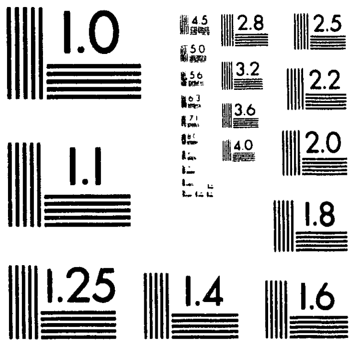
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EVALUATION OF DIURNAL THERMAL ENERGY STORAGE COMBINED WITH COGENERATION SYSTEMS -- PHASE II

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SUMMARY

This report describes the results of a study of thermal energy storage (TES) systems integrated with combined-cycle gas turbine cogeneration systems. 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 two significant advantages. First, electric power can be generated on demand, irrespective of the process heat load profile, thus increasing the value of the power produced. Second, 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.

An earlier study analyzed TES integrated with a simple-cycle cogeneration system and was published as PNL-8298. This follow-on study evaluated the cost of power produced by a combined-cycle electric power plant (CC), a combined-cycle cogeneration plant (CC/Cogen), and a combined-cycle cogeneration plant integrated with thermal energy storage (CC/TES/Cogen). Each of these three systems was designed to serve a fixed (24 hr/day) process steam load. The value of producing electricity was set at the levelized cost for a CC plant, while the value of the process steam was for a conventional stand-alone boiler.

The results presented here compared the costs for CC/TES/Cogen system with those of the CC and the CC/Cogen plants. They indicate relatively poor economic prospects for integrating TES with a combined-cycle cogeneration power plant for the assumed designs. The major reason is the extremely close approach temperatures at the storage media heaters, which makes the heaters large and therefore expensive. Two mediating factors should, however, be considered prior to rejecting this system combination. First, the designs developed here were not optimized from a size or cost and performance perspective. For example, increasing the approach temperatures for the storage media heaters might lower the media heater costs more than it would raise media storage costs. Quite simply, design optimization would improve

the economics, perhaps enough to make the CC/TES/Cogen system an attractive option for incremental peak power production. Second, the media heaters were based on conventional "shell-and-tube" heat transfer equipment. Direct-contact of gas turbine exhaust with the storage media would permit a much closer approach temperature, and reduce the cost of the media heater by as much as a factor of five. This magnitude of cost reduction for the high-temperature media heater could result in economically more attractive CC/TES/Cogen applications. Therefore, further analysis of this system combination, and especially, using direct-contact heat transfer equipment for media heating is strongly recommended.

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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 (gas turbine). 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. The previous study focused on the relative performance and economic benefits of incorporating a diurnal TES system with a simple-cycle gas turbine (GT) cogeneration system to produce dispatchable power during peak and/or intermediate demand periods (Somasundaram, et al. 1992). The relative benefit of combining a given TES system with a cogeneration system was determined by comparing the levelized energy costs of the combined system (for supplying the same preselected steam load) with that of a conventional system and the base case (boiler) system. Each of the configurations was evaluated for different gas turbine sizes and different utility rates. The results showed that the conventional

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

cogeneration system and the cogeneration plant combined with oil/rock TES could produce steam at a lower cost than a conventional boiler plant operation as long as the cost of electricity remained above $0.06/kWh. The breakeven electricity price (at which the steam costs were the same for the three plant options) was $0.035/kWh for the conventional cogeneration case, and $0.045 to $0.06/kWh for the combined system using oil/rock TES. This represented 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. The oil/rock storage system for TES was found to be the most attractive option for the assumed thermal load quality. A higher quality thermal load (e.g., at higher pressures and temperatures) might favor the molten salt TES because of the higher temperature range that is achievable in such a system, which is one of the main reasons for exploring the combined-cycle cogeneration 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 hot oil or salt recovery steam generator, as well as magnitudes of energy losses from the storage system, also favor the larger-sized system components.

This report discusses the results of a follow-on study incorporating a diurnal TES system with a combined-cycle 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 system (a combined-cycle electric power plant for electricity and a separate boiler plant for process steam production). Each of the configurations was evaluated for different gas turbine sizes and different utility rates.

This report contains seven sections. In Section 2, the basic concept of diurnal thermal energy storage is briefly discussed. This is followed by a detailed discussion of a conventional combined-cycle cogeneration plant and a combined-cycle cogeneration plant combined with TES for peak power production (Section 3). The economic model developed for the analysis and all the key assumptions are given in Section 4. A discussion of the results obtained from the overall levelized energy cost analysis is given in Section 5. The conclusions and recommendations in Section 6 are followed by a list of references in Section 7.

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 combined-cycle cogeneration facility is shown in Figure 2.1. High-temperature molten salt storage and medium-temperature oil storage systems are shown, but single-media systems based on molten salt or oil alone are also possible. The facility consists of a gas-turbine prime mover, heat recovery media heaters, thermal energy storage systems, media-heated steam generator, and a steam turbine. The gas turbine is operated during peak demand periods and the exhaust is used to heat the storage media in a media heater. Cold media is pumped from storage tanks, through the media heater, before being pumped to designated storage tanks. Hot media is continuously removed from the storage tanks and used as a heat source to meet the constant thermal load from the steam turbine and the process application.

