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EVALUATION OF TURBOMACHINERY FOR COMPRESSED AIR ENERGY STORAGE PLANTS

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EVALUATION OF TURBOMACHINERY FOR COMPRESSED AIR ENERGY STORAGE PLANTS

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ABSTRACT

This paper presents a study of possible turbomachinery options for compressed air energy storage plants. The plant is divided into four subsystems: a turbine system, compressor system, motor/generator, and an underground air storage reservoir. The turbine system comprises a high-pressure turbine and combustor, a low-pressure turbine and combustor, and a recuperator. The compressor system comprises a low-pressure compressor, booster compressor, intercoolers, and an aftercooler. A water-compensated mined cavern constitutes the underground air-storage reservoir. Plant performance is presented in terms of five parameters: specific air flow rate, specific heat rate, specific storage volume, specific compression rate, and overall plant efficiency. The capital and operating costs of the plant as a function of the turbomachinery options are presented. Design variables of the turbomachinery are the reservoir pressure and inlet gas temperatures to the turbines.

INTRODUCTION

Compressed air energy storage is a near-term technology for the load leveling and peak shaving strategies being considered by electric utilities. Assessments of the technical and economic feasibility of this storage system indicate that it is economically competitive with conventional gas-turbine peaker units. The CAES concept is based on a split Brayton cycle with an accompanying underground air storage reservoir. During periods of off-peak power demand, air is compressed with base-plant power and stored in the underground reservoir. For power generation, the air is discharged through a combustion turbine during the peak demand period.

Because the storage reservoir is usually the most costly single component in a CAES plant, its volume is a sensitive design parameter. The volume required is affected by storage pressure and temperature, power level, generation time, reservoir type, air quantity required by the turbine system, and pressure ranges permitted by the turbomachinery (turbines and compressors). Compressed air can be stored underground in caverns or in the pore space of porous rock formations.

The components of the subsystems of a CAES plant are delineated here for precision of reference in this paper. The turbine system consists of a low-pressure gas turbine (LGT) and combustor, a high-pressure gas turbine (HGT) and combustor, and a recuperator (see Fig. 1). The LGT is a turbine modified from a conventional gas-turbine peaker unit. For proposed CAES plants, the HGT is a modified steam turbine operating at gas temperatures of about 1000°F. Optimized designs for compressed-air turbines that operate at high temperatures have been investigated.[1] The combustors can be designs modified from conventional gas-turbine peaker units. Preliminary studies indicate that recuperators can be designed that are economically feasible for CAES application. These differ from conventional gas-turbine peaker units because of the high-pressure air leaving the reservoir.

The compressor system contains a low-pressure (LC), high-pressure (HC), and booster compressor (BC), intercoolers, and an aftercooler (see Fig. 1). Intercooling is required to operate the compressors within limits tolerable for standard

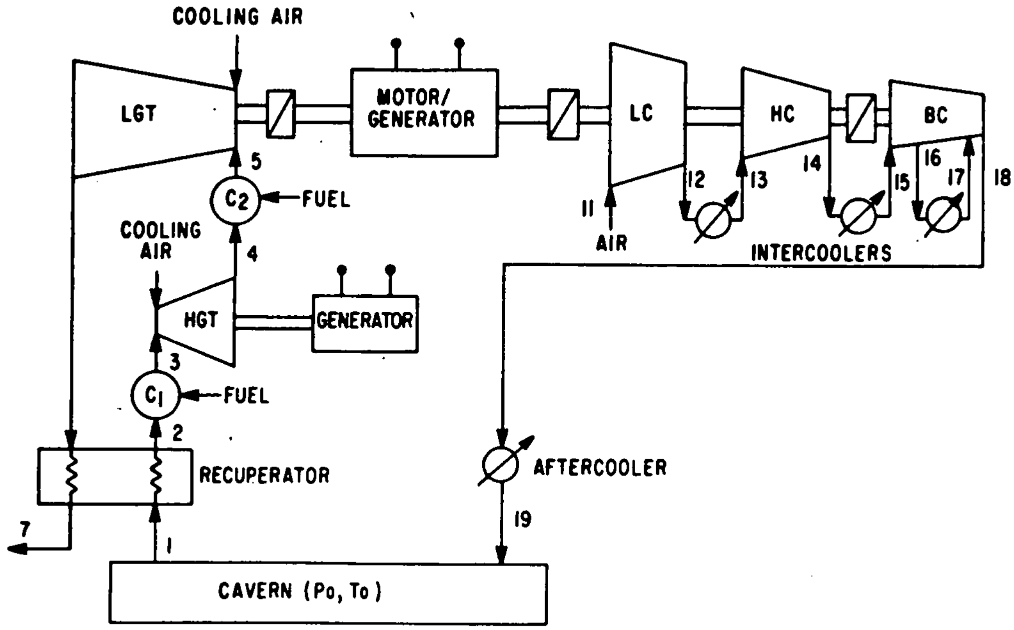

Fig. 1. Schematic Diagram of CAES Plant

materials. An aftercooler is used to cool the air to avoid possible thermal-stress damage to the storage reservoir.

