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District Heating/Cogeneration Application Studies for the Minneapolis–St. Paul Area

Overall Feasibility and Economic Viability for a District Heating/New Cogeneration System in Minneapolis–St. Paul

Peter Margen   Lars-Åke Cronholm
Kjell Larsson   Jan-Erik Marklund
Studsvik Energiteknik AB

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DISTRICT HEATING/COGENERATION APPLICATION STUDIES FOR THE MINNEAPOLIS-ST. PAUL AREA

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OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
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ABSTRACT

A study was undertaken to determine the feasibility of introducing a large-scale, hot water, district heating system for the Minneapolis-St. Paul area. The analysis was based on modern European hot water district heating concepts in which cogeneration power plants supply the base-load thermal energy. Heat would be supplied from converted turbines of existing coal-fired power plants in Minneapolis and St. Paul. Toward the end of the 20-year development period, one or two new cogeneration units would be required. Thus, the district heating system could use low-grade heat from either coal-fired or nuclear cogeneration power stations to replace the space heating fuels currently used — natural gas and distillate oil.

The following conclusions can be drawn: the concept is technically feasible, it has great value for fuel conservation, and with appropriate financing the system is economically viable.

EXECUTIVE SUMMARY

BACKGROUND

Contacts between Studsvik,* the U.S. Department of Energy (DOE), and Oak Ridge National Laboratory (ORNL) in 1977 resulted in a proposal for studying the technique of introducing district heating on a large regional scale in a suitable metropolitan area in the United States. The district heating system would replace fuels in limited supply — gas and oil — by using thermal energy from coal or nuclear cogeneration power plants. After further contacts with key personnel in several cities and states, the Twin Cities area — Minneapolis and St. Paul, Minnesota — was selected as the location for the study.

The overall study contract was awarded to Studsvik, and ORNL was to serve as coordinator of the various activities. The Minnesota Energy Agency (MEA), local utilities, and local consultants became deeply involved. This section of this report is an executive summary of work completed under the contract. Several phases of the study are being pursued in more detail by the electric utility, Northern States Power Company (NSP); MEA; and local consultants. Although the study is site specific, the general methodology is considered to be applicable for other cities in the northern area of the United States.

THE TWIN CITIES AREA

The Twin Cities area encompasses two concentrated municipalities about 7 miles apart — one in Minneapolis and one in St. Paul (Fig. 1). These areas are surrounded by a region of industrial sites and residential housing that links the areas into one continuous metropolitan region. The total metropolitan population of over 1 million includes 0.8 million within the two city boundaries. This dense population, coupled with the cold climate (>8000 Fahrenheit degree-days), creates a large heat demand.

*Studsvik Energiteknik AB, formerly AB Atomenergi.

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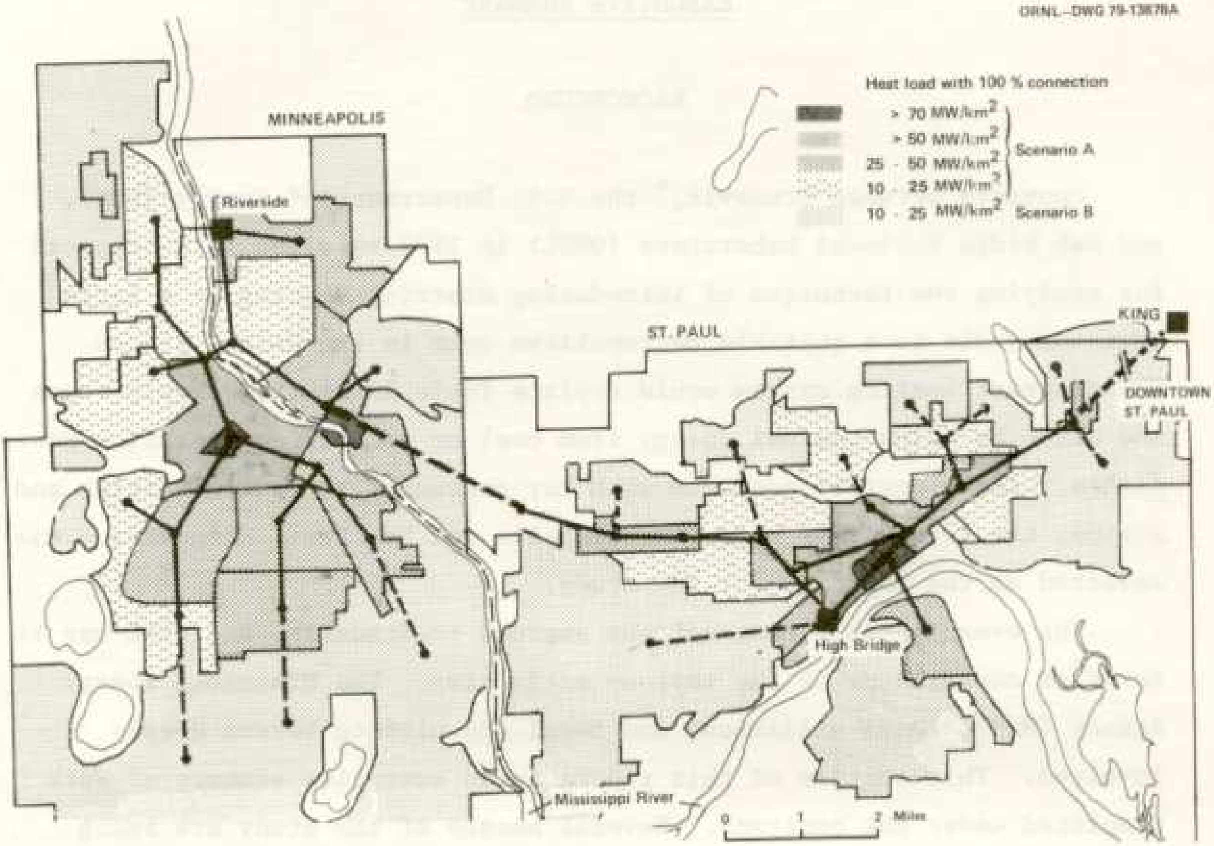

Fig. 1. Heat load densities in the Twin Cities area and possible regional piping systems.

Most of the heat demand is presently supplied by natural gas; however, gas supplies for the larger customers are interrupted during winter and replaced by oil. There are three small steam-based district heating systems in the area — an old one in downtown St. Paul [60 MW(t)], a fairly new one in downtown Minneapolis [about 80 MW(t), including also some district cooling], and one at the University of Minnesota [about 125 MW(t) also including some cooling]. These systems all use steam as the distribution medium and none uses cogeneration; however, a cogeneration plant has been proposed for the University. Thus, gas and oil have been the main fuels for district heating, with some conversion to coal at St. Paul and the University.

There are two fairly large coal-fired electric generating stations within the city boundaries — High Bridge for St. Paul and Riverside for Minneapolis — as shown in Fig. 1. A third station, Black Dog, is located about 10 miles south of Minneapolis, and there are several newer coal-fired and nuclear plants outside the metropolitan area. The closest of these is King, 17 miles from downtown St. Paul. King is also a possible site for another new unit.

This brief account indicates that the Twin Cities area is a prime candidate for a regional district heating system because of the following attributes:

1. a cold climate and a city structure well adapted to district heating and with a large potential heat load;
2. the present use of fuels that will become increasingly expensive and scarce (natural gas and oil);
3. the existence of coal-fired generating stations near the city with units suitable for conversion to cogeneration;
4. some tradition of district heating and yet not so much that the current steam distribution technology should strongly influence the technology to be used in the future; and
5. interested and cooperative local authorities and utilities with a desire to improve fuel usage and reduce air pollution.

SCOPE OF STUDY

Two levels of district heating implementation are discussed: Scenario A, which restricts district heating to the downtown and industrial commercial areas and nearby residential districts, and Scenario B, which also covers medium-density residential districts with one- and two-family houses outside the central parts of the cities. Over a 20-year period, these scenarios are estimated to involve a thermal load of around 2600 and 4000 MW(t), respectively, for the two scenarios (Fig. 2).

The 2600 MW(t) for Scenario A excludes the loads of the existing district heating systems in Minneapolis and at the University of

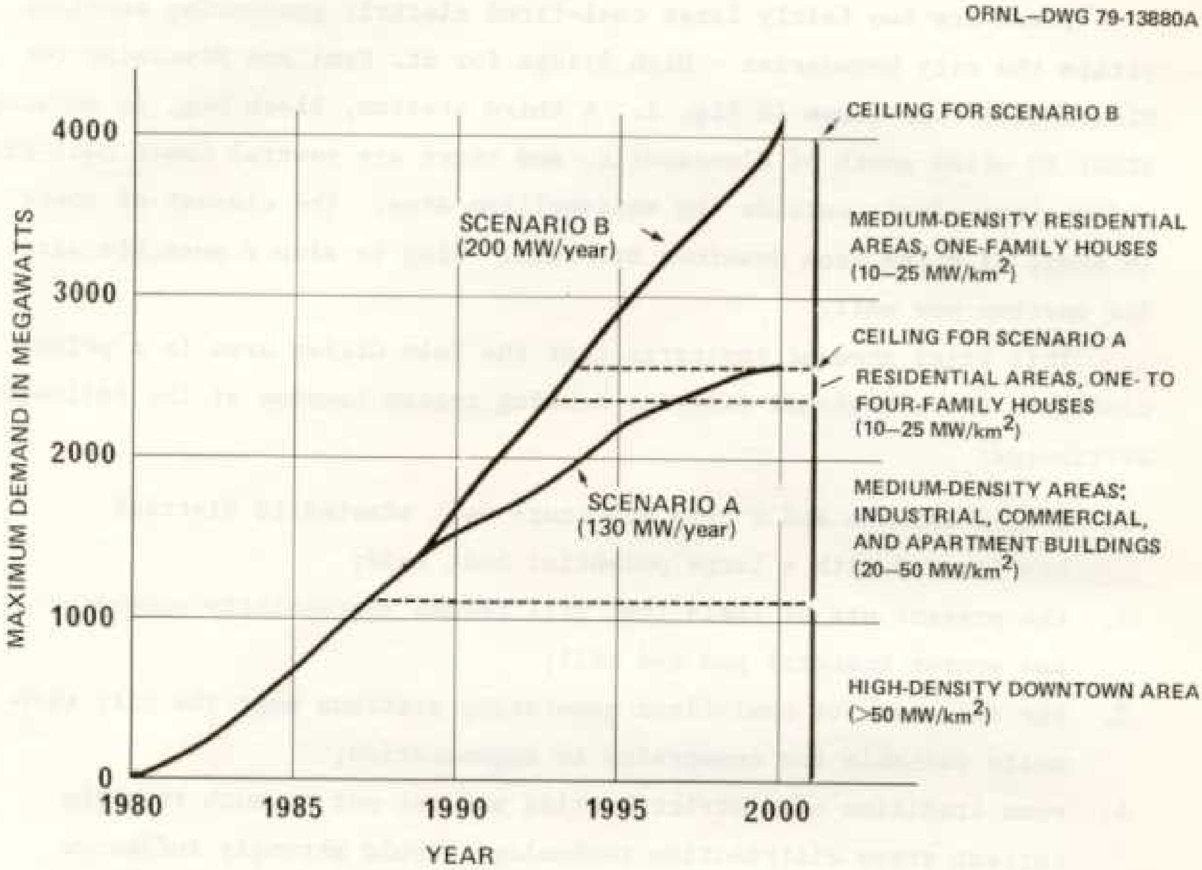

Fig. 2. Assumed thermal load connection rates for Scenarios A and B.

Minnesota because more detailed studies on integration of these schemes into the overall scheme are necessary. It also excludes the loads of some large industries that require more study and all loads for future establishments within the area. To compensate for the conservatism of these assumptions, it was assumed in the base case that all remaining consumers within the area would subscribe to the service. The influence of a lower effective subscription rate was evaluated separately. For Scenario B, 70% of the potential additional consumers over and above those of Scenario A were assumed to use the service.

Although the assumed starting date for the development is 1980, practical questions may delay the date by one or more years. The basic technology assumed is that used in modern Swedish systems, which now supply an increasingly large part of the national demand for space heating and domestic hot water by hot water distribution systems. About 3 million people in a population of 8 million are now served by district heating at home or at work.

Principal Features of Proposed Concept

The proposed district heating concept functions as follows:

1. The base load is supplied by cogeneration plants that provide about half the total peak-load capacity but nearly 90% of the annual heat energy (Fig. 3). Most of the thermal energy from cogeneration units is provided by converting turbogenerators to pass-out machines at two existing power stations — Riverside in Minneapolis and High Bridge in St. Paul. As illustrated in Fig. 4, this greatly improves fuel utilization. Toward the end of the period, these units would be complemented by new units. A new unit at Riverside is assumed for Scenario A. For Scenario B, two larger units about 17 miles from the center of the city area are proposed because it seems impracticable to use the city power plants exclusively. The cogeneration plants replace large quantities of oil and gas by small quantities of coal.

2. The peak load and reserve capacity requirements are supplied by oil-fired, heat-only boilers. These have a large total capacity but supply only a small percentage of the annual heat energy. They are located at various points of the heat-load demand area, thus reducing the size of pipes necessary between the central cogeneration plant sites and the demand areas.

3. The heat is transported from the production plants to the various parts of the demand area by hot water mains in accordance with modern European district heating technology. Large pipes run through tunnels for the parts of the area having adequate rock structure. Elsewhere underground pipes protected by concrete culverts are used. The transport systems are built up separately in Minneapolis and St. Paul initially and then interconnected during the second half of the period.

4. The heat is distributed from the regional system to individual buildings and houses by a hot water distribution system that runs under pavements, under streets, or, where possible, through cellars.

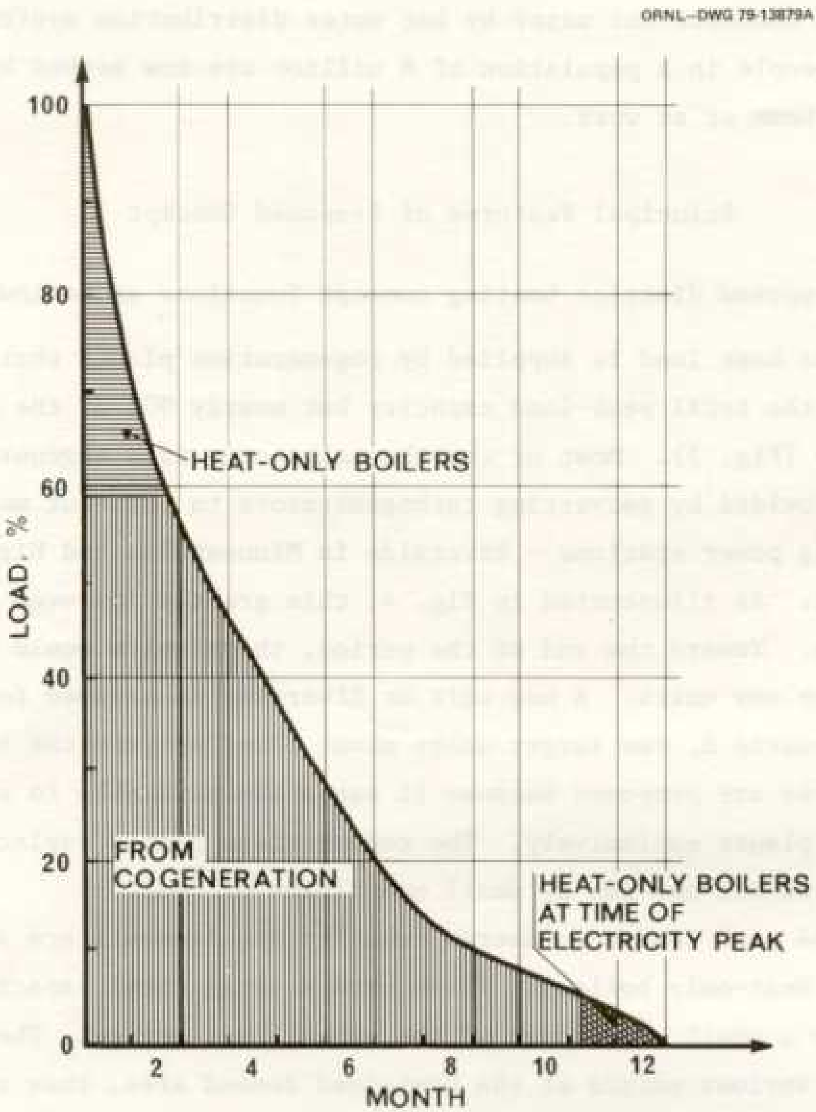

Fig. 3. Heat load duration curve and load distribution.

Prefabricated pipes complete with insulation and protection ducts are used. For Scenario B, in addition to conventional current piping systems, a newer type of piping distribution system for low-heat-density residential areas has been examined.

5. The heating systems of existing buildings are adapted so that they can be connected to the district heating system through heat exchangers. Different conversions are used for buildings and houses currently supplied by hot water, steam, or hot air.

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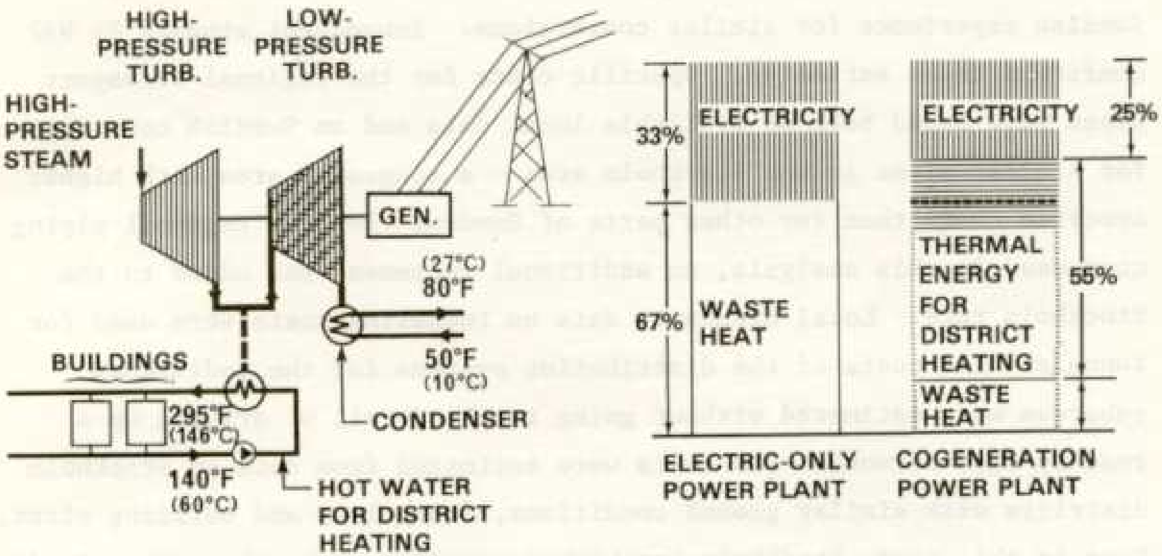

Fig. 4. Comparison of overall thermal efficiency of electric-only and cogeneration power plants.

6. The cooling loads were ignored in the analysis. However, in principle, existing absorption chillers could be converted to operate on hot water and could be supplied from the district heating system if certain restrictions are placed on the lowest permissible temperatures for hot water in the summer. The total capacity of such coolers is presently small, so that the impact on the overall economics would be minimal.

The system is built up progressively, starting with the densest heat load areas so as to start generating maximum revenues as soon as possible. The heat loads of the two existing district heating systems in central Minneapolis as well as the heat loads of some large industries have been ignored because more detailed studies are required before these loads can be integrated into the overall scheme.

Method for Calculations and Cost Estimates

Heat loads were calculated from data of actual gas consumption in the various subdistricts, corrected for curtailments and other factors.

Investments for the turbogenerator conversions were based on Swedish experience for similar conversions. Subsequent studies by NSP confirmed these estimates. Specific costs for the regional transport pipes were based both on available local data and on Swedish cost data for similar pipes in the Stockholm area — a congested area with higher specific costs than for other parts of Sweden. For the regional piping cost used in this analysis, an additional increment was added to the Stockholm rate. Local Minnesota data on tunneling costs were used for tunnels. The costs of the distribution systems for the individual subareas were estimated without going to the detail of drawing up a road-by-road network. The costs were estimated from data on Stockholm districts with similar ground conditions, densities, and building sizes. Even in this case, Stockholm has higher specific costs than other Swedish cities due to congestion and labor costs.

The regional piping system was designed using a computer program. The impact of the operation of the cogeneration plants on the electricity system was studied by comparing costs for all electric generating units in the NSP utility system without and with cogeneration.

The cost estimate for converting the heating systems of existing buildings for connection to a district heating system of the type proposed was based on a preliminary study carried out by MEA with the help of local consultants and advice from a Swedish consultant.

FUEL SAVINGS

The study shows that the district heating system would replace oil and natural gas equivalent to 49 and 61 million barrels of oil for Scenarios A and B, respectively, over the 20-year period studied (Fig. 5). Without district heating, the amount of fuels used for space heating with respect to the areas for Scenarios A and B is 57 and 72 million barrels. After correction for extra coal consumption at the power plants, the net fuel savings are 31 and 39 million barrels of oil, respectively. Thus, very substantial contributions to conservation of fuel — particularly the scarce fuels — are made. It should be pointed out that since the

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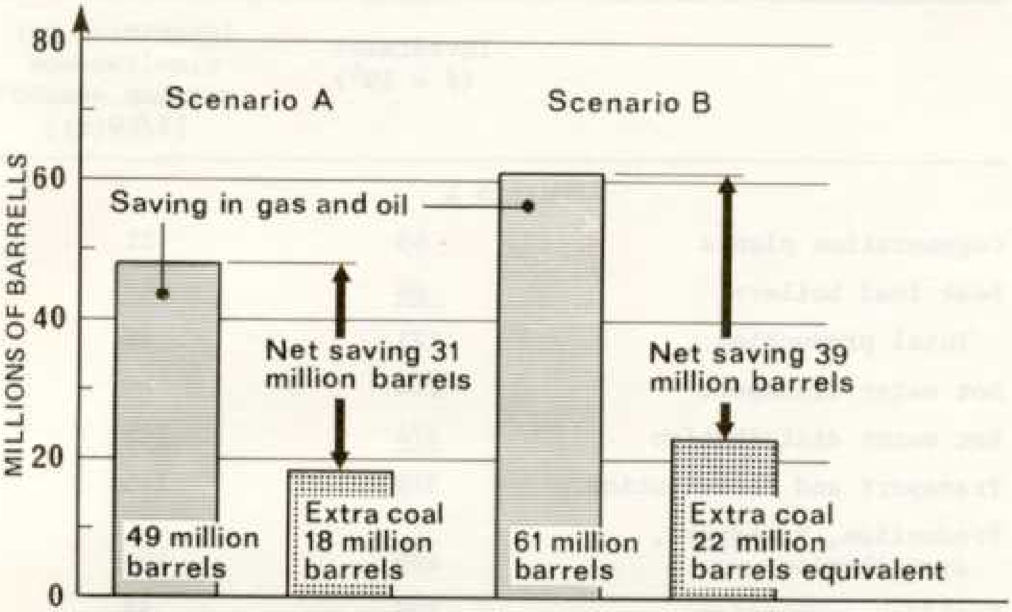

Fig. 5. Fuel savings realized with district heating, 1980–2000, Scenarios A and B.

system is developing from "ground zero" during this 20-year period, the fuel savings in the following years will be even greater. Almost as much fuel will be saved in the subsequent 10 years as in the first 20 years.

REQUIRED INVESTMENTS

The total additional investment for the utilities and buildings is estimated at 625 million 1978 dollars for Scenario A. The total investment for Scenario B is $1235 million with conventional distribution technology and $1136 million with newer technology (see Table 1).

ECONOMICS

Whereas, in practice, the cost of consumer heat system connections and conversions could be borne by the consumers or the utility (or both), it was assumed in the study that the utility would finance these investments. As a result, the rate charged for heat can be compared directly

Table 1. Total investments for Scenarios A and B

	Investment ($\$ \times 10^6$)		Investment per simultaneous maximum demand[a] [$/kW(t)]	
	Scenario A			
Cogeneration plants	55		21	
Peak load boilers	66		25	
Total production	121		46	
Hot water transport	104		40	
Hot water distribution	274		105	
Transport and distribution	378		145	
Production, transport, distribution	499		191	
Building conversion	126		48	
Grand total	625		239	
	Scenario B			
Cogeneration plants	98		24	
Peak load boilers	114		28	
Total production	212		52	
Hot water transport	221		54	
Hot water distribution	601	502[b]	149	124[b]
Transport and distribution	822	723	203	178
Production, transport, distribution	1034	935	255	230
Building conversion	201	201	50	50
Grand total	1235	1136	305	280

[a] 2621 MW(t), Scenario A; 4042 MW(t), Scenario B.

[b] New technology.

with the value of the fuel replaced by the elimination of individual boilers. The rate was set 10% below the cost of the fuel consumed by the cheapest alternative using individual boilers. Capital and operation and maintenance costs of individual boilers were not included in determining the cost of heat of the district heating alternatives.

The cheapest fuel, natural gas or oil, was used to assess these alternative costs, based on fuel price projections prepared by the utility (NSP). Initially the cheapest fuel is gas, but from the mid-1980s on it is oil. Swedish experience is that most consumers prefer district heating even if the cost is equal to that for alternative supplies because of the greater convenience.

If the cost of consumer system connections and conversions is borne by the consumers, the utility can offer a lower rate for the heat. This gives the consumer an additional saving that can be used to pay the capital charges on the investments.

The difference between the utility's income from sales of heat and the utility's annual operating costs and capital charges (including taxes) has been termed the "net saving."

Inflation and Fuel Costs

For the base cases, predictions by NSP on future inflation rates and development trends for fuel costs were used. These represent an inflation rate of 5 to 6%/year at the beginning of the period which will decrease to 4%/year by the year 2000. The cost projections are illustrated in Fig. 6. The inflation factor is applied in calculating investments and fuel costs in current dollars.

Coal costs are assumed to increase by about 1.3%/year in terms of 1978 dollars throughout the period. Electricity costs for auxiliaries such as pumps also increase only slightly in terms of 1978 dollars because the influence of some fuel price increases is counteracted by cost reductions due to the growth of the overall system.

Oil costs are assumed to reach world market prices of $16 per barrel of building heating oil by 1981* and to increase thereafter at about 2%/year

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*Significant increases in world market prices have occurred since the beginning of the study.

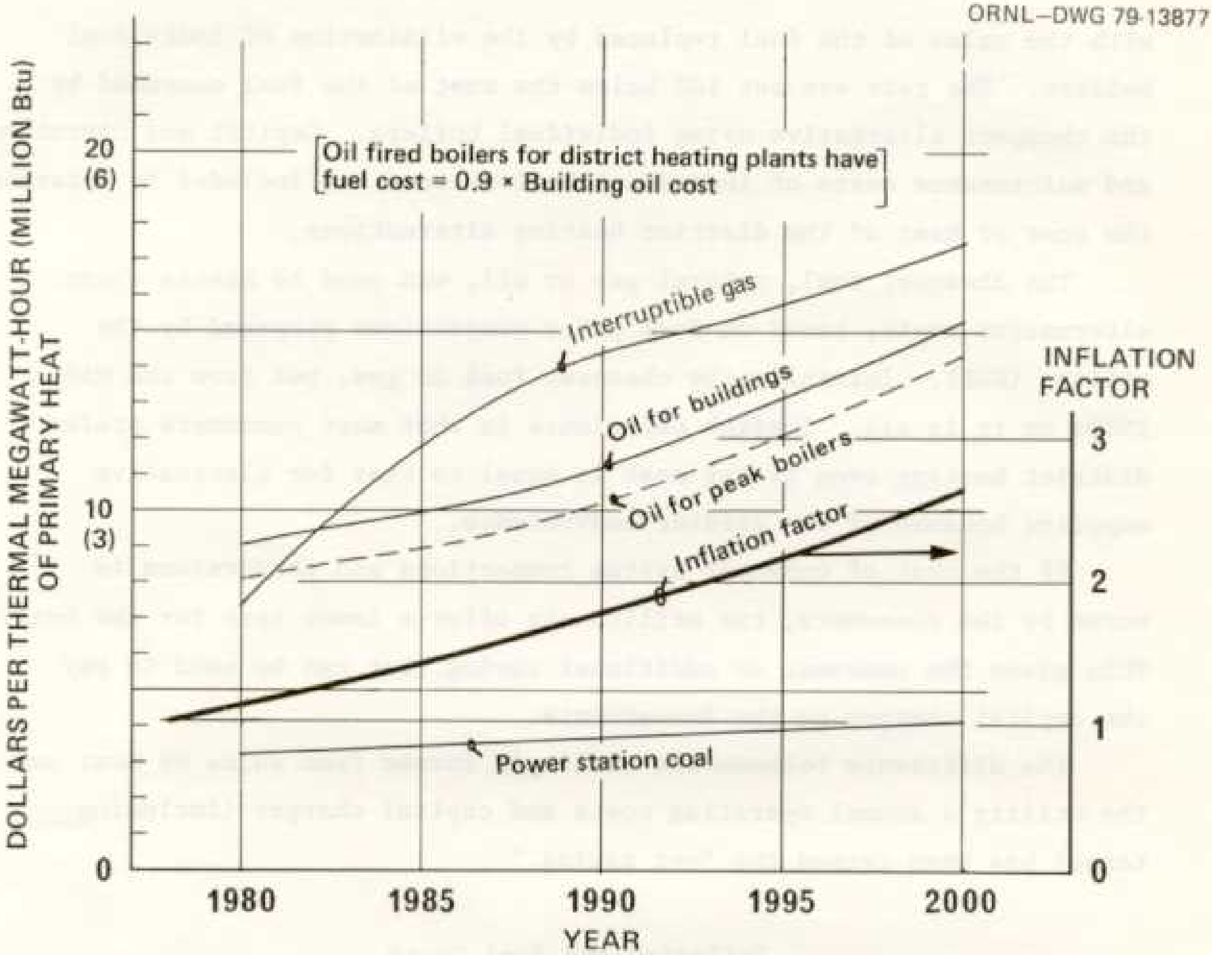

Fig. 6. Assumed costs of primary fuels over the period 1980–2000 in 1978 dollars (higher calorific value of fuel).

in terms of 1978 dollars (i.e., slightly more rapidly than inflation). The mean individual boiler efficiency is 70%, and efficiency for large heat-only district heating boilers is 90%. The additional residential load for Scenario B is assumed to have a mean individual boiler efficiency of 58%.

Gas prices are assumed to increase by a factor of 2.4 over the 20-year period. By the mid-1980s the gas prices to consumers begin to exceed those for light oil (houses) and medium-grade oil (buildings). The NSP estimators state that their oil price projections are on the low side for the long-term view. To compensate for this, an alternative case has been covered by the calculations in which gas and oil prices increase by an additional 1%/year.

Capital Charges

The capital charges (Table 2) for the district heating utility have been calculated on two bases: (1) with municipal utility financing and (2) with private utility financing including taxes.

Table 2. Capital charges and book depreciation periods[a]

Base	Capital (%)		Capital charges (%)		
	Debt	Equity	Interest on debt	Interest on equity	Tax
Private utility	50	50	8.4	13.36	51.95
Municipal utility	100		6.5		

[a]Book depreciation periods (years): transport and distribution lines (35), new cogeneration plants (30), conversion of existing turbines (20), heat-only boilers (25), consumer substations (15).

Results

The economic calculations for Scenario A and municipal financing show that the net savings are negative in the initial years but soon become positive (see Fig. 7). Over the entire period, there is an accumulated present worth net saving equivalent to 183 million 1978 dollars (Fig. 8).* With private utility financing, capital charges are higher and the accumulated present worth net saving therefore becomes negative — $77 million over the period studied. The sensitivity of the result to changes in assumptions (e.g., fuel cost projections) is also illustrated. With an intermediate financing system — private utility for the production plant and municipal financing for piping systems — the net accumulated savings would be about $132 million.

For Scenario B, municipal financing gives accumulated net annual savings of $238 million and $274 million for conventional and for newer distribution technology in the outer residential areas,

*All monetary figures in this section are in terms of 1978 dollars.