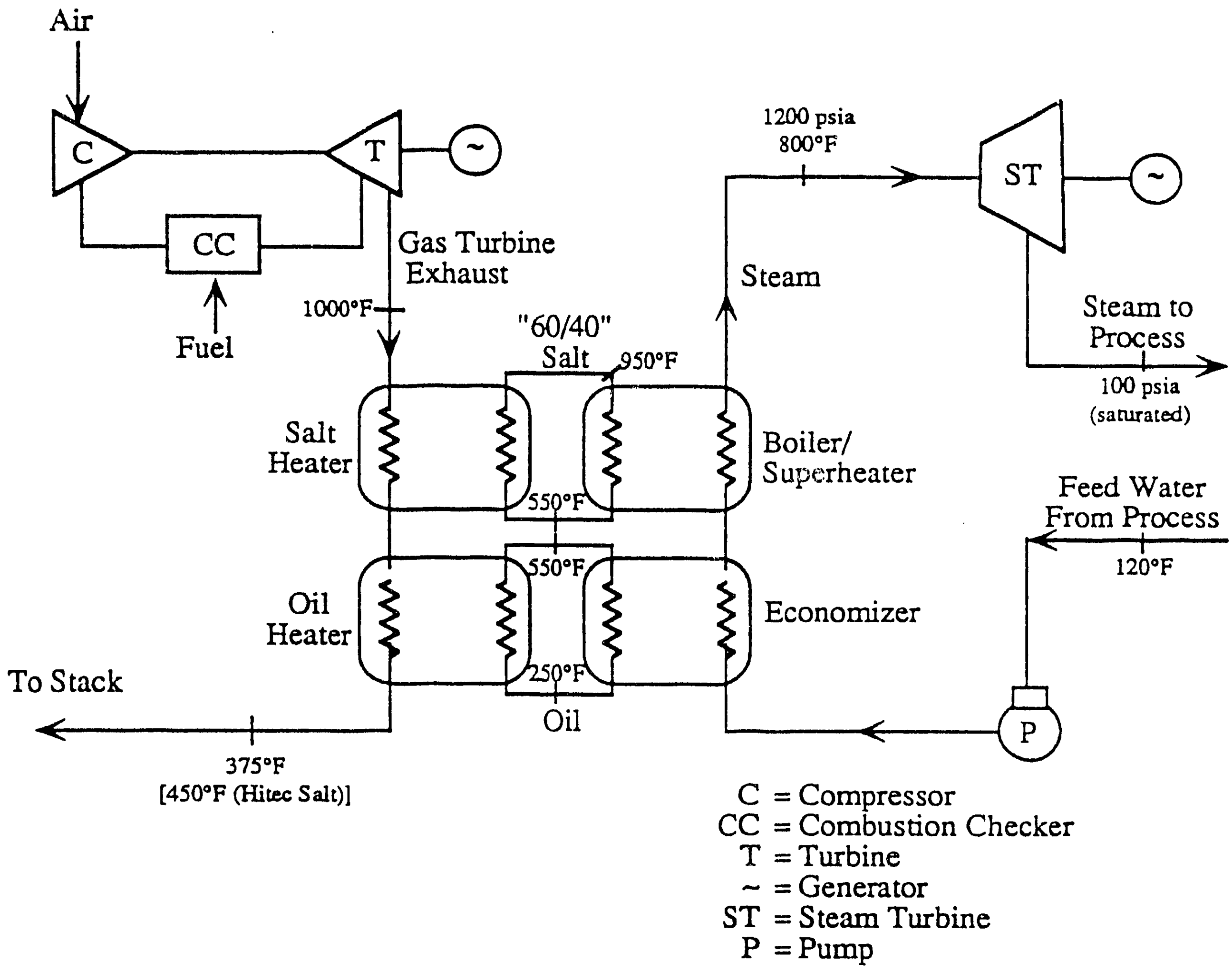

FIGURE 2.1. Schematic of a Combined-Cycle Cogeneration Plant with Thermal Energy Storage (CC/TES/Cogen)

2.2 TES SYSTEM DESCRIPTION

Depending on the characteristics of the thermal load, a variety of thermal storage systems can be used. The various options for thermal storage include the following systems, which are described in greater detail in Somasundaram et al. (1992):

- "60/40" salt (a mixture of 60% sodium nitrate and 40% potassium nitrate) TES [for relatively high-temperature storage of heat, i.e., 288°C (550°F) to 556°C (1050°F)]
- oil/rock TES [for lower temperature storage of heat, i.e., ≤288°C (≤550°F)]

- combined "60/40" salt and oil/rock TES (to encompass the full temperature range)
- Hitec[a] salt TES [has a wider temperature range of storage than the "60/40" salt, i.e., from 454°C (850°F) to 177°C (350°F)]

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 "60/40" salt TES, Hitec salt TES, or a combined "60/40" salt and oil/rock TES can be used. Alternatively, if the thermal load is 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 supplemental natural gas firing in 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.

2.4 TECHNICAL STATUS

Molten nitrate or "60/40" 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

(a) Trademark of the DuPont Corporation, Wilmington, Delaware.

of the concept to embark on the $40 million Solar II demonstration of molten salt central receiver technology. This suggests that the "60/40" salt TES is technically ready for a large-scale cogeneration demonstration. The technical status of this TES system is discussed in more detail in Drost et al. (1990).

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 can be justified. Successful development of a TES system using alternative salts could avoid the need for a combined "60/40" salt and oil/rock TES system to cover the entire temperature range. In the case of the heat recovery salt heater, it may be possible to use direct-contact heat exchange between the exhaust gas and the salt. If feasible, this direct-contact heat exchange process would dramatically reduce the cost of the heat recovery salt heater and would improve the overall plant performance.

2.5 SYSTEM DESCRIPTIONS

Design and performance characteristics were developed for the following four types of steam and/or electric power plants: 1) a boiler plant (boiler), as shown in Figure 2.2; 2) a combined-cycle electric power plant (CC) (Figure 2.3); 3) a combined-cycle electric power plant with steam cogeneration (CC/Cogen) (Figure 2.4); and 4) a combined-cycle electric power plant with steam cogeneration and thermal energy storage (CC/TES/Cogen) (Figure 2.1).

The first three plants were evaluated to provide a reference for comparing the cost of steam and electricity from the CC/TES/Cogen plants. The boiler plant was evaluated to define the reference cost of producing steam, hence the value of steam produced by the cogeneration plants. Similarly, the CC plant was evaluated to define the reference cost of producing electricity, hence the value of electricity produced by the cogeneration plants. Many factors affect the value of products such as steam and electricity. This approach is consistent with defining value as equal to the marginal cost of production from the likely alternative source. While a conventional boiler

