EVALUATION OF THERMAL ENERGY STORAGE FOR THE PROPOSED TWIN CITIES DISTRICT HEATING SYSTEM

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PROJECT OUTLINE

Project Title: Twin Cities District Heating, Thermal Energy Storage Study

Principal Investigator: C. F. Meyer

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Project Goals: Evaluate the technical and economic feasibility of incorporating thermal energy storage components (primarily based on the annual cycle) into the proposed Twin Cities District Heating (DH) Project.

Review technical status of the Twin Cities Project, including work done by Studsvik AB. Prepare a conceptual design of one or more DH systems which are comparable but include TES as an integral part of the design. Compare the DH systems with and without TES in terms of estimated capital requirements, fuel consumption, delivered energy cost, and environmental aspects.

This activity has been completed. Potential benefits are found to be substantial, including energy conservation, favorable economics, and reduced air and thermal pollution.

Contract Number: Union Carbide Contract No. 7604

Contract Period: September 1978 - July 1979

Funding Level: $135,000

Funding Source: U.S. Department of Energy
Division of Energy Storage Systems

PROJECT SUMMARY

Title: Evaluation of Thermal Energy Storage for the Proposed Twin Cities District Heating System

Principal Investigator: Charles F. Meyer

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Project Objectives: To evaluate the technical and economic feasibility of incorporating thermal energy storage components (primarily based on the annual cycle) into the district heating system proposed for the Minneapolis-St. Paul metropolitan area.

Project Status: Completed. Final report submitted July 1979 (ORNL/Sub-2604-2; GE79TMP-44).

The net energy savings of the proposed cogeneration/district heating system without TES are impressive. When TES is used, the net energy saved is found to be 2 to 14 percent greater, in spite of heat lost during storage, with fuel cost savings of $14 to $16 million per year. Reduction of air and thermal pollution are concomitant benefits. The capital investment requirements for boilers, cogeneration equipment, and transmission pipelines might be reduced by $66 to $122 million. The breakeven capital cost of aquifer TES is found to be from $43 to $59 per peak thermal kilowatt input to or withdrawal from storage.

Contract Number: UCC 7604

Contract Period: August 1978 - July 1979

Funding Level: $133,744

Funding Source: U.S. Department of Energy, Division of Energy Storage Systems, via Oak Ridge National Laboratory.

PURPOSE

TEMPO studies beginning in 1972 have shown that thermal energy storage (TES) in aquifers could greatly improve the opportunities for conserving substantial amounts of energy (with concomitant reduction in environmental pollution) through large-scale cogeneration (Meyer, Hausz, et al, 1976). If large-scale annual-cycle TES were available, it could solve the mismatch problem which limits the amount of cogenerated heat for which a market can be found. The mismatch problem arises because electricity must be generated in instantaneous response to demand (no feasible way to store electricity is available); and demands for heat seldom correspond to electric generation in time, location, or magnitude. The largest potential market for cogenerated heat is space heating — an annual-cycle load — served by district heat.

Comparing the capital requirements and fuel consumption of a specific cogeneration/district heating system which does not include TES to those of a system with TES, serving identical loads, provides a measure of the value of the TES.

BACKGROUND INFORMATION

A major series of studies have been undertaken to evaluate the feasibility of installing a new, large district heating (DH) system in the Minneapolis-St. Paul metropolitan area. It would be based upon cogeneration of power and heat by Northern States Power. Among the leading sponsors and participants in the studies are the Minnesota Energy Agency, Northern States Power Company, and DOE/ORNL. Also participating are several other governmental agencies, utilities, universities, and a number of contractors and consultants.

The proposed new DH system would not send out steam, as is the universal practice in large DH systems in the United States, but hot water, as is the common practice in Europe. A Swedish firm, Studsvik Energiteknik AB, under a DOE/ORNL contract beginning in 1977, prepared a general description of the system and analyzed its economic feasibility, based upon their experience with European systems (Karnitz and Rubin, 1978; Jaehne, et al, 1979; Margen, et al, 1979a, 1979b).

Supplying space heating, tap water, air conditioning (absorption cycle), and low-temperature industrial process heat needs from a central source is a more efficient way to use fuel than to burn it in many small furnaces and boilers. A particularly efficient central source is a plant cogenerating power and heat.

