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POTENTIAL BENEFITS OF THERMAL ENERGY
STORAGE IN THE PROPOSED TWIN CITIES DISTRICT
HEATING-COGENERATION SYSTEM

Final Report

By
Charles F. Meyer

October 1979
Date Published

Work Performed Under Contract No. W-7405-ENG-26

General Electric Company—TEMPO
Center for Advanced Studies
Santa Barbara, California

U. S. DEPARTMENT OF ENERGY

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OAK RIDGE NATIONAL LABORATORY
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DEPARTMENT OF ENERGY
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DIVISION OF ENERGY STORAGE SYSTEMS

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ABSTRACT

A new, large, cogeneration-district heating system has been proposed for the Twin Cities area, using hot water in a closed-loop system. The proposed system, as described by Studsvik Energiteknik AB of Sweden, does not employ thermal energy storage (TES). Four cases have been developed, describing system configurations which would employ TES, to evaluate the potential benefits of incorporating annual-cycle TES into the Twin Cities system. The potential benefits are found to be substantial, confirming results of earlier, generic studies of aquifer TES.

The reference (Studsvik) system employs oil-fired boilers to supplement cogenerated heat, for handling peak loads and providing standby reserve. TES can serve the same function, with net energy savings in spite of heat losses during storage, by making it possible to operate the cogeneration equipment at higher capacity factors. Coal replaces oil as the fuel consumed. Energy savings of the reference system are impressive; energy savings with TES are 2 to 22 percent better. Capital cost requirements for boilers, cogeneration equipment, and pipelines are reduced by \$66 to \$258 million. The breakeven capital cost of TES is estimated to range from \$43 to \$76 per kilowatt peak thermal input to or withdrawal from aquifer TES. A factor in evaluating the breakeven operating cost of TES is the \$14 to \$31 million per year saving in cost of fuel. Abatement of air pollution and thermal pollution are concomitant benefits.

Key words: Aquifers, Cogeneration, District heating, Energy conservation, Energy transmission, Groundwater, Pollution abatement, Sensible heat storage, Thermal energy storage, Thermal power plants.

EXECUTIVE SUMMARY

The potential benefits of incorporating thermal energy storage (TES) into the 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 storage of hot water in natural, underground, water-bearing formations (aquifers) appears capable of providing these benefits. Peak demands for winter space heating and hot tap water would be met with heat generated and stored during other seasons.

OBJECTIVE OF STUDY.

Evaluate

- Savings in capital cost of system elements (boilers, cogeneration capacity) that need not be installed if TES is used.
- Net energy and energy-cost saved by use of TES.
- Substitution of coal for oil and gas made possible by use of TES.
- Break-even capital and operating costs of TES.

BASIS. The reference for comparing performance and cost is the system described for the Twin Cities area by Studsvik Energiteknik AB, under contract to the U.S. Department of Energy via Oak Ridge National Laboratory.

Studies of aquifer TES by TEMPO and others, since 1972, and limited field testing, provide estimates of the performance of Heat Storage Wells for large-scale storage. More than three-fourths of the heat stored is expected to be recoverable after several months of storage. While novel as an energy-system component, the Heat Storage Well technology draws upon experience gained from millions of water and oil wells and from ongoing geothermal investigations.

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, not that it would be retrofitted. Details of when, where, and how TES would have been incorporated may be considered in a later study.

For this study, the availability of suitable aquifers for TES is assumed.

APPROACH. For the Scenario A and the Scenario B versions of the system as proposed by Studsvik, four study cases were developed to describe potential modifications of the mature system to incorporate TES. Heat loads for the study cases are those described by Studsvik in interim reports on their Scenario A and Scenario B reference cases. The load factor is 0.28; the load duration, 2465 hours.

	<u>Scenario A</u>		<u>Scenario B</u>	
Peak demand in megawatts thermal	2704	MW	4405	MW
Delivered to consumers	2621	MW	4266	MW
Pipeline losses	83		139	
Annual load in terawatt hours thermal	6.994	TWH	11.016	TWH
Delivered to consumers	6.298	TWH	9.798	TWH
Pipeline losses	0.695		1.218	

SUMMARY OF CASES STUDIED. Cases A-1 through A-4 are based on the Scenario A reference system, Cases B-1 through B-4 on the Scenario B system. The nominal heat recovery fraction is 0.75. The effects of recovering 65 or 85 percent of heat stored are also examined.

Case 1. All peak-load and standby boilers, located at hot-water transmission system nodes, are replaced with TES. Cogeneration equipment is the same as for the reference cases. For Case A-1, the capacity factor increases from the 0.45 reference value to 0.55; for Case B-1, from 0.51 to 0.60 – well within the operating constraints of the system and equipment, and representing a reduced capital cost per unit of energy produced by cogeneration plus the air-quality and other benefits of TES versus boilers.

The amount of heat stored annually in Case A-1 is 7.6 percent of the consumer load.

Case 2. Cogeneration capacity is reduced by 344 MW_t of extraction; the old turbines (High Bridge 3 and 4, Riverside 6) are not converted.

In Case A-2 the remaining extraction turbines operate at a 10-month capacity factor of 0.76, and the backpressure turbine (Riverside 7a, a new unit) at an annual capacity factor of 0.80. These capacity factors are within the constraints adopted: for one month, the CF may be as high as 0.95; for one year, no higher than 0.80; and the peak electric load of Northern States Power during July and August is taken into account by using steam from backpressure turbines in preference to extraction turbines, minimizing extraction during these months, and scheduling extraction machines for not more than 0.80 capacity factor for the remaining 10 months.

In Case B-2, eliminating 344 MW_t of extraction capacity requires only 0.74 as a 10-month capacity factor for the remaining extraction turbines.

Case 3. Using more backpressure machines than in the reference cases becomes feasible with TES because the cogenerated heat can always be either used or stored. Full advantage can be taken of the

reduced cost and high efficiency of the backpressure mode for cogenerating power and heat (e.g., 4400 Btu/kWh of electricity). Neither power nor heat is a byproduct; they are joint, useful products.

In Cases A-3 and B-3, the Riverside 9 (or High Bridge 9) 335 MW_t extraction unit of the reference cases would not be added. The King units would not be added, for Scenario B. The only extraction capacity on the system is the 727 MW_t from conversion of the relatively new existing machines (Riverside 8, High Bridge 5 and 6), which is needed during the early years of system implementation.

For Case A-3, the required backpressure capacity is 440 MW_t . Total system heat cogeneration capacity is 1167 MW, to be compared to 1516 MW for the reference system.

For Case B-3, the required backpressure capacity is 1040 MW_t and the total system heat cogeneration capacity is only 1767 MW_t —not much more than the 1516 MW postulated in the metro area for Scenario A, and 449 MW less than the 2216 MW needed for the reference Scenario B case. A question to be seriously considered is whether siting 251 MW_t of capacity within the metro area, in addition to the 1516 MW_t postulated for Scenario A, might be feasible by 1996. The cost and problems of constructing a pipeline from King would be avoided. Although air quality requirements are probably the principal problem in adding 251 MW_t of in-town capacity, the fact that there would be no cooling requirements should help, as should the reduced amount of trenching to install pipelines. Clean fuels or combustion processes for coal may be available by 1996.

Case 4. The purpose is to explore the effects of using TES at both the nodes and the plants, in order to minimize the size of hot water transmission pipeline required. The findings are that the required pipeline size might be reduced from 1615 MW_t in the Scenario A reference case, or 1167 MW_t in Case A-3, to 865 MW_t . For Scenario B, the potential reduction in pipeline size might be from 2216 MW_t in the reference case, or 1767 MW_t in Case B-3, to 1355 MW_t .

The same extraction capacity — 727 MW_t — is used as for Case 3. The required backpressure capacity is slightly larger than for Case 3 because more TES and more loss in storage is involved.

The total TES capacity required and the amount of heat stored are significantly larger than for other cases studied. The values are sensitive to the system operating schedule that is assumed.

Daily and Weekly Storage. In most cases, the average rate (megawatts) at which heat needs to go into or out of storage, to prepare for winter loads or to handle them, is substantially lower than the megawatt capacity required of TES in order to meet peak and standby loads. In Case A-1, for example, the maximum average monthly rate of energy storage or withdrawal is about 450 MW — less than one-third of the 1523 MW of TES capacity required to handle peak and standby loads.

If short- and mid-term TES could smooth, or average, the load and supply fluctuations so as to maintain a reasonably steady 450 MW rate of storage in Case A-1, more than 1050 MW of short/mid-term TES might be employed. A computer run by Studsvik, employing heat load data for 3-hour intervals over a one-year period, appears to roughly confirm this deduction. The required storage size is in the order of 100 gigawatt-hours (10^5 MWh). If short/mid-term TES is less expensive, or otherwise preferable, it might be employed in conjunction with long-term (annual-cycle) TES.

CAPITAL COSTS. The estimated TES breakeven capital costs for a heat recovery fraction of 0.75 are:

Case:	A-1	A-2	A-3	A-4	B-1	B-2	B-3	B-4
Capital costs avoided, \$M	66	92	110	122	109	146	226	258
TES capacity, MW_t	1523	1867	1872	2253	2539	2883	2988	3697
Break-even cost of TES, \$/ kW_t	43	49	59	54	43	51	76	70

The reference system for Scenario A employs boilers costing about \$66 million, cogeneration equipment costing about \$44 million, and transmission pipelines costing about \$105 million, in 1978 dollars. For Scenario B, the reference boiler cost is about \$109 million, cogeneration \$127 million, and transmission pipeline \$298 million. Aquifer TES can replace boilers, and reduce the amount of cogeneration capacity and size of pipeline. Thus, even though the amount of TES employed increases for each successive case, the breakeven capital cost 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 aquifer storage is \$23 to \$50 per peak thermal kilowatt into or out of storage. This rough estimate remains to be verified by field installation and test.

FUEL CONSUMPTION AND ENERGY BENEFITS. For the Scenario A 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 TWH_t 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 TWH_t 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 additional energy-conservation aspect of the TES systems.

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 TWH_t of coal per year (0.39 million tons), at a cost of \$11 million. The net annual fuel cost and energy savings for the

Scenario A reference are then about \$131 million and 5.28 TWH_t, equivalent to 2.83 million barrels of oil.

For the larger reference system of Scenario B, the corresponding net savings in fuel cost and energy are about \$197 million and 7.48 TWH_t (4.0 MBOE).

Systems with TES burn no oil and save the same amount of gas as the reference systems. 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 energy and cost savings for the cases studied are:

Case:	A-1	A-2	A-3	A-4	B-1	B-2	B-3	B-4
Net energy savings								
TWH/yr	6.03	5.43	5.46	5.37	9.14	8.78	8.76	8.63
TBtu/yr	20.6	18.5	18.6	18.3	31.2	30.0	29.9	29.5
* MBOE/yr	3.22	2.91	2.92	2.87	4.89	4.70	4.68	4.62
% over reference case	14	3	3	2	22	17	17	16
Cost saving compared to ref. case, \$M/yr	16	14	14	14	27	26	26	25
* Million barrels of oil, equivalent								

The energy-cost savings are a factor in evaluating the break-even operating cost of TES.

CONCLUSIONS. The potential benefits of incorporating aquifer thermal energy storage into a large cogeneration-district heating system are substantial, based on analysis of a specific candidate system. This improves the credibility of conclusions reached in earlier, generic studies.

Avoided capital and energy costs are large enough that the break-even costs of TES appear to be attainable. In spite of heat lost during storage, all of the cases studied are superior to the reference cases in energy savings.

That the systems with TES eliminate the need for peak load and standby boilers and the oil they would burn is an important energy-independence feature, making cogeneration-district heating systems even more worthwhile. Reducing thermal pollution from power plants is an added bonus.

Significant benefits in eliminating air pollution from dispersed oil-fired boilers and avoiding the problems of siting the boilers will accrue. These could be but have not been evaluated in terms of dollar benefits.

RECOMMENDATIONS. The estimates of system performance and cost derived in this study should be refined and verified, drawing upon final results of the Studsvik studies and information from other studies underway or recently completed.

Scenarios for implementation of the Twin Cities system with TES should be developed so that TES may be incorporated as soon as its potential benefits are verified.

Field tests of large-scale TES in the favorable aquifers underlying the Twin Cities (e.g., the Franconia sandstone) should be undertaken, with careful design and adequate instrumentation. Such tests might be conducted in cooperation with the University of Minnesota's Grid-ICES program.

A first-order study should be made of operating procedures for combined power and district-heat systems with and without TES capability. Operating guides for routine and for emergency system operation should be outlined. System control, flexibility, and stability; the unit commitment problem; reliability and reserve requirements; extension of resource-allocation programs to encompass both power and heat loads; the effect of heat-load fluctuations and TES capability on the electrical area control error; and needs for additional training of operators all should be examined in order to provide a firmer base for system design and evaluation than is now available.

SECTION 1 INTRODUCTION

The potential benefits of incorporating thermal energy storage (TES) into the 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.

APPROACH

The capital 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, to confirm or contradict the conclusions of earlier generic studies (Meyer, Hausz, and others, 1976).

The potential value of TES (particularly annual-cycle TES), evaluated from this and other studies, provides a basis for establishing the research, development, and demonstration priority to be assigned to TES technology.

Ground Rules

- The reference cogeneration-district heating system is that proposed by Studsvik Energiteknik AB (formerly AB Atomenergi), a Swedish firm engaged by the U.S. Department of Energy via Oak Ridge National Laboratory to evaluate cogeneration-district heating for the Minneapolis-St. Paul area in Minnesota (Karnitz and Rubin, 1978).
- 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. Details of when, where, and how TES would have been incorporated may be considered in a later study.
- 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 TES devices such as aquifer TES are still in the development stage and their 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 and cogeneration equipment might be avoided if TES displaced them in the system? How much less oil and how much more coal might be burned if TES displaced boilers? What is the break-even cost of TES?

Organization of the Report

Section 2 is an abbreviated description of the cogeneration-district heating system which Studsvik has proposed for the Twin Cities area, with emphasis on the system features and costs likely to be influenced by use of TES. Section 3 describes the Heat Storage Well concept proposed by TEMPO in 1972 as a key component of large-scale cogeneration-district heating systems, and discusses the current status of aquifer storage of hot water. In Section 4, the methodology

employed and the results obtained in analyzing the effects of TES on the system configuration are presented. Section 5 then gives estimates of the capital cost and fuel consumption benefits of TES, and of the break-even capital and operating costs of TES.

Section 6 provides a brief appraisal of the system control and stability problems that may be expected in systems that cogenerate power and heat, with and without annual-cycle or seasonal storage.

Section 7 is a list of references. Not all of the references are cited in the text; many have been included for bibliographic purposes.

ACKNOWLEDGMENTS

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Dr. Harvey H. Happ of General Electric's Electric Utility Systems Engineering Department served as a consultant on system control and stability and authored Section 6.

Studsvik Energiteknik AB was a subcontractor to TEMPO on this study. Dr. Peter Margen, Kjell Larsson, Lars-Åke Cronholm, and Jan-Erik Marklund of the Studsvik staff contributed substantially.

The support and technical guidance of Dr. Herbert W. Hoffman and Dr. David M. Eissenberg of Oak Ridge National Laboratory are gratefully acknowledged. Dr. Michael A. Karnitz of Oak Ridge National Laboratory, Dr. Alan M. Rubin of the U.S. Department of Energy, and Messrs. Herbert Jaehne and Conrad Aas of the Northern States Power Company provided invaluable information and assistance.

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SECTION 2
THE PROPOSED TWIN CITIES
COGENERATION-DISTRICT HEATING SYSTEM

A series of interim and draft reports have been issued by Studsvik Energiteknik via Oak Ridge National Laboratory (Dr. Michael A. Karnitz) to describe the cogeneration-district heating system that Studsvik proposes for the Twin Cities area. Their study commenced in April 1977. The latest report available is EP-79/105, *Minneapolis/St. Paul District Heating Study*, dated February 2, 1979 and identified as a draft of the final report. Additional information has been provided to TEMPO by Studsvik in their role as a subcontractor in the TEMPO project reported here. Studsvik's description of the system, emphasizing parameters directly relevant to this study, is synopsized in this section.* Studies by others are listed at the end of the section.

BACKGROUND

In Sweden, all cities of any size (about 60) have hot-water district heating systems supplying central urban areas and denser suburban areas. The 12 largest cities use reject heat from cogeneration plants. In the United States, use of district heat is much less prevalent than in Sweden; steam instead of hot water is distributed; and cogeneration does not supply a large fraction of the heat.

Studsvik's objective was to employ Swedish technology and experience to examine the feasibility and economic prospects of building up a hot-water district heating system in a large urban area in the United States, which would supply most of the demand for space heating and hot tap water with cogenerated heat from power stations burning coal, thus replacing scarce gas and oil.

* Because Studsvik's final report was not available during TEMPO's study, discrepancies are to be expected between the numerical values used here, from draft reports, and those appearing in the final report (scheduled to be issued in mid-1979; see List of References for ORNL citation).

