAVORABLE FACTORS AFFECTING LOCATION	GENERALLY UNFAVORABLE REGIONAL GEOLOGIC CONDITIONS	UNFAVORABLE ROCK CHARACTERISTICS AND OTHER FACTORS
	FOUNDATION	RESERVOIR		GENERAL GEOMETRIC CRITERIA	DEPTH RANGE (1000 psi)	GEOMETRY OF FAVORABLE ROCK	GENERALLY FAVORABLE ROCK TYPES	PERMEABILITY	STABILITY			
CONSTANT PRESSURE <u>HYDRAULICALLY COMPENSATED</u>	<u>Favorable:</u> Soil or rock capable of supporting civil structures. <u>Unfavorable:</u> Peat and organic soils. Compressible soils.	<u>Favorable:</u> Significant thickness of rock or soil of relatively low permeability at, or near, surface. Access to water. <u>Unfavorable:</u> Permeable rock*. Permeable soil*. Relatively thin rock or soil of low permeability underlain by permeable rock or soil.* * These conditions may require artificial lining.	<u>Favorable:</u> Controllable ground-water inflow. Good drilling characteristics. Rock capable of standing with minimum or no support. <u>Unfavorable:</u> Aquifer with high artesian head. Running sand. Squeezing ground. Deep unconsolidated materials.	Laterally elongate cavern. Conventionally mined.	To crown of cavern. 2300 ft. to 3500 ft.	Rock unit of large lateral extent.	Massive crystalline igneous or crystalline metamorphic. Massive limestone or dolomite.	<u>Cavern Rock:</u> Very low permeability.	Superior short and long term stability with minimum support under operational thermal and pressure cycling.	Thin soil cover. Deep water table. Homogeneous rock, generally free of discontinuities and weak strata or interbeds.	Extensively faulted regions. Regions of high seismic activity and active faulting. Heterogeneous and complex volcanic environments. Regions of extreme structural complexity. Regions of excessively thick unconsolidated sediments.	Thin-bedding or fissility. Weathered to decomposed. Fractured. Karstic. Susceptible to scaling or slaking. Highly water bearing. High geothermal gradient. Highly soluble.
VARIABLE PRESSURE <u>NON-COMPENSATED</u>		None		Shape variable. Conventionally mined.	To crown of cavern 2000 ft. to 3500 ft.	Cavern shaped to conform to geometry of favorable rock unit. Orientation not restricted.	Rock types as above.					Same as above. EXCEPT: Siting not limited by high geothermal gradient. Highly soluble rocks which can be hydraulically mined are favorable.
VARIABLE PRESSURE <u>AQUIFER STORAGE</u>			Wells	Storage bubble shape varies with geometry of most permeable zones. Geologic trap.	To top of reservoir rock 1500 ft. to 3500 ft.	<u>Reservoir Rock:</u> Sufficient to contain desired storage bubble. <u>Cap Rock:</u> Sufficient to contain storage bubble under desired pressure with no hydraulic fracturing.	<u>Reservoir Rock:</u> Sandstone. Carbonate reef rocks. <u>Cap Rock:</u> Shale.	<u>Reservoir Rock:</u> High permeability. <u>Cap Rock:</u> Low permeability.	Not Applicable	No significant water production from vicinity of storage bubble.		Potential interference with nearby wells.
VARIABLE PRESSURE <u>DEPLETED OIL OR GAS FIELD STORAGE</u>							<u>Reservoir Rock:</u> Sandstone. Limestone. Dolomite. <u>Cap Rock:</u> Shale.			Abandoned oil or gas field.		Residual hydrocarbons and natural gas under pressure.

Notes:

1. Areas shown as generally unfavorable may be favorable locally. Areas shown as generally favorable may be unfavorable locally.
2. This map is compilation of data on Exhibits II-4 through II-8. Refer to those exhibits for detail.

KILOMETERS
 0 500
 0 311
 MILES

LEGEND

Areas generally unfavorable for CAES or UPHS caverns (excluding CAES variable pressure cavern in salt).

Areas generally favorable for CAES or UPHS caverns (Excluding CAES variable pressure cavern in salt. Location of salt deposits shown on Exhibit II-9.).

ARGONNE

UPHS & CAES
Areas Generally Favorable
and Unfavorable for Caverns

HARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE

DWG. NO.

EXHIBIT II-3

Primary Sources: 1. U.S.G.S. 1974.
2. Geologic Atlas of the Rocky Mountain Region, 1972.

LEGEND

	Deep Cretaceous and Tertiary sedimentary rocks, generally unsuitable for caverns.
	Exceptionally deep sedimentary basins, generally unsuitable for caverns.
	Basin and Range contains significant areas of deep alluvium, unsuitable.
	Areas of igneous or metamorphic rock, or more favorable sedimentary rock.

ARGONNE

UPHS & CAES
Unfavorable Sedimentary
Areas

HARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE

DWG. NO.

EXHIBIT B-4

Primary Source: U.S.G.S., 1974.

LEGEND

Widespread areas of Volcanic rock.

Basin and range contains isolated areas of volcanic rock.

No extensive areas of volcanic rock.

ARGONNE

UPHS & CAES
Areas of Volcanic Rock

HARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE

DWG. NO.

EXHIBIT I-5

Primary Source: U.S.G.S., 1974.

LEGEND

Areas of complex geologic structure: Geologic conditions vary widely within short distances. Detailed study critical to site selection.

Areas of less complex geologic structure. May be complex locally.

ARGONNE

UPHS & CAES
Areas of Complex
Geologic Structure

MARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE

DWG. NO.

EXHIBIT II-6

Primary Source: Algermissen, 1969.

LEGEND

Zone 3 or higher seismic risk areas. Major destructive earthquakes may occur.

Other earthquake epicenters of intensity VII or higher.

Lower than Zone 3 seismic risk areas.

ARONNE

UPHS & CAES

Areas of High Seismic Risk

HARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE

DWG.NO.

EXHIBIT II-7

Primary Sources: 1. U. S. G. S., 1968.
2. U. S. G. S., 1974.

LEGEND

Approximate areas of extensive, major faulting.

Area containing no extensive, major faulting.
May be faulted locally.

ARGONNE

UPHS & CAES
Areas of Extensive Faulting

HARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE

DWG. NO.

EXHIBIT II-8

Primary Source: Fenix and Scisson, 1975.

LEGEND

Areas of bedded salt deposits.

Areas of salt dome occurrence.

Approximate areas of active salt mining.

Note: Salt is found at varying depths. Depth not considered in this map.

ARGONNE

CAES CAVERNS IN SALT

Areas of Salt Beds and Domes

HARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE

DWG. NO.

EXHIBIT II-9

Primary Source: Vlissides and Quirin, 1963.

LEGEND

Approximate boundaries
of oil and/or gas producing areas.

No significant oil and/or gas production.

ARGONNE

CAES IN OIL AND GAS FIELDS
Areas of Oil and Gas Fields

HARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE

DWG.NO.

EXHIBIT II-10

LEGEND

Areas unfavorable for CAES aquifer storage. Unfavorable areas include:
Massive igneous and metamorphic rocks,
Volcanic rocks, Faulted zones, Zone 3 seismic risk areas.

