Summary of Selected Compressed Air Energy Storage Studies

R.D. Allen
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January 1985

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FOREWORD

Electric utilities attempt to meet fluctuating demands for power at lowest cost and with least consumption of premium fuel. Baseload coal and nuclear plants supply about 40% of maximum load. Most of the remainder is supplied by less efficient cycling generators that burn natural gas, petroleum, or coal.

Compressed air energy storage (CAES) is a technique that reversibly converts electrical to mechanical energy. Air is compressed with excess baseload capacity during off-peak periods and is stored within an excavated geologic cavern, solution-mined cavity, or water-bearing porous rock formation. During peak-load periods, compressed air is released, mixed with fuel, burned, and expanded through turbines to generate power. Compressed air energy storage can reduce intermediate and peaking plant consumption of fluid hydrocarbons by more than 60% in comparison with conventional technology. Advanced conceptual plants could eliminate petroleum and natural gas consumption by storing the heat of compression to reheat the compressed air, or by using other reheat systems such as a pressurized fluidized coal-bed combustion chamber or a coal gasification system. Compressed air energy storage can provide flexibility, frequency control, rapid startup, and smaller environmental impact than conventional cycling plants and competing technologies.

For utilities with particular cyclical demand characteristics, CAES has the potential to lower generation costs and to decrease petroleum fuel consumption.

This report presents a descriptive summary of research and development in compressed air energy storage technology. It describes research funded primarily by the U.S. Department of Energy, although results of studies by other groups and experience at Huntorf, the only operational CAES facility in the world, are included. The report was originally prepared as a chapter in a book on energy storage being prepared under the auspices of Oak Ridge National Laboratory.

Landis D. Kannberg, Manager
Underground Energy Storage Program

SUMMARY

Conventional compressed air energy storage (CAES) is a practicable technology for electric load leveling as shown by its implementation and continued use at the Huntorf plant (290 MW, 50 Hz) in the Federal Republic of Germany. Here the feasibility of air storage in dissolved salt cavities is also demonstrated. Other geologic containments may consist of 1) dome-shaped, permeable, water-saturated formations (aquifers) overlain by impervious strata and 2) artificial caverns excavated from hard rock and compensated with surface water to maintain constant air pressure. The basis for storage of air in aquifers exists in the natural occurrence of hydrocarbon gas in original geologic traps; the utilization of other natural reservoirs to store such gas; and the field proof of principle within an aquifer formation at Pittsfield, Illinois. Research, development, and detailed design studies have identified no technological barriers to implementation of compensated hard rock cavern CAES, and some related precedent experience does exist. Both American and European manufacturers are willing and able to provide suitable and proven turbomachinery systems. The efficiency of conventional CAES can be significantly improved by using recuperative heat exchangers to transfer combustion energy to inflowing compressed air.

Advanced CAES methods eliminate or lessen the required amounts of liquid or gaseous fuels consumed in the generation side of the cycle. Fluid fuel consumption would be eliminated in CAES systems with adiabatic storage, pressurized fluidized bed combustion, coal gasification, and direct coupled steam. The so-called hybrid CAES method involves partial storage of the heat of compression but still requires combustion of some petroleum or natural gas.

The U.S. Department of Energy research and development technology base for conventional compressed air energy storage is essentially complete. This versatile storage method is geologically feasible in the majority of

electricity generating service areas. Implementation of this promising and flexible technology depends upon perceived future markets for electrical power, feasibility of new construction, and the institutional/legal/regulatory climate. The predicted intermediate and long-term increase in the cost of petroleum favors utilization of compressed air energy storage, especially within regions that are experiencing growth in electricity demand. Research and development of second-generation CAES concepts will await the successful implementation of conventional CAES plants.

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SUMMARY OF SELECTED COMPRESSED AIR ENERGY STORAGE STUDIES

1.0 INTRODUCTION

American electric utilities are confronted with the problem of meeting fluctuating demands at the lowest possible cost (Hobson 1978). A representative weekly demand curve is shown in Figure 1.1a. Combinations of generating plants with different economic and operating characteristics meet this load. Approximately 40% of a typical utility's load is supplied by large and costly coal and nuclear units operating at high efficiencies on the least expensive fuels. These baseload units operate continuously most of the year. The broad, intermediate daily peak in demand, 30 to 40% of the load, is met by less efficient, intermittently operating fossil fuel plants and combined cycle plants. The peak demands, 10 to 20% of the load, are met by oil-fired steam plants, hydroelectric power, gas- or oil-fired turbines, diesel engines, and pumped hydro. The intermediate and peaking units consume nearly 2 million barrels of oil per day in the United States. By using energy storage, it would be possible to store part of the output of baseload plants during periods of low demand for use during periods of high demand as shown in Figure 1.1b. This would reduce the need for gas- and oil-fired turbines and could result in savings of more than 1 million barrels of oil per day. Other advantages of energy storage include use of higher capacity factors for baseload plants; reduction of reserve capacity currently needed for peak demand and spinning reserve; and elimination of older, inefficient peaking units (Kannberg and Loscutoff 1981).

Continued use of natural gas and petroleum fuels for electric power generation is affected by intermittently rising prices and threatened shortages. These pressures are expected to grow more severe in future years as world demand increases. Solutions to this energy problem involve establishing alternative sources of primary energy and developing ways to utilize existing fossil fuel more efficiently. Energy storage can be a major factor in both endeavors.

a. Typical State-Wide Electrical Load Curve (Hobson 1978)

b. Load Curve with Effective Energy Storage

FIGURE 1.1. Comparison of Load Curves With and Without Energy Storage

Currently, the only established method of energy storage for utilities is pumped hydroelectric storage. However less than 2% of all U.S. electric energy is generated from this source. Shortage of suitable topographic sites and environmental objections limit the potential expansion of this technology.

1.1 PRESENT TECHNOLOGY

Compressed air energy storage (CAES) transfers electrical energy from off-peak to peak demand time. It uses modified state-of-the-art gas turbines and underground reservoirs--confined aquifers, solution-mined salt cavities, or excavated hard rock caverns. Currently, the only full-scale operating system uses salt cavities for air storage reservoirs (Quast and Lorenzen 1979). A schematic flow diagram for a conventional CAES cycle is shown in Figure 1.2 (Kannberg and Allen 1984). During charging, grid power is used to drive a compressor train, and air is compressed to a maximum of about 80 atm for storage in the compressed air reservoir. The heat of compression is rejected to the atmosphere through intercoolers and an aftercooler. During discharge, the motor/generator is uncoupled from the compressor train and coupled to the turbine train. Compressed air is withdrawn from the reservoir, heated in the recuperator by heat transferred from the low-pressure turbine exhaust, then successively heated and expanded in two stages as illustrated in Figure 1.2. One available turbomachinery set consists of a high-pressure turbine based on steam turbine technology that has an inlet air temperature of about 550°C (1022°F). The low-pressure turbine is based on gas turbine technology and has an inlet air temperature of around 890°C (1634°F). Exhaust gas from the discharge on the low-pressure turbine is used to preheat air from the reservoir before it enters the high-pressure turbine.

The CAES concept has been technically proven and, for utilities with the proper power generation mix, it is economically feasible. A 290-MW CAES plant is currently operational in Huntorf, West Germany, providing peaking power service for the utility Nordwestdeutsche Kraftwerke A.G. (Herbst and Stys 1980). The plant was commissioned in 1978; in operations since then, performance has equaled or exceeded design specifications.

FIGURE 1.2. Conventional Compressed Air Energy Storage Cycle Flow Diagram

This operational experience indicates CAES plants offer several other advantages over conventional systems for meeting peak- and intermediate-load requirements: energy storage offers flexibility and control in system operation (e.g., frequency stabilization); some CAES systems can qualify as a spinning reserve; and it can be started rapidly, thus being available as supplemental generation in times of emergency. In addition, CAES plants are not severely limited by the siting difficulties faced by conventional pumped hydroelectric plants. Further, a CAES plant should have a smaller impact on the environment than a conventional peaking or intermediate plant (Kannberg and Loscutoff 1981).

1.2 ADVANCED CONCEPTUAL PLANTS

Second-generation CAES plant concepts are being developed that require little or no petroleum or natural gas fuel to reheat the compressed air (Glendenning 1979). In the adiabatic type plant, the heat of compression would be stored and returned to the compressed air before its passage

through the turbine. In the coal-fired type, the required heat would be supplied from either fluidized bed combustion or combustion of synthetic gas derived from coal (Kannberg and Loscutoff 1981).

The adiabatic concept is based on the passage of compressed air through a surface or subterranean thermal energy storage reservoir containing refractory pebbles with high heat storage capacity and resistance to the mechanical degradation and oxidation caused by thermal cycling. This cooled compressed air would be stored conventionally within a deeper geologic cavern or permeable formation. During the energy production phase of the cycle, the compressed air would be reheated by reverse flow through the thermal energy storage reservoir and then expanded through turbines to generate power.

The reheat systems using coal and alternative fuels would provide direct replacement for the petroleum firing systems of the conventional plant.

1.3 RESERVOIR CHARACTERISTICS

The unique aspect of the CAES concept is the use of subsurface geology as an economical large-scale pressurized air storage element (Doherty 1981). For a nominal design, air at pressures between 2 MPa (20 atm) and 8 MPa (78.9 atm) is to be stored in the underground reservoirs and cycled daily. Reservoir depth is to be 750 to 850 m (2460 to 2788 ft). The reservoirs may be operated in either an uncompensated (constant volume) or compensated (constant pressure) mode in which compensation is accomplished with a water column. Three broad classes of rock have been identified as candidate reservoir hosts: hard rock, confined aquifers, and massive salt. Candidate hard rocks include granite, granodiorite, diorite, gabbro, peridotite, massive basalt, welded tuff, quartzite, massive gneiss, and dolomite. Confined aquifers would usually consist of relatively pure quartz sandstone overlain by impervious shale or dolomite with the strata in a dome-shaped configuration to prevent air escape. Massive salt may occur as a diapiric dome or bedded deposit.

The type of host rock is an important factor in the choice of mode for CAES operation (Weinstein et al. 1978). Excavation costs nearly exclude operation of an uncompensated storage system in hard rock. Operation of a compensated system requires relatively low storage temperatures [less than $\sim 100^{\circ}\text{C}$ (212°F)] to avoid boiling and to prevent condensation of large vapor plumes when warm water reaches the surface. Storage in salt would typically be uncompensated, as excavation costs are low and brine compensation has significant design and environmental issues. The peaking power plant at Huntorf in West Germany uses two uncompensated salt cavities that were mined by dissolution (Quast and Lorenzen 1979). Compressed air energy storage in salt is generally limited to temperatures of less than 80°C , because creep closure of the cavern is greatly accelerated at higher temperatures (Allen, Doherty and Fossum 1982a).

Compressed air energy storage in a confined aquifer is illustrated in Figure 1.3 (Allen, Kannberg and Doherty 1981). Aquifer storage is nearly uncompensated for short cycle times, but the longer-term air bubble pressure will approach equilibrium with the discovery pressure, the existing hydrostatic head in the formation. No major structural problems have been identified with storage of air in porous media at less than 150°C . Numerical, experimental, and field evaluations suggest that storage of the heat of compression within the rock formation would be feasible for temperatures to 200°C , but an upper temperature limit for stable reservoir operation is currently undetermined. Thermochemical and geochemical effects could restrict air storage temperatures to levels that would not allow high quality energy recovery. Storage of natural gas and oil in natural underground reservoirs has been practiced for nearly 50 years. This practice has involved seasonal cycling of gas and oil with mass flow rates and temperatures that are low relative to potential CAES reservoir operation parameters. Although CAES reservoirs will be subjected to daily cycling of air with attendant temperature, pressure, and humidity fluctuations and an oxidizing environment, the natural gas experience provides solid precedence for aquifer air storage.

FIGURE 1.3. Aquifer Air Storage System in Cross Section

1.4 SITING

The siting constraints on compressed air storage are determined by the availability of suitable formations located at the proper proximity to load centers, generation facilities, and transmission corridors and located in areas that are environmentally compatible (General Electric 1976). The distribution of igneous and metamorphic rocks in the United States is shown in Figure 1.4. These types of bedrock underlie or are proximate to the following metropolitan areas: 1) Boston, Springfield-Hartford-New Haven, New York, Newark, Philadelphia, Baltimore, Washington D.C., Richmond, Charlotte, Atlanta and Birmingham; 2) Minneapolis-St. Paul, Madison; 3)

FIGURE 1.4. Distribution of Igneous and Metamorphic Rock in the United States (Aamodt et al. 1975)

Seattle, Spokane; 4) San Francisco, Sacramento, San Jose, Los Angeles, San Diego; and 5) Denver, Phoenix, and Albuquerque.

Major deposits of domes and bedded rock salt in the United States are shown in Figure 1.5. Salt domes of the Gulf Coast are of primary interest because they are readily mineable by solution. The metropolitan areas of Houston, Dallas-Fort Worth, San Antonio, New Orleans, and Mobile are within electricity generating service areas that could implement CAES within salt cavities. Bedded salt within Michigan, Ohio, Pennsylvania, and New York is a less likely candidate lithology because of greater depths to salt and unproven ability to leach out stable cavities from the bedded salt.

Areas with potential for CAES in porous rock formations are illustrated in Figure 1.6. The coincidence of Paleozoic confined aquifers and the industrialized regions of the Midwest offers the most probable siting opportunity. Major cities within this region include Omaha, Des Moines, Kansas City (Missouri), St. Louis, Chicago, Indianapolis, Detroit, Louisville, Cleveland, Columbus, and Pittsburgh.

1.5 MARKET POTENTIAL

An assessment of the potential market for CAES systems in the United states was conducted by Boyd, Buckley and Clark (1982). That assessment was based on projections of CAES installations in areas of the country where early CAES sales are most likely to occur from the late 1980s to 2000. These projections were made using the DFI Utility Storage Commercialization Model developed in a series of studies for the Electric Power Research Institute (EPRI). The commercialization model was used to project commercial installations of not only CAES but all competitive storage technologies: conventional pumped hydro, underground pumped hydro, and batteries. In addition, customer-owned technologies were treated through sensitivity analyses.

The sales of CAES and its competitors depend on several specific factors that vary for different utilities and regions of the country. Some of the more important factors are the existing and projected mix of

FIGURE 1.5. Major Salt Deposits and Mines in the United States (Aamodt et al. 1975)

FIGURE 1.6 Areas Generally Favorable for CAES in Aquifers (Stottlemire and oscutoff 1979)

generating capacity and projected peak demand, how this demand varies across the day and the seasons, any geological or legal restrictions on CAES and alternative technologies, and the financial status of utilities. Based on these factors, the U.S. was divided into 14 market segments to determine the potential for early CAES sales. The Utility Storage Commercialization Model was used to calculate the potential installations for each market segment on a year-by-year basis, taking account of the factors described and their impact on utility expansion and operating decisions.

Currently, the environment in which utilities operate makes them reluctant to add capacity of any type. Projections of CAES installations assume an improvement in overall utility business conditions over the next few years, and define a base case data set. This data set was developed by synthesizing information on utility system growth projections obtained through utility interviews and system planning studies; current technology cost and performance assessments from technology experts; and pertinent economic, financial, and geological information.

The general conclusion is that, under a wide range of assumptions, there appears to be a solid role for the CAES technology if changes in the environment of electric utility decision-making allow utilities to return to capacity planning.

