

THERMAL ENERGY STORAGE AND TRANSPORT

Walter Hausz
General Electric Company - TEMPO

PROJECT OUTLINE

Project Title: Combined Thermal Storage and Transport for Utility Applications

Principal Investigator: Walter Hausz

Organization: General Electric Company - TEMPO
Center for Advanced Studies
P. O. Drawer QQ
Santa Barbara, CA 93102
Telephone: (805) 965-0551

Project Goals: Investigate technical and economic factors in utilizing TES and transporting thermal energy from electric utilities to industrial and commercial/residential consumers, distant from the utility plant. Examine benefits and problem areas for utilities.

Project Status: Completed. Final report submitted April 1979 (EPRI EM-1175: GE79TMP-26).

The sendout cost of thermal energy (from nuclear and coal baseload plants) versus temperature was found; the transport cost for 50 km of dual pipeline was found for high temperature water (HTW), steam, Caloria HT43, and HITEC. The delivered cost of thermal energy was compared to locally generated process heat from oil and coal. HTW was the most economic means of transport; it was superior to hot oil, molten salt, and steam for temperatures below 250°C (500°F). Delivered heat costs were less than locally generated heat - without any storage - if desired supply and demand patterns and capacity factor (CF) match; with TES - if low CF demand and the utility supply are completely decoupled. An added benefit of complete decoupling is the capability to generate peaking power at baseload costs.

Contract Number: EPRI Research Project 1199-3 (related to prior contracts NASA/DOE DEN3-12 and EPRI Project 1082-1)

Contract Period: September 1978 - April 1979

Funding Level: \$37,847

Funding Source: Electric Power Research Institute (FFAS/Storage; William Stevens, Program Manager)

THERMAL ENERGY STORAGE AND TRANSPORT

Walter Hausz — General Electric
Center for Advanced Studies

ABSTRACT

The extraction of thermal energy from large LWR and coal-fired plants for long distance transport to industrial and residential/commercial users is analyzed. Transport as high temperature water is considerably cheaper than transport as steam, hot oil, or molten salt over a wide temperature range. The delivered heat is shown to be competitive with user-generated heat from oil, coal, or electrode boilers at distances well over 50 km when the pipeline operates at high capacity factor. Thermal energy storage makes meeting of even very low capacity factor heat demands economic and feasible. Storage gives the utility flexibility to meet coincident electricity and heat demands effectively.

SUMMARY

It has long been recognized that there are thermodynamic benefits to the joint production of electricity and heat, and its aliases: cogeneration, Dual Energy Use Systems (DEUS), and Combined Heat and Power. Electricity and heat can be supplied by this means with less fuel than by separate production, by a factor of as much as two. Greater use of this technique has been inhibited in the past by economic, technical, and institutional problems.

Some of these problems can be mitigated by economic storage and transport of thermal energy. The study here described examined the range of thermal transport media, thermal storage concepts, and system configurations, under current scenarios of future energy costs, and found areas that should be attractive to utilities and to those concerned with energy conservation.

The study was performed for The Electric Power Research Institute as RP1199-3, "Combined Thermal Storage and Transport for Electric Utility Applications," W. Hausz, EPRI, 1979 [1]*. Thermal energy transport media compared include high temperature water (HTW), steam, hot oil (Caloria HT-43), and molten salt (HITEC). Thermal energy storage means examined included aboveground storage of HTW, dual-media hot oil and rock, and below-ground storage of HTW in excavated caverns. The economic and technical data in these storage concepts were derived from an earlier related study [2,3].

* Numbers in brackets designate References shown at the end of the paper.

The basic methodology used was the comparison of the delivered cost of heat, at the end of a dual pipeline (sendout/return), with the cost of heat from alternative sources, in dollars per megawatt hour thermal ($\$/MWh_t$ – equivalent to mills/kWh). Comparable specified economic scenario assumptions were used for all alternatives. The data and methodology is that of the EPRI *Technical Assessment Guide* (TAG) [4], except that mid-1976 dollars were used as in [2,3].*

Both conventional light water reactor (LWR) and high sulfur coal-fired steam plants (HSC) were considered as sources for extracted heat. The value of the extracted heat was equated to the cost of the electricity lost because of the heat extraction. Incremental costs of capital equipment such as heat exchangers and the thermal transport system, and of the operating costs such as pumping power and thermal losses through insulation gave a cost value to the delivered cost of heat. This was compared to steam or sensible heat generated by the conversion from oil or coal fired boilers or electrode boilers.

Over a wide range of temperatures, from under 100°C to over 300°C, high temperature water (HTW) was a more economic transport medium than steam, hot oil or molten salt. For HTW at 227°C (440°F), a 50-km pipeline, and operation at high capacity factor (0.75) of the dual energy use system (DEUS) and the competing alternatives, there was a marked advantage of DEUS over alternatives. The margin of benefit was 13 percent over local coal-fired boilers, 46 percent over oil-fired boilers and over 70 percent over electrode boilers.