The performance of a CAES plant can be characterized in terms of four specific parameters and an overall plant efficiency:

- Specific air flow is the mass flow rate of air supplied to the turbine system per kilowatt power generated. It is the major factor in determining the size of the turbines, compressors, and air-storage reservoir.
- Specific heat rate is directly proportional to fuel consumption and is equal to the product of specific fuel consumption and the lower heating value of fuel. It therefore affects the operating cost of the turbines.
- Specific storage volume, the volume of reservoir required per kilowatt of power generated, is dependent on the specific air flow rate and the temperature of stored air.
- Specific compression rate is the energy equivalent of the power supplied to the compressors per kilowatt of power generated. This parameter is the amount of off-peak energy required to operate the compressors.
- Overall plant efficiency is equal to the total energy output from the turbines divided by the sum of the energy input from the fuel and off-peak energy to the compressor system.

The cost of a CAES plant can be characterized in terms of capital cost and operating cost. Capital cost includes the direct cost of the air storage facility, the turbomachinery, the balance of plant, and the indirect cost due to a contingency allowance, engineering and administration, and escalation and interest during construction. The operating cost of the plant includes the capital charge, cost of fuel to the combustors, off-peak electricity to the compressors, and operation and maintenance costs.

This paper presents a study of possible turbomachinery options for CAES plants with particular emphasis on the turbine system. The performance and cost of the complete plant resulting from different turbomachinery options are presented. The turbine system design parameters considered are the reservoir storage pressure and the inlet gas temperatures to the LGT and HGT. The LGT was based on a nominal pressure ratio of 16:1.* A water-compensated mined cavern was chosen as the compressed air storage reservoir.

*Studies have indicated that pressure ratio has a minor effect on performance and conventional low-pressure turbines (from peaker units) having a nominal pressure ratio of 10-16:1 can be used.[2,3]

PERFORMANCE EVALUATION

THERMODYNAMIC ANALYSIS

A thermodyanmic analysis was carried out on each subsystem of a CAES plant, and the results were combined to evaluate overall plant performance. Design parameters considered in the analysis include: air storage pressure and inlet gas temperatures to the high-pressure gas turbine and low-pressure gas turbine. The details of the analysis are presented in Ref. 4.

Underground Air Storage System. The underground air storage reservoir considered is a water-compensated cavern. Therefore, the pressure variation in the cavern during the operating cycle is negligible. The air temperature of the storage cavern (T_O) was assumed as 120°F (322°K) and four different air storage pressures (p_O) were considered in the analysis: 30, 50, 70, and 100 atm (3×10^6, 5×10^6, 7×10^6, and 1×10^7 Pa).

Turbine System. The selection of the turbine system (see Fig. 1) evolved from the results of a previous study.[2] The following values of system parameters were considered:

Turbine efficiencies: $\eta_{LGT} = \eta_{HGT} = 0.90$,

Recuperator effectiveness: $\varepsilon = 0.8$

Temperatures: T_3 = 1000°,1600°,2000°,2400°F (811°,1144°,1366°,1589°K)

T_5 = 1600°,2000°,2400°F (1144°,1366°,1589°K),

Pressures: p_5 = 16 atm (1.6×10^6 Pa).

Subscripts given in the above parameters correspond to the components or stations in Fig. 1. The efficiencies of turbines and combustors are based on state-of-the-art values of available equipment.[1] Recuperator effectiveness is a function of the heat exchanger specifications. Because the temperature of the inlet gas to the turbines must be kept low enough to avoid thermal damage of the turbine blades and vanes, cooling air is required for higher inlet gas temperatures. The amount of cooling air required was determined from data presented in Ref. 1.

Compressor System. The study was extended to the compressor system in order to complete the analysis of the CAES plant. The following parameters were assumed to be known or specified.

Adiabatic efficiency of compressors:
$\eta_{HC} = \eta_{LC} = \eta_{BC} = 0.90$;

Temperatures: T_{11} = 77°F, $T_{13} = T_{15} = T_{17}$ = 100°F, T_{19} = 120°F; and

Pressures: p_{11} = 1 atm, p_{14} = 16 atm.

PERFORMANCE RESULTS

Results of the parametric study are presented in terms of the five performance parameters: specific air flow rate, specific storage volume, specific heat rate, specific compression rate, and overall plant efficiency. These values are given as a function of air storage pressure and inlet gas temperatures to the HGT and LGT.