2.0 HISTORICAL PERSPECTIVE

Compressed air storage on a small scale in rock caverns has been used by the mining industry for many decades to supply power for pneumatic equipment (General Electric 1976).

2.1 EARLY PATENTS AND DEVELOPMENT

Patents applying to storage of compressed air in general date back to around 1900. The first references to compressed air storage for utility application are contained in patents issued to Gay in the United States (1948), the turbine manufacturer Stal Laval in Sweden and Great Britain (1952), and to Djordjevic in Yugoslavia (1950) (General Electric 1976). During the 1950s and 1960s, CAES was studied widely (Kannberg and Loscutoff 1981). In 1973 Nordwestdeutsche Kraftwerke AG (NWK) of Hamburg, Federal Republic of Germany, decided to construct a 290-MW CAES plant using solution-mined salt caverns in the Huntorf salt dome in northwest Germany. Successful previous storage of natural gas elsewhere in the same dome provided a strong rationale. Construction of the plant began in 1974, and the plant was commissioned in December 1978 (Herbst, Hoffeins and Stys 1979). Since startup, the plant, which is designed for daily charge/discharge periods of 8 hr and 2 hr, respectively, has equaled or exceeded operational specifications (Maass and Stys 1980). Availability and starting reliabilities of 90% have been achieved for sustained periods. The Huntorf plant is dispatched and controlled remotely. Operating experience is discussed in Section 2.4.

2.2 OIL PRICE RISE AND EMPHASIS ON CONSERVATION

Compressed air energy storage technology received a significant economic stimulus in 1973, when the Organization of Petroleum Exporting Countries increased their per barrel cost of oil by more than three times the 1970 price. The CAES concept greatly improves the effectiveness of a gas turbine using petroleum fuels and could reduce petroleum fuel consumption of electric utility peaking plants by more than 100 million barrels of oil per

year (in 2000 AD) based on aggressive market penetration and implementation of the technology (Kannberg 1981). Computations based on the marketing study by Boyd, Buckley and Clark (1982) indicate a fuel consumption reduction of 15 to 60 million barrels of oil per year (in 200 AD).

2.3 SIMILARITY TO NATURAL GAS STORAGE

In the natural gas industry the advent of transcontinental gas pipelines was accompanied by the development of underground storage of natural gas. Local reservoirs were needed to supply heavy winter loads and to maintain steady year-round influx of gas through the pipelines (Katz and Lady 1976). All three preferred geologic storage modes (i.e., salt cavity, aquifer structural trap, and hard rock cavern) have been used to store either natural gas or liquified propane or butane. A body of experience and literature stretching back decades documents the implementation of this technology in the petroleum industry. In the midwest area, aquifer storage is the most practical.

The electrical utility industry has a daily load fluctuation comparable to the annual load fluctuation for natural gas. The principal differences between natural gas and air storage are 1) the air storage cycle is daily or weekly, instead of seasonal; 2) air may be injected deliberately at elevated temperature to gain thermodynamic advantage on use; 3) air may contain a higher percentage of water vapor; 4) air is almost twice as viscous as methane; and 5) air is an oxidizing medium (Allen and Gutknecht 1980). The difference in cycle time may impact the aquifer reservoir, especially near the wellbore.

2.4 GENERAL ELECTRIC STUDY

The General Electric Company completed a comprehensive economic and technical feasibility study of CAES in March 1976 (General Electric Co. 1976). The study, which concentrated primarily on the application of underground air storage with combustion turbines, consisted of two phases. In the first phase a general assessment of the technical alternatives,

economic characteristics and the institutional constraints associated with underground storage of compressed air for utility peaking application was carried out. The goal of this assessment was to identify potential barrier problems and to define the incentive for the implementation of compressed air storage. In the second phase, the general conclusions of the assessment were tested by carrying out the conceptual design of a CAES plant at two specific sites, and a program of further work indicated by the assessment study was formulated. The salient points, summarized below, are valid in 1983 and have been confirmed through many subsequent studies.

2.4.1 Technical Feasibility

The major component subsystems considered were the compressor train, including inter- and aftercoolers and water separators; the underground storage; the expander train, which consists of regenerator(s), combustor(s) and expander turbine(s); the motor-generator and couplings; the switchyard and transformer facility; the electrical, mechanical and air flow control subsystems; and auxiliary support systems, such as the fuel supply. Analysis of the turbomachinery alternatives was based on the evolutionary development of gas turbine technology from a base system representing the state of the art in 1975. The heat rate for this base system, 5541 kJ/kWh (5252 Btu/kWh), is less than one-half that for state-of-the-art simple cycle gas turbines [i.e., 11,922 kJ/kWh (11,300 Btu/kWh)]. Oil or natural gas used by this base-system CAES plant was to generate the same quantity of electrical energy. Modifications of the basic system incorporating either a high pressure combustor or a high pressure recuperator and expander were considered as the most likely alternative to improve performance. A second-generation unfired turbine system that stores the heat of compression was also considered.

A number of ways for providing the storage space were considered: natural caverns, mines, conventionally mined caverns, solution-mined caverns, aquifers and depleted oil and gas fields. The technical characteristics of each were considered in relation to the requirements of compressed air storage. The general conclusion was that only conventionally mined

caverns, solution-mined caverns, or aquifers offer the potential for widespread implementation of compressed air storage.

2.4.2 Economic Feasibility

To provide a basis for economic assessment, costs for complete turbomachinery systems were estimated for the base system and for a second-generation system with a high pressure recuperator and expander. Total costs (in 1975 dollars), including balance of plant, ranged from 110.8 to 179.8 \$/kW depending on the maximum pressure and the nature of the expansion train.

The costs of the turbomachinery and of the balance of plant components can be based on experience with standard manufactured equipment. However, the range of uncertainty in the costs of the underground storage needed in a CAES system is much greater because the cavern design or aquifer development plan must be based on the conditions prevailing at the specific plant site. The costs of construction at that site were recognized as affected not only by the geological characteristics of the host formation, but by such regional variables as labor costs, land values and the cost of disposal of waste rock or brine. In carrying out the economic assessment, a set of assumptions was drawn from experience in the construction of conventional and solution-mined caverns for hydrocarbon or gas storage, and from experience of natural gas storage in aquifers. Employing these assumptions, generalized conceptual designs and site development plans were prepared from which storage costs were derived. Typically, storage costs ranged from \$4.30/kWh to \$38.20/kWh in 1975 dollars. The lowest cost of storage was associated with solution-mined caverns, but the lowest cost aquifer storage was not significantly more costly than the lowest-cost solution-mined cavern storage.

From the cost estimates for turbomachinery, the balance of the plant, and storage, investment costs for a number of CAES alternatives were calculated. When these were combined with fuel, compression energy, and variable operating and maintenance cost, a total cost for generation was

obtained. Two comparison years were chosen: 1975 and 1981. In the 1975 comparison for the low-pressure CAES plants employing storage in solution caverns or aquifers, a compression energy cost of \$4/MWhr in 1975 dollars would favor the CAES alternatives over the simple cycle turbine alternative. In the 1981 comparison year, CAES alternatives were favored over the simple cycle turbine plant even at relatively high compression energy costs and turbine fuel costs. The relative economic attractiveness of CAES is enhanced relative to simple cycle turbines by a continuing increase in the price of turbine fuel.

2.4.3 Institutional Constraints

The General Electric study came to the conclusion that institutional problems generally do not limit the implementation of CAES. However, the requirement to dispose of waste from underground construction operations or the potential for contamination of ground or surface water during operation of a CAES plant may provide constraints at specific sites. This may be particularly true for the preparation of solution-mined caverns and air storage beneath shallow aquifers containing potable water. Local as well as state and federal regulations must be reviewed with regard to permitted uses for aquifers either as storage or as brine disposal sites.

2.4.4 Potential for Utilities Application

Geography, geologic suitability of sites, and proximity of transmission corridors were deemed the critical issues affecting probable siting. For storage of compressed air in salt, it is possible to estimate the availability of sites by comparing the locations of salt domes and bedded salt deposits with the locations of transmission corridors. Using 1971 figures for peak generation, it was estimated that 52,000 MW are provided by utilities situated in locations where they could employ CAES using salt cavity reservoirs. These utilities represented 17.6% of the peak generation in the United States in 1971. The East Central Area Reliability Coordination Agreement Area (ECAR) is the largest single group of utilities in terms of

generation capacity that potentially might employ storage in salt. Extensive application of CAES in solution-mined caverns by utilities belonging to the Electric Reliability Council of Texas and the Southwest Power Pool has a significant potential. It is more difficult to estimate the potential for storage in aquifers because sites for compressed air storage in aquifers have not been identified with the precision possible for salt storage. Based on regional geology, it can be estimated that utilities serving 148,000 MW, or about 50% of the United States peak demand in 1971, are in areas potentially suitable for aquifer storage. The economics of storage in mined caverns appeared generally unattractive in comparison with other options in the General Electric study.

Other factors must be considered in estimating the extent to which utilities may employ CAES. For example, the characteristics of the technology--in particular, system reliability and component availability, the environmental constraints applicable to a particular utility, the utility load characteristics, peak demand growth rate, and the availability of low-cost off-peak energy--will influence the utility's decision. A particular constraint, very difficult to quantify at this time, is the availability to the utility of a secure supply of oil to meet peak power demands. Availability of capital provides an additional constraint. Because of this complex of factors, this study recognized a considerable uncertainty in any estimate of the potential for implementation of CAES.

2.5 OPERATING EXPERIENCE AT HUNTORF

The potential for storage of compressed air in salt was brought to fruition by Nordwestdeutsche Kraftwerke AG (NWK), the utility that supplies the most northerly part of the Federal Republic of Germany. Maximum utilization of the Huntorf plant occurs in winter when great differences in demand exist between day and night. Some 5000 MW of installed capacity can be divided into:

- nuclear 26%
- coal plants 62%

- gas turbines 6%
- Huntorf ASSET plant 6%.

To improve the daily load curve, NKK decided in 1973 to build a CAES facility (ASSET) using caverns constructed in one of some 200 available salt domes on the North Coast as an air storage facility (Herbst and Stys 1980).

The important dates were:

- 1969 - feasibility study performed
- 1973 - order placed
- 1974 - construction started
- 1977 - construction finished.

The charging to discharging time ratio for Huntorf is 1:4. The equipment can generate 290 MW during 4 hr and uses 60 MW of power in the compressing mode during 16 hr.

The Huntorf plant covers predictable daily peaks, provides power during sudden outages, and lessens the operating times of baseload units.

2.5.1 compression Mode

The compressor train and the generator/motor are brought to synchronous speed with only the high-pressure combustion chamber. After synchronization, the driving gas turbine is declutched, and the compressor train starts the compression cycle. This start takes only 6 min.

2.5.2 Generating Mode

Also with only the high-pressure combustion chamber, the generator is brought up to speed and synchronized. At about 15 MW of load, the low-pressure combustion chamber is fired. The compressor train is uncoupled during generation.

The CAES unit can be used to provide

- a load level of 100 MW with load following
- load levels of 100 MW, 200 MW, 300 MW (300 MW in 11 min.)
- emergency startup to 290 MW in 6 min.

2.5.3 Emergency and Secondary Operation Provision

Power generation during the compression mode can be achieved by starting the gas turbine and in-clutching it to the synchronized generator. Because the compressor train cannot be declutched at this point, compressor blow-off valves are opened. In such a manner, 260 MW can still be generated. Secondary advantages of the Huntorf plant that are available include:

- Synchronous condenser operation - The generator/motor can be brought up to speed and synchronized with only the high-pressure combustion chamber. The gas turbine is then declutched. The compressor train is not involved during this operation.
- Frequency support - If the grid frequency falls by 0.4 Hz, the unit starts automatically in the emergency-start mode. Should this happen during the compression cycle, the unit will behave as described under Section 2.5.2.
- Black start - In case of nonavailability of power from the outside for startup, the emergency diesel set is automatically started.

All the above operation modes, with the exception of frequency support, can be accomplished by remote control by a dispatcher.

2.5.4 Huntorf Operational Record (Herbst and Stys 1980)

Originally design for: 2 hr generating daily
8 hr charging daily

Actual operation:

	To 12/7/78	To 12/31/79
Starts for compressor operation	132	474
Starts for generation	277	772
Fast starts for generation	24	35
Total number of starts	531	1518
Running hours compressor set	546	1930
Charging hours	510	1874
Running hours electricity generation	247	840
Produced MWh	20527	86495

Overhauled: 5/19/79 to 8/2/79 and found in excellent condition; no sign of any corrosion or erosion

Back in operation: 8/3/79

2.5.5 Availability and Reliability

As an example of availability and reliability of Huntorf, the following data can be quoted:

Operation during April 1979:

Starts for pumping	33
Starts for generation	44
Operating hours in pumping mode	129
Operating hours in generation mode	54
Availability during April 1979	97.78%
Availability during March 1979	97.98%
Start availability during March and April 1979	98%
Start reliability during March and April 1979	99.5%

Note that availability also includes the automatic remote control system.

2.5.6 Economic Aspects

The total cost of the plant was about 125 million DM (approximately 70 million U.S. dollars), which corresponds to about 430 DM/kW or 230 U.S. \$/kW (Herbst and Stys 1980). The cost of the two caverns is included in this price.

The energy composition for the electrical power produced by the CAES plant is approximately 83% compression and 17% combustion (Herbst and Stys 1980).

In spite of early startup and debugging problems, the Huntorf plant has operated to ~~NW~~ satisfaction. The high availability and reliability, as well as the flexibility of the whole installation and its rapid load following capability, have also resulted in economic benefit to the utility.

2.6 FEASIBILITY IN CALIFORNIA

The California Energy Commission and the U.S. Department of Energy cosponsored a CAES feasibility study (Hobson 1978). The study was performed by Acres American, Inc. , Buffalo, New York; Woodward-Clyde Consultants of Orange, California; and United Technologies Research Center of East Hartford, Connecticut. The purpose was to evaluate the technology, economics, and siting of CAES plants in California.

With a given set of operating characteristics of a CAES plant, technical and geologic criteria were established for identifying feasible sites. Desired operating pressure levels for a compressed air system imposed minimum and maximum depths for the storage formation or caverns. Permeable formations with sufficient volume to provide air storage for the CAES units in the 250-MW size range were designated. These formations were required to have a minimum permeability of 400 millidarcies to enable adequate air flow. The survey included a screening of all oil and gas fields in California and investigation of potential hard rock sites. Candidate hard rock sites are distributed throughout the state. However, no existing caverns met the established criteria.

Sites were ranked qualitatively for geologic and environmental suitability. Factors included rock type, stratigraphy, structural geology, hydrology, air quality, land use, population density, and areas of biotic significance. Elimination criteria included proximate active faults or location in exclusion areas, such as parks or national forests. Gas and oil fields expected to be active producers during the 1980s were not considered.

Final lists of preferred sites were ranked quantitatively by calculating index values representing the incremental plant costs in dollars per kilowatt above the cost of a plant sited in "ideal" conditions.

The quantitative factors were geologic and locational. The geologic factors considered the effect of the specific site characteristics on capital cost (e.g. , rock quality for a granite and permeability for a

sandstone). Depth, formation thickness, and lateral extent were also important. The locational factors considered site-specific capital cost factors: electrical transmission proximity, road access, fuel pipeline proximity, and land acquisition costs.