For lower capacity factors of the heat demand, the capital cost of the thermal transport and terminal equipment reduced the advantage of DEUS; at about 0.30 capacity factor (CF), it became zero versus both coal and oil but still had an advantage over electrode boilers.

* Use 1.26 factor for rough mid-1979\$.

If thermal energy storage is added to both ends of the pipeline to maintain its capacity factor at 0.75 or higher, the advantage is regained for low CF heat demand patterns. Even with the added costs of storage, the margin of DEUS is 20 percent over oil fired boilers at 0.25CF and 19 percent over coal.

The thermal storage permits completely decoupling the supply and demand of heat; a utility can supply maximum electrical output during peak hours and reduce electric output in order to charge the TES during off peak hours, while the heat demand peak can be at any time of day including coincidence with the electric peak demand. This additional benefit adds to the economic attractiveness of the DEUS.

JOINT PRODUCTION OF HEAT AND POWER

Utilities must recover all fixed and variable costs through revenues received from electricity generated. When some part of the steam mass flow through the turbine system is extracted before the shaft-work of normal operation has all been delivered, the electric output is decreased. The thermal energy extracted must return revenues at least equal to those lost from electric output. A reduction of one megawatt of electricity may accompany the extraction of from 3 to 10 megawatts thermal (MW_t). The ratio of electricity lost to thermal energy gained, an equivalence factor F_e , determines the minimum cost that must be charged for heat: $C_t = F_e \times C_e$.

Using the literature on district heating with HTW gives a scatter diagram of values of F_e versus temperature, for unspecified technical conditions. In addition to this data, conventional LWR and HSC plants, used as reference plants in [2,3] were computer analyzed with the assistance of General Electric's Large Steam Turbine Division, to find F_e as a function of both the amount of thermal energy extracted and the temperatures and state (HTW or steam) at

which it is extracted from and returned to the steam cycle. Figure 1 summarizes these results.

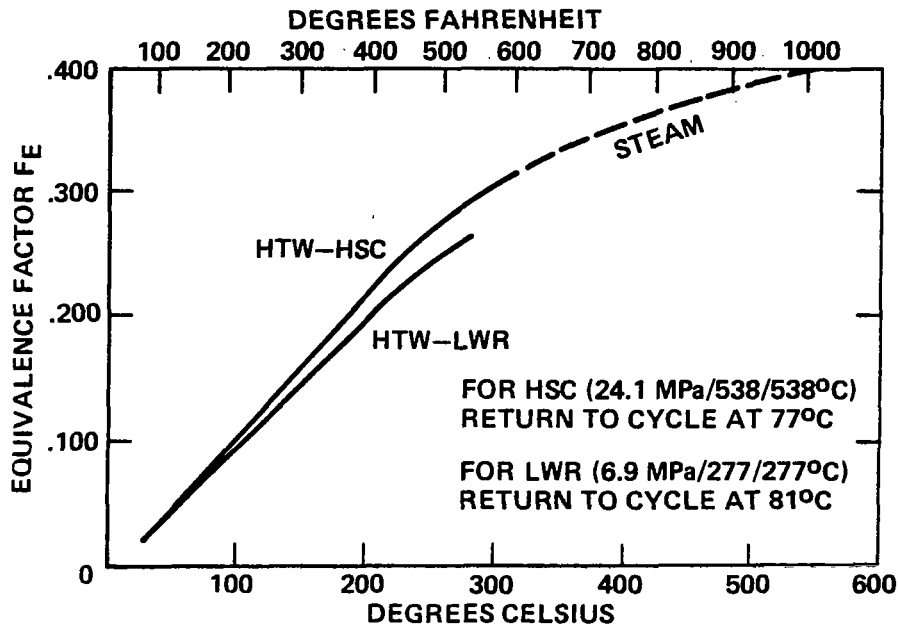


Figure 1. Equivalence factor relating heat cost to electricity cost.

The value of F_e is independent of the amount of thermal energy extracted, except that design constraints of the turbine system limit the maximum safe extraction. Extraction as HTW appears linear versus temperature for the small sample of extraction points analyzed; there is sound thermodynamic reasoning to confirm this over a reasonable range of temperatures. Since the coal-fired plant has a higher cycle efficiency than the LWR, the equivalence factor is higher, ie, it takes fewer MW_t to lose a MW_e . For both plants the water extracted is returned to a convenient point between feedwater heaters at a return temperature circa 80°C.

The economic methodology used [4] assumes 6 percent annual inflation indefinitely, and provides a scenario for each fuel; nuclear, coal, and oil with a higher escalation rate than the general inflation rate. This reflects in the investment costs as a fixed charge rate (FCR) of 0.18, to give uniform

levelized annual costs over the 30-year life of the plants. Fuel and O&M costs are also levelized to an equivalent value between the fuel cost in the year of initial operation and 30 years later. This roughly doubles the unit cost of fuels compared to current fuel prices, making the cost of electricity and heat look high to someone used to using current values. For the reference power plants operating at 0.75 CF, the unit cost of electricity in 1976 dollars for 1990 initial operation is 42.48 $\$/MWh_e$ (same as mills per kWh) from the LWR and 53.21 $\$/MWh_e$ from the HSC. As an example then, the equivalent cost of heat extracted at 227°C (440°F) is 9.56 $\$/MWh_t$ from the LWR and 13.40 $\$/MWh_t$ from the HSC.