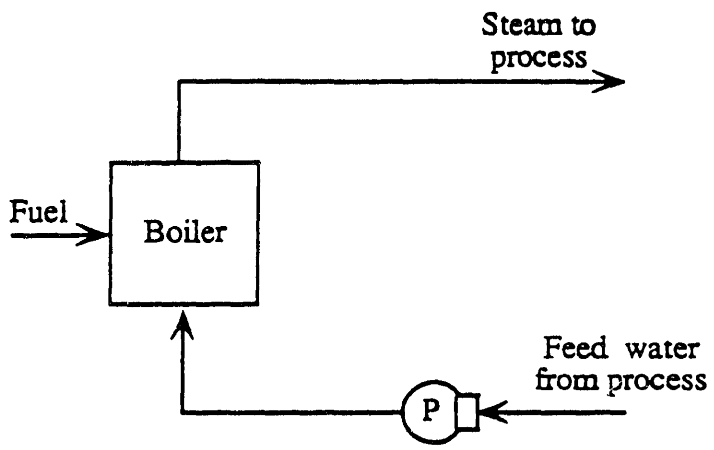

FIGURE 2.2. Schematic of a Boiler Plant

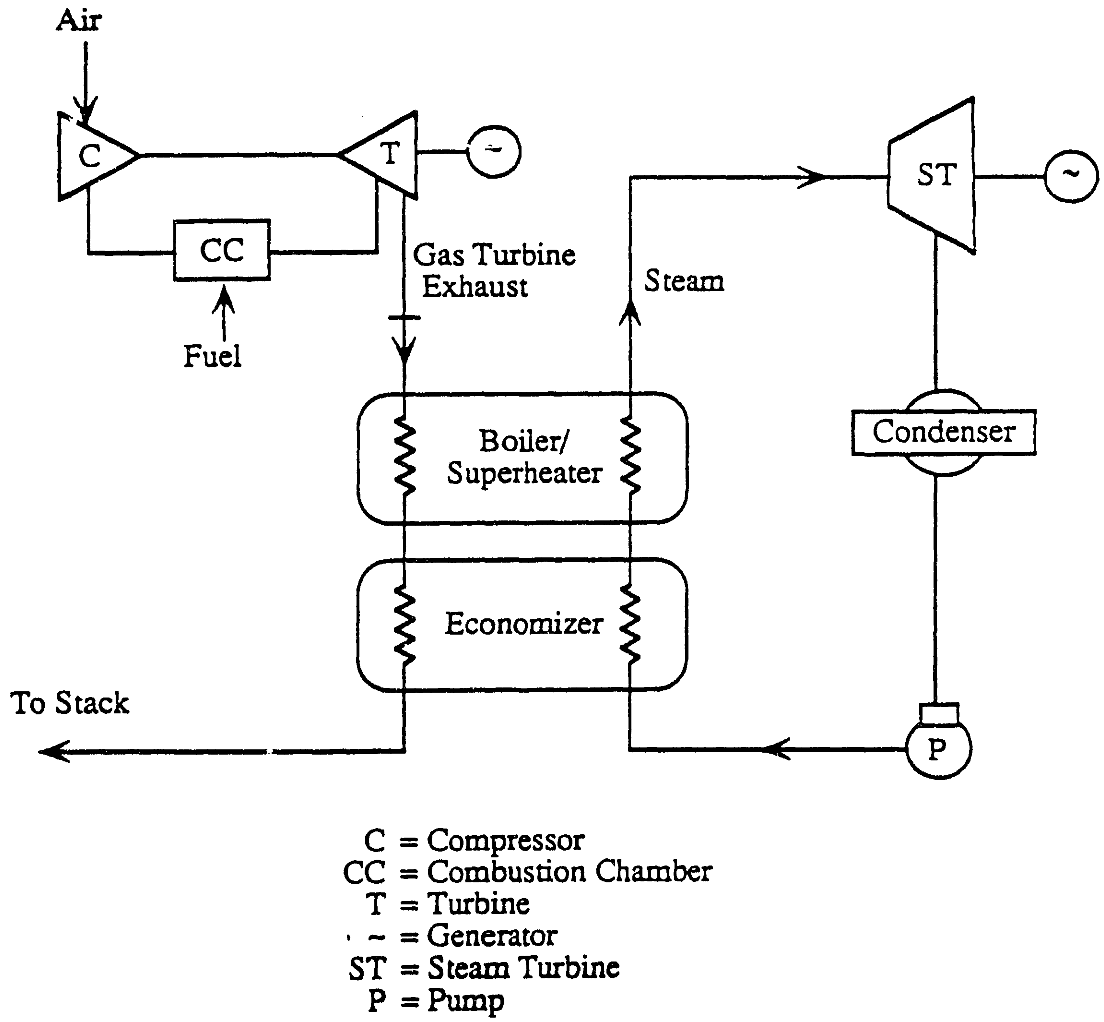

FIGURE 2.3. Schematic of a Combined-Cycle Electric Power Plant

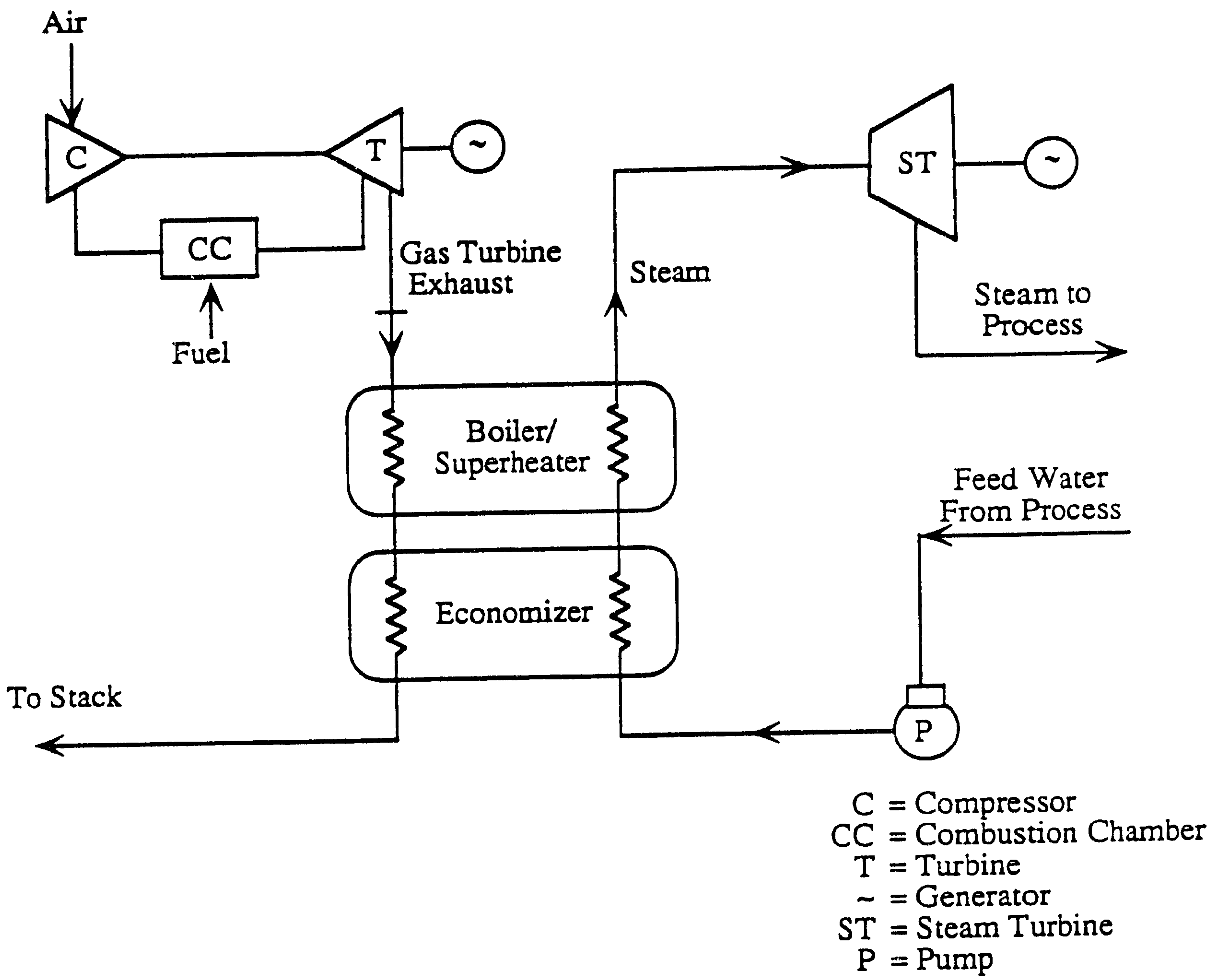

FIGURE 2.4. Schematic of a Combined-Cycle Electric Power Plant with Steam Cogeneration

plant was an obvious reference technology for producing steam, many different options are available for producing electricity. A CC power plant provides a convenient benchmark for comparison with CC/Cogen and CC/TES/Cogen because the latter two plants are based on modifications to the basic CC power plant technology.