Areas with potential for CAES aquifer storage.
Unfavorable locally.

ARGONNE

CAES AQUIFER STORAGE
Areas Unfavorable
for Aquifer Storage

HARZA ENGINEERING CO., CHICAGO

APPROVED.....

DATE DWG.NO.

CHICAGO, ILLINOIS

DATE	10/76
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DWG. NO.	
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LEGEND

- Category 1 Shafts in overburden and/or Precambrian rock, caverns in Precambrian rock.
- Category 2 Shafts in overburden and sedimentary rock (may include Precambrian rock), caverns in Precambrian rock.
 - 2a Single stage project-Invert depth 3000'-4500'
 - 2b Double stage project-Invert depths 1750'-2250' 3500'-4500'
- Category 3 Shafts in overburden and sedimentary rock (may include Precambrian rock), one or two caverns in dolomite or limestone
 - 3a Single stage project-Invert depth 3000'-4500'
 - 3b Double stage project-Invert depths 1750'-2250' 3500'-4500'

NOTE:
If the depth requirements listed above are changed, the boundaries of the areas shown on the map will change accordingly.

AREAS FAVORABLE FOR UPHS		
FPC REGION IV		
CONSULTING ENGINEERS		
HARZA ENGINEERING COMPANY		
CHICAGO, ILLINOIS	DATE 1/6/76	DWG. NO.

LEGEND

- Category 1 Shafts in overburden and/or Precambrian rock, caverns in Precambrian rock.
- Category 2 Shafts in overburden and/or sedimentary rock (may include Precambrian rock), caverns in Precambrian rock. Depth to cavern crown 2200'-3500' or 2000'-3500'.
- Category 3 Shafts in overburden and/or sedimentary rock (may include Precambrian rock), caverns in dolomite or limestone.
 - 3a Constant pressure, depth to cavern crown 2200'-3500'
 - 3b Variable pressure, depth to cavern crown 2000'-3500'
- Category 4 Reservoir in an aquifer, depth to top of reservoir 1500 to 3500 feet. Symbol indicates only where aquifers are present at these depths. Symbol does not indicate the presence of a geologic structure nor impermeable cap rock, essential requirements for CAES in an aquifer.

NOTES:

- 1) If the depth requirements listed above are changed, the boundaries of the areas shown on this map will change accordingly.
- 2) Aquifers include the St. Peter, Ironton-Galesville and Mt. Simon Sandstones in Illinois and the St. Peter and Jordan Sandstones in Iowa. Data on depths to other aquifers in Iowa and those in Missouri were unavailable for this study.
- 3) The Eau Claire Formation, the cap rock of the Mt. Simon aquifer becomes increasingly sandy and permeable toward the north. Impermeability of the cap rock is an essential requirement for aquifer storage.
- 4) The thickness of the aquifers ranges from 40 to over 2000 feet. Rock permeabilities vary both horizontally and vertically.

Scale 0 50 100 Miles

AREAS FAVORABLE FOR CAES		
FPC REGION IV		
CONSULTING ENGINEERS		
HARZA ENGINEERING COMPANY		
CHICAGO, ILLINOIS	DATE	DWG. NO.

POWERSTATION PLAN AND SECTION
REVERSIBLE PUMP/TURBINES

POWERSTATION SECTIONS
REVERSIBLE PUMP/TURBINES

FPC REGION I

MARYLAND-PENNSYLVANIA

GRANITIC ROCK - SURFACE TO LOWER RESERVOIR
2,000 MW - 20,000 MWH UPHS

<u>Item No.</u>	<u>Item</u>	<u>Amount in \$1,000</u>
330	LAND AND LAND RIGHTS	3,500
331	POWERPLANT STRUCTURES AND IMPROVEMENTS	
	Access Shafts	31,700
	Underground Powerstation Structures	33,108
	Above Ground Structures	<u>759</u>
	SUBTOTAL	65,567
332	RESERVOIRS, DAMS AND WATERWAYS	
	Upper Reservoir Dam	5,700
	Upper Reservoir Lining	15,375
	Lower Reservoir Excavation	132,635
	Rockbolting	12,915
	Disposal On-Site	9,194
	Intermediate Reservoir	6,786
	Lower Reservoir Air Vent	5,125
	Upper Reservoir Intakes	3,052
	Intermediate Reservoir - Intakes	870
	Penstock Shafts	11,913
	Manifolds and Construction Tunnels	12,034
	Draft Tubes	12,146
	Reservoir Filling - Pump Station and Conduit	<u>1,130</u>
	SUBTOTAL	228,875

FPC REGION I

MARYLAND-PENNSYLVANIA

GRANITIC ROCK - SURFACE TO LOWER RESERVOIR
2,000 MW - 20,000 MWH UPHS

<u>Item No.</u>	<u>Item</u>	<u>Amount in \$1,000</u>
333	PUMP/TURBINES AND GENERATOR/MOTORS	
	Pump/Turbines, Governors, Valves, and Installation	42,300
	Generator/Motors, Starting Equipment and Installation	<u>39,500</u>
	SUBTOTAL	81,800
334 & 352	ACCESSORY ELECTRICAL EQUIPMENT	
	High Voltage Bus	6,100
	All Other Electrical Equipment	<u>21,000</u>
	SUBTOTAL	27,100
335	MISCELLANEOUS MECHANICAL EQUIPMENT	
	Cranes and Hoists	9,700
	All Other Mechanical Equipment	<u>2,770</u>
	SUBTOTAL	12,470
336	ROADS AND RAILROADS	<u>5,130</u>
	SUBTOTAL DIRECT COSTS	424,442
	CONTINGENCIES, (Equipment 10%, Civil 20%)	72,658
	ENGINEERING, SUPERVISION AND OVERHEAD	<u>61,000</u>
	SUBTOTAL, Prior to AFDC	558,100
	AFDC	<u>147,200</u>
	TOTAL INVESTMENT COST, JUNE 1976 PRICE LEVELS (Excluding Transmission and Escalation)	705,300
	\$ Installed/kW	353

FPC REGION III

GEORGIA - VIRGINIA

GRANITIC ROCK - SURFACE TO LOWER RESERVOIR
2,000 MW - 20,000 MWH UPHS

<u>Item No.</u>	<u>Item</u>	<u>Amount in \$1,000</u>
330	LAND AND LAND RIGHTS	2,000
331	POWERPLANT STRUCTURES AND IMPROVEMENTS	
	Access Shafts	27,678
	Underground Powerstation Structures	28,908
	Above Ground Structures	<u>662</u>
	SUBTOTAL	57,248
332	RESERVOIRS, DAMS AND WATERWAYS	
	Upper Reservoir Dam	4,977
	Upper Reservoir Lining	13,425
	Lower Reservoir Excavation	115,810
	Rockbolting	11,280
	Disposal On-Site	8,030
	Intermediate Reservoir	5,925
	Lower Reservoir Air Vent	4,475
	Upper Reservoir - Intakes	2,665
	Intermediate Reservoir - Intakes	760
	Penstock Shafts	10,403
	Manifolds and Construction Tunnels	10,507
	Draft Tubes	10,606
	Reservoir Filling - Pump Station and Conduit	<u>985</u>
	SUBTOTAL	199,848

