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EVALUATION OF DIURNAL THERMAL ENERGY STORAGE COMBINED WITH COGENERATION SYSTEMS

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SUMMARY

This report describes the results of an evaluation of thermal energy storage (TES) integrated with simple gas turbine cogeneration systems. The TES system captures and stores thermal energy from the gas turbine exhaust for immediate or future generation of process heat. Integrating thermal energy storage with conventional cogeneration equipment increases the initial cost of the combined system; but, by decoupling electric power and process heat production, the system offers the following two significant advantages: 1) Electric power can be generated on demand, irrespective of the process heat load profile, thus increasing the value of the power produced; 2) Although supplementary firing could be used to serve independently varying electric and process heat loads, this approach is inefficient. Integrating TES with cogeneration can serve the two independent loads while firing all fuel in the gas turbine.

The study evaluated the cost of power produced by cogeneration and cogeneration/TES systems designed to serve a fixed process steam load. The value of the process steam was set at the levelized cost estimated for the steam from a conventional stand-alone boiler. Power costs for combustion turbine and combined-cycle power plants were also calculated for comparison. The results indicated that peak power production costs for the cogeneration/TES systems were between 25% and 40% lower than peak power costs estimated for a combustion turbine and between 15% and 35% lower than peak power costs estimated for a combined-cycle plant. The ranges reflect differences in the daily power production schedule and process steam pressure/temperature assumptions for the cases evaluated. Further cost reductions may result from optimization of current cogeneration/TES system designs and improvement in TES technology through future research and development.

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1.0 INTRODUCTION

Cogeneration is playing an increasingly important role in providing energy efficient power generation and thermal energy for space heating and industrial process heat applications. However, the range of applications for cogeneration could be further increased if the generation of electricity could be decoupled from the generation of process heat. Thermal energy storage (TES) can decouple power generation from the production of process heat, allowing the production of dispatchable power while fully utilizing the thermal energy available from the prime mover. The thermal energy from the prime mover exhaust can be stored either as sensible heat or as latent heat and used during peak demand periods to produce electric power or process steam/hot water. However, the additional materials and equipment necessary for a TES system will add to the capital costs. Therefore, the economic benefits of adding TES to a conventional system would have to outweigh the increased costs of the combined system.

The Pacific Northwest Laboratory[a] (PNL) leads the U.S. Department of Energy's Thermal Energy Storage Program. The program focuses on developing TES for daily cycling (diurnal storage), annual cycling (seasonal storage), and utility applications [utility thermal energy storage (UTES)]. Several of these technologies can be used in a cogeneration facility. This report discusses the relative performance and economic benefits of incorporating a diurnal TES system with a simple gas turbine cogeneration system. The relative benefit of combining a TES system with a cogeneration system was determined by comparing the annual costs and the levelized energy costs of the system (for supplying the same preselected steam load) with that of the base case (boiler) system. Each of the configurations was evaluated for different gas turbine sizes and different utility rates.

This report contains seven sections. In Section 2, the the basic concept of diurnal thermal energy storage is discussed, followed by a detailed discussion of a conventional cogeneration plant, and a cogeneration plant

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(a) Operated for the U.S. Department of Energy by Battelle Memorial Institute under Contract DE-AC06-76RLO 1830.

combined with TES for peak power production (Section 3). The economic model developed for the analysis together with all the key assumptions are given in Section 4.0. A discussion of the results obtained from the overall levelized cost analysis is given in Section 5.0. A summary of the main results and the conclusions in Section 6.0 is followed by the references in Section 7.0.

2.0 DIURNAL THERMAL ENERGY STORAGE

A number of emerging issues may limit the number of useful applications of cogeneration. One of these is a mismatch between the demand for electricity and thermal energy on a daily basis. Increasingly, utilities are requiring cogenerators to provide dispatchable power, while most industrial thermal loads are relatively constant. Diurnal TES can decouple the generation of electricity from the production of thermal energy, allowing a cogeneration facility to supply dispatchable power. Diurnal TES stores thermal energy recovered from the exhaust of the prime mover (gas turbine) to meet daily variations in the demand for electric power and thermal loads.

2.1 CONCEPT

The concept for integrating TES in a natural-gas-fired cogeneration facility is shown in Figure 1. The facility consists of 1) a gas-turbine prime mover, 2) a heat recovery salt heater, 3) a thermal energy storage system, and 4) a salt-heated steam generator. The gas turbine is operated during peak demand time periods and the exhaust heat is used to heat molten salt in a heat recovery salt heater. Cold salt [288°C (550°F)] is pumped from the cold salt tank, through the heat recovery salt heater, where it is heated to between 510°C (950°F) and 538°C (1000°F) before being pumped to the hot salt storage tank. Hot salt is continuously removed from the hot salt tank and used as a heat source to meet the constant thermal load. A cogeneration plant with a TES system sized for an 8-hr peak demand period would provide a 30 MWe peaking capacity compared to a similar conventional cogeneration facility that would provide a 10 MWe base load.

2.2 TES SYSTEM DESCRIPTION

Depending on the characteristics of the thermal load, a variety of thermal storage systems can be used. Options for thermal storage include:

- Molten Nitrate Salt TES - Molten salt is an excellent thermal energy storage medium for high-temperature TES applications. Current molten salt TES concepts use a mixture of sodium nitrate (60 wt%) and potassium nitrate (40 wt%) that can operate at temperatures up to 566°C (1050°F).