3.0 PLANT CONCEPT DETAILS

The conceptual design of a combined-cycle cogeneration plant with TES was developed in sufficient detail to determine a meaningful cost and performance characterization. The relevant features of a conventional CC/Cogen plant are discussed in Section 3.1, followed by a discussion of the selected arrangements of the CC/TES/Cogen plant (Section 3.2). The essential features of the oil/salt heater, the oil/salt storage system, and the steam generator are discussed in Somasundaram et al. (1992).

3.1 CONVENTIONAL CC/COGEN 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 layout of a cogeneration plant. Therefore, there is substantial similarity between a conventional combined-cycle cogeneration plant (CC/Cogen) and the combined-cycle cogeneration/TES design (CC/TES/Cogen). The conventional combined-cycle cogeneration plant (Figure 2.4) includes a prime mover (a gas turbine, in this case) that is fired by a natural-gas combustor. The gas turbine exhaust [at 538°C (1000°F)] is used to produce steam in a heat recovery steam generator (HRSG), which is then partially expanded in a back-pressure steam turbine. The low-pressure exhaust from the steam turbine provides process heating. The net efficiency of the gas turbine is assumed to be 31% (a heat rate of 11,000 Btu/kWh) for larger gas turbines (> 100 MWe rating) and 29.6% (a heat rate of 11,500 Btu/kWh) for smaller turbines (≤ 100 MWe rating).

3.2 CC/COGEN PLANT WITH TES FOR PEAKING

An oil/rock or a salt TES system interposed between the gas turbine and the steam generator in a conventional combined-cycle cogeneration plant can provide a cycling capability (Figure 2.1). Instead of generating steam directly, heat from the gas turbine exhaust is used to heat oil or the salt, which is then stored in a tank for later use. The gas turbine is operated whenever peaking power capacity is needed by the utility. TES serves to decouple steam generation from gas turbine operation, allowing process steam production for a steam turbine or other process thermal loads to continue 24 hr/day. No attempt was made to optimize the cost and performance of the different systems evaluated in this study. Rather, the systems evaluated could be described as workable and the results indicative of a preliminary assessment.

3.3 SYSTEM STEAM REQUIREMENTS

Several systems were evaluated for meeting the same process steam load. Process steam requirements are as follows:

- Flow rate: 181,440 kg/hr (400,000 lb/hr); 24 hr/day; 320 days/year
- Supply conditions: 690 kPa (100 psia); saturated steam with a quality of 0.973
- Condensate return conditions: 49°C (120°F) (saturated liquid)

In some cases, the systems are the same as one of four plant types described above, while others are combinations of two of the plant types described above. The gas turbine rating depends on the length of time during the day that the gas turbine is operated with intermediate- and/or 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 hr/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 additional system analyzed was the 8 hr operation of an oversized (threefold) gas turbine for selling peak power to the local utility. The alternative systems evaluated were 1) a boiler operating 24 hr/day, 2) a CC/Cogen plant operating 24 hr/day, 3) a CC/Cogen plant operating 8 hr/day and selling peak-load power to the utility and a boiler operating for the remaining 16 hr/day to supply the steam load, 4) a CC/Cogen plant operating 12 hr/day to sell intermediate-load power to the utility and a boiler operating 12 hr/day, and 5) a CC/TES/Cogen plant using "60/40" salt and oil/rock storage or Hitec salt storage. The latter alternative was evaluated with the gas turbine operating either 8 or 12 hr/day and the steam turbine operating 24 hr/day for both types of storage systems.

3.4 SYSTEM SIZING

Rudimentary design specifications were developed for each major system component to define the cost and performance basis. In general, equipment was sized to meet process steam requirements. Key design and performance assumptions are presented below:

- Natural-Gas-Fired Systems
  - Steam turbine inlet conditions:
    181,440 kg/hr (400,000 lb/hr)
    8274 kPa (1200 psia)
    427°C (800°F)

- Steam Turbine Power Calculations
  - turbine efficiency = 0.90
  - generator efficiency = 0.98
  - parasitic power = 0.02

- Gas Turbine Heat Rate
  - 11,500 Btu/hr for gas turbines ≤ 100 MWe
  - 11,000 Btu/hr for gas turbiens > 100 MWe

- Gas Turbine Exhaust Temperature = 538°C (1000°F)

- Overall Heat Transfer Coefficients
  - 150 $W/m^2.°C$ (26.6 $Btu/hr.ft^2.F$) for HRSG and storage media heaters
  - 846 $W/m^2.°C$ (150 $Btu/hr.ft^2.F$) for storage media steam generators

- Storage Media Cycle Temperatures
  - "60/40" salt: 550° to 950°F
  - oil/rock: 250° to 550°F
  - Hitec salt: 425° to 850°F

3.4.1 Steam Generator Sizing

Steam generators include conventional gas turbine heat recovery steam generators and steam generation equipment from thermal storage media. Process steam condensate and steam turbine inlet conditions define the economizer, boiler, and superheater duties and water/steam inlet and exit temperatures. Sizing of these units depends on both the gas turbine exhaust temperature and the stack reject temperature after heat recovery. In general, lowering the reject temperature increases the waste heat recovery fraction and reduces the size of the gas turbine required, but results in larger, more costly heat exchangers. The minimum reject temperature is limited by the boiler pinch point. A reasonable reject temperature [191°C (375°F) for oil/rock salt system and 232°C (450°F) for Hitec salt system] was selected from several investigated, but a formal optimization was not conducted.

The first step for sizing storage-media-heated steam generators was to select the media operating temperature range from within the upper and lower temperature limits. In general, the temperature range should be as large as possible to minimize storage costs. However, a higher upper temperature will reduce steam generator costs but, at the same time increase media heater costs. Boiler pinch point limitations must also be considered in setting the lower media temperature. Thus, the operating temperature range affects all TES charging and discharging equipment, as well as the TES unit itself. Again, the design approach was to select reasonable, but not necessarily optimal temperature ranges; the specific temperature range for each media type was given in the design and performance assumptions. Once the media temperature range was established, the design procedure was the same as that described for the HRSG.