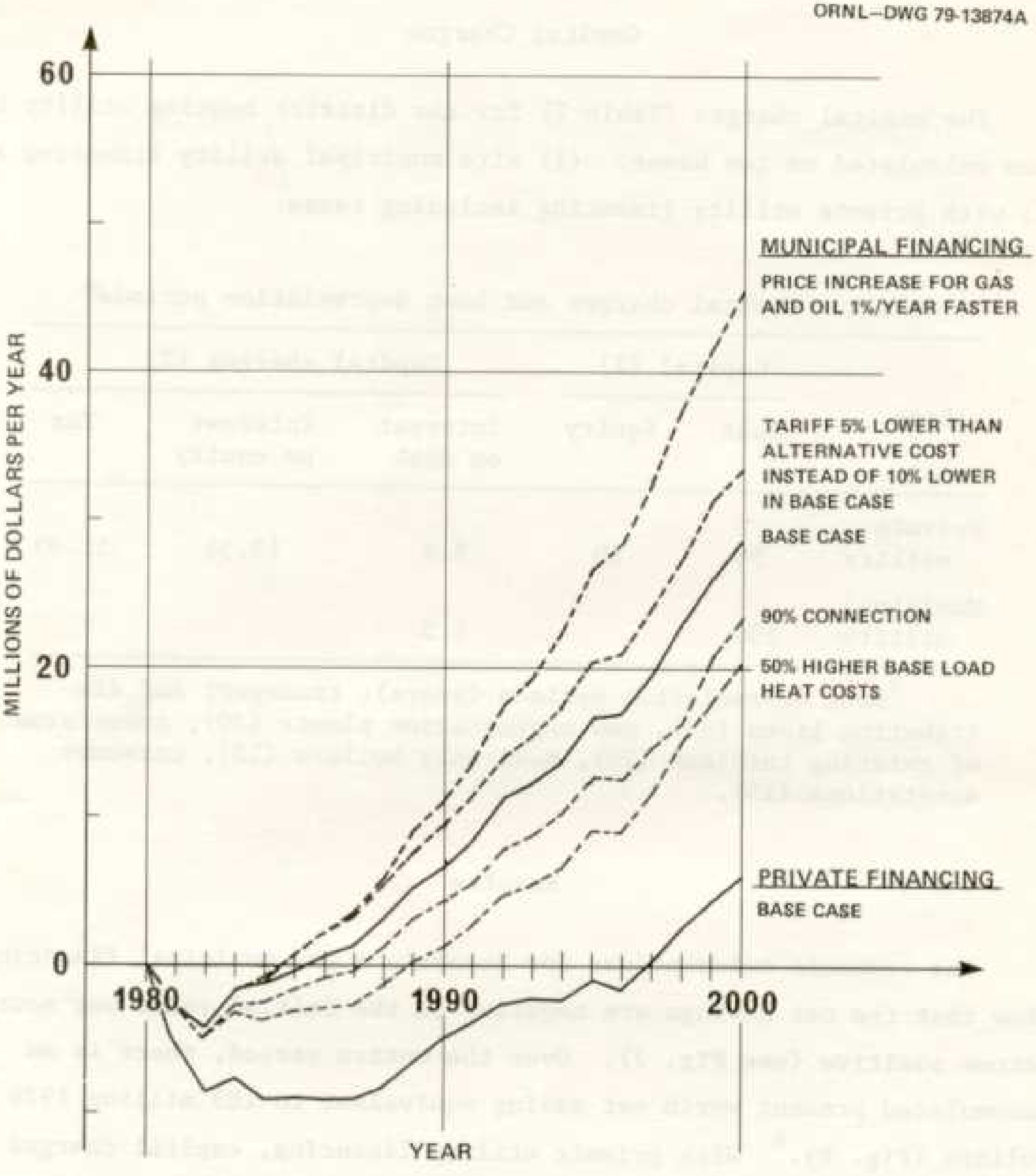

Fig. 7. Annual net savings in 1978 dollars, Scenario A.

respectively (Fig. 9). The savings are -\$151 million and -\$118 million for private utility financing and +\$171 million and +\$201 million for the intermediate case of private utility financing for production plants and municipal utility financing for distribution systems. Any significant positive net savings could be used to lower the rate charged for heat, thereby making the district heating system even more attractive to the customer when compared with the oil and gas alternative.

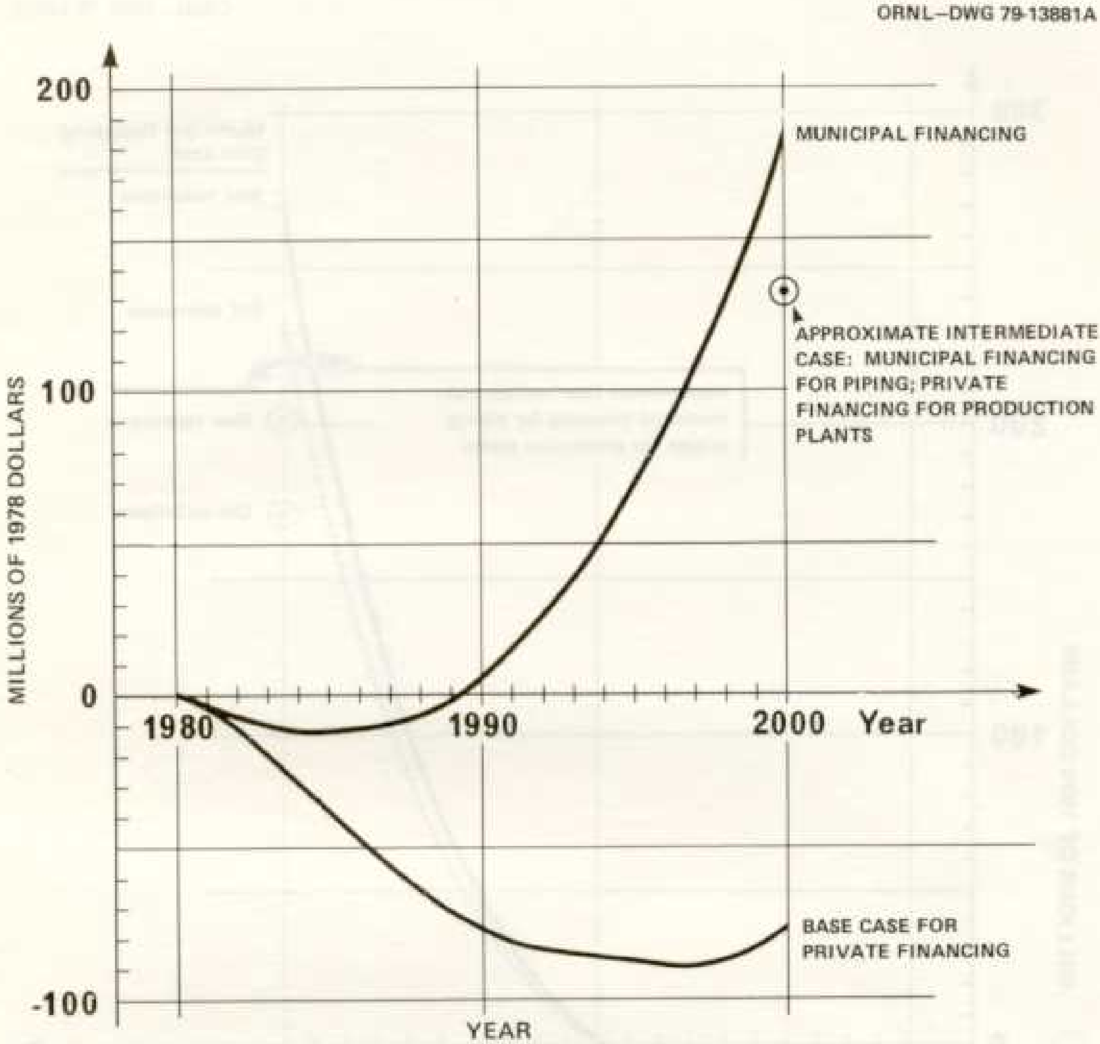

Fig. 8. Accumulated present worth of net savings for base case, Scenario A.

Sensitivity to Variations in Assumptions

The influence of different assumptions in the economic calculations has been evaluated (Table 3). For example, it is assumed that piping costs have been evaluated conservatively compared with the costs that would result if European experience were fully utilized. A 20% reduction in this cost would increase the accumulated net saving by about \$44 million, and a 1%/year faster rise in fuel costs would increase the accumulated net savings by \$125 million.

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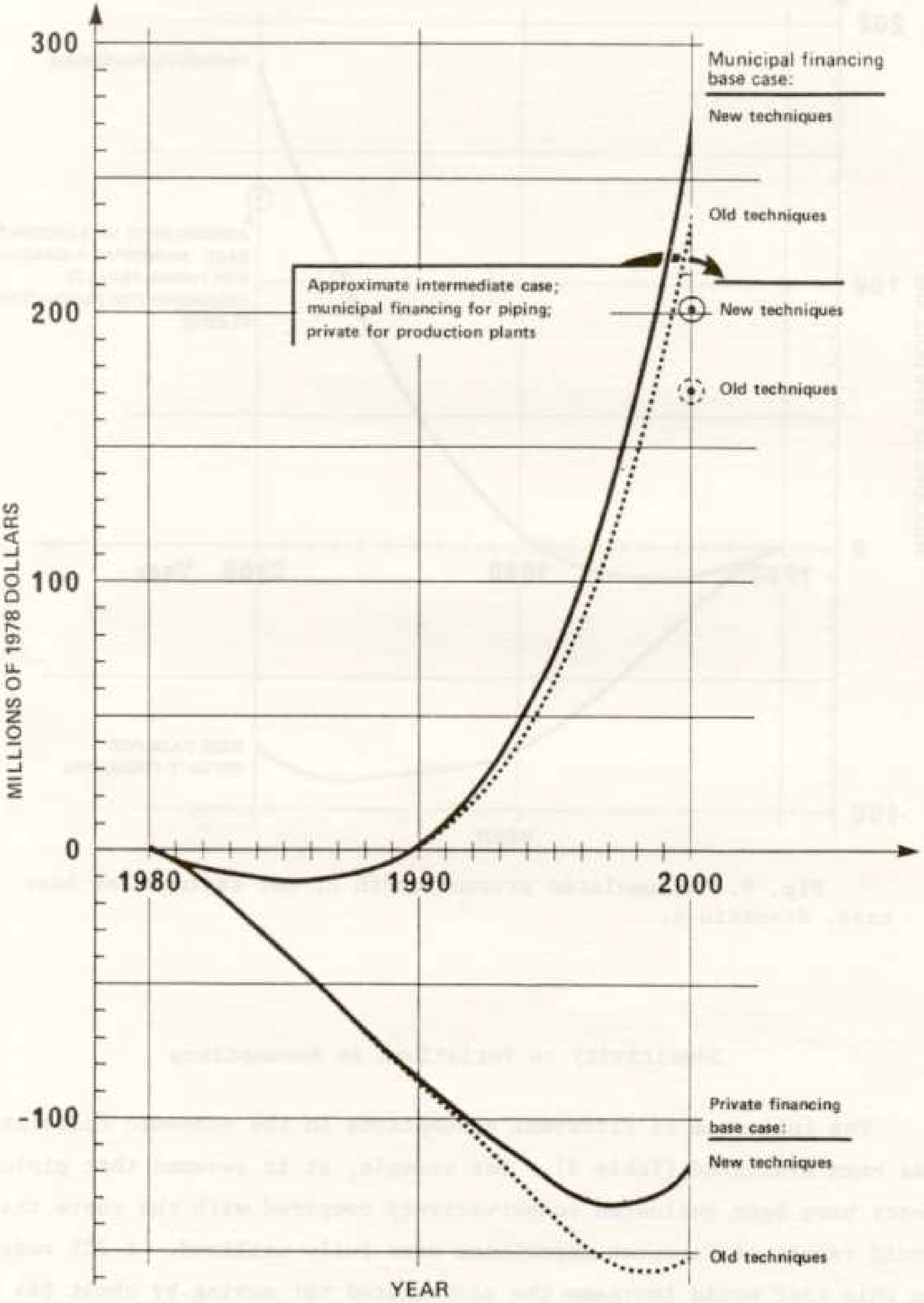

Fig. 9. Accumulated present worth of net savings for Scenario B.

Table 3. Sensitivity of net accumulated savings (millions of 1978 dollars) to changes in assumption, Scenario A

	Net accumulated saving		Change from base case	
	Municipal finance	Private utility finance	Municipal finance	Private utility finance
Base case	182.8	-76.5		
20% lower transmission and distribution costs	227.2	-32.5	+44.4	+44.0
90% connection without change in transmission and distribution costs[a]	127.2	-103.1	-55.6	-26.6
50% of building conversion costs charged to district heating system (instead of 60%)	189.6	-62.2	+6.8	+14.3
1%/year faster oil and gas cost increases	308.1	-13.7	+125.3	+62.8
50% higher base-load energy costs (coal)	81.3	-131.8	-101.5	-55.3
District heating rate at 5% below alternative fuel cost (instead of 10%)	234.3	-48.7	+51.5	+27.8
Includes the effect of property taxes (4.5% for the private utility finance)		-133.3		-56.8
Extends the economic analysis another 10 years for a total of 30 years	501.0	11.88	+318.2	+88.4

[a]Pessimistic assumption because transmission and distribution systems would be cheaper with 90% connection.

One of the potential benefits excluded in the analysis is the influence of a deferment of investments. This could be realized by connecting the low-pressure part of the existing steam district heating system in St. Paul to a hot water system via a heat exchanger producing low-pressure steam and then converting the system to water as the existing system becomes obsolete.

The variations in assumptions produce increases or reductions in the calculated accumulated net savings compared with the base cases. However, the base cases are assumed to represent a reasonable assessment with some conservatism of what really can be achieved (Table 4).

Table 4. Simplified assumptions that tend to give conservative (+) or optimistic (-) results compared with expectations, Scenario A

Assumption	Conservative assumptions	Optimistic assumptions
Heat-only boilers		
Neglect to use existing boilers at 3rd Street plant in St. Paul, at larger industries, and in larger buildings	+	
Assumption that sites can be found for new oil-fired boilers at all major line junctions		-
Heat storage		
Neglect of use of heat accumulators to cut daily load peaks and improve flexibility of cogeneration plants	+	
Existing low-pressure steam system		
Neglect to connect St. Paul 8-psi steam system load (about 40 MW) by heat exchanger to delay conversion and new mains	+	

More detailed studies are under way for the cost of converting the existing turbogenerators, for pipe design and cost estimates related to specified districts, and for building conversions that will allow the economic calculations to be refined successively during 1979.

ENVIRONMENT

Environmental effects are being studied separately, but some general observations may be made.

Experience from Swedish cities using mainly oil for heating indicates that district heating greatly improves air quality, particularly sulfur dioxide, at street levels. This improvement is partly due to elimination of low-level emissions and partly due to more complete combustion. In some cases, sulfur dioxide content at street level has been reduced by an order of magnitude. According to the assumptions made in the economic analysis for this study, without district heating, individual buildings would use the cheapest fuel available, which would be oil from the mid-1980s on. If the actual practice is in accordance with this assumption, a major increase in air pollution will occur in the Twin Cities area. However, district heating would restrict this pollution to limited amounts from high power station stacks, thus greatly improving air quality. If gas is used extensively for individual heating, even after the mid-1980s, the impact of district heating on air quality would be reduced, but the economics of district heating would be improved because gas prices are projected to be higher than oil prices.

INSTITUTIONAL ISSUES

Institutional issues are also being addressed separately. The present report emphasizes the importance of defining ownership at an early date, establishing favorable financing methods, at least for the piping systems, and the following:

1. clarifying at an early date permission to continue operation of converted cogeneration plants, bearing in mind the net beneficial effects on environment despite continued emission from these plants;
2. arranging forms of reasonably long-term loans for consumer connection and conversion investments; and
3. devising a rate structure for the sale of heat and other incentives to ensure that practically all consumers will connect to a distribution line once it is available (state and federal measures could help fulfill this goal).

CONCLUSIONS

The overall conclusion of the study is that district heating on a regional basis in the Twin Cities area is technically feasible, that large quantities of the potentially scarce and expensive fuels (natural gas and oil) can be saved, and that air quality can be improved. The economics are judged to be viable provided a suitable method of financing is used for the transmission and distribution systems.

The study should be complemented by more detailed engineering designs before the scheme can be implemented.

Much of the information and the methodology used is applicable also to other cities in the United States, though individual studies are necessary to establish the economics in each case.

OVERALL FEASIBILITY AND ECONOMIC VIABILITY FOR A DISTRICT HEATING/NEW COGENERATION SYSTEM IN MINNEAPOLIS—ST. PAUL

1. BACKGROUND

In most cities of the United States, natural gas and oil supply the bulk of space heating and domestic hot water demand. Natural gas supplies, however, are not keeping up with demand, and reserves of both natural gas and oil are limited to a few decades of use both nationally and worldwide. Therefore, the goals of energy conservation and conversion to other fuels are matters of global and national urgency.

These goals can be realized to a great degree by district heating (DH), whereby heat is distributed from a limited number of large production plants to a vast number of heat consumers by a system of hot water pipes (or steam pipes for older systems). Such large production plants can run on fuels impractical for use in small domestic plants — for example, coal and uranium, the fuels for which potentially the biggest reserves exist — or they can run on refuse. Also, heat otherwise expelled to the atmosphere or to rivers from industrial processes or power plants can be utilized, and at some future date so can heat from the sun. Thus, more efficient use of more abundant energy sources is possible. To achieve the major benefits from such fuels requires substantial investments in piping networks and production plants. Therefore, an overall economic analysis is needed.

In Europe after about 1950, the use of DH expanded rapidly. In most cases, hot water replaced the steam used in older systems as a distribution medium. In Sweden, all fairly large cities (a total of about 70) now use DH systems to supply the central urban areas and denser suburbs, and the 12 largest ones use reject heat from cogeneration plants. Today, more than half of all apartments, a high percentage of commercial buildings, and a few houses use DH. Characteristic features of the approach in Sweden are the use of hot water as the distribution medium (for reasons discussed in Sect. 5.1) and a gradual expansion of the system and the load that allows each part of the system to begin earning revenue as soon as possible. Prefabricated pipes and components have been used increasingly to minimize site work and overall costs. Large regional schemes are being seriously considered. These consist of entire major urban areas such as greater Stockholm or greater Gothenburg or of groups of cities such as the four cities in southern Sweden supplied by a single interconnected network.

The thought that this approach might prove to be equally interesting for the United States led to contacts between Studsvik (formerly AB Atomenergi), the Department of Energy (DOE) (formerly the Energy Research and Development Administration), and Oak Ridge National Laboratory (ORNL) during 1977. The end result was a proposal to study techniques of introducing DH on a large regional scale in a suitable metropolitan area in the United States. After further contacts with the authorities in several cities and states, the Twin Cities area, Minneapolis-St. Paul, was selected as the site for the study; ORNL was given the overall responsibility for coordinating data contributions from various groups; and Studsvik was designated as the subcontractor responsible for carrying out the basic study. The Minnesota Energy Agency (MEA), the utilities [the Northern States Power (NSP) Company and Minnegasco], and local consultants became involved.

The study, which began in April 1977 and was completed in April 1979, concentrated on the following:

1. assessment of the heating loads that could be connected over a 20-year period;
2. provision of alternative outlines for connecting the loads and supplying them by cogeneration plants and peak-load boilers;
3. examination of the overall economics for these plans with alternative methods of financing the investment.

The primary objective was to obtain an overall assessment of DH rather than to develop a step-by-step plan for the network based on detailed economic and engineering calculations.

The study proceeded in parallel with more in-depth studies of particular issues such as detailed piping network plans in central St.

Paul and cogeneration plant conversion cost studies by the turbine manufacturers (both sponsored by NSP), an energy source study for a new cogeneration power plant, an institutional issues study coordinated by MEA and ORNL, and an environmental impact study by ORNL and MEA. These in-depth studies were not completed or analyzed in time to have their results incorporated into this report.

2. THE TWIN CITIES AREA

The Twin Cities area contains two metropolises, Minneapolis and St. Paul, about 7 miles apart (see Fig. 2.1). These are surrounded by a region of industrial sites and residential housing that links the areas into one practically continuous metropolitan region. About 0.8 million people live within the two cities' boundaries, but, when nearby suburbs are included, the population exceeds 1 million. This large population, along with the cold climate (more than 8000 Fahrenheit degree-days), gives rise to a large heat demand. Appendix A gives a more detailed account of the population and climate.*

The vast majority of the heat demand is presently satisfied by natural gas; however, for customers using large amounts of natural gas, supplies have been partially replaced by oil during the winter months. Three small steam-based DH systems exist in the area: an old one in downtown St. Paul [60 MW(t)], a fairly new one in downtown Minneapolis [about 80 MW(t)] that includes some district cooling, and one at the University of Minnesota [about 125 MW(t)] that also includes some cooling. All use steam as the distribution medium and none use cogeneration, although cogeneration has been proposed for the university. Presently, mainly gas and oil are the fuels used for DH, although some conversion to coal is taking place for the St. Paul and university systems.

There are two fairly large coal-fired electric generating stations within the city boundaries, High Bridge for St. Paul and Riverside for Minneapolis (Fig. 2.1). A third station, Black Dog, is located south of Minneapolis, and several newer coal-fired and nuclear plants are at various distances outside the metropolitan area. The closest of these is King, 17 miles from downtown St. Paul, which is one possible site for another new unit.

This brief account indicates that the following attributes make the Twin Cities area a good candidate for a regional DH system:

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*All appendices appear inside back cover on microfiche.

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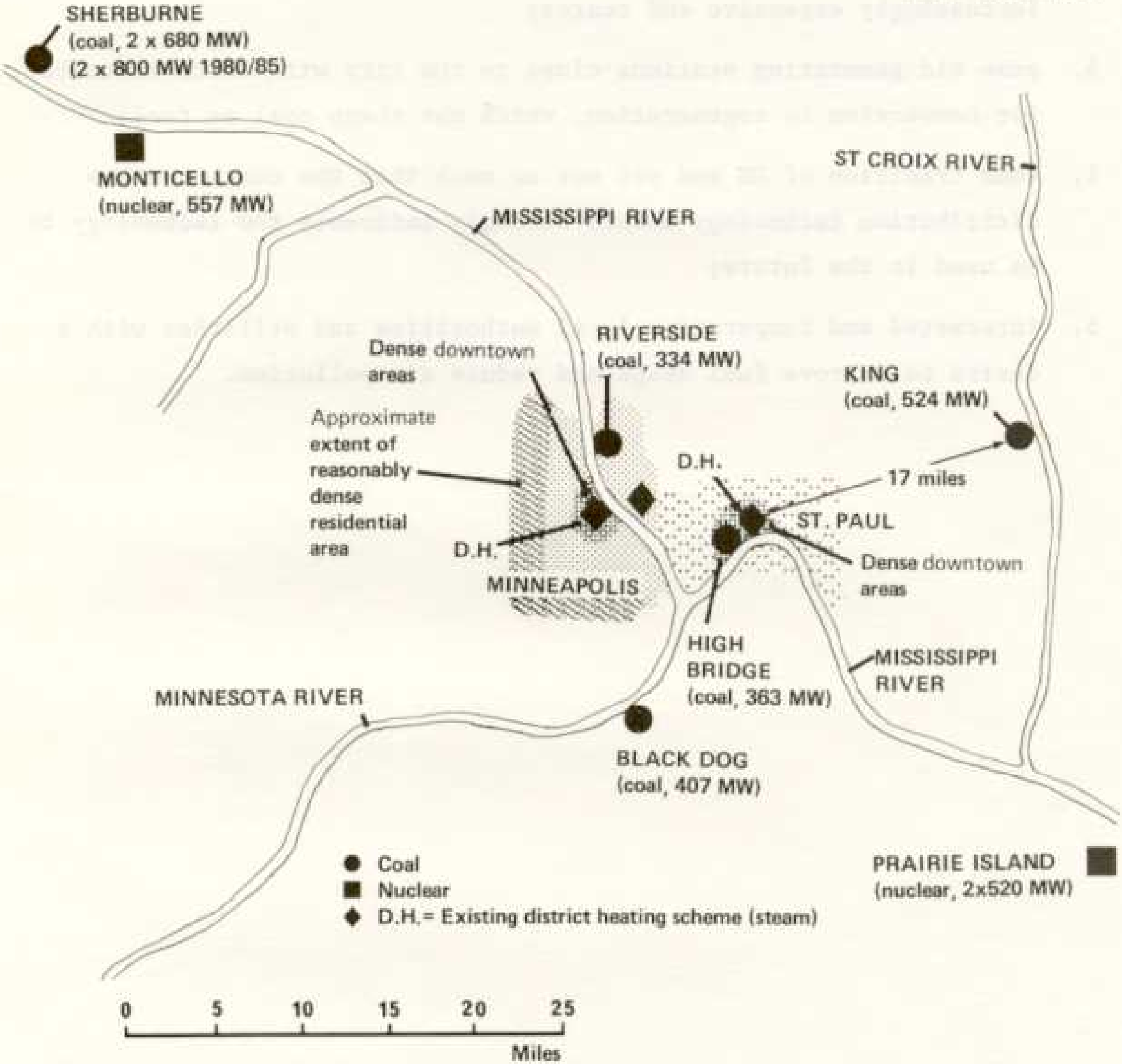

Fig. 2.1. Area map of existing steam-electric power plants.

1. a cold climate and a city structure that is well adapted to DH and has a large potential heat load;
2. the present use of fuels (natural gas and oil) that will become increasingly expensive and scarce;
3. some old generating stations close to the city with units suitable for conversion to cogeneration, which use cheap coal as fuel;
4. some tradition of DH and yet not so much that the current steam distribution technology should strongly influence the technology to be used in the future;
5. interested and cooperative local authorities and utilities with a desire to improve fuel usage and reduce air pollution.

3. HEAT LOADS AND DISTRICT HEATING AREAS

Before economic calculations can be made, a suitable area must be defined. This area is often densely populated and within a specified boundary. It must be large enough to permit the calculation to compare the economic limit for DH with that of alternative heating methods. The area should be divided into subareas where the heat demand can be estimated. The subareas are defined on the basis of an inventory of the heat load. A considerable part of the problem is to estimate the heat load, which gives the size of the DH system.

The Twin Cities area has been subdivided into 43 DH areas, or districts, encompassing homogeneous building types and natural geographical boundaries. The subdivision and the estimate of the energy demand were mainly based on records of natural gas consumption for 1976 and on building classifications according to zoning maps. The gas consumption figures have been corrected for gas supply curtailments and for gas used for purposes other than space heating and domestic hot water. Each district has been classified according to type of building and heat load density.

No allowance has been made for the influence of new developments between now and the year 2000, partly because the effect of additional housing would be counteracted to some extent by expected increased attention to fuel conservation and partly because the percentage of consumer participation is uncertain. The modern steam system in downtown Minneapolis and that at the university have not been included in either Scenario A or Scenario B. However, these probably could be connected to a large hot-water-based system both as base-load consumers and as peak-heat producers to benefit all parties involved.

The areas considered most economical for DH have been grouped under Scenario A. These areas account for about 50% [$\sim$2600 MW(t)] of the total heat load in the two cities concentrated in 30% of the gross land area. Addition of the remaining areas gives Scenario B, which covers (with 100% connection) almost 90% [$\sim$4600 MW(t)] of the heat load in about 70% of the area. The average heat load is 31 MW(t)/km^2 for Scenario A, 24 MW(t)/km^2 for Scenario B (100% connection), and 19 MW(t)/km^2 for the entire area.

Only 70% of the maximum possible additions for Scenario B is assumed to be connected; this gives a total load for Scenario B of about 4000 MW(t) (see Table 3.1).

Appendix B gives a detailed description of the derivation of the load figures. A short summary of the principles used and results obtained is included here.

Table 3.1. Areas and heat load densities

Type of area	Heat load [MW(t)] Minneapolis	St. Paul	Total
Very dense downtown areas with existing DH systems [>70 $MW(t)/km^2$]	206	60	266
Other customers needing special consideration	100	191	291
Dense downtown areas [>50 $MW(t)/km^2$]	313	244	557
Medium-density districts with commercial buildings and multi-family apartment buildings [20–50 $MW(t)/km^2$]	1000	286	1286
Residential areas with one- to four-family houses [>10 $MW(t)/km^2$]	370	195	565
Total load, including special customers	1987	976	2963
Scenario A	1781	840	2621
Additions for Scenario B			
Major users needing special consideration	48	51	80
Residential areas	1105	826	1931
Maximum additions	1153	877	2030
Scenario B (potential)	2934	1717	4651
Scenario B with 70% connection of maximum additions	2588	1454	4042

3.1 Heat Loads

To assess the technical and economic outcome of a DH project, a sufficiently good estimate of the expected heat load in power, energy, and load density is needed. In countries like Sweden, where DH has been used for a number of years, rules for such estimates have been established. However, applying those rules directly to the United States (Twin Cities) presents some uncertainty because of the different climate and life-style, notably in housing. Therefore, much effort has been expended to estimate the heat load from data specific to the study area. The main data available document consumption of natural gas, of steam from existing steam-based DH systems, and of electricity. Climatological data are also available.

Since gas deliveries were curtailed because of a shortage during the year studied (1976), corrections based on weather data (degree-days) and information from the local gas vendors (NSP and Minnegasco) were made to the gas sales data to estimate the total demand for each area. The total additions made in this way amount to about 50% of the total interruptible demand. The energy demand that might be met by a hot water DH system was calculated by discounting the demand of some large consumers assumed to use gas for purposes for which hot water would not be a viable alternative and then by applying boiler efficiencies ranging between 60% and 75% to the remaining demand. The energy demand was converted to a power demand for gas districts by dividing it by a load duration and then redistributing it to correspond to DH areas.

For the existing steam system, the demand was estimated mainly from steam production and sales figures. Some other large energy users were also given special attention (see Table 3.2).

The load duration (load factor or utilization time) is important because a high load duration will permit better utilization of the network, and the fraction of less expensive energy from base-loaded power plants will increase with increasing load duration.

The load duration was estimated from various sources of information, such as gas sales data, steam sales, building surveys, and a computer

Table 3.2. Assumed maximum connection of special customers

Consumer	Code[a]		Estimated demand[a]			Estimated duration (hr)	Notes
	Gas[b]	District heating	Gas (MMCF)	MTHW[c] (GWhr)	MTHW [MW(t)]		
Arsenal	?	[d]	786	(170)	(69)	2465	Location not known
Asphalt plant	3		42				Asphalt
Fleischmann	16	M6	326	71	29	2465	
GAF, Inc.	20	M7	240	52	9	6000	
Hoerner-Waldorf	0	(P11)	3802	(818)	(136)	6000	Paper mill
Lawrence Laundry	24	M15	83	18	6	3000	Steam?
Minneapolis Central Heating Co.	12	(M1)	1124	(280)	(80)	3500	Steam
Metropolican Medical Center	12	M3	562	120	34	3500	Steam?
3M, 7th Street	I	(P2)	920	(215)	(36)	6000	Process?
3M, Conway Street	R[e]	P17	1430	308	51	6000	
Mt. Sinai Hospital	13	M10	84	18	6	3000	Steam?
North Star Steel	Q[f]	(P18)	960	(206)	(34)	6000	Process
Northwest Airlines	55	M18	330	71	29	2465	
Olympia Brewery	I	P2	1120	247	41	6000	Brewery
Schmidt's Brewery	A	P5	410	90	15	6000	Brewery
Schweigert Meat	23		73				
St. Paul District Heating System	U[g]	P1	639	120	60	2000	
St. Mary's Hospital	6	M4	219	47	16	3000	Steam?
Trumbull Asphalt	19		102				
University of Minnesota, Farm Campus	?[h]			(204)	(51)	2465	
University of Minnesota, Minneapolis Campus	9	(M2)	1963	(486)	(126)	3850	Steam
Veterans Hospital	4	M18	218	47	19	2465	Steam?

model using climatological and building data. The computer-generated load curve (Figs. 3.1 and 3.2) has been adopted for most demand categories. The annual energy consumption divided by the peak demand gives a load duration of 2465 hr, as computed from weather data for 1976. These data were used mainly because gas sales data can be compared easily with the weather data and because no data for a "typical year" were available at the time of the study.

Weather data averaged over a number of years would not be appropriate because such averaging smoothes out all weather variations, particularly those over short periods of time. The year 1976 was slightly warmer than average (7846 compared with the normal 8159 degree-days), but most of this variance occurred during spring and summer. The total number of degree-days for the first and last three months agrees quite well with the normal values (7069 compared with 7021 degree-days). Numerical values are given in Appendix B. The load duration at the central plant(s) will probably be somewhat lower than this value in the first few years, when, primarily, only downtown areas have been connected. As the system is expanded, the load duration will increase both because of diversification and because of connection of residential areas with higher load duration. If a considerable portion of the cooling demand were included, the duration could increase by hundreds of hours.

No cooling loads have been included except for the very small (if any) amount now satisfied by gas or steam from the St. Paul DH system. Cooling loads have been excluded from the present study because the survey of existing buildings showed that very few buildings have absorption chillers that can be converted relatively easily to operate on energy supplied by hot water from a DH system. The system chosen allows such chillers to be supplied in this way or new buildings to be supplied with new absorption chillers, provided that water temperatures are maintained somewhat higher in summer than would otherwise be required. Future studies should establish whether or not the overall economics of the system would be improved.