Above about 300°C it is difficult to consider HTW. The dash line for the HSC extending to 538°C (1000°F) is an estimate of F_e for steam. Since steam in large quantities can only be extracted at a few points, between turbines, for any particular turbine design, interpolation is difficult. For steam temperatures below 300°C, the value of F_e does not differ greatly from the curves for HTW, depending on the details of extraction and return.

THERMAL TRANSPORT

For all transport fluids considered, dual pipelines (sendout and return) were assumed to be buried, with periodic U-shaped bends inserted for thermal expansion, and thermal insulation with a moisture protective outer layer around each pipe. Computer optimization of pipeline cost was performed for every case considered. For each pipe diameter considered, the thermal insulation thickness is varied in steps to minimize the sum of the annual costs for capital charges on the insulation and the cost of heat lost through the insulation. In an iterative calculation, pipe diameter is incremented in 2-inch steps (for conventionally available pipe sizes), and the annual costs for capital charges on the pipeline and its installation and on the pumps or compressors required are added to the cost of pumping power (electricity) and to the costs of the insulation-plus-

losses to find a minimum. Allowable stresses in the pipe are limited to 60 percent of the yield strength, as for moderately populated open country. The yield strength is derated per handbook data for the required pipe temperature.

With this program, transport media compared were HTW, steam (with condensate return), a hot oil such as Exxon Caloria HT-43, and a molten salt such as DuPont HITEC (eutectic of sodium and potassium nitrates and nitrites). Each was examined over its useful temperature range; each was examined over a range of transported thermal power levels from under 100 MW_t to 1000 MW_t . Figure 2 summarizes the results.

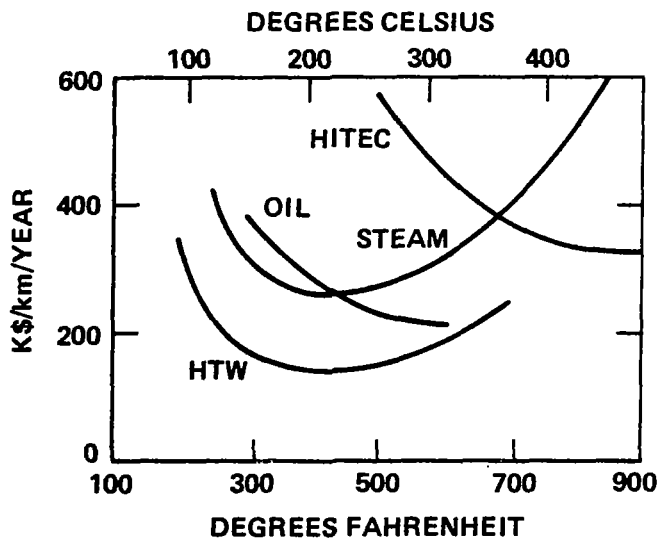


Figure 2. Cost of thermal energy transport dual pipeline.

The curves shown are for a sendout thermal power of 300 MW_t . The mass flow required for this level varies with the temperature and enthalpy difference between the sendout and return flows. As the return temperature is 80°C in all cases, the required mass flow, hence the annual costs, rise sharply as the sendout temperature decreases toward this limit. At high temperatures, high pressure containment is required for HTW or steam, so for these fluids the cost rises rapidly with temperature in the upper range. Oil and molten salt

do not require high pressure at high temperature, but the cost of temperature derating (or use of more exotic pipe materials) does tend to counterbalance the effect of increasing enthalpy difference with temperature.

For steam, saturated steam was considered up to 300°C; above that 4.5 MPa (650 psi) steam at variable superheat was considered up to 538°C (1000°F). The specific volume increases with temperature, contributing to the rise in annual cost.

The ordinate for these curves is the annual cost in thousands of dollars per kilometer (K\$/km/yr). At roughly the temperature of minimum transport cost of HTW, i.e. 227°C (440°F) the boiler feedwater temperature for the LWR, annual costs at 0.75 capacity factor are 141 K\$/km including the cost of heat losses through insulation or 116 K\$/km without it. This latter totals 4.8 M\$ for 50 km and adds 2.94 \$/MWh_t cost increment to the cost of heat extracted. Both the delivered heat and the pumping energy required are proportional to capacity factor; the other cost components are independent of it. At lower capacity factors the pipeline annual costs must be allocated over fewer MWh_t delivered so the cost of delivered heat increases. The cost increment per MWh_t delivered would decrease with the power level of the pipeline, roughly as 1/(power)^{1/2} over the range 100-1000 MW_t.

COST OF ALTERNATIVES

Commonly used local sources of industrial process heat are oil- or gas-fired boilers (for steam) or heat exchangers (for sensible heat), and coal-fired boilers where environmental constraints permit. For lower temperatures in residential and commercial use, oil and gas dominate.