Eleven candidate hard rock sites were identified in ten counties. Twelve candidate porous media sites were identified in seven counties. The confirmation of these sites would of course require more site-specific drilling, analysis, and testing.

Conceptual designs were developed for porous media storage in the Glenn County Princeton gas field and for water-compensated hard rock cavern storage in Mariposa County at Shultz Mountain. The energy recovery factors were 82 and 84%, respectively. Fuel consumption was about 4642 kJ (4400 Btu)/kWh for each plant. Capital cost for 20 hr of storage for both hard rock and porous media was around \$400/kW.

The Princeton site is underlain by a sand formation and caprock with sufficient closure to contain 7.85×10^8 scm (2.77×10^{10} scf) of compressed air. The formation is located between 671 and 732 m (2200 and 2400 ft) below the surface, which corresponds to a hydraulic pressure of approximately 6.9 MPa (1000 psia). The plant design comprising three CAES units was selected, with a unit generation between 200 and 250 MW, and a total plant capacity between 600 and 750 MW. This was considered a conservative size based upon the available void volume, which allowed for a "cushion" of approximately 900% of the cycled air volume to reduce pressure variation as air is discharged from the formation. The plant selected for this site required 2×10^7 scm (7.1×10^8 scf) of compressed air at approximately 6.9 MPa (1000 psia) storage pressure per CAES unit for 20 hr of continuous operation. A low concentration of methane in the aquifer reservoir was found to be neither a potential combustion hazard nor a prohibitive emission.

The conceptual CAES plant design for the Shultz Mountain site was based on three 250-MW units and 20 hr of storage in an excavated underground

cavern, located at a depth of 701 m (2300 ft). The problems of seasonal availability and potential shortage of water for the compensating column were addressed by doubling the required volume of the surface reservoir. The cost of underground caverns in hard rock is strongly influenced by ease of construction. A large tunnel allows the bulk of the rock to be removed by "benching" down from the upper levels. Rock is blasted and removed rapidly in relatively large sizes with minimum expenditure of energy and least cost per volume of excavation. Principles of ownership of underground rights are not clearly established; current legal interpretations suggest that surface rights must be obtained above underground holdings of commercial value. Consequently, the cavern layout was kept as compact as possible in the conceptual design to minimize surface land acquisition requirements.

The most influential economic factors affecting CAES in competition with gas turbines and combined cycles from this study were reservoir charging cost, electricity cost escalation, plant capacity factor, and overall capital cost. Other less significant factors include capital charges and cost of money, fuel cost and escalation, fuel consumption, and operating and maintenance costs.

2.7 EARLY DEPARTMENT OF ENERGY PROGRAM

The early U.S. Department of Energy (DOE) program supported a broad spectrum of technical, economic and geographic activities. Topics addressed included conventional and advanced systems, surface equipment, U.S. demonstration projects, natural and excavated reservoir technology, feasibility studies, economic projections, and institutional/legal issues. Most of these studies were presented at two conferences [Workshop on Compressed Air Energy Storage Systems, Airlie House, Virginia, December 18 and 19, 1975 (ERDA-76-124) or the Compressed Air Energy Storage Symposium in Pacific Grove, California, May 15 through 18, 1978].

3.0 DEPARTMENT OF ENERGY RESEARCH ACTIVITY

3.1 JOINT DEPARTMENT OF ENERGY/ELECTRIC POWER RESEARCH INSTITUTE. DEMONSTRATION STUDIES IN RESOURCE APPLICATIONS

The Electric Energy System Division under the Assistant Secretary for Resource Applications in the Department of Energy initiated a set of three parallel design, siting, and cost studies based on the three primary candidate reservoir types. These studies, sponsored jointly by DOE and the Electric Power Research Institute (EPRI), examined three specific types of geology (hard rock, rock salt, and porous media) as potential reservoirs, and designed and planned surface plant equipment for a 1000-MW CAES plant. The studies were conducted by Potomac Electric Power Company, Middle South Services, and by a consortium headed by the Public Service of Indiana.

3.1.1 Potomac Electric Power Company Hard Rock Feasibility Study

The hard rock program was concerned with two energy storage concepts, underground pumped hydro (UPH) storage and compressed air energy-storage (CAES). Both concepts require large caverns excavated in rock at depths ranging up to 1500 m (5000 ft) below ground level. Typically, the most economic pressures at which to store the air lie between 4.8 and 7.6 MPa (600 and 1100 psi). At 6.9 MPa (1000 psi) the volume of air required to provide 10,000 MWh of storage (1000 MW for 10 hr) amounts to approximately 690,000 m³ (900,000 yd³). Technical, economic, and environmental feasibility of underground energy storage under these conditions were evaluated by Willett and Curtis (1980).

3.1.1.1 Site Selection Investigation

A site selection process considering geologic, socioeconomic, environmental, and technical factors germane to Maryland and northern Virginia resulted in selection of a site northwest of Washington, D.C., in Maryland near the Triadelphia Reservoir as the prime candidate. The candidate storage geology was the uniform and massive Sykesville gneiss underlying

that site. Site investigation to assess subsurface conditions was completed in two phases. The first phase included drilling 10 shallow boreholes to depths of less than 30 m (100 ft) and two additional boreholes to depths of 150 m (500 ft). In the second phase a single deep borehole was drilled to the proposed cavern depth with continuous core recovery and logging, determination of physical and mechanical properties of the rock, geophysical logging, permeability measurements, and in situ stress determination using hydraulic fracturing (Willett and Curtis 1980).

The shallow drilling phase showed the Sykesville (boulder) gneiss to be competent and high quality below the shallow weathered zone. Rock cores were often extracted in lengths of about 3 m (10 ft) and showed rock quality designations (RQDs) of 75 to 100%. The hydraulic conductivity was measured at 10^5 to 10^7 cm/sec. The boulder gneiss is intensely foliated with the plane of foliation dipping at between 60 and 70° to the northwest.

The primary objectives of the deep borehole were to confirm the existence of the Sykesville formation to a depth of 1523 m (5000 ft) and to determine the suitability of the Sykesville for the underground pumped hydro (UPH) or CAES facility storage requirements. Because of limited funds, the final cored drill hole was restricted to the minimum size required for geophysical logging and hydrofracturing equipment. A borehole diameter not less than 75 mm (2.98 in.) was selected. However, difficulties in maintaining vertical alignment resulted in termination of the hole at 998 m (3274 ft), measured along the borehole with a deviation of 53° from vertical. This corresponded to a vertical distance of 780 m (2556 ft) below the surface.

Geophysical logging, performed in the uncased section of the borehole, included measurements of relative density, natural gamma radiation, temperature, hole diameter and three-dimensional sonic velocity. Elastic properties calculated from the geophysical logs were elastic modulus of 66 to 83 MPa (9.5 to 12 ksi) and Poisson's ratio of 0.28 to 0.31. The temperature at the base of the hole was 23°C (73°F), and the thermal gradient was 1.8°C/100 m (1°F/100 ft).

Initial testing of rock core showed highly anisotropic strength properties. Subsequently, the testing program was expanded to include several triaxial tests at various confining pressures and angles of confinement. The unconfined compressive strength ranged from a low of 57 MPa (8300 psi) with the foliation inclined at an angle of 45° with the maximum principal stress to a high of 100 MPa (14,600 psi) with an angle of foliation of either 0 or 90°.

3.1.1.2 Geotechnical Considerations

For both the UPH and CAES schemes, the storage arrangement consisted of a series of large parallel caverns connected at opposite ends by either water or air collector tunnels. The parallel caverns were oriented in the most favorable direction geotechnically, which was determined to be in a northwest-trending direction. The conceptual caverns were parallel to the maximum horizontal stress. Thus, stress concentrations around the caverns would be caused by the minimum horizontal stress and vertical stress that act in the plane of the cross section. Additionally, the caverns would be perpendicular to the strike of the foliation, which is generally considered to be the optimal orientation for construction (Willett and Curtis 1980).

Because the large caverns are in the most favorable direction with respect to the in situ stresses and the foliation, the collector tunnels will be in the least favorable direction with respect to these two factors. For this reason, and because the several intersections will be located along the collector tunnels, these tunnels have been designed to be smaller than the main parallel storage caverns.

At intersections there would be minimal confining stress in the walls together with large stress concentrations; therefore, stability would very likely be a problem. These areas would require considerable support. The use of a few relatively large caverns would reduce the number of intersections necessary.

The quantity of air leakage from the CAES caverns would be directly related to the rock mass permeability and would increase operational costs

for each system. As an example, a 2% per day air leakage rate would result in an additional annual levelized compression power cost in excess of \$1 million. Although permeability in the Sykesville is through fractures, calculations can be based on the equivalent permeability of a homogeneous medium. The permeability testing from the deep drilling program indicated an average permeability less than 10^{12} cm^2 (hydraulic conductivity equals 10^7 cm/sec). Calculated air leakage rates ranged from 0.02% to 1.5% of the cavern volume per day. These rates are considered acceptable without major remedial action. However, the cost estimate included provision for grouting of any open joints that might be found during excavation.

Construction of the CAES scheme was estimated to require 4-1/2 years. The entire underground cavern system could be completed in 4 years. It was estimated that 1-3/4 years would be required for shaft sinking and 2-1/4 years for cavern excavation. The cost of cavern excavation exclusive of shaft costs was estimated to be $\$53/\text{m}^3$ ($\$41/\text{yd}^3$). All costs were quoted in June 1979 U.S. dollars (Willett and Curtis 1980).

3.1.1 .3 Numerical Modeling

Brandshaug and Fossum (1980) modeled the Potomac Electric Power Company (PEPCO) caverns using both isotropic and anisotropic properties to confirm the architect-engineering rock mechanics design. The use of anisotropic elastic properties did not alter the state of stress around the caverns significantly compared with the stress involving isotropic elastic properties.

Application of a guide for required artificial support suggested no support would be needed for the cavern walls. Light support such as rock bolts, wire mesh, and shotcrete would be required for the cavern roof.

This requirement was confirmed by the results of the failure analyses, which showed limited failure along joints in the roof and floor. The thermoelastic analysis revealed no tensile stresses.

The overall PEPCO analysis strongly indicates that cavern stability can be maintained with a minimum artificial support both before and during CAES operations.

In general, this program showed that adequate information is available to enable design of an underground opening with the size, shape, and depth required of a CAES cavern. This conclusion is based on a combination of numerical modeling and precedent considerations and assumes excavation in a rock mass with relatively well-quantified rock properties and associated geotechnical characteristics.

3.1.2 Middle South Services Salt Cavity Study

Middle South Services, Inc. (MSS) was the host organization for the preliminary design of a compressed air energy storage plant with a salt dome for underground air storage (Middle South Services 1982). United Engineers & Constructors, Inc., architect-engineers; Fenix & Scisson, geological consultants; and Brown Boveri Corporation, turbomachinery manufacturer, performed the detailed engineering and assisted in the planning studies for this design effort.

After examining 47 sites, the Carmichael salt dome near Jackson, Mississippi, was chosen as the candidate site for the 220-MWe CAES plant. The aboveground and underground investigation as well as an environmental assessment indicated that this was a satisfactory location. Expansion capability at the site would allow for the installation of 880 MWe of capacity at the site. The 220-MWe surface plant would occupy approximately 0.8 ha (20 acres) initially.

Based upon the characteristics of the Middle South Utilities System, Inc. (MSU), a weekly charge and discharge operating cycle was proposed. The compression, or charging mode, was scheduled for 56 hr with full load power generation of 220 MWe for 40 hr per week. The compressed air would be stored at approximately 6.9 MPa (1000 psig) in two solution-mined salt caverns 60 m (200 ft) in diameter and 178 m (580 ft) high. The roof of each mined cavern is approximately 1060 m (3500 ft) deep, 150 m (500 ft) below the top of the salt. Because sufficient groundwater is not available

for solution-mining the caverns, a fresh-water aquifer at the site would be used for this purpose. The solution mining effluent could be discharged into a local deep saline aquifer.

Except for an enclosed structure housing the control room and electrical equipment, the surface plant is an outdoor installation. The turbomachinery is located on an elevated foundation with an in-line arrangement to simplify piping, minimize pressure losses and provide ease of maintenance with an overhead crane. The low pressure turbine exhaust discharges into a recuperator to improve plant heat rate during power generation. The net plant fuel heat rate is 4200 kJ/kWh (3980 Btu/kWh), while the overall plant heat rate including allowances for compression energy is estimated at 12,175 kJ/kWh (11,540 Btu/kWh) (29.6% overall efficiency).

The proposed fuel for the fired HP and LP turbines is No. 2 fuel oil. The estimated capital investment cost of the 220-MW CAES plant is \$85.6 million or \$389/kW expressed in July 1979 dollars. With appropriate additions, No. 6 fuel oil may be fired instead of the No. 2 fuel oil. The estimated capital investment cost when firing No. 6 fuel oil is \$90.9 million or \$413/kW. The project schedule from date of authorization to commercial operation is 70 months, which includes 28 months for licensing.

An environmental assessment of the site did not reveal any prohibitive factors that would prevent construction. Prior to the start of construction, an environmental impact statement (EIS) would be required because there is no previous history of a CAES plant constructed in the United States. The Energy Regulatory Agency (ERA) has indicated that a CAES plant may be granted an exemption from the Fuel Use Act by virtue of mixed fuel power generation: compressed air energy provided by coal, or nuclear power generation, with power generation from the oil-fired CAES plant. The ERA will consider exemptions on a case-by-case basis and did, in fact, grant one such exemption to Soyland Electric Cooperative in April 1981.

A preliminary examination of the economic feasibility of a CAES plant in the MSU system was investigated for the period 1986 to 2005. A final system planning study was not completed because of lack of funds. Based upon the trend observed in the preliminary analysis, installation of a CAES plant in the MSU system does not appear economical before the mid-1990s. This is caused by the unique system generation mix and financial data applicable to the MSU system. Under more favorable conditions, CAES may be economical for other systems at an earlier date.

Based upon the work of this preliminary design and cost estimate, CAES is considered a near-term energy storage technology. Several areas for further investigation would provide added confidence to utilities. These studies would include data on pressure cycling of salt caverns, CAES reliability analysis, dynamic simulation especially with respect to recuperator operation, and verification of nitrogen oxide emission limits when firing fuel oil.

3.1.3 Public Service Company of Indiana CAES Development

An aquifer CAES development program by Public Service Company of Indiana was sponsored jointly by the Department of Energy and the Electric Power Research Institute (McCafferty 1981). The siting study was initiated with a literature review of regional geology to identify sites for compressed air storage in an area within Illinois, Indiana, Kentucky, and Tennessee (Walke 1980). This review was performed by the Illinois State Geological Survey and the Indiana Geological Survey. The criteria used to identify potential sites included geologic and hydrologic characteristics as follows:

- discovery pressure of 1.38 to 6.9 MPa (200 to 1000 psi)
- aquifer depths of 145 to 723 m (475 to 2400 ft) below plant grade
- sufficient closure and volume for storage of 3.4×10^8 scm (12×10^9 scf) of air at 66°C (150°F)
- permeability of at least 750 millidarcies and preferably greater than 1000 millidarcies

- adequate caprock for storage.

Fourteen potential sites were identified--ten in Illinois, and four in Indiana (Figure 3.1). Most Illinois sites were selected from geologic structures known to the Illinois State Geological Survey to have been investigated but not developed for the underground storage of natural gas. Literature on the study region in Indiana was surveyed to identify sites in two stratigraphic horizons.