HEAT LOADS, SUPPLY, AND TRANSPORT

Loads

The area houses about one million people. Two scenarios for build-up of district heating are postulated. Scenario A restricts district heating to the downtown and industrial-commercial areas and the dense residential areas; load densities vary from more than 70 MW/km^2 (180 MW/mi^2) down to a minimum of 20 MW/km^2 (50 MW/mi^2). One hundred percent connection is assumed. Scenario B assumes 70-percent connection of some large customers and of residential areas with load densities as low as about 7 MW/km^2 (18 MW/mi^2). At the end of a 20-year buildup period, the mature Scenario A system would have a peak coinciding thermal load of about 2600 MW; the Scenario B system, about 4000 MW. These estimates were made from data on consumption of natural gas, of steam from three existing moderate-size steam-based district-heating systems, and of electricity; and from climatological data.

Studsvik estimated load duration (load factor or utilization time) by use of gas sales data, steam sales, building surveys, and a proprietary computer model using climatological and building data. Figure 2-1 shows load duration curves for each month of the year, computed for space and tap water heating, based on temperature data for 1976. (These curves, as will be explained in a subsequent section, were used by TEMPO to estimate monthly heat demands.) Figure 2-2 is an annual load duration curve. It shows a load duration of 2465 hours; ie, an annual load factor (ratio of average to peak load) of 0.28. The monthly and annual load duration curves are assumed to apply to both Scenario A and Scenario B.

Cooling loads were not included in the heat loads, because a survey of existing buildings showed that very few buildings have absorption chillers-- the type which can be converted relatively easily so that it can be fed by hot water from a district heating system. The possibility is recognized that absorption chillers might be a significant district heating load at some time in the future. (That the Northern States

Figure 2-1. Monthly load duration curves for space heat and hot tap water. (Source: Studsvik)

Figure 2-2. Annual load duration curve for space heat and hot tap water. (Source: Studsvik)

Power Company electrical load is summer peaking indicates the importance of the air conditioning load.)

Heat Supply from Cogeneration

The base load supply for district heating is to be from cogeneration plants, which would provide about half the required thermal capacity but close to 90 percent of thermal energy production. Most of the cogeneration units are obtained by converting existing steam turbines at the Riverside power station in Minneapolis and the High Bridge station in St. Paul to pass-out (extraction) operation.

Initially, the largest and most modern existing turbines — High Bridge 6, High Bridge 5, Riverside 8—would be converted, by connecting a steam pipe with appropriate regulating valves to the crossover steam line between the intermediate-pressure and low-pressure turbine cylinders. Such connections allow water supply temperatures of up to about 295°F (146°C) to be reached, with a total hot-water capacity of 727 MW. Thereafter, conversion of the small, older units (Riverside 6 and High Bridge 3 and 4) would take place. A new backpressure turbine, Riverside 7a, would then be installed, utilizing an existing boiler. These four units could deliver 190°F (88°C) water after conversion, with a total hot-water capacity of 554 MW. They can be connected in series with the larger units on the water side, so that together a two-stage heating process of the water is achieved.

The balance of the cogenerated heat capacity for Scenario A would be from a second new cogeneration unit, requiring a new boiler. From load considerations, this unit should be located at Riverside and is designated Riverside 9, but site considerations may require it to be at High Bridge. The pass-out (extraction) turbine would deliver 335 MW of hot water at full extraction, bringing the total hot-water supply capacity to 1516 MW.

A total heat supply of 1516 MW from cogeneration is about 60 percent of the maximum heat demand for Scenario A, which is considered typical for an economic proportion of load to be supplied by cogeneration plants located within or close to cities.

For Scenario B, to bring the hot-water base-load production capacity to 2216 MW, an additional 700 MW of cogenerated heat is needed. It is believed to be impracticable to extend the city power plants so extensively; this additional capacity would be installed at the King Power Station, about 17 miles from the center of the city area. A dual installation of two turbines is proposed, each with 350 MW thermal extraction capacity.

Table 2-1 summarizes the above information and shows the cost of converting existing turbines or adding new ones. Conversion costs are based upon the experience of STAL-LAVAL. The costs for converting the three modern units, High Bridge 5 and 6 and Riverside 8, average \$20.3/kW_t. For the three old units, High Bridge 3 and 4 and Riverside 6, the conversion costs average \$28.8/kW_t.

Table 2-1 also shows the year each turbine is to be converted or installed and, for existing turbines, the year when the Northern States Power Company has scheduled the unit to be retired from service. Note that the old units, High Bridge 3 and 4 and Riverside 6, would be kept in service rather than being retired on schedule.

Riverside 7a is a new backpressure unit, to be installed in building space vacated by the Riverside 7 unit which was removed some time ago. The new unit will be matched to the existing boiler. A cost estimate of \$12 million (\$218/kW electric) was obtained from a turbine manufacturer. The value of the turbogenerator for peak load electricity generation is estimated to roughly match this cost, so that the unit involves zero net equivalent conversion cost.

The total cost in 1978 dollars for the Scenario A cogeneration plant is estimated to be \$55 million.

For the Scenario B units to be installed at King, the cost penalty of \$103/kW_t shown in Table 2-1 is based on Oak Ridge data on the relative costs of two 400 MW_e units on one site as opposed to one 800 MW_e unit. The reason for using a dual rather than a single unit is to limit the size of the largest unit on the system, to reduce standby capacity requirements.

Table 2-1. Conversion and addition of turbines for cogeneration.
(Source: Studsvik)

Turbine ⁽¹⁾	Maximum Heat Output MW _t	Electric Generation Sacrificed MW _e	Cost		Date Converted or Installed	Scheduled Retirement Date ⁽²⁾
			\$M	\$/kW _{th}		
HB6	240	58	4.5	18.7	1981	1996
HB5	157	38	4.0	25.5	1982	1991
R8	<u>330</u>	<u>89</u>	5.5	16.7	1983	1999
SUBTOTAL	727	185				
R7a (new) ⁽³⁾	110	3	(12-12) ⁽⁴⁾	0	1983	--
HB4	117	14	3.3	28.2	1986	1984
R6	110	14	3.3	30.0	1987	1984
HB3	117	14	3.3	28.2	1990	1984
R9 (new) (or HB9)	<u>335</u>	<u>44</u>	29.0	81.0	1996	--
SCENARIO A TOTAL	1516	274				
King (new)	<u>2 x 350</u>	<u>100</u>	72.0	103.0	1996	--
SCENARIO B TOTAL	2216	374				

(1) HB = High Bridge; R = Riverside

(2) According to Northern States Power Company

(3) Backpressure (all others are extraction)

(4) Credit for added electrical generating capacity estimated to match cost.

The total cost in 1978 dollars for the Scenario B cogeneration plant is estimated to be \$127 million.

Heat Supply from Permanent Boilers

From the aspect of firm capacity, the largest cogeneration unit on the system should be discounted. Permanent oil-fired boilers will be installed to provide the requisite standby capacity: 335 MW_t for Scenario A, 350 MW_t for Scenario B.

Additional permanent boilers will be installed to supply peak loads on cold winter days. For Scenario A, the peak heat demand (coinciding load) of consumers is 2621 MW_t. To this is added the 83 MW_t heat loss rate from the district heating pipeline system. The peak heat load to be supplied is then 2704 MW_t. The cogeneration capacity is 1516 MW_t. The peak-load boiler capacity required is then (2704 - 1516 =) 1188 MW_t. Adding the standby capacity, the total required heat-only boiler capacity is (1188 + 335 =) 1523 MW_t.*

For Scenario B, the peak heat demand of consumers is 4266 MW_t. Adding 139 MW_t of heat loss in the pipeline system brings the peak heat load to be supplied to 4405 MW_t. The cogeneration capacity is 2216 MW_t. The peak-load boiler capacity required is then (4405 - 2216 =) 2189 MW_t. Adding the standby capacity, the total required boiler capacity is (2189 + 350 =) 2539 MW_t.

Figure 2-3 illustrates, on an annual heat load duration curve, the division of load between cogeneration and boilers for Scenario A. The heavy curve depicts the cumulative hours during the year when the load is at levels ranging from peak load to zero load; peak load is 2704 MW. The area under the curve represents thermal energy supplied annually from cogeneration (cross-hatched) and from heat-only boilers

* Confirmed by telegram of 5 March 1979 from K. Larsson of Studsvik. The 2 February 1979 report shows other Scenario A values; e.g., 1640 MW and 1827 MW.

Figure 2-3. Annual load duration curve for space heat, hot tap water, and pipeline losses, showing load split between cogeneration and heat-only boilers. (After Studsvik)

(stippled). Peak-load boilers supply a relatively small fraction of total thermal energy. Standby boilers supply a smaller fraction.

The area under the right-hand toe of the load curve in Figure 2-3 indicates that the heat-only boilers might take over heat production from cogeneration units when electrical loads are at their peak, in the summer, and maximum electrical generation is needed. Cogeneration reduces the maximum electrical output obtainable from the Riverside and High Bridge units. This may cause oil- or gas-fired peaking generators to be needed. It may be more economical or desirable to reduce the amount of steam extraction from cogeneration units, and produce district heat from heat-only boilers, than to utilize the oil- or gas-fired electrical peakers. Also, although only about 270 MW_e of additional electrical generation capacity can be obtained (in a system whose 1978 generating capacity was 6500 MW_e) by going from maximum extraction to zero extraction, it is conceivable that electrical system reserve may be very low during peak electric load periods and a few tens of megawatts may be important. The heat-only boilers would take care of the relatively small summer heat load at such times.

The heat-only boilers could be located either at the cogeneration plant sites, or at suitable points elsewhere in the system, or both. Location at the cogeneration plants would reduce the number of pumps required, simplify fuel distribution, and allow some pooling of operating staff. Dispersing the boilers to sites at the system nodes where transmission pipelines connect to distribution networks would allow the transmission pipelines to be sized to transport only cogenerated heat—roughly half the peak load. Also, this approach to siting permits the boilers to act as reserve units not only for cogeneration units but also for transmission pipeline outages. Recognizing that suitable sites may not be found for all boilers and adjustments will be necessary in a detailed network design, the assumption has been made that boilers will not be sited at cogeneration plants but at the system nodes, as follows.

MINNEAPOLIS

		Scenario A			Scenario B, 70% conn		
Node		Peak	Standby	Total	Peak	Standby	Total
Number		Load	Units	MW	Load	Units	MW
		MW	MW	MW	MW	MW	MW
Mp	1	26	7	33	28	4	32
Mp	2	68	16	84	72	11	83
Mp	3	36	9	45	40	6	46
Mp	4	150	36	186	157	24	181
Mp	5	42	10	52	54	8	62
Mp	6	65	16	81	69	11	80
Mp	7	78	19	97	83	13	96
Mp	8	56	13	69	57	7	64
Mp	9	14	3	17	52	8	60
Mp	10	90	20	110	95	15	110
Mp	11	23	5	28	23	4	27
Mp	12	29	7	36	30	5	35
Mp	13	98	22	120	103	16	119
Mp	14	61	14	75	64	10	74
Mp	15	52	12	64	55	8	63
Mp	16	26	6	32	45	7	52
Mp	17	45	10	55	53	8	61
Mp	18	--	--	--	135	21	156
Mp	19	--	--	--	116	18	134
Mp	20	--	--	--	135	21	156

ST. PAUL

Sp	1	10	5	15	20	3	23
Sp	2	39	18	57	40	6	46
Sp	3	17	8	25	34	5	39
Sp	4	24	11	35	49	7	56
Sp	5	34	16	50	40	6	46
Sp	6	31	15	46	40	6	46
Sp	7	15	7	22	18	3	21
Sp	8	7	3	10	57	8	65
Sp	9	21	10	31	27	4	31
Sp	10	13	6	19	76	12	88
Sp	11	11	5	16	26	4	30
Sp	12	13	6	19	30	5	35
Sp	13	--	--	--	16	2	18
Sp	14	--	--	--	23	3	26
Sp	15	--	--	--	17	3	20
Sp	16	--	--	--	29	5	34
Sp	17	--	--	--	50	8	58
Sp	18	--	--	--	46	7	53
Sp	19	--	--	--	78	12	90
Sp	20	--	--	--	107	16	123

The cost of heat-only boilers is estimated on the basis of their cost in Sweden: 200 Sw/Kr/kW_t, approximately \$43/kW_t in 1978 dollars. For 1523 MW_t of boiler capacity, the total cost is estimated to be about \$66 million for Scenario A. For Scenario B, the boiler capacity is 2539 MW and the estimated cost is \$109 million.

Prior to installation of permanent boilers for peaking and standby loads in the mature system, discussed above, small, mobile, heat-only boilers will be used for temporary production of heat during the buildup stage of load subareas before connection to the main district heating system. These are less expensive than permanent boilers, and are not included in the above estimates of capital cost.

Transmission Pipelines

Studsvik finds the merits of hot water for heat transport, as opposed to steam, become particularly strong on as large a system as that for the Twin Cities area and include four factors:

- Considerably less sacrifice of electrical generation in order to produce district heat.
- Much easier regulation, for the large distances and wide distribution ranges involved
- Lower costs for transport and distribution systems
- Lower heat losses than for steam systems without condensate returns and less corrosion and equipment problems than for steam systems with condensate returns.

For the main transmission pipeline, a design send-out temperature of 295°F (146°C) 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 140°F (60°C) for the coldest day.

The two-way transmission system (send-out and return) is shown diagrammatically in Figure 2-4. The total length of dual pipeline is about 50 km (30 miles). The range of diameters is from 0.15 m (6

Figure 2-4. Hot-water transmission network. (Source: Studsvik)

inches) to 0.9 m (36 inches); the maximum heat load for these sizes is 14 MW and 890 MW, respectively.

Methods for installing transmission pipeline pairs, in tunnels and culverts, are shown in Figure 2-5. The dimensions of tunnels and culverts are given in Table 2-2. Tunnels are preferred where large or multiple pipeline pairs are to be installed and good tunneling rock exists. Culverts are used elsewhere. The cost of installing dual pipelines in tunnels and in culverts in downtown and residential areas is shown in Figure 2-6, curves 1, 2a, and 2b. The total length and range of diameters of transmission pipeline pairs for Scenario A are given in Table 2-3.

The total cost of the hot-water transmission pipeline system is estimated to be \$105 million for Scenario A, \$298 million for Scenario B, in 1978 dollars.

Table 2-2. Dimensions of tunnels and culverts.

Pipe Diam.	Dimensions (m)			
	Tunnels		Culverts	
	B	H	B	H
2 x 0.7	3.5	3.4	2.1	1.1
2 x 0.8	3.5	3.5	2.3	1.2
2 x 0.9	3.5	3.6	2.5	1.4
2 x 1.0	3.6	3.8	2.7	1.5
2 x 1.2	3.8	4.3	3.0	1.7

Table 2-3. Length and diameter of transmission pipeline pairs, Scenario A.

Installation Method	Number of Links	Total Length		Range of Diameters	
		km	Thousand ft.	m	Inches
Tunnels	15	26.4	86.6	0.25 - 0.75	10 - 30
Culverts, downtown	6	8.4	27.6	0.25 - 0.75	10 - 30
Culverts, residential	7	13.1	11.8	0.15 - 0.90	6 - 36

a) Concrete culvert section

b) Tunnel section

Figure 2-5. Transmission pipeline installation methods. (Source: Studsvik)

(SOURCE: STUDSVIK)

Figure 2-6. Total installed cost of two-way hot-water transmission pipelines (urban).

Distribution System

The distribution system is assumed to use mainly prefabricated pipes with directly foamed insulation. Pipes are laid under pavements, in streets, or, where possible, through cellars.

The highest temperature currently allowed for prefabricated pipes is 130°C (266°F). The distribution system therefore is separated from the 146°C (295°F) transmission system by heat exchangers. This arrangement also makes flow and temperature regulation more convenient.

Although the distribution system accounts for a substantial fraction of the total cost of the district heating system, no further discussion is warranted here because it is considered unlikely that thermal energy storage devices will be located within the distribution system—ie, beyond the nodes where transmission lines connect to the distribution system.

The cost of the distribution system for Scenario A in 1978 dollars is estimated to be \$224 million; for Scenario B, \$551 million.

SUMMARY OF CAPITAL INVESTMENT COSTS

Table 2-4. Total investments (millions of 1978 dollars).

	<u>Scenario A</u>	<u>Scenario B</u>
Cogeneration Plants	55	127
Heat-only Boilers	66	109
Transmission Pipeline System	105	290
Distribution Pipeline System	224	551
Total District Heating System	450	1085
Building Conversion and Connection	160	238
Grand Total	610	1320

As noted earlier, Studsvik had completed only draft reports at the time this report was prepared, and discrepancies are to be expected between values such as those shown in Table 2-4 and those to be shown in the final report of Studsvik's work when it is issued.

The figures in Table 2-4 have been reproduced or deduced from Studsvik's draft final reports dated November 1978 (with addendum) and February 2, 1979, with modifications resulting from correspondence with Studsvik during the course of this study. The figures for Scenario B, in particular, are to be regarded as tentative.