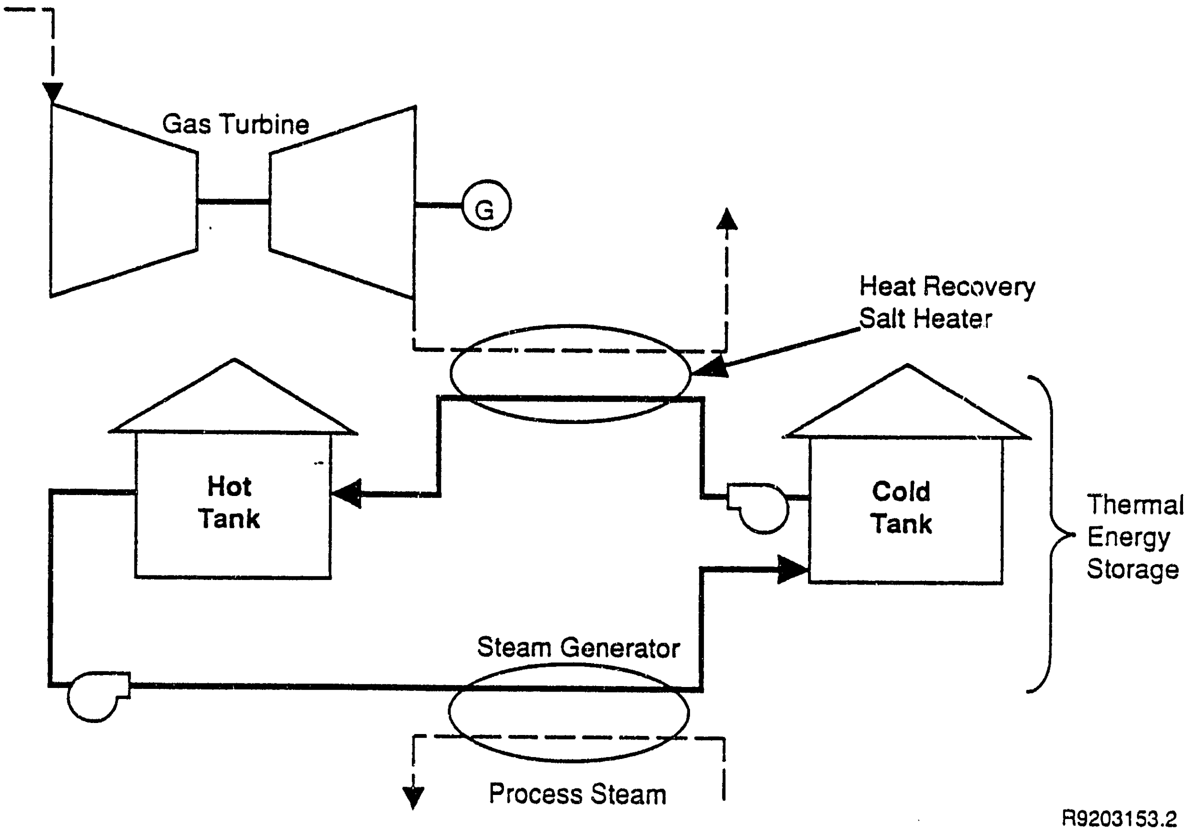

FIGURE 1. Concept of Integrating TES in a Cogeneration Facility

However, the mixture freezes at 240°C (464°F). To help prevent freezing, molten salt systems are usually operated at temperatures above approximately 288°C (550°F). The minimum operating temperature limits the amount of waste heat that can be recovered from a combustion turbine's exhaust because the exhaust can only be cooled to approximately 315°C (600°F). Typically molten salt TES uses separate hot and cold salt tanks. A more complete discussion of molten salt TES is presented in Drost et al. (1989).

- Oil/Rock TES - Oil/rock TES is an attractive alternative for lower temperature applications. Low-cost heat transfer oils such as Caloria HT-43[a] can operate at temperatures up to 304°C (580°F). The TES system consists of a single large tank that is filled with a mixture of oil and a low-cost filler, such as river rock. The tank is operated to maintain hot oil at the top of the tank and cold oil at the bottom of the tank. This arrangement stratifies the fluid in the tank resulting in minimal mixing between the hot and cold regions of the tank. During normal operation, cold oil is removed from the bottom of the tank, heated in the heat recovery oil heater, and returned to the top of the storage tank. Thermal energy is stored in the mixture of oil and rock. Oil/rock TES is less expensive than molten salt TES, but it is limited to low-temperature applications. Oil/rock TES is described in more detail in Drost et al. (1990).

- Combined Molten Salt and Oil/Rock TES - The advantages of both storage concepts can be retained by using a combination of molten salt TES for high-temperature (> 288 °C) and an oil/rock TES for lower temperature (< 288 °C) thermal energy storage. This allows the combustion turbine exhaust to be cooled to near ambient conditions.

- Hitec[b] Salt TES - Hitec salt is another molten salt that operates between 454°C (850°F) and 177°C (350°F). It is a mixture of sodium nitrate (7 wt%), potassium nitrate (53 wt%), and sodium nitrite (40 wt%). Hitec salt would allow greater heat recovery from turbine exhaust than molten salt, but would not be as applicable as the molten salt at higher temperatures (as in combined-cycle power production applications). In addition, the Hitec salt is a little more expensive than the molten salt.

Selection of the storage concept will depend on characteristics of the thermal load. If high-temperature thermal energy is required to meet the thermal load, a choice of the molten salt TES, Hitec salt TES, or a combined

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[a] Trademark of the Exxon Corporation, Houston, Texas.

[b] Trademark of the DuPont Corporation, Wilmington, Delaware.

molten salt and oil/rock TES can be used. Alternatively, if the thermal load uses thermal energy at a temperature below 288°C (550°F), oil/rock TES may be the preferred option.

2.3 BENEFITS

The use of high-temperature TES in cogeneration applications has the following benefits:

- High-temperature TES will allow a natural-gas-fired cogeneration facility to produce dispatchable power while meeting constant thermal loads.
- High-temperature TES integrated in a natural-gas-fired cogeneration facility allows all power generation to occur during periods of peak demand; the installed capacity of the prime mover will be substantially larger than for a conventional cogeneration facility. A cogeneration plant with a TES system sized for an 8-hr peak demand period would provide 30 MWe of peaking capacity compared to a similar conventional cogeneration facility that would provide 10 MWe of base-load capacity.
- All natural gas is used to fire the combustion turbine (compared to direct natural gas firing of the waste heat steam generator). This results in high-efficiency operation by ensuring that all natural gas is used to produce both electric power and thermal energy.
- The high efficiency operation also results in reduced emissions.

2.4 TECHNICAL STATUS

Molten nitrate salt TES has been extensively investigated for solar thermal power generation applications. Investigations have included bench-scale testing, detailed design studies, and field demonstrations. Based on the results of these investigations, the Department of Energy and a group of electric utilities are sufficiently confident of the technical feasibility of the concept to embark on the $40 million Solar II demonstration of molten salt central receiver technology. This suggests that molten nitrate salt TES is technically ready for a large-scale cogeneration demonstration. The technical status of molten salt TES is discussed in more detail in Drost et al. (1989). Oil/rock storage has been successfully demonstrated for solar thermal applications and is commercially available. Hitec salt has been used in several industries. Alternative salts that can operate between 566°C (1050°F) and 121°C (250°F) have been identified, but additional research is necessary before large-scale demonstration is justified. Successful development of a TES system using alternative salts could avoid the need for a combined molten salt and oil/rock TES system to cover the entire temperature range.