The 14 potential sites were first screened to determine their suitabilities for development of a 1000-MW CAES facility. Three major areas of concern were evaluated: geologic, economic, and environmental characteristics. All 14 sites were reviewed initially to determine where any prohibitive characteristics existed. None were identified, so all 14 sites were continued. A numerical rating system was developed to identify the most promising sites. Seventeen criteria included nine for geologic characteristics, five for economic characteristics, and three for environmental characteristics. Ranking values for each criterion ranged from least desirable at 1 to most desirable at 5.

Each group of characteristics was assigned a weighting factor and each criterion was ranked from 1 to 5. Fifty points were distributed among the criteria in the economics grouping. The remaining 50 points were divided equally between geological characteristics and environmental impacts.

The product of the ranking and weighting process resulted in the following ranking for the 14 sites:

<u>Ranking</u>	<u>Site</u>	<u>State</u>
1	Wapella East	Illinois
2	Deland	Illinois
3	Media	Illinois
4	Parnell	Illinois
5	Wadesville West	Indiana
6	Brookville	Illinois
7	Fishhook	Illinois
8	Paxton	Indiana

FIGURE 3.1. Potential Sites for the Public Service of Indiana CAES Aquifer System

<u>Ranking</u>	<u>Site</u>	<u>State</u>
9	Toulon B	Illinois
10	Toulon A	Illinois
11	Prairie Creek	Indiana
12	Lewis	Indiana
13	Hume	Illinois
14	Brocton	Illinois

Two criteria were then used to eliminate sites from further consideration: 1) the air reservoir should be able to support a minimum plant capacity of 1000 MW and 2) the total number of wells for a 1000-MW capacity plant should not exceed 2000.

The use of these two criteria resulted in the elimination of seven sites. Five sites, including all four in Indiana, could not support the 1000-MW capacity: Lewis, Paxton, Prairie Creek, Toulon B, and Wadesville West. Two sites, Brocton and Hume, exceeded a total of 2000 wells for site development because of the well selection procedure, which was based on primary permeability. The high number of wells resulted from low core permeabilities for the limestone media and low discovery pressures at these sites.

The seven final sites--Brookville, Deland, Fishhook, Media, Parnell, Toulon A, and Wapella East--all have generally high ratings for the characteristics evaluated. The top two sites--Deland and Wapella East--had high ratings for all the characteristics. The other five sites had only a few low ratings.

In the third phase of site investigation, the seven final sites were found suitable for the testing program. This evaluation consisted of determining the field testing activities that would be needed at each site, estimating the costs of these activities, and identifying the environmental impacts associated with the activities at each site. The planned field testing program should consist of four phases: drilling structure test wells, drilling injection-withdrawal and observation wells, performing an aquifer water pumping test, and performing an air injection test. The

purpose of the program would be to validate the performance of the site reservoir to enable the utility to make the final decision on site selection and compressed air energy storage system feasibility.

3.1.4 Economic Comparison of Designs Using Hard Rock, Salt, and Aquifer Storage

The three design studies performed by the utilities provided a solid basis for making techno-economic comparisons of the three types of air storage reservoirs available for a CAES plant: mined hard rock caverns, solution-mined salt deposits, and aquifer systems (Reilly and Schainker 1981). The first is a 924-MW hard rock CAES system designed for the Potomac Electric Power Company (PEPCO) in Maryland, the second is a 220-MW salt system for Middle South Services (MSS) in Mississippi, and the third is the 1120-MW system designed for a group of utilities led by Public Service Company of Indiana (PSI).

This section presents an analysis of the results of the three studies, concentrating on economics. In interpreting the results presented here, it is important to note that each of the three studies was performed by a different architect/engineer working under different assumptions and constraints. As such, this section is more a comparison of the three different CAES designs than it is of the three storage technologies. The general cost relationships among the three technologies are, however, certainly apparent in the results.

3.1.4.1 Comparison of CAES Designs

System performance estimates for the three CAES designs are listed in Table 3.1. Estimates are included for both the MSS weekly and daily cycles for general reference; only the daily information was used for the balance of the analysis. Operating and maintenance cost information for the PEPCO and MSS systems is expressed at a July 1979 price level, and for the PSI system at an April 1981 price level.

In general, the performances of the three systems, as characterized by the Fuel Heat Rate (FHR) and the Electric Energy Ratio (EER), are comparable. The PSI system has a slight edge in overall heat rate (based upon a charging

TABLE 3.1. System Performance Estimates

	<u>PEPCO</u> (Hard Rock)	<u>MSS</u> (Salt)		<u>PSI</u> (Aquifer)
Storage cycle	daily	weekly	daily	daily
Power (MWe)	924	220	220	1120
Storage capacity (hours)	10	24	8	10
FHR (Btu/kWh)	4250	3980	3980	4090
EER (kWh-in/kWh-out)	0.75	0.72	0.775	0.70
Forced outage rate	10%	10%	10%	10%
Planned maintenance (weeks)	2	2	2	4.5
Fixed O&M (\$1,000,000/year) ⁽¹⁾	3.47	0.24	0.24	1.04
Variable O&M (mills/kWh) ⁽¹⁾	0.25	0.6	0.6	2.2

energy heat rate of 10,500 Btu/kWh), caused chiefly by its low EER. The MSS turbomachinery has the best fuel heat rate at the expense of the highest electric energy ratio.

Considerable differences exist in the estimated costs of operations and maintenance for the systems. Both PEPCO and MSS systems are designed for 2 weeks of planned maintenance per year and a low rate for variable operating and maintenance. The PSI aquifer system is expected to require 4.5 weeks of planned maintenance, and its estimated rate for variable operating and maintenance is relatively high at 7.6 mills/kWh.

Table 3.2 lists the major differences among the three CAES systems. The turbomachinery for the PEPCO hard rock system was designed by Brown Boveri Corporation and consists of axial low- and intermediate-pressure compressors and a centrifugal high-pressure compressor. The system can be started by either a variable frequency system or by using stored compressed air to spin the turbomachinery train. Because of site considerations, a relatively expensive dry cooling system was used, and a large eight-line switchyard was coupled to the plant.

⁽¹⁾ July 1979 dollars

TABLE 3.2. System Turbomachinery Differences

	<u>PEPCO</u> (Hard Rock)	<u>MSS</u> (Salt)	<u>PSI</u> (Aquifer)
Source	Brown Boveri	Brown Boveri	Westinghouse
Installation	enclosed	weatherized	enclosed
HP compressor	centrifugal	centrifugal	axial
Combustors	silo	silo	can annular
Starting mode	variable frequency and turbine	turbine start only	variable frequency and turbine
Cooling mode	dry	wet	wet
Operating cycle	daily	daily	daily-weekly
Transmission lines	8	2	3

Brown Boveri provided roughly the same machinery for the MSS design effort, and most of the differences with the PEPCO system are caused by site-specific conditions. Because of the southern site, a turbomachinery building was not required, and less-expensive equipment weatherization was employed in the design. A variable frequency starting system is not cost-effective for a single-unit plant, so provision was made only for a turbine start. Inexpensive wet cooling and a small two-line switchyard were called for in the design.

Westinghouse provided the turbomachinery design for the PSI aquifer study, with a major design difference from the other two studies: all of the compressors are axial. Most of the rest of the plant design was similar to the PEPCO design, except for a wet cooling system and a smaller (three-line) switchyard.

3.1.4.2 Plant Schedule Estimates

In Table 3.3, the plant licensing and construction time estimates are presented. The aquifer and hard rock CAES plants are estimated to take

TABLE 3.3. Schedule Estimates

	<u>PEPCO</u> (Hard Rock)	<u>MSS</u> (Salt)	<u>PSI</u> (Aquifer)
Development time (months)			
Licensing	36	28	45
Engineering and construction	<u>87</u>	<u>64</u>	<u>63</u>
Total development time (months)	96	70	93

roughly the same amount of time, about 8 years, from the build-decision to plant operation, even though actual construction time is about 2 years less for the aquifer plant. This reflects increased licensing activities for the aquifer plant and the smaller overlap between licensing and construction time periods expected by the PSI architect-engineer. It is difficult to make any statements about comparable time estimates for the MSS salt design because the plant size is so much smaller.

3.1.4.3 Capital Cost Estimates

Capital cost estimates, as prepared by the architect-engineers, are presented in Table 3.4 (in total dollars, \$/kW, and as percentages of total direct cost). This information is reported for reference purposes only. The figures are not directly comparable with each other. They are based upon different plant sizes and storage capacities; the breakdown by component is inconsistent; and the estimates are presented in different price levels. Indirects are also handled differently. For the PEPCO system, a contingency of 15% is applied to all capital cost components. The MSS cost estimate provides no contingency for cavern construction and turbomachinery, considering these as fixed-price contracts, and 15% on the remainder of the capital cost. The PSI cost estimates include a bare-bones allowance for contingency (under 5%) within each of the individual cost estimates and no overall contingency.

These inconsistencies were corrected in Table 3.5, so that cost estimates are directly comparable. All estimates are at July 1979 price

TABLE 3.4. Capital Cost Estimates as Provided
(\$1,000,000)

	<u>PEPCO</u> <u>(Hard rock)</u> <u>July 1979\$</u>	<u>MSS</u> <u>(Salt)</u> <u>July 1979\$</u>	<u>PSI</u> <u>(Aquifer)</u> <u>April 1981\$</u>
Storage system	55.9	9.5	55.0
\$/kW	61	43	49
% of direct cost	16	13	14
Turbomachinery	172.2	48.0	176.5
\$/kW	186	218	158
% of direct cost	50	67	45
Balance of plant	<u>118.9</u>	<u>14.1</u>	<u>164.3</u>
\$/kW	129	64	147
% of direct cost	34	20	41
Total direct cost	347.1	71.7	395.9
\$/kW	376	326	353
Indirects/ contingency	<u>104.1</u>	<u>15.5</u>	<u>40.1</u>
Total capital costs	451.2	87.2	436.8
\$/kW	488	397	390

TABLE 3.5. Normalized Cost Estimates (\$/kW)

	<u>PEPCO</u> <u>(Hard rock)</u>	<u>MSS</u> <u>(Salt)</u>	<u>PSI</u> <u>(Aquifer)</u>
Power (MW)	924	880	1120
Storage (hr)	10	10	10

Storage system \$/kW	68 19%	45 13%	40 14%
Turbomachinery	179 49%	196 55%	136 47%
Balance of plant	<u>114</u> <u>32%</u>	<u>114</u> <u>32%</u>	<u>114</u> <u>39%</u>
Direct cost	361 100%	355 100%	290 100%
Indirects and contingency @ 30%	<u>108</u>	<u>106</u>	<u>87</u>
Total cost	469	461	377

levels. The **MSS** storage cost was increased to allow for 10 hr storage instead of 8, and comparable plant sizes were considered. Component cost breakdowns are also consistent among plant designs.

For the hard rock design, the storage component costs include the pressure-compensation reservoir, water intake structure, air shaft, water shaft and U-tube, underground caverns, waste disposal from mining activities, and piping from the turbomachinery building to the air shafts. The salt storage costs include well drilling, solution-mining activities, brine disposal, and piping from **turbomachinery** building to the well sites. Costs for the aquifer system include purchase of below-ground storage rights, air wells and access roads, piping and related earthwork from the turbomachinery building to the wells, initial air bubble development, and the electric controls for the wellhead equipment.

Rather than attempting to normalize the balance-of-plant (BOP) cost estimates among designs, because site conditions are so radically different, the **PSI** BOP is assigned to the **PEPCO** and **MSS** systems on a \$/kW basis. Hence, the normalized plant cost estimates assume all of the site-specific assumptions of the **PSI** study, including wet cooling, enclosed turbomachinery, and a switchyard connected to three transmission lines.

Indirect costs are applied consistently: 15% contingency and 15% overhead for the architect-engineer. (The small contingency allowed for the **PSI** study is still contained within the individual cost estimates, and so **PSI** estimates include slightly more contingency than the other two studies.) These normalized cost estimates indicate that salt and aquifer storage have roughly comparable capital costs, both considerably less than the cost of hard rock storage.

The biggest cost differences among the designs lie not in cavern construction estimates, but in the estimates for turbomachinery. The **PSI** cost is only 75% of the **PEPCO** estimate and 69% of the **MSS** estimate. There are undoubtedly economies of scale inherent in construction of **PSI's 20MW** turbomachinery trains, but not enough to create such a large cost differential. The major difference must lie in the basic cost expectations of

Brown Boveri Corporation (PEPCO and MSS) versus those of Westinghouse (PSI).

3.1.4.4 Estimates of Economic Performance

Levelized **busbar** costs were developed for each of the CAES designs, based upon the assumptions listed in Table 3.6, and upon consistent assumptions for funds used during construction. The results are depicted in Figure 3.2, plotted against capacity factor. Two costs of compression energy (15 and 35 mills/kWh) are investigated. The original architect-engineering estimates for O&M expense are used in the analysis. The results indicate that the systems generate electricity in about the same cost range for high capacity factors, with aquifer systems generally most cost effective. Most of this apparent superiority is, of course, directly related to the relatively inexpensive **turbomachinery** in the PSI system, rather than superiority of the aquifer storage system. All of the systems were said to be more economical than conventional peaking plants on the basis of levelized costs (Reilly and Schainker 1981).

TABLE 3.6. Assumptions for **Busbar** Comparisons

Discount rate	10%
Fixed charge rate	18%
Energy prices (July 1979\$)	
Compression energy	15 and 35 mills/kWh
Distillate #2	\$5/MBtu
Escalation rates	
General inflation	6%
Compression energy	7%
Distillate #2	8%
Construction costs	6%
O&M expense	6%
System lifetime	30 years
Start of plant operation	January 1990
Base year for cost estimates	July 1979

a. 15 mills Charging Energy (1979 dollars)

b. 35 mills Charging Energy (1979 dollars)

FIGURE 3.2. Comparative Busbar Cost for CAES Designs

3.1.4.5 Summary

This section has examined the economic performance of three CAES designs, each developed by a different architect-engineer under different assumptions and constraints, and each employing a different type of air storage facility: a hard rock-mined cavern, a solution-mined salt cavity, and an aquifer. The results indicate that *aquifer* and salt storage facilities cost roughly 60 to 70% of the equivalent hard rock mined cavern. In this comparison the *aquifer* storage facility was somewhat less expensive than the salt cavity, but this difference could be reversed with different salt and/or aquifer characteristics. For instance, if the aquifer had been less permeable, then more wells would have been required for the same power level, and total storage cost would have been higher.

The major difference between the plant cost estimates lies not in the cost of storage facilities, but rather in vendor estimates of turbomachinery cost. And, because turbomachinery contributes about half of total plant cost, this difference could be critical to the decision to build a CAES plant.

3.2 COMPRESSED AIR ENERGY STORAGE RESEARCH AND DEVELOPMENT PROGRAMS AND PROJECTS

The previous studies noted here indicate that the CAES concept is technically feasible and economically viable. In view of the concept's potential benefits, the U.S. Department of Energy has undertaken a comprehensive research and development program to accelerate commercialization of this technology. Programs structured to pursue commercialization of CAES are depicted in Figure 3.3. The three design studies discussed previously were funded under the predemonstration area.

The CAES Technology Program promoted development of CAES technology for electric utility applications. The primary motivation is the annual conservation of more than 100 million barrels of oil. Two major program goals have therefore been established:

FIGURE 3.3. Department of Energy Programs to Pursue Development of CAES

- Determine long-term reservoir stability criteria for CAES operating conditions.