FUEL CONSUMPTION AND SAVINGS

For the Scenario A district heating system in the year 2000, Studsvik's report EP-79/105 (February 1979 draft) estimates the annual energy savings shown in Table 2-5.

Table 2-5. Annual energy savings, Scenario A.

	<u>TWH</u>	<u>10⁶ MBtu</u>	<u>MBOE*</u>
Gas	9.23	31.5	4.94
Oil	-1.20	-4.1	-0.64
Coal	-2.75	-9.4	-1.47
NET	5.28	18.0	2.83
* Million barrels of oil, equivalent			

Corresponding figures for Scenario B, from Studsvik's November 1978 Addendum to their November 1978 *Draft of Final Report, Minneapolis/St. Paul District Heating Study*, are given in Table 2-6.

Table 2-6. Annual energy savings, Scenario B.

	<u>TWH</u>	<u>10⁶ MBtu</u>	<u>MBOE*</u>
Gas	14.00	47.8	7.49
Oil	-1.84	- 6.3	-0.98
Coal	-4.68	-16.0	-2.51
NET	7.48	25.5	4.00
* 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 for Scenario A, 9.798 TWH for Scenario B) 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 heat-only 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 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 kWh of coal to replace the electricity sacrificed in cogenerating 1000 kWh of heat. A boiler at 90 percent efficiency would burn 1111 MWH of fuel to produce 1000 MWH of heat; the trade-off is a good one.

*The applicable value of β_N depends on the turbines involved. To obtain the coal savings shown in Table 2-5, the value of β_N is not 0.2 but 0.18, corresponding to the loss of electric generation capacity, 274 MW_e, for 1516 MW_t of heat output (see Table 2-1). Note that this composite value for factor β_N is made up of a wide range of individual factors: (3/110 =) 0.027 for R7a, a new back-pressure machine; (14/117 =) 0.12 for HB3 and HB4, which are old turbines; (44/335 =) 0.13 for R9, to be installed in 1996; and (185/727 =) 0.25 for 727 MW_t from the three newest existing machines, HB6, HB5, and R8. These differences and their significance are relevant to the cases with TES which will be described in Section 4.

The very low value of β_N ascribed to R7a is somewhat misleading, in that a factor of 0.027 is not generally applicable to backpressure operation. A factor of about 0.09 would be more representative of

OTHER STUDIES

A large number of governmental agencies, corporations, associations, universities, consultants, and interested individuals have become involved in various studies related to the proposed Twin Cities district heating system.

At a District Heating/Cogeneration Symposium held in Minneapolis on April 2-3, 1979, a number of papers were presented which described work related to the proposed Twin Cities system. The titles and authors are listed in Section 7. (Oak Ridge National Laboratory, 1979). The proceedings are to be published.

In addition to the basic Studsvik Energiteknik study and the TEMPO study reported here, the Northern States Power Company lists 20 other related studies. It is beyond the scope of this report to describe these related studies in detail, but a brief review is appropriate because details and results from some of them were provided to Studsvik to be incorporated into their work.

a turbine designed to deliver power and also hot water at a temperature of 190°F (88°C), as is the case with R7a. (Hausz, April 1979, Figure 3-2.) Based on a telephone communication with Dr. Peter Margen of Studsvik (June 28, 1979), the low value of β_N is understood to be related to the small exhaust area of the machine, which permits only a modest increase in steam flow when the exhaust is connected to a cold condenser.

The values of β_N of about 0.12 found applicable to the old machines converted for extraction are not unreasonable estimates on the basis of their delivering water at 190°F. As noted earlier, R7a and the three old machines (HB3, HB4, and R6, after conversion) will be connected in series on the water side with the three newer machines (HB5, HB6, and R8, to be converted for extraction at the crossover line). The combination of the machines delivering 190°F water with the machines delivering 295°F water gives two-stage heating which, by Second Law considerations, is thermodynamically more efficient than single-stage heating. Thus, even though HB5, HB6, and R8 operate at a β_N value of 0.25, the composite value of β_N is 0.18 when all machines are operating at maximum heat production.

The β_N of 0.13 for R9 is consistent with expectations for a modern, multi-stage machine delivering water at 295°F.

With the permission of the Northern States Power Company, selected excerpts from their *District Heating Quarterly Update* of January 18, 1979, are reproduced below. (Also see Jaehne, and others, 1979.)

St. Paul District Heating Distribution System

Work performed by:	C. T. Main Inc., Boston, Massachusetts
Authorization:	Northern States Power Co. (NSP)
Funding:	\$540,000
Schedule:	Started December 1977; Completion February 1979
NSP Involvement:	Complete funding and study management. NSP personnel will assist in market survey and other data collection.

An indepth study of the St. Paul downtown loop area, including the existing NSP Steam Utility, to determine the economic feasibility of establishing a major district heating system. The study is composed of the following phases:

1. Market Analysis - a customer survey and analysis to determine the potential heating and cooling demand
2. System Design - a piping distribution system design and layout to determine the capital and operating costs
3. Financial - a financial analysis to assess the economic feasibility of the system using various financing methods, tax structures, regulation and management methods, and customer saturation levels.

High Bridge Generating Plant Conversion to District Heating

Work performed by:	United Engineers and Constructors—Philadelphia, PA
Authorization:	Northern States Power Company
Funding:	\$70,000
Schedule:	Start April 1978; Complete February 1979
NSP Involvement:	Complete study funding and management

The study will analyze the existing turbines at the High Bridge Generating Plant to develop a conceptual plan for a district heating energy source from the St. Paul area. The services of the turbine manufacturers will be used to assist in the turbine design modifications and costs. The study will develop capital and operating and maintenance costs for the facility.

Feasibility Study for Conversion of
Existing Condensing Turbines to District Heating

Work performed by: EKONO Consulting Engineers, Bellevue, WA
 Authorization: Northern States Power Company
 Funding: \$25,000
 Schedule: Start October 1977; Completed December 1977
 NSP Involvement: Complete funding and study management

A short duration study to determine the technical feasibility of converting the existing generation units at the High Bridge and Riverside plants to district heating.

District Heating Conversion Methods and Costs
for Existing Buildings

Work performed by: Minnesota Energy Agency, ORR-Schelen-Mayeron (OSM) and Michaud-Cooley and Associates, Inc.
 Authorization: Oak Ridge National Laboratory
 Funding: \$56,000
 Schedule: Started August 1977; Complete October 1978
 NSP Involvement: Provide representation at meetings. Review and comment on interim reports
 Study Participants: Local building owners and engineering firms

The study will develop detailed engineering specifications and costs for converting existing building heating systems in the Twin Cities to hot water district heating.

Environmental Analysis of the
Use of District Heating

Work performed by: Oak Ridge National Laboratory, Lockheed Engineering and Minnesota Energy Agency
 Authorization: Oak Ridge National Laboratory
 Funding: \$100,000
 Schedule: Start January 1978; Complete mid-1979
 NSP Involvement: Provide representation at meetings. Review and comment on interim reports
 Study Participants: Minnesota Pollution Control and Metro Council

The study will determine the impact of a large district heating system on the air quality of the area. The environmental analysis will utilize computer modeling techniques to compare three scenarios (1) current fuel use conditions, (2) future conditions with less natural gas, and (3) conditions with a district heating system in operation.

Study of Institutional Issues for a
Twin Cities Cogeneration-District Heating System

Work performed by: Minnesota Energy Agency and Touche Ross and Co.
 Authorization: Oak Ridge National Laboratory
 Funding: \$140,000
 Schedule: Start April 1978; Complete May 1979
 NSP Involvement: NSP will be represented on the Steering Committee of the study
 Study Participants: All local government agencies and private organizations with an interest in district heating

The study is to identify and examine all major institutional issues affecting the implementation of large cogeneration-district heating system for the Twin Cities metropolitan area. The major institutional issues are those which relate to ownership, financing, operation, and regulation of the heating system.

Coal Cogeneration-District Heating
New Plant Assessment for Metro Area (Proposed)

Work performed by: United Engineers and Constructors
 Authorization: Oak Ridge National Laboratory and Northern States Power Company
 Funding: \$230,000
 Schedule: To be determined
 NSP Involvement: Northern States Power Company will manage and partially fund the study. Northern States Power Company will also perform all site-related analyses

A technical and economic feasibility study for utilizing new coal fired cogeneration plants for district heating. Conceptual reference plant designs will be developed for a new metro area site and at existing metro area generating plant sites.

Feasibility Study of Nuclear
Cogeneration Plants for District Heating

Work performed by: United Engineers and Constructors, Babcock and Wilcox
 Authorization: Oak Ridge National Laboratory
 Funding: Phase I - \$130,000; Phase II - undetermined
 Schedule: Start April 1978; Complete Phase I late 1978; Final June 1979
 NSP Involvement: Northern States Power Company will be represented at local meetings, will review and comment on reports, and provide data pertinent to the study
 Study Participants: Minnesota Energy Agency

A general feasibility study for using small nuclear cogeneration units to produce thermal energy for district heating and electrical generation. A hypothetical plant siting region near the Twin Cities will be used to provide a realistic setting for this application study.

St. Paul Twin Resco Refuse-Energy Facility

Work performed by: Twin Resco Inc.
 Authorization: City of St. Paul
 Funding: -
 Schedule: Started January 1977; Operational 1981
 NSP Involvement: Northern States Power Company has made a commitment to utilize the refuse derived steam from the plant

The City of St. Paul has commissioned Twin Resco Inc. (Wheelabrator-Frye and Phoenix Corp.) to design, construct, and operate a refuse disposal facility for the city. The facility will be designed to mass-burn refuse to generate steam which is to be sold. The facility is to be located near the Northern States Power High Bridge Generating Plant.

Hennepin County Solid Waste Energy Recovery Plant

Work performed by: Ellerbe Inc., and Camp, Dresser and McKee
 Authorization: Hennepin County Government
 Funding: To be determined
 Schedule: To be determined
 NSP Involvement: Northern States Power Company has offered to utilize refuse-derived fuel or energy
 Study Participants: Central Heating Company, City of Minneapolis and Minnegasco

The study is to develop a resource and energy recovery system as the primary method of solid waste disposal. The resource and energy recovery systems must recover maximum energy and materials from the municipal solid waste on an economic basis.

University of Minnesota - ICES (Integrated Community Energy System)

Work performed by: University of Minnesota; Helmick and Lutz Inc.
 Authorization: Department of Energy
 Funding: Phase I - \$50,000; Phase II - \$380,000
 Phase III - \$1,000,000
 Schedule: Started February 1977; Operational 1981
 NSP Involvement: Northern States Power Company is committed to support the University in establishment of the system
 Study Participants: Local hospitals near the University

The study will determine the technical and economic feasibility of installing an integrated energy system on the University campus. The system design includes a 12 MW electrical generator with a back-pressure turbine to produce steam and hot water for the campus and hospital building heating systems.

Study of Cogeneration for
District Heating and Electricity

Work performed by: United Engineers and Constructors, Philadelphia, PA
 Authorization: Oak Ridge National Laboratory
 Funding: \$10,000
 Schedule: Start June 1977; Completed November 1977
 NSP Involvement: Recent power plant construction cost data was provided

The study analyzed in detail the effects of thermal extraction on the design and operation of a power plant turbine used for district heating and electrical generation.

Red Wing Generating Plant
District Heating Study

Work performed by: Northern States Power Company personnel
 Authorization: Northern States Power Company
 Funding: Internal funding
 Schedule: Start October 1977; complete early 1979
 Study Participants: City of Red Wing and local industries

The study will determine the technical and economic feasibility of supplying thermal energy to industrial customers and the City of Red Wing.

Wilmarth Generating Plant
District Heating Study

Work performed by: Northern States Power Company personnel
 Authorization: Northern States Power Company
 Funding: Internal funding
 Schedule: Start January 1978; Complete, unscheduled
 Study Participants: University and City of Mankato and local industries

The study will determine the technical and economic feasibility of supplying thermal energy to the City of Mankato, the University campus and local industries

Riverside Generating Plant Steamline to Minneapolis (Proposed)

Work performed by: Northern States Power Company personnel
 Authorization: Northern States Power Company
 Funding: Internal funding
 Schedule: Start: 1979
 Study Participants: City of Minneapolis, Central Heating Company

The study will provide a preliminary design and cost estimate for a steam line from the Northern States Power Company Riverside Generation Plant to the existing district heating system in Minneapolis.

District Heating in Swedish Urban Residential Areas

Work performed by: KVB Inc., Minneapolis, Minnesota
 Authorization: Northern States Power Company
 Funding: \$2,000
 Schedule: Start February 1978; Completed April 1978

The study will survey, document and analyze ten distinct residential district heating areas in Stockholm, Sweden. Information concerning metering, housing density and type, service quality and costs will be compiled and analyzed.

Swedish District Heating Institutional and Financial Methods

Work performed by: Protans Consultants, El Paso, Texas
 Authorization: Northern States Power Company
 Funding: \$7,000
 Schedule: Start May 1978; Completed August 1978
 NSP Involvement: Complete funding and management

This study is an independent financial assessment of the meaning of private and public ownership of district heating as practiced in Sweden. The various financial terms and methods as well as legislative incentives will be detailed and compared to U.S. practices.

Evaluation of District Heating Systems in Minnesota

Work performed by: Minnesota Energy Agency, Pfeifer and Schultz
 Authorization: State of Minnesota
 Funding: \$12,000 for consultant
 Schedule: Started March 1978; Completed August 1978
 Study Participants: Various Minnesota district heating systems

The study will evaluate the existing district heating systems in the State of Minnesota. The systems will be surveyed to determine their current condition and compliance with pollution regulations. Cost projections will then be made to upgrade the systems and comply with pollution regulations.

District Heating and Cooling Systems for
Communities through Power Plant Retrofit and
Network Distribution (Minnesota Project)

Work performed by: Minnesota Energy Agency, KVB Inc., Touche Ross
and Company
Authorization: Department of Energy
Funding: Phase I - \$348,000
Schedule: Start September 1978 - Complete April 1979
NSP Involvement: Provide information for NSP outstate power
plants and service area
Study Participants: Various Minnesota private and municipal power
plants

Phase I of the study will identify potential areas that can be developed into a district heating/cooling demonstration system by retrofitting of existing power plants to service existing communities in outstate Minnesota.

Definition of Model Coal-Fired Electric
Generating Stations in 50 MW to 2400 MW Range

Work performed by: Burns and Roe, Inc.
Authorization: Minnesota Environmental Quality Board
Funding: \$40,000
Schedule: Start September 1978; Complete March 1979
NSP Involvement: Review draft report

The study will provide engineering design information and related environmental impacts for state-of-the-art coal-fired electric power generating stations in the 50 MW, 200 MW, 400 MW, 800 MW and 2400 MW (3-800 MW) size range. Conventional power plants producing electric power only are to be investigated in the 200 MW to 2400 MW range. Cogeneration power plants producing electric power and district heating are to be investigated in the 50 MW to 400 MW range. The power plant modeling information is to be used in ancillary studies to develop an inventory of plant study areas in Minnesota.

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SECTION 3
HEAT STORAGE WELLS
FOR
ANNUAL-CYCLE THERMAL ENERGY STORAGE

Natural, underground, porous formations have been used for large-scale storage of energy-bearing fluids since at least 60 years ago, when natural gas was first injected into old gas fields for storage during seasons of low consumption. Hundreds of underground gas reservoirs are now in use for seasonal storage so that gas pipelines can be operated year-round at full capacity (Katz and Coats, 1968).

Aquifers are formations at depths shallower than gas and oil reservoirs, hence less consolidated and therefore of greater porosity and permeability. Aquifer storage of heated water appears to be particularly well suited for seasonal or annual-cycle storage of large amounts of thermal energy. The volume of inexpensive storage space in aquifers is almost beyond comprehension: the estimated amount of groundwater contained in the upper half-mile of the continental crust is nearly 20 times greater than all of the water in all rivers and lakes (USGS, 1972, p 15). The land area required for a water well is quite small. The cost of storing and of withdrawing the hot water is low if spread over enough units of heat — i.e., if large, efficient wells are used.

The heat loss per unit of heat stored in an aquifer for a given period of time decreases as the amount of energy stored increases. Heat loss occurs principally at the interface between hot and cold water in the aquifer, and between hot water and the layers of low-permeability clay or rock which confine the vertical movement of water in an aquifer. The ratio of surface area to contained volume of hot water decreases with increasing volume, hence with the amount of thermal energy stored. These considerations suggest that aquifer

storage of heated water may be particularly well suited to large cogeneration systems.

APPLICATION TO COGENERATION-DISTRICT HEATING SYSTEMS

TEMPO studies beginning in 1972 have shown that aquifer TES 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; Hausz, 1977). 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.

Neither American nor European district heating systems now employ thermal energy storage to any substantial extent. This situation may be attributed to three principal factors:

- Fuel has been cheap and plentiful
- District heat has been produced largely by dedicated boilers, not by cogeneration
- Annual-cycle TES components have only been suggested, not demonstrated.