Specific air flow rate is the flow rate of air coming out of the cavern per unit output of the turbine system. It is directly proportional to the turbine and compressor sizes, and, thus, is an important factor in determining the cost of the above-ground facility. A plot of specific air flow rate against air storage pressure at different turbine inlet gas temperatures (Fig. 2) shows that the air flow rate varies from 6.6-12.0 lb/kWh (3.0-5.4 kg/kWh) for the conditions specified in this study, and it decreases as air storage pressure increases. In addition, higher turbine inlet gas temperatures result in smaller air flow rate, even though cooling air is required.

Specific storage volume, the required storage cavern volume per unit work output, is directly related to the cost of the underground facility for a CAES plant. This storage volume depends on the required specific air flow rate as well as on cavern conditions, such as pressure and temperature of stored air. Consequently, results for the specific storage volume show a trend similar to that for the specific air flow. Figure 3 shows the effects of air storage pressure and turbine inlet gas temperatures on the storage volume. It is seen that smaller storage volume results from higher air storage pressure or higher turbine inlet gas temperatures. Specific storage volume in this study varies from 0.96 ft^3/kWh (0.027 m^3/kWh) to 5.84 ft^3/kWh (0.162 m^3/kWh).

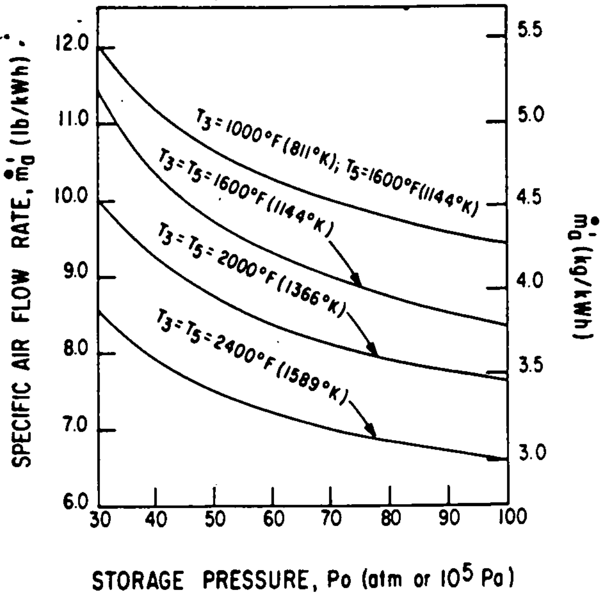

Fig. 2. Effect of Storage Pressure on Specific Air Flow Rate

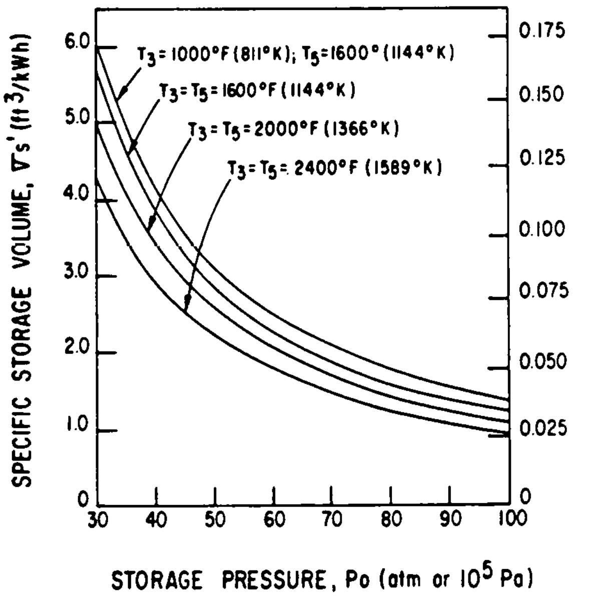

Fig. 3. Effect of Storage Pressure on Specific Storage Volume

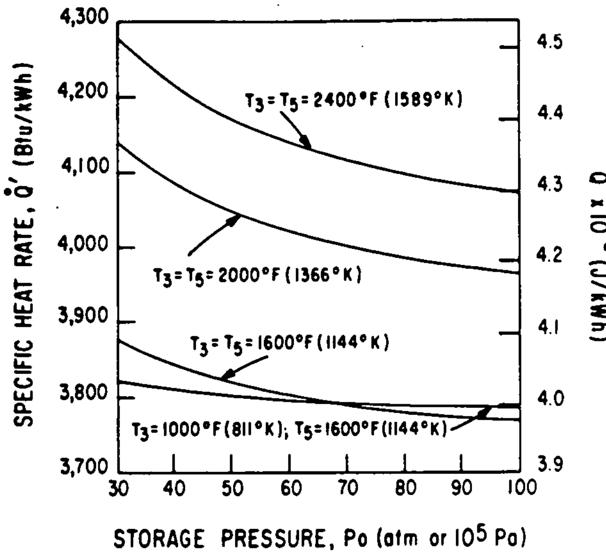

Fig. 4. Effect of Storage Pressure on Specific Heat Rate

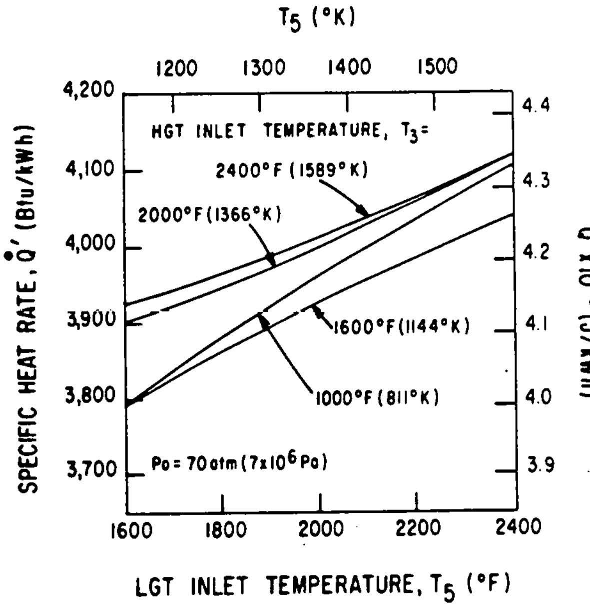

Fig. 5. Effect of Turbine Inlet Temperatures on Specific Heat Rate