Identify, determine feasibility of, and develop second-generation CAES concepts that minimize the need for, or do not require, petroleum fuels for firing the CAES plant turbines.

The small utilities program had as its goal the application of the developed technology base to smaller utility systems. The question of the risk involved in CAES systems was evaluated and environmental projects focused on identifying and evaluating the critical environmental factors to consider during CAES development.

In addition to the DOE development efforts, parallel and complementary studies were carried out by the Electric Power Research Institute (EPRI) and industry. The total research effort was formally coordinated through regular DOE-EPRI/industry program review and planning meetings. Some of the topics of this complementary research discussed here include:

- cost-shared predemonstration studies
- champagne effect studies

- CAES applicability methodologies
- recuperator evaluation.

Current and future research and development efforts on CAES technology are now the responsibility of EPRI, as DOE policy and priority has dictated that most CAES development effort is near-term and supportable by industry.

3.2.1 Reservoir Stability Studies

3.2.1.1 Overview

The objective of the reservoir stability studies project was to develop stability criteria for large underground reservoirs in salt domes, hard rock caverns, and porous rock structures for air storage in utility applications (Doherty 1982). Because reservoir stability was deemed crucial to CAES system commercialization, this project received major emphasis in the overall CAES program. A long-term plan, including state-of-the-art assessment, numerical model development, and experimental studies culminating in field research, as necessary, was formulated and carried out.

The type of host rock is an important factor in the choice of mode for CAES operation. Excavation costs in hard rock dictate that CAES operations use a compensated storage system. Operation of a compensated system requires relatively low storage temperatures [less than $\sim 100^{\circ}\text{C}$ (212°F)] to avoid boiling and large vapor plumes when warm water reaches the surface. Basic concerns for compensated hard rock caverns center on the rock mechanics aspects of cavern shape and layout, air leakage, and the response of the rock surfaces and near-cavern fabric to cyclic loadings and wetting-drying (Doherty 1982).

State-of-the-art numerical modeling and laboratory experimental studies for hard rock were conducted by RE/SPEC, Inc. (Gnirk et al. 1979; Fossum 1979; Brandshaug and Fossum 1980; Fossum 1980; Fossum and Brandshaug 1982).

Storage in salt (primarily domal) can be either compensated or uncompensated, although uncompensated is more acceptable because of brine

storage problems at the surface, metal corrosion, and concerns about control of solution, precipitation, and potential erosion of the salt. The only operational CAES peaking power plant, at Huntorf in West Germany, uses an uncompensated salt cavity. Compressed air energy storage in salt is generally restricted to lower temperatures, less than 80°C (176°F), because creep closure of the cavern is greatly accelerated at higher temperatures. Good operational experience to date at Huntorf ensures feasibility of storage in solution-mined salt caverns. Differences between American and German domal salts, the mechanics of long-term cyclic salt performance, and development of useful monitoring systems determined the research needs for domal salt reservoirs (Doherty 1982).

State-of-the-art, numerical modeling and laboratory experimental studies for salt were conducted by Serata Geomechanics, Inc. (Serata and McNamara 1980) and by Louisiana State University (Thoms 1979; Thoms 1980; Thoms and Gehle 1982).

Compressed air energy storage in porous media operates in a damped, compensated mode. It is uncompensated for short cycle times, but the longer-term approach to equilibrium with a specific discovery pressure in the storage system is a compensated response. Experience with storage of natural gas and oil in similar underground reservoirs has accumulated for nearly 50 years. In most instances, this storage has involved seasonal cycling of gas and oil with low mass flow rates and at low temperatures relative to potential CAES reservoir operation. Compressed air energy storage reservoirs will be subjected to daily cycling of air with attendant temperature, pressure, and humidity fluctuations. The CAES reservoirs must remain stable and operational under these conditions over periods of 30 to 50 years. Thus, while previous gas storage experience is valuable, little data exist for specific CAES operation conditions (Doherty 1982). No major structural problems have been identified with storage of air in porous media at less than 150°C (302°F). Storage of the heat of compression within the rock formation is being investigated for temperatures to 200°C (392°F) through numerical, experimental, and field evaluations to utilize

the formation for thermal energy storage. This could reduce fuel use in the cycle and positively affect system economics. Temperature and geochemical effects could restrict air storage temperatures to levels that would not allow sufficient energy recovery to be feasible.

For porous media, state-of-the-art studies were carried out by Pacific Northwest Laboratory (Stottlemire, Katz and Smith 1979; Allen and Gutknecht 1980). Laboratory experiments simulating CAES environments were performed at the University of Wisconsin-Milwaukee (Pincus 1980); at Los Alamos National Laboratory (Blacic, Halleck and D'Onfro 1979); and at Terra Tek, Inc., and the Pacific Northwest Laboratory (Stottlemire 1980). Numerical modeling studies were performed at Pacific Northwest Laboratory (Wiles 1979; Wiles and McCann 1981; Wiles et al. 1982).

Geotechnical factors and guidelines for storage of compressed air in each subterranean environment are explained and set forth in the following sections.

3.2.1.2 Hard Rock Caverns

Geotechnical criteria for the design and stability of CAES caverns in hard rock formations involve geologic, hydrological, geochemical, geothermal, and in situ stress state characteristics of generic rock masses (Allen, Doherty and Fossum 1982a). The design criteria must be established from the viewpoint of 1) the type of CAES system, 2) the desired air volume and pressure, and 3) the thermal/rock mechanics/hydrologic constraints appropriate to the rock mass. These constraints must be used in determining optimal cavern shape, cavern orientation, dimensions and spacing, and excavation methods.

Because of the high excavation costs associated with the larger volumes required by other storage schemes, a CAES reservoir in hard rock would probably be a constant pressure, water-compensated cavern. Compressed air energy storage operations, including daily temperature cycling and wall wetting, lead to the following design concerns:

- cavern geometry and size

- cavern orientation
- thermal response
- low frequency fatigue, coupled with temperature cycling and wetting
- air penetration of rock mass
- hard rock properties at nonambient conditions
- residual strength of hard rock after failure
- mineralogical alteration of hard rock under CAES conditions.

The following guidelines regarding air storage in hard rock masses have been identified:

- a Rocks must be competent (with high structural strength and stability), and capable of sustaining openings with minimal support and rock improvement measures. Candidate rock types include granite/granodiorite, quartzite, massive gneiss, dolomite, and limestone.
- Rock masses must be characterized by overall hydraulic conductivities less than 10^{-8} m/sec for water.
- Long-term containment of stored air may not be possible in tightly folded, heavily fractured, jointed, or faulted rocks.
- Cavity geometry and orientation must be selected for minimal support requirements. Important geologic parameters include extent of fracturing, nature of joint surfaces, permeability in zones of weakness, and hydrologic conditions.
- Storage cavern design and construction must minimize slaking, spalling, and loss of groundwater above the cavern.
- Cyclic temperature and humidity variations must not significantly decrease rock strength by fatigue.
- Geologic formations with high horizontal in situ stresses are unfavorable. Maximum horizontal stress should not exceed vertical stress by more than a factor of 1.5.

- The construction cost of CAES caverns can be seriously impacted by conditions, such as degree of jointing and faulting and incompetence of the overburden. Access shafts for CAES caverns should not be sunk in areas with more than 50 m (164 ft) of incompetent, water-bearing overburden.

Additional considerations that must be evaluated when constructing a CAES reservoir in hard rock include:

- Hydrostatic pressure within the host rock must balance the pressure of stored air (and the equal pressure of the water-compensating column).
- Surface water must be available for pressure compensation.
- The "champagne effect", rapid evolution of air in the water column connecting the cavern to the surface lake, must be considered and minimized by the design of CAES plants with compensated caverns.
- Unconfined compressive strength should exceed 25 MPa (3600 psi) over the cycling life.
- The nearest dissimilar geologic formation contact should not be closer than 100 m (328 ft).
- Areas of active volcanism, faulting, seismic activity, excessive subsurface solution, and subsidence are to be avoided.
- Long axes of caverns should be oriented with respect to structural discontinuities and in situ stress fields to maximize stability and minimize construction costs.
- The most likely cavern depth is 600 to 850 m (2400 to 2800 ft) because of operating pressure requirements of about 6 to 8 MPa (60 to 80 bar).
- Air loss should not exceed 1% during each storage cycle.
- Operating pressures, essentially constant, will fluctuate within a very narrow range with differences attributable to variations in the effective height of the water-compensating column. The most likely

design range for operating pressures is 6 to 8 MPa (60 to 80 bar). Maximum charging pressure will be 12.0 kPa/m (0.53 psi/ft) of depth.

- Compressed air should enter the cavern at 30 to 80°C (90 to 180°F).
- Compensating water temperature may fluctuate between 0 and 30°C (30 to 90°F).
- Cavern depressurization should be gradual, not exceeding 1 MPa/hr (10 bar/hr). Thus, total depressurization would take at least 8 hours, and the compensating water column would be isolated.

In conclusion, the chief geotechnical issues for the development and operation of CAES caverns in hard rock are impermeability for containment, stability for sound openings, and hydrostatic balance.

3.2.1.3 Salt Cavities

The state of knowledge about utilization of solution-mined salt cavities for CAES including laboratory experiments, numerical modeling, field characterization, solution mining experience, and operating parameters was summarized by Allen, Doherty and Thoms (1982b). Salt caverns for CAES systems will undergo daily cycles of pressure, temperature, and humidity. Effects that could damage the cavern must be controlled.

Topics evaluated in recent studies include:

- cavern geometry and size
- long-term creep and creep rupture of rock salt
- effects of pressure and temperature loading rates
- low frequency fatigue, coupled with cyclic pressure, temperature, and wetting conditions
- progressive deterioration of salt fabric with possible air penetration
- cavern monitoring methods
- salt properties at nonambient conditions.

Department of Energy studies (Allen, Doherty and Thoms 1982b) have identified several criteria that could serve as guidelines for long-term stability of salt cavities:

- Cavity floor depths to 1500 m (500 ft) may be acceptable depending on site conditions. For the anticipated maximum operating pressures of 9.0 MPa (90 bar) or less, optimal depth to cavern roof is about 800 m (2600 ft). [Maximum air pressure is to be 1.639 MPa per 100 m (5 bar per 100 ft) of depth.]
- Cavity wall temperatures should not exceed 80°C (180°F).
- Cavity separation (center-to-center) to diameter ratio (S/D) should be at least 4. Salt thickness between a cavern wall and the lateral salt dome boundary should be at least three times the cavern diameter.
- Minimum thickness of salt above a solution cavity should be 150 m (500 ft). The ratio of overburden salt thickness to cavity span is to be at least 2.5. Cavern span should not exceed 60 m (200 ft).
- Cavity height to diameter ratio (H/D) should be in the range of 1 to 5.
- Octahedral shear strength should lie between 3.8 and 5.2 MPa (500 and 750 psi).
- In situ horizontal stress should not exceed 120% of overburden pressure.
- Depressurization should not exceed 1 MPa/hr (10 bar/hr).
- Salt cavities must be protected against groundwater encroachment.
- Surface subsidence in the region overlying a CAES cavity must not be significant.
- Accessory minerals in salt reduce self-healing of fractures and contribute to irregular cavern shapes. Site selection should take this into consideration.

3.2.1.4 Porous Media Reservoirs

The natural accumulation of liquid and gaseous hydrocarbons in confined anticlinal or domal porous strata makes possible the economic recovery of these resources (Allen et al. 1983). The reverse process of storing natural gas within similar stratigraphic traps is widely accepted and well understood. The storage of compressed air in porous medium reservoirs as a technique to convert low cost off-peak baseload electricity into mechanical energy for subsequent reconversion during high demand periods is a logical extension of this technology. In the aquifer, air is injected at a pressure higher than the hydrostatic discovery head, displacing an equal volume of water from the near-well region. Subsequent expansion of the stored air mass through a conventional combustion turbine-generator would provide an increment of electrical energy above baseload output to meet peak loads on demand.

Although most of the experience derived from natural gas storage can be applied to aquifer compressed air storage, several differences exist between the two systems. The storage of air for CAES involves daily or weekly, rather than seasonal, cycling. Moist air is more viscous than natural gas; and air storage at elevated temperatures may be desirable. Frequent pressure, temperature, and humidity cycles may have detrimental impacts on the aquifer matrix. In addition, the chemical environment produced by air storage may cause formation problems through oxidation of inorganic and organic substances.

Aquifers are suitable sites for compressed air storage because of low construction costs and widespread availability. The storage volume of interest consists of interconnecting pores, microcracks, channelways, permeable bedding planes, and joints that characterize the porous medium. An impermeable caprock and some form of structural trap are required to contain the air. Target aquifers must be deep enough below the water table to provide a static air pressure suitable for turbine operation.

Issues related to the stability of porous rock reservoirs include:

- low frequency fatigue, coupled with cyclic pressure, temperature, and humidity influences on porous media and caprocks
- reservoir and caprock material properties under CAES conditions
- effects of reservoir morphology, anisotropy, and inhomogeneity
- response of wellbore casing and cementation materials
- wellbore desaturation and reversible air-water interface movements
- potential for geochemical reactions
- generation, transport, and deposition of fine particulate matter.

Studies of these concerns and operational requirements have yielded the following guidelines and precautions for CAES reservoir selection, design, and operation:

- A doubly plunging anticlinal or domed sandstone aquifer conformably overlain by impervious shale, dolomite, or limestone caprock represents the most desirable geology for a porous rock CAES reservoir.
- The range of parameters that should be considered includes injection temperature--from formation temperature to 200°C (400°F), thickness and closure--10 m (30 ft) or more each, permeability--300 md minimum, porosity--10% minimum, depth--200 to 1000 m (650 to 3300 ft), storage pressure--2.0 to 15.0 MPa (20 to 100 bar), primary caprock thickness--6 to 10 m (20 ft) or more, a maximum charging pressure of 18.1 kPa/m (0.8 psi/ft) of depth, and a maximum storage pressure equal to the local hydrostatic head.
- Disaggregation of the porous medium can occur as a result of differential thermal expansion, cement dissolution, hydrolytic weakening of silicon-oxygen bonds, and/or other chemical reactions. This should be considered in completion design.
- Thermomechanical permeability changes may take place if air is injected at very high temperatures.

- Leakage of air through the caprock from drying or fracture should not be significant if CAES excess pressure over discovery pressure is 0.5 of caprock threshold pressure or less.
- Regional groundwater flow gradients should be insufficient to significantly distort or displace the air bubble within an aquifer.
- Corrosion of well casings, although not a serious problem, should be considered in materials selection.
- Rock matrix disaggregation and other geochemical effects could restrict maximum injection temperatures to about 300°C (550°F). An absolute upper temperature limit for confined media remains to be identified.
- About 10,000 lb of air storage at typical pressures is necessary to generate each megawatt-hour of capacity.
- At least one redundant overlying caprock formation is desirable.
- Air cycling should not involve more than 10% of the mass of the air bubble due to back pressure maintenance requirements.
- Water coning must not inhibit air withdrawal.
- Injection well completions within the reservoir rock must provide for an adequate area of stable sand face to avert high air velocities and degeneration from particulate plugging or geochemical reactions.