The configurations proposed by Studsvik for a Twin Cities DH system did not include TES except that incidental to use of large hot-water pipelines: hot water has a high energy density, compared to steam, and the DH system has significant thermal inertia.

PROJECT DESCRIPTION

District Heating System Proposed by Studsvik

Figure 1 shows an annual load duration curve for space heat and hot tap water for the Twin Cities DH system after 20 years of buildup. The area houses about one million people. Two scenarios were developed by Studsvik. Only Scenario A

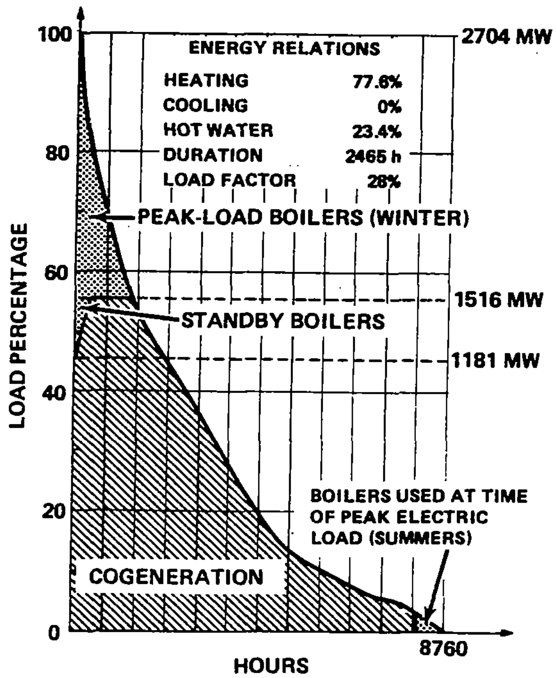

Figure 1. Annual load duration curve for space heat, hot tap water, and pipeline losses, showing load split between cogeneration and heat-only boilers. (After Studsvik)

will be discussed here. It restricts DH to the downtown and industrial/commercial areas and the dense residential areas. Heat load densities vary from 20 MW/km^2 (50 MW/mi^2) to more than 70 MW/km^2 (180 MW/mi^2). The peak coinciding consumer load is slightly more than 2600 thermal megawatts and heat loss from pipelines is about 83 thermal megawatts; 100-percent load on the vertical scale of Figure 1 thus corresponds to about 2700 thermal megawatts. The DH base load supply is from cogeneration plants, which would provide about 56 percent of the required thermal capacity but close to 90 percent of the thermal energy production.

During wintertime peak heat load conditions, 1188 MW of boiler capacity would be required in addition to 1516 MW of total heat production capacity of cogeneration plants. For reliability, the largest cogeneration plant, 335 thermal megawatts, is discounted and equivalent standby boiler capacity is added, bringing the total permanent boiler capacity to 1523 thermal megawatts. (Temporary, portable boilers would also be used, during the DH system buildup stage, until hot-water pipelines reach all heat-load areas.)

The cogeneration heat production capacity is obtained from a total of eight turbines, of which six are existing machines at two Northern States Power Company stations and two would be added. Initially, the newest three of the six existing turbines would be converted from single-purpose to extraction machines by connecting a steam pipe with appropriate regulating valves to the crossover steam line between the intermediate- and low-pressure turbines. These connections and appropriate heat exchangers would provide hot water at the DH sendout temperature of about 146°C (295°F), with a total capacity of 727 thermal megawatts. Next, a new backpressure turbine of 110 MW thermal capacity would be added, using an existing boiler and building space. A few years later, the oldest three of the existing turbines would be converted, to supply 344 MW of heat extraction. The backpressure machine and the three older machines would supply 88°C (190°F) water, with a total capacity of 454 MW. This intermediate-temperature water would be heated to sendout temperature (146°C) by passing it through the heat exchangers of the three larger machines, achieving a two-stage heating process to improve thermodynamic efficiency. The eighth and final cogeneration unit, to be installed after the DH system has reached nearly full growth, would add 335 MW of thermal capacity, bringing the total cogeneration heat production capacity to 1516 MW.