3.0 PLANT CONCEPT DETAILS

The conceptual design of a cogeneration plant with TES was developed in sufficient detail to determine a meaningful cost estimate. The relevant features of a conventional cogeneration plant are discussed in Section 3.1, followed by a discussion of the selected arrangements of the cogeneration plant with TES (Section 3.2). The essential features of the oil/salt heater design is followed by a discussion of the oil/salt storage system design and the steam generator design.

3.1 CONVENTIONAL COGENERATION PLANT

One of the primary goals of this study was to develop concept arrangements that minimize the impact of including TES on the design and the layout of the cogeneration plant. Therefore, there is substantial similarity between the conventional cogeneration plant and the cogeneration/TES design. The conventional cogeneration plant consists of a prime mover (a gas turbine, in this case) that is fired by a natural gas combustor. In addition to producing power through the generator, the turbine exhaust at 531°C (988°F) is used in a heat recovery steam generator (HRSG) to produce process steam loads. The net efficiency of the plant is assumed to be 31% (a heat rate of 11,000 Btu/kWh) for larger gas turbines (≥ 180 MWe rating) and 29.6% (a heat rate of 11,500 Btu/kWh) for smaller turbines (< 180 MWe rating).

3.2 COGENERATION PLANT WITH TES FOR PEAKING

An oil/rock or salt TES system interposed between the gas turbine and the steam generator in a conventional cogeneration plant can provide a cycling capability. Instead of generating steam directly, the heat from the gas turbine exhaust is used to heat the oil or molten salt, which is then stored. The gas turbine is operated whenever peaking power capacity is needed by the utilities. The TES serves to decouple the steam generator and the turbine from the rest of the plant, allowing process steam production to continue for the entire day. The oil/rock storage system has been developed extensively for solar thermal power generation, while the molten nitrate salt system has been discussed in an earlier study (Drost, et al. 1989). In the case of the heat recovery salt heater, it may be possible to use direct heat exchange between the exhaust gas and the salt. If feasible, direct-contact heat exchange would dramatically decrease the cost of the heat recovery salt heater and would improve performance. There was no attempt made to optimize the sizes of the components of the different systems evaluated in the study. Hence, more advantageous versions of each TES/cogeneration system or other system configurations including combined-cycle systems with molten salt storage could have been designed and analyzed.

3.2.1 Oil/Salt Heater Design

The turbine exhaust oil (or molten salt) heater replaces the HRSG in the conventional cogeneration plant. The overall convective heat transfer coefficient was assumed to be 150 $W/m^2 \cdot °C$ (26.6 $Btu/h \cdot ft^2 \cdot °F$) and the same for all the heater designs because the dominant resistance to heat transfer is on the gas side. However, the clean turbine exhaust (from combusting natural gas) permits extensive use of fins to improve heat transfer on the gas side. The calculated log mean temperature difference was calculated to be about 111°C (200°F), 17°C (31°F) and 48°C (87°F) for the oil heater, molten salt heater and the Hitec salt heater, respectively.

3.2.2 Oil/Salt Storage System Design

The oil storage system consists of a heat transfer oil and river rock storage medium. The oil and rock are contained in one or more carbon steel tanks, depending on the size of the TES system. The tank or tanks are insulated to reduce heat loss, and appropriate foundations and miscellaneous equipment are included. A substantial fraction of the tank volume is filled with the inexpensive rock; the remaining volume is filled with the more costly oil. The oil, which is about a quarter of the storage volume, stores about 20% of the thermal energy as sensible heat, while the rest of it is stored in the rock. Hot oil is added or removed from the top of the tank, while cool oil is added or removed from the bottom of the tank. This arrangement maintains a density-driven segregation (thermocline) between the hot oil in the top of the tank and the cool, denser oil in the bottom of the tank. The thermal storage capacity of the tank is determined by the temperature range achievable in the heat transfer medium (oil, in this case). The typical range has been from 288°C (550°F) at the high end to about 121°C (250°F) at the low end. This would give rise to a ΔT of 300°F unless pinch-point considerations in the steam generator dictated a higher exit temperature for the oil, which would typically increase the size of the storage system.

The salt storage system could also use a single storage tank (with a thermocline) or separate hot and cold molten salt tanks. Recent studies suggest that the cost savings associated with a thermocline system are small because the cost of the cold tank in the two-tank system is a small fraction of the total cost. In addition, it may be difficult to maintain the thermocline because of the radiation heat transfer between the hot and cold regions of the tank. The design temperatures were assumed to range from 288°C (550°F) to 510°C (950°F), and 177°C (350°F) to 454°C (850°F) for the molten salt and the Hitec salt systems, respectively.