3.4.2 Storage Sizing

Thermal storage capacity (kWht) is independent of the media type because the same total energy must be transferred in the steam generator and the storage efficiency is essentially the same. Thermal losses for large (500,000 to 2,500,000 kWht) storage systems, such as those required for the systems evaluated in this study, are less than 1% (Williams et al. 1987). An overall efficiency of 97%, which allows for losses in piping and the thermal equivalent of pumping parasitics, was presumed. The required storage capacity is directly proportional to the steam generation energy and the number of hours the steam generator is operated from storage (or 24 minus the number of hours the gas turbine operates).

3.4.3 Storage Media Heater Sizing

Media heater thermal duties and media temperatures were established as part of the media heated steam generator sizing process. Design considerations and procedures were similar to those described above for the HRSG sizing. In general, the minimum gas turbine exhaust temperature is limited by the minimum media temperature. For the salt and oil/rock storage system, consideration must also be given to the pinch point at the low-temperature end of the salt heater and high-temperature end of the oil heater.

3.4.4 Gas Turbine Sizing

The required gas turbine generating capacity depends on its heat rate and the stack reject temperature (after thermal recovery in the HRSG or the media heater). Heat rates (HR) are normally quoted in Btu/kWh. For example, gas turbines with a generating capacity greater than 100 MWe were assumed to have a heat rate of 11,000 Btu/kWh. If inputs and outputs are both expressed in kWh, the equivalent heat rate may be expressed in the following manner:

- for every kWh of fuel energy supplied, 31% of it is converted to electricity and 69% into exhaust heat, part of which is recoverable in a useful form. Thus, the ratio of electrical energy to exhaust energy is 31/69 or 1/2.225 or more generally, $1/({}^{HR}/_{3413}-1)$

In this study, all exhaust heat was assumed to leave the turbine in the form of the exhaust gas at a temperature of 538°C (1000°F). Recoverable energy in the exhaust is measured relative to 25°C (77°F) , the reference temperature for measuring the energy input from the gas fuel. Therefore, the heat recovery fraction becomes (1000-TR)/(1000-77), where "TR" equals the stack reject temperature after heat recovery. The waste heat recovery fraction can be combined with the electric/exhaust energy ratio to produce Equation (3.1) defining the relationship between gas turbine generating capacity and the waste heat recovery rate. The maximum capacity of an individual gas turbine unit was limited to 150 MWe, resulting in either two or three parallel gas turbine and heat recovery trains.

$$kWe = \frac{kWt * 923}{({}^{HR}/_{3413}-1) * (1000 - TR)} \tag{3.1}$$

3.4.5 Equipment Sizes

Gas turbine, steam turbine, media heater, storage, and steam generator equipment sizes are summarized in Table 3.1.

TABLE 3.1. System Equipment Sizes

Systems	Size/Rating
Boiler	181,440 kg/hr (400,000 lb/hr) (steam)
Combined-Cycle (CC)	
Gas Turbine (GT), MWe	94.2
Heat Recovery Steam Generator, m^2	
Economizer	5846
Boiler	6143
Superheater	1041
Steam Turbine, MWe	50.0 (condensing)
Combined-Cycle/Cogeneration (CC/COGEN)	
Gas Turbine, MWe	94.2
Heat Recovery Steam Generator, m^2	
Economizer	5846
Boiler	6143
Superheater	1041
Steam Turbine, MWe	50.0 (condensing)

	Size/Rating			
	Oil/Rock and "60/40" Salt		Hitec Salt	
Combined-Cycle Cogeneration with TES (CC/TES/COGEN)	12 hr GT Operation	8 hr GT Operation	12 hr GT Operation	8 hr GT Operation
Gas Turbine, MWe	2 x 103.5	3 x 103.3	2 x 117.5	3 x 117.3
Steam Turbine, MWe	24.4	24.4	24.4	24.4
Media Heater, m^2				
Oil	2 x 9201	3 x 9201		
"60/40" salt	2 x 32528	3 x 32528		
Hitec salt			2 x 26580	3 x 26580
Storage, MWht				
Oil/rock	597	795		
"60/40" salt	1233	1644		
Hitec salt			1830	2440
Steam Generator, m^2				
Economizer	2379	2379	1236	1236
Boiler	1840	1840	1989	1989
Superheater	223	223	428	428

4.0 ECONOMIC EVALUATION

This section presents details of the costs and the economic analysis of the boiler, CC, CC/Cogen, and CC/TES/Cogen systems. Section 4.1 defines the ground rules and assumptions used in the analysis. Sections 4.2 and 4.3 discuss the 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.

4.1. GROUND RULES AND ASSUMPTIONS

The ground rules and assumptions used in this evaluation were identical to those used in the previous evaluation of TES applications with simple-cycle cogeneration systems (Somasundaram et al. 1992). The information is repeated for reference.

The economic evaluation was conducted by calculating and comparing the levelized cost of steam and/or electricity 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 and/or electricity costs of alternative boiler and combined-cycle plant concepts. The specific methodology used is defined in Brown et al. (1987).

Financial assumptions used to calculate the levelized steam cost are listed in Table 4.1. 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.

TABLE 4.1. 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

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).

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, either the electric or steam revenue rate was assumed for each cogeneration case and the levelized cost analysis solved for the required revenue rate for the other product. The value of cogenerated steam and electricity was established based on the cost of steam from a stand-alone boiler plant and the cost of electricity from a combined-cycle plant.

4.2 CAPITAL COST ESTIMATES

Many of the capital cost estimating equations developed in Somasundaram et al. (1992) for the simple-cycle TES application were used again for the combined-cycle TES application. The following steam or cogeneration plant components were previously evaluated:

- oil-heated steam generator
- gas turbine
- heat recovery steam generator
- oil heater
- oil/rock thermal energy storage
- boiler plant
- "60/40" salt thermal energy storage
- salt heater
- Hitec salt thermal energy storage
- salt-heated steam generator.

Additional components evaluated for the combined-cycle TES application were a combined-cycle electric power plant and a back-pressure steam turbine. The latter component was substituted for a condensing steam turbine in the combined-cycle power plant to provide cogeneration of steam and electricity in the bottoming-half of the combined-cycle application.

Again, for ease of reference, the cost equations originally developed in Somasundaram et al. (1992) are presented here, as well as the equations specifically developed for the combined-cycle TES application. All cost equations presented below represent the complete construction cost, including indirect costs and contingency, but do not include allowances for start up and working capital, which were calculated separately. All cost data presented in this section are in 1990 $.

The capital cost model for the boiler plant 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 plant producing 690 kPa (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% for each 100 psi increase in steam pressure above 690 kPa (100 psia).

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

where S is the net steam generating capacity in thousands of lb/hr.