For the main transmission pipeline, a design sendout temperature of 146°C (295°F) was chosen because it can be obtained from the natural point of steam extraction from converted turbines. A lower design temperature would not decrease the amount of electrical generation sacrificed. The nominal return temperature is 60°C (140°F) for the coldest day.

The two-way transmission system (sendout and return) for Scenario A is shown diagramatically in Figure 2. The total length of dual pipeline is about 50 km (30 miles). For Scenario A, the transmission network terminates at 29 nodes, indicated by dots in Figure 2. At these points, the distribution subsystem is connected to the transmission system, via heat exchangers. The distribution subsystem operates at a temperature of 130°C (266°F), to permit the use of prefabricated pipes. Auxiliary peak-load and standby boilers are located at the nodes, to allow the transmission pipelines to be sized to transport only cogenerated heat — roughly half the peak load. This approach to siting permits the boilers to act as reserve units not only for cogeneration units but also for transmission pipeline outages. It is recognized that suitable sites may not be found for all boilers and adjustments will be necessary in a detailed network design. (The same reasoning is followed for siting TES; Heat Storage Wells would be located at the nodes.)

Figure 2. Hot-water transmission network for Scenario A. (Source: Studsvik)

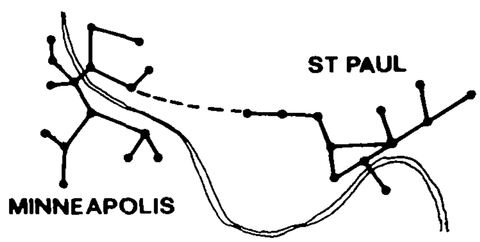

Table 1 shows the estimated capital investment costs for the three subsystems of the reference (Studsvik) cogeneration-DH system that may be affected by use of aquifer TES: the cogeneration capacity, the boilers, and the transmission pipelines. The total cost of cogeneration plant is divided into components which are of interest when TES is included in the system. Studsvik treats the cost of the new 110 MW backpressure turbine as zero for the following reasons: it will be installed in building space vacated some time ago, and matched to an existing boiler; a cost estimate of $12 million ($218/kW electric) was obtained from a turbine manufacturer, and the value of the turbogenerator for peak load electric generation is estimated to roughly match this cost; therefore, the unit involves zero net equivalent conversion cost.

TABLE 1. Estimated capital investments (millions of 1978 $US).

Cogeneration plant (1516 thermal megawatts capacity):		
Conversion of three newest machines for extraction of 727 MW	14.0	
Adding new backpressure machine, 110 MW	-0-	
Conversion of three old machines for extraction of 344 MW	12.0	
Adding new turbine to produce 335 MW	29.0	
TOTAL		55.0
Boilers for peak and standby loads of 1523 MW at $43 per thermal kilowatt		66.0
Transmission pipeline network, installed		105.0

The costs of the distribution subsystem and of converting buildings to use hot-water heat are substantial but are not shown because they are not affected by use of TES.

For the mature cogeneration-DH system proposed by Studsvik, the estimated annual fuel consumption and savings are shown in Table 2.

TABLE 2. Annual energy consumption and savings, reference system.

	TWH	PJ	TBtu	MBOE*
Gas saved	9.23	33.2	31.5	4.94
Oil burned	-1.20	- 4.3	- 4.1	-0.64
Coal burned	-2.75	- 9.9	- 9.4	-1.47
NET SAVINGS	5.28	47.4	18.0	2.83

*Million barrels of oil, equivalent.

The saving in gas shows the fuel saving of consumers of gas, oil, or whatever alternative fuel might have been used instead of district heat service. This fuel saving is deduced by Studsvik on the assumption that the efficiency of the average consumer's boiler, burning gas or oil, is 70 percent: the total heat delivered to consumers by district heating service during the year, 6,461 TWH, is divided by 0.7 to find the energy saved.

The negative saving in oil consumption is the amount of oil needed to fire the peak load and standby boilers at 90 percent efficiency.

The negative saving in coal gives the equivalent increase in coal consumption if coal-fired plants are used to produce the electricity sacrificed due to cogeneration of hot DH water. It is computed as the loss of electricity due to cogeneration divided by an efficiency factor of 0.4 to convert to coal input for electricity production in a condensing power station.