Oil and natural gas as sources are high cost fuels, but permit relatively low capital costs for the boiler/heat exchanger. Using similar leveling assumptions, the fuel costs of oil and gas based on [4] give 6.64 \$/MBtu for

1 percent sulfur residual oil, and 7.55 \$/MBtu for gas, or 22.66 and 25.76 \$/MWh_t. Fixed charges on the oil- or gas-fired capital equipment are only 1.13 \$/MWh_t at 0.75 CF. At 85 percent boiler efficiency, and including variable O&M, the variable costs for oil are 26.86 \$/MWh_t and total costs are 28 \$/MWh_t. Costs are clearly dominated by the cost of fuel and the boiler efficiency. For small sizes, eg, residential use, the boiler efficiency will be much lower, hence the cost of heat higher.

Coal-fired boilers have a lower fuel cost but higher capital plant costs for the boilers, fuel handling and storage, and flue gas desulfurization and cleanup. With a levelized fuel cost of 2.08 \$/MBtu or 7.09 \$/MWh_t, a boiler efficiency of 82 percent, and variable O&M including consumables of 2.82 \$/MWh_t, the variable charges total 11.47 \$/MWh_t. Exxon [5] provides a basis for capital costs of small coal-fired plants (100 to 400 thousand pounds of steam per hour) which, adjusted to 1976 dollars and an investment cost basis comparable to that used for the reference electric plants, gives fixed charges of 6 \$/MWh_t at 0.75 CF. These total to 17.47 \$/MWh_t.

For very small boilers, industry may use electrode boilers, using electricity as "fuel." For these the fixed charges are trivial, but the variable charges very high. The total must be over 45 \$/MWh_t, and counting transmission and distribution fixed charges and losses may be over 65 \$/MWh_t even at high capacity factor.

COMPARISON WITH ALTERNATIVES

A method of comparing the delivered cost of heat with the alternatives available to users is displayed by the example in Figure 3. The cost of heat delivered (COH_d) is found by adding the cost increments incurred in each step. For this base case example, the utility supplies 300 MW_t heat extraction at 227°C sendout, 80°C return. The capacity factor is 0.75, depicted as 18 hours

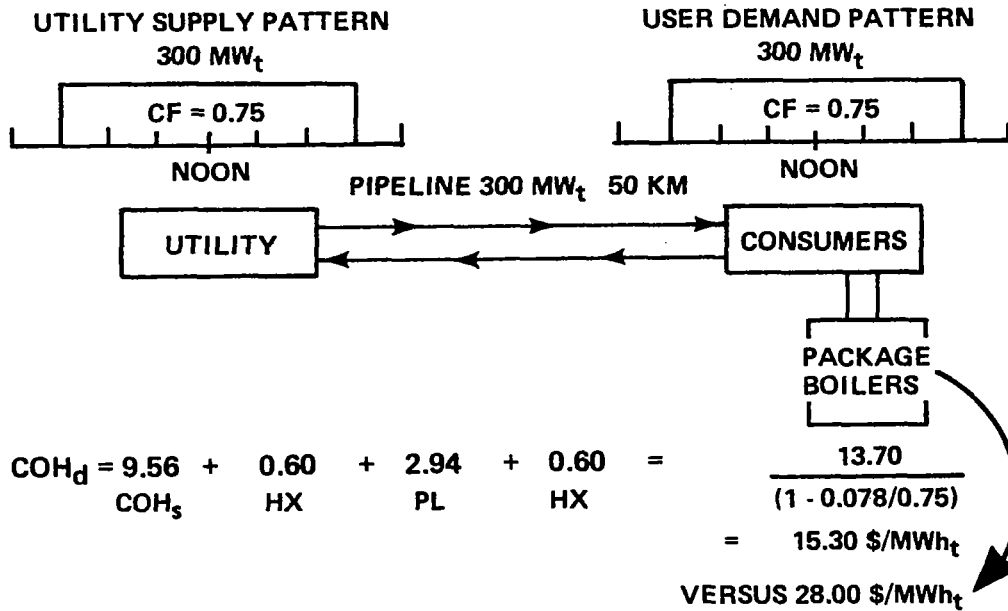


Figure 3. Approach to COH_d base case.

a day, although the actual outages may be forced outage or maintenance distributed through the year. The consumer demand for heat is also at 0.75 CF, matching the utility output in time so no storage is needed.

For these conditions, it was indicated that the equivalence factor F_e for the LWR gives a cost of heat at the sendout point (COH_s) of 9.56 \$/MWh_t. Some terminal equipment is required at both ends for suitable interfaces. At the sendout end, additional feedwater heater capacity must be added to handle the mass and heat flows of heat extraction. The cost of these heat exchangers is the 0.60 \$/MWh_t increment shown as HX. Assuming that the pipeline is a closed loop of high purity water, a similar heat exchanger capacity is needed at the user end for steam or sensible heat production for the user's processes.