Specific heat rate is a measure of premium-fuel usage for the combustors per unit power output of the system. It varies in this study from 3700 Btu/kWh (3.98×10^6 J/kWh) to 4280 Btu/kWh (4.52×10^6 J/kWh). The effect of storage pressure on the heat rate is given at different turbine inlet gas temperatures in Fig. 4: higher storage pressure results in lower heat rate. Figure 5 shows that heat rate increases as the LGT inlet gas temperature increases and that the HGT inlet gas temperature has a minor effect on the heat rate.

Specific compression rate is the fuel equivalent of the off-peak electrical energy input to the compressor system per unit power output of turbine system. In this study, specific compression rate is based on an off-peak heat rate, including electrical and mechanical losses, of 10,400 Btu/kWh (1.097×10^7 J/kWh). For the conditions of this study, the rate varies from 5280 Btu/kWh (5.57×10^6 J/kWh) to 7790 Btu/kWh (8.22×10^6 J/kWh). Figure 6 shows that, in general, compression rate increases slowly with increasing storage pressure and smaller compression rate is required by higher turbine inlet gas temperatures.

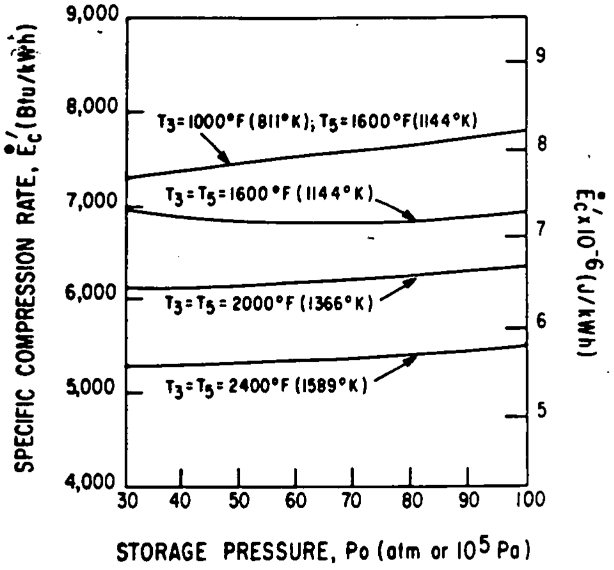

Fig. 6. Effect of Storage Pressure on Specific Compression Rate

The overall plant efficiency, the ratio of turbine power output to the sum of the power input to the compressors and the power equivalent of fuel energy, varies from 0.538-0.581 for the conditions specified in this study. The effects on the overall plant efficiency are given in Figs. 7 and 8.

Figure 7 shows the effects of storage pressures on plant efficiency: (a) for $T_3 = T_5 = 2400°F$ (1589°K) or $T_3 = T_5 = 2000°F$ (1366°K), plant efficiency increases with the storage pressure; (b) for $T_3 = T_5 = 1600°F$ (1144°K), plant efficiency increases up to 70 atm (7 x 10^6 Pa) and then decreases as the storage pressure further increases; and (c) for $T_3 = 1000°F$ (811°K), $T_5 = 1600°F$ (1144°K), plant efficiency decreases monotonically with storage pressure.