FPC REGION III

GEORGIA - VIRGINIA

GRANITIC ROCK - SURFACE TO LOWER RESERVOIR
2,000 MW - 20,000 MWH UPHS

<u>Item No.</u>	<u>Item</u>	<u>Amount in \$1,000</u>
333	PUMP/TURBINES AND GENERATOR/MOTORS	
	Pump/Turbines, Governors, Valves, and Installation	40,677
	Generator/Motors, Starting Equipment and Installation	<u>37,965</u>
	SUBTOTAL	78,642
334 & 352	ACCESSORY ELECTRICAL EQUIPMENT	
	High Voltage Bus	5,811
	All Other Electrical Equipment	<u>19,425</u>
	SUBTOTAL	25,236
335	MISCELLANEOUS MECHANICAL EQUIPMENT	
	Cranes and Hoists	9,290
	All Other Mechanical Equipment	<u>2,560</u>
	SUBTOTAL	11,850
336	ROADS AND RAILROADS	<u>4,475</u>
	SUBTOTAL DIRECT COSTS	379,299

FPC REGION III

GEORGIA - VIRGINIA

GRANITIC ROCK - SURFACE TO LOWER RESERVOIR
2,000 MW - 20,000 MWH UPHS

<u>Item No.</u>	<u>Item</u>	<u>Amount in \$1,000</u>
	CONTINGENCIES, (Equipment 10%, Civil 20%)	64,301
	ENGINEERING, SUPERVISION AND OVERHEAD	<u>61,000</u>
	SUBTOTAL, Prior to AFDC	504,600
	AFDC	132,200
	TOTAL INVESTMENT COST, JUNE 1976 PRICE LEVELS (Excluding Transmission and and Escalation)	<u> </u>
	SUBTOTAL	636,800
	\$ Installed/KW	318

FPC REGION IV

NORTHERN ILLINOIS

GRANITIC ROCK - 2000 FT BELOW SURFACE
2,000 MW - 20,000 MWH UPHS

<u>Item No.</u>	<u>Item</u>	<u>Amount in \$1,000</u>
330	LAND AND LAND RIGHTS	2,500
331	POWERPLANT STRUCTURES AND IMPROVEMENTS	
	Access Shafts	68,346
	Underground Powerstation Structures	32,300
	Above Ground Structures	<u>740</u>
	SUBTOTAL	101,386
332	RESERVOIRS, DAMS AND WATERWAYS	
	Upper Reservoir Dam	5,561
	Upper Reservoir Lining	15,000
	Lower Reservoir Excavation	129,400
	Rockbolting	12,600
	Disposal On-Site	8,970
	Intermediate Reservoir	6,620
	Lower Reservoir Air Vent	6,400
	Upper Reservoir - Intakes	2,978
	Intermediate Reservoir - Intakes	850
	Penstock Shafts	30,616
	Manifolds and Construction Tunnels	11,740
	Draft Tubes	11,850
	Reservoir Filling - Pump Station and Conduit	<u>1,100</u>
	SUBTOTAL	243,685

FPC REGION IV

NORTHERN ILLINOIS

GRANITIC ROCK - 2000 FT BELOW SURFACE
2,000 MW - 20,000 MWH UPHS

<u>Item No.</u>	<u>Item</u>	<u>Amount in \$1,000</u>
333	PUMP/TURBINES AND GENERATOR/MOTORS	
	Pump/Turbines, Governors, Valves, and Installation	42,000
	Generator/Motors, Starting Equipment and Installation	<u>39,200</u>
	SUBTOTAL	81,200
334 & 352	ACCESSORY ELECTRICAL EQUIPMENT	
	High Voltage Bus	6,000
	All Other Electrical Equipment	<u>20,500</u>
	SUBTOTAL	26,500
335	MISCELLANEOUS MECHANICAL EQUIPMENT	
	Cranes and Hoists	9,600
	All Other Mechanical Equipment	<u>2,700</u>
	SUBTOTAL	12,300
336	ROADS AND RAILROADS	<u>5,000</u>
	SUBTOTAL DIRECT COSTS	472,571
	CONTINGENCIES, (Equipment 10%, Civil 20%)	82,529
	ENGINEERING SUPERVISION AND OVERHEAD	<u>61,000</u>
	SUBTOTAL, Prior to AFDC	616,100

FPC REGION IV

NORTHERN ILLINOIS

GRANITIC ROCK - 2000 FT BELOW SURFACE
2,000 MW - 20,000 MWH UPHS

<u>Item No.</u>	<u>Item</u>	<u>Amount in \$1,000</u>
	AFDC	167,600
	TOTAL INVESTMENT COST, JUNE 1976 PRICE LEVELS (Excluding Transmission, and Escalation)	<u>783,700</u>
	\$ Installed/kW	392

ARGONNE	
UPHS PROJECT SCHEDULE	
HARZA ENGINEERING CO., CHICAGO	
APPROVED.....	
DATE	DWG.NO.

**ELEVATION CONSTANT PRESSURE COMPRESSED
AIR ENERGY STORAGE ROCK CAVERN
ARGONNE NATIONAL LABORATORY**

EXHIBIT IV-2

EXHIBIT IV-3

ELEVATION
VARIABLE PRESSURE COMPRESSED AIR ENERGY STORAGE
SALT FORMATION

HARZA ENGINEERING COMPANY

EXHIBIT IV-4

COST SUMMARY
2088 MW COMPRESSED AIR STORAGE PLANT
CONSTANT PRESSURE SYSTEM - HYDRAULICALLY COMPENSATED

Amount in \$1,000

CIVIL ITEMS

1. Shafts	4,972
2. Upper Reservoir	9,868
3. Underground Structures	48,712
4. Site Improvements	1,901
	<u>65,453</u>
Contingencies @ 20%	13,091
Subtotal Civil	78,544

ELECTRICAL/MECHANICAL ITEMS

5. Generating Units	240,780
6. Auxiliary Compressing Equipment	32,983
7. Cooling Equipment	23,925
8. Fuel Storage and Treatment Equipment	11,615
9. Regenerator	5,191
10. Air Manifold Piping	2,552
11. Power Plant Building	4,377
12. Process Air Plant	238
13. Control Valves	392
14. Transformers, Switchgear and Accessory Electrical Equipment	17,972
	<u>340,020</u>
Contingencies @ 20%	68,004
Subtotal Electrical and Mechanical	408,024
Subtotal Civil, Electrical and Mechanical Engineering, Supervision and Overhead @ 11% +	486,568
	<u>53,432</u>
SUBTOTAL Prior to AFDC	540,000
Land and Land Rights	2,500
AFDC	<u>135,200</u>
TOTAL INVESTMENT COST, JUNE 1976 PRICE LEVELS	677,700
\$ Installed/kW	325

All costs include allowance for installation.

Adjustment factors: FPC Regions I (1.025), III (0.895),
IV (1.0).