3.2.2 Pittsfield Aquifer Field Test

An aquifer field test (Istvan 1981; Allen, Kannberg and Doherty 1981) near Pittsfield, Illinois, was developed to: 1) demonstrate the feasibility of storage and cyclic injection/retrieval of compressed air at ambient and elevated temperatures; 2) examine physical, chemical, and mineralogical effects of CAES on reservoir rock, caprock, and wellbore; 3) compare numerical modeling with field results for bubble development, dehydration and water displacement, thermal growth, and cyclic thermal performance; and 4) evaluate system performance with respect to bubble growth rate, mass transfer rate, thermal development and recovery, water production, and entrainment of mineral particulates. Partial achievement of these objectives is related below.

The field test was sponsored initially by the Department of Energy (Kannberg 1983). Pacific Northwest Laboratory (PNL), Richland, Washington, conceived the experiment and conducted field exploration with Dames & Moore of Park Ridge, Illinois. PB-KBB, Inc., Houston, Texas, was the major subcontractor with responsibility for the design, construction, and operation of the field test facility. Pacific Northwest Laboratory acted as manager for DOE and also provided laboratory and modeling support. Early in 1983, the project was transferred to the Electric Power Research Institute (EPRI), Palo Alto, California.

From eleven candidate sites in the Illinois Basin the Pittsfield "dome" in Pike County was selected for detailed exploration to identify a small, structure with adequate volume, closure, lithologic characteristics, and hydrostatic pressure. This effort consisted of seismic reflection surveying, drilling, permeability and threshold pressure testing of reservoir and caprock cores, and hydrostatic head measurement (Allen, Trapp and Jensen 1982). The site selected and the larger Pittsfield dome are illustrated in the structure contour map of Figure 3.4. Contours describe the upper Silurian surface which almost parallels the respective underlying Ordovician strata.

The surface facility consisted of an air compression plant, process and surface instrumentation, data acquisition equipment, and control building. The basic elements are shown in Figure 3.5. The prime mover was a naturally aspirated gas 385-hp engine driving a four-stage intercooled and aftercooled reciprocating compressor. The maximum flow rate was 35.4 scmm (1250 scfm) with a backpressure of 2.07 MPa (300 psig).

Processing of compressed air included filtration to remove oil and dust, drying, and optional heating. Processing of withdrawn air included filtration to collect entrained particles and scrubbing to remove water. Surface instrumentation measured pressure, temperature, mass flow rate, and humidity for both compressed and withdrawn air.

Nine wells were drilled through a Paleozoic sedimentary sequence to the designated reservoir bed, the permeable St. Peter sandstone beneath the impervious Galena-Platteville-Joachim carbonate caprock complex. Both the

FIGURE 3.4. Structure Contours of the Pittsfield Dome and Test Structure.

FIGURE 3.5. Basic Elements of the Surface Facility

St. Peter and caprock complex are of Ordovician age. The stratigraphy and monitor well locations are shown in Figures 3.6 and 3.7. The injection/withdrawal (I/W) well, located at the peak structural high point was drilled through an uppermost thin green layer of the St. Peter sandstone to a depth of 201 m (660 ft). The hole bottom coincided with the interface between the green layer and the much thicker underlying white section of the St. Peter. The green layer is friable and about 2.5 m (8 ft) thick at this location. The cemented 17.8-cm (7-in.) casing was perforated over this 2.5-m (8-ft) length.

Wells A, B, C, and D were drilled north, east, and south of the I/W well to monitor air bubble thickness and relative variation of air

FIGURE 3.6. Schematic Section of Pittsfield Aquifer Field Test Stratigraphy

FIGURE 3.7. The Pittsfield Well Field

saturation in the reservoir; these wells also confirmed the geologic structure. Wells A and C were perforated so that pressure and temperature could be monitored and air samples collected. Wells F and G were drilled 5 and 7.3 m (16 and 24 ft) from the I/W well to provide instrumentation locations near the point of injection/withdrawal.

Well H (not shown in Figure 3.7) was drilled 7.5 m (24.5 ft) due east of the I/W well to a total depth of 220 m (722 ft). The well was perforated over a 1.5 m (5 ft) interval [between 200.6 and 202.1 m (658 and 663 ft)] within the white portion of the St. Peter sandstone. Well H provided for wireline monitoring of temperature and pressure at the injection depth, and was also used as an alternate injection/withdrawal well during a late portion of the experiment. An important difference between the behaviors of the green and white St. Peter strata was expressed in their respective resistances to air injection and withdrawal. The green sand layer in the

vicinity of the I/W well contains clay minerals and secondary mineralization; its petrology is erratic. The underlying white St. Peter is more uniform in composition; open fracture zones, identified in core, probably accounted for higher permeability.

Bubble development began in October 1982. Air with relative humidity less than 5% and temperature close to that of the natural reservoir was injected into the green St. Peter sandstone through the I/W well. Even after reperforation of the I/W well casing and three acidizations of the well, the injection flow rate never exceeded 35% of the calculated upper limit, which was based upon a permeability of 700 millidarcies (estimated from core tests). Therefore bubble development time was extended to about 6 months (Allen et al. 1984).

Bubble development information on mass flow rate and total volume as functions of time are shown in Figures 3.8 and 3.9 for the six-month period ending after March 1983 (Kannberg 1983). The discontinuity during the last week of January occurred during project transfer from DOE to EPRI.

The complex purpose of air cycling experiments was to monitor: pressure response and flow characteristics within the reservoir; hydrologic interactions with the air bubble; temperature, pressure, and humidity variations near the wellbore; stability of air containment; amount of oxygen depletion; and efficiency of both mechanical and thermal energy recovery.

The injection parameters impressed upon the injection well and reservoir were pressure, temperature, relative humidity, and time. The mass flow rate and volume flow rate were determined by these factors and were restricted to lower-than-predicted values in all injection experiments involving the I/W well alone. In the withdrawal experiments mass flow rate, volume flow rate, air temperature, and air humidity were controlled by imposed back pressure and conditions of the reservoir and I/W well. The results of four injection/withdrawal cycles involving the I/W well are shown in Figures 3.10, 3.11, 3.12, and 3.13.

In later experiments involving well H, the injection mass flow rate available from the compressor was the regulating injection parameter. In other words, the resistance to flow was so substantially reduced that the design maximum injection pressure could not be reached before the design

FIGURE 3.8. Bubble Development--Mass Flow Rate Versus Time

FIGURE 3.9. Bubble Development--Volume Versus Time

FIGURE 3.10. Reservoir Response under Cycle Type A at 50°C Temperature

FIGURE 3.11. Reservoir Response under Cycle Type B at 50°C Temperature

FIGURE 3.12. Reservoir Response under Cycle Type C at 50°C Temperature

FIGURE 3.13. Reservoir Response under Cycle Type D at 50°C Temperature

maximum flow rate. Wide differences in the permeabilities of the perforated zones for well I/W and well H are believed to be the main cause for the contrast in injectivity.

Typical parameters and parametric ranges for injection and withdrawal involving the I/W well are shown in Table 3.7. Contrasting parameters and parametric ranges for the limited cycling experiments involving well H are shown in Table 3.8. The significant contrast between these data sets is seen in the difference between mass and volume flow rates. Well H is clearly less resistant to air injection and withdrawal.

Experimental curves which contrast mass flow rates between well I/W and well H are shown in Figures 3.14 and 3.15. Note that air injection and withdrawal rates decline parabolically in the I/W well whereas they tend to remain constant in well H.

Important behavioral characteristics of the cycling experiments included: 1) thermal development of the reservoir and energy recovery; 2) water coning; 3) sandface stability; 4) air bubble dimensional change; 5) chemical composition of the stored air; and 6) effect of injecting humid air (Allen et al. 1984).

Thermal development of the reservoir took place at a substantially lower rate than expected. Even during air injection at 200°C the greatest

TABLE 3.7. Physical Parameters for Injection and Withdrawal in Well I/W

	<u>Injection</u>		<u>Withdrawal</u>	
Pressure, MPa (psig)	2.07	(300)	0.28-0.41	(40-60)
Mass flow rate, scmm (scfm)	28-17	(1000-600)	17-8.5	(600-300)
Wellhead temperature °C (°F)	20-50	(68-122)	20-25	(68-77)
	125	(257)	25-35	(77-95)
	200	(392)	30-40	(86-104)

TABLE 3.8. Physical Parameters for Injection and Withdrawal in Well H

	<u>Injection</u>		<u>Withdrawal</u>	
Pressure, MPa (psig)	1.90	(275)	0.41	(60)
Mass flow rate, scmm (scfm)	31.6	(1130)	23	(800)
Wellhead temperature °C (°F)	15-25	(59-77)	17-20	(63-68)

FIGURE 3.14. Mass Flow Rate for the I/W Well

FIGURE 3.15. Mass Flow Rate for Well H

temperature measured near the sandface (through a wireline device in well I/W) was approximately 55°C. The dominant mechanisms of heat loss were by radial conduction and radiation from the wellbore. An attempt to insulate the wellbore by evacuation of the annulus was made but pressure was reduced only to about one-half atmosphere, an ineffectual level for increasing molecular mean free paths to macroscopic distances. In most elevated temperature experiments the withdrawal air temperature range was 25 to 35°C at the wellhead. The highest wellhead withdrawal air temperature was only about 40°C. In order to transfer heat to and from the reservoir at efficient rates the wellbore would require high performance insulation (Allen et al. 1984).

Water coning, the differential upward movement of aquifer water near the wellbore during air withdrawal, is caused by incremental pressure differences between air and water; in the extreme this effect can cause water production or water-restriction of the sandface. Neither event was recorded during air withdrawals from the IW well. During air withdrawal from well H a minor amount of water was withdrawn; this was attributed to lack of dehydration in the near wellbore region.

Sandface stability was satisfactory during most withdrawal experiments. However, during extended withdrawal at constant backpressure, sand production began which required periodic cleaning and occasional replacement of the filter, but this was not a serious operational handicap. The sand was unaltered and apparently originated from rock disaggregation near the wellbore.

Air bubble dimensional change during the cycling operations involved thickening and lateral growth because the mass of air injection predominated over the mass of air withdrawal throughout most of the cycling period. During air cycling the bubble volume grew from 2.13 to 3.17 million scm (75 to 112 million scf). The final bubble thickness at well H was approximately 9.2 m (30 ft). Air bubble thicknesses at observation wells were: Well A--8.2 m (27 ft), Well C--5.5m (18 ft), and Well D--5.5 m (18 ft). The thicknesses were measured with neutron and gamma ray logs. The air bubble configuration was determined by the geologic boundary above and the

hydrologic interface below. In plan, the air bubble base may have been approximately elliptical with major axis nearly east-west and minor axis nearly north-south. In three dimensions, the air bubble may have approximated a segment of a triaxial ellipsoid with the bubble thickness corresponding to the altitude. Mutually perpendicular dimensions calculated at PB-KBB were 9.2 m (30 ft) x 263 m (863 ft) x 395 m (1296 ft).

The chemical composition of air stored over a period of about 6 months showed depletion of oxygen to less than one-half percent by volume. The air sample was extracted from well C. This effect was attributed to oxidation of either suboxide minerals or sulfides such as marcasite and chalcopyrite, both of which are minor constituents of the green St. Peter. Loss of oxygen is believed to be a long-term effect. Analysis of samples of cycled air indicated insignificant oxygen reduction in the near-wellbore, cycling region (from which a CAES plant would draw air).

The effect of injecting water-saturated air at ambient temperature into the I/W well was studied over a three-week period just before terminating the experiments in 1983. The possibility of loss of wellbore permeability due to water condensation was not substantiated by results. Numerical modeling had predicted that ambient temperature injection of saturated air would not affect near wellbore air flow.

The following conclusions are drawn from CAES testing activities at the Pittsfield site: 1) Air injection, storage, and daily cycling have been demonstrated within a shallow, confined dome-shaped structure involving the permeable, water-saturated Ordovician St. Peter sandstone; 2) The importance of well completion within a sufficiently porous and permeable portion of the reservoir bed has been demonstrated; 3) Water coning was not an obvious problem; 4) Reservoir disaggregation was relatively minor; 5) Loss of oxygen was a long-term effect, unlikely to impact the near-wellbore cycling region at this or other similar sites, where the subsurface chemistry could affect CAES plant operation; and 6) Injection and recovery of significant thermal energy from the compression cycle would require high performance wellbore insulation.

3.2.3 Advanced CAES Concepts

Advanced CAES concepts are broadly defined as CAES systems that use little or no petroleum fuels for operation (Glendenning et al. 1979; Zaloudek and Reilly 1982). The advanced CAES concepts discussed are:

- CAES with fluidized bed coal combustion (CAES/FBC)
- CAES integrated into a coal gasification plant (CAES/CG)
- adiabatic CAES (ACAES)
- hybrid conventional/adiabatic CAES (hybrid CAES)
- direct coupled steam/CAES cycle (DCS/CAES)
- solar CAES coupled system.

3.2.3.1 Fluidized Bed Combustion

The CAES/FBC concept reduces the dependence on petroleum fuels by substituting coal as the principal fuel. Fluidized bed combustion can be integrated into a CAES cycle in a number of ways. To identify the most attractive cycle, PNL funded a study by United Technologies Research Center (UTRC) in which these cycle concepts were screened from the standpoint of technological and economic viability (Giramonti et al. 1981). Following this screening study, UTRC conducted a conceptual design of a CAES plant based on the most attractive cycle arrangement identified.

The optimal CAES/FBC cycle identified by UTRC used an open, pressurized, fluidized bed combustor (PFBC) integrated into a conventional CAES cycle. The UTRC conceptual design is diagrammed schematically in Figure 3.16.

The operating sequence of the CAES/PFBC plant design requires that the turbine section and compressor section be alternately connected and disconnected from the motor/generator. The compression side of the cycle is similar to a conventional CAES plant.

During the generating mode of operation, the compressor is disconnected from the motor/generator, and the turbine section is connected. Air

FIGURE 3.16. Pressurized, Fluidized Bed Combustion Plant Flow Diagram

is directed from storage and then travels to the recuperator where it is heated to 260°C (500°F). The heated air is then expanded in an expansion turbine from approximately air storage pressure down to a level compatible with that of the low-pressure turbine.

After leaving the expansion turbine, side streams of air are removed from the main stream to provide turbine blade cooling and to serve as transport air for the coal and dolomite fuel system and the coal ash and spent dolomite handling system. The main flow of air goes to the fluid bed combustor system, where it is used as combustion air in the fluidized bed. The transport air is reunited with the main stream prior to and within the fluid bed combustor. The hot exhaust gases at 890°C (1562°F) from the fluid bed are cleansed and are expanded in the low-pressure turbine.

The gas stream then travels to the recuperator. En route, however, another side stream of air is removed to provide drying for the coal and dolomite feed. The remaining stream proceeds to the recuperator to release a portion of its thermal energy to the storage air traveling to the expansion turbine. The relatively cool gases are then directed to the stack.

The UTRC conceptual design was based on the site used in the PEPCO/Acres American conventional CAES study to take advantage of the extensive geologic information available about this site and to enhance subsequent technical and economic comparisons. The key operation parameters of the UTRC CAES/PFBC design are given in Table 3.9. A detailed description of the design is provided by Giramonti et al. (1981).

3.2.3.2 Coal Gasification

The CAES coal gasification concept is another method for substituting coal for oil in a conventional CAES cycle. In this concept, a CAES cycle is integrated with a coal gasification plant to obtain synergistic benefits from the various internal air and energy flows. For example, in a CAES/CG plant, the gasifier could provide fuel for the CAES cycle; and the CAES cycle could, in turn, provide compressed air for the gasifier.