The effects of turbine inlet gas temperatures on plant efficiency are given in Fig. 8. It shows that higher plant efficiency is obtainable with higher HGT inlet gas temperature. It also shows that efficiency increases with the LGT inlet gas temperature for $T_3 = 2000°F$ (1366°K) or 2400°F (1589°K), and it has a minimum at about $T_5 = 2000°F$ (1366°K) for $T_3 = 1000°F$ (811°K) or 1600°F (1144°K).

ECONOMIC ANALYSIS

An economic analysis of the CAES plant was made to show the effects of the parameters on capital and operating costs. The analysis was based on the performance results described above. In order to provide a reasonable basis for the economic analysis, the following operating cycle was chosen: 20-hr nominal cavern storage capacity and 2190-hr/yr generation time.

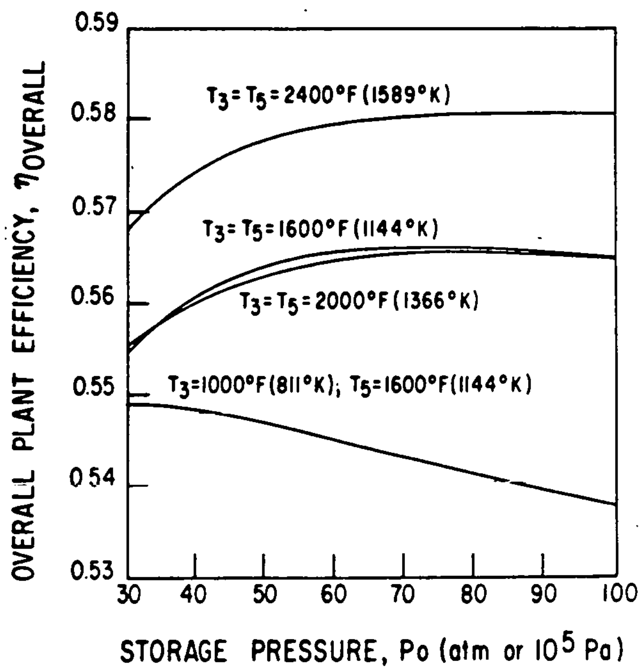

Fig. 7. Effect of Storage Pressure on Overall Plant Efficiency

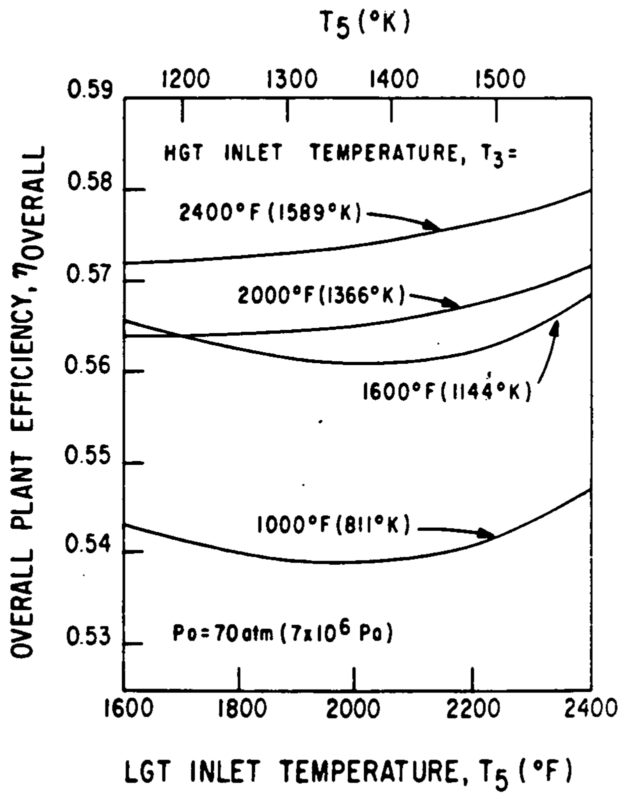

Fig. 8. Effect of Turbine Inlet Temperatures on Overall Plant Efficiency

CAPITAL COSTS

Direct capital cost of the CAES plant was divided into the following: cost of underground air storage cavern and water-compensating reservoir, cost of turbomachinery equipment, and *balance of the plant*.

The storage cavern cost included the cost of the air and water shafts, cavity, development and mobilization, and completion. The cost of the air and water shafts was estimated based on the cavern depth which was determined by the air storage pressure. The cost of the cavity was estimated based on specific storage volume with a 10% capacity margin. Since the storage cavern considered in the analysis is water-compensated, the cost of the water reservoir was also included. The storage-related costs were based on Ref. 5.