The first of these factors began its dramatic change in 1973. The second is changing, principally because electric power plants using thermal cycles can, with well-understood design modifications, produce power and useful heat instead of wasting two units of heat for each unit of power generated. The third factor is being changed by investigations in the United States and Europe (e.g., Warman and Molz, 1977; Werner and Kley, 1977; Despois and Nougarede, June 1977; Cormary and others, 1978).

HEAT STORAGE WELL CONCEPT

Figure 3-1 is a schematic diagram of the basic Heat Storage Well doublet. The water-bearing aquifer may be at a depth of several hundred meters. Valves, pumps, and control equipment, not shown in the sketch, will be required. Each of the two wells comprising a doublet should be capable of serving as either an injection or a production well, with easy changeover between the two modes, and adjustable flow rate. These degrees of flexibility are not standard features of water supply wells; engineering design, development, and field testing are needed.

Figure 3-1. Schematic diagram of Heat Storage Well doublet operation.

Aquifers which are not confined by impermeable formations cannot contain the vapor pressure of water heated above the local boiling point. This is a limitation on both the energy density and the usefulness of the hot water for space heating, hot tap water, absorption air conditioning, or industrial process heat. Confined aquifers can contain higher-temperature, pressurized water.

Liquid-dominated geothermal reservoirs illustrate pressurized storage in confined aquifers at temperatures well above 212°F (100°C).^{*} Impermeable layers overlying these geothermal reservoirs contain the vapor pressure and cause the hot geothermal fluid to remain liquid at temperatures of 400°F (200°C) or higher. Confined, pressurized (artesian) aquifers containing brackish or saline water are often found beneath aquifers from which potable water is produced for municipal and industrial use. The fact that the salty water has not migrated upward into lower-pressure freshwater aquifers shows that the deeper formation is indeed confined.

Heat Storage Wells will be drilled into confined saline aquifers wherever possible. A reasonable expectation is that deep, saline aquifers will be sufficiently pressurized to maintain hot water injected into the aquifer as a liquid at temperatures of 300°F (149°C) or more; saturation pressure at 300°F is 67 psi (462 kPa), requiring a hydrostatic head of at least 125 feet (38 m) to prevent the water from flashing into steam.

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 30 m thick, and the hot

* The several distinctions between naturally-occurring geothermal reservoirs and underground artificial storage of injected hot water limit the analogy between geothermal energy and aquifer TES.

water may extend 100 or more meters 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 to 20 megawatt thermal capacity. Larger capacities would be obtained from wells arranged in circular or linear arrays. In contrast to most TES components, only the power capacity determines the cost of storage.

When heat is to be stored in the aquifer, hot water from the send-out pipeline flows through the counterflow heat exchanger and to the return pipeline as shown by the open arrows in Figure 3-1. Groundwater is pumped from the warm well, flows through the heat exchanger where it picks up heat, and is injected into the hot well. As shown by the open arrows, the thermocline between warm and cold water moves inward toward the warm well, and the thermocline between hot and cold water moves radially outward from the hot well. When heat is to be recovered from storage, water flow and thermocline movement are reversed as shown by the solid arrows.

Storage Efficiency

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; Tsang and others, 1978). This remains to be demonstrated on the necessary scale, with water injected at temperatures above 100°C.

The fraction of stored heat that is lost will depend on the ratio of surface area, through which heat escapes, to the enclosed volume where the heat is contained. The ratio of surface area to enclosed volume decreases for larger volumes; hence heat loss will be higher for small-scale than for large-scale storage. This effect sets a lower bound on the applicability of aquifer TES (Meyer, 1978, P-785).

The effects of temperature on heat loss are not simply described. Not only will higher storage temperature cause larger heat-flow rates across the temperature interface (thermocline); the viscosity and density of the stored water will decrease, tending to cause greater tilt of the temperature interface within the aquifer, with corresponding changes in hydrodynamics.

More heat will be lost during early cycles of injection-storage-recovery than during later cycles, after the aquifer matrix has been warmed. One TEMPO estimate of heat recovery versus cycle is shown in Figure 3-2. Two cases are plotted. For the base case, water at 340°F (171°C) is injected into the aquifer at a rate of one million gallons (380 m³) per day for 90 days. Then the stored water is withdrawn at the same rate until the temperature of the water being withdrawn has dropped to an arbitrary "lowest useful temperature" — in this case, 300°F (149°C). At the end of the first cycle, about 30 percent of the injected heat remains behind. The recovery ratio (efficiency) increases with successive cycles and levels off at about 80 percent after four or five cycles. (Other estimates using more elaborate computer models and different withdrawal-temperature criteria usually

Figure 3-2. Heat recovery fraction.

indicate higher recovery efficiencies.) If the aquifer is prewarmed by injecting hot water for 90 days and leaving it in place rather than withdrawing it, the first-cycle efficiency is well over 90 percent. However, the cumulative recovery, shown by the dashed lines, is very nearly the same for both cases after about five cycles.

PROBLEM AREAS

A potential problem inherent to HSW doublet operation is the possibility of breakthrough. Solid lines in Figure 3-1 suggest the shape of the temperature interfaces within the aquifer between hot, warm, and cold water. The hot and warm water, being less dense and less viscous than the cold native groundwater, will tend to override the cold water and cause the interface to tilt. The temperature interface does not coincide with the fluid interface where injected water meets native water. The location of the fluid interface is suggested in the diagram by a dashed line. A tracer in the injected water would move appreciably beyond the temperature interface because hot water moving outward from an injection well delivers heat to the aquifer matrix (porous rock and trapped water), and is cooled to essentially the ambient temperature.

The warm and the hot well must be far enough apart to prevent breakthrough of hot water to the warm well, or vice versa: the two temperature interfaces should not meet. The breakthrough effect in doublet wells has been analyzed by BRGM in France (1974) and others. The required separation between wells will depend upon the aquifer parameters, the maximum injection volume, and (probably) the injection rate. Fingering due to anisotropies may be a problem.

Ordinary water-well pumps, submersible motors, and other well equipment are not usually rated for operation above about 160°F (70°C). Special well equipment will be required, increasing in cost with increasing temperature. Corrosion and erosion are potential problems. Deep groundwater probably will be saline and hot injected water may dissolve aquifer minerals. Fortunately, a substantial program is under way to develop equipment for geothermal wells, where

problems of temperature and mineralization are much more severe than with Heat Storage Wells. Geothermal literature and responses to TEMPO inquiries indicate that suitable equipment is or will be available for Heat Storage Wells.

Geochemical reactions may produce precipitates, or cause swelling and dispersion of clays in the aquifer material, which will lead to plugging of the injection well. Relevant information is available from experience with secondary recovery in petroleum reservoirs, injection of spent brines back into geothermal reservoirs, and design and operation of waste-disposal wells. Using the same aquifer for both supply and injection will minimize geochemical problems.

SECTION 4
EFFECTS OF THERMAL ENERGY STORAGE
ON
SYSTEM CONFIGURATION

This section discusses the methodology employed and the results obtained in analyzing the effects on system configuration of incorporating thermal energy storage (TES) into the proposed Twin Cities cogeneration/district heating system.

OBJECTIVES

The objectives of incorporating TES into the system are:

- To reduce the permanent heat-only boiler capacity required or to eliminate these boilers entirely
- To increase the effectiveness of cogenerating heat
- To improve the capacity factor of transmission pipelines.

APPROACH

Annual-cycle TES is of principal interest. The availability of aquifers suitable for Heat Storage Wells is assumed. This assumption remains to be evaluated in a subsequent study.

For each of the two Studsvik scenarios described in Section 2, four cases were developed to describe potential modifications of the mature (year 2000) system, to incorporate TES. This is not on a retrofit basis, but rather on the assumption that TES had been incorporated into the system as it was implemented. Scenarios for system implementation with TES remain to be developed in a subsequent study.

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.

HEAT LOADS

In all of the Cases, the peak demand and the annual heat load — heat delivered to consumers plus pipeline-system heat losses — are as shown in Table 4-1.

Table 4-1. Peak and annual heat loads.*

	Scenario A		Scenario B	
Peak demand in megawatts thermal	2704	MW	4405	MW
Delivered to consumers	2621	MW	4266	MW
Pipeline losses	83		139	
Annual load in terawatt hours thermal	6.994	TWH	11.016	TWH
Delivered to consumers	6.298	TWH	9.798	TWH
Pipeline losses	0.695		1.218	

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 295°F (146°C) to 266°F (130°C) at the nodes where most of the TES would be located; and, since the ratio of stored heat to transmitted heat usually is fairly small, blending mitigates the temperature drop.

SUMMARY OF CASES AND RESULTS

Tables 4-2 and 4-3 summarize the Scenario A and B system configurations for the reference case with no thermal storage and for the four cases with storage. Figure 4-1 illustrates graphically the use of a smaller amount of cogeneration capacity, at a higher capacity factor, with TES, and with no boilers, to satisfy the same heat demand as the reference case shown earlier in Figure 2-3.

*The data base and methods used to estimate or calculate the values shown in this table and in other places in this report clearly do not justify showing four or five significant figures. However, it is convenient to do so to help recognize that the same or a slightly discrepant number has been used elsewhere in this report and in various Studsvik reports. For example, the Scenario A figure for heat delivered to consumers is slightly lower in this table than the value (6.461 TWH) mentioned in connection with Table 2-5: the value shown here came from Studsvik's November 1978 draft and is the one used in developing the cases to be discussed. The differences have negligible effect on results and conclusions.

Table 4-2. Summary of effects of TES on Scenario A system configuration.

		Studsvik's Scenario A	Case A-1 Base case. No boilers. Same cogen. capacity as ref. case.	Case A-2 Reduce cogen. capacity by 344 MWth of old turbines.	Case A-3 Convert only new turbines. Add backpressure units. TES at nodes only.	Case A-4 Minimize pipe- line 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	1.33	1.52	1.51	1.54
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

Table 4-3. Summary of effects of TES on Scenario B system configuration.

		Studs vik's Scenario 3	Case B-1 Base case. No boilers. Same cogen. capacity as ref. case.	Case B-2 Reduce cogen. capacity by 344 MWh of old turbines.	Case B-3 Convert only new turbines. Add backpressure units. TES at nodes only.	Case B-4 Minimize pipe- line size. TES at both plant and nodes.
COGENERATION						
Extraction:	MW Capacity	2106	2106	1762	727	727
	Annual TWH	8.878	10.438	10.645	4.239	4.239
	10-month CF		0.65	0.74	0.80	0.80
Backpressure:	MW Capacity	110	110	110	1040	1090
	Annual TWH	0.487	0.775	0.775	7.293	7.640
	Annual CF	0.51	0.80	0.80	0.80	0.80
Total:	MW	2216	2216	1872	1767	1817
	Annual TWH	9.365	11.213	11.420	11.532	11.879
Elec. sacrificed, TWH		1.87	1.95	2.09	2.10	2.15
BOILERS						
Peak:	MW Capacity	2189	-0-	-0-	-0-	-0-
Standby:	MW Capacity	350				
Total:	MW Capacity	2539				
	Annual TWH	1.653				
	Annual CF	0.67				
HEAT STORAGE, WELLS						
At Nodes:	MW Capacity	-0-	2539	2883	2988	3050
	Annual TWH		1.080	1.911	2.282	3.800
At Plant:	MW Capacity	-0-	-0-	-0-	-0-	647
	Annual TWH					1.890
Total:	MW Capacity		2539	2883	2988	3697
Total annual TWH stored			1.080	1.911	2.282	5.690
Approx. annual TWH lost (at 0.75 recovery fraction)			0.270	0.478	0.571	1.423
TRANS. PIPELINES (lumped)						
Peak capacity required, MW		2216	2216	1872	1767	1355
Annual capacity factor		0.51	0.58	0.70	0.75	1.0

Figure 4-1. Load curve for Case A-3, showing cogeneration and annual-cycle storage.

METHODOLOGY

The steps followed in analyzing the potential application and benefits of thermal energy storage in the Twin Cities system are:

1. Obtain or develop a description of the consumer heat loads for time frames of interest:
 - Hourly to daily for short-term TES
 - Weekly for mid-term TES
 - Monthly, seasonal, or annual for long-term TES.
2. Obtain or calculate system heat losses. Add these to the consumer load, for the time frames of interest, to find heat demand.
3. Obtain a description of the electric generators and system load. Ascertain the correlation between electric loads and heat loads, for the time frames of interest, and the availability of heat cogeneration capacity.
4. Compare heat production available from cogeneration to the demand for heat, including losses, for the time frames of interest. When demand exceeds available heat-production capacity, TES (in lieu of boiler capacity) will be required to deliver heat. When available heat-production capacity exceeds demand, TES is charged. The amount of thermal energy stored must equal (at least) the amount to be withdrawn for delivery, plus pipeline and storage losses, over an annual cycle.
5. Find the TES capacity required -- the larger of the maximum rate for delivery and for storage. The maximum rate of heat delivery required from TES is usually the same as the required boiler capacity. The amount of thermal energy to be stored in a given period of time establishes an average rate of heat storage required; the maximum rate does not usually exceed total heat cogeneration capacity.
6. By iteration, develop operating schedules for heat production and TES, subject to the constraints and objectives.

established by system production capability, heat loads, TES charging and withdrawal, conditions imposed for the case being studied, and economic considerations.

7. Find capital cost and fuel consumption benefits with respect to the reference system which has no TES.

APPLICATION OF METHODOLOGY TO ANNUAL-CYCLE STORAGE

Steps 1 through 6 are discussed here. Step 7 is covered in Section 5.

Heat Loads

The heat load duration curves shown in Figures 2-1 and 2-2 were developed by Studsvik from climatological data and estimates of hot tap water demand, and are assumed to apply to both scenarios. To analyze application of long-term TES, monthly heat demand and production capabilities are appropriate base data from which to develop requirements for seasonal and annual-cycle storage and to analyze its benefits. The monthly load-duration curves of Figure 2-1 were used to subdivide the known annual consumer heat load (TWH_t) into monthly heat loads.

From Figure 2-1, the peak heat demand (100 percent on the vertical scale) is in December and January. From Table 4-1, the 100-percent load is 2704 MW. Using this value, the vertical scale is converted from percentage to megawatts thermal. The area under each curve is found by graphical integration. For the number of hours in each of the twelve months, the areas are expressed in MWH of heat demand for each month. The sum of the areas is compared to the 6.298 TWH of annual heat delivery to consumers (Table 4-1) and adjustments are made to bring the coarse graphical approximation into reasonable agreement with the reference value.

Because the hot-water pipeline system operates at an essentially constant year-round temperature, the rate of heat loss is essentially constant. The annual pipeline losses are 0.695 TWH, from Studsvik calculations. (Almost all of this loss occurs in the distribution

system, which is simulated by Studsvik's computer code.) The heat loss in megawatts and in megawatt hours is found by dividing 0.695 TWH by the hours in a year and into monthly fractions. The heat loss rate, added to consumer peak demand, gives peak load as shown in Figure 4-1. The required boiler capacity is then determined, as described in Section 2. The monthly heat energy loads are also determined. The second step in the analysis is complete.

Available Cogeneration Capacity

The third step is to ascertain the amount of heat cogeneration capacity that is available. As discussed in Section 2 and tabulated in Table 2-1, the rated capacity for cogenerating heat is 1516 MW for Scenario A, 2216 MW for Scenario B. The full rated capacity will not always be available. Scheduled and forced outages must be taken into account; and equipment may be unavailable for heat generation for system control reasons — full electric generation is required, or the cogenerated electricity cannot be utilized efficiently.

As will be discussed in Section 6, some study will be needed to establish operating guides for optimum system control when thermal storage and cogeneration of electricity and heat are involved. Part of the input data needed to develop operating guides is an evaluation of the benefits of controlling equipment so as to meet various objectives. Therefore, for the cases studied here, only the fact that the Northern States Power system load peaks during July and August is taken into account. More detailed system control aspects can be worked out after potential benefits are evaluated.

With regard to scheduled and forced outages, a general guide was adopted on the basis of broad experience of electric utilities: 95 percent of rated heat output is assumed to be available for a one-month period, 80 percent for a one-year period. This is equivalent to stating that the maximum one-month capacity factor is assumed to be 0.95 and the maximum annual capacity factor is 0.80. Capacity factor is defined as the ratio of average load on a machine or equip-

ment for the period of time considered to the capacity of the machine or equipment (IEEE Std. 346-1973).

Heat Production vs Heat Demand

The fourth step in the analysis is to compare the available heat production from cogeneration, for each month of the year, to the consumer demand plus pipeline losses for the month. Tabulated values by month are shown for each of the cases studied.

Thermal Energy Storage Capacity Requirement

The fifth step is to ascertain the TES heat-storage rate required. In three of the four cases, boiler capacity exceeds cogeneration capacity and determines the TES capacity required. The fourth case employs TES at both the plants and the nodes and requires additional TES capacity.

Operating Schedules for Heat Production and TES

To develop operating schedules for heat cogeneration and TES, the procedure is to follow a logical sequence of calculations which employ information from the first five steps and factor in assumptions for the various cases.