The electricity sacrificed is found by multiplying the cogenerated heat production by a factor β_N which is approximately 0.2; i.e., 200 MWH of electricity is lost per 1000 MWH of cogenerated heat. At 40 percent efficiency, a coal plant (somewhere in the system) would burn 500 MWH of coal to replace the electricity sacrificed in cogenerating 1000 MWH of heat. A boiler at 90 percent efficiency would burn 1111 MWH of fuel to produce 1000 MWH of heat; the tradeoff is a good one.

Analysis of DH System with TES

The capital investment requirements and fuel consumption of the Twin Cities system as proposed, with no TES, are compared to those of systems with TES and serving identical heat loads. The comparison provides a measure of the value of TES in a specific system. Some of the ground rules and assumptions are:

- The reference cogeneration-district heating system is that proposed by Studsvik. To facilitate comparison against the reference system, Studsvik's data on costs and performance, and their methodology for analysis of systems, are utilized wherever possible.

- Only the mature system is considered. The assumption is that TES devices would have been incorporated into the system during the 20 years from inception to maturity.

- Annual-cycle TES is of principal interest. The only annual-cycle TES technology to be considered is storage of hot water in aquifers.

- Availability of suitable aquifers for thermal storage is assumed.

- Because aquifer TES is still in the development stage and its cost and performance are speculative, a full cost-benefit analysis is not attempted at this time. Instead, the potential benefits are of principal interest. How much investment in boilers, cogeneration equipment, and transmission pipelines might be avoided if TES were used? How much less oil would be burned if TES displaced some or all of the boilers? How much more coal would have to be burned? What is the breakeven or allowable cost of aquifer TES?

- Utilizing the heat-cogeneration plant at as high a capacity factor* as possible is desirable.

- The temperature drop between hot water into and hot water out of TES does not appear to be a substantial problem in the proposed Twin Cities system, because the system incorporates a drop from 146°C (295°F) to 130°C (266°F) at the nodes where most of the TES would be located; and the ratio of stored heat to transmitted heat usually is fairly small, so that blending will mitigate the temperature drop.

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*Capacity factor is defined as the ratio of average load on a machine or equipment for the period of time considered to the capacity of the machine or equipment (IEEE Std. 346-1974).

Aquifer TES

Figure 3 illustrates schematically the Heat Storage Well concept of annual-cycle TES at low cost and low heat loss. Two water wells are drilled deep enough — say, 500 to 1000 feet — to provide sufficient hydrostatic heat to maintain superheated water in liquid form, and to avoid aquifers used for water supply. The two wells of the doublet comprise a closed hydraulic system; water pumped from one well is injected into the companion well, several hundred feet away. The heat-storage medium is the porous rock comprising the aquifer and the water filling the pores, together with the relatively impervious aquifer cap and bottom. The energy storage capacity is very large — the aquifer may be 100 feet thick, and the hot water may extend 300 or more feet radially from the well — and costs essentially nothing. The TES capacity — the rate at which heat can be stored or withdrawn from storage — is determined by the size of the wells, the pumps employed, and the flow parameters of the aquifer. A reasonable estimate is that a Heat Storage Well doublet may have a 15-megawatt thermal capacity. Multiple wells are employed to obtain larger capacities. Thus, in contrast to most TES components, only the power capacity determines the cost of storage.