The cost increment for 50 km of pipeline is 2.94 \$/MWh_t as described. All these components total 13.70 \$/MWh_t. However, thermal energy losses through the optimized insulation reduce the amount of heat delivered; the assigned COH_d must be larger to produce the revenues required to recover all costs. For 50 km of pipeline, and 300 MW_t the pipeline losses are 23 MW_t or 7.8 percent.

Heat losses occur continuously; power output is assumed at 0.75 CF so a larger percentage as indicated in the denominator in Figure 3 is required to correct COH_d . The corrected COH_d is 15.30 $\$/MWh_t$. This can be compared to the cost of heat from oil-fired boilers of 28 $\$/MWh_t$ as shown, or the 17.47 $\$/MWh_t$ found for coal-fired boilers at this CF. The benefit over oil, gas, or electrode boilers is great; that over coal-fired boilers is small.

To get a similar comparison for both the LWR and HSC plants over a range of temperatures of HTW transport, Figure 4 shows the COH_d from both plants over the temperature range to over 300°C, and the cost of the oil and coal alternatives, which are essentially independent of temperature over this range. The low temperature of the minimum cost points reflects not only pipeline costs (Figure 2) but the equivalence factor (Figure 1). There is a significant temperature range for which the COH_d from both LWR and HSC plants is lower than local coal-fired boilers.

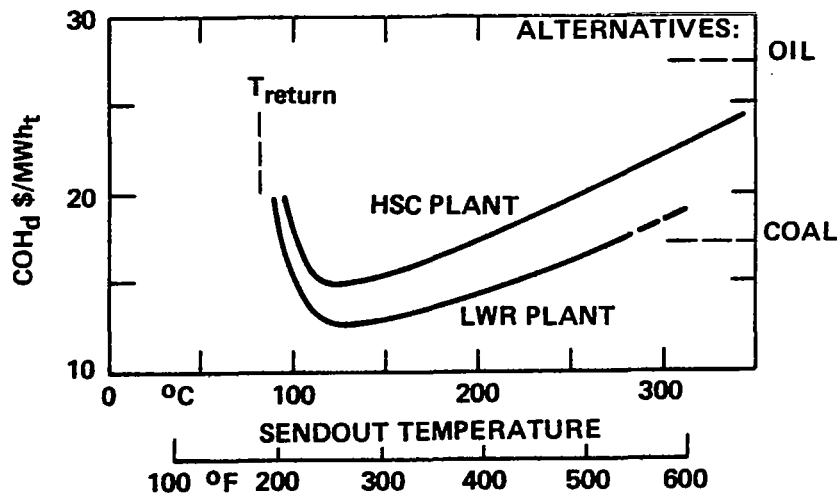


Figure 4. Delivered cost of heat vs sendout temperature for high capacity factor case (CF = 0.75).

THE USES OF TES

For lower capacity factors of the user's heat demand, the cost of delivered heat from the pipeline will increase if the pipeline must operate at the user's capacity factor. Thermal energy storage should be considered.

Thermal energy storage (TES) has two functions: To keep the pipeline and terminal equipment capacity factor high, and to provide flexibility in supply management to the utility to meet heat and electricity demands. For the former use, only TES at the user end of the pipeline is needed to buffer the difference between supply and demand. For the latter use, TES at both ends is desirable to decouple the electricity demands on the utility from user demands for heat.

Earlier studies [2,3] found that underground storage of HTW in excavated caverns, and dual-media TES using insulated tanks filled with rocks or taconite, with the voids partly filled with hot oil used as a heat transfer fluid, were the two lowest cost forms of TES. Caverns are lowest cost but only feasible where the geology is suitable; dual-media storage has a low technical risk with taconite and complete filling of the voids with oil, but would be considerably lower cost with riverbed gravel and reduced use of oil by draining each tank except during the charging and discharging period.

The capital costs of TES have energy-dependent and power-dependent parts. For the cavern storage these components were found to be [1]: 4500 \$/MWh_t stored and 13,000 \$/MW_t maximum charge or discharge rate. For the dual-media storage, they are: 1740 \$/MWh_t, 66,000 \$/MW_t. Clearly, the cavern storage is superior for rapid charging and discharging; dual-media storage becomes superior when slow charge and discharge of 15 hours or more is needed.

An example portrayed in Figure 5 illustrates the method and benefits of storage for low capacity factor heat demands. The same 300 MW_t, 50 km pipeline is assumed; the same sendout and return temperatures of HTW (227/80°C), and source, an LWR, are assumed. The heat demand pattern is made extreme;

900 MW_t is required for six hours at mid-day, or the capacity factor is 0.25. Extraction of heat from the utility plant is assumed to be completely mismatched, ie, occurs solely during 12 nighttime hours when electric loads are light.