For each of the cases studied, a sensitivity analysis was performed to evaluate the effect of various fractions of heat recovery versus heat stored. The nominal recovery fraction is 0.75. Calculations are also made for recovery fractions of 0.65 and 0.85. The smaller recovery fraction might apply to the first one or two annual cycles of injecting, storing, and recovering hot water in aquifer TES. The larger recovery fraction might apply when water is stored for a brief period of time and then withdrawn, for example, to smooth hourly, daily, or weekly fluctuations in supply and load.

RULES FOR ESTIMATING HEAT LOSS IN STORAGE. Several mathematical models have been developed to calculate, numerically, the heat loss in aquifer TES (Meyer, Todd, and Hare, 1972; INTERCOMP, 1976; Tsang, and others, 1978). Utilizing one of these models to simulate the

injection, storage, and recovery of hot water was considered. However, even if the aquifer parameters were known, the simulation would not be very useful unless a number of years of injection-storage-recovery cycles were modeled, which would make the simulation quite expensive.

To estimate heat loss, an approach consistent with other approximations made in describing the cogeneration-district heating system and its operation was adopted: full heat loss is assumed for all hot water stored. This approximation is quite conservative, because simulation models indicate the expected heat loss is less than the nominal 25 percent assumed here, and occurs only after about six months of storage time (Tsang, and others, 1978). Much of the hot water in the cases studied is stored for a shorter period of time than six months. The application of this rule will be illustrated in a subsequent discussion of Cases A-1 and B-1.

A modified "full heat loss in storage" rule is used for Cases A-4 and B-4, where TES is used both at the plants and at the transmission nodes. (In all other cases, TES is employed only at the nodes.) In Cases A-4 and B-4, heat is stored at the plant end of the transmission system until there is pipeline capacity available to carry it to the nodes; it is then withdrawn from TES at the plant and sent to the nodes, where some of it may again be stored until needed. The rule is to count loss in storage only once when heat is transferred from storage at the plant to storage at the nodes. The reasoning is that a "first in, last out" operating strategy is followed with the Heat Storage Wells: hot water, when needed, is withdrawn from the well most recently charged. Because the temperature observed at the well-head during recovery falls (approximately) as the square root of storage time, only a small temperature drop — hence, heat loss in storage — would occur in much of the water stored at the plant. The storage process is thought of as beginning at the plant and continuing at the nodes.

The validity of these heat-loss approximations should be evaluated by utilizing one of the numerical simulations, if TES is judged of sufficient promise for the Twin Cities system to merit more extensive study.

RULES FOR CAPACITY FACTOR. As discussed earlier, the general rule adopted for capacity factor is that it should not exceed 0.80 for 12 months or 0.95 for one month, to allow for scheduled and forced outages. In addition, heat output from extraction turbines may be restricted during the peak electric-load months of July and August, to permit maximum production of electricity. This is taken into account by (a) scheduling backpressure machines at up to maximum capacity factor during these two months; (b) taking steam from extraction machines only if heat demand exceeds heat production available from backpressure machines; (c) taking only enough heat from extraction machines to satisfy the deficiency, if any; and (d) scheduling extraction machines for not more than 0.80 capacity factor for the remaining 10 months.

In analyzing the sensitivity of the results to recovery fractions of other than the nominal 0.75, monthly capacity factors are adjusted. No monthly capacity factor is allowed to exceed 0.95, but the 12-month capacity factor for backpressure equipment is allowed to exceed 0.80 in some instances. In the tabulated results, adjustments in monthly capacity factor are shown above the affected values, and the annual effect is also shown.

RULE FOR SCHEDULING HEAT OUTPUT FROM COGENERATION. Within the constraints on capacity factor, heat output from cogeneration is scheduled to provide maximum storage rates during months just preceding the months of high demand, and maximum transmission to load during the months of high demand. This minimizes the storage time and the amount of heat stored, hence the heat loss in storage.

Because backpressure machines are superior to extraction machines in terms of the total cost of the joint products produced, as much heat as possible is taken from backpressure machines.

CASES STUDIED

A summary of the results of case studies was presented in Tables 4-2 and 4-3. Tables giving details for each case will be found at the end of this section. A graph follows the table for each case, showing key results of the analysis using the nominal recovery fraction (0.75).

Cases A-1 and B-1

All permanent boilers, located at the nodes, are replaced with TES. The annual cogeneration capacity factor is found to increase from 0.45 for the reference case to 0.55 for Case A-1, and from 0.51 to 0.60 for Case B-1 — well within the constraints set, and representing a somewhat reduced capital cost per unit of energy output plus the other benefits of TES versus boilers.

No attempt is made in this or other cases to consider capacity factor or heat loss of individual transmission pipeline links. However, the required capacity and the capacity factor for a single (lumped) transmission line are noted: For Case A-1, the required capacity is that required to handle peak cogeneration output, 1516 MW. The annual capacity factor is, of course, the same as that of the cogeneration equipment: 0.55.

In Table 4-4, for Case A-1, the annual heat load, including pipeline system losses, is 6.994 TWH. A total of $(6.351 + 0.775 =) 7.126$ TWH of heat is produced. The 0.132 TWH difference between 7.126 TWH production and 6.994 TWH demand is the amount of heat needed to supply heat lost during storage: 0.25×0.533 TWH stored = 0.132 TWH, for a recovery fraction of 0.75. (Note that storage loss is about 2 percent of total load.)

Slightly more production is needed if the recovery fraction is 0.65. It is obtained by setting the capacity factor of extraction equipment at 0.80 instead of 0.73 for the month of October, as noted in the column showing heat stored and withdrawn for a recovery fraction of 0.65. Similarly, if the recovery fraction is 0.85 the October capacity factor for extraction is reduced from 0.73 to 0.65.

The column headed " Δ , Production minus Load," shows whether heat is being stored in TES or withdrawn from TES during the month. When heat is withdrawn (indicated by a minus sign) the amount withdrawn is equal to the figure in the Δ column divided by the recovery fraction: $0.201/0.75 = 0.268$, for the month of January in Table 4-4, Case A-1, 0.75 recovery fraction. (This is the approach, mentioned earlier, for estimating heat loss in storage.) Heat production is increased, by increasing the capacity factor, to cause enough heat to be generated at the appropriate time to charge TES — during the autumn months just preceding the cold winter months — so that hot water is stored for a minimum period of time before being recovered, and heat loss in storage is (roughly) minimized. (See Figure 4-2, a graph of Case A-1.)

Clearly, the above procedure could be computerized, but this would be warranted only for more extensive data (e.g., hourly or weekly variations) and analysis.

Cases A-2 and B-2

Case 1 shows that boilers could be replaced with TES with only a modest increase in capacity factor of cogeneration. Might the amount of cogeneration capacity be reduced?

It was noted in Section 2, Table 2-1, that three of the turbines to be converted for steam extraction (High Bridge 3 and 4, Riverside 6) are old units scheduled for retirement in 1984. Their total heat production capacity is 344 MW. Avoiding the cost of converting and operating these old machines is a possibility worth investigating.

In Case A-2, the cogeneration capacity is reduced by 344 MW of extraction. The remaining extraction turbines are then operated at a 10-month capacity factor of 0.76, the backpressure machine at an annual CF of 0.80. Thus, the cogeneration capacity is adequate. Similarly, for Case B-2 the elimination of the 344 MW capacity of the old machines requires only 0.74 as a 10-month capacity factor for the remaining extraction turbines.

The TES capacity is increased by the amount of the decrease in cogeneration capacity, 344 MW_t , to maintain the ability to serve the same peak demand. The required pipeline size decreases, with the cogeneration capacity, and its capacity factor increases.

The amount of electricity sacrificed for each of the cases, shown in Tables 4-2 and 4-3, is found as described in Section 2, Fuel Consumption and Savings. Of interest in Cases A-2 and B-2 is that more electricity is sacrificed per unit of heat cogenerated when the old turbines are not used than when they are used. The reason is that the old machines heat water to only 190°F (88°C), and have a good β_N factor, 0.12. However, the 190° water must be passed through a second stage of heating, in other machines, to raise it to the required 295°F (146°C). Thus, Cases A-2 and B-2 require less capital investment than Cases A-1 and B-1 and permit the old machines to be retired on schedule instead of being kept in service, which will simplify the system and increase reliability; but the net energy savings are not as high as in Cases A-1 and B-1.

Cases A-3 and B-3

These cases are perhaps the most pragmatic and interesting of the cases studied. A maximum amount of backpressure cogeneration capacity is postulated.

Some extraction capacity is retained in the system. The new turbines (High Bridge 5 and 6, Riverside 8) are converted for crossover extraction — a total of 727 MW of heat capacity, needed in the first three years of implementation of the district heating system.

Using more backpressure machines 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 because there are no low-pressure stages, cold condenser, or 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 mode as compared to the extraction mode. (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 1000 Btu/pound.

The key point to be made is that TES expands the role of the backpressure turbogenerator used in a district heating system. It is no longer to be regarded as basically a source of district heat with electricity as a byproduct. It can be operated to produce electricity at a better heat rate than base-load plants (e.g., 4400 Btu/kWh_e; EKONO, 1977, page 10) 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 is available when needed. However, there is considerable latitude in choosing the appropriate times.

The Riverside 9 (or High Bridge 9) extraction unit proposed for addition in 1996 (see Table 2-1) would not be added. At \$81/kW_t, it accounts for more than half the total Scenario A cost of cogeneration capacity (\$29 million of \$55 million).

For Case A-3, the required backpressure capacity is 440 MW_t. This might take the form of 110 MW in the third year of implementation and 330 MW toward the end of implementation.

For Case B-3, the total system cogeneration capacity is only 1767 MW, 449 MW less than the 2216 MW needed in the reference case. A question to be seriously considered is whether siting (1767 - 1516 =) 251 MW of capacity within the metro area, in addition to the capacity in the metro area postulated for Scenario A, might be feasible by 1996. The object, of course, is to avoid the cost and the problems of constructing a pipeline from King. Although air quality requirements are probably the principal problem in adding 251 MW of in-town capacity, the fact that there would be no cooling requirements should help, as should the reduced requirements for trenching to install pipe. Clean fuels or combustion processes for coal may be available by 1996.

The transmission pipeline capacity is somewhat less for Case 3 than for Cases 1 and 2, and its capacity factor is higher. The TES capacity required increases by the amount of the decrease in cogeneration capacity, to maintain the ability to serve the same peak demand.

Cases A-4 and B-4

The purpose of these cases is to explore the effects of using TES both at the plant and the nodes, in order to minimize the transmission pipeline size. These are bounding cases, to find limits: the analysis is made on the basis of the (lumped) pipeline operating at full capacity year-round. An actual system obviously would not be so designed.

The required pipeline size is reduced from 1516 MW in the Scenario A reference case, or 1167 MW in Case A-3, to 865 MW. For Scenario B, the reduction is from 2216 MW in the reference case, or 1767 MW in Case B-3, to 1355 MW. In addition to savings in the capital cost of pipeline and pumps, there would be less pumping power needed and heat loss would be lower with smaller pipe. The latter is of small consequence since distribution system heat loss dominates.

The same extraction capacity is used as for Cases A-3 and B-3 — 727 MW. The required backpressure cogeneration capacity is adjusted so that both extraction and backpressure machines operate at a capacity factor of 0.80 when the recovery fraction is 0.75.

The analysis proceeds somewhat differently from earlier cases. Two iterations are performed. One finds the required pipeline capacity and the second determines the cogeneration capacity. The TES capacity at the plant must be large enough to store heat at a rate equal to the difference between that which the pipeline carries and the full cogeneration capacity; or large enough to deliver heat at a rate sufficient to keep the pipeline flowing at full capacity. The latter proves to be the governing requirement for both Case A-4 and Case B-4.

The storage capacity required at nodes need not include reserve capacity, for these cases. A drop in heat generation capacity due to forced outage would be taken up by the TES at the plant, which includes many wells and therefore is highly reliable. The required TES capacity at nodes is the peak demand minus the pipeline capacity. (As in all other cases, including the reference cases, Studsvik's observation that pipeline outages are rare and can be repaired in a matter of hours is the basis for providing neither boiler nor TES capacity as standby against pipeline failure.)

Full heat loss during storage is included for TES at the nodes. No heat loss during storage is included for TES at the plant, because storage begins at the plant and continues at the nodes after transfer of hot water through the pipeline into storage at the nodes. This can be observed both in the tabulated information and in plots of energy stored versus time in Figures 4-5 and 4-9.

The monthly heat load and heat production are shown in Tables 4-7 and 4-13, for a recovery fraction of 0.75, as in earlier tabulations. The energy flow through the transmission pipeline varies from month to month, as shown in the seventh column, only because of the varying number of hours in a given month. The flow rate is constant. When total heat cogeneration for a given month (sum of fourth and sixth columns) exceeds the pipeline capacity, the excess heat is stored at the plant. Conversely, heat is withdrawn from plant storage to keep the pipeline flowing at full capacity when production is less than pipeline capacity.

When flow through the pipeline is less than needed for consumer heat demand plus system heat losses, heat is withdrawn from node TES. Withdrawals from storage at the nodes, indicated by a minus sign, include allowance for full heat loss in storage. The amount of heat needed to supply demand that exceeds pipeline capacity is indicated by negative values in the ninth column. When flow through the pipeline exceeds that needed for demand, the excess heat is put into storage at the nodes. Put differently, when pipeline capacity is

available it is used to transfer heat from storage at the plant to storage at the nodes.

The minimum amount of TES needed at the plant, as noted earlier, is determined in Cases A-4 and B-4 by the largest withdrawal rate. For Case A-4, Table 4-7 shows the maximum monthly withdrawal from TES is 0.308 TWH — an average rate of 414 MW. The sum of pipeline capacity and this TES withdrawal rate, $(865 + 414 =) 1279$ MW, exceeds total cogeneration capacity, 1202 MW. The required TES capacity at the plant to accept the maximum cogeneration rate would be only $(1202 - 865 =) 337$ MW.

At the nodes, the TES capacity required is peak system demand minus pipeline capacity.

Cases A-4 and B-4 serve to illustrate a somewhat different methodology for applying TES than the earlier cases. A substantial increase in TES capacity is found to be required in order to achieve the objective of these cases — reducing the size of the transmission pipelines. Whether the increase in TES capacity is worthwhile will depend upon the relative cost of TES and pipelines.

NUMBER OF HEAT STORAGE WELLS REQUIRED

The total TES capacity needed for Cases A-1 through B-4 ranges from 1523 MW to 3697 MW. How many Heat Storage Wells would be required?

Assuming a water well capacity of one million gallons (380 m^3) per day and a temperature difference between the warm well and hot well of 150°F (83°C), the rate of heat storage or withdrawal is about 15 MW. An approximate upper bound on the number of wells can be found by assuming two wells (a doublet) are required per 15 MW of TES capacity required: for 1523 MW of capacity, 101 doublets, 202 wells; for 3697 MW of capacity, 247 doublets, 494 wells.

The actual number of wells required will be influenced by the TES capacity required at each node (see page 2-11), which will not be an even multiple of 15 MW and therefore will cause the number of

wells required to increase. A more significant effect is the influence of viscosity on the well capacity. The flow of groundwater through an aquifer, for a given head gradient, is shown by Darcy's Law to be proportional to density and inversely proportional to viscosity. (Todd, 1959, page 51.) Over the temperature range from 20°C (68°F) to 150°C (302°F), density decreases by 8.7 percent and viscosity decreases by a factor of 5.4. In terms of well capacity, these changes mean that a well yielding 500,000 gallons (190 m³) per day from an aquifer whose native temperature is 68°F is capable of yielding about one million gallons per day at 140°F (the approximate temperature of the return pipeline and of the warm well), and over two million gallons per day at 300°F (the approximate temperature of the hot water supply pipeline and the hot well, neglecting losses). Pumps, pipes, heat exchangers, and control valves being sized accordingly, it becomes possible to use one hot well per pair of warm wells when more than one doublet is required. Stated differently, one warm well is required per 15 MW of TES capacity, one hot well per 30 MW of TES capacity. With the wells arranged in a linear or circular array to establish proper flow conditions, the required number of wells would then be 0.75 times the number required if doublets were employed.

Scanning the table on page 2-11, and assigning wells wherever possible in accordance with the above 2:1 rule, suggests that the total number of wells needed for the Case A-1 TES capacity of 1523 MW at the nodes is about 170. Compared to the 202 needed for doublets, this indicates a reduction factor of about 0.84 rather than 0.75, or about 8.9 MW per well rather than 7.5 MW if doublets were employed. Thus, the number of wells required would range from about 170 for 1523 MW to about 416 for 3697 MW of TES capacity.

COMBINING SHORT- AND MID-TERM TES WITH LONG-TERM TES

The TES capacity required for each of the first three cases studied is established by the peak load and standby requirements as determined by Studsvik in the reference cases. Even in the fourth

case, where TES capacity required at the plant is determined by the required rate of withdrawal from storage, the TES capacity required at nodes is established by peak load requirements. A portion of the required TES capacity might be provided by short- and mid-term TES.