COST SUMMARY
2088 MW COMPRESSED AIR STORAGE PLANT
CONSTANT PRESSURE SYSTEM - AQUIFER STORAGE

	<u>Amount in \$1,000</u>		
	<u>Aquifer 1000 Millidarcy 40 Feet Thick</u>	<u>Aquifer 100 Millidarcy 100 Feet Thick</u>	<u>Aquifer 100 Millidarcy 400 Feet Thick</u>
<u>CIVIL ITEMS</u>			
1. Site Improvements	1,932	1,932	1,932
2. Air Wells and Casings	59,850	174,710	74,450
	61,782	176,642	76,382
Contingency @ 20%	12,356	35,328	15,276
Subtotal Civil	74,138	211,970	91,658
<u>ELECTRICAL/MECHANICAL ITEMS</u>			
3. Generating Units	240,780	240,780	240,780
4. Auxiliary Compressing Equipment	32,983	32,983	32,983
5. Cooling Equipment	23,925	23,925	23,925
6. Fuel Storage and Treatment Equipment	11,615	11,615	11,615
7. Regenerator	5,191	5,191	5,191
8. Air Manifold Piping	21,086	79,170	21,086
9. Power Plant Building	4,377	4,377	4,377
10. Process Air Plant	4,937	4,937	4,937
11. Control Valves	392	392	392
12. Transformers, Switchgear and Accessory Electrical Equipment	17,972	17,972	17,972
	363,260	421,340	363,260
Contingencies @ 20%	72,652	84,268	72,652
Subtotal Electrical and Mechanical	435,912	505,608	435,912
Subtotal Civil, Electrical and Mechanical	510,050	717,578	527,570
Engineering, Supervision and Overhead @ 11% ±	56,000	78,422	58,430
SUBTOTAL, Prior to AFDC	566,000	796,000	586,000
Land & Land Rights	2,500	2,500	2,500
AFDC	126,200	175,400	130,500
TOTAL INVESTMENT COST JUNE, 1976 PRICE LEVELS	694,700	973,900	719,000
\$ Installed/kW	333	466	344

All costs include allowance for installation.

Adjustment Factors: FPC Region I (1.025), III (0.895), IV (1.0).

COST SUMMARY
2000 MW COMPRESSED AIR STORAGE PLANT
VARIABLE PRESSURE SYSTEM - ROCK CAVERN

CANDIDATE SYSTEM, FPC REGIONS I AND IV

Amount in \$1,000

CIVIL ITEMS

1.	Shafts	6,354
2.	Underground Structures	150,320
3.	Site Improvements	1,716
		<u>158,390</u>
	Contingencies @ 20%	31,678
		<u>190,068</u>

ELECTRICAL/MECHANICAL ITEMS

4.	Generating Units	246,250
5.	Auxiliary Compressing Equipment	32,983
6.	Cooling Equipment	23,925
7.	Fuel Storage and Treatment Equipment	11,615
8.	Regenerator	5,191
9.	Air Manifold Piping	2,552
10.	Power Plant Building	4,377
11.	Process Air Plant	4,937
12.	Control Valves	392
13.	Transformers, Switchgear and Accessory Electrical Equipment	<u>17,972</u>
		<u>350,190</u>
	Contingencies @ 20%	70,038
		<u>420,228</u>
	Subtotal Electrical and Mechanical	420,228
	Subtotal Civil, Electrical and Mechanical	610,296
	Engineering, Supervision and Overhead @ 11% +	<u>66,704</u>
	SUBTOTAL, Prior to AFDC	677,000

EXHIBIT IV-7 (Cont'd)

	<u>Amount in \$1,000</u>
Land and Land Rights	2,500
AFDC	<u>222,900</u>
TOTAL INVESTMENT COST, JUNE, 1976	
PRICE LEVELS	902,400
\$ Installed/kW	451

All costs include allowance for installation.

Adjustment factors: FPC Regions I (1.025, III (0.895)
IV (1.0).

ARGONNE	
HYDRAULICALLY COMPENSATED CONSTANT PRESSURE SYSTEM	
HARZA ENGINEERING CO., CHICAGO	
APPROVED.....	
DATE	DWG.NO.

ARGONNE	
AQUIFER STORAGE	
CONSTANT PRESSURE SYSTEM	
HARZA ENGINEERING CO., CHICAGO	
APPROVED.....	
DATE	DWG.NO.

STATE REGULATORY COMMISSION PRACTICES AND INVESTMENT RANKING

State	Test Period	Rate Base		Interim Rates	Rate Decision Timetable (Months)	Orig. Cost ROE Allowed	Adjustment Clauses		Accounting Def. Tax.	H. & W. - H., N. Regulatory Climate Rankings
		Type	CWIP Incl.				Fuel	Purch. Power		
Alabama	H. A.	EPOC	Partial	Periodically	6	13-15	Yes	Yes	N	III
Arizona	H	EPFV	No	Yes	7-10	14.0-15.0	Yes	Yes	FT	III
Arkansas	H. A.	EPOC	Not Constant	Yes	9-12	13.5	Yes	Yes	N	IV
California	F. P.	AOC	No	Periodically	18-24	12.4	Yes	Yes	FT	IV
Colorado	H. A.	EPOC*	All	No	4-8	15	Yes	No	FT	II
Connecticut	H. A.	EPOC	Not Constant	Periodically	6	14.1-15.5	Yes	No	FT	IV
Delaware	H&P	EPOC*	All	Yes	7-10	14.0	Yes	No	N	II
Dis. of Col.	H	EPOC	Most	Periodically	8-12	13	Yes	No	FT	IV
Florida	H	EPOC	Partial	Yes	8	13.8-14.8	Yes	Yes	N	I
Georgia	F. P.	AOC	Not Constant	No	6	13.0	Yes	Yes	N	IV
Hawaii	F. P.	EPOC	No	No	12-15	13.0	Yes	No	N	III
Idaho	H&P	A&EPOC	No	Yes	6	13.8-14.5	No	No	N	III
Illinois	H&P	EPOC	Not Constant	Periodically	11	11.9-12.3	Yes	No	N	IV
Indiana	H. A.	EPFV	Partial	Periodically	10	15	Yes	Yes	N	I
Iowa	H. A.	AOC	No	Yes	12-24	12.2	Yes	Yes	N	IV
Kansas	H. A.	EPOC	No	No	8-17	13-14.9	Yes	No	N	IV
Kentucky	H. A.	EPOC	Not Constant	Yes	5-10	13	Yes	No	N	IV
Louisiana	H. A.	EPOC	Partial	No	2-12	14-15	Yes	Yes	N	IV
Maine	H&P	AOC	No	No	9	12.5	Yes	Yes	N	IV
Maryland	H&P	EPOC	Most	Yes	6-9	12.5-13	Yes	Yes	N	III
Mass.	H. A.	AOC	No	Periodically	10	12-13	Yes	Yes	N	IV
Michigan	H&P	AOC*	All	Periodically	9-15	12.0-12.8	Yes	Yes	N	V
Minnesota	H&P	AOC*	All	Yes	9-10	12.5-13.5	Yes	Yes	N	III
Mississippi	F. P.	AOC	No	Yes	5-6	12	Yes	Yes	N	V
Missouri	H&P	EPOC	Partial	No	11	12.9-14.0	Yes	Yes	N	III