Estimation of the turbomachinery cost was based on Ref. 1. In this reference, the selling price is estimated for 10, 20, and 50 units. Based on the evaluation of regional markets and development potential for CAES conducted by Harza Engineering Company,[6] a 50-unit selling price was used in this study. The cost of the low-pressure gas turbine with a cycle-pressure ratio of 16:1 was determined by the inlet gas temperature and the cost of the high-pressure gas turbine was determined by both the inlet gas temperature and air storage pressure. Costs of the LC and HC with the overall compression ratio of 1:16 were estimated from the air flow rate, and the cost of BC was determined by the air flow rate and air storage pressure. A 25% allowance was given for the ducting and installation of the turbomachinery equipment.

The remainder of the plant equipment, which includes the clutches, motor/generator, recuperator, combustors, fuel storage, coolers, electrical power system, land, and plant structure was denoted as the *balance of plant*. This equipment is relatively insensitive to CAES design parameters and a fixed cost of $80/kW was used for the balance of plant for all cases of this study.

Total capital cost of the plant was estimated from the direct capital cost considering the following allowances: 15% for contingency, 10% for engineering and administration, and 30% for escalation and interest during the construction period.

OPERATING COSTS

Operating cost of the CAES plant consists mainly of capital charge, cost of fuel to the combustors, off-peak electricity to the compressors, and operation and maintenance. Annual capital charge was estimated from the total capital cost based on the fixed capital charge rate of 18% per year. Estimation of the cost of premium fuel was made by multiplying the specific heat rate by the cost of No. 6 oil. Cost of the off-peak electricity to the compressors was estimated from the specific compression rate and the electricity cost from the base plant. A value of 2 mills/kWh was used as the cost of operating and maintenance for all cases.

ECONOMIC RESULTS

Results of the economic study are given in terms of the two specific costs: capital cost ($/kW) and operating cost (mills/kWh). The values are presented as a function of the storage pressure (p_o) and the turbine inlet temperatures (T_3 and T_5).

Capital Costs. Capital cost of a CAES plant varied from $285/kW to $406/kW for the range of design parameters specified in the study. The cost of the underground storage cavern was found to be the highest component cost for most cases varying from 26-46% of the total capital cost and the cost of the turbomachinery equipment varied from 16-31% of the total direct capital cost. In general, it was found that higher turbine inlet temperatures result in higher turbomachinery cost.

Total capital cost is given in Fig. 9 as a function of storage pressure for four different combinations of inlet gas temperatures to the HGT and LGT. Capital cost sharply decreases with increasing storage pressure for all the cases up to 70 atm (7×10^6 Pa) and either slowly decreases or increases thereafter. Higher turbine inlet temperatures result in lower capital cost at low storage pressures, for example 30 atm (3×10^6 Pa). However, at storage pressures greater than 70 atm (7×10^6 Pa), higher turbine inlet temperatures result in higher capital cost. Among the cases considered in the study, the design parameters that result in the lowest capital cost are those when $T_3 = T_5 = 1600°F$ (1144°K) and p_o = 100 atm (1×10^7 Pa).