Consider Case A-1, for a recovery fraction of 0.75. The maximum amount of energy stored or withdrawn is the 0.334 TWH stored in October (Table 4-4). This is an average rate of $(0.334 \text{ TWH}/744 \text{ hours} =) 449 \text{ MW}$, which is 1074 MW less than the TES capacity of 1523 MW called for at the nodes to handle peak and standby loads. If short- and mid-term TES could smooth, or average, the load and supply fluctuations so as to maintain a reasonably steady 499 MW rate of storage, and if the short/mid-term TES is less expensive or otherwise preferable to aquifer storage, up to 1074 MW of short/mid-term TES might be employed in Case A-1. (Similar deductions can be drawn for the other cases.)

Note that this possible application of short/mid-term TES depends upon its use in combination with long-term TES. Without the long-term TES, the short/mid-term storage is beneficial only when there are heat loads both above and below the available heat production capacity of the cogeneration units during the period studied; e.g., mainly during early spring and late autumn.

For this study, Studsvik made a computer run for mid-term storage for Case A-1, based on the following assumptions:

- The TES is located at the nodes.
- The heat storage capacity is based only on the variations of the heat load at three-hour intervals for the year 2000.
- The computer runs are made for complete heat-load neutralization over weekly and monthly periods.
- The electrical system, the running strategy of cogeneration units, and costs of equipment have not been taken into account.

The results are as follows:

	<u>Storage Capacity, MW</u>		<u>Storage Size, GWH</u>
	In	Out	
Week	1632	1088	100
Month	1737	1139	190

The results for a one-week time period appear to roughly confirm the suggestion that up to 1074 MW of short/mid-term TES might be employed in conjunction with 449 MW of long-term TES. The computer run, incorporating hourly load data which Studsvik has developed, provides an estimate of the storage size required: 100 GWH. Assuming a ΔT of 150°F (66°C), to store this much energy would require 273 million gallons ($1.03 \times 10^6 \text{ m}^3$) of water.

TABLES AND GRAPHS

The results of case studies are summarized in tables and graphs on the following pages.

Table 4-4. Case A-1 - 1516 MW cogeneration capacity.
1523 MW TES at nodes.

Month	Load, Incl. Transport Losses TWH	Extraction (1406 MW)		Backpressure (110 MW)		Δ Prod.-Load TWH	Heat Stored (+) and Withdrawn (-)		
		Capacity Factor	Pro- duction TWH	Capacity Factor	Pro- duction TWH		(1)	(2)	(3)
							TWH	TWH	TWH
Jan	1.273	0.95	0.994	0.95	0.078	-0.201	-0.268	-0.309	-0.236
Feb	0.793	0.76	0.718	0.95	0.072	-0.003	-0.004	-0.005	-0.004
Mar	0.778	0.70	0.709	0.95	0.078	0.009	0.009	0.009	0.009
Apr	0.383	0.34	0.344	0.50	0.040	0.001	0.001	0.001	0.001
May	0.281	0.25	0.262	0.30	0.025	0.006	0.006	0.006	0.006
Jun	0.191	0.17	0.172	0.25	0.020	0.001	0.001	0.001	0.001
Jul	0.178	0.10	0.105	0.95	0.078	0.005	0.005	0.005	0.005
Aug	0.194	0.12	0.125	0.95	0.078	0.009	0.009	0.009	0.009
Sep	0.262	0.20	0.202	0.95	0.075	0.015	0.015	0.015	0.015
Oct	0.508	0.73	0.764	0.95	0.078	0.334	0.334	CF = 0.80 0.407	CF = 0.65 0.250
Nov	0.887	0.95	0.962	0.95	0.075	0.153	0.153	0.153	0.153
Dec	1.261	0.95	0.994	0.95	0.078	-0.189	-0.256	-0.291	-0.222
TOTAL	6.994		6.351 ⁽¹⁾		0.775 ⁽¹⁾				
STORAGE, TWH/YEAR:							0.533	0.606	0.404
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.60	0.60	0.59
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.80	0.80	0.80
(1) For 0.75 recovery fraction. (2) For 0.65 recovery fraction. (3) For 0.85 recovery fraction.

Figure 4-2. Case A-1 — 1516 MW cogeneration capacity.
1523 MW TES at nodes.

Table 4-5. Case A-2 — Cogeneration capacity, 1172 MW: 1062 MW extraction, 110 MW backpressure.
1867 MW TES at nodes.

Month	Load, Incl. Transport Losses TWH	Extraction (1062 MW)		Backpressure (110 MW)		Δ Prod.-Load TWH	Heat Stored (+) and Withdrawn (-)		
		Capacity Factor	Pro- duction TWH	Capacity Factor	Pro- duction TWH		(1) TWH	(2) TWH	(3) TWH
Jan	1.273	0.95	0.750	0.95	0.078	-0.445	-0.593	-0.685	-0.524
Feb	0.793	0.95	0.678	0.95	0.072	-0.043	-0.057	-0.066	-0.051
Mar	0.778	0.89	0.703	0.95	0.078	0.003	0.003	0.003	0.003
Apr	0.383	0.45	0.344	0.50	0.040	0.001	0.001	0.001	0.001
May	0.281	0.33	0.261	0.30	0.025	0.005	0.005	0.005	0.005
Jun	0.191	0.23	0.175	0.25	0.020	0.004	0.004	0.004	0.004
Jul	0.178	0.43	0.340	0.95	0.078	0.240	0.240	0.240	CF = 0.23 0.082
Aug	0.194	0.44	0.348	0.95	0.078	0.232	0.232	CF = 0.70 0.437	0.232
Sep	0.262	0.95	0.726	0.95	0.075	0.539	0.539	0.539	0.539
Oct	0.508	0.95	0.750	0.95	0.078	0.320	0.320	0.320	0.320
Nov	0.887	0.95	0.726	0.95	0.075	-0.086	-0.115	-0.132	-0.101
Dec	1.261	0.95	0.750	0.95	0.078	-0.433	-0.577	-0.666	-0.509
TOTAL	6.994		6.551 ⁽¹⁾		0.775 ⁽¹⁾				
STORAGE, TWH/YEAR:							1.34	1.55	1.19
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.76	0.76	0.76
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.80	0.80	0.80
(1) For 0.75 recovery fraction. (2) For 0.65 recovery fraction. (3) For 0.85 recovery fraction.

Figure 4-3. Case A-2 — 1172 MW cogeneration capacity.
1867 MW TES at nodes.

Table 4-6. Case A-3 — Cogeneration capacity, 1167 MW: 727 MW extraction, 440 MW backpressure.
1872 MW TES at nodes.

Month	Load, Incl. Transport Losses TWH	Extraction (727 MW)		Backpressure (440 MW)		Δ Prod.-Load TWH	Heat Stored (+) and Withdrawn (-)			
		Capacity Factor	Pro- duction TWH	Capacity Factor	Pro- duction TWH		(1)	(2)	(3)	
							TWH	TWH	TWH	
Jan	1.273	0.95	0.514	0.95	0.311	-0.448	-0.597	-0.689	-0.527	
Feb	0.793	0.95	0.464	0.95	0.281	-0.048	-0.064	-0.074	-0.056	
Mar	0.788	0.95	0.514	0.95	0.311	0.047	0.047	0.047	0.047	
Apr	0.383	0.45	0.236	0.50	0.158	0.012	0.012	0.012	0.012	
May	0.281	0.45	0.243	0.30	0.098	0.060	0.060	0.060	0.060	
Jun	0.191	0.45	0.236	0.25	0.079	0.124	0.124	CF = 0.91 0.333	0.124	
Jul	0.179	0	0	0.95	0.311	0.133	0.133	0.133	0.133	
Aug	0.194	0	0	0.95	0.311	0.117	0.117	0.117	0.117	
Sep	0.262	0.95	0.503	0.95	0.301	0.542	0.542	0.542	CF = 0.45 0.384	
Oct	0.508	0.95	0.514	0.95	0.311	0.317	0.317	0.317	0.317	
Nov	0.887	0.95	0.503	0.95	0.301	-0.089	-0.111	-0.128	-0.098	
Dec	1.261	0.95	0.514	0.95	0.311	-0.436	-0.581	-0.671	-0.513	
TOTAL	6.994		4.241 ⁽¹⁾		3.084 ⁽¹⁾					
STORAGE, TWH/YEAR:							1.35	1.56	1.19	
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.80	0.80	0.80	
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.80	0.86	0.76	
(1) For 0.75 recovery fraction. (2) For 0.65 recovery fraction. (3) For 0.85 recovery fraction.

Figure 4-4. Case A-3 — 727 MW extraction, 440 MW backpressure.
1872 MW TES at nodes.

Table 4-7. Case A-4 – Minimize pipeline size; recovery fraction is 0.75. Cogeneration capacity, 1202 MW; 727 MW extraction, 475 MW backpressure. TES: 414 MW at plant, 1839 MW at nodes.
Pipeline: 865 MW.

Month	Load, Incl. Transport Losses TWH	Extraction (727 MW)		Backpressure (475 MW)		Flow in Transm. Pipe* TWH	Heat Stored (+) and Withdrawn (-)		
		Capacity Factor	Pro- duction TWH	Capacity Factor	Pro- duction TWH		Storage at Plant TWH	Pipe Capacity Less Load and Transport Losses TWH	Storage at Nodes TWH
Jan	1.273	0.95	0.514	0.95	0.336	0.644	0.206	-0.629	-0.839
Feb	0.793	0.95	0.464	0.95	0.303	0.581	0.186	-0.212	-0.283
Mar	0.778	0.95	0.514	0.95	0.336	0.644	0.206	-0.134	-0.187
Apr	0.383	0.45	0.236	0.35	0.120	0.623	-0.267	0.240	0.240
May	0.281	0.45	0.243	0.35	0.124	0.644	-0.277	0.363	0.363
Jun	0.191	0.45	0.236	0.35	0.120	0.623	-0.267	0.432	0.432
Jul	0.178	0	0	0.95	0.336	0.644	-0.308	0.466	0.466
Aug	0.194	0	0	0.95	0.336	0.644	-0.308	0.450	0.450
Sep	0.262	0.95	0.503	0.95	0.325	0.623	0.205	0.361	0.361
Oct	0.508	0.95	0.514	0.95	0.336	0.644	0.206	0.136	0.136
Nov	0.887	0.95	0.503	0.95	0.325	0.623	0.205	-0.264	-0.352
Dec	1.261	0.95	0.514	0.95	0.336	0.644	0.206	-0.617	-0.823
TOTAL	6.994		4.241		3.333		1.42		2.45
TES CAPACITY, MW:							414		1839
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.80		
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.80		
* Lumped pipeline capacity = 865 MW. Annual capacity factor = 1.0.

Figure 4-5. Case A-4 —
 Minimize pipeline size; recovery fraction is 0.75.
 Cogeneration capacity, 1202 MW; 727 MW extraction,
 475 MW backpressure. TES: 414 MW at plant, 1839 MW
 at nodes. Pipeline: 865 MW.

Table 4-3. Case A-4a — Minimize pipeline size; recovery fraction is 0.65. Cogeneration capacity same as Case A-4.
 TES: 452 MW at plant, 1799 MW at nodes. Pipeline: 905 MW.

Month	Load, Incl. Transport Losses TWH	Extraction Capacity Factor	(727 MW) Pro- duction TWH	Backpressure Capacity Factor	(475 MW) Pro- duction TWH	Flow in Transm. Pipe* TWH	Heat Stored (+) and Withdrawn (-)		
							Storage at Plant TWH	Pipe Capacity Less Load and Transport Losses TWH	Storage at Nodes TWH
Jan	1.273	0.95	0.514	0.95	0.336	0.673	0.177	-0.600	-0.923
Feb	0.793	0.95	0.464	0.95	0.303	0.608	0.159	-0.185	-0.285
Mar	0.778	0.95	0.514	0.95	0.336	0.673	0.177	-0.105	-0.162
Apr	0.383	0.56	0.293	0.53	0.181	0.652	-0.178	0.269	0.269
May	0.281	0.56	0.303	0.53	0.187	0.673	-0.183	0.392	0.392
Jun	0.191	0.56	0.293	0.53	0.181	0.652	-0.178	0.461	0.461
Jul	0.178	0	0	0.95	0.336	0.673	-0.337	0.495	0.495
Aug	0.194	0	0	0.95	0.336	0.673	-0.337	0.479	0.479
Sep	0.262	0.95	0.503	0.95	0.325	0.652	0.176	0.390	0.390
Oct	0.508	0.95	0.514	0.95	0.336	0.673	0.177	0.165	0.165
Nov	0.887	0.95	0.503	0.95	0.325	0.652	0.176	-0.235	-0.362
Dec	1.261	0.95	0.514	0.95	0.336	0.673	0.177	-0.588	-0.905
TOTAL	6.994		4.415		3.518	7.297	1.22		2.65

TES CAPACITY MW:							452	1799	
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.83		
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.85		
* Lumped pipeline capacity = 905 MW. Annual capacity factor = 1.0.									

Table 4-9. Case A-4b — Minimize pipeline size; recovery fraction is 0.85. Cogeneration capacity same as Case A-4.
TES: 448 MW at plant, 1864 MW at nodes. Pipeline: 840 MW.

Month	Load, Incl. Transport Losses TWH	Extraction Capacity Factor	(727 MW) Pro- duction TWH	Backpressure Capacity Factor	(475 MW) Pro- duction TWH	Flow in Transm. Pipe* TWH	Heat Stored (+) and Withdrawn (-)		
							Storage at Plant TWH	Pipe Capacity Less Load and Transport Losses TWH	Storage at Nodes TWH
Jan	1.273	0.95	0.514	0.95	0.336	0.625	0.225	-0.648	-0.762
Feb	0.793	0.95	0.464	0.95	0.303	0.564	0.203	-0.247	-0.291
Mar	0.778	0.95	0.514	0.95	0.336	0.625	0.225	-0.153	-0.180
Apr	0.383	0.45	0.236	0.15	0.051	0.605	-0.318	0.222	0.222
May	0.281	0.45	0.243	0.14	0.049	0.625	-0.333	0.344	0.344
Jun	0.191	0.45	0.236	0.15	0.051	0.605	-0.318	0.414	0.414
Jul	0.178	0	0	0.95	0.336	0.625	-0.289	0.447	0.447
Aug	0.194	0	0	0.95	0.336	0.625	-0.289	0.431	0.431
Sep	0.262	0.95	0.503	0.95	0.325	0.605	0.223	0.343	0.343
Oct	0.508	0.95	0.514	0.95	0.336	0.625	0.225	0.117	0.117
Nov	0.887	0.95	0.503	0.95	0.325	0.605	0.223	-0.282	-0.332
Dec	1.261	0.95	0.514	0.95	0.336	0.625	0.225	-0.636	-0.748
TOTAL	6.994		4.241		3.120	7.359	1.55		2.32
TES CAPACITY MW:							448		1864
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.80		
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.76		
* Lumped pipeline capacity = 840 MW. Annual capacity factor = 1.0.									

Table 4-10. Case B-1 - 2216 MW cogeneration capacity.
2539 MW TES at nodes.

Month	Load, Incl.	Extraction (2106 MW)		Backpressure (110 MW)		Δ Prod.-Load	Heat Stored (+) and Withdrawn (-)		
	Transport	Capacity	Pro-	Capacity	Pro-		(1)	(2)	(3)
	Losses	Factor	duction	Factor	duction		TWH	TWH	TWH
	TWH		TWH		TWH				
Jan	1.978	0.95	1.489	0.95	0.078	-0.411	-0.548	-0.632	-0.484
Feb	1.236	0.83	1.175	0.95	0.072	0.011	0.011	0.011	0.011
Mar	1.213	0.73	1.144	0.95	0.078	0.009	0.009	0.009	0.009
Apr	0.604	0.38	0.576	0.50	0.040	0.012	0.012	0.012	0.012
May	0.445	0.27	0.423	0.30	0.025	0.003	0.003	0.003	0.003
Jun	0.307	0.19	0.288	0.25	0.020	0.001	0.001	0.001	0.001
Jul	0.288	0.14	0.219	0.95	0.078	0.009	0.009	0.009	0.009
Aug	0.311	0.15	0.235	0.95	0.078	0.002	0.002	0.002	0.002
Sep	0.417	0.31	0.470	0.95	0.075	0.128	0.128	CF = 0.42 0.295	CF = 0.23 0.007
Oct	0.796	0.95	1.489	0.95	0.078	0.771	0.771	0.771	0.771
Nov	1.382	0.95	1.441	0.95	0.075	0.134	0.134	0.134	0.134
Dec	1.960	0.95	1.489	0.95	0.078	-0.393	-0.524	-0.605	-0.462
TOTAL	11.016		10.438 ⁽¹⁾		0.775 ⁽¹⁾				
STORAGE, TWH/YEAR:							1.08	1.25	0.96
1C-MONTH CAPACITY FACTOR (EXTRACTION):							0.65	0.66	0.64
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.80	0.80	0.80
(1) For 0.75 recovery fraction. (2) For 0.65 recovery fraction. (3) For 0.85 recovery fraction.