State	Test Period	Rate Base		Interim Rates	Rate Decision Timetable (Months)	Orig. Cost ROE Allowed	Adjustment Clauses			Accounting Def. Tax.	H. & W. - H., N. Regulatory Climate Rankings
		Type	CWIP Incl.				Fuel	Purch.	Power		
Montana	F. P.	EPOC	No	No	14-16	12-13	No	No		N	IV
Nevada	H. A.	EPOC	No	No	6	13.8-14	No	No		FT	IV
New Hampshire	H. A.	AOC	No	Yes	10	14-14.5	Yes	Yes		FT	III
New Jersey	H. A.	EPOC	Not Constant	Periodically	12-14	13	Yes	Yes		N	III
New Mexico	H. A.	EPOC	Partial	No	-0-	13.5-14.5	Yes	Yes		N	II
New York	H&P.	AOC	Not Constant	Periodically	11	13-14	Yes	Yes		FT	III
N. Carolina	H. A.	EPFV	No	Yes	7-11	13.6-14	Yes	Yes		N	II
N. Dakota	H. A.	AOC	No	Yes	7	11-11.5	Yes	Yes		N	V
Ohio	H.	AFV	No	Emergency	22-30	15	Yes	Yes		FT	IV
Oklahoma	H. A.	EPOC	Partial	No	4- 8	13	Yes	No		N	II
Oregon	A&E	AOC	Not Constant	Yes	7- 8	13.5	No	No		FT	III
Pennsylvania	H. A.	EPFV	Partial	Periodically	23 plus	14.0-15.0	Yes	Yes		N	IV
Rhode Island	H&A.	AOC	No	No	10	12.5	Yes	Yes		N	V
South Carolina	H. A.	EPOC	All	Yes	10-13	12.5-13.5	Yes	No		N	III
South Dakota	H&P	AOC	No	Yes	12	11-12	Yes	Yes		N	V
Texas	New commission to begin on 9-1-76.				Historic information not yet available.		Yes	Yes		N	II
Utah	F. P.	P	Most	Yes	8	16	No	No		N	I
Vermont	H. A.	AOC	Partial	Yes	6	14.5-15	Yes	Yes		FT	III
Virginia	H. A.	EPOC	All	Periodically	6-14	13.5	Yes	Yes		N	III
Washington	H. A.	AOC	Most	Emergency	5- 7	13	No	No		FT	IV
W. Virginia	H. A.	AOC	Partial	Yes	24 plus	13	No	No		N	V
Wisconsin	F. P.	AOC	All	Yes	7- 9	12-13	Yes	Yes		N	II

N - Normalized
 FT - Flowed Through
 H. A. - Historical Adjusted
 H - Historical
 F. P. - Forward Projected
 H&P - Part Historical And Part Projected
 EPOC - End-Of-Period Original Cost
 EPFV - End-Of-Period Fair Value
 AOC - Average Original Cost
 AFV - Average Fair Value
 * Attrition Allowance Is Included

Source: Hornblower & Weeks - Hemphill, Noyes Incorporated, August, 1976

LOAD FACTORS BY RELIABILITY COUNCILS AREAS - 1976

Reliability Council	Annual Load Factor %	Month of April		Month of August		Month of December	
		Peak Demand % of Annual	Monthly Load Factor %	Peak Demand % of Annual	Monthly Load Factor %	Peak Demand % of Annual	Monthly Load Factor %
ECAR	66.0	83.3	74.8	100.0	68.1	95.0	73.6
ERCOT	56.2	70.8	68.9	100.0	72.2	67.2	74.9
MAAC	57.4	72.3	72.9	98.0	63.4	81.9	72.5
MAIN	56.1	67.7	73.5	100.0	60.6	78.0	72.2
MARCA	58.6	71.1	83.9	100.0	70.6	87.5	75.9
NPCC ^{1/}	70.3	88.1	74.4	93.7	68.8	100.0	70.4
SERC	62.6	78.2	71.2	100.0	69.8	93.4	67.6
SWPP	53.3	79.6	72.3	100.0	71.1	72.0	79.5
WSCC	67.2	84.0	75.1	100.0	70.6	98.1	70.4

Source: Regional Reliability Council reports filed with FPC, April 1976.

^{1/} Includes New England, New York, New Brunswick, Ontario.

ANNUAL PEAK DEMANDS BY RELIABILITY COUNCIL AREAS

Reliability Council	FPC Region	Area Approximate Percent of Total	Population ^{1/} 1985	Peak Demand ^{2/} - Summer, Million kW		
			Percent of Total	1980	1985	1995
NPCC	Part of I	3	14	41	52	80
MAAC	Part of I	2	10	39	50	78
ECAR	II	6	16	76	101	177
SERC	III	13	17	106	145	260
MAIN	Part of IV	5	9	42	57	102
MARCA	Parts of IV and VI	12	5	20	27	48
SWPP	Part of V	15	7	48	69	142
ERCOT	Part of V	7	5	34	46	82
WSCC	VII, VIII and Parts of V and IV	<u>37</u>	<u>17</u>	<u>85</u>	<u>110</u>	<u>181</u>
Total Continental U.S.		100	100	491	657	1150

1/ Based on the Bureau of the Census Series "E" projections of 1972.

2/ Excludes purchases and sales of capacity between Council regions.
Demand projected by the Regional Electric Reliability Councils.

GENERATION MIX BY RELIABILITY COUNCIL AREAS

Reliability Council	Generating Capacity million kW	Percentage of Total Generating Capacity						
		Nuclear	Coal	Oil Steam	Gas Turbine	Pumped Storage	Hydro	Undetermined
1975								
ECAR	74	2	7	5	5	4	1	0
ERCOR	33	0	4	91	4	0	1	0
MAAC	40	10	37 ^{1/}	28	20	3	2	0
MAIN	32	16	75 ^{1/}	-	7	1	1 ^{2/}	0
MARCA	20	19	48	3 ^{3/}	16	-	14 ^{2/}	0
NPCC	48	12	-	58 ^{3/}	14	5	11	0
SERC	104	11	68 ^{1/}	-	11	1	9	0
SWPP	41	7	-	80 ^{3/}	12	-	1 ^{2/}	0
WSCC	82	3	16	30	6	1	44	0
1985								
ECAR	119	15	77 ^{1/}	-	4	3	1	0
ERCOT	57	8	-	87 ^{3/}	3	0	1	1
MAAC	64	30	29 ^{1/}	25	12	2	2	0
MAIN	66	30	62 ^{1/}	-	7	-	1	0
MARCA	34	19	59 ^{1/}	-	10	3	9	0
NPCC	70	29	-	4 ^{3/}	10	5	8	0
SERC	171	30	54 ^{1/}	-	7	4	5	0
SWPP	78	-	-	-	-	-	-	-
WSCC	142	15	-	41 ^{3/}	7	3	32	2
1995								
ECAR	216	31	63 ^{1/}	-	2	4	-	0
ERCOT	98	25	-	65 ^{3/}	2	-	1 ^{2/}	7
MAAC	97	36	33 ^{1/}	18	9	3	1	0
MAIN	118	41	55 ^{1/}	-	4	-	-	0
MARCA	56	29	57 ^{1/}	-	6	3	5	0
NPCC	102	49	-	35 ^{3/}	4	-	12 ^{2/}	0
SERC	294	40	48 ^{1/}	-	4	-	8	0
SWPP	161	-	-	-	-	-	-	-
WSCC	228	31	-	41 ^{3/}	-	-	26 ^{2/}	2

Source: Regional Reliability Council reports filed with FPC under Order 383-3, April 1976.