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 Marshall & Swift (M&S) 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 heater, and salt ("60/40" or Hitec salt) heater were based directly on cost models developed in Drost et al. (1990) for these components. The cost models were updated to 1990 $ using the Chemical Engineering Plant Cost Index for heat exchangers and tanks (Chemical Engineering Magazine 1990). The general cost relation is shown in Equation (4.3), with the cost multiplier varying depending on the presumed heat exchanger tubing and "shell" materials. Construction materials were presumed to be carbon steel tubing and "shell" for the heat recovery steam generator economizer and the oil heater; carbon steel tubing and stainless steel "shell" for the heat recovery steam generator boiler; and stainless steel tubing and "shell" for the heat recovery steam generator superheater and salt heater. For the boiler plant described above, the reference pressure for Equation (4.3) is 690 kPa (100 psia). Costs for the heat recovery steam generator components were assumed to increase by about 1% for each 100 psi increase in steam pressure above 690 kPa (100 psia).

$$\text{Heat recovery heat exchanger capital cost} = \$C * (A)^{0.95} \tag{4.3}$$

where A is the bare tube surface area of a finned-tube heat exchanger surface in ft^2, C equals 111 for carbon steel tubing and "shell", C equals 168 for carbon steel tubing and stainless steel "shell", and C equals 224 for stainless steel tubing and "shell".

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 "60/40" salt; Bradshaw and Tyner (1988) for Hitec salt; and Williams et al. (1987) for oil/rock. Equations (4.4) through (4.14) describe the relationships used for estimating thermal energy storage capital costs.

<u>"60/40" Salt Storage</u>:

$$\text{Hardware capital cost} = \$10{,}310{,}000 * (TC_{500}/1500)^{0.52}, \quad \text{for } TC_{500} \leq 1500 \tag{4.4}$$

$$= \$3{,}070{,}000 + \$4826 * TC_{500}, \quad \text{for } 1500 < TC_{500} < 3000 \tag{4.5}$$

$$= \$5850 * (TC_{500}) \quad \text{for } TC_{500} \geq 3000 \tag{4.6}$$

$$\text{Media capital cost} = \$12{,}431 * (TC_{500}) \tag{4.7}$$

where TC is the thermal capacity in MWht.

<u>Hitec Salt Storage</u>:

$$\text{Hardware capital cost} = \$10{,}310{,}000 * (TC_{500}/1563)^{0.52}, \quad \text{for } TC_{500} \leq 1563 \tag{4.8}$$

$$= \$3{,}070{,}000 + \$4634 * (TC_{500}), \quad \text{for } 1563 < TC_{500} < 3125 \tag{4.9}$$

$$= \$5616 * (TC_{500}) \quad \text{for } TC_{500} \geq 3125 \tag{4.10}$$

$$\text{Media capital cost} = \$14{,}296 * (TC_{500}) \tag{4.11}$$

<u>Oil/Rock Storage</u>:

$$\text{Hardware capital cost} = \$303{,}000 * (TC_{300})^{0.3857} \quad \text{for } TC_{300} < 1000 \tag{4.12}$$

$$= \$4329 * (TC_{300}) \quad \text{for } TC_{300} \geq 1000 \tag{4.13}$$

$$\text{Media capital cost} = \$2779 * (TC_{300}) \tag{4.14}$$

The three alternative hardware cost equations for molten salt storage (or the two alternatives for the oil/rock storage) reflect the transition from single to multiple tanks above the indicated transition values for the thermal capacity. The subscript "500" or "300" identifies the cost equations as being valid for thermal capacities calculated for a 500°F temperature range, e.g., from 550°F to 1050°F for "60/40" salt or 350°F to 850°F for Hitec, or for a 300°F temperature range from 250°F to 550°F for the oil/rock system, respectively. The capacity requirements associated with other temperature ranges must be adjusted to a 500°F (or 300°F) basis before using these equations as shown in Equation (4.15).

$$TC_{500} = TC_x * (500/x) \quad \text{or} \quad TC_{300} = TC_x * (300/x) \tag{4.15}$$

For example, if x = 250, then $TC_{500} = TC_{250} * (500/250)$. This adjustment accounts for the doubling of the physical size of a 250°F range storage system that would be required to achieve the same thermal capacity as a 500°F range storage system.

The capital cost model for the storage-media-heated steam generator presumed a 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). The general cost relation is shown in Equation (4.16), with the cost multiplier again varying depending on the presumed heat exchanger tubing and shell materials. Construction materials were presumed to be carbon steel tubing and shell for the oil-heated or salt-heated economizers, carbon steel tubing and stainless steel shell for salt-heated boilers, and stainless steel tubing and shells for salt-heated superheaters.

$$\text{Oil-heated steam generator capital cost} = \$1000 * C * (A/10{,}000)^{0.8} \qquad (4.16)$$

where A equals the heat exchanger surface area in ft^2, C equals 370 for carbon steel tubing and shells, C equals 520 for carbon steel tubing and stainless steel shells, and C equals 740 for stainless steel tubing and shells.

The cost equation presented above for storage-media-heated steam generators applies for steam production at 690 kPa (100 psia). Again, steam generator costs were assumed to increase by about 1% for each 100 psi increase in steam pressure above 690 kPa (100 psia).

The capital cost model for the CC electric power plant was based on data presented in EPRI (1989) and Esposito (1989). Data from EPRI (1989) were used to establish the reference cost for a 120-MW power plant. Data from Esposito (1989) were used to establish the relative costs of CC power plants with different generating capacities. The original data were updated to 1990 $ using the M&S Equipment Cost Index for electrical power (Chemical Engineering Magazine 1990). The resulting cost relation is shown in Equation (4.17).

$$\text{CC plant capital cost} = \$3{,}550{,}000 * (P)^{0.6} \quad (4.17)$$

where P is the net electric generating capacity in MW.

Capital costs attributable to the back-pressure steam turbine and ancillary equipment in a CC/Cogen power plant were established based on an examination of combined-cycle power plant cost components presented in Esposito (1989) and the cost equations presented above for combined-cycle [(Equation (4.17)] and gas turbine [(Equation (4.2)] power plants. Rather than directly estimating the cost of a back-pressure turbine for coupling with gas turbine and HRSG components of a CC/Cogen or CC/TES/Cogen system, its cost was based on subtracting cost components of a CC plant that would not be required in a CC/Cogen or CC/TES/Cogen plant or would be separately estimated by one or more of the equations already described above. This approach minimizes the possibility of excluding miscellaneous ancillary equipment and having the components of a CC/Cogen plant add up to a figure significantly less than the expected total cost.

Substitution of a back-pressure turbine for the condensing turbine and elimination of heat rejection and HRSG costs presented in Esposito (1989) resulted in systems costing about 77% of the full cost of a combined-cycle plant. Gas-turbine-related costs were subtracted from this modified combined-cycle plant figure to yield the steam-turbine-related costs. The resulting cost estimating relation is shown in Equation (4.18).