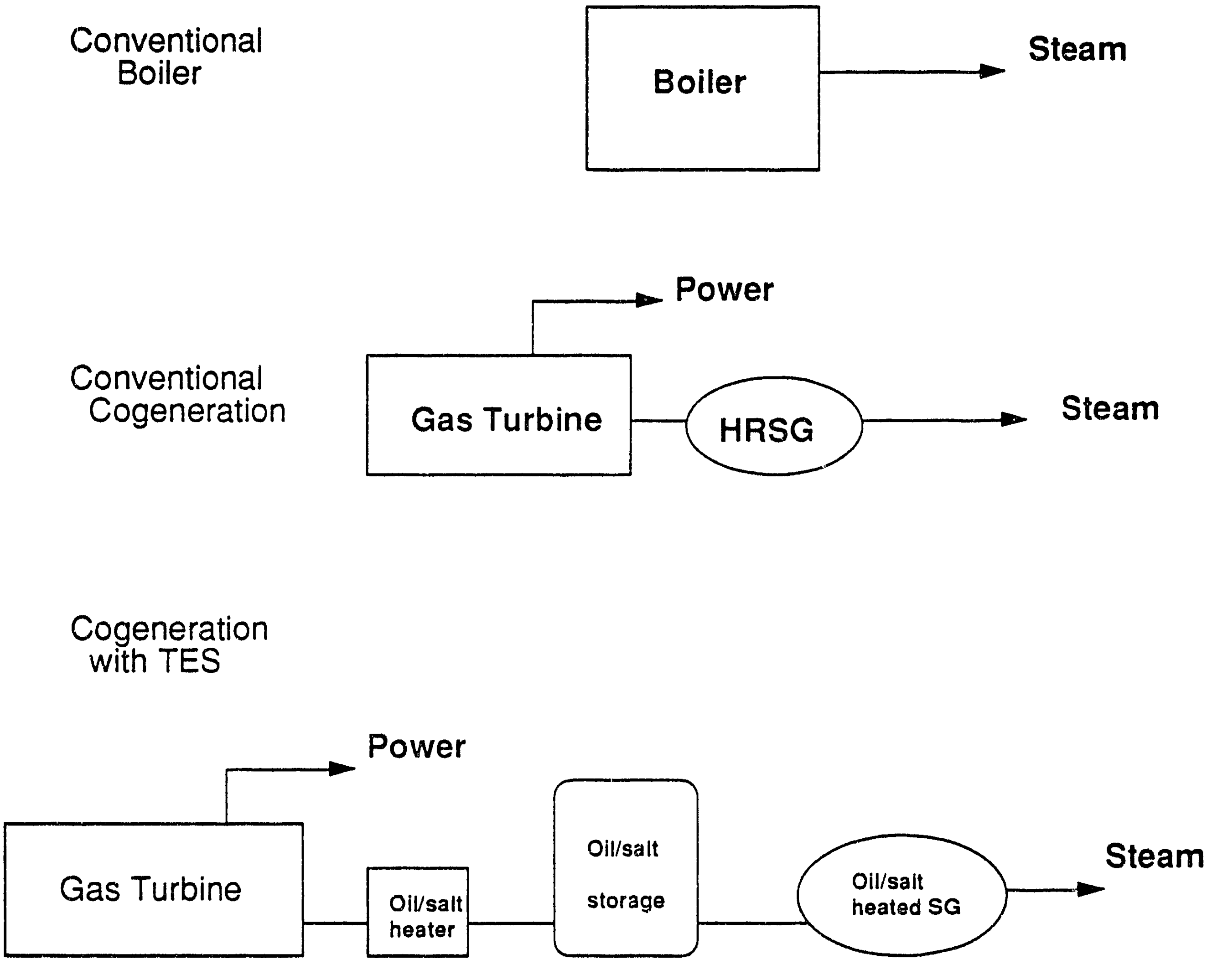
3.2.3 Steam Generator Design

The steam generator is used to supply the constant 24-hr steam load from the hot oil or salt. The steam generator system consists of two separate heat exchangers: 1) a preheater where the temperature of the feedwater is raised to the saturation temperature, and 2) an evaporator where saturated steam is generated. The heat exchangers are of single-pass tubular design with water/steam contained in the tubes. A single-pass design was selected because of the desire to have counterflow heat exchange in the preheater, whereas the evaporator uses a parallel-flow arrangement.

3.3 PLANT ARRANGEMENTS

The base case system is a conventional boiler plant system against which a simple conventional cogeneration system with a gas turbine prime mover and a HRSG was compared. Both systems were designed to supply the same thermal loads. Base-load electricity from the cogeneration system was presumed to be sold to a local utility. The performance parameters and the levelized energy costs for producing the steam were evaluated, and the results compared with those of other system configurations that combine cogeneration with TES using an oil/rock or a salt system. The system configuration includes a gas turbine prime mover with an oil/salt heater, oil/rock or salt storage system, and a oil/salt-heated steam generator to supply the steam load. The gas turbine rating depends upon the length of time during the day that it is operated with peak-load electricity being sold to the utility. For example, having assumed the system will supply a constant 24-hr steam load, the rating is twice the base-load size if it were operating only for 12 hours a day. The waste heat recovery is in the form of heated oil or salt that is then stored in the oil/rock or salt storage tank to supply the 24-hr steam load. The three basic configurations are shown schematically in Figure 2. The additional system analyzed was the 8-hr operation of an oversized (threefold) gas turbine for selling peak power to the local utility. The production of saturated steam was assumed to be constant at 181,818 kg/hr (400,000 lb/hr). Two different steam pressures [690 kPa (164 °C) (or 100 psia and 328 °F) and 3448 kPa (242 °C) (or 500 psia and 467 °F)] were evaluated.

The various equipment required for the plants were sized to supply the given steam loads, assuming that the overall thermal energy loss in the storage unit is about 1% (Drost, et al. 1989), and that the overall parasitic losses (electric power consumption related to oil/salt pumping) in the flow loop resulting from the pumping power requirements is about 2%. The ratings and sizes for the various components of the conventional cogeneration plant, as well as the cogeneration plant with a TES system, are shown in Table 1. The economic analysis was then completed to determine the levelized costs of producing the steam load by the different plant configurations. The assumptions made in the economic model are discussed in the next section.



HRSG - Heat Recovery Steam Generator
SG - Steam Generator

FIGURE 2. Basic Plant Configurations for the Analysis

TABLE 1. Ratings and Sizes of the System Components

Steam Pressure	Storage Medium	Gas Turbine Rating MWe	Heat Recovery Steam Generator ft^2	Oil/Salt Heater ft^2	Storage Size MWht	Hot Oil/Salt Steam Generator ft^2
	(24 hr) Conventional cogeneration	89	49,782	---	---	---
	(12 hr)					
690 kPa (100 psi)	Oil/rock	194	---	140,012	1874	34,803
	Molten salt	276	---	1,098,035	1953	6,988
	Hitec salt	194	---	393,241	1562	11,872
	(8 hr)					
	Oil/rock	291	---	223,510	2500	34,803
	Molten salt	413	---	1,646,992	2604	6,988
	Hitec salt	291	---	589,840	2083	11,872
	(24 hr) Conventional cogeneration	90	70,937	---	---	---
	(12 hr)					
3448 kPa (500 psi)	Oil/rock	237	---	182,100	4328	73,824
	Molten salt	281	---	1,115,470	1984	9,203
	Hitec salt	198	---	399,485	1587	21,611
	(8 hr)					
	Oil/rock	355	---	273,139	5771	73,824
	Molten salt	420	---	1,673,144	2645	9,203
	Hitec salt	296	---	599,206	2116	21,611

4.0 ECONOMIC ANALYSIS

This section presents detailed information regarding the cost and economic analysis of boiler, cogeneration, and cogeneration/TES systems for producing low-pressure process steam. Section 4.1 defines the cost estimating and economic assumptions used in the analysis. Sections 4.2 and 4.3 discuss the estimating approach and results for estimating initial capital, fuel, and other operation and maintenance (O&M) costs. The results of the overall levelized cost analysis are presented in Section 5.0.