1/ Includes some oil steam.

2/ Includes surface pumped storage.

3/ Includes some coal steam.

MARKET CAPTURE POTENTIAL IN ECAR

<u>Types of Generating Capacity</u>	<u>Nuclear</u>	<u>Coal</u> ^{1/} <u>Steam</u>	<u>Gas</u> <u>Turbines</u>	<u>UPHS-</u> <u>CAES</u>	<u>Hydro</u> ^{2/}	<u>Total Capacity</u>
<u>(As Planned by the Reliability Council)</u>						
Generation Mix in 1985						
Million kilowatt	17.8	91.6	4.8	0	4.8	119
Percentage	15	77	4	0	4	100
Generation Mix in 1995						
Million kilowatts	67.0	136.1	4.3	0	8.6	216
Percentage	31	63	2	0	4	100
Increment between 1985 & 1995						
Million kilowatts	49.2	44.5	-0.5	0	3.8	97
Percentage	51	46	-1	0	4	100
<u>(Adjusted for UPHS - CAES)</u>						
Generation Mix in 1995						
Million kilowatts	65.0	123.1	4.3	15.0	8.6	216
Percentage	30	57	2	7	4	100
Increment between 1985 & 1995						
Million kilowatts	47.2	31.5	-0.5	15.0	3.8	97
percentage	49	33	-1	15	4	100

1/ Includes some oil steam.

2/ Includes surface pumped storage.

MARKET CAPTURE POTENTIAL IN ERCOT

<u>Types of Generating Capacity</u>	<u>Nuclear</u>	<u>Oil^{1/} Steam</u>	<u>Gas Turbines</u>	<u>UPHS- CAES</u>	<u>Hydro^{2/}</u>	<u>Under- terminated</u>	<u>Total Capacity</u>
<u>(As Planned by the Reliability Council)</u>							
Generation Mix in 1985							
Million kilowatts	4.6	49.5	1.7	0	0.6	0.6	57
Percentage	8	87	3	0	1	1	100
Generation Mix in 1995							
Million kilowatts	24.5	63.7	1.9	0	1.0	6.9	98
Percentage	25	65	2	0	1	7	100
Increment between 1985 & 1995							
Million kilowatts	19.9	14.2	0.2	0	0.4	6.3	41
Percentage	49	35	-	0	1	15	100
<u>Adjusted for UPHS - CAES</u>							
Generation Mix in 1995							
Million kilowatts	24.5	63.7	1.9	0	1.0	6.9	98
Percentage	25	65	2	0	1	7	100
Increment between 1985 & 1995							
Million kilowatts	19.9 ^{1/}	14.2	0.2	0	0.4	6.3	41
Percentage	49	35	-	0	1	15	100
Generation Mix in 2005							
Million kilowatts	68.3 ^{1/}	64	2.9	0	1.0	10.8	147
Percentage	46	44	2	0	1	7	100
Increment between 1995 & 2005							
Million Kilowatt	43.8	0.3	1.0	0	0	3.9	49
Percentage	89.4	.6	2	0	0	8	100

^{1/} Includes some coal

^{2/} Includes surface pumped storage

MARKET CAPTURE POTENTIAL IN MAAC

<u>Types of Generating Capacity</u>	<u>Nuclear</u>	<u>Coal</u>	<u>Oil Steam</u>	<u>Gas Turbines</u>	<u>UPHS- CAES</u>	<u>Hydro^{1/}</u>	<u>Total Capacity</u>
<u>(As Planned by the Reliability Council)</u>							
Generation Mix in 1985							
Million kilowatt	19.2	18.6	16.0	7.6	0	2.6	64
Percentage	30	29	25	12	0	4	100
Generation Mix in 1995							
Million kilowatts	34.9	32.0	17.5	8.7	0	3.9	97
Percentage	36	33	18	9	0	4	100
Increment between 1985 & 1995							
Million kilowatts	15.7	13.4	1.5	1.1	0	1.3	33
Percentage	48	41	4	3	0	4	100
<u>(Adjusted for UPHS - CAES)</u>							
Generation Mix in 1995							
Million kilowatts	34.9	31.7	16.0	7.6	2.9	3.9	97
Percentage	36	33	16	8	3	4	100
Increment between 1985 & 1995							
Million kilowatts	15.7	13.1	0	0	4.2	0	33
percentage	47	40	0	0	13	0	100

1/ Includes surface pumped storage.

MARKET CAPTURE POTENTIAL IN MAIN

<u>Types of Generating Capacity</u>	<u>Nuclear</u>	<u>Coal^{1/} Steam</u>	<u>Gas Turbines</u>	<u>UPHS CAES</u>	<u>Hydro^{2/}</u>	<u>Total Capacity</u>
<u>(As Planned by the Reliability Council)</u>						
Generation Mix in 1985						
Million kilowatts	19.8	40.9	4.6	0	0.7	66
Percentage	30	62	7	0	1	100
Generation Mix in 1995						
Million Kilowatts	48.4	64.9	4.7	0	0	118
Percentage	41	55	4	0	0	100
Increment between 1985 & 1995						
Million kilowatts	28.6	24	0.1	0	-0.7	52
Percentage	55	46	-	0	-1	100
<u>(Adjusted for UPHS-CAES)</u>						
Generation Mix in 1995						
Million kilowatts	48.4	51.9	4.7	13.0	0	118
Percentage	41	44	4	11	0	100
Increment between 1985 & 1995						
Million kilowatts	28.6	11.0	0.1	13.0	-0.7	52
Percentage	55	21	-	25	-1	100

1/ Includes some oil steam.

2/ Includes surface pumped storage.

MARKET CAPTURE POTENTIAL IN MARCA

<u>Types of Generating Capacity</u>	<u>Nuclear</u>	<u>Coal^{1/} Steam</u>	<u>Gas Turbines</u>	<u>UPHS- CAES</u>	<u>Hydro^{2/}</u>	<u>Total Capacity</u>
<u>(As Planned by the Reliability Council)</u>						
Generation Mix in 1985						
Million kilowatts	6	21	3	0	4	34
Percentage	10	59	10	0	12	100
Generation Mix in 1995						
Million kilowatts	16	32	3	0	5	56
Percentage	29	57	6	0	8	100
Increment between 1985 & 1995						
Million kilowatts	10	11	0	0	1	22
Percentage	45	50	0	0	5	100
<u>(Adjusted For UPHS-CAES)</u>						
Generation Mix in 1995						
Million kilowatts	14	32	3	2	5	56
Percentage	26	57	5	3	9	100
Increment between 1985 & 1995						
Million kilowatts	8	11	0	2	1	22
Percentage	36	50	0	9	5	100
Generation Mix in 2005						
Million kilowatts	27	51	3	6	5	92
Percentage	29	57	3	6	5	100
Increment between 1995 & 2005						
Million kilowatts	13	19	0	4	0	36
Percentage	36	53	0	11	0	100

1/ Includes some oil steam.