Figure 4-6. Case B-1 — 2216 MW cogeneration capacity.
2539 MW TES at nodes.

Table 4-11. Case B-2 — Cogeneration capacity, 1872 MW: 1762 MW extraction, 110 MW backpressure.
2883 MW TES at nodes.

Month	Load, Incl. Transport Losses TWH	Extraction (1762 MW)		Backpressure (110 MW)		Δ Prod.-Load TWH	Heat Stored (+) and Withdrawn (-)		
		Capacity Factor	Pro- duction TWH	Capacity Factor	Pro- duction TWH		(1)	(2)	(3)
							TWH	TWH	TWH
Jan	1.978	0.95	1.245	0.95	0.078	-0.655	-0.873	-1.008	-0.771
Feb	1.236	0.95	1.125	0.95	0.072	-0.039	-0.052	-0.051	-0.039
Mar	1.213	0.87	1.141	0.95	0.078	0.005	0.005	0.005	0.005
Apr	0.604	0.45	0.571	0.50	0.040	0.006	0.006	0.006	0.006
May	0.445	0.32	0.420	0.30	0.025	0	0	0	0
Jun	0.307	0.23	0.292	0.25	0.020	0.005	0.005	0.005	0.005
Jul	0.288	0.42	0.551	0.95	0.078	0.341	0.341	0.341	CF = 0.27 0.144
Aug	0.311	0.44	0.577	0.95	0.078	0.344	0.344	CF = 0.68 0.658	0.344
Sep	0.417	0.81	1.028	0.95	0.075	0.686	0.686	0.686	0.686
Oct	0.796	0.95	1.245	0.95	0.078	0.527	0.527	0.527	0.527
Nov	1.382	0.95	1.205	0.95	0.075	-0.102	-0.136	-0.157	-0.120
Dec	1.960	0.95	1.245	0.95	0.078	-0.637	-0.849	-0.980	-0.750
TOTAL	11.016		10.645		0.775				
STORAGE, TWH/YEAR:							1.91	2.23	1.71
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.74	0.74	0.74
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.80	0.80	0.80
(1) For 0.75 recovery fraction. (2) For 0.65 recovery fraction. (3) For 0.85 recovery fraction.

Figure 4-7. Case B-2 — 1872 MW cogeneration capacity.
2883 MW TES at nodes.

Table 4-12. Case 3-3 - Cogeneration capacity, 1767 MW: 727 MW extraction, 1040 MW backpressure.
2988 MW TES at nodes.

Month	Load, Incl. Transport Losses TWH	Extraction (727 MW)		Backpressure (1040 MW)		Δ Prod.-Load TWH	Heat Stored (+) and Withdrawn (-)		
		Capacity Factor	Pro- duction TWH	Capacity Factor	Pro- duction TWH		(1) TWH	(2) TWH	(3) TWH
Jan	1.978	0.95	0.514	0.95	0.735	-0.729	-0.972	-1.122	-0.858
Feb	1.236	0.95	0.464	0.95	0.664	-0.108	-0.144	-0.166	-0.127
Mar	1.213	0.95	0.514	0.95	0.735	0.036	0.036	0.036	0.036
Apr	0.604	0.60	0.314	0.45	0.337	0.047	0.047	0.047	0.047
May	0.445	0.40	0.216	0.35	0.271	0.042	0.042	0.042	0.042
Jun	0.307	0.35	0.183	0.25	0.187	0.063	0.063	CF = 0.72 0.415	0.063
Jul	0.288	0	0	0.95	0.735	0.447	0.447	0.447	0.447
Aug	0.311	0	0	0.95	0.735	0.424	0.424	0.424	0.424
Sep	0.417	0.95	0.503	0.95	0.712	0.798	0.798	0.798	CF = 0.59 0.528
Oct	0.796	0.95	0.514	0.95	0.735	0.453	0.452	0.452	0.452
Nov	1.382	0.95	0.503	0.95	0.712	-0.167	-0.223	-0.257	-0.196
Dec	1.960	0.95	0.514	0.95	0.735	-0.711	-0.948	-1.094	-0.836
TOTAL	11.016		4.239 ⁽¹⁾		7.273 ⁽¹⁾				
STORAGE, TWH/YEAR:							2.28	2.63	2.01
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.80	0.80	0.80
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.80	0.84	0.77
(1) For 0.75 recovery fraction. (2) For 0.65 recovery fraction. (3) For 0.85 recovery fraction.

Figure 4-8. Case B-3 — 727 MW extraction, 1040 MW backpressure.
 2988 MW TES at nodes.

Table 4-13. Case 3-4 — Minimize pipeline size; recovery fraction is 0.75. Cogeneration capacity, 1817 MW:
727 MW extraction, 1090 MW backpressure. TES: 647 MW at plant, 3050 MW at nodes.
Pipeline: 1355 MW.

Month	Load, Incl. Transport Losses TWH	Extraction Capacity Factor	(727 MW) Pro- duction TWH	Backpressure (1090 MW) Capacity Factor	Pro- duction TWH	Flow in Transm. Pipe* TWH	Heat Stored (+) and Withdrawn (-)		
							Storage at Plant TWH	Pipe Capacity Less Load and Transport Losses TWH	Storage at Nodes TWH
Jan	1.978	0.95	0.514	0.95	0.770	1.008	0.276	-0.970	-1.293
Feb	1.236	0.95	0.464	0.95	0.696	0.911	0.249	-0.325	-0.433
Mar	1.213	0.95	0.514	0.95	0.770	1.008	0.276	-0.204	-0.272
Apr	0.604	0.45	0.236	0.35	0.275	0.976	-0.465	0.372	0.372
May	0.445	0.45	0.243	0.35	0.283	1.008	-0.481	0.572	0.572
Jun	0.307	0.45	0.236	0.35	0.275	0.976	-0.465	0.669	0.669
Jul	0.288	0	0	0.95	0.770	1.008	-0.238	0.720	0.720
Aug	0.311	0	0	0.95	0.770	1.008	-0.238	0.697	0.697
Sep	0.417	0.95	0.503	0.95	0.746	0.976	0.273	0.559	0.559
Oct	0.796	0.95	0.514	0.95	0.770	1.008	0.276	0.212	0.212
Nov	1.382	0.95	0.503	0.95	0.746	0.976	0.273	-0.406	-0.541
Dec	1.960	0.95	0.514	0.95	0.770	1.008	0.276	-0.952	-1.269
TOTAL	11.016		4.241		7.641	11.879	1.90		3.80
TES CAPACITY, MW:							647		3050
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.80		
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.80		
* Lumped pipeline capacity = 1355 MW. Annual capacity factor = 1.0.

Figure 4-9. Case B-4 —

Minimize pipeline size; recovery fraction is 0.75.
 Cogeneration capacity, 1817 MW: 727 MW extraction,
 1090 MW backpressure. TES: 647 MW at plant, 3050 MW
 at nodes. Pipeline: 1355 MW.

Table 4-14. Case B-4a - Minimize pipeline size; recovery fraction is 0.65. Cogeneration capacity same as Case B-4.
TES: 484 MW at plant, 2995 MW at nodes. Pipeline: 1410 MW.

Month	Load, Incl. Transport Losses TWH	Extraction Capacity Factor	(727 MW) Pro- duction TWH	Backpressure (1090 MW) Capacity Factor	Pro- duction TWH	Flow in Transm. Pipe* TWH	Heat Stored (+) and Withdrawn (-)		
							Storage at Plant TWH	Pipe Capacity Less Load and Transport Losses TWH	Storage at Nodes TWH
Jan	1.978	0.95	0.514	0.95	0.770	1.049	0.235	-0.929	-1.429
Feb	1.236	0.95	0.464	0.95	0.696	0.948	0.212	-0.288	-0.443
Mar	1.213	0.95	0.514	0.95	0.770	1.049	0.235	-0.164	-0.252
Apr	0.604	0.45	0.236	0.55	0.432	1.015	-0.347	0.411	0.411
May	0.445	0.45	0.243	0.55	0.446	1.049	-0.360	0.604	0.604
Jun	0.307	0.45	0.236	0.55	0.432	1.015	-0.347	0.715	0.715
Jul	0.288	0	0	0.95	0.770	1.049	-0.279	0.761	0.761
Aug	0.311	0	0	0.95	0.770	1.049	-0.279	0.738	0.738
Sep	0.417	0.95	0.503	0.95	0.746	1.015	0.234	0.598	0.598
Oct	0.796	0.95	0.514	0.95	0.770	1.049	0.235	0.253	0.253
Nov	1.382	0.95	0.503	0.95	0.746	1.015	0.235	-0.367	-0.565
Dec	1.960	0.95	0.514	0.95	0.770	1.049	0.235	-0.911	-1.402
TOTAL	11.016		4.24		8.118	12.359	1.62		4.08
TES CAPACITY, MW:							484	2995	
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.80		
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.85		
* Lumped pipeline capacity = 1410 MW. Annual capacity factor = 1.0.									

Table 4-15. Case B-4b — Minimize pipeline size; recovery fraction is 0.85. Cogeneration capacity same as Case B-4.
TES: 788 MW at plant, 3095 MW at nodes. Pipeline: 1310 MW.

Month	Load, Incl. Transport Losses TWH	Extraction Capacity Factor	(727 MW) Pro- duction TWH	Backpressure (1090 MW) Capacity Factor	Pro- duction TWH	Flow in Transm. Pipe* TWH	Heat Stored (+) and Withdrawn (-)		
							Storage at Plant TWH	Pipe Capacity Less Load and Transport Losses TWH	Storage at Nodes TWH
Jan	1.978	0.95	0.514	0.95	0.770	0.975	0.309	-1.003	-1.180
Feb	1.236	0.95	0.464	0.95	0.696	0.880	0.280	-0.356	-0.419
Mar	1.213	0.95	0.514	0.95	0.770	0.975	0.309	-0.238	-0.280
Apr	0.604	0.45	0.236	0.18	0.141	0.943	-0.566	0.339	0.339
May	0.445	0.45	0.243	0.18	0.146	0.975	-0.586	0.530	0.530
Jun	0.307	0.45	0.236	0.18	0.141	0.943	-0.566	0.636	0.636
Jul	0.288	0	0	0.95	0.770	0.975	-0.205	0.687	0.687
Aug	0.311	0	0	0.95	0.770	0.975	-0.205	0.664	0.664
Sep	0.417	0.95	0.503	0.95	0.746	0.943	0.306	0.526	0.526
Oct	0.796	0.95	0.514	0.95	0.770	0.975	0.309	0.179	0.179
Nov	1.382	0.95	0.503	0.95	0.746	0.943	0.306	-0.439	-0.516
Dec	1.960	0.95	0.514	0.95	0.770	0.975	0.309	-0.985	-1.159
TOTAL	11.016		4.241		7.236	11.477	2.128		3.561
TES CAPACITY, MW:							788		3095
10-MONTH CAPACITY FACTOR (EXTRACTION):							0.80		
12-MONTH CAPACITY FACTOR (BACKPRESSURE):							0.76		
* Lumped pipeline capacity = 1310 MW. Annual capacity = 1.0.									

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SECTION 5

CAPITAL COST AND FUEL CONSUMPTION BENEFITS OF TES

In this section, the capital cost and fuel consumption benefits of TES are evaluated and compared to the Studsvik reference system to find breakeven costs of TES. All costs are in 1978 dollars.

CAPITAL COSTS (Table 5-1)

Boilers

In each of the cases studied, peak load and standby boilers are found to be unnecessary when TES is employed. The installed cost of permanent boilers is estimated by Studsvik to be \$43/kW_t. Table 5-1 shows the capacity and capital cost of these boilers in the reference cases for Scenarios A and B, which are avoided in the cases with TES.

Cogeneration Equipment

The Studsvik estimates summarized in Table 2-1 are used here as the basis for estimating capital costs saved in the cases studied. The annual cost of capital for different financing methods, the operating and maintenance costs, and the revenue requirements are also covered in the Studsvik reports, to appraise net savings and economic viability over the period of system implementation. These aspects are not included here because scenarios for implementation of the Iwin Cities system with TES have not been developed.

The capital costs assigned to backpressure turbines are the same as Studsvik's for the first 110 MW of heat capacity; the only backpressure machine proposed in the reference cases is Riverside 7a, a 110 MW_t unit. For that unit, the benefits of electricity production capacity are taken by Studsvik as equal to the cost of the unit (\$12 million). The cost allocated to district heat is then zero. For the cases with TES, the cost of the first 110 MW_t of backpressure capacity is also assumed to be zero.

Table 5-1. Capital costs, savings, and breakeven TES cost (1978 dollars).

	<u>Boilers</u>		<u>Cogeneration</u>				<u>Pipeline</u>		<u>Total</u>	<u>Cost Saved</u>	<u>TES</u>		
	MW	\$M	<u>Extraction</u>		<u>Backpressure</u>		MW	\$M	\$M	\$M	Capacity, MW	Break-even, \$/kWt	
			MW	\$M	MW	\$M							
<u>Scenario A</u>													
Reference Case	1523	66	1406	55	110	0	1516	105	226	Ref	-0-		
Case A-1	-0-	-0-	1406	55	110	0	1516	105	160	66	1523	43	
Case A-2	-0-	-0-	1062	42	110	0	1172	92	134	92	1867	49	
Case A-3	-0-	-0-	727	14	440	$\left\{ \begin{smallmatrix} 110 \\ 330 \end{smallmatrix} \right.$	$\left\{ \begin{smallmatrix} 0 \\ 10 \end{smallmatrix} \right.$	1167	92	115	110	1872	59
Case A-4	-0-	-0-	727	14	475	$\left\{ \begin{smallmatrix} 110 \\ 375 \end{smallmatrix} \right.$	$\left\{ \begin{smallmatrix} 0 \\ 11.3 \end{smallmatrix} \right.$	865	79	104	122	2253	54
<u>Scenario B</u>													
Reference Case	2539	109	2106	127	110	0	2216	298	534	Ref	-0-		
Case B-1	-0-	-0-	2106	127	110	0	2216	298	425	109	2539	43	
Case B-2	-0-	-0-	1762	114	110	0	1872	274	388	146	2883	51	
Case B-3	-0-	-0-	727	14	1040	$\left\{ \begin{smallmatrix} 110 \\ 930 \end{smallmatrix} \right.$	$\left\{ \begin{smallmatrix} 0 \\ 27.9 \end{smallmatrix} \right.$	1767	266	308	226	2988	76
Case B-4	-0-	-0-	727	14	1090	$\left\{ \begin{smallmatrix} 110 \\ 980 \end{smallmatrix} \right.$	$\left\{ \begin{smallmatrix} 0 \\ 29.4 \end{smallmatrix} \right.$	1355	233	276	258	3697	70

For costing additional backpressure capacity there is no specific parallel in the Studsvik descriptions, because it is the use of TES that makes feasible the use of straight backpressure turbines with no provision for cold condensing ("condensing tail") or for discarding exhaust steam into a cooler. For a given electrical generating capacity, the cost of a backpressure turbine should be lower than that of a cold-condensing condenser, and the cooling facilities need not be provided. Building space and land area requirements are reduced. Economies of scale do not enter the picture as for the King unit in the reference Scenario B case, where a cost penalty of $\$80/\text{kW}_e$ ($\$103/\text{kW}_t$) is estimated for two 400 MW_e units compared to one 800 MW_e unit; the choice of alternatives is different. For example, the "heat chargeable to power" in industrial situations, where topping turbines are used to generate electricity for in-plant use, is in the order of 4400 Btu/kWh — a much better heat rate than is achievable in any 800 MW_e single-purpose power plant with cold condensing.

The most flexible and defensible approach to allocating cost of a boiler and backpressure turbogenerator, recognizing this system is a high-efficiency producer of both electricity and heat, is to find the joint cost of producing the joint products. The joint cost may then be allocated as desired. For example, the value of the electrical output may be set at the going rate for power, which will make the heat output relatively cheap; or the benefits may be divided equitably between customers for power and heat. This type of analysis is beyond the scope of the present study.

The approach chosen for assigning a cost to backpressure capacity in excess of 110 MW_t is to use $\$30/\text{kW}_t$ for the heat output. This is based on the assumption that the cost of the larger boiler required to produce a given amount of electricity is partly offset by the reduced cost of a backpressure machine compared to a cold condensing machine.

Pipelines

The advantage of TES in reducing the required size of transmission pipelines has been estimated for the cases studied. The effect on

pipeline cost of reducing its required power-carrying capacity is taken as the factor $(P_0/P)^{1/2}$; e.g., if the required capacity P is one-half the reference-pipeline capacity P_0 , the cost is reduced by a factor of 1.4.