The load duration of 2465 hr has been used to convert from annual deliveries of natural gas to coinciding peak demand for subareas. This demand has then been used to determine the size of the main transmission

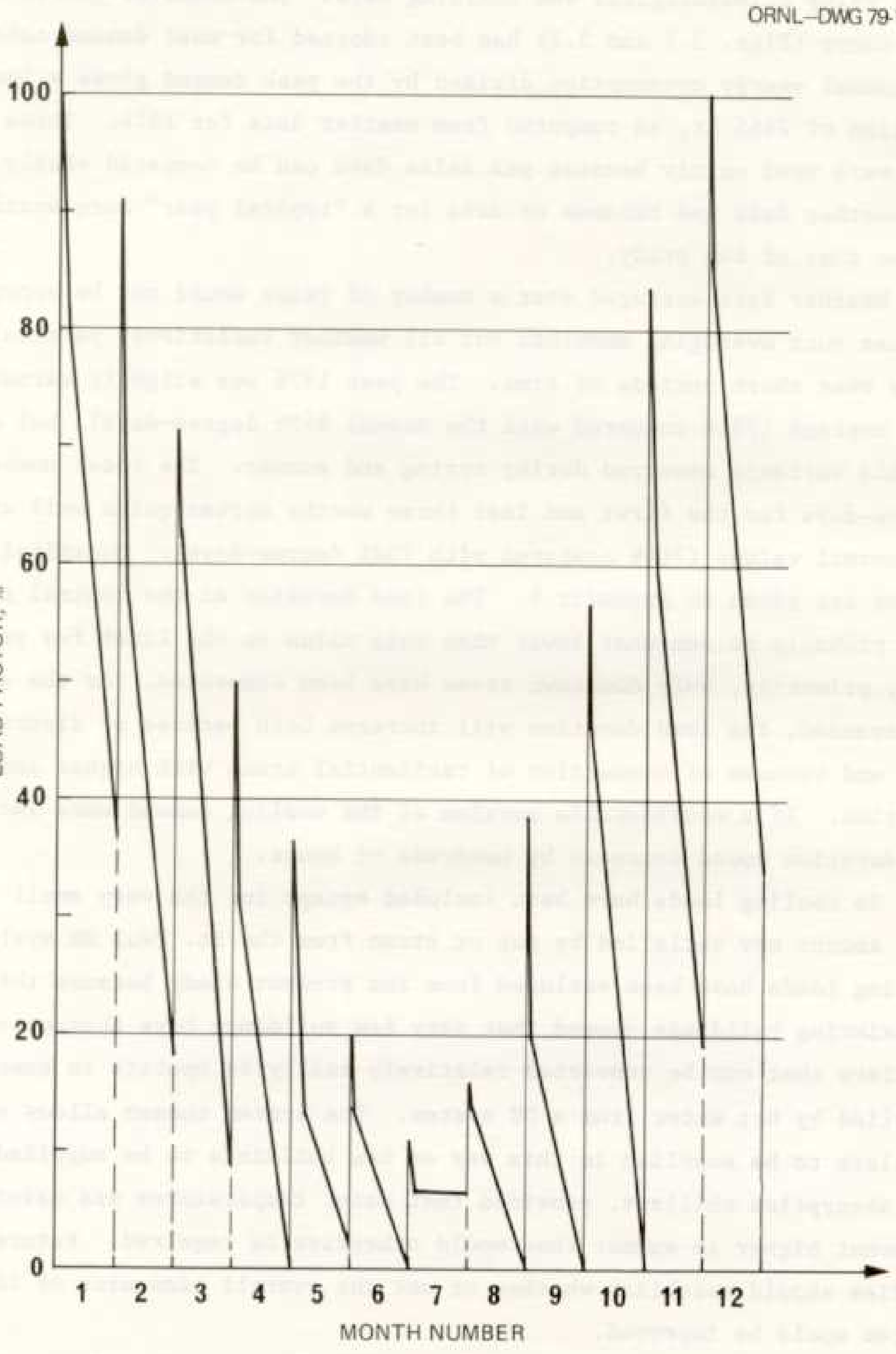

Fig. 3.1. Adopted monthly load duration curves for heat and domestic hot water. Computed from actual temperatures in Twin Cities, 1976.

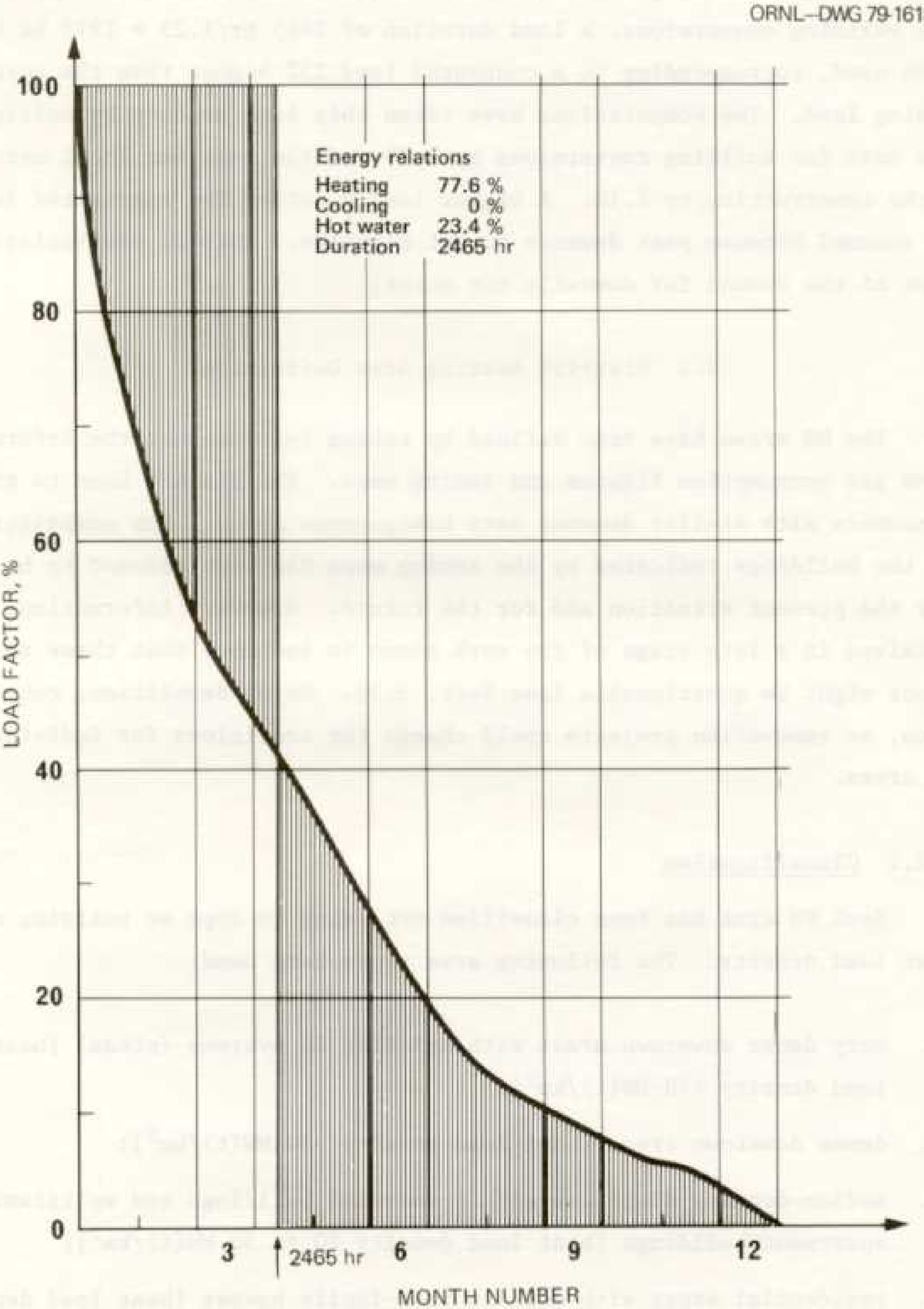

Fig. 3.2. Adopted annual load duration curve for heat and domestic hot water.

lines. In determining the cost of the local distribution networks and the building conversions, a load duration of 2465 hr/1.25 = 1972 hr has been used, corresponding to a connected load 25% higher than the coinciding load. The computations have taken this into account by multiplying the cost for building conversions by 1.25 and the cost for local networks construction by 1.10. A higher load duration for aggregated loads is assumed because peak demands do not coincide. This is particularly true of the demand for domestic hot water.

3.2 District Heating Area Definition

The DH areas have been defined by taking into account the information from gas consumption figures and zoning maps. The aim has been to group consumers with similar demands into homogeneous areas. The composition of the buildings indicated by the zoning maps has been assumed to be valid for the present situation and for the future. However, information received in a late stage of the work seems to indicate that these assumptions might be questionable (see Sect. 3.3). Major demolition, construction, or renovation projects could change the conditions for individual DH areas.

3.2.1 Classification

Each DH area has been classified according to type of building and heat load density. The following area types were used:

1. very dense downtown areas with existing DH systems (steam) [heat load density >70 MW(t)/km^2];
2. dense downtown areas [heat load density >50 MW(t)/km^2];
3. medium-density districts with commercial buildings and multifamily apartment buildings [heat load density 20 to 50 MW(t)/km^2];
4. residential areas with one- to four-family houses [heat load density >10 MW(t)/km^2].

3.2.2 Zoning maps

Zoning maps of both Minneapolis and St. Paul divide the towns into subareas classified by intended usage. The main subdivisions are residential and nonresidential areas. These areas are then subdivided according to building size, lot size, etc. The notation and definition for each class differ for the two towns.

The city of Minneapolis is zoned into nine districts: residence, general residence, office-residence, neighborhood business, community business, central business, light manufacturing, limited manufacturing, and heavy manufacturing. The classifications and definitions for the residential areas according to ref. 1 are shown in Table 3.3.

The city of St. Paul is zoned into six districts (one-family houses, two-family townhouses, multifamily houses, business, industrial, and special areas) and then subdivided into classes.

The classifications and definitions according to ref. 1 for residential areas are shown in Table 3.4. The overall classification system for both cities is shown in Table 3.5.

3.3 Comments

Because the heat load is the basis for the whole project, the figures obtained from the gas sales figures must be verified by some alternative method. One method could be to make an inventory of the floor space for some selected areas and compute the expected heat load, either by "rule of thumb" or by a computer program using actual climatological parameters, heat resistance of walls, and so forth.

We received a map similar to the zoning map but with more detailed information. This map is titled "Existing Land Use" (the publisher was not indicated but was probably the Metro Council or the city of St. Paul). The correspondence between this new map and the zoning map of St. Paul is not too good. The zoning maps seem to give upper limits of the building (or house) sizes instead of actual sizes. Therefore, some of the assumptions based on the zoning maps may not be as valid as expected. If, or when, the "Existing Land Use" map is available for a larger area (the version sent to us covers only the part of St. Paul between Case

Table 3.3. Official classification of residential areas in Minneapolis

Symbol	Class	Lot size		Parking garages per unit	Floor area (ft^2)
		m^2	ft^2		
R-1	Single family	557	6000 (or lot of record)	1 space offstreet if lot ⩾33 ft wide	
R-1-A	Single family	464	5000 (or lot of record)	1 space offstreet if lot ⩾33 ft wide	
R-2-B	Two family	232	2500 per unit	1 offstreet	350 (efficiency)[a] 400 (1 bedroom)
R-3[b]	Multifamily	232	2500 per unit	1 offstreet	350 (efficiency) 400 (1 bedroom)
R-4	Multifamily	139	1500 per unit	1 offstreet	350 (efficiency) 400 (1 bedroom)
R-5	Multifamily	84	900 per unit	1 offstreet	350 (efficiency) 400 (1 bedroom)
R-6	Multifamily	37	400 per unit	1 offstreet	350 (efficiency) 400 (1 bedroom)
B-1-1	Office, residential	139	1500 per unit	8 to 9 offstreet	
B-1-2	Office, residential	37	400 per unit	8 to 9 offstreet	
B-1-3	Office, residential	28	300 per unit	8 to 9 offstreet	

[a] Total floor area required, including hallways, is 500 ft^2 per unit for all multifamily zones.

[b] Maximum density ranges from 17 units per acre in the R-3 zone to 145 units per acre in B-1-3 zone.

Table 3.4. Official classification of residential areas in St. Paul

Symbol	Class	Lot size m^2	Lot size ft^2	Parking garages per unit
R-1	Single family	899	9600	2 offstreet
R-2	Single family	669	7200	2 offstreet
R-3	Single family	557	6000	2 offstreet
R-4	Single family	464	5000	2 offstreet
RT-1	Two family (residence)	325	3500/unit	1.5 offstreet
RT-2	Two family (townhouse)	204 307 409	2200 (1 bedroom) 3300 (2 bedrooms) 4400 (3 bedrooms)	1.5 offstreet
RM-1	Multifamily	167 251 334	1800 (1 bedroom) 2700 (2 bedrooms) 3600 (3 bedrooms)	1.5 offstreet
RM-2	Multifamily	111 167 223	1200 (1 bedroom) 1800 (2 bedrooms) 2400 (3 bedrooms)	1.5 offstreet
RM-3[a]	Multifamily	56 84 111	600 (1 bedroom) 900 (2 bedrooms) 1200 (3 bedrooms)	1.5 offstreet

[a]Maximum density is 73 units per acre.

Street, Isabel Street, Frank Street, and Virginia Street), it might prove a valuable tool in revising the extent of the DH areas. Another important point to verify is the assumption used concerning the largest energy consumers (see Table 3.2).

The extent and content of the DH areas are described below. The boundary lines are not to be regarded as rigid. On the contrary, the local distribution nets of the areas will be tied together by numerous pipes crossing the boundaries and nearby industries, and other larger energy users will be connected by suitable extensions.

3.4 Description of the District Heating Areas

Sections 3.4.1 and 3.4.2 give a description of the DH areas intended to supplement the maps shown in Figs. 3.3 and 3.4.

Table 3.5. General classification of DH areas in the Minneapolis-St. Paul region

Minneapolis	St. Paul
Residence districts	One-family house
R1	R-1
R1A	R-2
R2	R-3
R2A	R-4
R2B	
	Two-family townhouse
	RT-1
	RT-2
General residence districts	Multifamily house
RA	RM-1
R3	RM-2
R4	RM-3
R5	
R5A	
R6	
R6A	
Office-residence districts	
B1-1, -2, -3	
Neighborhood business districts	Business
B2-1, -2, -3, -4	OS-1
B2S-1, -2, -3, -4	B-1
	B-2
Community business districts	B-3
B3-1, -2, -3, -4	B-4
B3S-1, -2, -3, -4	B-5
B3C-1, -2, -3, -4	
B3SP-1, -2, -3, -4	Special
Central business districts	ES
B4-1, -2	P-1
B4S-1, -2, -3	PD
B4C-1, -2	
B4SP	
Light manufacturing districts	Industry
M1-1, -2, -3, -4	I-1
Limited manufacturing districts	I-2
M2-1, -2, -3, -4	I-3
Heavy manufacturing districts	
M3-1, -2, -3, -4	

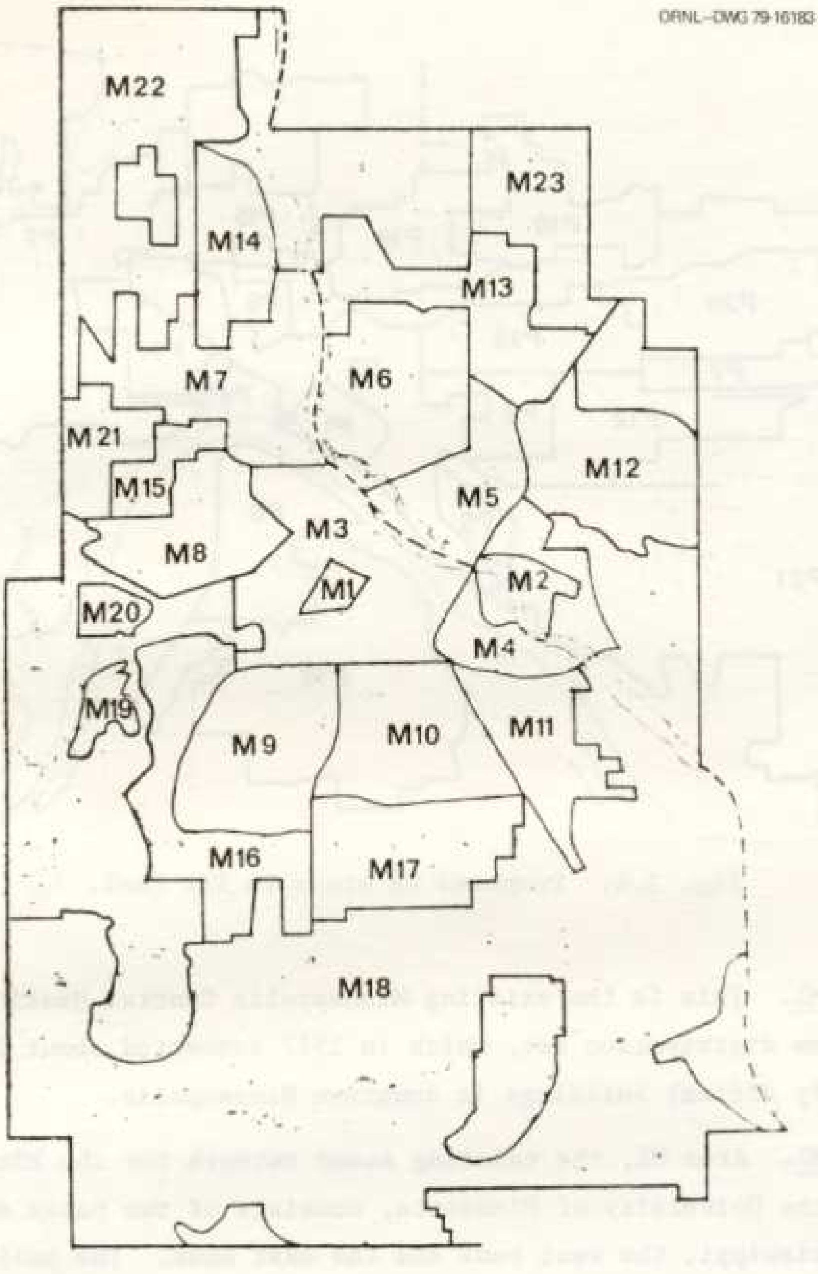

Fig. 3.3. Proposed DH areas in Minneapolis.

3.4.1 District heating areas in Minneapolis

The part of Minneapolis with the highest heat load has been subdivided into 17 areas, M1 through M17. To those have been added the six areas M18 through M23 that cover low-density residential parts of the town. Characteristic data for each area are listed in Table 3.6, and the dimensions of the areas are shown in Fig. 3.3.

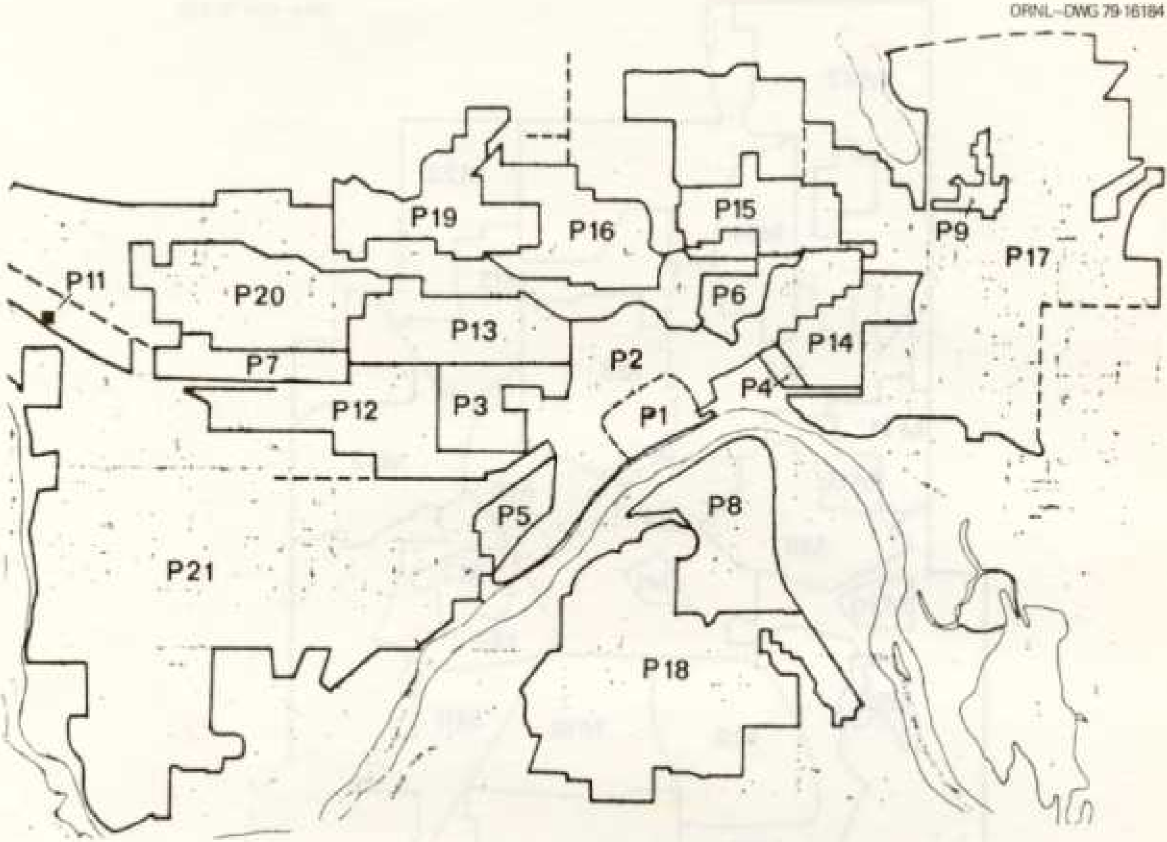

Fig. 3.4. Proposed DH areas in St. Paul.

Area M1. This is the existing Minneapolis Central Heating Company (MCHC) steam distribution net, which in 1977 connected about 23 high-rise (mainly office) buildings in downtown Minneapolis.

Area M2. Area M2, the existing steam network for the Minneapolis campus of the University of Minnesota, consists of two parts on each side of the Mississippi, the west bank and the east bank. The buildings on the west bank (~14 MW) are heated internally by hot water and could easily be connected to a hot water DH system, while only a few buildings on the east bank use hot water internally.

Area M3. This area covers the central southern core of Minneapolis limited by Plymouth Avenue and the Mississippi River to the north, Interstate Highways 35 and 94 to the east and south, and Lyndale Avenue to the west.

Table 3.6. Proposed local networks in Minneapolis, Scenarios A and B

District heating area	Type	Area (km^2)	Maximum load [MW(T)] Total	Nonspecial	Load[a] density [MW(t)/km^2]
			Scenario A		
M1[b]	1		80	0	
M2[b]	1		126	0	
M3	2	5.9	347	313	53
M4	3	3.6	108	92	25
M5	3	2.5	69	69	27
M6	3	5.0	127	98	20
M7	3	4.6	100	91	20
M8	4	3.6	52	52	16
M9	3	4.3	210	210	49
M10	3	4.0	183	177	44
M11	3	2.9	96	96	33
M12	3	6.1	145	145	24
M13	3	3.9	98	98	25
M14	4	2.2	26	26	12
M15	4	1.2	26	20	16
M16	3	4.6	83	83	18
M17	3	3.9	114	114	28
Total			1987	1681	
Total less M1, M2		58.3	1781	1681	29
			Scenario B (100% connection)		
M3-M17[c]		58.3	1781	1681	29
M18	3	40	975	927	23
M19	3	0.6	15	15	25
M20	4	0.6	10	10	17
M21	4	2.5	16	16	7
M22	4	8.3	95	95	11
M23	4	3.6	43	43	12
Total		113.9	2934	2786	24
Total less M3-M17		55.6	1153	1105	20

[a]The load density figures are very approximate.

[b]M1 (Minneapolis Central Heating Co.) and M2 (University of Minnesota, Minneapolis campus) have existing steam systems.

[c]Scenario A.

The central business district with its high-rise commercial buildings covers most of the area. There are substantial manufacturing districts near the borders and also some community business areas. The MCHC serves one part (Area M1) of the district.

Area M4. This area consists of the land on both sides of the Mississippi limited to the south by Highway 94, to the west and the north by Highway 35, and to the northeast by the Great Northern (GN) Railway.

The University of Minnesota dominates the area but is defined as M2. Excluding the campus area, the area mostly contains multifamily houses. There are also some business districts on the east side of the river and some larger heat consumers like hospitals and schools.

Area M5. The area is limited to the east by Highway 35 up to Broadway. The northwestern border is the GN Railroad and to the south the Mississippi River is the natural border. The area consists of limited manufacturing areas along the river, multifamily houses in the central parts, and heavy manufacturing areas in the northern part.

Area M6. This area is situated between Lowry Avenue to the north, Central Avenue to the east, GN Railroad to the south, and the Mississippi River to the west. The area is dominated by general residence districts and multifamily houses. There are some limited manufacturing districts in the south and the west.

Area M7. This area is limited by Lowry and Plymouth avenues to the north and south, respectively, and extends from the Mississippi River to Xerxes Avenue in east-west direction. Some smaller areas are excluded because of lower land utilization. The area is therefore dominated by a general residence district of multifamily houses. Along the rivers, heavy manufacturing districts are included.

Area M8. This area is limited to the south and west by the GN Railway and to the north by the Olsen Memorial Highway, with an extension up to Plymouth Avenue in the eastern part. The district contains areas of medium- to high-density multifamily houses and some manufacturing areas near the railroad.

Area M9. This area is limited to the north by Highway 94, to the east by Highway 35, and to the south by 32nd Street and East Hennepin Avenue. The area is dominated by multifamily houses of high and medium density. There are substantial business areas along the borders of the district and also along certain streets in the middle of the area.

Area M10. The area is limited by Highway 94 to the north, Hiawatha Avenue to the east, Lake Street to the south, and Highway 35 to the west. Land use primarily consists of multifamily houses of high and medium density, with an area containing two-family houses in the center. There are some business districts along border streets.

Area M11. The M11 area is limited by Highway 94 to the north, 30th Avenue to the east, and extends to Bracket Field north of Lake Street. The western border is Hiawatha Avenue. There are mainly multifamily houses of high and medium density, with some manufacturing areas along Hiawatha Avenue.

Area M12. This area is situated between the eastern border of Minneapolis, Highway 35W, and the GN Railway. Predominant land use is manufacturing. Some areas of two-family houses are located in the central part.

Area M13. This area extends from Hillside Cemetery and Highway 35W to Columbia Park and west to the Mississippi River at the Riverside power plant. The area comprises the rest of the multifamily houses of medium and low density, and the border is drawn at the single-family houses.

Area M14. This area is limited by the Mississippi River to the east, Camden Park to the north, Givard Avenue to the west, and 26th Street to the south. There are mainly two-family houses in the area and some limited manufacturing along the river.

Area M15. This small area east of Wirth Park between Golden Valley Road and Olsen Memorial Highway consists of two-family houses.

Area M16. This area of two-family houses east of Lake Calhoun and Lake of the Isles surrounds area M9.

Area M17. This two-family housing area south of Lake Street down to 38th Street includes some multifamily houses in the southern part and smaller businesses along some crossing streets.

Area M18. This large area occupying most of Minneapolis south of 38th Street contains mainly residential houses, with some small commercial buildings along the main streets. It also contains some fairly large lakes surrounded by parks.

Area M19. This small area located between Lake of the Isles, Cedar Lake, and Kenwood Park contains mostly residential houses and a school.

Area M20. This small area north (or northeast) of Cedar Lake contains mostly homes and some small commercial buildings.

Area M21. This area between Golden Valley Road and Olsen Highway at the border to Golden Valley contains mostly residential houses.

Area M22. This area covers the northwest corner of Minneapolis, approximately south to Lowry Avenue and east to Fremont Avenue (southern part) or Lyndale Avenue (northern part). It consists mainly of residential houses, with some scattered small commercial buildings, a large cemetery, and some large parks.

Area M23. This area, which covers the northeast corner of Minneapolis, is limited on the south by 22nd Avenue and on the west by Central Avenue. It contains mainly residential houses, with some scattered, small commercial buildings.

3.4.2 District heating areas in St. Paul

The part of St. Paul with the highest heat load density has been divided into 15* DH areas denoted as P1 through P16. To those have been added five districts (P17 through P21) that cover large lower density residential parts of St. Paul and two of its closest suburbs. The enumeration approximately follows a possible future order of connection to a DH network. Characteristic data for each area are listed in Table 3.7. The areas are shown in Fig. 3.4.

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*Area P10 appearing in earlier reports has been included in area P17.

Table 3.7. Proposed local networks in St. Paul, Scenarios A and B

District heating area	Type	Area (km^2)	Maximum load [MW(t)] Total[b]	Nonspecial	Load[a] density [MW(t)/km^2]
			Scenario A		
P1	1	0.8	60	0	75
P2	2	4.7	285	244	51
P3	3	1.9	50	50	26
P4	4	1.0	15	15	15
P5	3	0.8	35	20	25
P6	3	1.2	32	32	27
P7	3	1.0	40	40	40
P8	3	1.9	69	69	37
P9	3	1.2	29	29	24
P11[c]	3		46[d]	46	
P12	4	3.3	47	47	14
P13	4	2.8	51	51	18
P14	4	1.5	21	21	14
P15	4	2.0	21	21	10
P16	4	2.6	40	40	16
Total			840	725	
Total less P1, P11		26	735	679	26
			Scenario B (100% connection)		
P1-P16[e]		26	840	725	26
P17	4	17	256	205	12
P18	4	8	98	98	12
P19	4	2.3	40	40	17
P20	3	3.2	75	75	23
P21	4	21.5	408	408	19
Total		78	1717	1551	20
Total less P1-P16		52	877	826	16

[a] The load density figures are very approximate.

[b] Some large-volume energy consumers needing special consideration are included.

[c] Former area P10 now included in P17.

[d] Excluding Hoerner-Waldorf [136 MW(t)].

[e] Scenario A.

Area P1. This area is defined as the part of St. Paul now connected to the St. Paul steam DH system, that is, the central part of downtown St. Paul. It consists mainly of commercial and office highrise buildings (B-4) and has an old steam network that will probably have to be replaced. The 3rd Street plant steam production in 1976 (estimated to be 554×10^6 lb) corresponds to an energy demand of 187 GWhr [88 MW(t)], and the steam sales (442×10^6 lb) to the customers correspond to 120 GWhr [60 MW(t)]. In this report, we assume that the steam distribution system is gradually replaced by a hot water system with a consumer demand of 120 GWhr [60 MW(t)].

Area P2. This area is the area studied by Main,[2] excluding the area south of the Mississippi and the existing St. Paul DH system. It consists of a strip that extends from High Bridge power station to the northwest, including part of downtown St. Paul, and follows East 7th Street up to its bend to the east. The area will have to be subdivided later into three to five smaller parts. The mixed (RT-2, RM-2, RM-3, B-2, B-3, B-5, OS-1, I-1, I-2, I-3) character of the area makes it hard to estimate the cost of the distribution network. It contains some of the major consumers of energy (3M Company, Olympia Brewery, the state capitol, etc.).

Area P3. Area P3 is defined as an almost quadratic area between University Avenue (both sides), Holly Avenue, Grotto Street, and Virginia Street, plus a smaller area between the technical vocational school and University Avenue. It contains mainly multifamily (RM-2, RT-1, R-4) buildings (47 MW) and some commercial (B-2, B-3) buildings (3 MW) mostly along University Avenue but also along Selby Avenue and St. Anthony Avenue.

Area P4. This small triangular area between 6th Street to the northeast, the continuation of Arcade Street to the south, and Highway 94 contains a mixture of small business and small multifamily buildings (B-2 and RM-2).

Area P5. This area between Highway 35E and the industrial area west of High Bridge is centered along 7th Street West, where there are some small commercial buildings (B-2 and B-3, assumed peak heat demand of

3 MW). The rest of the area contains two-family (RT-2, some RT-1, and R-4) and small multifamily buildings (RM-2 and RM-3). It also contains one of the major energy consumers, Schmidt Brewing (90 GWhr, 15 MW) near the southwest corner of the area.

Area P6. This area north of district P2 and east of the railway crossing Highway 35E east of Oakland Cemetery extends northward approximately to York Avenue and sometimes to Jenks Avenue. It contains mainly multifamily buildings (RM-2) mixed with some commercial buildings (B-3) along Payne and Arcade avenues.

Area P7. This narrow strip between University Avenue (both sides) and Highway 94 from Grotto Street to Fairview Avenue contains many medium-sized businesses and industries (B-2, B-3, I-1, and OS-1) mixed with multifamily buildings (RM-2 and RM-3). Because the area contains only major customers, the cost of the local network will be low.

Area P8. This is an area south of the Mississippi River roughly between the St. Paul downtown airport, Page Street, Winslow Avenue, and the river. It consists of two to three subareas with different characteristics. The northern part, which is also treated in the report by Main,[2] is dominated by small- and medium-sized industries (I-1 and I-2). The ground is quite flat, built up by river sediments, and is not suited for tunnels. A major energy consumer in this area is American Hoist (10 MW). Another area on the hill and hill slopes consists of multi- and two-family buildings (RM-2, RT-1) mixed with some small- or medium-sized commercial buildings (B-1, B-2, and B-3). The commercial buildings are located mainly along Concord Street and constitute about 7 MW of the total 82 MW. The largest of these is Wilder Foundation, with 3.7 MW.