To meet the load and keep the pipeline capacity at 0.75, storage of a day's heat extraction is necessary, 5400 MWh_t, with two-thirds at the user end and one-third at the utility end. The train of incremental costs in COH_d are as shown. The sendout cost of heat and the pipeline cost are unchanged. Because of the reduced capacity factor at each end, terminal equipment (HX) costs rise, corresponding to 0.50 CF at the utility and 0.25 at the user end. The cost of 5400 MWh_t storage, dischargeable over six hours is 6.20 \$/MWh_t with dual-media storage, or 3.24 \$/MWh_t with cavern storage. Figure 5 uses the former, more expensive but more available. As with Figure 3, a correction to the sum of these costs is made to account for the 10.5 percent energy losses during transmission. The resulting COH_d of 23.90 \$/MWh_t is to be compared to that for oil-fired boilers at 0.25 CF, 30 \$/MWh_t or for coal-fired boilers at the same CF, 29.47 \$/MWh_t.

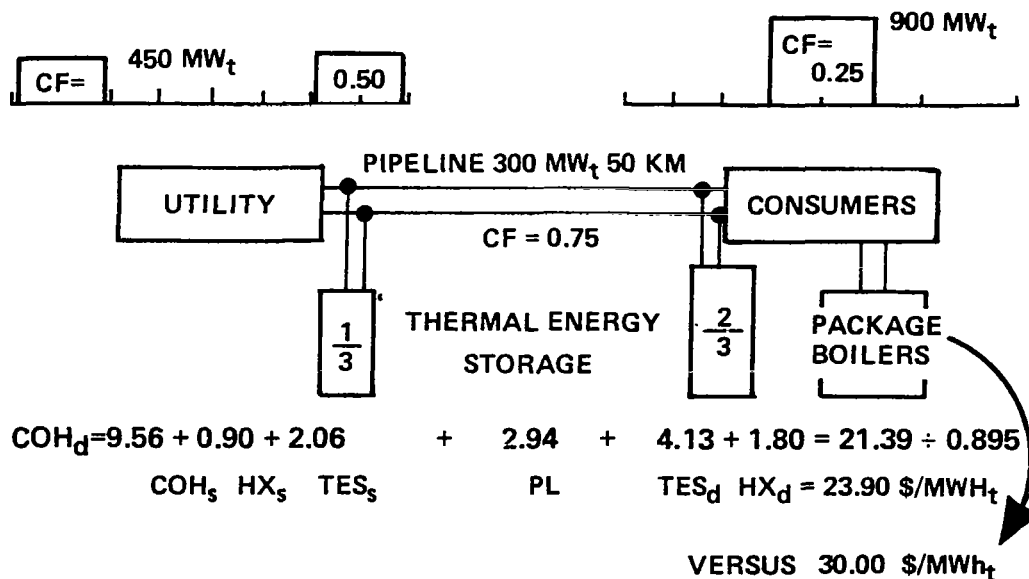


Figure 5. Effect of storage on COH_d.

Figure 6 depicts the comparable results for other transport temperatures for both the LWR and the HSC sources. This case of extreme mismatch and low capacity factor also shows considerable margin for COH_d over the alternatives for both sources over a wide range of temperatures. Designs for specific utilities and site areas will usually fall between the no storage and maximum storage cases with intermediate margins of benefit.

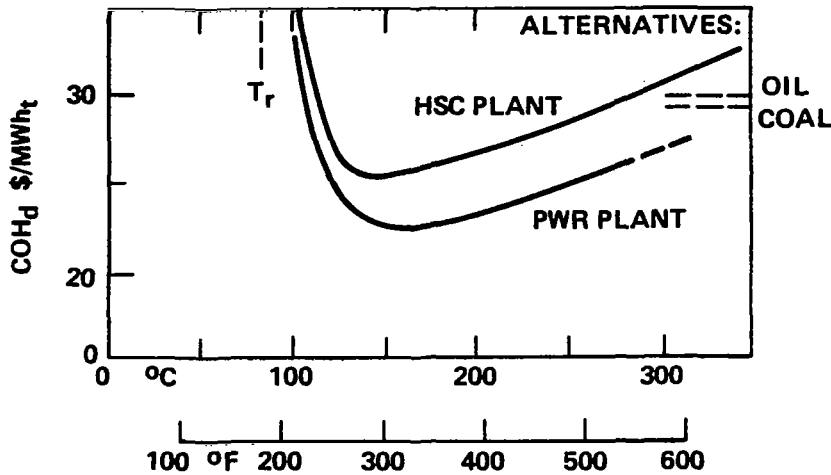


Figure 6. Delivered cost of heat vs sendout temperature with storage, and demand CF = 0.25.

BENEFITS AND PROBLEMS

- CONSERVATION. DEUS or joint production of heat and power conserves energy. A 1000 MW_e LWR can, with near-term available technology, produce 775 MW_e and 920 MW_t delivered, at 215°C, with 14 percent less primary energy than separate production of this heat and electricity. The savings is still greater if lower temperature heat is wanted or if backpressure turbine technology is used to raise the ratio of heat to electricity output. A concomitant utility benefit is the reduction of the waste heat discharge requirements.