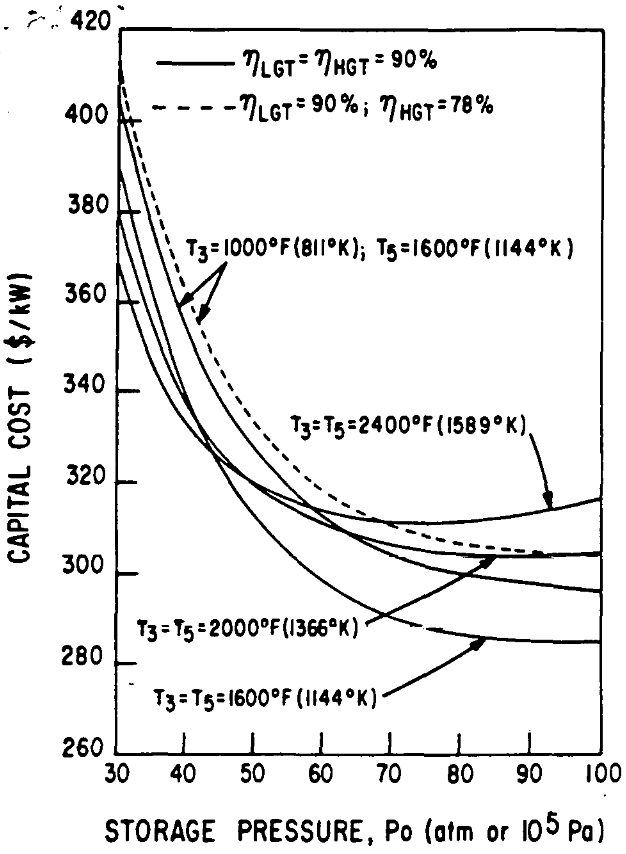

Fig. 9. Effect of Turbine Options on Capital Cost

The dotted curve in Fig. 9 represents the cost of a plant using a modified steam turbine (η_{HGT} = 78%) for the HGT, which operates at 1000°F (811°K) inlet gas temperature. The solid curve for T_3 = 1000°F (811°F) and T_5 = 1600°F (1144°K) is based on the assumption that the cost of this new, high-efficiency HGT (η_{HGT} = 90%) would be the same as that of the modified steam turbine. The actual cost of this new turbine would depend upon the development cost and the number of units sold. Thus, the actual high-efficiency cost curve should be somewhere between the solid and dotted curves. The net result is that the cost differences would be negligible, therefore favoring the use of the modified steam turbine because of proven reliability and equipment availability.

Operating Costs. The operating cost of the CAES plant is given in Fig. 10 as a funtion of the design parameters. The cost of premium fuel was selected as $2.50/$10^6$ Btu and the electricity cost was 15 mills/kWh. In this figure the operating cost varies from 44.8-55.5 mills/kWh.

The capital charge was found to be much higher than the cost of fuel or electricity; it amounts to 52-60% of the total operating cost. Consequently, the operating cost in Fig. 10 shows a similar trend to that of the capital cost. The figure shows that the operating cost decreases with increasing air storage pressure for all cases but $T_3 = T_5$ = 2400°F (1589°K), which has a minimum at about 70 atm (7 x 10^6). It also shows that, among the cases studied, the lowest operating cost results when $T_3 = T_5$ = 1600°F (1144°K) for $p_o \geq 58$ atm (5.8 x 10^6 Pa) and $T_3 = T_5$ = 2400°F (1580°K) for $p_o < 58$ atm (5.8 x 10^6 Pa). However, in the pressure range of 50-90 atm, which is the most likely range for CAES with a water-compensated reservoir, the difference in operating cost between different turbine systems is less than about 3 mills/kWh.

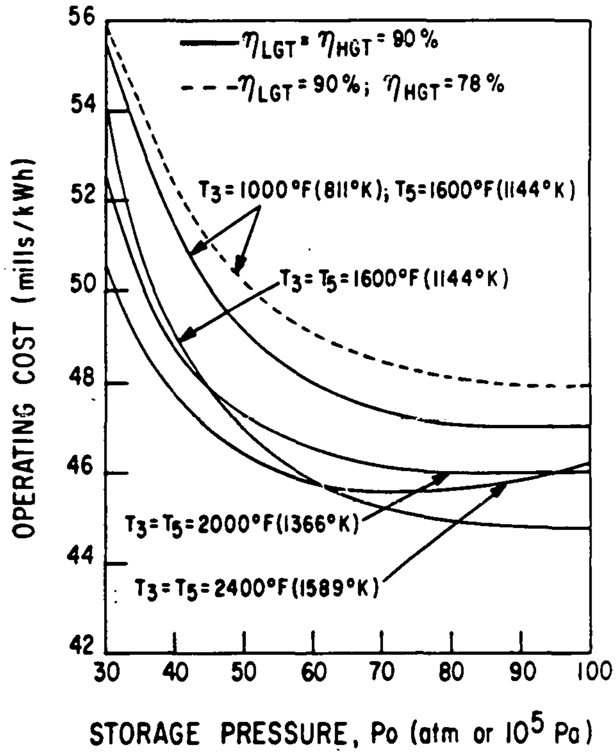

Fig. 10. Effect of Turbine Options on Operating Cost

Figure 10 also illustrates that for T_3 = 1000°F (811°K) and T_5 = 1600°F (1144°K) the difference in operating cost between a modified steam turbine for the HGT and a new, high-efficiency design is negligible; i.e., less than 1 mill/kWh. Thus, the use of a modified steam turbine would be favored because of proven reliability and equipment availability.

Effect of Electricity and Fuel Costs on Operating Costs. Table 1 illustrates the effect of different electricity and premium fuel costs on the overall operating cost of a CAES plant. Two plant designs are compared: Plant A where T_3 = 1000°F

Table 1. Effect of Electricity and Fuel Costs on Operating Costs

Electricity Cost (mills/kWh)	Fuel Cost ($/10^6 Btu)	Operating Cost (mills/kWh)		
		Plant A[a]	Plant B[b]	% Decrease[c]
15	2.50	47.4	45.3	4.4
15	3.75	52.2	50.0	4.2
15	5.00	56.9	54.7	3.9
20	2.50	51.1	48.5	5.1
20	3.75	55.8	53.3	4.5
20	5.00	60.0	58.0	4.3
25	2.50	54.7	51.8	5.3
25	3.75	59.5	56.6	4.9
25	5.00	64.2	61.3	4.5

[a]Turbine inlet temperatures: T_3 = 1000°F (811°K) (η_{HGT} = 78%)
T_5 = 1600°F (1144°K).