Area P9. This small area southeast of Lake Phalen, roughly between Prosperity, East Magnolia, and Germain streets, consists mainly of multifamily buildings (RM-1 and RM-2) with some business areas (B-2 and B-3).

Area P10. This area existed in earlier reports but is now included in area P17.

Area P11. This district consists of Hoerner-Waldorf and some other business and industrial consumers (I-1, I-2, B-3) along University Avenue from the bend of the avenue in St. Paul up to the border between St. Paul and Minneapolis. A main question is whether Hoerner-Waldorf can be connected or not.

Area P12. This almost triangular area between Highway 94 and Portland Avenue, enclosed by Snelling Avenue, the Chicago-Milwaukee Railroad, and Grotto Street, consists mainly of two-family houses and some multifamily (RM-2, KI-1) and commercial (B-2, B1-3) buildings. The commercial (B-2 and B-3) buildings along Grand Avenue could be added.

Area P13. This area between University Avenue, Lexington Parkway, the railway, Como Avenue, and Rice Street consists mainly of two-family houses (RT-1), with some scattered multifamily (RM-2, RM-3) and commercial (B-2, B-3) buildings.

Area P14. This area includes an area northeast of downtown St. Paul enclosed by 7th Street, Johnson Parkway, Highway 94, and an imaginary continuation of Arcade Street to the south, excluding most of the southeast corner (south and east of Mounds Park Jr. High School). It contains mainly two-family houses (RT-1), with some scattered multifamily and commercial (RM-2, B-2) buildings.

Area P15. This area is northeast of downtown St. Paul and is enclosed (approximately) by Arcwright Street, Case Avenue, Earl Street, and Hawthorne Avenue. It contains mainly two-family houses (RT-1) with commercial buildings (B-2, B-3) along Payne Avenue and Arcade Street.

Area P16. This area north of the state capitol is enclosed by Como Avenue and the railroads (excluding some area close to the south of the Northern Pacific railroad and Oakland Cemetery). It contains mainly two-family buildings (RT-1) with commercial buildings along Rice Street (B-3) and Front Avenue (B-2) and a couple of multifamily buildings (RM-2).

Area P17. This area covers most of the eastern part of St. Paul not included earlier. It is a large area limited to the south roughly by Highway I-94 and to the west by Highway 35E and districts P14, P2, and P15. To the north and east, it is limited roughly by the border to Maplewood. It also contains some minor parts of Maplewood close to the border and encloses area P9. It contains mostly one-family houses but has some two-family houses and commercial buildings along the main streets (White Bear Avenue) and Highway I-94.

Area P18. This large area southwest of the St. Paul downtown airport covers most of the part of St. Paul south of the river that is not included in area P8, plus the northern part of west St. Paul roughly down to Emerson Avenue and some minor parts of Mendota and south St. Paul. It contains mostly one- and two-family houses, with some small commercial buildings along the main streets (Schmidt Avenue and Robert Street).

Area P19. This area north of Calvary Cemetery and the GN Railroad is limited to the west by Lexington Parkway, to the north by Wheelock Parkway, and to the east by area P16 (near Arundel Street). It contains mostly one-family houses, with some two-family houses, multifamily buildings, and small commercial buildings, mainly in the southern part.

Area P20. This area is located between Sherburne Avenue and the GN Railroad and is limited by Prior Avenue to the west and Oxford Street to the east. It contains mostly one-family houses, with some scattered two-family houses, multifamily buildings, and small commercial buildings.

Area P21. This large area covers most of St. Paul southwest of a line between the High Bridge power plant and the crossing point between Highways I-94 and 280. Highland Park and the area south and east of it are not included: It contains mostly one-family houses, with some two-family houses, multifamily buildings, and small commercial buildings along some of the main streets (Ford Parkway, St. Clair Avenue, Grand Avenue, Cleveland Avenue, and Snelling Avenue).

4. PRODUCTION PLANTS

4.1 General Information

District heating allows the use of various large, efficient production sources. Cogeneration plants and heat-only boilers can be designed for different kinds of fuels, such as coal, nuclear fuel, and peat. Use can also be made of stored heat, industrial waste heat, and heat from burning refuse.

Normally, heat produced in cogeneration plants or recovered waste heat is used as the base load because of its comparatively low operating cost. Heat-only boilers have high operating costs but are used as peak and standby units because of their low initial capital cost. The primary fuel for the peak-load heat-only boilers is assumed to be oil, but coal can be used if boilers are used for peak loads at suitable sites (Fig. 4.1). Heat storage could also be used to supply peak heat capacity, but the possible use of storage has not been assessed in the present report.

This report assumes that coal-fired cogeneration plants are used as base-load production units and that peak-load and standby units are designed to use grade 2 oil as fuel.

4.1.1 Cogeneration plants

Cogeneration plants produce both electricity and heat (steam or hot water). The turbine can be designed as a back-pressure or extraction unit. Because of heat production, electricity output is reduced for a given fuel input. This loss of electricity must be compensated for in some way, either from another production plant (see Sect. 4.3) or, if possible, by increasing the fuel input to the cogeneration unit (Fig. 4.2).

This report assumes that some existing turbines will be converted and that two new units will be built. This alternative has been assessed by Bjarne Frilund of Sweden[3] and Ekono Oy of Finland.[4] Costs of converting the turbines are given in Table 4.1. The cost estimate is based on the experience of Stal-Laval. The estimated cost of civil engineering can vary widely depending on local conditions.

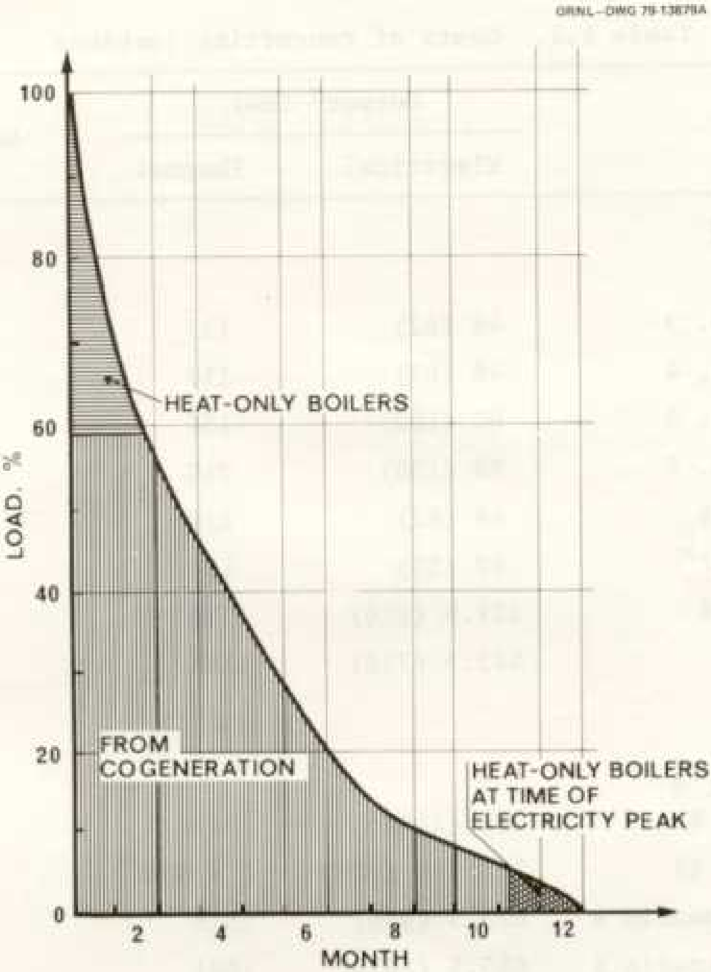

Fig. 4.1. Heat load duration curve and load split.

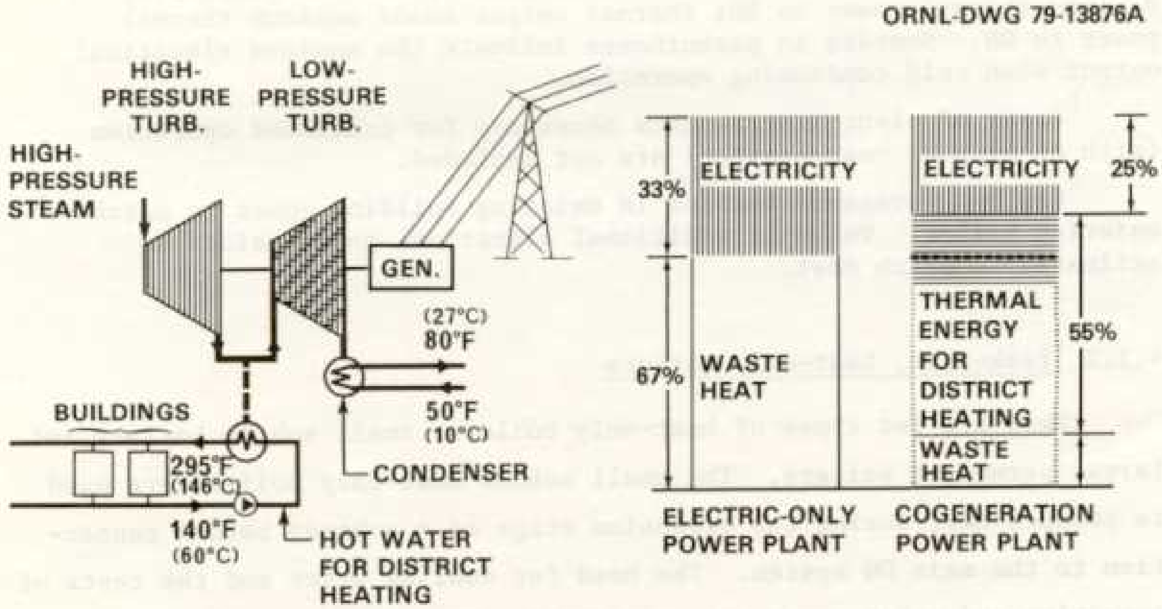

Fig. 4.2. Influence of turbine conversion on heat utilization.

Table 4.1. Costs of converting turbines

Turbine	Output[a] (MW) Electrical	Thermal	Estimated costs[b] ($ × 10^6)
Those possible to convert			
High Bridge No. 3	48 (62)	117	3.3
High Bridge No. 4	48 (62)	117	3.3
High Bridge No. 5	64 (102)	157	4.0
High Bridge No. 6	98 (156)	240	4.5
Riverside No. 6	48 (62)	110	3.3
Riverside No. 7[c]	52 (55)	110	0.0
Riverside No. 8	127.5 (216)	330	5.5
Total	485.5 (716)	1181	23.9
New turbines			
High Bridge No. 9 or Riverside No. 9	190 (240)	335	29
King (Scenario B)	2 × 400 (900)	2 × 350	72
Total, Scenario A	675.5 (956)	1516	53
Total, Scenario B	885.5 (1616)	1881	96

[a]The electrical output means electrical power when supplying maximum thermal power to DH; thermal output means maximum thermal power to DH. Numbers in parentheses indicate the maximum electrical output with cold condensing operation.

[b]Costs of plant improvements necessary for continued operation (with or without cogeneration) are not included.

[c]New back-pressure turbine in existing building space to match existing boiler. Value of additional electrical power gained is estimated to match cost.

4.1.2 Peak-load, heat-only boilers

There are two types of heat-only boilers, small mobile boilers and larger permanent boilers. The small mobile heat-only boilers are used to produce heat during the expansion stage of a subarea before connection to the main DH system. The need for cooling water and the costs of operation and maintenance are very small. The efficiency of a heat-only boiler is about 90%.

Large permanent heat-only boilers are used as peak-load units on cold winter days and as standby units. For Swedish conditions, a cost of $43/kW is normal for a permanent heat-only boiler. The cost includes boiler, design, land, and buildings.

4.1.3 Large customers with existing production plants

Very little information has been obtained concerning boilers other than those used by the steam systems in central Minneapolis and St. Paul. However, it may be inferred that boilers of fairly large capacity will exist at the following sites:

1. the four existing steam-based DH systems,
2. the Hoerner-Woldorf paper mill,
3. two breweries and two 3M facilities,
4. some facilities in unfavorable locations, and
5. some hospitals, colleges, and supermarkets.

Of these, the first two sites and perhaps also the breweries and 3M facilities could possibly be used for peak-load and standby in a DH network covering a large part of the towns. Some of the industries might alternatively be contracted as waste-heat sources.

The existing production capacity for three of the four DH systems is ~600 MW(t) [322 + 109 + 170 MW(t)], including the southeast plant. Addition of the farm campus plant [80 MW(t)] gives about 680 MW(t).

The capacities and conditions of the plants of Hoerner-Waldorf, Olympia Brewery, and the 3M facilities are not known, but they are expected to have capacities of at least 200, 60, and 50 MW(t) (3M, 7th Street) respectively. Integration of these into the network would give an additional peak capacity of at least 300 MW(t) at two points in St. Paul [60 + 50 = 110 MW(t) at 7th Street], which is a total of about 1000 MW(t) at six points (Olympia and 3M at 7th Street are very close) in St. Paul and Minneapolis.

The MCHC plant has space available for three times as many boilers as are presently there, which increases its total capacity to 327 MW(t). The Integrated Community Energy System (ICES) project[5,6] presupposes a shift to low-grade coal, which reduces the capacity from 322 to 286 MW(t). Of this, 110 MW(t) would come from the converted southeast power plant and 12 MW(t) from the solid waste plant of the university. These assumptions would give a total of about 1200 MW(t), mainly peak and standby, at six points in the cities. To this figure might be added some capacity from a possible large refuse-burning plant.[7] The approximate location of these production plants may be inferred from Figs. 4.3 and 4.4.

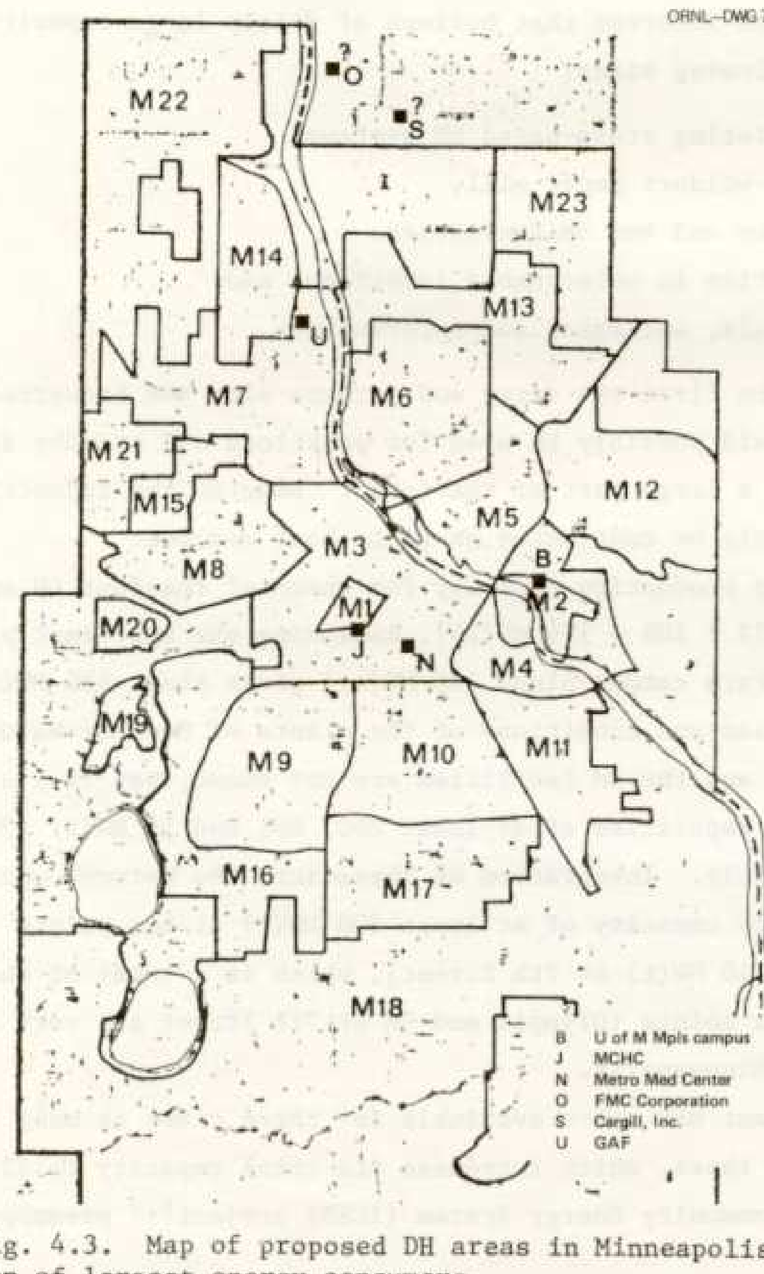

Fig. 4.3. Map of proposed DH areas in Minneapolis including the location of largest energy consumers.

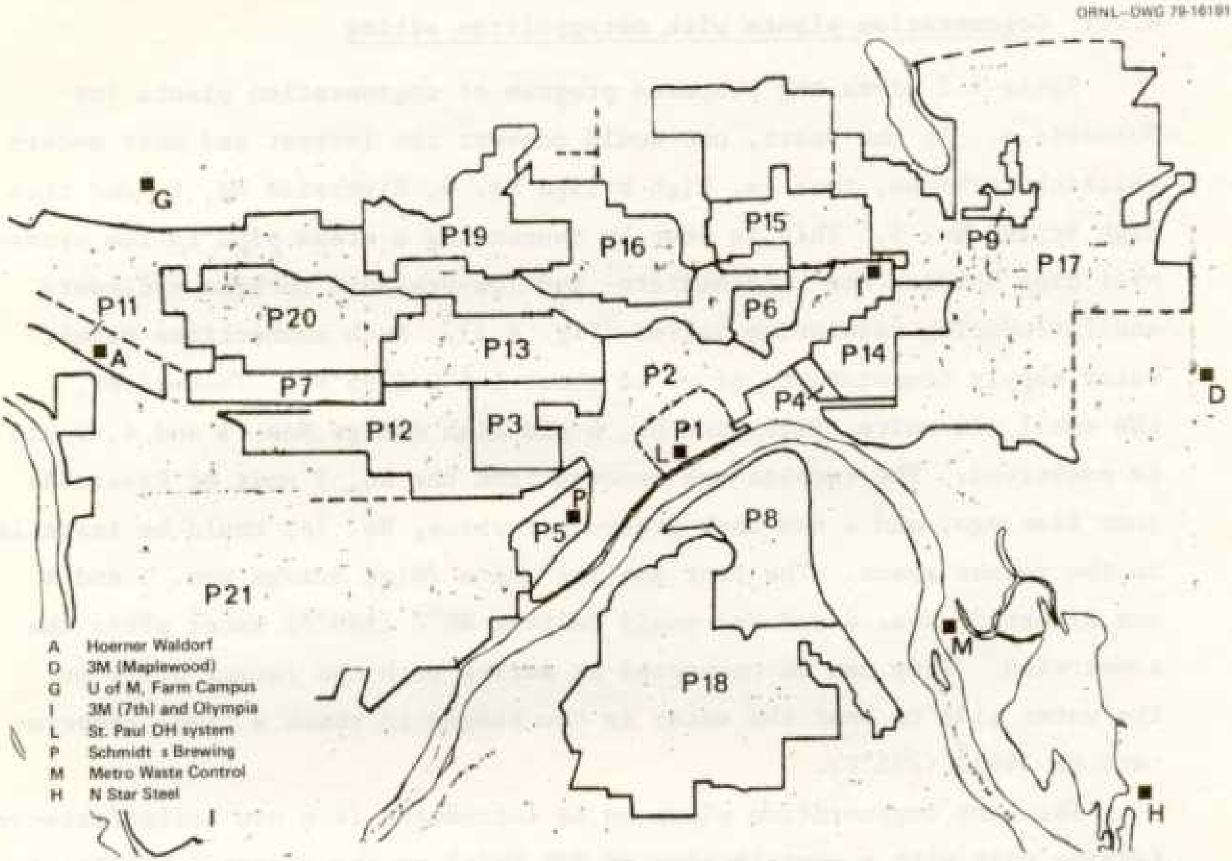

Fig. 4.4. Map of proposed DH areas in St. Paul including the location of large energy consumers.

Note that no credit has been taken for the possible use of the above-mentioned boiler capacity. A possible, more detailed future study may consider maximum boiler capacities.

4.2 Production Plants

Two alternative programs for production plants have been examined. For Scenario A, all cogeneration sites could presumably be located within the metropolitan area, that is, at High Bridge for St. Paul and Riverside for Minneapolis, with some transfer after an interconnector is built. For Scenario B, all existing units at the metropolitan sites would be converted, but new units would have to be located at an out-of-town site. The preliminary analysis assumed this site to be King, located about 17 miles from downtown St. Paul. To some extent, the two cases allow the economics of out-of-town siting to be judged.

4.2.1 Cogeneration plants with metropolitan siting

Table 4.2 gives the proposed program of cogeneration plants for Scenario A. At the start, one would convert the largest and most modern existing turbines, that is, High Bridge No. 6, Riverside No. 8, and then High Bridge No. 5. This is done by connecting a steam pipe to the cross-over pipe between the intermediate- and low-pressure turbine cylinders and introducing regulation valves (Fig. 4.2). Such connections permit water supply temperatures of up to about 146°C (295°F). Thereafter, the small old units, Riverside No. 6 and High Bridge Nos. 3 and 4, would be converted. The turbine was removed from the No. 7 unit at Riverside some time ago, and a new back-pressure turbine, No. 7a, could be installed in the vacant space. The four smaller units (High Bridge Nos. 3 and 4 and Riverside Nos. 6 and 7a) could deliver 88°C (190°F) water after the conversion. They can be connected in series with the larger units on the water side to heat the water in two stages to reach a final temperature of 146°C (295°F).

The last cogeneration plant to be introduced is a new boiler/pass-out turbine unit with a contribution of 335 MW(t) to the district heating load and 190 MW(t) electrical output in the pass-out mode of operation, or 234 MW(t) electrical output when operating with all steam to the cold condenser. A two-stage steam pass-out scheme should be used to get a low ratio of electricity sacrifice to DH heat output. For this new unit a reduction of 44 MW(e) allows 335 MW(t) energy to be provided at a ratio of about 1 to 7.6. This unit should be located at Riverside from the load aspect but may have to be located at High Bridge when certain site conditions are also taken into consideration. This has little influence on overall cost.

As summarized in Table 4.2, the total heat contribution from the cogeneration program at High Bridge and Riverside is 1516 MW(t), which corresponds to about 60% of the ultimate maximum demand. This is typical for the economic proportion of load supplied by cogeneration plants located within or close to cities.

Table 4.2. Cogeneration capacity and costs by unit

	High Bridge 6	High Bridge 5	High Bridge 4	High Bridge 3	Total	Riverside 8	Riverside 6	Riverside 7a	Total	Scenario A: High Bridge No. 9 or Riverside No. 9	Scenario B: King
Turbine	Existing	Existing	Existing	Existing		Existing	Existing	New		New	New
Boiler	Existing	Existing	Existing	Existing		Existing	Existing	Existing		New	New
1. DH thermal output, MW	240	157	117	117	631	330	110	110	550	335	2 × 350
2. Cold condensing electrical output, MW	156	102	62	62	382	216	62	(55)[a]	333	234	2 × 450
3. Extraction or back-pressure operation electrical output, MW	98	64	48	48	258	127.5	48	52	227.5	190	2 × 400
4. Difference, item 2 − item 3, MW	58	38	14	14	124	88.5	14	(3)	105.5	44	2 × 50
5. Conversion cost (or equivalent cost), $ × 10^6	4.5	(4)[b]	3.3	3.3	15.1	5.5[c]	3.3	0[d]	8.8	(29)[e]	72
6. Specific conversion cost, $/kW(t)	18.7	25.5	28.2	28.2	23.9	16.7	30	(0)	(16)	(81)	103
7. Electricity generated by steam before exhaustion for DH,[f] MW	85.5	56.6	42.5	42.5	227.1	110.2	42.5	52	204.7	169	357
8. Ratio of item 7 to item 1: criterion for operation priority	0.36	0.36	0.36	0.36	0.36	0.335	0.386	0.47	0.37	0.47	0.51
9. Year (autumn) commissioned as cogenerating unit	1981	1982	1986	1990		1983	1987	1983		1996	1996, 1998

[a]Numbers in parentheses indicate the maximum electrical output with cold condensing operation.

[b]Estimated from Frilund's estimate for High Bridge No. 6.

[c]Equivalent cost, taking account of estimated credit for added capacity.

[d]12 - 12 = 0.

[e]Equivalent cost of "economy-of-size penalty" as compared with full-size plant.

[f]Calculated from approximation 0.95(item 3) − 0.05(item 2), which takes account of cooling steam needed for low-pressure turbine.

4.2.2 Heat-only boilers with metropolitan siting

From the aspect of firm capacity, the largest unit on each system should be discounted, as Fig. 4.5 illustrates, to allow for the possibility of that unit being down. After the two systems are interconnected, only one reserve unit is needed. On completion of the program, this leaves a firm cogeneration capacity of 1516 — 335, or approximately 1180 MW(t). The deficiency to be made up by heat-only boilers is 2709 — 1181, or 1527 MW(t). In practice, part of this capacity could be supplied by some of the existing boilers for the existing DH systems and large buildings (see Sect. 4.1.3) and the remainder by cheap new oil-fired hot water boilers. However, because sufficient information was not available on the condition of the existing boilers, their use was not assumed in the study, thus giving conservative results. Because the new heat-only boilers are needed only for peak loads and reserve, making additional investments for coal firing is pointless. These new units could be located both at the cogeneration sites and at suitable points of the network (see Chap. 7).

Because the conversion of turbines should cost considerably less than building new heat-only boilers and, in addition, bring about lower energy costs, the turbine conversions should receive priority in the program. Nevertheless, new heat-only boilers are required in the early stages during the initial load expansion phase. Mobile units are used to build up load at concentrated load islands before these are interconnected to the main system.

4.2.3 Out-of-metropolitan-area sites

For Scenario B, conversion of existing turbines and addition of Riverside turbine 7a to match the existing boiler No. 7 would contribute only about 30% of the maximum heat demand of 4042 MW(t) for the system. Hence, a more substantial addition of new cogeneration capacity is required. The assumption is that this would take the form of a plant sited out of town and supplying a maximum of 700 MW(t) of heat to the DH system. This brings the total cogeneration contribution to 1881 MW(t), which equals 47% of the maximum demand of the system. This is reasonably

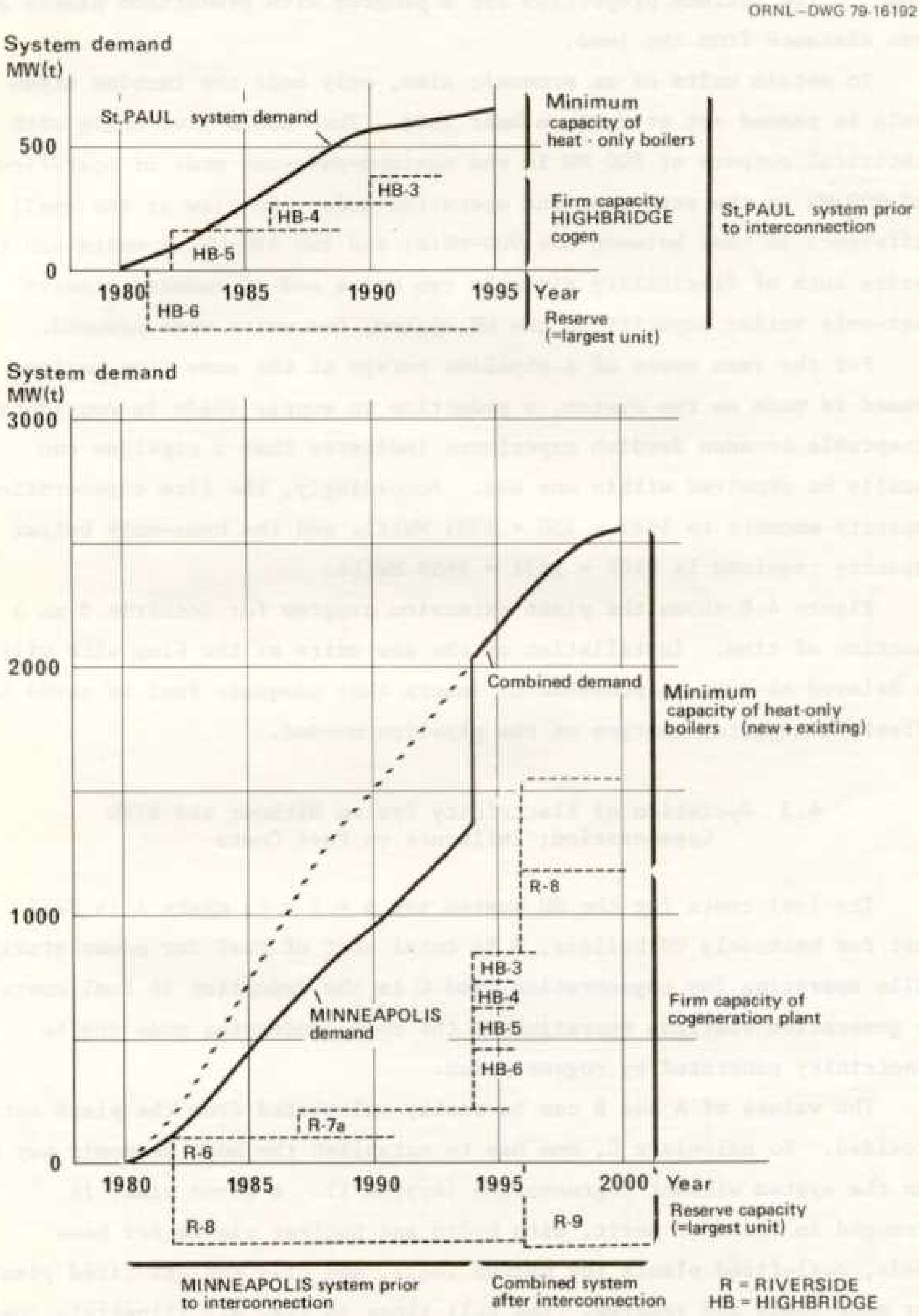

Fig. 4.5. Plant extension program, Scenario A.

close to the optimum proportion for a program with production plants at some distance from the load.

To obtain units of an economic size, only half the turbine steam would be passed out at maximum heat load. This would give units with electrical outputs of 800 MW in the maximum-pass-out mode of operation and 900 MW in the zero-pass-out operation mode. In view of the small difference in cost between one 900-MW(e) and two 450-MW(e) units and the merits both of flexibility given by two units and of reduced reserve heat-only boiler capacity on the DH system, two units were assumed.

For the rare event of a pipeline outage at the same time maximum demand is made on the system, a reduction in supply loads is considered acceptable because Swedish experience indicates that a pipeline can usually be repaired within one day. Accordingly, the firm cogeneration capacity amounts to 1881 - 350 = 1531 MW(t), and the heat-only boiler capacity required is 4189 - 1531 = 2658 MW(t).

Figure 4.6 shows the plant extension program for Scenario B as a function of time. Installation of the new units at the King site will be delayed as long as possible to ensure that adequate fuel is saved to offset the capital charges of the pipeline needed.

4.3 Operation of Electricity System Without and With Cogeneration; Influence on Fuel Costs

The fuel costs for the DH system are A + B − C, where A is fuel cost for heat-only DH boilers, B is total cost of fuel for power stations while operating for cogeneration, and C is the reduction in fuel costs at generation stations operating in the cold condensing mode due to electricity generated by cogeneration.

The values of A and B can be easily calculated from the plant data provided. To calculate C, one has to establish the most economic way to run the system without cogeneration (system 1). A given plant is arranged in order of merit, with hydro and nuclear plants for base loads, coal-fired plants for medium loads, and oil- and gas-fired plants for peak loads and reserve. The full lines in Fig. 4.7 illustrate load allocation in this fashion.