4.1. GROUND RULES AND ASSUMPTIONS

The economic evaluation was conducted by calculating and comparing the levelized cost of steam produced by the alternative concepts being considered. Levelized cost analysis combines initial cost, annually recurring cost, and system performance characteristics with financial parameters to produce a single figure-of-merit (the levelized cost) that is economically correct and can be used to compare the projected steam costs of alternative boiler and cogeneration plant concepts. The specific methodology used was that defined in Brown, et al. (1987). The economic assumptions used to calculate the levelized steam cost are listed in Table 2. These assumptions are intended to be representative of industrial ownership. The discount rate, general inflation rate, property tax and insurance rate, and combined state and federal income tax rate were obtained from Brown et al. (1987). The economic life was set at 30 years based on standards prescribed by the Electric Power Research Institute (EPRI) (1989) for facilities similar to the boiler and cogeneration plants considered in the current study. The corresponding depreciable life is 20 years (Van Knapp et al. 1989). The first year of operation was set at 1995 because the storage systems considered in the current study are mature and could be implemented immediately. The price year was set to mid-1990 for convenience. The system construction period, set at 2 years, was also based on data presented in EPRI (1989) for similar systems. Capital and non-fuel O&M costs were assumed to escalate in the future at the same rate as general inflation. Natural gas was assumed to escalate at 3.8% in excess of general inflation (i.e., at 7%/year overall) based on fuel price projections prepared by the Energy Information Administration (1991).

TABLE 2. Financial Assumptions

Description	Assumption
System economic life	30 years
System depreciable life	20 years
Nominal discount rate	9.3%/year
General inflation rate	3.1%/year
Capital inflation rate	3.1%/year
O&M inflation rate	3.1%/year
Natural gas inflation rate	7.0%/year
Combined state and federal income tax rate	39.1%
Property tax and insurance rate	2.0%
System construction period	2 years
Price year	1990
First year of system operation	1995

In general, a levelized cost analysis solves for the revenue required to exactly cover all costs associated with owning and operating a facility, including return on investment. Typically, the required revenue is expressed per unit of production, e.g., $/kWh or $/klb steam. For cogeneration systems, there are two revenue producing products, electricity and steam. Increasing the revenue associated with electricity decreases the revenue required from steam and vice-versa. In this analysis, the electric revenue rate was assumed for each cogeneration case and the levelized cost analysis solved for the required steam revenue. As initial assumptions, baseload power was assumed to be valued at $0.05/kWh and peaking power (for 8-hr or 12-hr periods) was assumed to be valued at $0.08/kWh.

4.2 CAPITAL COST ESTIMATES

Capital cost estimating equations were developed for the following steam production systems or steam production system components:

- oil-heated and salt-heated steam generators
- heat recovery steam generator
- oil/rock and salt thermal energy storage systems
- boiler system (plant)
- gas turbine
- oil and salt heaters

All cost equations represent the completed construction cost, including indirect costs and contingency, but do not include allowances for startup and working capital, which were calculated separately. All cost data presented in this section are in 1990 $.

The capital cost model for the boiler system was developed from cost data presented in Brown, et al. (1992) for a boiler plant consisting of three 50,000 kg/hr (110,000 lb/hr) units producing steam at 1551 kPa (225 psig) and 236 °C (456 °F). The raw cost data were adjusted to the expected cost for a single unit of the same total production capacity using rules-of-thumb presented in Coffin (1981). Cost data from Ulrich (1984) were used to establish relative costs at alternative steam production rates. The resulting cost relation for a boiler system producing 100 psia steam is shown in Equation (4.1). Data in Ulrich (1984) and Coffin (1981) indicate that costs would be expected to increase by about 1% per each 100 psi increase in steam pressure above 100 psia up to 500 psia.

$$\text{Boiler system capital cost} = \$16{,}900{,}000 * (S/330)^{0.76} \tag{4.1}$$

where S is the net steam generating capacity in thousand of pounds per hour.

The capital cost model for the gas turbine was based on data presented in EPRI (1989) for conventional natural-gas-fired combustion turbine plants. The raw cost data for two plant sizes were used to develop a cost estimating equation as a function of electric generating capacity. The original data was updated to 1990 $ using the M&S (Marshall & Swift) Equipment Cost Index for electrical power (Chemical Engineering Magazine 1990). The resulting cost relation is shown in Equation (4.2).

$$\text{Gas turbine capital cost} = \$30{,}600{,}000 * (P/80)^{0.76} \tag{4.2}$$

where P is the net electric generating capacity in MW.

The capital cost models for the heat recovery steam generator, oil and salt heaters, and oil/rock and salt storage systems were based directly on cost models developed for these components (Drost, et al. 1990). The values calculated from the equations include direct costs, indirect costs, contingency, and sales tax, but not startup and working capital. The cost models were updated to 1990 $ using the Chemical Engineering Plant Cost Index for heat exchangers and tanks (Chemical Engineering Magazine 1990). The resulting cost relations are shown below.

$$\text{Heat recovery steam generator capital cost} = \$111 * (A)^{0.95} \tag{4.3}$$

where A is the bare tube surface area of a finned-tube heat exchanger surface in ft^2.

The pressure-related cost factor (that applies to the boiler and all steam generators) derived from data in Ulrich (1984) and Coffin (1981) is given by the following relation:

$$\text{Pressure-related cost factor} = 1.0 + \{0.0001 * (\text{pressure} - 100)\} \tag{4.4}$$

$$\text{Oil heater capital cost} = \$111 * (A)^{0.95} \tag{4.5}$$

$$\text{Molten salt (or Hitec salt) heater capital cost} = \$\ 224 * (A)^{0.95} \tag{4.6}$$

where A is the bare tube surface area of a finned-tube heat exchanger surface in ft^2.