- MARKET. A significant portion of the industrial process heat market and the need in all sectors for space heating and hot water, which total to roughly

44 percent of the U.S. primary fuel usage, can be served. Temperature requirements data of the thermal energy use, both past and forecast, are sparse and disparate. A projection derived from several sources [6,7,8] was projected for the year 2000 as shown in Figure 7.

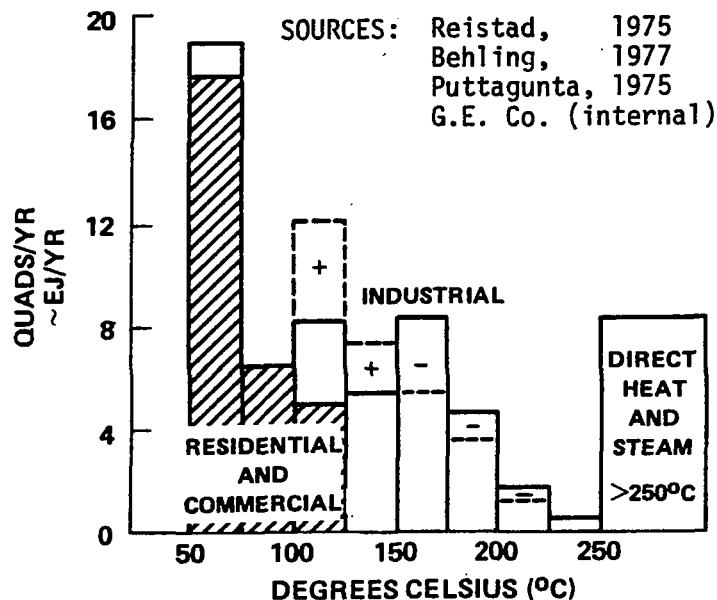


Figure 7. Estimated U.S. energy use by temperature range AD 2000.

In 25°C increments the expected annual use in exajoules (EJ) or quads is shown. Residential and commercial space heating and hot water needs are in the 50-100°C range; some commercial use, eg absorption air cooling, is in the 100-125°C range. About 40 percent of the industrial heat use is direct heat or steam above 250°C, which is not the most likely market for transported heat. While some industrial heat use below 250°C is sensible heat most of it is process steam. One disparity found is that between the temperature at which heat is generated and that at which it is used. The solid bars indicate the estimated temperature distribution of steam produced; the dotted bars indicate the temperature distribution at which it is used. It is convenient where multiple steam temperatures are needed to generate at the highest temperature and

throttle some part of the flow to the other temperatures and pressures needed. The - and + indicate the estimated transferral of part of the thermal energy to a lower temperature regime by throttling or cascaded processes.

Transport of HTW at 227°C can meet all sensible heat needs at 200°C and lower. For conversion of HTW to steam a fairly high temperature drop is required in the heat exchanger to convert most of the delivered energy to steam. HTW at 227°C can be 75 percent converted to 0.2 MPa (30 psia) steam with the remainder as sensible heat for water and space heating, or can be 15 percent converted to 1.55 MPa (225 psia) steam at 200°C, 30 percent converted to 0.50 MPa (70 psia) steam at 150°C, 30 percent at 0.2 MPa and the 25 percent remainder as sensible heat. A major portion of the steam needs below 200°C depicted in Figure 7 can be met from HTW at 227°C, but a problem of matching the multi-temperature needs of each consumer may exist. Transport at 277°C or higher will of course permit higher conversion rates to the higher temperatures of steam with only moderate penalties as in Figures 4 and 6.

PEAK POWER BENEFITS

The use of TES to decouple utility supply from user demand for heat permits the utility to load storage and supply heat needs during off-peak hours. It can produce full rated electric output during peak hours, say for 6 hours a day, 2200 hours per year. Generation of such electricity at 0.25 CF normally costs the utility about twice as much as base load electricity, counting the increase in the fixed charges per MWh_e required by the low CF, and the more expensive fuel and/or lower efficiency plant used for peaking generation. With the peaking flexibility of the DEUS system described by Figures 5 and 6, peaking electricity is made at the base load cost. Alternatively the benefit can be credited to the thermal output, decreasing the COH_d by 6 to 10 $\$/MWh_t$.

The use of TES directly for electric peaking power was studied in depth in [2,3] and found not to be attractive to utilities unless major cost reductions were possible. Using the same cost data and storage methods, this study [1] finds TES attractive for peak power production. The reasons for this difference should be briefly explained.

The direct approach was to extract steam off-peak, store it as HTW or dual media, and discharge it by converting to boiler feedwater or to steam to run through a peaking turbine. The turnaround efficiency was low (40-80 percent), because of the degradation in steam conditions entering the peaking turbine compared to that extracted for storage. The cost per kW_e of peaking turbines and related equipment was high because of low efficiency from the degraded steam. The cost of storage limited discharge to the number of hours likely to be used frequently. When discharged, there was no flexibility to maintain power if the peaking requirement continued, so utility reserve capacity could not be reduced.