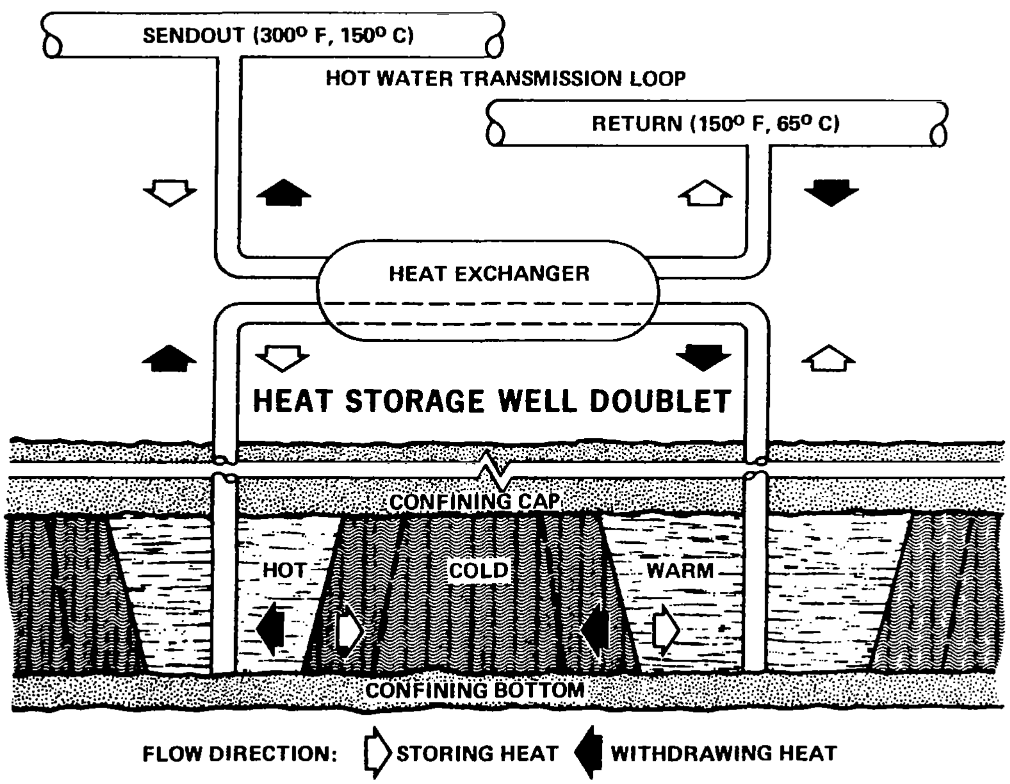

Figure 3. Schematic diagram of Heat Storage Well doublet operation.

Somewhat as with root cellars and ice caves, natural rocks and sand insulate the hot water stored in an aquifer. Three-fourths or more of the stored heat would appear to be recoverable after six months or longer (Meyer, Hausz, et al, 1976; *ATES Newsletter*, September 1979, reports by Molz and Tsang). This remains to be demonstrated on the necessary scale with water injected at temperatures above 100°C.

Cases Studied

Four study cases were developed to describe potential DH system configurations which would incorporate TES and satisfy the same heat loads and pipeline losses as the reference system.

Each study case was analyzed month by month to find the heat production required to satisfy consumer heat loads, pipeline losses, and a nominal 25 percent heat loss from aquifer TES. (Losses of 35 and 15 percent were also considered but the results are not reported here.)

When heat demand exceeds available cogeneration heat-production capacity, TES is required to deliver heat. When available cogeneration heat-production capacity exceeds demand, excess capacity is used as appropriate to produce hot water to be stored. Maximum storage is scheduled during months just preceding the winter months of peak heat demand. This minimizes the storage time and the amount of hot water stored, hence the heat lost in storage.

RESULTS

The four cases were developed sequentially. The rationale and system configuration for each case are discussed in what follows. The results are summarized in Table 3. The effects on capital investment requirements and fuel consumption, and the allowable (breakeven) cost of TES, will then be presented and discussed.

TABLE 3. Summary of effects of TES on system configuration and performance.

		Studsvik's Scenario A Reference case.	CASE 1 Base case. No boilers. Same cogen. capacity as ref. case.	CASE 2 Reduce cogen. capacity by 344 MWth of old turbines.	CASE 3 Convert only new turbines. Add backpressure units. TES at nodes only.	CASE 4 Minimize pipeline size. TES at both plant and nodes.
COGENERATION						
Extraction:	MW Capacity	1406	1406	1062	727	727
	Annual TWH	5.480	6.344	6.551	4.241	4.241
	10-month CF		0.60	0.76	0.80	0.80
Backpressure:	MW Capacity	110	110	110	440	475
	Annual TWH	0.465	0.775	0.775	3.084	3.333
	Annual CF	0.45	0.80	0.80	0.80	0.80
Total:	MW	1516	1516	1172	1167	1202
	Annual TWH	5.945	7.119	7.326	7.325	7.574
Elec. sacrificed, TWH		1.10	1.24	1.43	1.16	1.17
BOILERS						
Peak:	MW Capacity	1188	-0-	-0-	-0-	-0-
Standby:	MW Capacity	335				
Total:	MW Capacity	1523				
	Annual TWH	1.049				
	Annual CF	0.08				
HEAT STORAGE WELLS						
At Nodes:	MW Capacity	-0-	1523	1867	1872	1839
	Annual TWH		0.533	1.344	1.350	2.450
At Plant:	MW Capacity	-0-	-0-	-0-	-0-	414
	Annual TWH					1.430
Total:	MW Capacity		1523	1867	1872	2253
Total annual TWH stored			0.533	1.344	1.350	3.880
Approx. annual TWH lost (at 0.75 recovery fraction)			0.133	0.336	0.338	0.613
TRANS. PIPELINES (lumped)						
Peak capacity required, MW		1516	1516	1172	1167	865
Annual capacity factor		0.45	0.54	0.71	0.72	1.0