Molten salt and oil/rock storage cost estimating equations were developed as a function of thermal capacity with an adjustment factor for different storage media temperature ranges. Data sources were Arizona Public Service (1988) and DeLaquil, Kelly, and Egan (1988) for the molten salt, Bradshaw and Tyner (1988) for Hitec salt, and Williams et al. (1987) for oil/rock. Furthermore, the cost equations for the storage systems have been segregated into hardware and media components. This should allow easier identification of the cost split between these two components at any capacity and facilitate sensitivity studies investigating improvements in containment or media, as well as future cost updating.

Oil/rock thermal energy storage capital costs are calculated from the following relations:

$$\text{Hardware cost} = \$303{,}000 * (C_{300})^{0.3857} \text{ for } C_{300} < 1000 \quad (4.7)$$

$$= \$4329 * (C_{300}) \text{ for } C_{300} \geq 1000 \quad (4.8)$$

$$\text{Media cost} = \$2779 * (C_{300}) \quad (4.9)$$

Molten salt thermal energy storage capital costs are calculated from the following relations:

$$\text{Hardware cost} = \$10{,}310{,}000 * (C_{500}/1500)^{0.52} \text{ for } C_{500} \leq 1500 \quad (4.10)$$

$$= \$3{,}070{,}000 + \$4826 * (C_{500}) \text{ for } 1500 < C_{500} < 3000 \quad (4.11)$$

$$= \$\ 5850 * (C_{500}) \text{ for } C_{500} \geq 3000 \quad (4.12)$$

$$\text{Media cost} = \$12{,}431 * (C_{500}) \quad (4.13)$$

where C is the thermal capacity in MWht.

The subscript "300" or "500" identifies the cost equations as being valid for thermal capacities calculated for a 300°F (or 500°F in the case of molten salt or Hitec salt) temperature range, e.g., from 250°F to 550°F. The thermal capacity requirements asociated with other temperature ranges must be adjusted to the 300°F (or 500°F) basis using the following equation.

$$C_{300} = C_x * (300/x) \quad \text{or} \quad C_{500} = C_x * (500/x) \quad (4.14)$$

The volumetric heat capacity for the molten salt and the Hitec salt were compared to determine the effect on the size and cost of the TES hardware. Based on the average temperature for each of the salts, the volumteric heat capacity of the Hitec salt was found to be about 4% greater than for the molten salt. Thus, the actual thermal capacity required for a Hitec salt storage system would have to be reduced by 4% before using the molten salt hardware cost estimating equations. As for the media costs, the relative cost of the Hitec salt is given as \$0.37/lb, while the molten salt costs \$0.33/lb

(Bradshaw and Tyner 1988). This, coupled with the slightly greater gravimetric heat capacity of the molten salt, yields a Hitec cost that is 15% higher than the molten salt on a \$/MWht basis. Therefore, the Hitec salt thermal energy storage capital costs are given by:

$$\text{Hardware cost} = \$10{,}310{,}000 * (C_{500}/1563)0.52 \text{ for } C_{500} \leq 1563 \quad (4.15)$$
$$= \$3{,}070{,}000 + \$4633 * (C_{500}) \text{ for } 1563 < C_{500} < 3125 \quad (4.16)$$
$$= \$\ 5616 * (C_{500}) \text{ for } C_{500} \geq 3125 \quad (4.17)$$

$$\text{Media cost} = \$\ 14{,}296 * (C_{500}) \quad (4.18)$$

where C is the thermal capacity in MWht.

The three alternative hardware cost equations for molten salt storage reflect the transition from single to multiple hot tanks for $C_{500} > 1500$ and single to multiple cold tanks for $C_{500} > 3000$. The transition points for Hitec salt are slightly greater, as indicated in the Hitec cost equations.

The capital cost model for an oil-heated steam generator presumed a low-pressure, carbon steel, shell-and-tube design. Raw cost data presented in Ulrich (1984); Peters and Timmerhaus (1980); Purohit (1983); Corripio, et al. (1982); and Guthrie (1974) were updated to 1990 \$ using the Chemical Engineering Plant Cost Index for heat exchangers and tanks (Chemical Engineering Magazine 1990). This model was then modified to reflect the higher operating temperatures encountered in the salt-heated units, and assuming a stainless steel shell with carbon steel tubes. Data presented in Ulrich (1984) were used to estimate the economic impact of using stainless steel in the shell. The resulting cost relations are shown below.

$$\text{Oil-heated steam generator capital cost} = \$370{,}000 * (A/10{,}000)^{0.8} \quad (4.19)$$

$$\text{Salt-heated steam generator capital cost} = \$520{,}000 * (A/10{,}000)^{0.8} \quad (4.20)$$

where A is the heat exchanger surface area in ft^2.

Startup and working capital cost estimates were based on information presented in EPRI (1989). Startup costs include operator training, equipment checkout, minor changes in equipment, extra maintenance to get the system on-line, and fuel consumption incurred after the plant is constructed, but prior to regular operation. Working capital represents a "revolving account" used to pay for the procurement of current expenses and an investment in spare parts. The cost relations used for estimating startup and working capital are shown below.

$$\text{Startup capital cost} = 0.02 * \text{total system construction cost} + 1/12 * \text{total annual O\&M} + 1/52 * \text{total annual fuel} \quad (4.21)$$

$$\text{Working capital cost} = 0.005 * \text{total system construction cost} + 1/6 * \text{total annual O\&M} + 1/6 * \text{total annual fuel} \quad (4.22)$$

4.3 OPERATION AND MAINTENANCE COST ESTIMATES

O&M costs include fuel, operating labor, maintenance labor and materials, consumable supplies, and overhead. Non-fuel O&M cost estimating relations were developed for each of the system cost elements described in Section 4.2. The development of these relations and the fuel price assumption are described in this section.

Each of the systems uses natural gas as its energy source. Natural gas was assumed to cost $2.92/million Btu in 1990 $. This represents the average price of natural gas in the industrial sector, according to the Energy Information Administration (1991).

Detailed O&M cost data presented in Brown, et al. (1992) for a gas-fired boiler plant were used to develop non-fuel O&M cost estimating relations for the three steam generators ("oil-heated", "salt-heated", and "heat recovery" types), as well as the boiler plant. Cost data in Brown, et al. (1991) were grouped into fixed labor, fixed maintenance materials, variable maintenance materials, and consumable supply categories. The fixed labor (i.e, fixed for a given plant size) was assumed to be proportional to initial capital cost, with the ratio varying as a function of steam production capacity. Data presented in Drost, et al. (1990) and EPRI (1989) describing the variation of fixed O&M with power plant size was combined with the data from Brown, et al. (1991), and resulted in the following estimating relation:

Steam generation fixed labor cost = \$0.07 * $(S/330)^{-0.5}$ * construction capital (4.23)

where S is the steam generating capacity in thousands of pounds per hour.