2/ Includes surface pumped storage.

MARKET CAPTURE POTENTIAL IN NPCC

<u>Types of Generating Capacity</u>	<u>Nuclear</u>	<u>Oil^{1/} Steam</u>	<u>Gas Turbines</u>	<u>UPHS- CAES</u>	<u>Hydro^{2/}</u>	<u>Total Capacity</u>
<u>(As Planned by the Reliability Council)</u>						
Generation Mix in 1985						
Million kilowatts	21	33	7	0	9	70
Percentage	20	48	10	0	13	100
Generation Mix in 1995						
Million kilowatts	50	35	7	0	10	102
Percentage	49	34	7	0	10	100
Increment between 1985 & 1995						
Million kilowatts	29	2	0	0	1	32
Percentage	91	6	0	0	3	100
<u>(Adjusted for UPHS-CAES)</u>						
Generation on Mix in 1995						
Million kilowatts	50	35	7	0	10	102
Percentage	49	34	7	0	10	100
Increment between 1985 & 1995						
Million kilowatts	29	2	0	0	1	32
Percentage	91	6	0	0	3	100
Generation Mix in 2005						
Million kilowatts	75	49	7	6	11	148
Percentage	51	33	5	4	7	100
Increment between 1995 & 2005						
Million kilowatts	25	14	0	6	1	46
Percentage	55	30	0	13	2	100

1/ Includes some coal steam.

2/ Includes surface pumped storage.

MARKET CAPTURE POTENTIAL IN SERC

<u>Types of Generating Capacity</u>	<u>Nuclear</u>	<u>Coal^{1/} Steam</u>	<u>Gas Turbines</u>	<u>UPHS- CAES</u>	<u>Hydro^{2/}</u>	<u>Total Capacity</u>
<u>(As Planned by the Reliability Council)</u>						
Generation Mix in 1985						
Million kilowatt	51.3	92.3	12.0	0	15.4	171
Percentage	30	54	7	0	9	100
Generation Mix in 1995						
Million kilowatts	117.6	141.1	11.8	0	23.5	294
Percentage	40	48	4	0	8	100
Increment between 1985 & 1995						
Million kilowatts	66.3	48.8	-0.2	0	8.1	123
Percentage	54	40	-	0	6	100
<u>(Adjusted for UPHS - CAES)</u>						
Generation Mix in 1995						
Million kilowatts	117.6	138.2	11.8	2.9	23.5	294
Percentage	40	47	4	1	8	100
Increment between 1985 & 1995						
Million kilowatts	66.3	45.9	-0.2	2.9	8.1	123
Percentage	54	37	-	2	7	100

1/ Includes some oil steam.

2/ Includes surface pumped storage.

MARKET CAPTURE POTENTIAL IN WSCC

<u>Types of Generating Capacity</u>	<u>Nuclear</u>	<u>Oil^{1/} Steam</u>	<u>Gas Turbines</u>	<u>UPHS- CAES</u>	<u>Hydro^{2/}</u>	<u>Undetermined</u>	<u>Total Capacity</u>
	<u>(As Planned by the Reliability Council)</u>						
Generation Mix in 1985							
Million kilowatts	21	58	10	0	50	3	142
Percentage	15	41	7	0	35	2	100
Generation Mix in 1995							
Million kilowatts	71	93	-	0	59	5	228
Percentage	31	41	-	0	26	2	100
Increment between 1985 & 1995							
Million kilowatts	50	35	-10	0	9	2	86
Percentage	58	41	-12	0	11	2	100
	<u>(Adjusted for UPHs - CAES)</u>						
Generation Mix in 1995							
Million kilowatts	106 ^{1/}	58	-	0	59	5	228
Percentage	47	25	-	0	26	2	100
Increment between 1985 & 1995							
Million kilowatts	85	0	-10	0	9	2	86
Percentage	99	0	-12	0	11	2	100
Generation Mix in 2005							
Million kilowatts	235	58	-	6	67	-	366
Percentage	64	16	-	2	18	-	100
Increment between 1995 & 2005							
Million kilowatts	129	0	-	6	8	-5	138
Percentage	94	0	-	4	6	-4	100

1/ Includes same coal steam.

2/ Includes surface pumped storage.

LIST OF PUMPED STORAGE PROJECTS IN THE CONTINENTAL U.S.
IN OPERATION, UNDER CONSTRUCTION AND PROJECTED
AS OF JANUARY 1976

<u>Reliability Council</u>	<u>FPC Power Supply Region</u>	<u>Project Name</u>	<u>Owner</u>	<u>Total Capacity (MW)</u>	<u>Year in Operation</u>
NPCC	I	Rocky River	Connecticut Light & Power	28	1929
NPCC	I	Lewiston	Power Authority of the State of N.Y.	2,188	1961
NPCC	I	Northfield Mountain	Northeast Utilities	1,028	1972
NPCC	I	Blenheim-Gilboa	Power Authority of the State of N.Y.	1,400	1973
NPCC	I	Bear Swamp	New England Power Company	596	1974
NPCC	I	Cornwall	Consolidated Edison Co. of N.Y.	2,056	Pending
NPCC	I	Breakabeen	Power Authority of the State of N.Y.	1,000	Pending
NPCC	I	Prattsville	Power Authority of the State of N.Y.	1,000	1965
MAAC	I	Yards Creek	Jersey Central Power & Light Co., & Public Service Electric & Gas Co.	339	1965
MAAC	I	Muddy Run	Philadelphia Electric Company	824	1967
MAAC	I	Seneca	Cleveland Electric Illuminating Co. & Pennsylvania Electric Co.	422	1070
MAAC	I	Mount Hope	General Public Utility	1,000	Pending
ECAR	II	Ludington	Consumers Power Co. & Detroit Edison Co.	1,848	1973
ECAR	II	Davis	Allegheny Power Company	1,000	Pending

Sources: FPC News Release, January 1976

IEEE Committee Report, "Survey of Pumped Storage Projects in the United States and Canada to 1975". January 1976.