Case 1 is a study of replacing boiler capacity with aquifer TES capacity. It shows that all boilers could be replaced with aquifer storage without exceeding capacity factor constraints on the reference-system cogeneration equipment.

Case 2 is a study of how much heat cogeneration capacity may be removed from the Case 1 configuration without exceeding capacity factor constraints on the cogeneration plant. It shows that the 344 MW of heat production capacity obtained by converting the three old machines could be dispensed with.

Case 3 examines the benefits of using as much backpressure capacity as is realistically possible. Some extraction capacity is retained: the three newest turbines are converted for crossover extraction to give 727 MW of heat capacity, needed during the first three years of implementation of the DH system.

Using more backpressure capacity than in the reference case becomes feasible with TES because the cogenerated heat can always be either used or stored. There is no need for cold condensing. The capital cost to be amortized from electricity and heat revenues is lower than when extraction machines are used because there are no low-pressure stages, cold condenser, and cooling water facilities to stand idle during maximum heat production. Full advantage can be taken of the inherently smaller size, lower cost, and slightly better cogeneration efficiency of the backpressure turbine as compared to the extraction turbine. (The extraction mode is slightly less efficient because even at full extraction a small amount of steam must be bled through the low pressure stages for temperature control, then condensed at a loss of roughly 2300 J/kg (1000 Btu/pound).)

A key point to be made is that use of TES expands the role of the backpressure turbogenerator used in a DH system. It is no longer to be regarded as basically a source of district heat with electricity as a byproduct, or vice versa. It can be operated to produce electricity at a lower heat rate than base-load power plants (e.g., 1.29 kWh thermal per kWh electric; 4400 Btu/kWh_e), with heat as a byproduct; or to produce district heat in the most energy-efficient way with electricity as a byproduct; or as a high-efficiency low-cost producer of electricity and heat as joint products. There is a limitation: enough heat must be produced at appropriate times to charge TES, so that heat from TES will be available when needed. However, there is considerable latitude in choosing the appropriate times.

Figure 4 illustrates graphically the use in Case 3 of less cogeneration capacity, at a higher capacity factor, with TES, and with no boilers, to satisfy the same heat demand as the reference system shown earlier in Figure 1.

Case 4 explores the effects of using TES both at the plant and the nodes, rather than only at the nodes, in order to minimize the transmission pipeline size. This is a limiting case: the analysis is made on the basis of a single pipeline operating year-round at full capacity, which obviously would never be the actual situation. It shows that a substantial reduction in pipeline size is possible (up to 43 percent), saving capital cost, pumping power, and heat loss.

Capital Cost Benefits and Allowable TES Cost (in 1978 $US)

Table 4 summarizes the capital investment costs of the reference system that may be avoided by use of TES (assuming a heat recovery fraction of 0.75). In

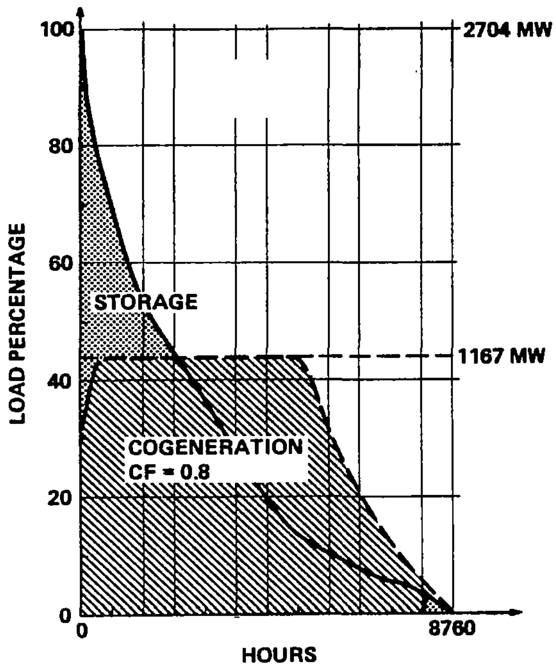

Figure 4. Load curve for Case 3, showing cogeneration and annual-cycle storage.