Fixed maintenance was presumed to be required regardless of the actual frequency of use of the equipment. On the other hand, variable maintenance was presumed to be proportional to the number of operating hours per year (at full capacity). Equations (4.24) and (4.25) describe the relations for estimating fixed and variable maintenance for steam generators.

Steam generation fixed
maintenance materials cost = \$0.0085 * construction capital (4.24)

Steam generation variable
maintenance materials cost = \$3 x 10^{-6} * annual operating hours at full capacity * construction capital (4.25)

Consumable supplies include make-up water, water treatment chemicals, and electricity. Cost data presented in Brown, et al. (1991) for these items were used to develop the following cost estimating relation:

Steam generation consumable
supplies cost = \$0.1335 * annual steam production in thousands of pounds. (4.26)

O&M cost data presented in EPRI (1989) for gas-fired combustion turbine power plants were used to develop fixed and variable O&M cost estimating equations for gas turbines. According to EPRI (1989), the majority of gas turbine O&M costs are proportional to annual power production, but the unit cost per kWh varies with the turbine generating capacity. Fixed and variable O&M costs for gas turbines were estimated with the following relations:

Gas turbine fixed O&M cost = \$0.002 * construction capital (4.27)

$$\text{Gas turbine variable O\&M cost} = \$0.04019 * (P)^{-0.377} * \text{annual energy production, kWh} \quad (4.28)$$

where P is the turbine generating capacity in MW.

No detailed O&M estimating data similar to that found for boilers and gas turbines was found for oil/salt heaters and oil/rock or salt thermal energy storage components. Annual O&M costs were estimated as 10% of the hardware costs, based on estimating rules-of-thumb described in publications by the American Association of Cost Engineers (1990), Ulrich (1984), and Peters and Timmerhaus (1980). Note that the 10% factor was not applied to TES media capital; media maintenance was assumed to be negligible at the operating temperatures being considered.

5.0 RESULTS AND DISCUSSION

The results of the economic analyses for two different steam pressures and for the different system configurations considered in this study are given in Tables 3 and 4. Having calculated the levelized cost of steam delivery of the electric rates, a reverse calculation that yielded the same levelized steam cost was undertaken. The breakeven electric rates at which the levelized steam cost is the same as that of the conventional boiler is given in Table 3. The breakeven rate for the conventional cogeneration system is 3.5 ¢/kWh, while that for the combined system varies depending on the storage medium for the TES system. There is very little variation of the rate between the two steam pressure conditions assumed. The corresponding rate for a gas turbine plant is given for comparison. It can be seen that the oil/rock TES system can provide on-peak power at a cost of 4.5 to 6.0 ¢/kWh, which is less expensive than the simple gas turbine case. The Hitec and molten salt cases are less attractive for these two steam pressure conditions. The Hitec salt can provide peak power at a slightly less expensive rate than the molten salt, primarily because of the wider temperature range of the storage system. Alternative system configurations such as combined-cycle systems and higher temperature storage conditions may prove more attractive for systems with molten salt as the storage media. In general, lower temperature storage reduces the size and cost of the storage media heater while higher temperature storage reduces the size and cost of the media-heated steam generator. Poor heat transfer in the gas-turbine exhaust heater (on the gas side) puts a premium on the lower approach temperatures required of high-temperature storage systems. Thus, the oil-rock system has a heat exchanger sizing and cost advantage over the two salt systems. The oil-rock system is also the least expensive (on a $/MWht basis) when each storage system is allowed to cycle through its maximum temperature range. Pinch-point design restrictions in the steam generator reduce, but do not eliminate the advantage of oil-rock storage at 3448 kPa (500 psi) steam pressure compared to the 690 kPa (100 psi) case. It should also be noted that the systems evaluated have not be optimized; more advantageous versions of each TES/cogeneration system could be identified by considering other combinations of storage media temperature range and heat exchanger approach temperatures. Varying these design factors trades off heat exchanger and storage system costs. Also, future research and development efforts focused on the salt storage media may further reduce the costs of such storage media and make them more attractive for wider range of temperature conditions.

The cost breakdown, as well as the total revenue from the sale of electricity (corresponding to the breakeven electric rates) for the different system configurations, is given in Table 4. The combination of TES with a base cogeneration system does add to the capital equipment costs and the total O&M costs, but the increase in the electric power revenue (resulting from sales during intermediate and peak periods of the day at higher rates compared to the sale of base-load power) more than offsets the increased costs. It can also be seen (Figure 3) that the predominant portion of the total cost of producing steam by the different system configurations is associated with fuel, which, in turn, essentially dictates the overall economic feasibility of the system. The combined system is assumed to operate either 12 hours a day or 8 hours a day (peak period) to maximize value of the electric power.

TABLE 3[a] Breakeven Electric Rates for Boiler Steam Costs (Levelized)

	Case Number 1	Case Number 2
Steam pressures	690 kPa (100 psi)	3448 kPa (500 psi)
Levelized cost of steam from conventional boiler	$9.03/klb	$9.13/klb
System configuration	**Breakeven electric rates**	
Conventional cogeneration (base-load power)	3.5	3.8
Cogeneration with TES (12-hr peak power)		
Oil-rock	4.5	5.4
Molten salt	7.9	7.9
Hitec salt	5.9	6.0
Cogeneration with TES (8-hr peak power)		
Oil-rock	5.0	6.0
Molten salt	9.5	9.6
Hitec salt	7.0	7.1
Simple gas turbine	7.5 to 8.0	7.5 to 8.0

[a] All figures are in ¢/kWh.