[b]Turbine inlet temperatures: $T_3 = T_5$ = 1600°F (1144°K).

[c]100(Plant A - Plant B)/Plant A.

(811°K) (η_{HGT}) = 78%) and T_5 = 1600°F (1144°K), and Plant B where $T_3 = T_5$ = 1600°F. These two plants bracket the highest and lowest estimated operating costs.

From this table it is seen that for fixed electricity cost, the difference between plant designs decreases as the fuel cost increases. This means that if fuel costs increase faster than electricity costs, then the type of plant design (i.e., the selection of turbine system) becomes less significant. This scenario would favor using Plant A because of proven reliability and equipment availability.

For fixed fuel cost, the difference between the operating costs of the two designs increases as the electricity cost increases. This means that if base plant power increases in cost at a faster rate than fuel costs, then Plant B would be favored. In this case, the use of a new, high-efficiency HGT would be justified.

CONCLUSIONS

This paper has considered the performance and cost of possible turbomachinery options for CAES power plants. Particular emphasis was directed toward the turbine system of the plant. The main design variables were the reservoir storage pressure and the turbine inlet gas temperatures. A water-compensated mined cavern was selected as the storage reservoir. The results of this study should be applicable to the other two reservoir types (i.e., aquifer reservoirs and salt caverns), but further study is recommended to fully evaluate the affect of reservoir type on CAES plant performance and cost.

From the performance analysis, the following trends were observed:

1. Specific air flow rate and storage volume decrease as p_o, T_3, or T_5 increases.

2. Specific heat rate decreases as p_o increases and increases as T_5 increases; but is relatively insensitive to T_3.

3. Specific compression rate, in general, slightly increases as p_o increases; it decreases with increasing T_3 or T_5.

4. In general, overall plant efficiency increases as T_3 increases; is only weakly affected by p_o or T_5.

From the above, it can be concluded that optimum performance results from the use of a high storage pressure and high inlet gas temperature to both turbines.

The economic analysis, however, illustrates that minimum cost (capital and operating) does not necessarily correspond to optimum plant performance. Considering the specific operating cost (i.e., mills/kWh), which can be considered the *true* indicator of plant cost, at storage pressures below about 60 atm, the highest temperature turbine system considered in this study (i.e., $T_3 = T_5 = 2400°F$ (1589°K)) results in the lowest cost; whereas, above 60 atm, the turbine system with $T_3 = T_5 = 1600°F$ (1144°K) results in the lowest cost.

A significant result is that for the pressure range of 50-90 atm, which is the range of present interest for water-compensated caverns, the operating cost for all of the turbine systems considered in this study are within about 3 mills/kWh of each other; the average cost is about 47 mills/kWh. Furthermore, it was observed that if the cost of premium fuel increases as a faster rate than the cost of base power electricity, which seems to be a logical scenario for the future, the cost difference between turbine systems decreases.

The economic study indicated that for a turbine system with $T_3 = 1000°F$ (811°K) and $T_5 = 1600°F$ (1144°K), the use of a new, high-efficiency, high-pressure turbine could not be justified and a modified steam turbine could be used with little cost penalty.

Based on the above factors, the overall conclusion of this study is that the turbine system can be constructed using available turbines with proven reliability without significantly sacrificing cost. The HGT can be a modified steam turbine and the LGT can be obtained from a peaker unit which operates at an inlet gas temperature of about 1600°F (or lower), requiring little, if any, cooling air. Interestingly, this is the approach being used at the Huntorf Plant,[7] which is the world's first CAES plant.

ACKNOWLEDGMENTS

The research activities in compressed air energy storage, which formed the basis of this paper, were funded by the Division of Energy Storage Systems, Office of Conservation, U.S. Department of Energy.

NOMENCLATURE

$\dot{E}'_c$	Specific compression rate
$\dot{m}'_a$	Specific air flow rate
p	Pressure
$\dot{Q}'$	Specific heat rate
T	Temperature
$\dot{V}'_s$	Specific storage volume
ε	Recuperator effectiveness
η	Efficiency
$\eta_{overall}$	Overall plant efficiency

Subscripts

BC	Booster compressor
C_1	Combustor 1
C_2	Combustor 2
HGT	High-pressure gas turbine
LGT	Low-pressure gas turbine
HC	High-pressure compressor
LC	Low-pressure compressor
0-19	Correspond to Fig. 1

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