Note that the back-pressure steam turbine-related costs (Equation 4.18) are related to the theoretical gas turbine and CC plant power generating capacities that are possible if the steam entering the back-pressure turbine was fully expanded in a condensing turbine. The thereotical gas turbine generating capacity was found to be 7/3 of condensing steam turbine generating capacity based on performance data presented in Esposito (1989) for CC power plants. Therefore, the theoretical CC plant generating capacity would be 1 + 7/3 or 10/3 of the condensing steam turbine's generating capacity.

$$\text{Back-pressure Steam-Turbine Costs} = 0.77 * 3{,}550{,}000 * (P_1)^{0.6} - 30{,}600{,}000 * (P_2/80)^{0.76} \qquad (4.18)$$

where P_1 is the thereotical CC power plant generating capacity (MWe) corresponding to the back-pressure steam turbine inlet steam conditions and P_2 is the generating capacity (MWe) of the gas turbine portion of the CC power plant.

Start up and working capital cost estimates were based on information presented in EPRI (1989). Start up costs include operator training, equipment checkout, minor changes in equipment, extra maintenance, 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 start up and working capital are given below.

$$\text{Start up capital cost} = 0.02 * \text{total system construction cost} + 1/12 * \text{total annual O\&M} + 1/52 * \text{total annual fuel} \qquad (4.19)$$

$$\text{Working capital cost} = 0.005 * \text{total system construction cost} + 1/6 * \text{total annual O\&M} + 1/6 * \text{total annual fuel} \qquad (4.20)$$

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 described here 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 natural-gas-fired boiler plant were used to develop non-fuel O&M cost estimating relations for the steam generators as well as the boiler plant. Cost data from Brown et al. (1992) 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. (1992), resulting in the following estimating relation:

$$\text{Steam generation fixed labor cost} = 0.07 * (S/330)^{-0.5} * \text{construction capital} \qquad (4.21)$$

where S is steam generating capacity in klb/hr.

Fixed maintenance was presumed to be required regardless of the actual frequency of equipment use. On the other hand, variable maintenance was presumed to be proportional to the number of operating hours per year (at full capacity). Equations (4.22) and (4.23) describe the relations for estimating fixed and variable maintenance for the steam generators and boiler plants:

$$\text{Steam generation fixed maintenance materials cost} = \$0.0085 * \text{construction capital} \qquad (4.22)$$

$$\text{Steam generation variable maintenance materials cost} = \$3 \times 10^{-6} * \text{annual operating hours at full capacity} * \text{construction capital} \qquad (4.23)$$

Consumable supplies include make-up water, water treatment chemicals, and electricity. Cost data presented in Brown et al. (1992) for these items were used to develop the following cost estimating relation:

Steam generation consumable supplies cost = \$0.1335 * annual steam production, klb (4.24)

O&M cost data presented in Hevia (1989), Esposito (1989), and EPRI (1989) were used to develop fixed and variable O&M cost estimating equations for gas-turbine and combined-cycle power plants. The data presented in these three reports indicate that O&M rates might vary from 1 to 8 mills/kWh, although it is not clear how much of this range is attributable to variation in design and operating conditions or actual O&M requirements rather than differences in cost estimating assumptions. A key factor affecting power plant O&M cost is the plant duty cycle. In general, continuous (base load) operation results in reduced maintenance requirements compared to cycling (peaking or intermediate) operation if the same number of operating hours are incurred in both operating modes. Therefore, variable costs per kWh should be lower for continuous operation. Data presented in Esposito (1989) indicates that cycling power plants would be expected to have variable O&M costs that are about 20% higher per kWh than continuously operated power plants. Fixed and variable O&M costs for gas-turbine and combined-cycle power plants were estimated with the following relations:

Gas turbine fixed
O&M cost = 0.002 * construction capital (4.25)

Gas turbine variable
O&M cost = 0.00486 * annual power production (kWh)

for operation times <24 hr/day (4.26)

or Gas turbine variable
O&M cost = 0.00405 * annual power production (kWh)

for operation times = 24 hr/day (4.27)

CC plant fixed
O&M cost = $141.4 * (P)^{-0.737} * 1000 * (P)$ (4.28)

where P is the CC plant generating capacity in MWe.

CC plant variable
O&M cost = 0.00415 * annual power production (kWh)

for operation times <24 hr/day (4.29)

or CC plant variable
O&M cost = 0.00346 * annual power production (kWh)

for operation times = 24 hr/day (4.30)

O&M cost for the back-pressure steam turbine and ancillary equipment in a CC/Cogen power plant was estimated by modifying and combining O&M cost estimating equations developed for gas-turbine and CC power plants using an approach similar to that described above for estimating the initial capital cost for this component. Fixed and variable O&M were each assumed to equal 90% of the value for a complete CC plant, minus the O&M associated with the gas turbine portion of the CC plant, based on the theoretical gas turbine and CC plant generating capacities possible for the back-pressure turbine inlet steam conditions.

No detailed O&M estimating data similar to that used for boilers, gas turbines, and CC power plants was available for storage media heaters and thermal energy storage systems. Annual O&M costs were estimated as 10% of hardware construction capital costs for these components, based on chemical process industry 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 cost; media maintenance cost was assumed to be negligible at the media operating temperatures being modelled.

Initial capital costs and annual fuel and O&M costs are summarized for each system evaluated in Table 4.2. Construction costs for the CC/TES/Cogen systems are itemized in Table 4.3.

TABLE 4.2. Initial Capital and Annual Fuel and O&M Costs

System	Initial Capital Costs, 10^6			Annual Costs, 10^6	
	Construction	Start up	Working	O&M	Fuel
Boiler					
24 hr	19.6	0.8	2.5	2.3	11.9
12 hr	19.6	0.7	1.4	1.8	6.0
8 hr	19.6	0.6	1.0	1.7	4.0
CC					
24 hr	70.1	2.3	5.4	4.4	25.9
12 hr	70.1	1.9	3.0	2.8	12.9
8 hr	70.1	1.7	2.1	2.1	8.6
CC/Cogen					
24 hr	66.0	2.2	5.3	5.4	24.6
12 hr	66.0	1.9	3.0	3.8	12.2
8 hr	66.0	1.7	2.2	3.0	8.1
CC/TES/Cogen Oil/rock and "60/40" salt					
12 hr	225	6.3	8.1	16.3	25.5
8 hr	319	8.7	9.4	21.4	25.5
Hitec salt					
12 hr	214	6.0	8.2	14.1	29.0
8 hr	303	8.1	9.3	17.9	28.9

TABLE 4.3. CC/TES/Cogen Construction Costs (millions of $)

System	Oil/Rock and "60/40" Salt		Hitec Salt	
	8 hr GT	12 hr GT	8 hr GT	12 hr GT
Gas turbines	111.5	74.4	112.8	82.0
Heaters				
Oil/Rock	18.5	12.4		
60/40 Salt	124.1	82.7		
Hitec Salt			102.5	68.4
Thermal storage				
Oil/Rock	6.2	5.2		
60/40 Salt	38.6	29.7		
Hitec Salt			57.4	43.8
Steam generators				
Oil-heated	0.6	0.6		
60/40 Salt-heated	1.6	1.6		
Hitec Salt-heated			2.0	2.0
Steam turbin	18.1	18.1	18.1	18.1
Total	319.2	224.7	302.8	214.3

5.0 RESULTS AND DISCUSSION

The results of the economic analyses are presented in this section. As described in Section 4.1, the levelized costs of steam production from a boiler plant, and that of electricity production from a CC plant were calculated to establish the reference cost/value of these two commodities when produced by a cogeneration plant. The levelized energy costs (LECs) for these two systems are shown in Table 5.1 for different daily operating periods. As would be expected, the LECs decline with increased daily operating hours as the fixed capital and O&M costs are spread over a larger annual energy output.