In a system with cogeneration (system 2), some of the medium-size coal plants can be operated either for cogeneration or for electricity

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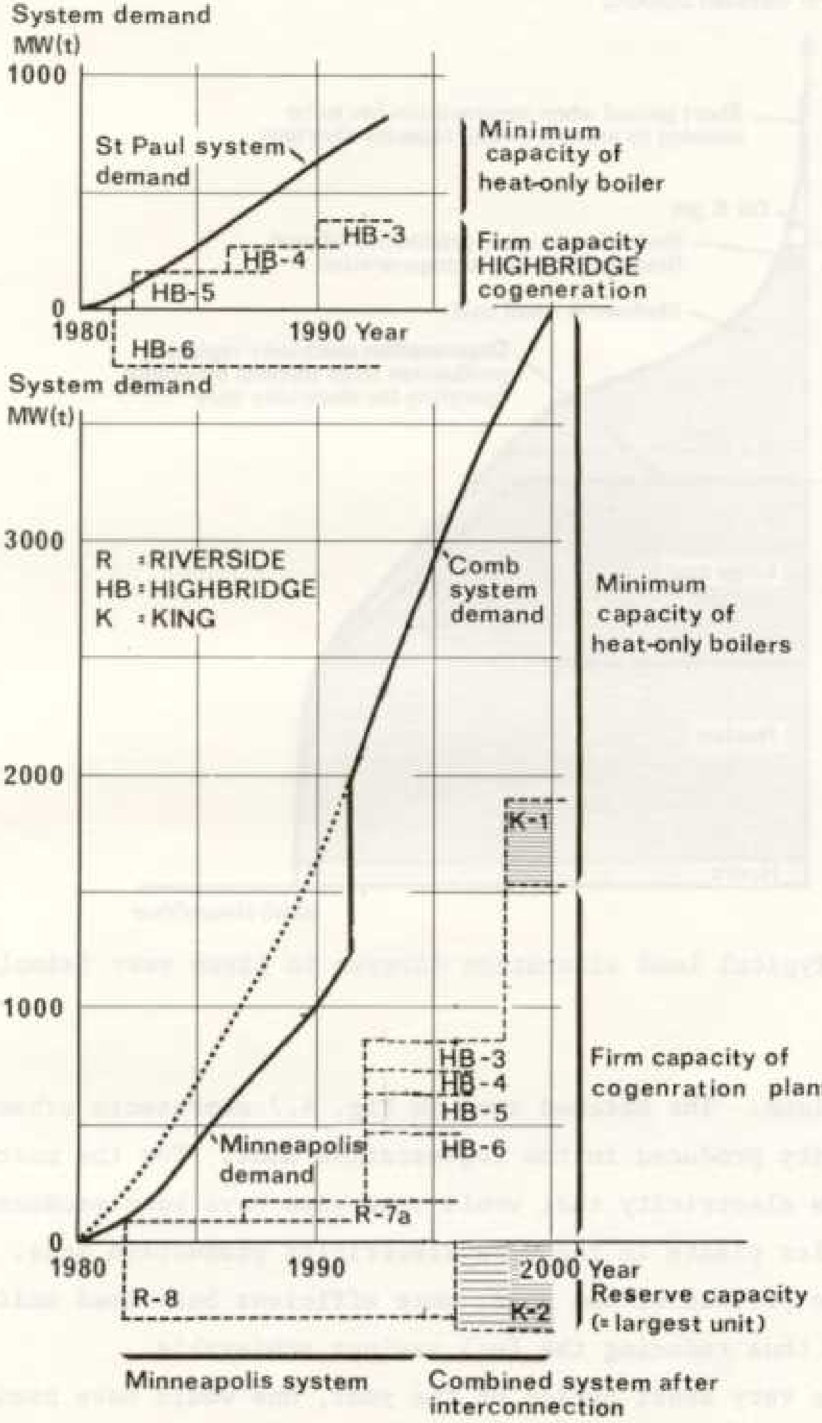

Fig. 4.6. Plant extension program, Scenario B.

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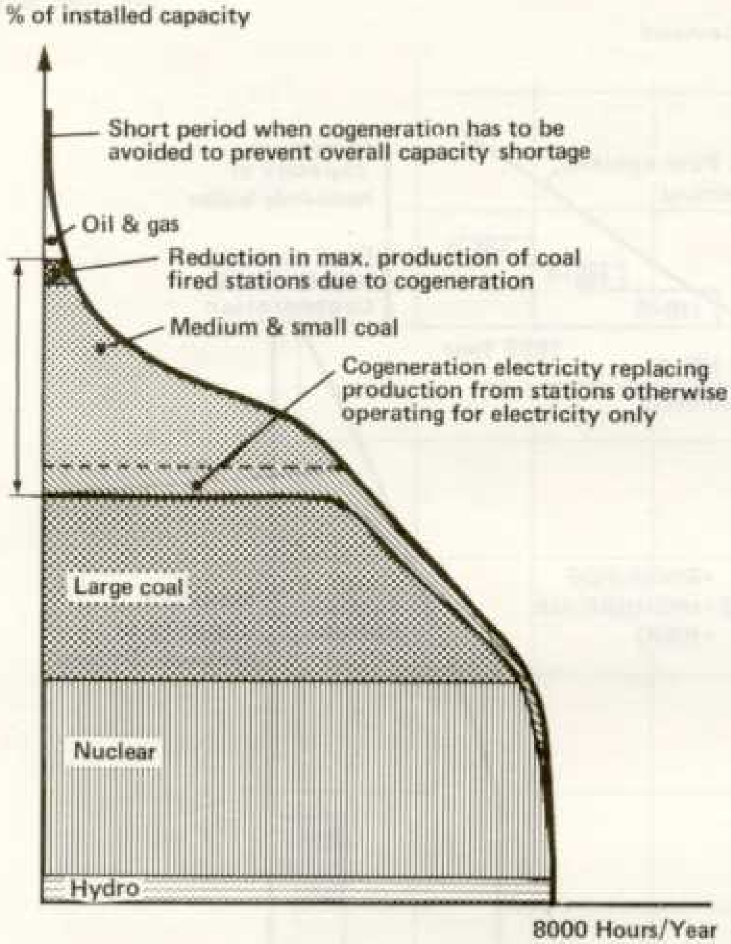

Fig. 4.7. Typical load allocation diagram in given year (simplified).

production alone. The hatched area in Fig. 4.7 represents schematically the electricity produced in the cogeneration mode. For the most part, this replaces electricity that would otherwise have been produced by the same or similar plants in the pure electricity production mode. However, at some periods of the year, more efficient base-load units would be replaced, thus reducing the fuel savings achievable.

During a very short period of the year, one would have needed full output from all coal-fired plants to prevent the need for operating the oil- or gas-fired peaking plants. Since cogeneration reduces the maximum electrical output obtainable from the Riverside and High Bridge units, this increases the generation required from the oil-fired units, as shown by the crosshatched area.

Finally, during very infrequent periods, even the oil- and gas-fired peaking and reserve electricity-generating plant is not sufficient to compensate for the reduction in electrical output due to cogeneration. During this short period, one cannot allow cogeneration to take place. Instead, the heat-only reserve boilers on the DH system have to take over the load. This brings about extra fuel costs. Because the electricity peak of the NSP network occurs in the summer, the extra fuel needed is quite small. In the base case, it has been assumed that in no year will the base units deliver more than 85% of the total energy demand for that year to compensate for unplanned cogeneration outages and temporary DH islands. Bearing in mind the large proportion of cogeneration capacity on the DH system, this assumption is probably too conservative.

For the report, data were obtained from NSP, allowing the system operation to be arranged in order of merit for system 1 for each year during a 20-year period, and annual fuel costs were calculated. Included in the NSP data were seasonal and daily load variation data, load growth projections, specific plant performances, fuel cost data for all generation units today, fuel cost increases projected as a function of time, plant extension programs, and plant maintenance and forced-outage provisions. Thereafter, the procedure was repeated for system 2, the system with cogeneration. The difference between the fuel costs for the two systems gives the term B — C in the equation above, that is, the net increase in fuel costs for the electricity system due to cogeneration. The procedure is described in more detail in Appendix E.

Typically the term B — C gives a cost of 3 to 4 mills/kWhr heat ($\sim$\$1/10^6 Btu) supplied over the period considered in terms of 1978 dollars.

4.4 Investments in Cogeneration Plants — Conclusions

The discussion in Sect. 4.3 shows that the conversion of some existing turbines for cogeneration introduces extra fuel costs, which the calculations account for, but it does not require extra generation capacity because cogeneration can be discontinued when the electricity cannot be sacrificed. For this reason, the investment in the existing turbogenerator is "sunk capital," which is not charged to DH.

The costs originally projected for the turbine conversions were based on Swedish experience with such conversions. The costs average about $20 per kilowatt of heat to the DH system. More exact calculations involving the turbine manufacturers are in progress.

For new electricity-producing plants, only the cost of the "economy-of-size" penalty (compared with full-size turbines) needs to be charged to DH. This is defined as $(D - E)/F$. In this expression, D is the cost per kilowatt of electrical output of the cogeneration plant in the cold condensing mode, when installed at an existing site; E is the cost per kilowatt of electrical output, including the extra cost of transmitting electricity to a metropolitan area, for a full-size, out-of-town plant producing electricity only; and F is the ratio between the maximum heat output to the DH scheme and the electrical output from the cogeneration plant with the cold condensation operation.

The new unit that forms the last cogeneration plant in the program, Scenario A, has a maximum electrical output of 234 MW. If installed at a new site, such a unit would have a much higher specific cost than a full-size unit, despite the specialization by some manufacturers in medium-size cogeneration turbines. However, part of this cost increase would be offset by using existing facilities, including fuel handling, at the High Bridge or Riverside site and by not needing to build electric power lines from an out-of-town site to the Twin Cities area. These questions have to be studied by the utility. Awaiting the results of these studies, we assumed the quantity $(D - E)$ to equal $120 per kilowatt and F to equal 355/240 or 1.48. Thus, the overall economy-of-size penalty becomes 120/1.48 or $81 per kilowatt of heat. Because the new cogeneration unit will not be needed until 1997, that is, near the end of the period considered, even a relatively large change in the assumed figure would not affect the overall conclusions significantly.

For the new No. 7a turbine in an existing building, a cost of $12 million [$218/kW(e)] was estimated by a turbine manufacturer. The value of the unit for peak-load electricity generation is estimated to roughly match this cost so that the No. 7 unit involves zero net equivalent conversion cost.

For Scenario B, which has two units instead of one for the out-of-town station, a cost penalty of \$80 per kilowatt is estimated from data by ORNL on the relative costs of two 400-MW units on one site as opposed to one 800-MW unit. Preliminary information from NSP suggests that the difference in cost between these cases might be even smaller. The cost penalty per kilowatt of heat given to the DH scheme becomes [\$80 × 450 MW(t)]/350 MW(t), or \$103 per kilowatt of DH heat output.

5. HEAT TRANSPORT AND DISTRIBUTION SYSTEM

5.1 Hot Water or Steam?

The trend for DH systems is to use hot water rather than steam as the distribution medium. The merits of hot water become particularly strong on a system as large as that for the Twin Cities area and include the following factors:

1. considerably lower electricity sacrifice at the power plant than with steam at pressures and temperatures suitable for long-distance transport;
2. much easier regulation, particularly for the long distances and wide distribution ranges involved;
3. lower costs for transport and distribution systems; and
4. lower heat losses than in steam systems without condensate returns and fewer corrosion and equipment problems than in steam systems with condensate returns.

Standard prefabricated equipment is available for most parts of the system.

Hot water distribution also has disadvantages that include the following:

1. limited application to cooling systems in that while steam operates both steam-turbine-driven chillers and absorption chillers, hot water permits only certain types of absorption chillers to be used;
2. difficulty in absorbing the small existing steam-operated district heating systems in the area (except for obsolete systems) and industrial steam users without building new hot water mains or constructing additional steam trunk pipes especially for these consumers.

The above advantages have been judged to be more important for the overall economics and ease of operation than the two disadvantages, and thus the study has been based on the use of hot water. Moreover, the advantages will increase as a function of time.

5.2 Hot Water Design Temperatures

In general, a high design temperature for the water in the main transport system reduces the water flow rate and pipe dimensions required for a given return water temperature and also provides an advantage for buildings connected with existing low-pressure steam heating systems and steam-supplied cooling systems. A low design temperature allows more electricity to be generated by the cogeneration plant for a given heat supply, reduces the design pressure required for the system, and allows cheaper types of insulation to be used. The Studsvik optimization programs[8] for DH systems allow the optimum design temperature to be found for a given system. In some cases, however, step functions in design conditions or costs allow the optimum to be determined without elaborate optimization.

In Sweden, where buildings do not use steam heating systems, a design temperature of 120°C (248°F) is generally used, although higher values of about 160°C (320°F) have been proposed for some regional systems with long pipelines. In some cases, lower temperatures may be desirable to allow cheaper piping materials under development to be used.

In the Minneapolis-St. Paul system, converted turbines are used for the majority of the cogeneration plants. The steam extraction pressure of these can be used to heat water to about 146°C (295°F). The choice of a design temperature lower than this will not increase the electricity output from these plants. Therefore, one can say even without an elaborate optimization that a temperature of about 146°C would be one of the "natural" choices for the system design. This choice also gives small pipe dimensions.

An alternate choice could be 130°C (266°F), which, as discussed in more detail in Sect. 5.3, is the highest temperature currently allowed for prefabricated pipes of medium and small diameters [less than 500 mm (20 in.)]. These use polyurethane foam insulation between the inner steel pipe and the outer protective pipe.

For the present report, the transport system was designed for the higher of the two temperatures. This system uses mainly large-diameter pipes, so that prefabricated pipes would be used only to a limited extent. The choice gives small pipe dimensions and therefore relatively low costs for this part of the system. For convenience of regulation, this system has been separated from the local distribution systems by heat exchangers to allow the cheaper type of prefabricated pipe with directly foamed insulation to be used for the distribution system at a design temperature of 130°C (266°F). It also allows more direct application of the Swedish and other European hot-water-pipe techniques. A system without heat exchangers and using a 146°C (295°F) water temperature throughout for both transport and distribution would be another possibility. In any event, those two systems differ little in cost and can be examined further in a detailed design study.

5.3 Type of Piping and Specific Costs

The large regional pipes that transport heat from the production plants to various areas of the city are distinguished from the distribution pipes that deliver heat from the transport system to individual buildings.

The large-diameter insulated steel pipes are usually placed in common concrete protection ducts (Fig. 5.1*a*) to keep out the groundwater or in tunnels (Fig. 5.1*b*) if the rock quality is sufficiently good or the space under streets and pavements is particularly congested. Usually, the first approach is cheaper for moderate diameters and the second is cheaper for large diameters. The tunnel and culvert sizes for different pipe dimensions are shown in Table 5.1.

The Twin Cities area has good-quality tunneling rock in many areas in the form of St. Peter sandstone (Fig. 5.2). Where this sandstone exists, tunnels can be used to locate the main transport pipes, with tunnel risers to the surface at intervals. The distribution lines would be connected to the risers. The eastern part of St. Paul and the western part of Minneapolis do not have such favorable conditions, so all pipe runs would be surface covered.

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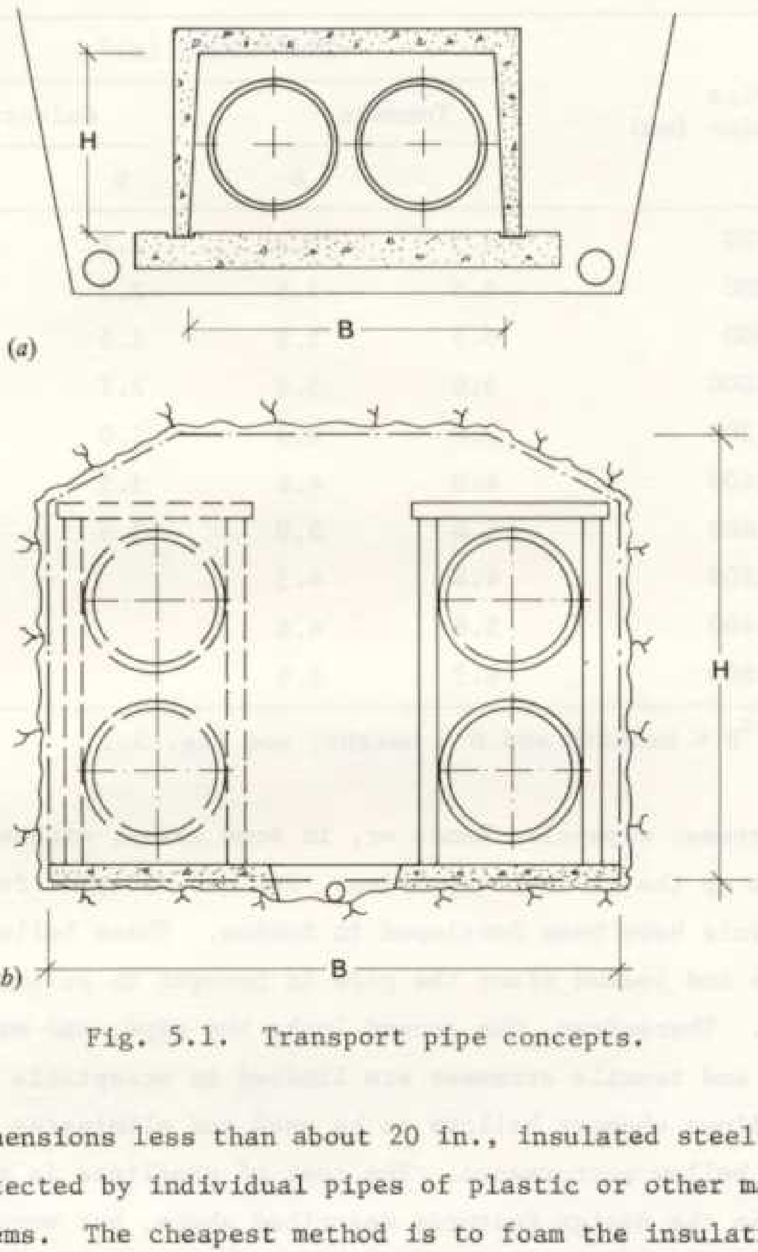

Fig. 5.1. Transport pipe concepts.

For dimensions less than about 20 in., insulated steel pipes are usually protected by individual pipes of plastic or other materials in modern systems. The cheapest method is to foam the insulation — usually with polyurethane — directly between the protection sheet and steel pipe, except at joints that require special methods. Such pipes and ducts are delivered as prefabricated assemblies. Lately, this procedure has been used for even larger pipes. It currently applies only for temperatures up to 130°C (266°F).

For higher temperatures, other insulation has to be used close to the pipe and polyurethane thereafter with a gap to allow the steel pipe to expand while the protection pipe is held by the ground. In most

Table 5.1. Dimensions of tunnels and culverts

Pipe diameter (mm)	Dimensions (m)[a]			
	Tunnels		Culverts	
	B	H	B	H
2 × 700	3.5	3.4	2.1	1.1
2 × 800	3.5	3.5	2.3	1.2
2 × 900	3.5	3.6	2.5	1.4
2 × 1000	3.6	3.8	2.7	1.5
2 × 1200	3.8	4.3	3.0	1.7
2 × 1400	4.0	4.6	3.5	1.9
2 × 1600	4.6	5.0	3.9	2.1
4 × 1200	4.8	4.3		
4 × 1400	5.6	4.6		
4 × 1600	6.7	5.0		

[a]B = breadth and H = height; see Fig. 5.1.

existing systems, expansion bends or, in some cases, expansion bellows are used to take up the thermal expansion. Bellows designed for only one expansion cycle have been developed in Sweden. These bellows are located at intervals and locked after the pipe is brought to an intermediate temperature. Thereafter, the ground locks the pipe, and maximum thermal compression and tensile stresses are limited to acceptable values. This procedure allows cheaper bellows to be used and eliminates long-term reliance on bellow performance. The cost of pipelines is strongly influenced by the design features described above, but even more by local ground conditions, traffic, and so on.

For the present study, the cost for the main tunnel system in the metropolitan area for given dimensions was estimated from Twin Cities tunneling cost data (see curve 1, Fig. 5.3). For the cost of covered pipes, we have shown costs (points on the figure) of prefabricated pipes from the downtown and residential regions of Stockholm. Due to congested traffic and relatively high labor costs, Stockholm represents the highest specific costs in Sweden and should represent Minneapolis-St. Paul

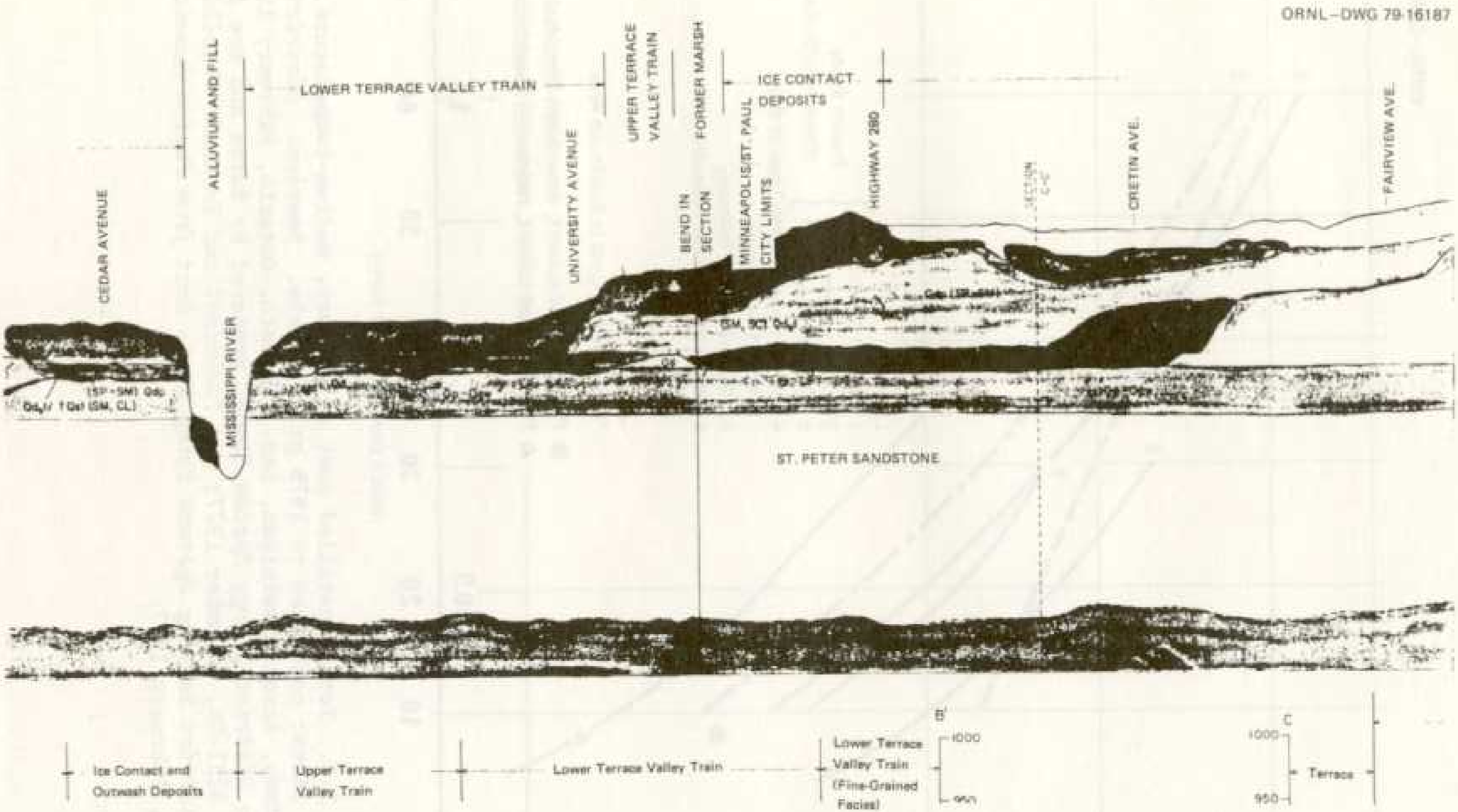

Fig. 5.2. Section showing extent of St. Peter sandstone under Minneapolis—St. Paul.

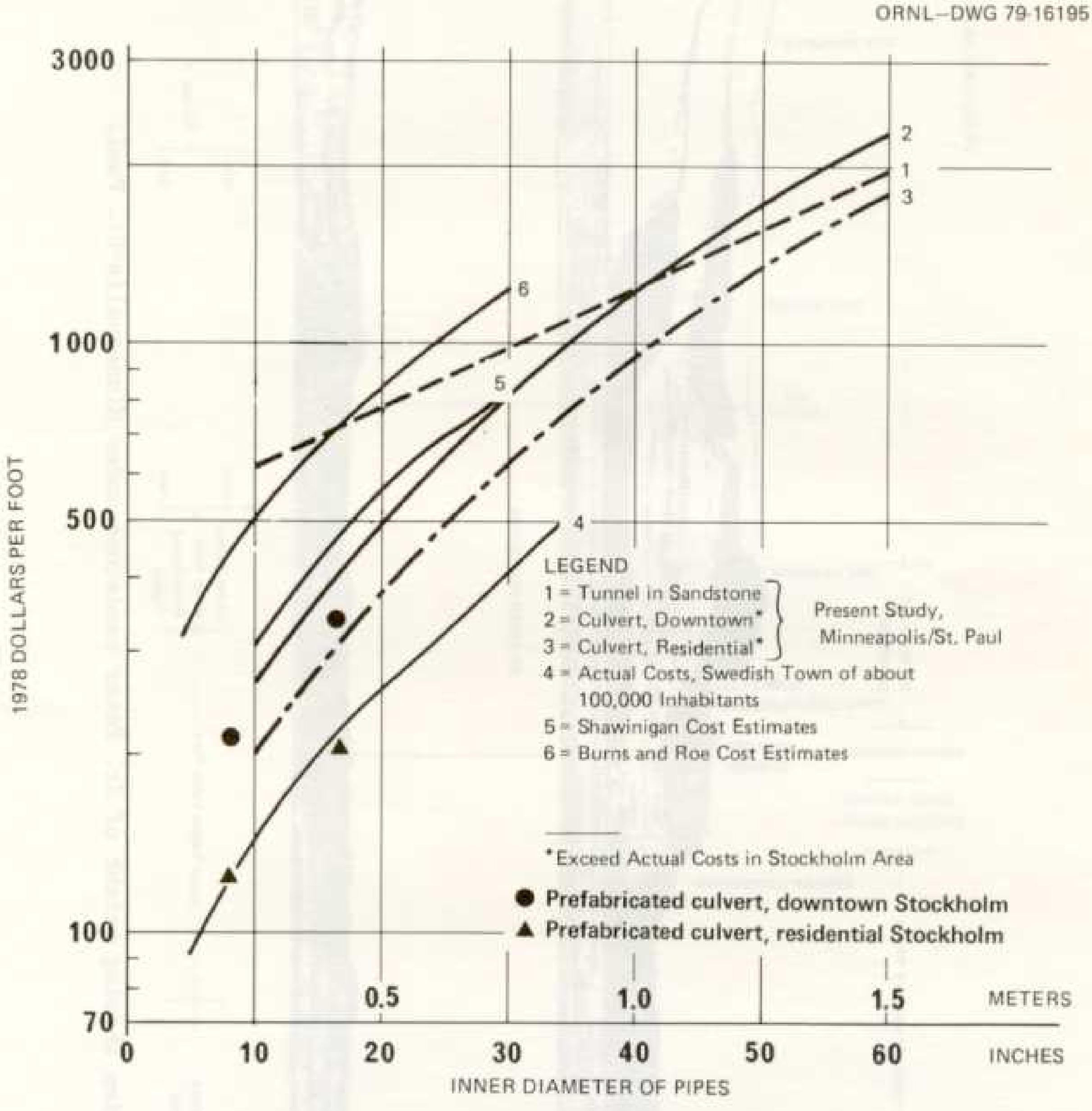

Fig. 5.3. Total installed cost of two-way, medium-temperature, urban hot water lines; corrected to 1978 price levels. Sources: *District Heating Study*, Acres Shawinigan, Ltd., Toronto, Ontario, February 1976; *Urban Area District Energy System Study*, prepared by Burns and Roe for ERDA W.O. 3251-06, November 1977; and *Technical and Economic Feasibility of U.S. District Heating Systems Using Waste Heat from Fusion Reactors*, BNL-50516, February 1977.

reasonably well. We have based our calculations of costs for surface cover pipes on curves 2 and 3, which lie somewhat above the points that represent Stockholm costs, so the estimate is conservative. The costs include excavation, pipes, installation, fittings, interest during construction, and compensation for traffic diversions and disturbances. Costs for prefabricated culverts in the Stockholm area are itemized in Table 5.2.

Curve 4 of Fig. 5.3 shows that costs for typical Swedish towns with about 100,000 inhabitants correspond to the residential area costs in Stockholm. A Swedish-U.S. team recently studied costs in smaller U.S. cities and found costs almost identical to that curve, suggesting little difference between U.S. and Swedish conditions. The cost calculation assumed purchase of the pipes in Europe and added transport costs, thus establishing a ceiling cost level. In practice, pipes manufactured in the United States would be used to avoid transport if possible at a lower or equal overall cost.

For comparison, the figure also shows some curves based on U.S. estimates. Curve 5 shows a curve from a Canadian engineering firm, Shawinigan, for North American conditions. It agrees well with our curve 2, while curve 6 from Burns and Roe lies about 50% above it.

In summary, Swedish experience under similar conditions, along with other information, indicates that the cost levels assumed in this study can be maintained or even lowered if there is maximum use of prefabricated pipes and modern European hot water technology.

5.4 Availability of Bridges for River Crossings

A Minnesota Department of Transportation (DOT) memorandum indicates that some of the existing bridges or bridge sites might be available

Table 5.2. Cost for prefabricated culverts in Stockholm

Steel pipe diameter, in.	2	5	8	16
Protection pipe diameter, in.	5	9	12	22
Excavation volume, ft^3/ft	14	20	22	37
		Cost ($/ft)		
Cost in downtown Stockholm				
Civil engineering	77	110	136	186
Prefabricated culvert	11	22	32	84
Installation[a]	4	6	11	22
Administration	16	24	32	51
Total	108	162	211	343
Used for Twin Cities downtown culverts			224	394
Breakdown of installation cost				
Welding	1.5	2.2	3.9	7.2
Laying	1.8	2.7	4.9	9.6
Fittings and access	1.0	1.4	2.2	5.0
Cost in outer districts, Stockholm				
Civil engineering	40	55	67	69
Prefabricated culvert	11	22	32	84
Installation	4	6	11	21
Administration	10	14	19	31
Total	65	97	129	205
Used for Twin Cities residential culverts			172	298
Check by 1978 price list Lubonyl for prefabricated culvert[a]	9	16	32	
Converted at \$4.5/SwCr × 0.305 ft/m = 0.0678 (\$/ft)/(SwCr/m)[b]				

[a]Including couplings and prefabricated joint insulation; a 10% discount is allowed on this price for larger orders.

[b]Sw Cr = Swedish crown.

for placing steam lines with diameters of 0.5 to 1 m (20 to 40 in.) across rivers. Most interesting to our study are the following:

1. The 3rd Avenue-Central Avenue Bridge (No. 2440) through the center of downtown Minneapolis is scheduled for reconstruction in April 1979, and any decision affecting this bridge should therefore be made as soon as possible.

2. The 10th Avenue SE Bridge (No. 2796) and the Washington Avenue Bridge (No. 9360), both situated between the University and downtown Minneapolis, could be used for 0.5-m pipes, the latter bridge possibly needing floor beams cut.

3. The new bridge (No. 9600) over the Minnesota River immediately downstream of the Black Dog power plant is judged unsuitable for 1-m pipes. Possibly the river span could be used, but this would involve unsightly risers at the river piers. The old bridge (No. 5521) at the same location will be removed (river traffic hazard), and the bridge (No. 3145) over Long Meadow Lake immediately north along Cedar Avenue is considered unsuitable for 1-m pipes.

4. The Lake Street-Marshall Avenue Bridge (No. 6520) at the border between St. Paul and Minneapolis and the High Bridge (No. 5357) are both due for future replacement and might therefore be available for crossings after about 1985 or 1990.

5. The freeway bridges are not available for pipe crossings because federal regulations prohibit such use of them.

Our conclusion is that some of the bridges in central Minneapolis may be used for carrying DH pipes. None of the bridges at Black Dog seem appropriate for use as pipe carriers. Whether the Marshall Avenue Bridge, High Bridge, and Wabasha Street Bridge will be used is still open to question.

5.5 Network Evolution

In view of the existence of two concentrated downtown areas, each at a reasonable supply distance from the site for one of the proposed cogeneration plants, parallel development of these two areas is desirable.

Eventually, the two areas could be merged by an interconnector that allows a spare production plant to be pooled and load dispatching to be carried out more effectively.

5.5.1 Minneapolis

Figure 5.4 shows how the distribution system can expand in the Minneapolis area. A hot water pipe line would be built from the Riverside plant to connect the central districts. Thereafter the network would expand outward, picking up loads in order of decreasing density.