In the DEUS approach, the turnaround efficiency for peaking power is 100 percent and the turbine efficiency is maximum, not degraded during peaking hours. The turbine cost for rated capacity is included in the foregoing analyses, and is not an extra. If the peaking requirement continues beyond six hours, rated electric output can be continued, so there is full capacity credit for it in determining reserves. It is only necessary to assure that the storage is replenished before the next day's peak heating demand.

CONCLUSIONS

We conclude that not only are DEUS systems economically viable with available technology but also they can provide added benefits to utilities in peaking power flexibility and reduced thermal discharges. This route to energy conservation could provide the largest contribution to energy savings, scarce

fuel displacement, and urban pollution reduction available to us within the next two decades.

Implementation will not proceed rapidly without a large and convincing demonstration. Are there sites where the concentration of industrial process heat, and residential/commercial heat requirements can use DEUS effectively? A study by Dow Chemical Co. [9] found 119 locations in the U.S. which require at least 160 MW_t as process heat within a two-mile radius. An additional 24 locations needed 650 MW_t within a five-mile radius and another 19 locations required over 1300 MW_t within a ten-mile radius. The study covered steam use at under 200°C (400°F) and omitted plants smaller than 70 MW_t. The sites occur in 36 States; about half of them are in the Gulf Coast States.

A recent study of district heating in the Twin Cities area, Minneapolis and St. Paul, [10] showed a potential need for 3000 to 4500 MW_t peak thermal energy production in two growth scenarios. The study shows benefits in cost and energy savings for up to 2000 to 3000 MW_t of seasonal energy storage.

Opportunities abound. The next step however must be a site-specific study and design with the cooperation and participation of the responsible utility, local industry, local and State regulatory agencies, and the Department of Energy.

REFERENCES

1. Hausz, Walter, *Combined Thermal Storage and Transport for Utility Applications*, GE79TMP-26 (EPRI EM-1175); Prepared for the Electric Power Research Institute; General Electric Co.-TEMPO, Santa Barbara, California, April 1979.
2. Hausz, W., B.J. Berkowitz, and R.C. Hare, *Conceptual Design of Thermal Energy Storage Systems for Near Term Electric Utility Applications; Volume One: Screening of Concepts, Volume Two: Appendices - Screening of Concepts*,

- GE78TMP-60 (NASA CR-159411) (NTIS: DOE/NASA/0012-78/1 and DOE/NASA/0012-78/2); Prepared under Contract DEN3-12 for the U.S. Department of Energy, the National Aeronautics and Space Administration, and the Electric Power Research Institute; General Electric Co.-TEMPO, Santa Barbara, California, October 1978.
3. Hall, E.W., W. Hausz, R. Anand, N. LaMarche, J. Oplinger, and M. Katzer, *Conceptual Design of Thermal Energy Storage Systems for Near Term Utility Applications*, GE79ET0101 (NASA CR-159577); Prepared for the National Aeronautics and Space Administration-Lewis Research Center under Contract DEN3-12 for the U.S. Department of Energy-Office of Energy Technology and the Electric Power Research Institute under Contract RP1082-1; General Electric Co.-Energy Technology Operation, Schenectady, New York, July 1979.
 4. (EPRI) Electric Power Research Institute, *Technical Assessment Guide*, Special Report EPRI PS-866-SR, The Technical Assessment Group of The EPRI Planning Staff, Palo Alto, California, June 1978.
 5. Exxon Research and Engineering Company, *Application of Fluidized-Bed Technology to Industrial Boilers*, NTIS #PB-264 528; Final report prepared for the U.S. Energy Research and Development Administration; January 1977.
 6. Reistad, Gordon M., *Analysis of Potential Nonelectrical Applications of Geothermal Energy and Their Place in the National Economy*, UCRL-51747, Lawrence Livermore Laboratory, University of California, Livermore, February 14, 1975.
 7. Behling, David J., Jr., *Analysis of Past and Expected Future Trends in U.S. Energy Consumption, 1947-2000*, BNL-50725; Prepared for the Office of the Assistant Administrator for Planning and Analysis, U.S. Department of Energy; Economic Analysis Division, National Center for Analysis of Energy Systems, Brookhaven National Laboratory, Upton, New York, February 1977.

8. Puttagunta, V.R., *Temperature Distribution of the Energy Consumed as Heat in Canada*, AECL-5235, Atomic Energy of Canada Ltd., Whiteshell Nuclear Research Establishment, Pinawa, Manitoba, Canada, October 1975.
9. Barnes, R.W., *The Potential Industrial Market for Process Heat from Nuclear Reactors*, ORNL/TM-5516; Prepared for Oak Ridge National Laboratory/ Energy Research and Development Administration; Dow Chemical Company, Midland, Michigan, 196 pp, July 1976.
10. Meyer, Charles F., *Potential Benefits of Thermal Energy Storage in the Proposed Twin Cities District Heating-Cogeneration System*, GE79TMP-44 (ORNL/SUB-7604-2); Final report prepared for the Oak Ridge National Laboratory; General Electric Co.-TEMPO, Santa Barbara, California, July 1979.