TABLE 3.9. Key Operational Characteristic of a CAES/FBC Plant

Turbine output, four units	876.4 MW
Compressor input, four units	799.6 MW
Heat rate	
Generation	4788 kJ/kWh (4538 Btu/kWh)
Compression	9595 kJ/kWh (9095 Btu/kWh)
Round trip	14,383 kJ/kWh (13,633 Btu/kWh)
Storage pressure	7.22 MPa (71.2 atm)
PFBC bed temperature	850°C (1562.0°F)
PFBC bed pressure	1.52 MPa (15.0 atm)
ET inlet temperature	264°C (507.5°F)
LT inlet temperature	850°C (1562.0°F)
Annual utilization	2190 hr/yr
Capacity factor	0.25

Under EPRI sponsorship, UTRC studied this concept (Giramonti and Sadala 1979) to examine the technical and economic implications of integrating CAES and coal gasification technologies. This study did not include the conceptual design of a CAES/CG plant, but involved only a screening to identify the most technologically and economically promising concepts.

After preliminary screening, the UTRC study focused on four gasification processes and two cleanup systems. The coal gasification systems included:

- U-Gas
 - Texaco
 - Foster Wheeler/BCR
- Kellogg.

Both daily cycling of the gasifier with power production and continuous operation were investigated. No one gasifier type appeared to offer significant advantage over the others considered. The CAES plants using continuous gasifiers were found to be uneconomical. Cycling plants, on the other hand, were found to be possibly competitive with conventional power peaking technologies. In contrast with these results, recent studies by Haydock and Hobson (1981) indicate that continuously operating coal gasifiers are particularly well suited to mid-range generation. In the limit, they can operate completely independently of a supply of energy from the utility power system (for charging air storage). Whatever the generation mix in the power system may be, now or in the future, such plants need never consume any fuel but coal.

A very simplified flow diagram of one cycling CAES/CG concept considered by UTRC is shown in Figure 3.17. This concept uses a Foster Wheeler/BCR cycling gasifier with a Conoco cleanup system. The cycle is very complicated and involves many components, which have been grouped or omitted in Figure 3.17 for clarity. In brief, the compressed air from storage at about 6.9 MPa (1000 psia) provides air for both the gasifier and the compressor trains. The gasifier produces fuel for the otherwise conventional CAES turbine system. The performance parameters for this system are provided in Table 3.10.

3.2.3.3 Adiabatic CAES

In the adiabatic CAES cycle no fuel is consumed. The heat of compression is stored during the charging cycle instead of being discarded as is done in a conventional CAES plant. This stored heat is used during the discharge cycle to heat the compressed air withdrawn from storage before it is expanded in the turbine. The adiabatic CAES concept can be used with any type of storage reservoir--hard rock caverns, salt domes, or aquifers.

Acres American, Inc., performed a conceptual design study and economic analysis of adiabatic CAES under DOE sponsorship (Hobson 1981). This study considered underground thermal storage and a water-compensated hard rock cavern for high-pressure air storage. It was based on the earlier DOE/EPRI/

FIGURE 3.17. CAES/Coal Gasifier Conceptual Configuration

TABLE 3.10. Integrated CAES/Coal Gasification System
Performance with Cycling Gasifier Operation

Gasifier system	Foster Wheeler/BCR
Cleanup system	Conoco
Power cycle	Gas turbine
Power, MW	
LP turbine	207.0
HP turbine	76.2
Fuel gas expander	7.0
Cooling air expander	9.4
Gross output	299.6
Auxiliaries	6.8
Boost compressor	1.2
Net output	291.6
Heat rate, kJ/kWh	
Generation	4760 (4512 Btu/kWh)
Compression(a)	7681 (7281 Btu/kWh)
Round trip	12,442 (11,793 Btu/kWh)
Compression/generation	
Time ratio	1.0
<hr/>	
(a) Energy from utility grid at 10,550 kJ/kWh (10,000 Btu/kWh) heat rate, compressor power equals 212 MW.	

PEPCO study of a 920-MW conventional CAES plant design prepared by Acres for a site in Maryland. A flow diagram of the adiabatic CAES cycle finally selected by Acres is shown in Figure 3.18.

During charging, grid power is used to drive the compressor train, which compresses air to 8.38 MPa (1215 psi) for storage in the mined hard rock cavern air storage reservoir. When the air emerges from the low-pressure compressor, its temperature and pressure are 466°C (870°F) and

During discharge, the motor/generator is uncoupled from the compressors and coupled to the turbine train. Air from the reservoir is heated to 443°C (830°F) in the high-pressure TES and expanded in the high-pressure turbine to 166 MPa (240 psi) and 227°C (440°F). It is reheated to 463°C (865°F) in the low-pressure TES and further expanded in the low-pressure turbine. Because the turbine inlet air temperatures are much lower in adiabatic CAES than in a conventional cycle, the adiabatic cycle suffers poor performance parameters. The performance parameters for the Acres design adiabatic CAES system are given in Table 3.11.

TABLE 3.11. Adiabatic CAES System Performance Parameters

Unit output (four units)	205 MW	
Charging ratio	1.48	
Compressor design flow rate	295 kg/sec (650 lb/sec)	
Expander design flow rate	340 kg/sec (750 lb/sec)	
Compression period	12 hr	
Generation period	10 hr	
Storage pressure	8.38 MPa (1215 psi)	
Storage temperature	52°C (125°F)	
Overall heat rate	15,614 kJ/kWh (14,800 Btu/kWh)	
Plant efficiency	0.23	
Thermal energy storage	<u>TES I</u>	<u>TES II</u>
Pressure	1.56 MPa (226 psia)	8.38 MPa (1215 psia)
Mass flow rate	1179 kg/sec (2600 lb/sec)	1179 kg/sec (2600 lb/sec)
Temperature hot air in	466°C (870°F)	443°C (830°F)
Temperature cool air in	238°C (460°F)	38°C (100°F)
Effectiveness	0.966	0.966
Pressure loss	34.5 kPa (5 psi)	27.6 kPa (4 psi)

The thermal energy storage unit is one of the most important items of an adiabatic CAES system. These units are essentially regenerative air heaters. However, performance, lifetime, and cost restraints imposed by the CAES application preclude use of conventional materials and technology in their design and construction. Acres American examined a wide range of TES types and materials to find a preferred design. This final design consists of sensible heat storage beds composed of sintered iron oxide pebbles. (See Section 3.2.2.5.) These beds are contained in a mined hard rock cavern for pressure containment. Bypass air from storage keeps the cavern walls cool. It is expected that the TES beds will slowly comminute due to the effects of thermal cycling. Therefore, particulate separators are provided to remove the detritus from the air to protect the turbines from erosion damage. Figure 3.19 shows a cross section of the Acres American TES design.

FIGURE 3.19. Acres American Thermal Energy Storage Design

3.2.3.4 Hybrid Compressed Air Energy Storage Concept

The hybrid CAES cycle includes features of both the conventional petroleum fuel-fired CAES cycle and the adiabatic CAES cycle. The addition of thermal energy storage to conventional CAES can reduce petroleum fuel use without the performance penalties associated with the adiabatic cycle.

United Engineers & Constructors, Inc. (UE&C) and Brown Boveri Corporation performed an engineering and economic study (Karalis and Stys 1981) of a hybrid CAES cycle under EPRI sponsorship. In this study, air is stored in solution-mined salt caverns with the site conditions prevailing at the Carmichael Salt Dome southwest of Jackson, Mississippi.

Figure 3.20 shows the general flow diagram for this hybrid cycle and includes both the heat and mass balance. During charging, grid power is used to compress air in the low and intermediate compressors without intercooling to 1.66 MPa (240 psi) and 482°C (900°F). The heat of compression is removed in a thermal energy storage unit. The air is

FIGURE 3.20. Hybrid CAES Cycle with Thermal Energy Storage

then further compressed in a high-pressure compressor and cooled in intercoolers and aftercoolers. Air at 7.6 MPa (1100 psi) and 60°C (140°F) is stored in the salt cavern. During discharge, the compressed air is removed from the reservoir, heated in the recuperator, and expanded in the high-pressure turbine. This air is then reheated to 460°C (860°F) at 1.38 MPa (200 psi) by passing it through the TES unit. This air is further heated by the firing of petroleum fuel to 890°C (1634°F), then expanded in the low-pressure turbine; remaining heat is removed in the recuperator. The performance parameters for the hybrid CAES design are listed in Table 3.12.

TABLE 3.12. Hybrid CAES System Operating Parameters

Unit output	220 MWe
Compression hours	8.61 hr/day
Generation hours	8 hr/day
Charging ratio	1.038
Overall plant heat rate	14,306 kJ/kWh (13,560 Btu/kWh)
Fuel consumption	2806 kJ/kWh (2660 Btu/kWh)
Overall plant efficiency	25.2%
Compressor design flow rate	300 kg/sec (661 lb/sec)
Expander design flow rate	323 kg/sec (712 lb/sec)
Storage	
Pressure	8.31-5.4 MPa (1204-789 psia)
Temperature	40°C (104°F)
Thermal energy storage unit	
Air flow rate	18.9 l/sec (0.667 ft ³ /sec)
Temperature hot air in	491°C (916°F)
Temperature hot air out	460°C (860°F)
Maximum inlet pressure	1.66 MPa (241 psia)

The thermal energy storage unit designed by UE&C was a sensible heat storage device similar to the unit designed for the adiabatic CAES study by Acres American. However, this unit differed in two important ways. First, UE&C used an aboveground post-tensioned concrete pressure vessel to contain the TES. Because the pressures attained in the TES are relatively low, a single containment vessel is not outside the capability of existing technology. Second, UE&C chose to use 1.27-cm (0.5-in.) diameter balls of Denstone® Product #57 as the TES material. Iron oxide such as used by Acres American in the adiabatic CAES study was also considered as a primary candidate. However, it was not used in the final design because of insufficient available information regarding its properties.

3.2.3.5 Thermal Energy Storage Bed Materials Testing

Recent experimental results are germane to the selection of durable and reliable regenerative heat exchangers that could endure for a 30-year plant lifetime under the thermally and chemically aggressive conditions expected in an advanced adiabatic or hybrid CAES system. A joint DOE/EPRI-sponsored study was performed by Pacific Northwest Laboratory and Fluidyne Engineering Corporation to experimentally screen four materials to determine their performance and durability (Zaloudek, Wheeler and Marksberry 1983).

The materials considered included 0.95-cm (0.375-in.) iron oxide pellets, 1.27cm (0.5-in.) OD Denstone pebbles, 2.54-cm (1-in.) OD cast-iron balls, and crushed Dresser basalt. The iron oxide pellets are an intermediate product in the production of steel from ore and are available in large quantities. Denstone is commonly used as a catalyst bed support in the petroleum processing industry. The cast-iron balls are commercially produced for tumbling and grinding processes. The crushed Dresser basalt rock selected for evaluation was 1.00 to 5.00-cm (0.5 to 2-in.) in diameter. This material was processed by autogenous grinding, screening, and washing before being tested.

®Denstone 57 is an alumina-silica product of Norton Company.

The experimental approach used in evaluating these materials was strongly influenced by capabilities of available testing facilities. Two types of tests were performed. In one the particulate formation characteristics and thermal ratcheting of these materials during thermal cycling was investigated. Tests were performed at a maximum temperature of 482°C (900°F), with temperature oscillation from 38 to 482°C (100 to 900°F) and mechanical loads equivalent to a 20-m (65-ft) high TES bed. However, dry, approximately atmospheric pressure air was used because of equipment limitations. This test was expected to produce realistic information on particulate formation and ratcheting, and conservative information on particulate carryout rates and sizes. Each sample was subjected to approximately 100 thermal cycles.

In the second type of test, the chemical attack of the TES system environment on these materials was investigated. This investigation was performed in autoclaves under static conditions for 30 days. Two types of autoclave tests were performed. The first considered the oxidation of the materials at approximately the maximum temperature [460°C (860°F)] and pressure [8.38 MPa (1215 psia)] expected in service. The second type considered the chemical attack of mechanically-loaded TES samples [simulating the loads from a 20-m (65-ft) high TES bed)] by air contaminated with 0.5 to 1.0 ppm SO₂, in the presence of liquid water simulating the condensation of atmospheric moisture. Temperatures were limited in these autoclave tests to the maximum dewpoint condition [138°C (280°F) and 8.38 MPa (1215 psia)].

The results indicated that the iron oxide pellets produced large quantities of large particulates that could potentially damage advanced CAES turbomachinery. Furthermore, the effect of moisture was observed to significantly lower the crush strength of the material, making it more susceptible to particle formation and particulate carryout. Therefore, iron oxide is not recommended as a satisfactory advanced CAES thermal energy storage material.

The cast iron tests showed evidence of thermal ratcheting, which is a buildup of internal stresses in the bed that could lead to material failure or rupture of the TES bed. However, this material performed satisfactorily in all other respects.

The Denstone also performed satisfactorily, except for a loss of crush strength when subjected to repeated thermal shock. This loss of crush strength was not apparently reflected in increased particulate formation rates or breakage in regions of the bed so affected. This material would require further testing before its suitability for advanced CAES plant TES service could be determined.

The crushed Dresser basalt appeared to perform satisfactorily in all respects in all of the tests. The acceptable performance, along with its comparatively low cost (\$4/ton in large quantities), led to the recommendation that Dresser basalt should be the preferred material in future advanced CAES plant TES system developmental activities.

3.2.3.6 Direct-Coupled Steam/CAES Cycle

Direct-coupled steam/CAES, a system conceived and analyzed by Drost and Reilly in 1981, has two generic features that make the cycle unique. First, the steam turbine of the steam power plant is directly shafted to the compressor, eliminating generator, motor, and transmission line losses. Second, a thermal energy storage (TES) unit is included to provide periodic thermal energy required by the CAES cycle without having to cycle the heat source. Direct coupling has the added advantage of providing a convenient use for the heat of compression (i.e., feedwater heating). One simulation indicated a round trip heat rate of 12,449 kJ/kWh (11,800 Btu/kWh). A cost analysis indicated a capital cost for the DCS/CAES of \$635/kWe in 1980 dollars. The levelized energy cost was determined to be 95 mills/kWh for an intermediate load facility. The levelized energy cost is 25% below the cost of a cycling coal plant for the same application and 35% below the cost of a combined-cycle plant.

Results of a performance analysis show that the DCS/CAES performance compares well with other advanced CAES cycles. This is caused by the direct coupling of the steam turbine to the compressor train in the DCS/CAES. The components of levelized energy cost for the DCS/CAES, the cycling coal plant, and the combined cycle plant are shown in Table 3.13 (Drost and Reilly 1981). In addition, the heat of compression is used to improve the performance of the steam cycle. It would be less expensive to build a small baseload coal plant and store the energy via the DCS/CAES concept than to build a full-size coal plant that would be idle 70% of the time.

The DCS/CAES cycle has not been optimized, and it appears that plant performance can be further improved. The performance of the direct-heated storage cycle may substantially improve with the addition of a regenerator. The advanced pebble bed storage cycle arrangement, which has not been the subject of a performance simulation or cost analysis, has the potential for a 15% decrease in heat rate.