Because the small existing steam supply system in the central area is fairly new, it would initially be retained with its independent production plant and has not been included in the present study. Several alternative strategies for gradually supplying this area with heat from the central power plants should be studied, including the possibility

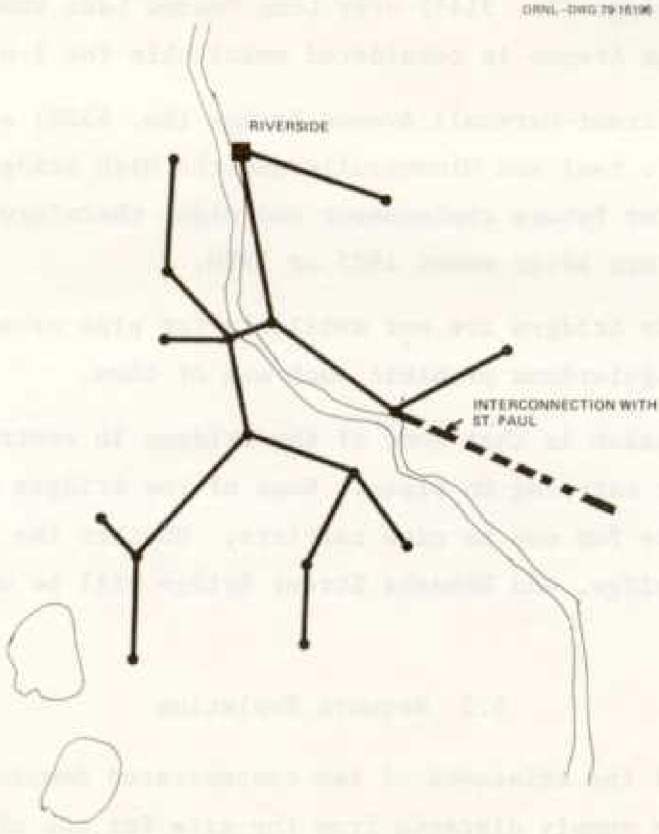

Fig. 5.4. Minneapolis heat transport pipes, Scenario A.

of building a steam line from Riverside parallel to the proposed hot water line using the same trench.

Such a steam line could also feed part of the University of Minnesota DH system and some of the industrial consumers in the industrial belt between Minneapolis and St. Paul. The main objective would be to increasingly substitute the use of reject heat from of coal-fired cogeneration plants for the use of natural gas and oil. Coal-fired burners and a proposed turbine may permit the University initially to supply the base load of its present steam DH system and other nearby steam consumers. This possibility should be examined. Such a plant could, at a later stage, take over some peak-load duty of the overall system.

5.5.2 St. Paul

The present DH scheme in St. Paul covers part of the densest downtown area with a load of 60 MW(t) supplied by two parallel steam systems for 75 and 8 psig, respectively. Both are fed from old boilers at the 3rd Street station using oil or coal. Coal costs there are higher than at the large electricity stations because the handling methods are more primitive. The site is only 1 mile away from the High Bridge power plant.

The proposed plan (see Fig. 5.5) provides for a system of hot water pipes that would initially cover the parts of the dense downtown area not yet supplied by the existing steam systems but that would gradually include blocks now supplied by DH steam as buildings are progressively converted.

The main feeder pipes from High Bridge to the 3rd Street station would have delivery temperatures of 146°C (295°F). By using water and steam heat exchangers, they could also initially generate 8-psig steam for the existing low-pressure network. Also the heating of makeup water for existing 75-psig system could be taken over by heat exchangers. Gradually, however, most buildings in the entire area would be converted to hot water supplies and, at that stage, the steam pipe systems would be shut down. Allowing High Bridge to provide some of the heat for the existing St. Paul DH system will further reduce costs compared with

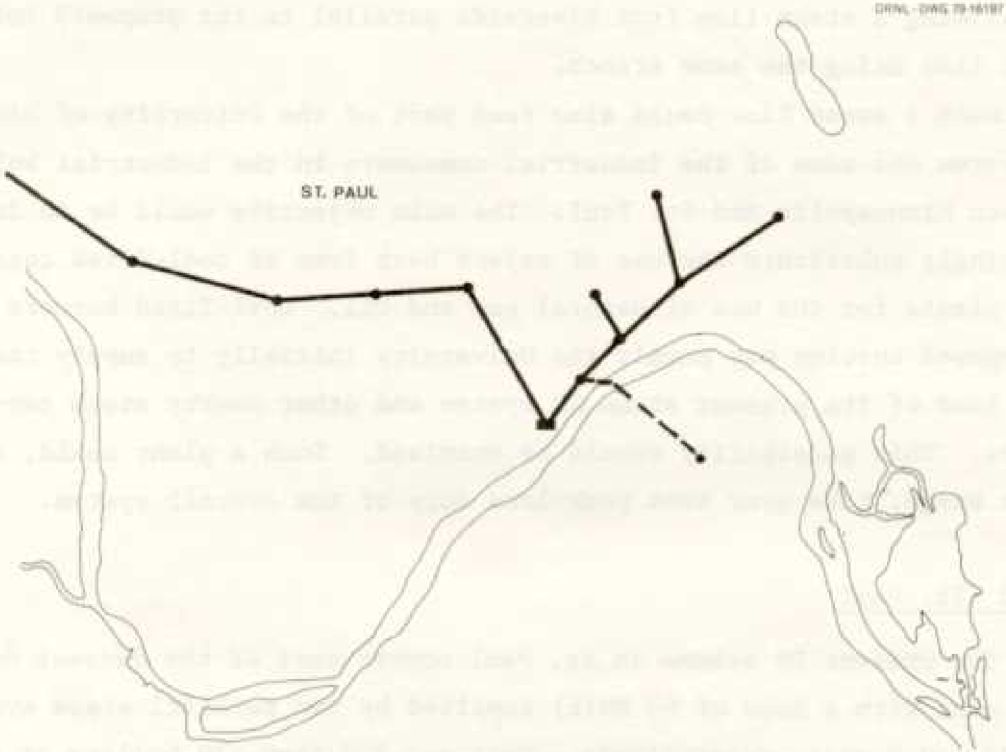

Fig. 5.5. St. Paul heat transport pipes, Scenario A.

those assumed in the study. High Bridge could contribute to St. Paul DH even before buildings in the area are converted and new mains constructed.

Eventually, as districts farther away from the generating stations are connected, the system would expand in the direction of the industrial area between the two cities and would finally interconnect with the Minneapolis system.

A steam pipe laid in the same tunnel as the water pipes going west from the High Bridge station would be justified at that stage to pick up additional industrial steam consumers. This has not been considered in the present study.

5.5.3 Integration of system

As Figs. 5.4 and 5.5 show, the proposed DH systems in Minneapolis and St. Paul can be interconnected by an east-west pipeline. The last part of the interconnector should be built only when justified by the saving from reducing reserve boiler capacity (the cost of standby boilers of a capacity equal to the largest unit) and by the benefit of better sharing the capacities of the most efficient cogeneration units for the combined base load. Estimates indicate that this stage would be reached when the combined system load is around 2000 MW(t).

5.5.4 Scenario B

Figure 5.6 shows the main hot water transport lines for Scenario A by solid lines and the additional pipe lines for Scenario B by broken lines. One major difference is the transport line from King, which extends into the St. Paul area. The tunnel between St. Paul and Minneapolis is sufficiently large to transfer the production from the King station to Minneapolis. In addition, the transport pipes are extended farther into the residential areas, and larger pipe dimensions are used for the part of the system closest to the cogeneration plants.

Figure 9.2 shows the sequence in which various districts are assumed to be connected to the district heating system, and Fig. 9.3 shows the length of transport lines that have to be built both for the various areas and in total each year. This represents a logical but not necessarily fully optimized sequence.

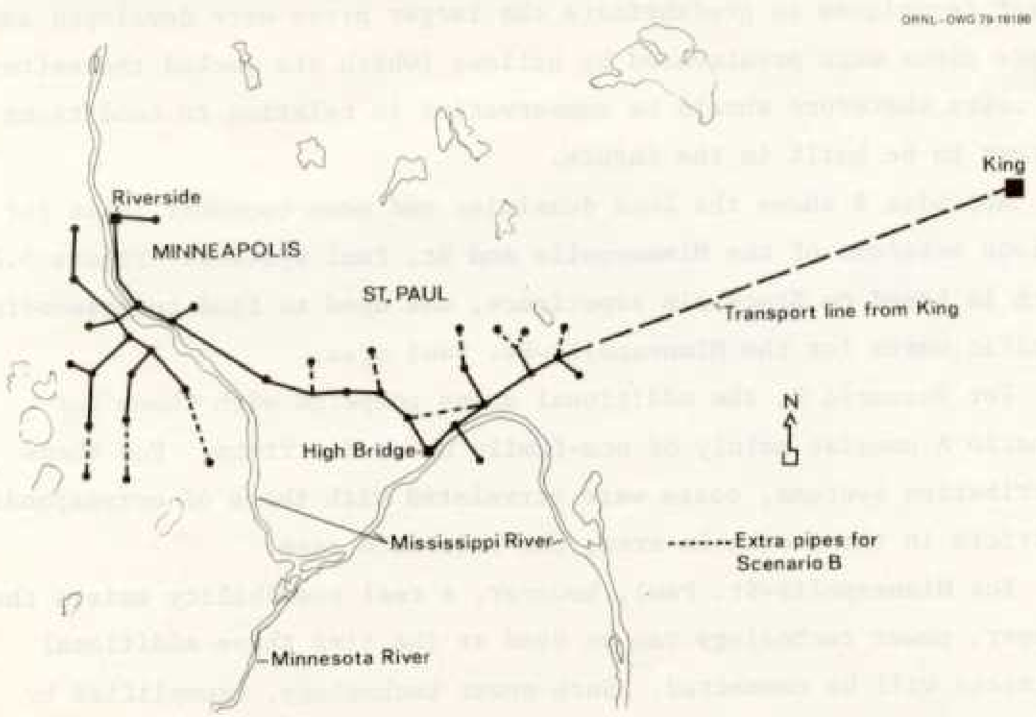

Fig. 5.6. Transmission lines for Minneapolis-St. Paul, Scenario B.

5.6 Local Distribution Systems

The distribution system is assumed to use mainly prefabricated pipes with directly foamed insulation. Pipes will be laid under pavements, in streets, or, where possible, through cellars. The last method generally costs the least. Permission to go through cellars can generally be negotiated at the time of connection to the DH system.

For planning studies of this type covering large areas, the practice in Sweden is not to do road-by-road surveys of the whole area but to find other cities with comparable conditions for which cost data are available from actual network construction. For this study, Stockholm has been selected because the degree of congestion and a mixture of rock excavation and surface construction is similar to that of the Twin Cities. Because of its high degree of congestion, Stockholm is the city in Sweden with the highest specific distribution costs in relation to load densities.

Figure 5.7 shows data on system distribution costs for Stockholm (excluding its regional transport system) for districts with various load densities and an average number of consumers. The costs are index corrected to the year 1978. Many of the systems were built before the latest techniques to prefabricate the larger pipes were developed and before pipes were prestressed by bellows (which are locked thereafter). The costs therefore should be conservative in relation to conditions for systems to be built in the future.

Appendix B shows the load densities and mean consumer loads for the various subareas of the Minneapolis and St. Paul systems. Figure 5.7, which is based on Stockholm experience, was used to find corresponding specific costs for the Minneapolis-St. Paul area.

For Scenario B, the additional areas compared with those for Scenario A consist mainly of one-family house districts. For these distribution systems, costs were correlated with those of corresponding districts in the Stockholm area, the reference case.

For Minneapolis-St. Paul, however, a real possibility exists that cheaper, newer technology can be used at the time these additional districts will be connected. Such newer technology, exemplified by the plastic pipes illustrated in Fig. 5.8, has already been applied

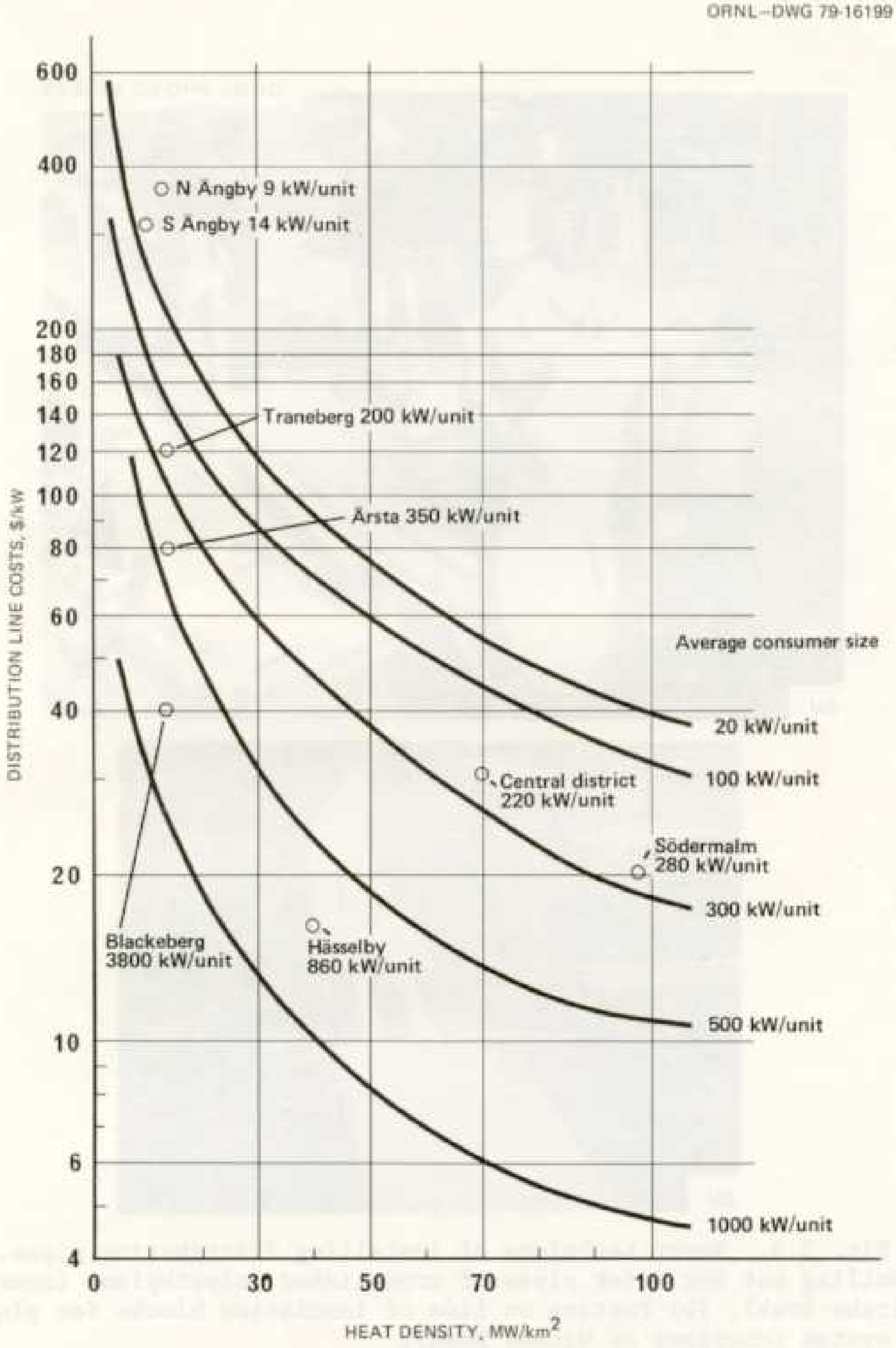

Fig. 5.7. Distribution network cost as a function of heat density. Source: Courtesy of Jörg Liljeqvist, Stockholm Energiverk.

ORNL PHOTO 3819-79

Fig. 5.8. Newer technique of installing distribution pipes. (a) Rolling out hot water pipes of crosslinked polyethylene (courtesy of Wirsbo Bruk), (b) Putting on lids of insulation blocks for plastic pipe system (courtesy of Wirsbo Bruk).

for some years in certain Swedish systems and has been evaluated extensively at Studsvik in laboratory and field tests. It promises to considerably reduce the labor of laying and installing pipelines (welding pipes and joining protection sheets are both avoided) and therefore the overall cost. From experience with installations so far, we assume the cost of this system will be 30% less than that of a conventional system. For Scenario B, therfore, two cases have been treated: one in which conventional piping technology is assumed throughout and the other in which the new piping technology is assumed for the additional one-family-house districts included in Scenario B only.

6. CONVERSION OF EXISTING BUILDING HEATING SYSTEMS

District heating systems can be used for space heating, air heating, and water heating in buildings and homes. For new buildings and houses, the cost of additional equipment needed to connect the systems to a DH network is relatively easy to calculate. Such equipment largely consists of heat exchangers, regulating equipment, and meters. Meters are generally paid for by the heat utility, whereas all other equipment is paid for by the building owner. The additional equipment generally costs less than does the alternative of heating with an individual boiler.

Under Swedish conditions, there is ample experience with the cost of converting existing systems but little under U.S. conditions. Few hot water DH systems to date have been applied to existing buildings in the United States.

The MEA has conducted a study[9] to examine the cost of converting the heating systems of buildings in the Minneapolis–St. Paul area for connection to hot water DH systems. In the survey, 280 buildings in the downtown areas of Minneapolis and St. Paul were classified according to the type of building and existing heating system.

Different types of conversions were studied for various return water temperatures. In general, conversions that produced the lowest temperatures were not significantly more expensive than those that produced higher ones because the extra cost of large heat exchangers needed to cool the return water was largely offset by the lower cost of indoor piping. Low return water temperature is important because it requires low water flow rates, it minimizes transmission and distribution pipe sizes, and it maximizes power yield at the cogeneration plant.

For five buildings typical of broad groups, the cost of conversion was estimated in detail. For other buildings, correction factors were applied as a function of capacity. The overall results are represented graphically in Fig. 6.1. The cost covers all equipment within the buildings, including heat exchangers, piping, insulation, temperature control, labor, and demolition.

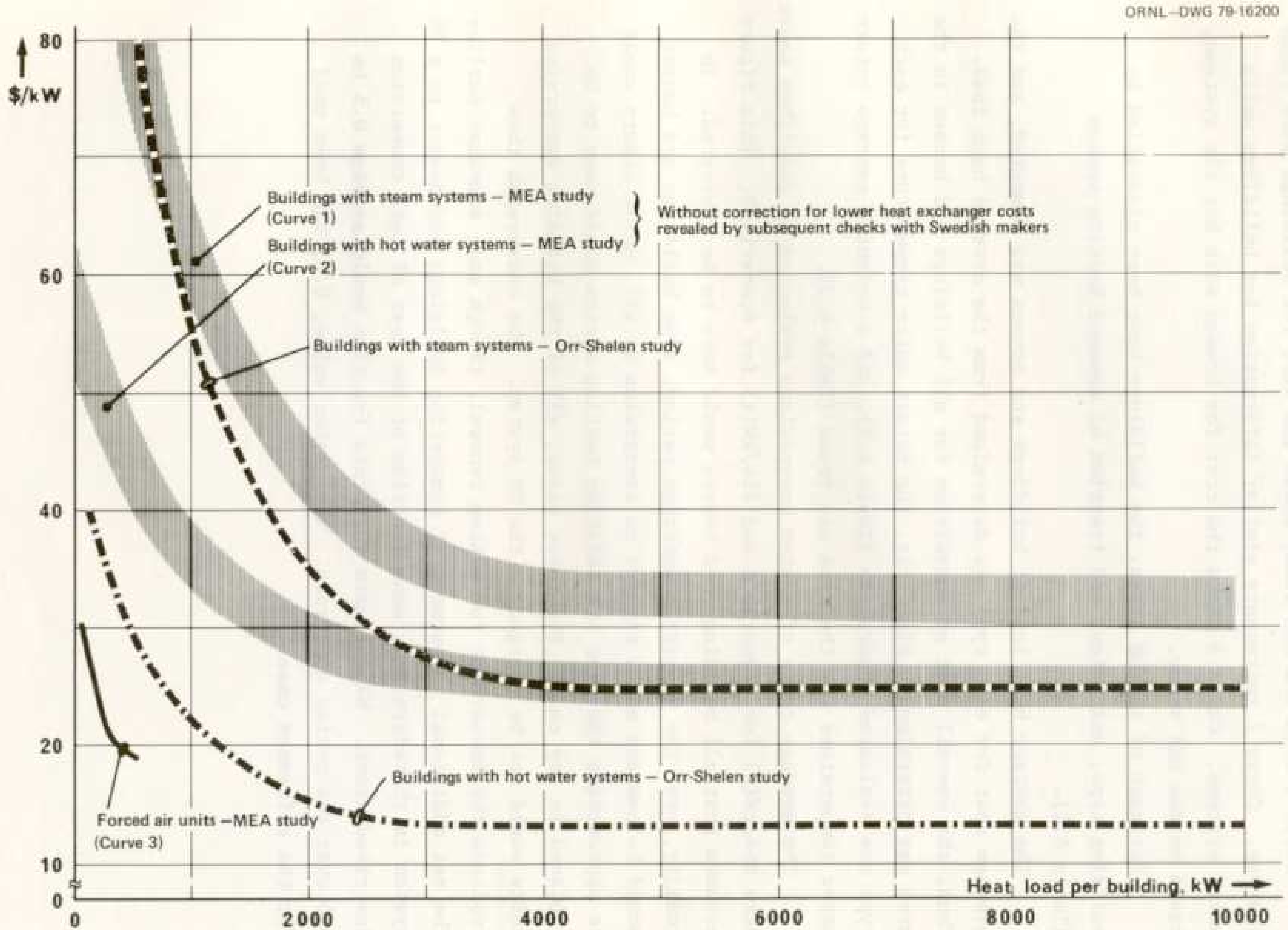

Fig. 6.1. Conversion cost for steam, hot water, and hot air heating systems.

Curve 1 from the MEA study shows the cost for buildings with steam systems. Curve 2 represents similar information for buildings using water systems. Curve 3 shows the cost for houses with hot air systems, based on the MEA study.

For each of the DH areas, the buildings have been classified by building type, unit size, and fraction of assumed heating system (Table 6.1).

The average heat load of buildings and houses was computed, and the average cost for each type was determined from the average heat load. Thus, the overall cost of conversion for all buildings and houses in the area was determined. Similarly, the return water temperature for each type was evaluated separately (Table 6.1), and a weighted average return water temperature for the area was found (Table 6.2).

The average costs of system conversions evaluated as described above were \$64/kW(t) for Scenario A and \$66/kW(t) for Scenario B. This figure assumes that all buildings and houses would have to be converted. In reality, over the 20-year connection period, some buildings and houses would be new and would require no conversion at all, while others would be approaching the year the existing heating system would have to be replaced in any case. For these cases, all of the building conversion costs would not be charged to the DH system. The conversion thus replaces the investment for system renewal, though made somewhat earlier. The net additional investment of connecting buildings and houses to a DH system is therefore only some fraction of the cost of full conversion described above. We estimate that this fraction would average 0.5 to 0.6 over the period concerned. The higher value, 0.6, has been used for the reference case.

Table 6.1. Classification of buildings by type

Building category[a]	Description	Unit size[a]		Assumed heating system[b]		
				Air	Steam	Hot water
1	Industry	1.0	Fraction, %	11	87	2
			Return temperature, °C	40	71	60
			Conversion costs, $/kW(t)	20	62	36
2	Hospital, central business, commercial building	0.5	Fraction, %	19	58	23
			Return temperature, °C	40	71	60
			Conversion costs, $/kW(t)	30	80	43
3	Hotel, business, school	0.4	Fraction, %	33	37	30
			Return temperature, °C	40	71	60
			Conversion costs, $/kW(t)	30	90	45
4	Hotel, business, school	0.3	Fraction, %	33	37	30
			Return temperature, °C	40	71	60
			Conversion costs, $/kW(t)	30	100	49
5	Multifamily residence	0.2	Fraction, %	33	37	30
			Return temperature, °C	40	71	60
			Conversion costs, $/kW(t)	36	110	51
6	Multifamily residence	0.05	Fraction, %	100		
			Return temperature, °C	40		
			Conversion costs, $/kW(t)	58		
7	Two-family residence	0.02	Fraction, %	100		
			Return temperature, °C	40		
			Conversion costs, $/kW(t)	70		
8	Single-family residence	0.02	Fraction, %	100		
			Return temperature, °C	40		
			Conversion costs, $/kW(t)	70		

[a]Building type and unit size according to the input data used in the computer program.

[b]By Studsvik assumptions calculated from unpublished report, *District Heating Conversion Methods and Costs for Existing Buildings*, Minnesota Energy Agency, Oct. 27, 1978.

Table 6.2. Return water temperatures for various building types

District	Coinciding heat load (MW)	Connected heat load (MW)	Average (MW/km^2)	Categories[a] 1	2	3	4	5	6	7	8	Average assumed temperature of return water (°C)	Average conversion costs ($/kW)
M1	80	100											
M2	126	156											
M3	347	434	53		868							57	62
M4	108	135	25			338						57	56
M5	69	86	27			216						57	56
M6	127	156	20						3,163			40	58
M7	100	125	20						2,500			40	58
M8	52	65	16								3,250	40	70
M9	210	263	49					1,050		2,625		54	69
M10	183	229	44					1,143				57	68
M11	96	120	33					606				57	68
M12	145	181	24	182								67	57
M13	98	123	25						1,215		3,056	40	64
M14	26	33	12								1,619	40	70
M15	26	33	16								1,625	40	70
M16	83	104	18							5,163		40	70
M17	114	143	28							7,113		40	70
M18	975	1,219	23							60,938		40	70
M19	15	19	25							938		40	70
M20	10	13	17								625	40	70
M21	16	20	7								1,063	40	70
M22	95	119	11								5,906	40	70
M23	43	54	12								2,675	40	70
P1	60	75	75				250					57	62
P2	285	356	51		710							63	62
P3	50	63	26					313				57	68
P4	15	19	15					94				57	68
P5	35	44	25					175		438		43	69
P6	32	40	27					200				57	68
P7	40	50	40		100							63	62
P8	69	86	37			170				93		53	59
P9	29	36	24					181				57	68
P10													
P11	46	58		56								67	57
P12	47	59	14							2,938		40	70
P13	51	64	18							3,188		40	70
P14	21	26	14							1,313		40	70
P15	21	26	10							1,313		40	70
P16	40	50	16							2,500		40	70
P17	256	320	12								16,125	40	70

Table 6.2 (continued)

District	Coinciding heat load (MW)	Connected heat load (MW)	Average (MW/km²)	Categories[a] 1	2	3	4	5	6	7	8	Average assumed temperature of return water (°C)	Average conversion costs ($/kW)
P18	98	123	12								6,125	40	70
P19	40	50	17								2,500	40	70
P20	75	94	23							4,688		40	70
P21	408	510	19							25,500		40	70
Total	4,857	6,071											
Total excluding M1 and M2	4,651	5,814	24	238	1,678	724	250	3,762	6,878	118,748	44,569	47	66

[a]Building type and unit size according to the input data used in the computer program.

7. DESIGN RULES AND COMPUTER MODELS

The following philosophies were used to prepare the design of the piping networks for the economic calculations.

7.1 Reserve Capacity

Usually, the production capacity of DH systems can meet the maximum system demand even with the largest single unit out of service. For pipes, on the other hand, repairs can usually be made within 24 hr so that a lower reserve level is acceptable. The level generally chosen when the system is developed is for any subarea to be supplied to 50% of the maximum demand on the coldest day even with any one pipe out of commission. This can be achieved by the following:

1. installing two 50%-capacity lines for spur lines from the main cogeneration centers to the central point of the loads, that is, High Bridge-3rd Street plant and Riverside-central Minneapolis;
2. arranging the transport system in loops; and
3. having peak-load and reserve boilers located along transport lines so that they can also serve as reserve to the lines between the main cogeneration plants and the areas concerned.

In this analysis, approach "3" has been used as discussed in Sect. 7.2. Similarly, the distribution system is designed so that larger buildings or critical customers can be supplied even though any one distribution pipe is out of commission. In Sweden, following these guidelines results in only a few hours of supply interruption per customer per ten-year period, on the average. Given that heat can be stored in buildings, this degree of reliability is adequate.

Because cost data for the Swedish system were based on those designed in accordance with this philosophy, the distribution systems for the Minneapolis-St. Paul study automatically conform to this practice. The transport system is discussed below.

7.2 Location of Heat-Only Boilers

As mentioned in Chap. 5, the heat-only boilers could be located either at the main cogeneration plants or at suitable points within the heat-load demand areas. In practice, some existing boilers at 3rd Street or in larger industries or buildings would probably be used, but we have disregarded this possibility because we lack information on the condition of existing boilers.

Location at the cogeneration station sites would reduce the number of pumps required, simplify fuel distribution, and allow some pooling of operating staff. Location within the heat-load demand areas would allow the heat-only boilers to act as peak-load and reserve units for the transport system (in addition to their functioning for the production system). This would reduce the required capacity of the transport pipes between the cogeneration plants and demand areas, as well as the need to form loops for the security of supplies. In a system with as large a demand area as the Minneapolis-St. Paul system, the second of these approaches will cost less than the first, assuming that appropriate sites for the heat-only boilers can be found. To make the calculations, we assumed that such sites could be found at all major junction points of the transport network. In practice, it will probably not be possible to go quite so far, so that fewer heat-only boiler sites will be used, including some existing installations. The use of fewer sites would increase costs slightly over those of the system assumed in this report, while the use of existing boilers would reduce them. The net influence on overall costs should therefore be small. Before a detailed network is designed, the question of how to site heat-only boilers, of course, must be examined in detail.

As mentioned earlier, the buildings and houses have been grouped into three classes according to type of heating system, and each type gives a different return water temperature. The proportion of these building types in the various areas was used to find the average return water temperature for each area. This is shown in detail in Chap. 6.

7.3 Seasonal Control of Heat, Water Flow Rates, and Temperatures

The Swedish practice is to design the hot water systems for 120°C, which is reached on the coldest winter day. A control actuated by outside temperature then reduces the water delivery temperature to match the falling heat demand as the outside temperature increases, while maintaining the water flow rate approximately constant. This progressive reduction in delivery temperature conserves electricity due to pass-out steam for cogeneration. After the minimum acceptable delivery temperature of about 80°C (176°F) is reached, that temperature is kept constant, and further increase in outside temperature causes a pump or other device to slow the water flow. This practice is adapted to systems with buildings that do not need high water temperatures during the summer. During that season, the heat exchangers for the domestic hot water determine the required temperature. Return water temperatures of the system usually average 45 to 50°C (113 to 122°F) and reach a maximum of about 60°C (140°F) on the coldest winter day. Heat supplied to each consumer is finely controlled by the apparatus at each subscriber station.

For the Minneapolis-St. Paul system, no incentive exists to conserve electricity on warmer days by reducing the delivery water temperature relative to the design temperatures of 146°C (295°F) for the transport system and 130°C (266°F) for the distribution system. This is because the steam is tapped off at a given point of the converted turbogenerators regardless of the temperature of the environment. Moreover, the older buildings with steam systems are assumed to be converted by installing heat exchangers between high-temperature water and low-pressure steam. This requires certain minimum water delivery temperatures. As a result, delivery water temperatures may be reduced only by very limited amounts during the rest of the year. Control valves with a greater than normal range of control over water flow will have to be used at the subscriber stations.

As mentioned in Chap. 6, the three types of heating systems assumed for buildings produce three average return water temperatures. Depending on the proportions of the three types of systems in various districts, different mean return water temperatures are obtained for the different areas. These are evaluated individually and corrected for seasonal variations.

For each transmission pipeline, there are three optimization variables:

1. the maximum design water flow rate, which determines the maximum return water temperature at which the pipe can transmit the full power output from the cogeneration plants [For higher return water temperatures during the coldest day, some restriction in cogeneration capacity may result (see Fig. 4.1).];
2. the pipe diameter; and
3. the design pumping head or power, which is a function of items 1 and 2.

Pipes with large diameters cost more but require less pumping power, so that an optimum can be found. An increased water flow rate necessitates an increase in pipe size or pumping power, which introduces extra costs but reduces the curtailment of cogeneration production during the coldest year. Also in this respect, there is an optimization that is solved by the computer program.

The optimization was performed for the last year of the system development, which implies that the pipes are somewhat oversized compared with an optimization carried out for costs during the initial period. This oversizing of pipes gives some margin for future system expansion.

With regard to seasonal variations, the computer program optimizes the water flow rate in various seasons for the given pipe diameter and pump capacity. Roughly speaking, it reduces the flow rate to the lowest value needed to meet the heat transport requirements.

8. ECONOMIC ANALYSIS

8.1 Scope of Analysis

From our economic analysis for this study we aim to determine whether a comprehensive DH system would both benefit consumers more and produce a bigger profit than the small DH schemes now in use. If all parties will profit, they can negotiate how to divide the profits equitably, making it sufficiently attractive for an organization to own and run the DH system and the consumers to use it. This report will not recommend ways for making such agreements because an institutional issues study will take up this question separately.

Our analysis also shows how various assumptions in the methods of financing and variations in the rates at which fuel prices are predicted to rise can influence the system's net operation and the cash flow year by year.

8.2 Definitions

As a first approximation, rates for the sale of DH were set to give consumers a small net economic incentive to buy it over alternative forms of heat. From these rates, the DH authorities would obtain an annual income, I_n in the n^{th} year. This quantity is denoted by "Gross Revenue" in the computer output (see Chap. 9).

The DH authority would also have to meet various fuel and operating costs for the system. The difference between the annual income, I_n, and the costs for fuel, operation, and maintenance has been termed "Operating Income," O_n.