LIST OF PUMPED STORAGE PROJECTS IN THE CONTINENTAL U.S.
IN OPERATION, UNDER CONSTRUCTION AND PROJECTED
AS OF JANUARY 1976 (Cont'd)

<u>Reliability Council</u>	<u>FPC Power Supply Region</u>	<u>Project Name</u>	<u>Owner</u>	<u>Total Capacity (MW)</u>	<u>Year in Operation</u>
SERC	III	Hiwassee	Tennessee Valley Authority	62	1956
SERC	III	Smith Mountain	Appalachian Power Company	130	1965
SERC	III	" "	" " "	304	1965
SERC	III	" "	" " "	104	Pending
SERC	III	Jocassee	Duke Power Company	696	1973
SERC	III	Carters	U.S. Corps of Engineers	258	1975
SERC	III	Wallace	Georgia Power Company	334	1978-79
SERC	III	Fairfield	South Carolina Electric & Gas Co.	440	1976-77
SERC	III	Raccoon Mountain	Tennessee Valley Authority	1536	1977
SERC	III	Bad Creek	Duke Power Company	1000	Pending
SERC	III	Bath County	Virginia Electric and Power Co.	2100	1983
SERC	III	Blue Ridge	Appalachian Power Company	1600	Pending
SERC	III	Madison County	Carolina Power & Light Co.	1000	Pending
SERC	III	Rocky Mountain	Georgia Power Company	675	Pending
SERC	III	Randolph	Southside Electric Corporation	3575	Pending
SERC	III	Green River	EPIC, Inc.	500	Pending

Sources: FPC New Release, January 1976

IEEE Committee Report "Survey of Pumped Storage Projects in the United States and Canada to 1975". January 1976.

LIST OF PUMPED STORAGE PROJECTS IN THE CONTINENTAL U.S.
IN OPERATION, UNDER CONSTRUCTION AND PROJECTED
AS OF JANUARY 1976 (Cont'd)

<u>Reliability Council</u>	<u>FPC Power Supply Region</u>	<u>Project Name</u>	<u>Owner</u>	<u>Total Capacity (MW)</u>	<u>Year in Operation</u>
MAIN	IV	Taum Sauk	Union Electric Company	440	1963
SWPP	V	Salina	Grand River Dam Authority	134	1968
SWPP	V	De Gray	U.S. Corp of Engineer	33	1969
SWPP	V	Clarence Cannon	U.S. Corps of Engineers	32	1974
SWPP	V	Harry S. Truman	U.S. Corps of Engineers	160	1977
ERCOT	V	Village Bend	Brazos Electric Power Corporation	730	Pending
MARCA	VI	Boyd County	Nebraska Public Power District	1000	Pending
WSCC	VI	Flatiron	USBR	9	1954
WSCC	VI	Cabin Creek	Public Service Co. of Colorado	326	1967
WSCC	VI	Mt. Elbert	USBR	103	1975
WSCC	VI	Blair Mountain Dev.	The Colorado River Water Conservation District	525	Pending
WSCC	VII	Grand Coulee	USBR	85	1974
WSCC	VII	Antilon Lake	PUD #1, Chelan Co.	1000	Pending
WSCC	VII	Brown's Canyon	PUB #1, Douglas Co.	1000	Pending

Sources: FPC News Release, January 1976

IEEE Committee Report, "Survey of Pumped Storage Projects in the United States and Canada to 1975". January 1976.

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IN OPERATION, UNDER CONSTRUCTION AND PROJECTED
AS OF JANUARY 1976 (Cont'd)

<u>Reliability Council</u>	<u>FPC Power Supply Region</u>	<u>Project Name</u>	<u>Owner</u>	<u>Total Capacity (MW)</u>	<u>Year in Operation</u>
WSCC	VIII	Mormon Flat	Salt River Project Power District	10	1926
WSCC	VIII	"	"	42	1971
WSCC	VIII	Horse Mesa	"	30	1927
WSCC	VIII	"	"	87	1972
WSCC	VIII	San Luis	USBR	320	1968
WSCC	VIII	Neil Forebay	USBR	24	1968
WSCC	VIII	Edward Hyatt	State of California	269	1968
WSCC	VIII	"	"	351	1968
WSCC	VIII	Thermalito	State of California	77	1968
WSCC	VIII	Castaic	City of Los Angeles	1230	1977
WSCC	VIII	Helms	Pacific Gas & Electric Company	1050	1981
WSCC	VIII	Black Star	Southern California Edison Co.	1235	Pending
WSCC	VIII	Montezuma	Salt River Project Power District	500	Unavailable

Sources: FPC News Release, January 1976

IEEE Committee Report, "Survey of Pumped Storage Projects
in the United States and Canada to 1975". January 1976.

LIST OF CONVENTIONAL HYDROELECTRIC PROJECTS IN THE CONTINENTAL
U.S. PROJECTED AS OF JANUARY 1976

<u>Reliability Council</u>	<u>FPC Power Supply Region</u>	<u>Project Name</u>	<u>Applicant</u>	<u>Capacity (MW)</u>	<u>Remarks</u>
NPCC	I	Black River	Town of Springfield, Vt.	22.5	(3)
NPCC	I	Ashuelot River	City of Keene, N.H.	18	(3)
NPCC	I	Chace Mill	Green Mt. Power Corp. City of Burlington, Vt.	6	(3)
NPCC	I	Missiquoi (4)	Swanton Village, Vt.	80	(3)
NPCC	I	East Georgia	Central Vermont Public Service Corp.	10	(3)
ECAR	II	Cannelton	City of Vanceburg, Ky	70	(1)
ECAR	II	Greenup	City of Vanceburg, Ky	70	(1)
ECAR	II	Meldahl	City of Vanceburg, Ky	70	(1)
ECAR	II	Galipolis	Ohio Power Co.	40	(2)
SERC	III	Martin	Alabama Power Co.	60	
SERC	III	Bartlett's Ferry	Georgia Power Co.	100	(1)
MAIN	IV	Carlyle	Cities of Breese and Carlyle, Illinois	8	(2)

Notes:

- (1) Applications for license or amendment of license pending, January 1976
- (2) Outstanding preliminary permits, January 1976
- (3) Applications for preliminary permit pending, January 1976
- (4) Conventional hydro and pumped storage

Source: FPC New Release, January 1976

LIST OF CONVENTIONAL HYDROELECTRIC PROJECTS IN THE CONTINENTAL
U.S. PROJECTED AS OF JANUARY 1976
(Con'td)

<u>Reliability Council</u>	<u>FPC Power Supply Region</u>	<u>Project Name</u>	<u>Applicant</u>	<u>Capacity (MW)</u>	<u>Remarks</u>
WSCC	VI	Rodcliff	Colorado Water Conservation District	11.25	(1)
WSCC	VI	Juniper- Cross Mt.	Colorado Water Conservation District	78	(3)
WSCC	VI	Sheephorn	City of Golden & Vidler Tunnel Co., Colorado	62	(3)
WSCC	VII	Hells Canyon	Idaho Power Co.	225	(1)
WSCC	VII	Cowlitz River	City of Tacoma, Wash.	40.5	(1)
WSCC	VII	Kootenni River	Northern Lights, Inc., Montana	140	(1)
WSCC	VIII	Big Creek No. 3	Southern Calif. Edison Co.	35	(1)
WSCC	VIII	Northfork Stanislaris River	Calaveras Co. Water District, California	320	(1)
WSCC	VIII	Kings River	Kings River Irrigation District, Calif.	394.5	(2)
WSCC	VIII	Southfork American River	El Dorado County Water Agency, Calif.	300	(3)

Notes:

- (1) Applications for license or amendment of license pending, January 1976
- (2) Outstanding preliminary permits, January 1976
- (3) Applications for preliminary permit pending, January 1976
- (4) Conventional hydro and pumped storage

Source : FPC News Release, January 1976