The LECs from a CC/Cogen plant were also calculated to establish a reference for measuring the impact of adding TES. Again, for any multiple energy product operation, the value of all but one energy product must be fixed to solve for the LEC of the remaining product. Thus, the LECs of steam and electricity from a CC/Cogen plant were calculated by alternately fixing the value of steam or electricity at the levels indicated in Table 5.1. The results are presented in Table 5.2. The lowest cost steam and electricity are associated with the 24 hr/day operation.

TABLE 5.1. Reference Steam and Electricity Costs/Values

	Daily Operating Period		
	8 hr	12 hr	24 hr
Boiler LEC, $/klb	11.23	10.01	8.71
CC Plant LEC, $/kWh	0.072	0.064	0.055

TABLE 5.2. Reference Combined-Cycle Cogeneration Plant LECs

Operating Period	Steam LEC, $/klb (value at reference electricity costs)	Electricity LEC, $/kWh (value at reference steam costs)
8 hr/day	4.07 ($0.072/kWh)	0.048 ($11.23/klb)
12 hr/day	3.45 ($0.064/kWh)	0.042 ($10.01/klb)
24 hr/day	2.90 ($0.055/kWh)	0.035 ($8.71/klb)

Two different types of TES systems were evaluated as part of CC/TES/Cogen power plant analysis. The first evaluation was a combination of "60/40" salt and oil/rock storage systems; the second evaluation was a Hitec salt storage system. Each type of TES system was evaluated for gas turbine operation for either 8 or 12 hr/day. The resultant steam and electricity LECs are shown in Table 5.3. The figures in Table 5.3 indicate that, in general, adding TES to a CC/Cogen plant results in steam and electricity costs that are higher than those to produce steam and electricity separately in the boiler and CC plants. The exception is for the Hitec salt storage system with the gas turbines operating 12 hr/day, where a slight cost advantage can be seen for the CC/TES/Cogen system.

The steam and electricity production systems and LECs presented in Tables 5.1 through 5.3 can be combined to generate a simplified comparison of alternative systems for providing steam and electricity. Table 5.4 presents steam LECs for alternative systems producing identical rates of steam flow 24 hr/day, with electric power being produced at different schedules and amounts. The results indicate that a CC/Cogen plant operating 24 hr/day would produce steam at the lowest possible cost. In addition, a CC/Cogen/boiler hybrid system would produce steam at a lower average cost than a stand-alone boiler, as long as the CC/Cogen part of the system is operated for at least 8 hr/day (Note: At some daily operating period of less than 8 hr, a stand-alone boiler would be preferred; but, this break point was not determined).

TABLE 5.3. Combined-Cycle/TES/Cogeneration Plant LECs

Peaking Period, hr/day	Storage Media	Steam LEC, \$/klb (value at reference electricity costs)	Electricity LEC, \$/kWh (value at reference steam costs)
8	"60/40" salt and oil/rock	12.97 (\$0.072/kWh)	0.088 (\$8.71/klb)
12	"60/40" salt and oil/rock	9.72 (\$0.064/kWh)	0.068 (\$8.71/klb)
8	Hitec salt	10.77 (\$0.072/kWh)	0.079 (\$8.71/klb)
12	Hitec salt	8.46 (\$0.064/kWh)	0.063 (\$8.71/klb)

TABLE 5.4 Levelized Cost of Base Load Steam

System Description	Levelized Energy Cost, $/klb
24 hr boiler	8.71
24 hr CC/Cogen	2.90
12 hr CC/Cogen and 12 hr boiler	6.73
8 hr CC/Cogen and 16 hr boiler	7.62
12 hr CC/Hitec salt TES/Cogen	8.46
8 hr CC/Hitec salt TES/Cogen	10.77

Table 5.5 presents electricity LECs for alternative systems producing power 8 or 12 hr/per day at different rates with steam being produced at identical rates 24 hr/day. Finally, Table 5.6 shows the marginal cost of electric power provided by the CC/Hitec Salt TES/Cogen system relative to the reference CC/Cogen system. The results in these two tables further emphasize that the CC/Cogen system is the preferred option to the CC/TES/Cogen systems. In fact, the marginal cost of power from the CC/Hitec Salt TES/Cogen system is significantly higher than the cost of power produced by a CC plant alone.

TABLE 5.5 Levelized Cost of Peaking Power

	Levelized Energy Cost, $/kWh	
System Description	8 hr peak	12 hr peak
CC	0.072	0.064
CC/Cogen	0.061	0.050
CC/Hitec Salt TES/Cogen	0.079	0.063

TABLE 5.6 Marginal Cost of Peaking Power

	Levelized Energy Cost, $/kWh	
System Description	8 hr peak	12 hr peak
CC/Hitec Salt TES/Cogen	0.105	0.099

6.0 CONCLUSIONS AND RECOMMENDATIONS

Thermal energy storage can help meet the challenges of power generation options in the 1990s by increasing the flexibility and performance efficiency of existing and new cogeneration plants. The results from an earlier study of integrating TES with a simple gas turbine cogeneration system were extremely encouraging (Somasundaram et al. 1992). However, the results presented in this report indicate relatively poor economic prospects for integrating TES with conventional combined-cycle cogeneration plants with the assumed designs and loads. The major reason can be attributed to the extremely close approach temperatures at the storage media heaters, which makes them large and therefore expensive. Two potentially mediating factors, however, should be considered prior to rejecting this system combination. First, the designs developed here were practical and operable, but were not optimized from a system cost and performance perspective. For example, increasing the approach temperatures for the storage media heaters might lower the media heater costs more than it would raise media storage costs. Quite simply, design optimization would improve the economics, perhaps enough to make the CC/TES/Cogen plant an attractive option for incremental peak power production. Second, the media heaters were based on conventional "shell-and-tube" heat transfer equipment. Direct-contact of gas turbine exhaust with the storage media would permit a much closer approach temperature, while reducing the cost of the media heating equipment by as much as a factor of five (Drost et al. 1990). This magnitude of cost reduction for the high-temperature media heater could result in economically more attractive CC/TES/Cogen applications. Therefore, further analysis of this system combination, and especially, using direct-contact heat transfer equipment for media heating is strongly recommended.

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