TABLE 4[a] Cost Breakdown for the Different System Configurations and Steam Loads

Steam Pressure	System Configuration	Capital Cost	Fuel Cost	O&M Cost	Electric Revenue
	(24 hr) Conventional boiler	22.9	12.3	2.3	--
690 kPa (100 psi)	(24 hr) Conventional cogeneration	42.9	22.8	5.8	23.9
	(12 hr)				
	Oil/rock	91.7	24.0	6.5	33.7
	Molten salt	255.1	34.0	19.2	83.9
	Hitec salt	150.5	24.0	10.4	44.3
	(8 hr)				
	Oil/rock	123.0	24.0	6.6	37.5
	Molten salt	355.9	34.0	24.7	101.0
	Hitec salt	205.3	24.0	12.2	52.5
	(24 hr) Conventional boiler	23.7	12.4	2.4	--
3448 kPa (500 psi)	(24 hr) Conventional cogeneration	44.9	23.2	6.0	26.2
	(12 hr)				
	Oil/rock	124.4	29.4	8.4	49.1
	Molten salt	259.3	34.6	19.5	85.4
	Hitec salt	152.7	24.4	10.5	45.2
	(8 hr)				
	Oil/rock	166.6	29.4	8.9	54.4
	Molten salt	361.1	34.6	25.0	103.0
	Hitec salt	208.5	24.4	12.4	53.5

[a] All figures are in millions of dollars.

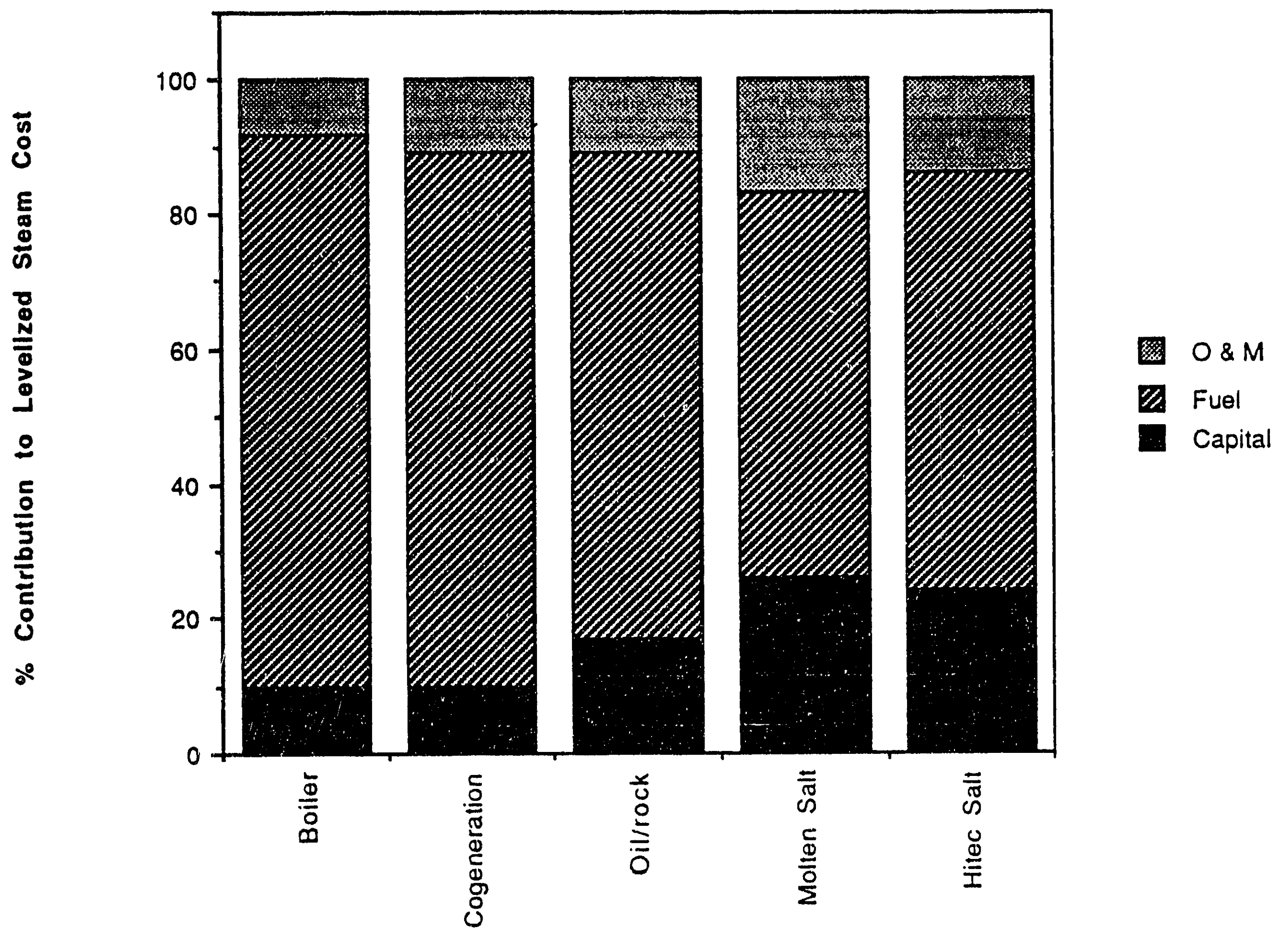


FIGURE 3. Contributions to Levelized Steam Cost for the Plant Configurations

6.0 CONCLUSIONS

Thermal energy storage can help cogeneration meet the challenges of the 1990s by increasing the flexibility and performance of cogeneration facilities. Thermal energy storage also allows a cogeneration facility to provide dispatchable electric power while providing a constant thermal load. The results for the assumed steam load show that the conventional cogeneration system and the cogeneration plant combined with the oil/rock TES system do have lower levelized costs of producing steam compared to the conventional boiler plant operation as long as the selling price of electricity remains above \$ 0.06/kWh. The breakeven price for the sale of electricity (at which the steam costs are the same for the three plant options) is in the range of \$0.035/kWh for the conventional cogeneration case to about \$0.045 to 0.06/kWh for the combined system using oil/rock TES. This represents a 25% to 40% reduction in the cost of peak power when compared to \$0.08/kWh for a gas turbine plant; and a 14% to 35% reduction compared to a peak power cost of approximately \$0.07/kWh for a combined cycle plant. This magnitude of cost reduction is seldom encountered in a mature industry, like the utility industry.

The oil/rock storage system for TES remains the most attractive option for the assumed thermal load quality. A higher quality of the assumed thermal load (e.g., at higher pressures and temperatures) will favor the molten salt TES system because of the higher temperature range that is achievable in such a system. The economies-of-scale with respect to the costs of the gas turbine, the oil/salt heater, oil/rock or salt storage system, and the heat recovery steam generator, as well as magnitude of energy loss from the storage system also favor the larger-sized system components. Further cost reductions may result from optimization of individual components in the combined plant configurations and research and development induced TES system improvements.

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