The DCS/CAES cycle has several problem areas that should be addressed in any further study. These include the control of a complicated hybrid plant and the potential for reduced reliability caused by the combination of several technologies. The second problem can be reduced by designing the cycle so that the steam plant can be decoupled and operated as a

TABLE 3.13. Components of Levelized Energy Cost
(mills/kWh, 1980 dollars)

	<u>DCS/CAES</u>	<u>Cycle Coal</u>	<u>Combined Cycle</u>
Amortized capital cost	42.5	77.7	32.2
Operation and maintenance	18.4	16.0	14.6
Fuel cost	<u>34.1</u>	<u>31.9</u>	<u>99.1</u>
Total	95.0	125.6	145.9

steam plant alone in case of a failure in the CAES cycle or TES. In addition, the lack of operating experience with large thermal storage units may be a problem. All other components of the direct heated storage cycle are felt to be commercially available. It should be noted that the DCS/CAES concept opens a new market for CAES technology. System-wide CAES is applicable to utilities with excess baseload capacity. The DCS/CAES concept will be of interest to utilities that do not have excess base-load capacity but that want to add an intermediate load facility. This type of utility would not previously have been interested in CAES.

The DCS/CAES concept has potential to substantially reduce the cost of power for intermediate load applications. Further study is recommended on cycle analysis and resolution of questions concerning control and reliability.

3.2.3.7 Solar CAES-Coupled System

Solar thermal augmentation of adiabatic CAES was evaluated with two 3.25-MPa (32-atm) design variants on a study by Flynn and Nash-Webber in 1979. The solar thermal energy raised the turbine inlet temperature from the adiabatic 427°C (800°F) to 816°C (1500°F). This had the effect of increasing the energy return ratio from 0.75 to 1.2, thus decreasing charging costs. It also decreased turbine specific mass flow and thus cavern volume and TES costs. However, the high capital cost of the solar collectors and the central receiver more than offset the capital cost savings for the CAES system. For the variant using sensible-heat storage as a backup system, the costs were not competitive with gas-turbine peaking. Unless the cost of solar collection decreases greatly, while at the same time off-peak electricity costs remain low and distillate fuel costs increase rapidly, this peaking-power system concept does not appear attractive in the near term.

3.2.3.8 Conclusions

The PNL assessment of second-generation CAES technology led to the following conclusions:

1. The adiabatic CAES appears to be the most attractive second-generation CAES system considered. It is operationally practicable, economically attractive, and close to technological readiness. Design of a demonstration plant could proceed in 2 to 3 years if research regarding TES system performance is undertaken in a timely manner.
2. The hybrid CAES concept is also a candidate for early demonstration. It is similarly operationally viable and close to technological readiness. However, it is not as economically attractive as ACAES. It has a more favorable charging ratio than ACAES, which may make it more attractive to some utilities.
3. The CAES/PFBC concept has numerous and complex developmental problems; their solution would require a major developmental program. Such development generally lies beyond the scope of CAES studies. Perhaps later, when PFBC technology becomes more advanced, this concept may become more attractive.
4. The CAES/CG concept with a cycling gasifier appears unsuitable for demonstration in the foreseeable future. The CAES/CCG concept is not as economically attractive as adiabatic CAES nor is it as near to technological readiness as adiabatic CAES.
5. Direct-coupled steam/CAES is an attractive second-generation system because direct coupling of the steam turbine to the compressor train eliminates generation, line, and motor losses. The heat of compression also improves cycle performance by preheating feed-water. This system compresses air without using electricity. Development time and expense are likely to be large.
6. Solar augmentation of adiabatic CAES is not yet feasible because of the high cost of solar heat collection systems.

3.2.4 Other Research and Development Activity

3.2.4.1 Utility Applications

The Utility Applications Program represents several studies sponsored by the Division of Electric Energy Systems in the U.S. Department of

Energy to assist in the development and transfer of CAES and Underground Pumped Hydroelectric Storage (UPH) technologies (Doherty and Loscutoff 1982). The primary beneficiaries of these studies are utilities that have indicated interest in implementing these energy storage technologies. The studies assist in identification and resolution of the practical problems associated with siting, constructing, and operating first-of-a-kind plants in the utility environment. The work within the scope of this program includes site selection and suitability studies; licensing, environmental, and fuel use exemption investigations; conceptual design; and utility systems studies. A primary project activity consisted of support of the Soyland Power Cooperative's original efforts to site and build a CAES plant. Assistance to Soyland's CAES siting and development studies constituted the major effort under this project. Support was provided in recommendation of architect/engineering services; siting, licensing and environmental investigations; obtaining conceptual equipment designs; and reviewing and advising on contract negotiation and cost estimate information critical to Soyland's decision making process. Subcontract activities in support of Soyland consisted of an environmental and technical siting study to provide a basis for Soyland's site selection process. This effort is complete (Doherty and Loscutoff 1982). Information from these studies provided a data base that utility managements can utilize in their determinations of economic feasibility for both CAES and UPH technologies.

The Soyland Power Cooperative, Inc., is a Rural Electric Administration (REA) generation and transmission cooperative composed of 15 REA distribution cooperatives whose service region is in central Illinois. It has part ownership of the Clinton Nuclear Plant and had planned construction of a coal-fired plant with a capacity of 500 MW in Pike County, Illinois. The cooperative now purchases its power from the local utility grid. Soyland's generation capacity planning studies indicated a 620-MW peak-load demand in 1987. Soyland therefore considered compressed air energy storage to meet its peak demand loads. The cooperative undertook preliminary feasibility investigations of a

hard rock reservoir CAES facility, and applied for and received a fuel use exemption from the Economic Regulatory Administration under the Fuel Use Act in order to build a CAES plant.

A decision was made to defer construction of the coal-fired plant. This deferral directly impacted Soyland's plans to construct the 220-MW compressed air energy storage plant. CAES plans were suspended including expenditures on engineering and planning efforts.

3.2.4.2 Electric Power Research Institute and Industry Effort

The Electric Power Research Institute, in addition to cosponsorship of the predemonstration studies and some of the research noted above, sponsors research and development of other projects related to CAES power plants. These efforts are focused on using the following R&D strategy: Resolve near-term problems that might adversely effect the first USA-based CAES plants; if problem solutions call for hardware rather than paper study projects, actively pursue a budget teaming or cosponsorship approach in such a manner that important problems are addressed by using the right tools; and actively pursue the technology transfer of existing R&D results into the utility, manufacturing, excavation, and architect and engineering firm industries. Below are described specific on-going project areas (Schainker 1981).

3.2.4.2.1 Champagne Effect. The champagne effect is a phenomenon associated with operation of a water-compensated air storage cavern. The effect depends upon pressurized dissolution of air within water at the cavern air-water interface and subsequent exsolution of air from water at the reduced pressure within the compensating column (Blecher, Giramonti and Smith 1979). The effect is potentially triggered during air injection (cavern charging) when air-saturated cavern water is displaced to a lower-pressure environment in the compensating shaft. Once air exsolution begins, the compensating column will tend to accelerate upward due to buoyancy as the exsolution process increases the volume proportion of gas to liquid.

Design features suggested for preventing the champagne effect can be grouped into those that attempt to 1) restrict the rate at which air goes into solution in the cavern, 2) reduce the buoyancy effects caused by the bubbles in the shaft, 3) minimize or balance the pressure differential that tends to accelerate the fluid, 4) introduce geometric constraints that tend to reduce acceleration of the fluid, and 5) combine any of the above (Giramonti and Smith 1981). Representative of these generic design changes are 1) introduction of a physical barrier to prevent dissolution of air, 2) construction of a U-bend in the water-compensating shaft beneath the cavern to balance the buoyant head, 3) modification of the height and/or cross section of the compensating shaft to counter the buoyancy effect, and 4) introduction of flow restrictions to increase fluid friction and slow fluid ascent.

Numerical modeling of the champagne effect in water-compensated CAES operations was conducted by Rowe and McMonagle (1981) and McMonagle and Rowe (1982) in concert with Dr. J.C. Mollendorf of the State University of New York at Buffalo to evaluate the effect's importance to the Potomac Electric Power Company CAES plant design. A conservative analysis showed that the champagne effect can produce flow oscillations during charging but that these oscillations can be restrained to acceptable levels by appropriate design and operation parameters. Four factors were projected (Schaub, 1981):

The diffusion rates of air into water, even at the high pressures being considered, are relatively low. This is true even when the cavern water volume is small.

The degree of air saturation reached in the cavern water over a given period can be minimized by maintaining a high water level in the cavern.

- When startup of air compressing occurs with the cavern almost full of water, the adverse impacts of the champagne effect are minimal, even when the cavern water is fully air-saturated.

- When startup of the air compressing operation occurs with the cavern almost full of air, the results of the analysis still indicate that safe operation of the plant is possible.

Although additional analytical and testing work is necessary to more fully understand and evaluate the details of the air diffusion and release process, the following conclusions stand (Schaub 1981):

- The technical and economic feasibility of CAES to meet the needs of the PEPCO system is not significantly affected by the champagne effect.
- Safe operation of the plant is possible under all conditions.
- With reasonable operational constraints imposed on compressor startup and extended shutdowns, the effect of the air diffusion¹ release process on plant operation can be essentially eliminated.

The champagne effect, at our present state of knowledge, does appear to impose cost penalties on the construction of a CAES plant. Electric Power Research Institute activities now underway consist of refinement of models, experimental systems and the high pressure air water system data base in order to better characterize the effectiveness of control measures and minimize cost penalties.

3.2.4.2.2 Evaluating Applicability of CAES to a Utility System

Currently the assessment of a CAES plant for future installation in a utility system is a detailed, time consuming, costly process (Karalis et al. 1982). A simplified evaluation procedure has been assembled by United Engineers and Constructors under contract to EPRI and consists of both a first-cut CAES geology and system screening analysis and a more detailed geology and system economic analysis. Additionally, the economics potential of CAES is compared with other alternative types of intermediate/peaking generation, on a utility-specific basis.

Based on economics, the preferred type(s) of generating plant for installation in a given year are selected for further study. The results are not meant to be a basis for a decision to design and con-

struct a facility, but rather to determine whether further examination of CAES in a more detailed feasibility study is worthwhile.

The first part of the evaluation, system screening for CAES operation, examines both the available geology and the compatibility of a CAES plant with the operating characteristics of the utility. The geology of the utility's service area and that of the adjacent utilities is reviewed for potential CAES plant sites by examining generic geology data. If suitable geology is present in a selected area, a system screening analysis investigates the availability of compression energy for CAES operation and whether the system characteristics will allow the CAES plant to operate economically for a given future year. If the results are favorable, a system comparative economic analysis is undertaken. If the results are unfavorable, appropriate additional future years are screened for system operation.

The second part of the evaluation, system comparative economic analysis, includes the preparation of a CAES plant definition and cost estimate specific to the system. The CAES cost estimate is used together with other appropriate input data in an economic unit system dispatch, which is performed manually. The total generating cost of the CAES plant is compared with that of alternatives, typically taken from the system expansion plan. After an economic comparison on the same basis, the best candidate is selected for subsequent examination in a detailed follow-on feasibility study.

The simplified evaluation of a CAES facility is applicable to a conventionally fired CAES plant with either salt, hard rock, or aquifer air storage. Advanced CAES designs (adiabatic or hybrid) are not included because this evaluation is oriented to CAES systems that use existing technology and whose components are commercially available.

3.2.4.2.3 Recuperative Heat Exchangers in CAES Optimization of the conventional CAES cycle requires use of a recuperator to recover

exhaust waste heat and use it to preheat incoming combustion air (Lukas and Schainker 1982). The tubular design, in which many small tubes are welded to a heavy tubesheet, is well suited to CAES because of the high pressure on the inlet side. Three main problems were identified: 1) cracking of recuperator welds or tubes from thermal stresses, 2) low temperature corrosion by condensed sulfuric acid, and 3) difficulty of repairing leaks caused by thermal stress failure or corrosion. Finite element modeling was used to calculate thermally-induced stresses.

Thermal stresses can be reduced by:

- adding flexibility to the joints
- reducing the heat flow rate to thinner sections
- maintaining temperature during shutdown periods
- lengthening the startup cycle

selecting appropriate alloys

eliminating gaps in heat transfer paths.

Overcoming low-temperature corrosion requires selection of acid-resistant alloys.

3.2.4.3 Insurability of CAES Plants

International Research and Technology Corp. has performed a preliminary Cavity Degradation Risk Insurance Assessment (1979). This work was conducted in parallel with the three predemonstration studies under the sponsorship of the Division of Electrical Energy Systems within DOE. Their report includes 1) technical background and status of CAES; 2) potential failure modes in hard rock, salt, and porous media; 3) risk analysis, actuarial assessment, and loss-preventive measures; and 4) insurance implications, including conditions for electric utility insurance underwriting and alternatives to commercial insurance.

The following germane points are made in the report:

Risks associated with CAES are similar to risks encountered in underground storage of natural gas and LPG, in subsurface mining by

excavation, in solution mining of salt, and in aboveground pumped hydroelectric operations. Losses associated with these similar technologies have rarely been large.

- The experience at Huntorf is directly applicable to succeeding CAES plants that use salt cavities.
- Traditional information sought by insurers for first-of-a-kind technologies includes utility risk management data, corporate financial data, and technical data on the new installation.
- Design and stability criteria for hard rock, salt, and aquifers are developed to minimize all plausible risks associated with siting, construction, and operation.
- Equipment, operating, and monitoring specifications are developed to reduce risks and detect environmental change.
- Current insurance coverages maintained by utilities are likely to be flexible enough to cover new operations, including CAES.
- Electric utilities usually prefer to assume large portions of risk, say \$1 million or more.
- Alternatives to commercial insurance include 1) self-insurance, 2) multi-utility risk sharing, 3) trust funds, 4) mutual assessment associations, 5) government-sponsored insurance, and 6) government-enforced liability limitation.

3.2.4.4 Environmental Concerns—

Environmental studies and issues involving CAES have been summarized by Beckwith & Associates (1983). The following environmental impacts are considered: 1) air pollutant emissions, 2) water consumption and discharge, 3) land requirements, 4) fuel requirements, 5) noise, 6) meteorological impacts, and 9) hydrologic impacts. Site selection methods and regulatory issues are discussed. Work summarized includes environmental studies performed independently, as part of

design studies, and within technology development programs, funded by both DOE and EPRI.

Significant conclusions are as follows:

- The environmental impacts associated with construction and operation of the CAES facilities are generally similar to or less severe than those associated with construction of conventional electrical generating facilities. They are therefore generally amenable to conventional mitigation strategies.
- Adverse subsurface and surface environmental impacts can be largely avoided by thorough geological characterization of subsurface conditions, careful evaluation of surface environmental factors, and avoidance of unsuitable sites.
- A large number of suitable sites exists throughout the U.S.
- Siting flexibility for CAES facilities is much greater than for other energy storage technologies, such as pumped hydroelectric storage.
- Land use requirements are generally significantly less than for conventional (coal, nuclear, hydroelectric) generating facilities of similar generating capacity.
- Petroleum fuel use is much less than for conventional peak power generating facilities, such as combustion turbines. This results in significantly less impact on air quality.
- CAES technology offers the potential for increased efficiency of utilization of utility system generating capacity resulting in reduced overall commitment of resources and therefore reduced environmental impacts.
- Uncertainty still surrounds the legal and regulatory issues associated with CAES, primarily because of the recent implementation of several environmental regulatory programs and the lack of experience and precedent in implementation of this new technology.

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