The total annual revenue requirements, C_n, to meet capital charges on investments and taxes will depend on whether the authority is a municipal or a privately owned utility. Principles for the calculations of C_n for these two cases are shown in Tables 8.1 and 8.2 based on information from NSP.[10]

The difference between the annual operating income and the annual revenue requirements defined in these ways has been termed the "net annual saving," $S_n = O_n - C_n$. This can be negative in the initial years when

Table 8.1. Overview of municipal utility financing[a]

Year	Book depreciation	Book depreciation reserve at first of year	Net investment[b]	Return requirement	Total revenue requirement
				(Column 4 × 0.065)	(Column 2 plus Column 5)
1	10,000		100,000	6,500	16,500
2	10,000	10,000	90,000	5,850	15,850
3	10,000	20,000	80,000	5,200	15,200
4	10,000	30,000	70,000	4,550	14,550
5	10,000	40,000	60,000	3,900	13,900
6	10,000	50,000	50,000	3,250	13,250
7	10,000	60,000	40,000	2,600	12,600
8	10,000	70,000	30,000	1,950	11,950
9	10,000	80,000	20,000	1,300	11,300
10	10,000	90,000	10,000	650	10,650
Total	100,000				

[a]Based on $100,000 investment with 10-year life and zero net salvage.

[b]Original investment of $100,000 minus the cumulative book depreciation reserve.

Table 8.2. Example calculation of capital-related revenue requirements

Year (Col. 1)	Beginning of year gross plant (Col. 2)	Book depreciation reserve (Col. 3)[a]	Deferred tax reserve (Col. 4)	Investment credit reserve (Col. 5)	Beginning of year net plant (Col. 6)	Return on equity (Col. 7)	Return on debt (Col. 8)	Book depreciation (Col. 9)	Tax depreciation (Col. 10)	Deferred taxes (Col. 11)	Investment credit general (Col. 12)	Investment credit flow-through (Col. 13)	Income taxes (Col. 14)	Total revenue required[b] (Col. 15)
1	100,000	0	0	0	100,000	6,680	4,200	3,330	8,310	2,691	10,000	333	-5,829	20,739
2	100,000	3,330	2,691	9,667	93,979	6,278	3,947	3,330	8,320	2,592	0	333	3,835	19,649
3	100,000	6,660	5,283	9,334	88,057	5,882	3,698	3,330	7,940	2,395	0	333	3,604	18,576
4	100,000	9,990	7,678	9,001	82,332	5,500	3,458	3,330	7,560	2,197	0	333	3,389	17,541
5	100,000	13,320	9,876	8,668	76,804	5,131	3,226	3,330	7,180	2,000	0	333	3,187	16,541
6	100,000	16,650	11,876	8,335	71,474	4,774	3,002	3,330	6,810	1,808	0	333	2,994	15,575
7	100,000	19,980	13,684	8,002	66,336	4,431	2,758	3,330	6,430	1,610	0	333	2,820	14,644
8	100,000	23,310	15,294	7,669	61,396	4,101	2,579	3,330	6,050	1,413	0	333	2,661	13,751
9	100,000	26,640	16,707	7,336	56,653	3,784	2,379	3,330	5,670	1,216	0	333	2,515	12,891
10	100,000	29,970	17,923	7,003	52,107	3,481	2,189	3,330	5,290	1,018	0	333	2,385	12,070
11	100,000	33,300	18,941	6,670	47,759	3,190	2,006	3,330	4,910	821	0	333	2,268	11,282
12	100,000	36,630	19,762	6,337	43,608	2,913	1,832	3,330	4,540	629	0	333	2,161	10,532
13	100,000	39,960	20,390	6,004	39,650	2,649	1,665	3,330	4,160	431	0	333	2,073	9,813
14	100,000	43,290	20,822	5,671	35,888	2,397	1,507	3,330	3,780	234	0	333	1,998	9,133
15	100,000	46,620	21,055	5,338	32,325	2,159	1,358	3,330	3,400	36	0	333	1,938	8,488
16	100,000	49,950	21,092	5,005	28,958	1,934	1,216	3,330	3,020	-161	0	333	1,892	7,878
17	100,000	53,280	20,931	4,672	25,789	1,723	1,083	3,330	2,650	-353	0	333	1,856	7,306
18	100,000	56,610	20,577	4,339	22,813	1,524	958	3,330	2,270	-551	0	333	1,838	6,766
19	100,000	59,940	20,027	4,006	20,033	1,338	841	3,330	1,510	-945	0	333	2,032	6,263
20	100,000	63,270	19,081	3,673	17,649	1,179	741	3,330	0	-1,730	0	333	2,645	5,832
21	100,000	66,600	17,351	3,340	16,049	1,072	674	3,330	0	-1,730	0	333	2,529	5,542
22	100,000	69,930	15,621	3,007	14,449	965	607	3,330	0	-1,730	0	333	2,413	5,252
23	100,000	73,260	13,891	2,674	12,849	853	540	3,330	0	-1,730	0	333	2,295	4,963
24	100,000	76,590	12,161	2,341	11,249	751	472	3,330	0	-1,730	0	333	2,182	4,672
25	100,000	79,920	10,432	2,008	9,648	645	405	3,330	0	-1,730	0	333	2,067	4,384
26	100,000	83,250	8,702	1,675	8,048	538	338	3,330	0	-1,730	0	333	1,952	4,095
27	100,000	86,580	6,972	1,342	6,448	431	271	3,330	0	-1,730	0	333	1,836	3,805
28	100,000	89,910	5,242	1,009	4,848	324	204	3,330	0	-1,730	0	333	1,720	3,515
29	100,000	93,240	3,512	676	3,248	217	136	3,330	0	-1,730	0	333	1,605	3,225
30	100,000	96,570	1,782	343	1,648	110	69	3,430	0	-1,782	0	343	1,530	3,014

[a]Col. 3 = $\sum_{1}^{\text{year}-1}$ Col. 9 .

Col. 4 = $\sum_{1}^{\text{year}-1}$ Col. 11 .

Col. 5 = $\sum_{1}^{\text{year}-1}$ Col. 12 − $\sum_{1}^{\text{Year}-1}$ Col. 13 .

Col. 6 = Col. 2 − Col. 3 − Col. 4 .

Col. 7 = Col. 6 (1 − debt ratio) × (cost of equity) .

Col. 8 = Col. 6 (debt ratio) × (cost of debt) .

Col. 9 = (original cost)/(average service life) .

Col. 10 = given .

Col. 11 = (Col. 10 − Col. 9) × T, where T = income tax rate .

Col. 12 = (original cost) × (investment tax credit rate) .

Col. 13 = (original cost) × (investment tax credit rate)/(average service life) .

Col. 14 = (Col. 7 + Col. 9 − Col. 10 + Col. 11 − Col. 13) × [T/(1 − T)] − Col. 12 .

Col. 15 = Col. 7 + Col. 8 + Col. 9 + Col. 11 + Col. 12 − Col. 13 + Col. 14 .

[b]Present worth of revenue requirements at 10.88% = 122,681. Revenue requirements levelized over the average service life = 13,978.

Original cost = $100,000.
Average service life = 30 years.
Net salvage = 0.
Income tax rate[c] = 51.95% (composite of state and federal tax rates).
Sum-of-years digits tax depreciation.
Tax life = 22.5 years.
Debt ratio = (debt capital)/(total capital) = 0.48.
Cost of debt = 8.75%.
Cost of equity = 12.85%.
Composite cost of capital = [(1 − 0.48) × 12.85] + (0.48 × 8.75) = 10.88%.
Investment tax credit rate = 10%.

revenue is insufficient to meet costs but positive thereafter. We are not suggesting that rates would necessarily be set in a way that would allow a DH authority to accumulate net savings over a long period of time but are merely using the term S_n as a measure of the calculated economic viability of the project.

The sum of the values of this annual saving in various years can be referred to the year 1978 by applying the appropriate interest rate, r, and inflation factor, F_n. This sum,

$$\sum_{n=1}^{n=20} S_n(1 + r)n/F_n$$

is then a measure of the overall viability for the period concerned.

8.3 Income from Heat Sales

In Sweden, DH utilities sell heat at a rate that provides consumers with heat at the lowest cost of alternative supplies or somewhat less for the largest DH schemes. Such rates are usually subdivided into a connection charge, a fixed annual charge, and an energy charge.

An overall rate equal to the cost of the cheapest alternative heat source is usually sufficient to persuade consumers to connect because the consumers appreciate (1) the convenience of not having to operate and maintain the boiler plant and (2) the access to the space normally occupied by boilers (compared with the much smaller space of a DH heat exchanger).

For existing buildings with a fuel cost C (cents per 10^6 Btu), the rate charged should be FC, where F is a factor less than 1.0, to give a margin for covering the equipment costs the consumer has to pay to have the building connected to the DH system and preferably to provide, in addition, a further small financial inducement.

In our study, we allowed for a 10% margin for this additional financial inducement, which could be obtained with a value of F = about 0.85, with the difference between F = 0.9 and F = 0.85 creating the capital to repay the average extra building conversion costs over 15 years.

(For convenience of treatment in the computer program, we charged the building conversion costs to the utility and used a value F = 0.9 for the base case, but this gives the same net saving as the procedure described above.) The state and/or the federal government might give the further incentive of tax rebates on building conversion costs provided the building owner connects to the DH scheme shortly after a pipe has been laid in his street. This would give strong additional incentives for connection, particularly for consumers with higher-than-average building conversion costs, and help promote full or nearly full connections.

In deriving the fuel cost C for rate calculations, we assumed that the consumer would use the cheaper of the alternative fuels, gas or oil, when heat is provided by individual boilers. This is a somewhat conservative assumption from the aspect of DH economics for the initial part of the period because, in reality, most consumers in the Twin Cities area are already on interruptible gas supplies and are therefore forced to use some oil, although gas is presently cheaper. The influence of this will increase for some years if regulations force the increased use of oil but will decline again as gas prices approach those of oil and eventually exceed them. Although our assumption is conservative, the overall influence is not very strong.

8.4 Inflation and Fuel Costs

For the base cases, NSP predictions of future inflation rate and development trends for fuel costs were used. For inflation, this represents a rate of 5 to 6%/year at the beginning of the period, decreasing to 4%/year by the year 2000. The cost projections are illustrated in Fig. 9.5. The inflation factor is applied when calculating investments and fuel costs in current dollars.

Coal costs are assumed to increase by about 1.3%/year in terms of 1978 dollars throughout the period. Also, electricity costs for auxiliaries such as pumps increase only slightly in terms of 1978 dollars because the influence of some fuel price increases is counteracted by cost reductions due to the growth of the overall system.

Oil costs are assumed to reach world market prices by 1981 and to increase thereafter at about 2%/year in terms of 1978 dollars, which is slightly more rapid than the rate of inflation. Mean individual boiler efficiency is 70%, and efficiency for large heat-only DH boilers is 90%.

Gas prices are assumed to increase by a factor of 2.4 over the 20-year period. By the mid-1980s, the price consumers have to pay for gas will begin to exceed that for light oil (houses) and medium-grade oil (buildings). The NSP estimators state that their oil price projections[11] are to be regarded as on the low side for the long term. Because of this, an alternative case has been covered by the calculations in which gas and oil prices increase by an additional 1%/year.

8.5 Capital Charges and Staffing Costs

Capital charges were calculated on two bases as shown below.

Financing basis	Debt (%)	Equity (%)	Interest on debt (%)	Interest on equity (%)	Tax (%)
Private utility	50	50	8.4	13.36	51.95
Municipal utility	100		6.5		

Book depreciation periods include transport and distribution lines, 35 years; new cogeneration plants, 30 years; conversion of existing turbines, 20 years; heat-only boilers, 25 years; and consumer substations, 15 years.

The tax depreciation calculations are based on a tax life of 22.5 years and calculated on a sum-of-the-years digits method. A tax rebate equal to 10% of the investment was allowed for the year after an investment is made. Although this tax procedure differs slightly from that actually used in Minnesota, it does not significantly influence results.

No taxes were included for the piping system because DH with cogeneration was assumed to be in the interest of the environment and fuel conservation, so it was encouraged. In practice, several intermediate solutions may be practical, such as financing at least the distribution network by municipal bonds. The two bases are intended merely to illustrate the influence that the method of financing can have on the overall operating results.

Costs of operation and maintenance for the transport and distribution system were assumed to be 1%/year of the investment, in accordance with practice in many Swedish DH utilities. For a production plant, 2%/year on investment was allowed.

9. RESULTS, SCENARIO A

9.1 Assumptions for Technical and Economic Calculations

9.1.1 Expansion period

The base case assumes that water-based DH systems are expanded gradually in Minneapolis and St. Paul during a 20-year period. The development will proceed from dense city areas to suitable areas with two- and four-family housing. The total coincident demand for heat is 1781 MW(t) for Minneapolis and 840 MW(t) for St. Paul, or a total of 2621 MW(t). The DH buildup and the power plant expansion program are further discussed in Sect. 5.5 and Chap. 4 respectively. Figures 9.1-9.3 and 4.5 summarize the development of the system.

Heat load increases and conversion of production plants are scheduled so that a positive annual net income can be obtained in a reasonable time.

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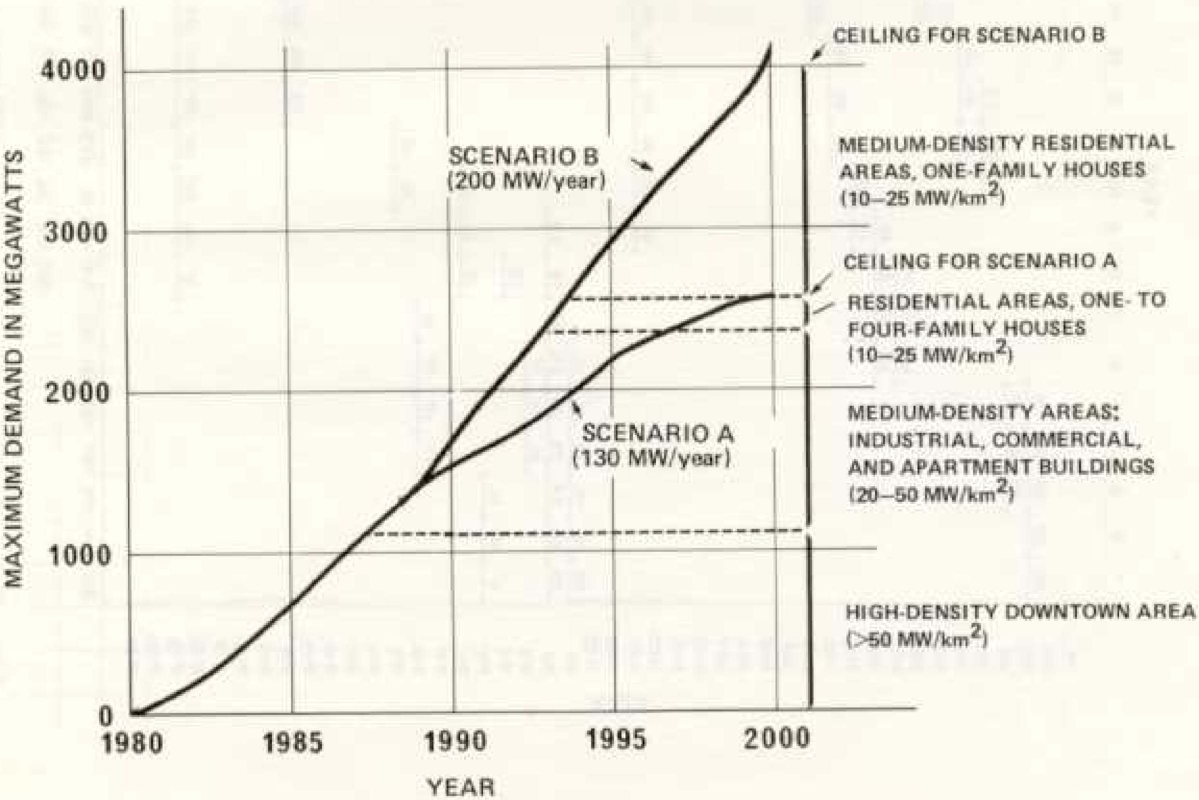

Fig. 9.1. Assumed thermal load connection rates for Scenarios A and B.

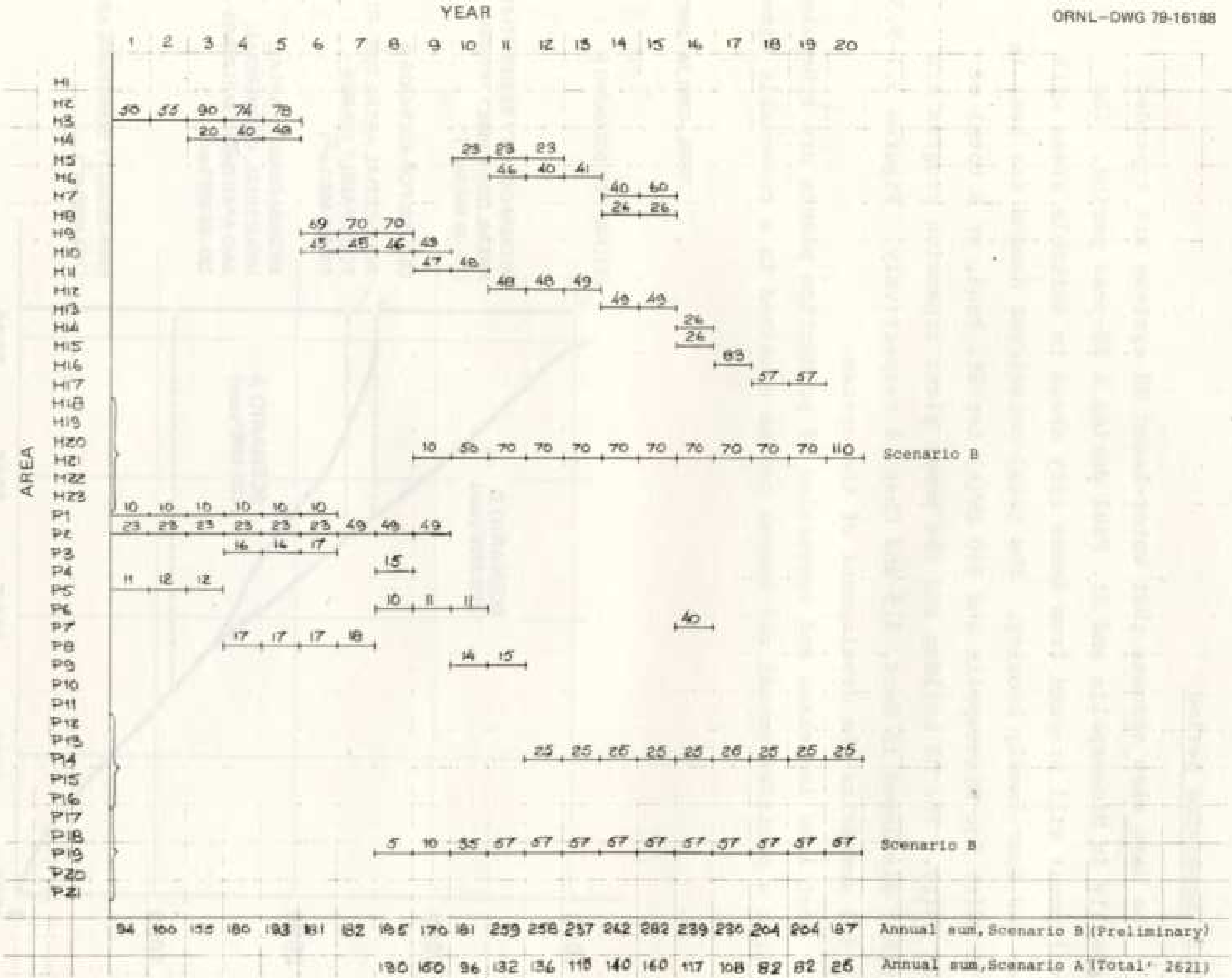

Fig. 9.2. Annual connection rate [MW(t)/year] and DH areas for Scenarios A and B.

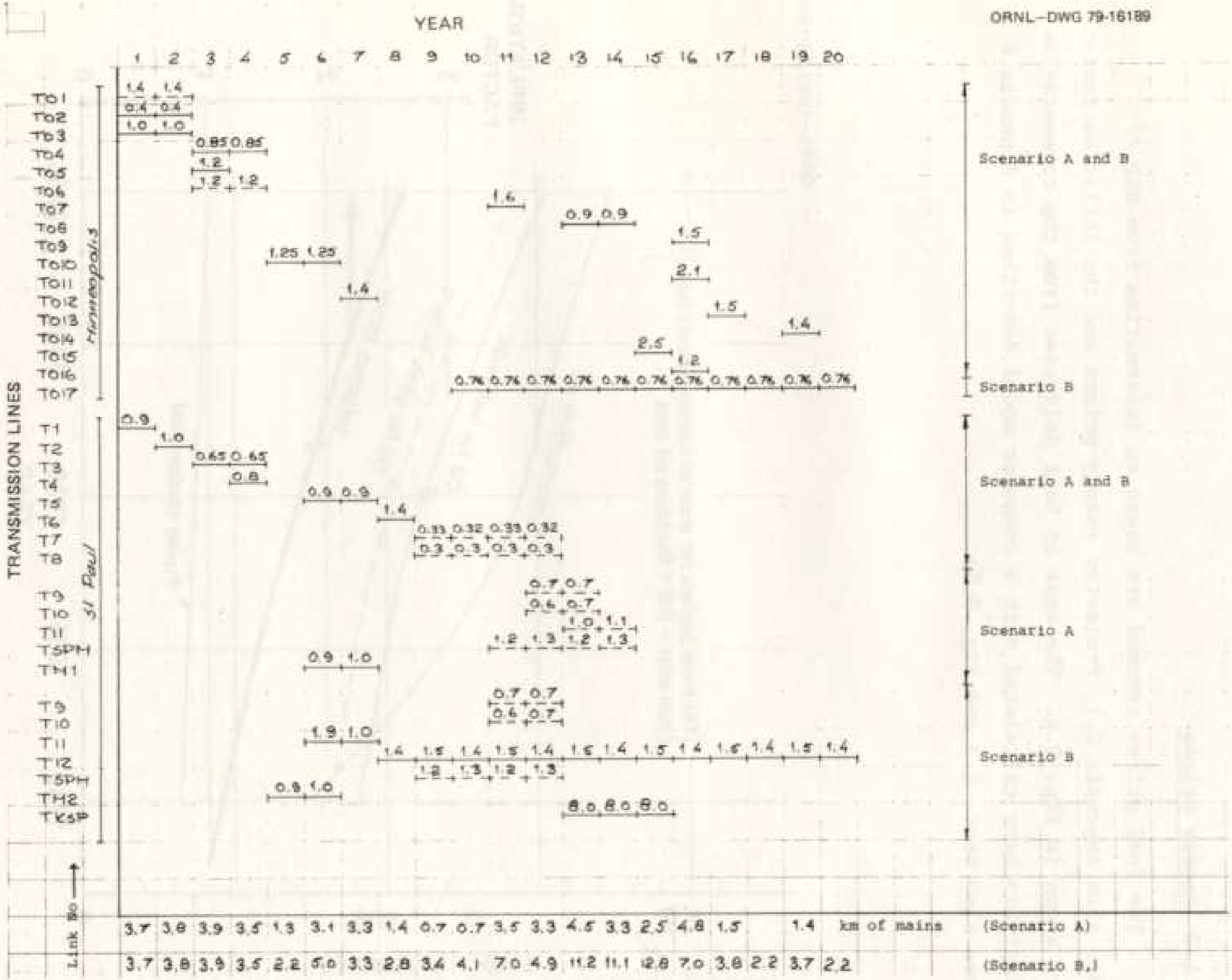

Fig. 9.3. Schedule for construction of mains (km/year) for Scenarios A and B.

The increase of the heat load represents a logical but not necessarily fully optimized sequence.

9.1.2 Energy prices

The fuel prices assumed are based on information from NSP.[11] (See also Appendix C.) Projected energy prices and the inflation factor are shown in Fig. 9.4. The cost of heat delivered from the cogeneration plant has been calculated with a computer model described in Appendix E (see also Sect. 4.3 and Fig. 9.5).

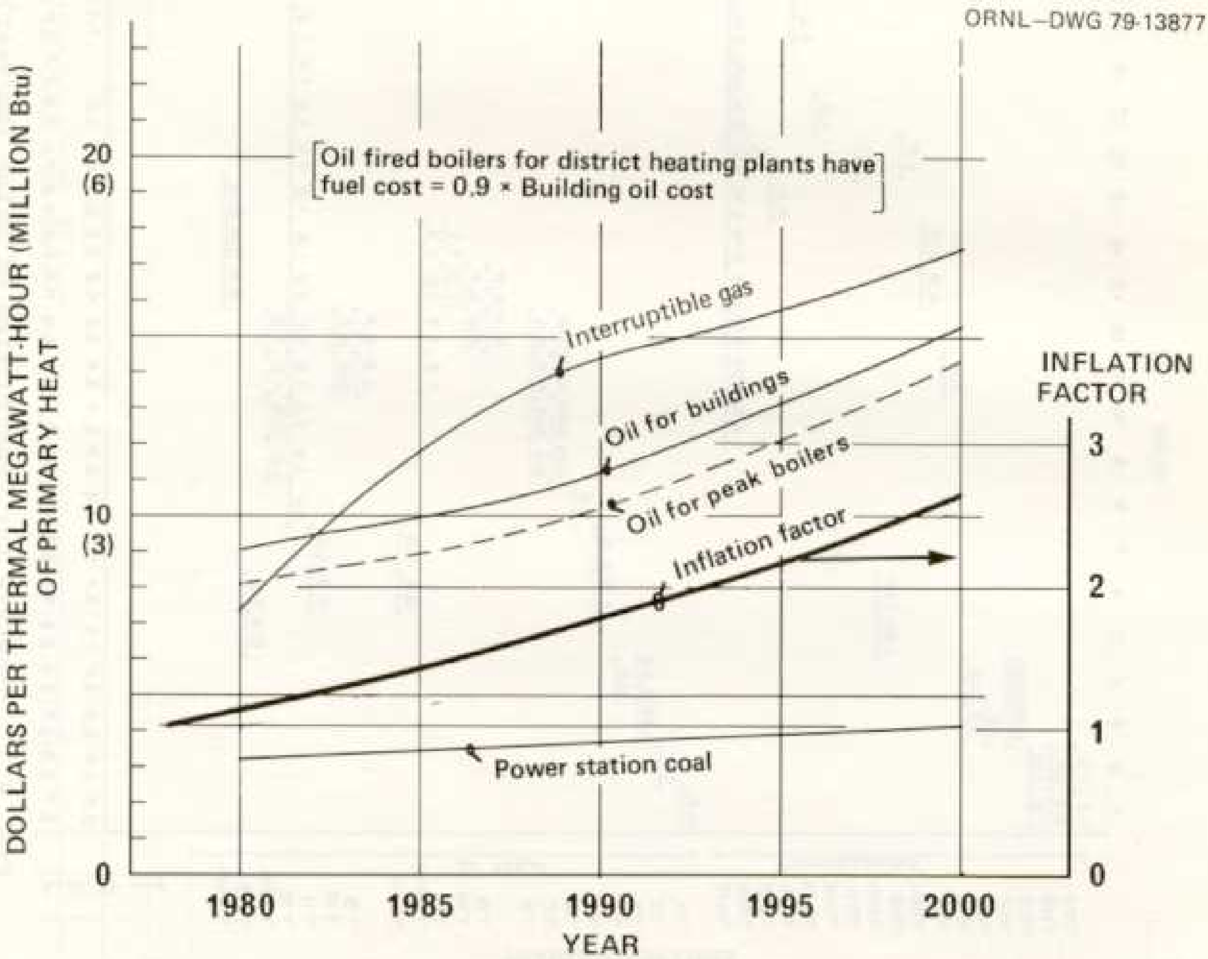

Fig. 9.4. Assumed costs, in 1978 dollars, of primary fuels per megawatt-hour of fuel heat content for the higher calorific value of fuel.

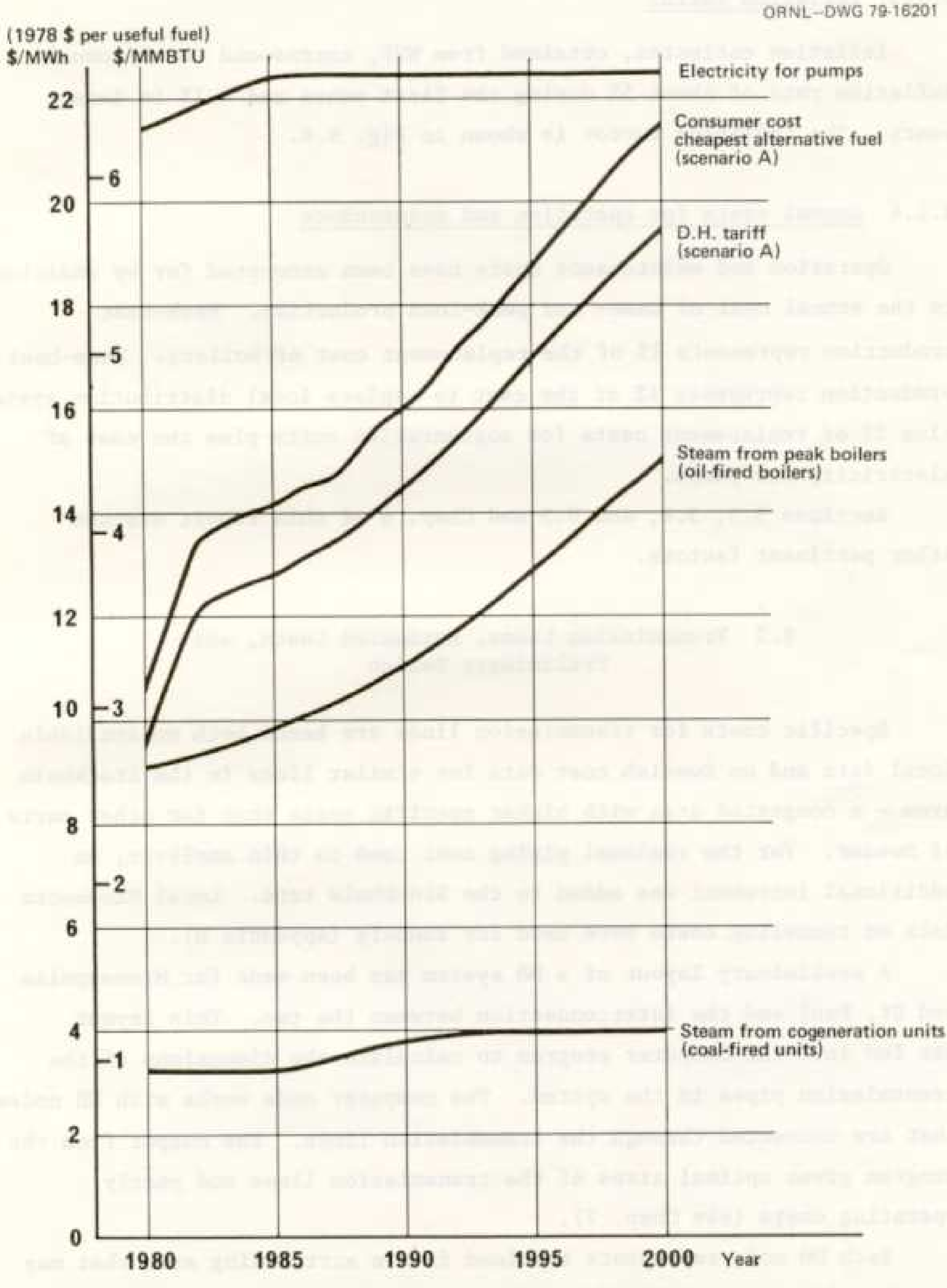

Fig. 9.5. Adopted energy prices, in 1978 dollars, including conversion efficiencies.

9.1.3 Inflation factor

Inflation estimates, obtained from NSP, correspond to an annual inflation rate of about 5% during the first years and 4.1% in later years. The inflation factor is shown in Fig. 9.4.

9.1.4 Annual costs for operation and maintenance

Operation and maintenance costs have been accounted for by additions to the annual cost of base- and peak-load production. Peak-heat production represents 1% of the replacement cost of boilers. Base-heat production represents 1% of the cost to replace local distribution systems plus 2% of replacement costs for cogeneration units plus the cost of electricity for pumps.

Sections 5.3, 5.8, and 8.5 and Chap. 6 of this report discuss other pertinent factors.

9.2 Transmission Lines, Estimated Costs, and Preliminary Design

Specific costs for transmission lines are based both on available local data and on Swedish cost data for similar lines in the Stockholm area — a congested area with higher specific costs than for other parts of Sweden. For the regional piping cost used in this analysis, an additional increment was added to the Stockholm rate. Local Minnesota data on tunneling costs were used for tunnels (Appendix D).

A preliminary layout of a DH system has been made for Minneapolis and St. Paul and the interconnection between the two. This layout was fed into the computer program to calculate the dimensions of the transmission pipes in the system. The computer code works with DH nodes that are connected through the transmission lines. The output from the program gives optimal sizes of the transmission lines and yearly operating costs (see Chap. 7).