TABLE 4. Capital cost savings and breakeven cost of TES.

Case:	1	2	3	4
Capital costs avoided, \$M	66	92	110	122
TES capacity, MW_t	1523	1867	1872	2253
Breakeven cost of TES, \$/kW_t	43	49	59	54

Case 1, for example, the \$66 million represents the cost of boilers replaced by TES. Other cases include, in addition to the cost of the boilers, reduced cost of cogeneration equipment and of the transmission pipeline.

Even though the required amount of aquifer TES increases for each successive case, the breakeven or allowable capital cost per kilowatt of TES capacity also increases, because of capital costs avoided.

Unlike other TES devices, the cost of aquifer TES is almost entirely determined by the megawatt (power-related) capacity. The storage medium (water), the containment (aquifer), and the insulation (sand and rock) cost nothing once wells are drilled; the only energy-related cost, for pumping, is very low. A very rough estimate of the capital cost of the aquifer storage is \$23 to \$50 per peak thermal kilowatt into or out of storage. This rough estimate remains to be verified by field installations and tests.

Fuel Consumption and Energy Benefits

For the reference system and for the systems with TES, the gas (or oil, or other alternative fuel) not used by consumers of district heat amounts to 9.23

thermal TWH per year (31.5 trillion Btu) and would cost about 161 million 1978 dollars. This is the basic energy-conservation benefit of a Twin Cities cogeneration-district heating system.

Peak load and standby boilers required for the reference system would burn about 1.20 thermal TWH of oil per year (0.64 million barrels). These boilers are not needed in the systems with TES; the oil is replaced by coal used in cogeneration. This is an important fuel-substitution benefit of the TES system.

Cogeneration plants sacrifice some electrical generation in order to produce useful heat instead of waste heat. To replace electricity sacrificed in cogenerating heat, the reference system requires burning about 2.75 thermal TWH of coal per year (0.39 million tons), at a cost of $11 million. The net annual savings in fuel cost and energy for the reference system are then about $131 million and 5.28 thermal TWH, equivalent to 2.83 million barrels of oil.

Systems with TES burn no oil and save the same amount of gas as the reference system. Partially offsetting the saving in oil is the extra coal that must be burned to provide heat otherwise produced by boilers, and to make up the heat lost in storage. The net annual thermal energy and fuel cost savings for the cases studied are summarized in Table 5.

The fuel cost savings are a factor in evaluating the breakeven operating cost of TES.

TABLE 5. Net annual energy and fuel cost saved by TES.

Case:	1	2	3	4
Net thermal energy savings				
TWH/yr	6.03	5.43	5.46	5.37
TBtu/yr	20.6	18.5	18.6	18.3
* MBOE/yr	3.22	2.91	2.92	2.87
% over reference system	14	3	3	2
Fuel cost saving compared to reference system, $M/yr	16	14	14	14

*Million barrels of oil, equivalent

Conclusions

The potential benefits of incorporating aquifer TES into the proposed Twin Cities cogeneration-district heating system include:

- Saving the cost of installing boilers
- Avoiding problems of siting boilers at each transmission node
- Avoiding air-pollution problems of dispersed boilers
- Replacing oil burned in boilers with coal burned at central cogeneration plants
- Reducing net energy consumption and cost
- Operating cogeneration equipment at higher capacity factor, to reduce cost of both electricity and heat

- Permitting more economic cogeneration, with backpressure turbines instead of extraction turbines
- Reducing the amount of cogeneration capacity required
- Reducing thermal pollution from power plants
- Reducing the need for cooling water or towers
- Reducing size, cost, and heat losses of transmission pipelines.

Annual-cycle aquifer storage appears capable of providing these benefits.

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