Breakeven Capital Cost of TES

Table 5-1 summarizes the capital costs of boilers, cogeneration equipment, and pipelines. The column headed "Cost Saved" indicates the capital cost avoided by use of TES. This cost saving divided by the required TES capacity gives one factor for evaluating the breakeven cost of TES. For aquifer TES, where there is only a power-related capital cost and no energy-related capital cost of storage capacity (the storage medium, containment, and insulation are essentially free), this factor gives an idea of the allowable capital cost.

For Cases A-1 and B-1, in which the permanent boilers are simply replaced with aquifer TES, the breakeven capital cost of storage is the cost of the boilers.

In Cases A-2 and B-2, \$13 million investment in extraction cogeneration is avoided by not converting the old machines, High Bridge 3 and 4 and Riverside 6, at \$3.3 million each plus approximately \$3 million for overhaul to extend their life beyond their scheduled 1984 retirement. Another \$13 million saving is estimated due to a 29 percent reduction in pipeline capacity requirement. Thus, even though more TES capacity is required than in Case A-1, the break-even cost per kilowatt of TES increases.

In Case A-3, the \$29 million cost of Riverside 9, 335 MW_t , is eliminated. The added cost of backpressure capacity is estimated as discussed: zero for the first 110 MW_t , as for Riverside 7a, and \$30/ kW_t for the balance. Slightly less pipeline capacity is required. The costs avoided increase by \$18 million, again more than offsetting the additional TES capacity required and increasing the breakeven cost per kW. Case B-3 is similar, but the breakeven cost of TES increases even more rapidly. The breakeven capital cost of TES is larger in Case 3 than in any of the other cases.

In Cases A-4 and B-4, the costs of the increase in backpressure capacity and the increase in TES capacity more than offset the decrease in pipeline capacity and cost, resulting in lower breakeven TES cost than Case 3. (Case 4 results are quite sensitive to specific assumptions concerning the Twin Cities system control guidelines.)

Cost of Aquifer TES

A study of the cost of Heat Storage Wells is just being undertaken by the National Water Well Association, sponsored by the Oak Ridge National Laboratory. In an earlier study of this question, for which only scanty data were found, TEMPO concluded the cost in 1974 dollars of Heat Storage Wells, with surface equipment (heat exchanger, pumps, shelter), would be \$17 to \$37 per peak kilowatt input to or output from aquifer storage (Meyer, Hausz, and others, 1976). Inflation would increase these figures to perhaps \$23 to \$50 per kW_t . NWWA will survey a number of their well-driller members across the country and secure up-to-date information from them.* However, the range of uncertainty may be expected to remain at least 2:1, because of regional and geological variations.

Estimates or quotations specific to the Twin Cities should be obtained for further refinement of this study.

FUEL CONSUMPTION BENEFITS (Table 5-2)

Analysis of the fuel consumption benefits of systems with TES compared to the reference systems for Scenarios A and B includes an evaluation of the net annual energy savings in energy units and in dollars, as well as by type of fuel consumed annually in the mature system; i.e., substitution of coal for oil and gas. The fuel consumption and energy savings for the reference systems are as shown in Tables 2-5 and 2-6.

In Table 5-2, column (1) shows the amount of electricity sacrificed due to extraction of heat from turbines, as discussed in Section

* Personal communication, May 22, 1979, Mr. Harold Heiss, NWWA.

Table 5-2. Annual fuel consumption and energy benefits (1978 dollars).

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Electric Generation Sacrificed	Coal to replace Electricity		Oil to fire Boilers		Gas not Consumed			Net Energy Savings			Cost Savings	
	TWH	TWH	\$M	TWH	\$M	TWH	\$M	TWH	10 ⁶ MBtu	MBOE	%	\$M	Δ, \$M
<u>Scenario A</u>													
Reference System	1.10	2.75	11.1	1.20	18.1	9.23	160.7	5.28	18.0	2.83	Ref	131	Ref
Case A-1	1.33	3.20	12.9	-0-	-0-	9.23	160.7	6.03	20.6	3.22	14	148	16
Case A-2	1.52	3.72	15.0	-0-	-0-	9.23	160.7	5.43	18.5	2.91	3	145	14
Case A-3	1.51	3.46	14.0	-0-	-0-	9.23	160.7	5.46	18.6	2.92	3	145	14
Case A-4	1.54	3.53	14.2	-0-	-0-	9.23	160.7	5.37	18.3	2.87	2	145	14
<u>Scenario B</u>													
Reference System	1.87	4.58	18.9	1.84	27.8	14.0	243.7	7.48	25.5	4.00	Ref	197	Ref
Case B-1	1.95	4.86	19.59	-0-	-0-	14.0	243.7	9.14	31.2	4.89	22	224	27
Case B-2	2.09	5.22	21.0	-0-	-0-	14.0	243.7	8.78	30.0	4.70	17	223	26
Case B-3	2.10	5.25	21.1	-0-	-0-	14.0	243.7	8.76	29.9	4.68	17	223	26
Case B-4	2.15	5.37	21.6	-0-	-0-	14.0	243.7	8.63	29.5	4.62	16	222	25

2. To replace this electricity requires burning coal at a condensing power plant, which, for consistency with Studsvik, is assumed to be 40 percent efficient. Thus, to find the extra coal burned, shown in column (2), the value in column (1) is divided by 0.4. (To convert from terawatt hours to millions of Btu, multiply TWH by 3.41×10^6 .) The cost of the coal at \$1.18 per million Btu is shown in column (3), in millions of 1978 dollars.*

Column (4) shows the amount of oil required to fire permanent heat-only boilers in the reference cases. Use of TES makes boilers unnecessary in the mature system and the entire amount of oil is saved in the systems with TES; *substitution of coal for this oil is the most notable energy-conservation attribute of the systems with TES*. Even if more rather than fewer total energy units were needed, the substitution is in line with national energy-independence goals. (To convert from TWH to millions of barrels of oil at 6.38 million Btu/barrel, multiply TWH by 0.535.) The cost of the oil at \$4.48 per million Btu is given in column (5).

"Gas not consumed," column (6), quantifies the basic energy-conservation benefit of a Twin Cities cogeneration-district heating system. It is the fuel saved by consumers of gas, oil, or whatever alternative fuel might have been used instead of district heat service. A generous efficiency of 70 percent for the average consumer's boiler or furnace is assumed. (To convert from TWH to millions of standard cubic feet of gas at 1000 Btu/SCF, multiply TWH by 3413.) The value of the gas saved, at \$5.10 per million Btu, is shown in column (7).

The net energy savings are found by subtracting from the savings in gas the extra energy used as coal and oil. The results are shown in units of TWH, trillions of Btu, and millions of barrels of oil equivalent, in columns (8), (9), and (10).

* Fuel prices are those shown in Studsvik's November 1978 draft.

Columns (11) and (13) represent conclusions concerning energy and cost savings of systems with TES with respect to the reference systems. *In spite of heat lost during storage*, all of the cases studied are superior to the reference case, by amounts ranging for Scenario A from 2 to 14 percent in energy savings and from \$14 million to \$16 million dollars per year in cost of fuel. For Scenario B, the TES cases save from 16 to 32 percent more energy than the reference case, and from \$25 million to \$27 million per year in cost of fuel. These cost savings give some idea of the allowable annual operating cost of TES.

It is to be noted that different assumptions might either increase or decrease the net energy savings. For example, if the heat lost during storage is more than 25 percent of the heat stored, or if the efficiency of coal-burning power plants is less than the assumed 40 percent, the net energy savings can be negative instead of positive. Even so, the fuel-substitution benefits may be worthwhile. For example, in a power plant more TWH of coal must be burned than of oil or gas, for a given electrical output, because of stack-gas cleanup requirements; but this substitution is required by national policy.

COMBINED ANNUAL SAVINGS (Table 5-3)

The analysis of capital cost saved suggests the allowable capital investment per kilowatt of TES capacity varies from \$43 to \$59 for Scenario A, from \$43 to \$76 for Scenario B. The annual energy cost saving for each of the four Scenario cases with TES is about \$14 million, and about \$26 million for each of the Scenario B cases. Annualizing the capital cost by using a fixed charge rate, as is common practice in electric utility economic analysis, permits combining the capital cost and fuel consumption benefits to find an allowable combined annual cost of TES for each case. The combined cost may then be reallocated as desired between fixed and variable annual charges. (Note, however, that variable operating and maintenance costs have not been included in the analysis; a true system total is not obtained.)

Table 5-3 shows the annual capital costs saved by TES for two fixed charge rates, 12 percent and 18 percent, which are representative of municipal financing (public ownership) and of private financing (investor ownership). The annual fuel cost savings, from Table 5-2, are shown in the fourth column. For each type of financing, the breakeven (allowable) annual cost of TES is found by combining the annual capital and fuel cost savings.

Dividing the total allowable costs, shown in the sixth and eighth columns of Table 5-3, by the TES capacity for each case gives an indication of the allowable annual cost per kilowatt of capacity, shown in the seventh and ninth columns. These results are applicable for evaluating aquifer TES, whose cost is almost entirely power-related. For other TES devices, the energy-related costs — containment, insulation, medium, and pumping — are significant; both the cost per kW and per kWh would have to be considered.

SUMMARY

The analysis of capital costs saved indicates that Case 3 is preferred over the other cases studied: the likelihood of lowest investment costs is highest. The breakeven TES cost per kilowatt for Case A-3 is 37 percent higher than for Case A-1, and for Case B-3 it is 77 percent higher than for Case B-1.

The analysis of fuel consumption and energy benefits shows Case A-1 strongly superior to other Scenario A cases in terms of energy units, and Case B-1 definitely superior to other Scenario B cases. However, in each scenario the energy cost savings are very nearly the same for all cases, and the principal benefit — displacing oil and gas by use of coal — is the same for all cases.

When the capital costs are annualized, the differences between cases studied are both lessened and shifted. Case A-1 becomes superior to Case A-3 for both municipal and private financing, but by less than 10 percent — a meaningless margin within the framework of this study. For Scenario B, Case B-3 becomes sufficiently superior to Case B-1 and to the reference case that it should be kept in mind, in view of the marginal economic feasibility of the reference Scenario B system for the Twin Cities.

Table 5-3. Combined savings and resultant breakeven annual cost of TES (1978 dollars).

	Capital Costs Saved Due to TES		Fuel Cost Savings Due to TES	Breakeven Annual Cost of TES*			
	Municipal Financing†	Private Financing‡	\$M/yr	Municipal Financing		Private Financing	
	\$M/yr	\$M/yr		\$M/yr	\$/yr per kW of TES Capacity	\$M/yr	\$/yr per kW of TES capacity
Case A-1	7.9	11.9	16	23.9	15.7	27.9	18.3
Case A-2	11.0	16.6	14	25.0	13.4	30.6	16.4
Case A-3	13.2	19.8	14	27.2	14.5	33.8	18.1
Case A-4	14.6	22.0	14	28.6	12.7	36.0	16.0
Case B-1	13.1	19.6	27	40.1	15.3	46.6	18.4
Case B-2	17.5	26.3	26	43.5	15.1	52.3	18.1
Case B-3	27.1	40.7	26	53.1	17.8	66.7	22.3
Case B-4	31.0	46.4	25	56.0	15.1	71.4	19.3
* For a recovery fraction of 0.75							
† Fixed charge rate = 0.12							
‡ Fixed charge rate = 0.18							

SECTION 6
SYSTEM CONTROL AND STABILITY ASPECTS OF
COGENERATION-DISTRICT HEATING WITH STORAGE

This section addresses operating problems and opportunities in the presence of cogeneration and thermal energy storage (TES) in power systems. Two categories of cogeneration will be considered: (1) only a small percentage (10% or less) of cogeneration present on power systems; and (2) a large percentage of total generation consisting of cogeneration. Any system in the United States, even if it desires to acquire a large percentage of cogeneration, will for some time be in category (1).

The analysis is made for three specific time periods consistent with present system operations. The first time period is that experienced in control called "Automatic Generation Control" (AGC) which concerns itself with the second-by-second to minute-by-minute control of the generation and thus of the power system. The second time period is that of hour-by-hour, up to 48 hours, over which time individual units are committed or decommitted (started and stopped). The third time period extends from weekly to monthly or to a season, over which time the energy resources of the power system are allocated.

SMALL PERCENTAGE OF COGENERATION
ON THE SYSTEM

Seconds to Minutes:
No Seasonal Heat Storage

No problems are expected with performing AGC. A problem that requires study is the determination, as a guide for operating personnel, of the level of reliability that should be maintained for district heating among the cogeneration units and heat-only boilers. This is particularly important in the case where TES capability is limited.

Studies should be conducted to establish operating guides for emergencies, as during a forced outage of one or more generation units, to establish the mode in which to operate the cogeneration units. The latter requires that a priority of service be established for district heating since cogeneration units could possibly be switched over from heating to serving electric load.

Seconds to Minutes:
With Seasonal Storage

Again, no problems with performing AGC are expected. The great benefit of TES is that it allows flexibility in system operations and an inherently higher level of reliability in district heating than without the storage. The most economic use of the storage in conjunction with cogeneration units (and heat-only boilers, if any) should be determined in the second and third time periods. As an example of the flexibility afforded by TES capability, assume that a forced outage of an electric generation unit has occurred. Cogeneration can be applied to supply as much of the electric load as possible, relying on storage, heat-only boilers, and a portion of cogeneration to satisfy district heating.

Hours to Days:
No Seasonal Heat Storage

In this period a forecasted electric load is provided and similarly a heating load has to be forecasted. Generation and cogeneration has to be "committed" or "decommitted" to the load with reserves specified. The result is a start and stop schedule for all units which satisfies all constraints and minimizes the costs over the entire time period. The basic problem of "unit commitment" is not a new one although the full problem has so far only been solved by heuristic methods. Cogeneration represents a new element in the unit commitment problem and would complicate it to some extent, although not severely. A bigger problem is that of determining the reserves that are required for the district heating consistent with the service reliability required. With the reserve problem resolved the unit commitment problem can be

solved, particularly using heuristic methods, since it represents only a slight modification of the present state of the art.

Hours to Days:
With Seasonal Storage

In the presence of storage capability a great deal more flexibility exists in the commitment of units to satisfy a forecasted electric and district heating load plus reserves than without the storage. Assuming that the reserve required for district heating is provided, the problem then becomes one of determining the optimum solution to the unit commitment problem. Assuming a small percent of district heating compared to electric load, and a corresponding small percent of cogeneration and storage, modifications to present heuristic techniques may well suffice.

Weekly to Seasonal:
With or Without Seasonal Storage

Heuristic and quasi-rigorous programs now exist which allocate the resources to a projected electric load demand. These programs would have to be extended to incorporate cogeneration, heat-only boilers, etc, for simultaneously meeting the electric load and the district heating load demand. So long as the percent of cogeneration present is 10 percent or less, present techniques probably suffice for obtaining a solution. It may be worthwhile to determine how close the heuristic solution is to the global optimum. The latter requires the development of a rigorous or near rigorous methodology since at present no such logic exists.

LARGE PERCENTAGE OF COGENERATION
PRESENT ON THE SYSTEM

Seconds to Minutes:
No Seasonal Heat Storage

No problems with automatic generation control are expected under normal operating conditions. Since extraction is controlled, swings in the district heating requirement may cause increases in the area control error (ACE), which requires subsequent control action of

electric generation units. The latter may be called a "transient control problem" and needs to be studied to be sure that the heat storage capability designed into district heating systems is sufficient to avoid transient swings through the electric system. This transient problem is distinct from the emergency problem discussed previously where a forced outage of one or more units occurs. As the percent of cogeneration increases on a system it becomes increasingly important to have operating guides for emergencies to establish the priorities of electric generation vis-a-vis district heat production.

Seconds to Minutes:
With Seasonal Storage

With seasonal storage present, the transient problem described above is lessened or may even disappear entirely. The emergency problem is also lessened although the precise use of the resources and the storage deserves careful study.

Hours to Days:
No Seasonal Heat Storage

As outlined previously, the reserves required for the combined electric and district heating service have to be determined consistent with the reliability required. The new problem is that of committing to a projected electric and district heating load, including reserves, with a fair percent of cogeneration in the system. In the case considered here, the present unit commitment solution methodology has to be reviewed, and cogeneration properly incorporated, to optimally commit all energy resources.

Hours to Days:
With Seasonal Heat Storage

The heat storage capability allows much greater flexibility in the use of the resources than would be possible otherwise. All comments made in the absence of storage apply here with the exception that it is imperative to carry out the optimization in as rigorous a manner as possible to take full advantage of storage and thereby to decrease operating costs.

Weekly to Seasonal:
With or Without Seasonal Storage

As in the previous case, it is most important here, where the co-generation is a fair percent of the total, to develop a solution procedure which optimally allocates the generation resources so as to meet the simultaneous requirements of electric and district heating load and the reserves specified, and minimizes costs over the time period. The latter appears to represent a new endeavor.

TRAINING

It should be carefully noted that present operating personnel are untrained in supplying electric load and district heating simultaneously. Their work will become more complex as the number of cogeneration units on the system increases and the system expands. Operator training will have to be developed both for routine operation and for dealing with emergencies.

6-6

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SECTION 7

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