Each DH node represents the load from a surrounding area that may consist of a part or all of one DH area or of parts of more than one. The locations of the nodes in Minneapolis and St. Paul are presented in Figs. 9.6 and 9.7. The heat loads for each node are listed in

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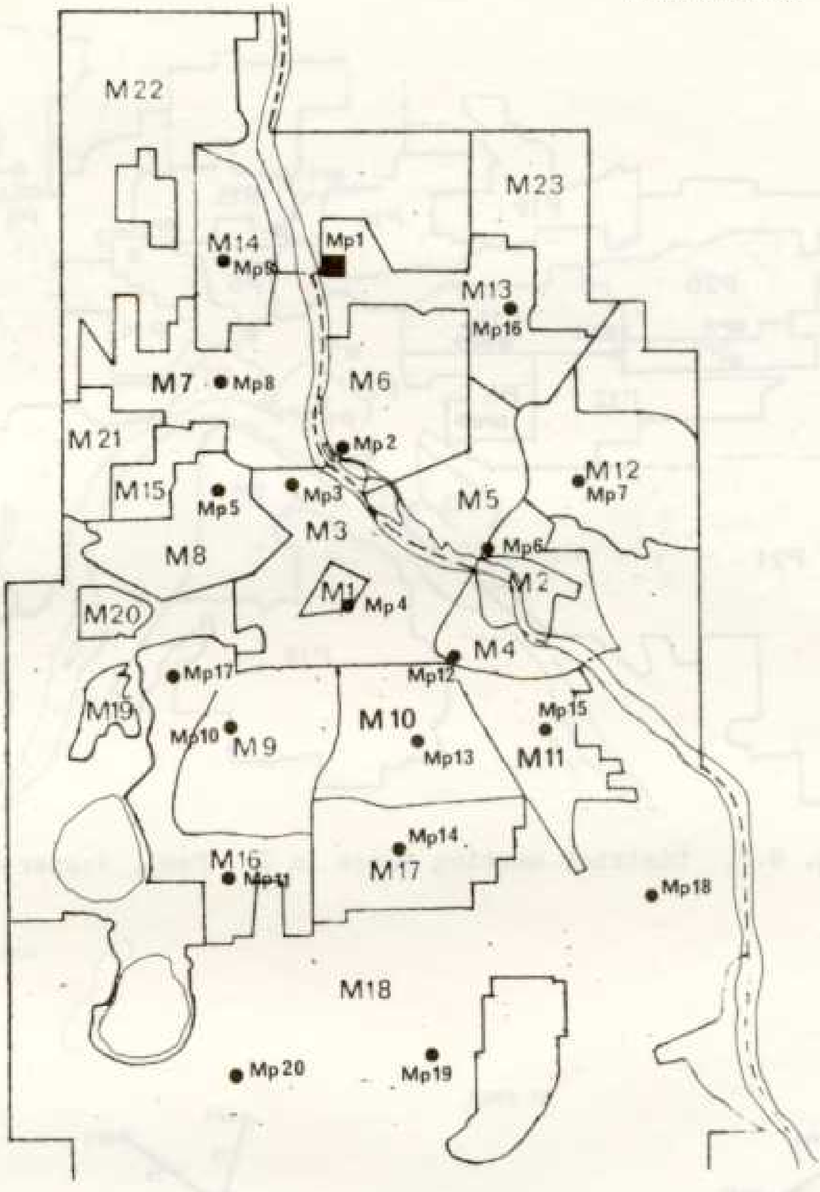

Fig. 9.6. District heating nodes in Minneapolis.

Table 9.1. The network for the transmission lines is presented in Figs. 9.8 and 9.9. Figure 9.9 depicts both scenarios. Scenario A is obtained from Scenario B by deleting nodes Mp 18 through Mp 20 and their connections. The detailed technical data are presented in Table 9.2. In Table 9.2, cost levels for three types of transmission lines have been used: tunnel; culvert, downtown; and culvert, residential areas. The cost functions used in the calculations are presented in Fig. 5.3, curves

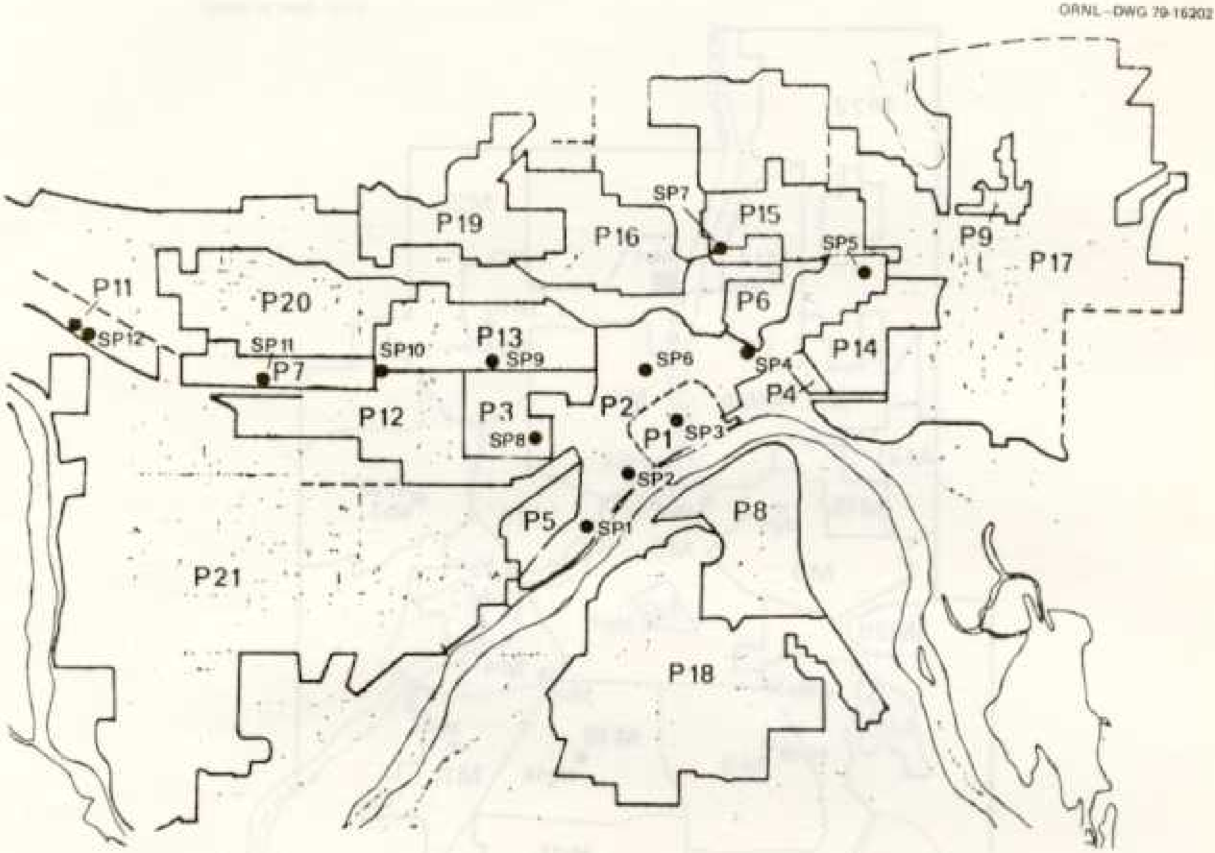

Fig. 9.7. District heating nodes in St. Paul, Scenario A.

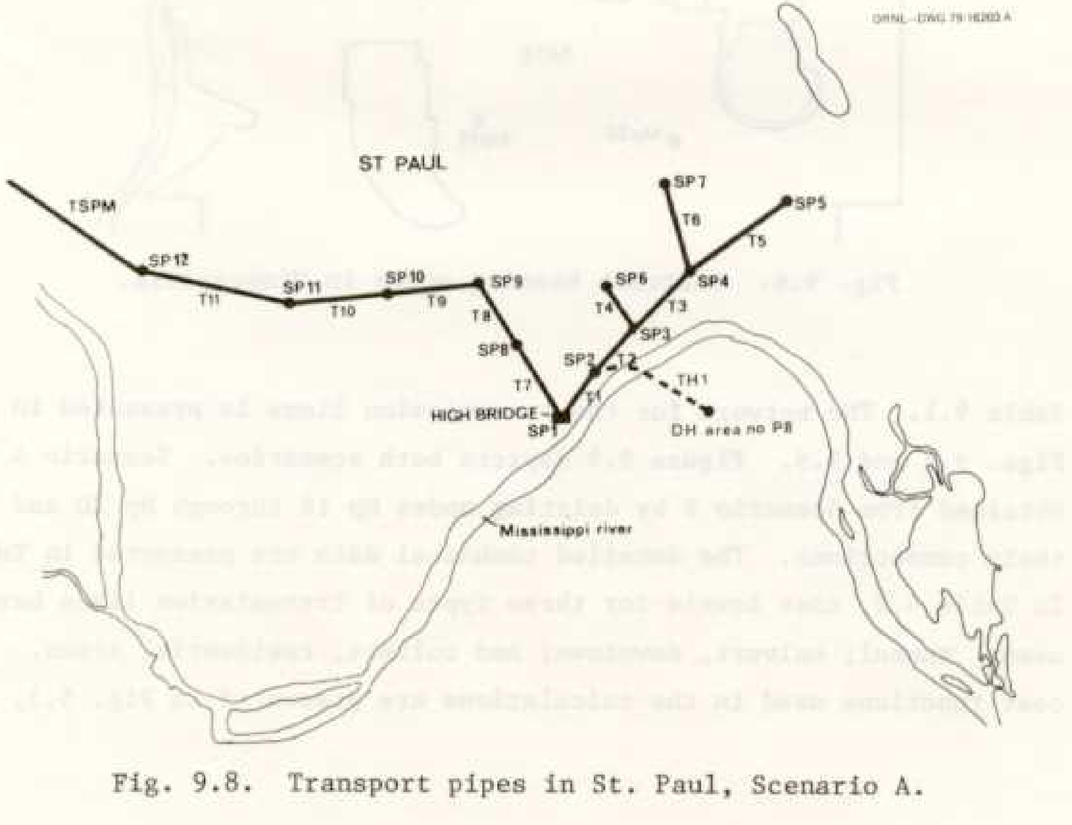

Fig. 9.8. Transport pipes in St. Paul, Scenario A.

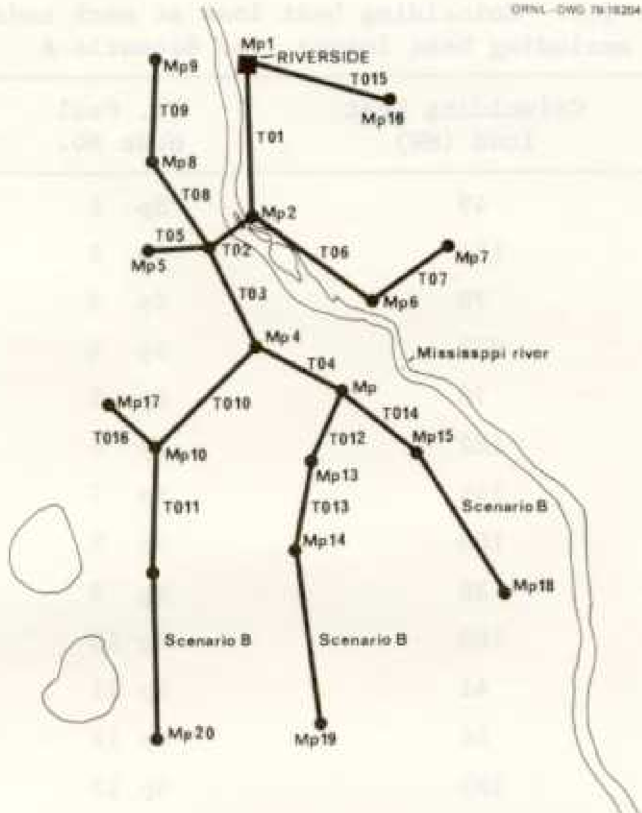

Fig. 9.9. Transport pipes in Minneapolis.

1, 2, and 3. Methods for producing the cost functions are found in Appendix D. The lengths of the transmission lines were measured from maps, and their dimensions are optimal, as calculated from the computer program and according to standard dimensions of pipes.

Heat losses in Table 9.2 have been calculated according to the following formula:

$$P = 2\pi dLk\left(\frac{T_1 + T_2}{2} - T_0\right) \approx 200dL ,$$

where

P = heat loss, W,

d = pipe diameter, m,

L = length, m,

$k = \lambda/d_{is}$,

d_{is} = insulation thickness, m,

Table 9.1. Coinciding heat load at each node, excluding heat losses, for Scenario A

Minneapolis node No.	Coinciding heat load (MW)	St. Paul node No.	Coinciding heat load (MW)
Mp 1	49	Sp 1	35
Mp 2	127	Sp 2	140
Mp 3	70	Sp 3	60
Mp 4	278	Sp 4	86
Mp 5	78	Sp 5	121
Mp 6	122	Sp 6	111
Mp 7	146	Sp 7	53
Mp 8	100	Sp 8	25
Mp 9	26	Sp 9	76
Mp 10	168	Sp 10	47
Mp 11	41	Sp 11	40
Mp 12	54	Sp 12	46 (182)[a]
Mp 13	183	Sp 13	
Mp 14	114	Sp 14	
Mp 15	97	Sp 15	
Mp 16	49	Sp 16	
Mp 17	83	Sp 17	
Mp 18		Sp 18	
Mp 19		Sp 19	
Mp 20		Sp 20	
Total	1785		840 (976)[a]

[a]This figure includes Hoerner-Waldorf, 136 MW.

λ = heat conductivity, W m^{-1} K^{-1},

T_1 = temperature of water from cogeneration plant, °C or K,

T_2 = temperature of return water, °C or K,

T_0 = temperature of the ground, °C or K.

9.3 Costs of Local Distribution Systems

The costs of the local distribution systems are estimated from actual costs in Stockholm. The cost estimated for each DH area is given in Table 9.3.

Table 9.2. Transmission lines for Scenario A

Transmission line	Node		Tunnel	Culvert		Maximum heat load (MW)	Length (km)	Size (m)		Heat loss[a] (MW)	Investments ($ × 10^6)		Pump capacity ΔP [MW(e)]
	From	To		Downtown	Residential			Optimum	Standard		Including pumps	Excluding pumps	
T 1	Sp 1	Sp 2	X			455	0.9	0.65	0.65	0.12	3.15	2.61	0.28
T 2	Sp 2	Sp 3	X			345	1.0	0.57	0.60	0.12	3.2	2.69	0.26
T 3	Sp 3	Sp 4		X		210	1.3	0.43	0.45	0.12	2.32	1.77	0.31
T 4	Sp 3	Sp 6	X			90	0.8	0.31	0.35	0.06	2.03	1.68	0.08
T 5	Sp 4	Sp 5		X		96	1.8	0.30	0.30	0.10	2.28	1.78	0.24
T 6	Sp 4	Sp 7		X		43	1.4	0.21	0.25	0.08	1.44	1.06	0.11
T 7	Sp 1	Sp 8	X			350[a]	1.3		0.60[a]	0.16		3.62[a]	0.30[a]
T 8	Sp 8	Sp 9	X			350[a]	1.2		0.60[a]	0.16		3.34[a]	0.28[a]
T 9	Sp 9	Sp 10	X			350[a]	1.4		0.60[a]	0.16		3.90[a]	0.32[a]
T 10	Sp 10	Sp 11	X			350[a]	1.3		0.60[a]	0.16		3.62[a]	0.30[a]
T 11	Sp 11	Sp 12	X			350[a]	2.1		0.60[a]	0.26		5.85[a]	0.48[a]
TSPM	Sp 12	Mp 6	X			350[a]	5.0		0.60[a]	0.60		13.93[a]	1.14[a]
TO 1	Mp 1	Mp 2			X	890	2.8	0.87	0.90	0.50	8.42	6.91	1.48
TO 2	Mp 2	Mp 3		X		675	0.8	0.74	0.75	0.12	2.7	2.08	0.42
TO 3	Mp 3	Mp 4	X			530	2.0	0.71	0.75	0.30	6.96	6.16	0.63
TO 4	Mp 4	Mp 12	X			235	1.7	0.49	0.50	0.18	4.74	4.24	0.29
TO 5	Mp 3	Mp 5			X	42	1.2	0.22	0.25	0.06	1.01	0.71	0.06
TO 6	Mp 2	Mp 6	X			350[a]	2.4		0.60[a]	0.28		6.69[a]	0.55[a]
TO 7	Mp 6	Mp 7		X		80	1.6	0.28	0.30	0.10	1.91	1.5	0.17
TO 8	Mp 3	Mp 8			X	70	1.8	0.27	0.30	0.10	1.62	1.24	0.14
TO 9	Mp 8	Mp 9			X	14	1.5	0.13	0.15	0.04	0.99	0.68	0.04
TO 10	Mp 4	Mp 10	X			152	2.5	0.41	0.45	0.10	6.22	5.75	0.32
TO 11	Mp 10	Mp 11			X	22	2.1	0.16	0.20	0.08	1.38	1.05	0.07
TO 12	Mp 12	Mp 13	X			155	1.4	0.41	0.45	0.12	3.63	3.23	0.18
TO 13	Mp 13	Mp 14		X		61	1.5	0.25	0.25	0.06	1.67	1.29	0.13
TO 14	Mp 12	Mp 15	X			50	1.4	0.24	0.25	0.08	3.11	2.78	0.08
TO 15	Mp 1	Mp 16			X	26	2.5	0.18	0.20	0.10	1.65	1.30	0.09
TO 16	Mp 10	Mp 17			X	43	1.2	0.23	0.25	0.06	1.03	0.72	0.07
TM 1	Sp 2	DH area P8		X		52[a]	1.9		0.25[a]	0.10		1.6[a]	0.14[a]

[a]Manual calculations on the basis of the computed results.

Table 9.3. Estimated costs of DH areas in local distribution system using conventional technology for Scenario A

DH area	Cost[a] ($\$ \times 10^6$)
M1	
M2	
M3	8.4
M4	7.7
M5	4.4
M6	25.3
M7	20.0
M8	13.0
M9	18.0
M10	13.6
M11	8.9
M12	3.0
M13	16.9
M14	7.9
M15	6.6
M16	18.7
M17	18.7
P1	1.4
P2	6.9
P3	5.7
P4	2.4
P5	4.7
P6	3.4
P7	1.2
P8	7.6
P9	3.5
P10	
P11	0.7
P12	12.5
P13	11.6
P14	5.6
P15	6.9
P16	10.1

[a]1978 dollars.

9.4 Explanations of Tables 9.4-9.16

The output from the computer program that deals with economics is given in Tables 9.4-9.16. Costs might be expressed either in the cost level of a fixed base year (1978) or in that of the actual year (current dollars). In the computation of the utilization time of the cogeneration units, local systems connected to the central system have been separated from those not connected. The heat losses from the transmission lines have been included under the local distribution system heading.

9.4.1 Annual energy savings (Tables 9.4 and 10.4)

Table 9.4 gives the annual fuel savings in equivalent barrels of oil. Because this study does not attempt to forecast the relative quantities of gas and oil needed for heating nor to forecast the proportions of uranium, coal, oil, and gas to be used as fuel for power stations, the use of a single energy unit, "equivalent barrels of oil," facilitates energy comparisons, and "barrels of oil" is a well-known unit in the United States.

The conversion factor used equates 1 bbl of oil to 1.87 MWhr(t). The bottom line gives the accumulated value over all 21 years.

The "oil" column gives the amount of oil needed to fire the peak-load boilers. It is computed as the peak energy production (in terawatt-hours) divided by boiler efficiency (0.9) and converted to barrels:

$$\text{oil required} = \text{peak production}/[0.9(1.87 \times 10^{-6})] \ .$$

The "gas" column gives the fuel savings to consumers of oil, gas, or whatever fuel they would have used instead of DH. This fuel savings is converted to an equivalent amount of oil by dividing the energy consumed (in terawatt-hours) (see column 3 of Table 9.9) by the assumed average boiler efficiency (0.7) times a conversion factor:

$$\text{gas saving} = \text{energy consumed}/[0.7(1.87 \times 10^{-6})] \ .$$

The "coal" column gives the equivalent increase in coal consumption if the electricity sacrifice due to cogeneration is produced by coal-fired power plants. It is computed as the loss of electricity due to cogeneration (assuming that all the cogeneration units have the same utilization time) multiplied by a factor that converts electricity production in a condensing power station to coal input, expressed in equivalent barrels of oil:

$$\text{increase in coal consumption} = \text{electricity sacrifice}/[0.4(1.87 \times 10^{-6})] \ ,$$

where electricity sacrifice equals β_N, a factor slightly less than 0.2, times base-heat production (see column 4 of Table 9.8).

Table 9.4. Annual energy savings, in equivalent barrels of oil, for the Twin Cities, Scenario A, base case

Year	Oil	Gas	Coal	Total	Accumulated
1980	0	0	0	0	0
1981	-151,402	177,013	0	25,611	25,611
1982	-240,716	365,325	-39,175	85,434	111,044
1983	-84,295	657,208	-246,966	325,947	436,992
1984	-147,462	996.169	-354,981	493,726	930,717
1985	-174,257	1,357,727	-497,668	685,802	1,616,519
1986	-219,210	1,698,571	-607,062	872,300	2,488,819
1987	-264,409	2,041,299	-696,657	1,080,233	3,569,052
1988	-311,565	2,399,091	-804,550	1,282,975	4,852,027
1989	-349,249	2,689,091	-901,860	1,437,982	6,290,009
1990	-372,426	2,869,870	-941,284	1,556,160	7,846,170
1991	-404,313	3,118,442	-1,001,902	1,712,226	9,558,395
1992	-437,628	3,374,545	-1,084,457	1,852,460	11,410,856
1993	-465,874	3,591,104	-1,154,453	1,970,777	13,381,632
1994	-500,148	3,854,740	-1,239,384	2,115,208	15,496,840
1995	-548,914	4,231,364	-1,360,227	2,322,223	17,819,063
1996	-568,544	4,376,364	-1,351,827	2,455,993	20,275,055
1997	-596,002	4,579,740	-1,370,526	2,613,213	22,888,268
1998	-616,891	4,734,156	-1,418,562	2,698,703	25,586,971
1999	-637,781	4,888,571	-1,466,598	2,784,193	28,371,164
2000	-644,276	4,935,649	-1,481,534	2,809,840	31,181,004
21 years	-7,735,000	56,936,000	-18,020,000	31,181,000	31,181,000

9.4.2 Annual investments (Tables 9.5 and 10.5)

Table 9.5 gives the annual investments in the cost level of the construction year. The column for consumer equipment contains the consumer equipment conversion costs multiplied by the relevant factor, which for the base case is 0.6.

9.4.3 Replacement cost of system (Tables 9.6 and 10.6)

Table 9.6 could be thought of as the cost of developing an identical new system in the cost level for the year in the left column. Note that this is not the value of the actual system but the value of an identical but unused system. The actual value of the system should be considerably lower due to aging of equipment.

Table 9.5. Annual investments[a] ($\$ \times 10^6$) for the Twin Cities, Scenario A, base case

Year	Consumer equipment	Local network	Base-load plants	Transmission lines	Heat-only plants	Total
1980	0.00	0.00	0.00	0.00	0.00	0.00
1981	5.19	4.07	5.28	14.30	4.87	33.71
1982	5.75	4.93	4.94	16.25	0.00	31.87
1983	9.17	8.14	9.89	7.44	0.00	34.64
1984	11.16	12.46	0.00	12.16	10.57	46.35
1985	12.57	14.04	0.00	6.12	12.17	44.90
1986	13.61	20.70	4.95	6.38	4.56	50.19
1987	13.99	19.61	5.17	7.48	5.30	51.56
1988	15.78	23.28	0.00	2.36	13.86	55.28
1989	12.80	17.36	0.00	2.99	11.66	44.80
1990	8.39	15.49	5.86	3.11	0.00	32.85
1991	10.68	24.77	0.00	13.20	9.33	57.98
1992	11.69	29.86	0.00	8.32	11.62	61.49
1993	10.52	28.55	0.00	23.85	10.24	73.15
1994	14.08	58.56	0.00	23.28	12.96	108.88
1995	20.52	72.22	0.00	3.58	0.02	96.33
1996	9.11	44.08	65.25	9.34	0.05	127.83
1997	13.41	55.93	0.00	5.93	0.18	75.45
1998	10.65	35.56	0.00	0.00	0.07	46.28
1999	11.09	37.03	0.00	7.93	0.18	56.23
2000	3.58	13.43	0.00	0.00	2.54	19.56

[a]Current dollars.

Table 9.6. Replacement cost[a] of system ($\$ \times 10^6$) for the Twin Cities, Scenario A, base case

Year	Consumer equipment	Local network	Base-load plants	Transmission lines	Heat-only plants	Total
1980	0.00	0.00	0.00	0.00	0.00	0.00
1981	5.19	4.07	5.28	14.30	4.87	33.71
1982	11.22	9.22	10.51	31.32	5.14	67.40
1983	20.98	17.84	20.95	40.41	5.41	105.58
1984	33.17	31.18	21.98	54.56	16.25	157.13
1985	47.40	46.77	23.07	63.40	29.23	209.86
1986	63.22	69.66	29.10	72.73	35.15	269.87
1987	80.09	92.43	35.59	83.51	42.05	333.66
1988	99.39	119.78	37.16	89.54	57.76	403.63
1989	116.37	142.18	38.73	96.30	71.85	465.44
1990	129.54	163.51	46.18	103.36	74.80	517.39
1991	145.54	195.00	48.07	120.81	87.21	596.64
1992	163.22	232.87	50.05	134.10	102.41	682.65
1993	180.44	270.98	52.10	163.45	116.86	783.82
1994	201.90	340.62	54.24	193.41	134.60	924.77
1995	230.64	426.72	56.45	204.88	140.10	1058.79
1996	248.15	486.33	123.75	221.67	145.25	1225.14
1997	272.92	564.52	129.42	237.75	152.07	1356.68
1998	294.71	623.12	134.70	247.45	158.35	1458.31
1999	317.95	685.84	140.25	265.58	165.07	1574.69
2000	334.50	727.24	145.97	276.41	174.34	1658.47

[a] Current dollars.

9.4.4 Heat production capacity and demand (Tables 9.7 and 10.7)

Column 4 gives the total peak and reserve boiler capacity, which may be divided into units connected or not connected to the larger centralized system. The cogeneration heat production capacity is given in column 5, and the sum of columns 4 and 5 is in column 6. Columns 7, 8, and 9 give the heat demand divided into consumer demand, heat loss, and their sum. The excess capacity, in megawatts, is computed as total capacity minus total demand and in percent as 100 times the excess capacity divided by the total demand.

9.4.5 Heat production and operating costs (Tables 9.8 and 10.8)

Columns 2 and 3 denote the total heat production capacity of cogeneration units and heat-only boilers (both peak-load and reserve

Table 9.7. Heat production capacity and heat demand of the Twin Cities, Scenario A, base case

Year	Heat-only boilers (MW)			Heat production capacity (MW)		Heat (MW)			Overcapacity	
	Decentralized	Centralized	Total	Cogeneration	Total	Demand	Loss	Total	MW	%
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	96.6	96.6	240.0	336.6	94.0	2.6	96.6	240.0	248.4
1982	0.0	96.6	96.6	397.0	493.6	194.0	5.5	199.5	294.2	147.5
1983	0.0	96.6	96.6	837.0	933.6	349.0	9.8	358.8	574.9	164.2
1984	0.0	276.8	276.8	837.0	1113.8	529.0	14.8	543.8	570.0	104.8
1985	0.0	474.3	474.3	837.0	1311.3	721.0	20.3	741.3	570.0	76.9
1986	0.0	545.0	545.0	954.0	1499.0	902.0	27.0	929.0	570.0	61.4
1987	0.0	623.6	623.6	1064.0	1687.6	1084.0	33.6	1117.6	570.0	51.0
1988	0.0	820.6	820.6	1064.0	1884.6	1274.0	40.6	1314.6	570.0	43.4
1989	0.0	979.5	979.5	1064.0	2043.5	1428.0	45.5	1473.5	570.0	38.7
1990	0.0	979.5	979.5	1181.0	2160.5	1524.0	48.2	1572.2	588.3	37.4
1991	0.0	1096.9	1096.9	1181.0	2277.9	1656.0	51.9	1707.9	570.0	33.4
1992	0.0	1237.3	1237.3	1181.0	2418.3	1792.0	56.3	1848.3	570.0	30.8
1993	0.0	1356.1	1356.1	1181.0	2537.1	1907.0	60.1	1967.1	570.0	29.0
1994	0.0	1500.6	1500.6	1181.0	2681.6	2047.0	64.6	2111.6	570.0	27.0
1995	0.0	1500.8	1500.8	1181.0	2681.8	2247.0	70.8	2317.8	364.0	15.7
1996	0.0	1501.2	1501.2	1516.0	3017.2	2324.0	74.2	2398.2	619.0	25.8
1997	0.0	1503.0	1503.0	1516.0	3019.0	2432.0	79.0	2511.0	508.0	20.2
1998	0.0	1503.7	1503.7	1516.0	3019.7	2514.0	82.7	2596.7	423.0	16.3
1999	0.0	1505.4	1505.4	1516.0	3021.4	2596.0	86.4	2682.4	339.0	12.6
2000	0.0	1527.7	1527.7	1516.0	3043.7	2621.0	87.7	2708.7	335.0	12.4

Table 9.8. Heat production and operating costs for the Twin Cities, Scenario A, base case

Year	Heat production capacity [MW(t)]		Energy produced (TWhr)		Operating costs[a] ($/MWhr)		Operation and maintenance costs[a] ($/MWhr)	
	Base load	Heat only	Base load	Heat only	Base load	Heat only	Base load	Heat only
1980	0.0	0.0	0.0000	0.0000	3.55	10.18	0.00	0.00
1981	240.0	96.6	0.0000	0.2548	3.74	11.20	0.00	0.19
1982	397.0	96.6	0.1211	0.4051	10.83	11.94	6.88	0.13
1983	837.0	96.6	0.8039	0.1419	5.68	12.99	1.53	0.38
1984	837.0	276.8	1.1854	0.2482	5.71	14.07	1.36	0.65
1985	837.0	474.3	1.6619	0.2933	5.73	15.23	1.16	1.00
1986	954.0	545.0	2.0906	0.3689	6.04	16.31	1.15	0.95
1987	1064.0	623.6	2.5217	0.4450	6.40	17.11	1.16	0.94
1988	1064.0	820.5	2.9714	0.5244	6.70	18.37	1.12	1.10
1989	1064.0	979.5	3.3308	0.5878	7.24	19.97	1.10	1.22
1990	1181.0	979.5	3.5518	0.6268	7.87	21.08	1.16	1.19
1991	1181.0	1096.9	3.8559	0.6805	8.24	22.61	1.21	1.28
1992	1181.0	1237.3	4.1737	0.7365	8.64	24.52	1.26	1.39
1993	1181.0	1356.1	4.4430	0.7841	9.07	26.04	1.36	1.49
1994	1181.0	1500.6	4.7699	0.8417	9.58	28.30	1.51	1.60
1995	1181.0	1500.8	5.2350	0.9238	10.04	29.97	1.58	1.52
1996	1516.0	1501.2	5.4222	0.9569	10.74	32.08	1.92	1.52
1997	1516.0	1503.0	5.6841	1.0031	11.33	34.44	2.03	1.52
1998	1516.0	1503.7	5.8833	1.0382	11.83	36.88	2.10	1.53
1999	1516.0	1505.4	6.0825	1.0734	12.39	39.22	2.19	1.54
2000	1516.0	1527.7	6.1445	1.0843	12.95	41.74	2.28	1.61

[a]Current dollars.

boilers). Columns 4 and 5 give the total amount of heat delivered from these, including consumer demand and heat losses. Columns 6 and 7 give the operating costs, including both running costs and costs of operation and maintenance. The computation of running costs is described in Appendix E. The costs of operation and maintenance, given in columns 8 and 9, are based on the replacement cost of the system. Pumping cost is included in the base-load column.

9.4.6 Heat consumption and heat rate (Tables 9.9 and 10.9)

Coinciding demand is the total load connected to the central system and to isolated DH islands. Consumed energy is the energy demand of the consumers, excluding distribution losses.

"Rate" in dollars per megawatt-hour is the average price per megawatt-hour that consumers pay for heat. This rate is averaged over all consumer categories; fixed charges are also included. "Rate" in cents per million Btu is a simple conversion of the preceding figure, using 1 MWhr = 3.413×10^6 Btu or 10^6 Btu = 0.293 MWhr.

9.4.7 Income statement (Tables 9.10 and 10.10)

"Gross revenue," the revenue obtained from the sale of heat, equals the consumed energy times the rate (columns 3 and 4 of Table 9.9).

"Operating costs" are the running and operation and maintenance costs of heat production, including losses. These costs equal the sum of the cost of base-load production (product of columns 4 and 6 in Table 9.8) and peak-load production (product of columns 5 and 7 in Table 9.8). "Operating income" is the gross revenues minus the operating costs.

9.4.8 Income statement (Tables 9.11 and 10.11)

Table 9.11 corresponds to Table 9.10, but the figures have been divided by the consumed energy times 3.413 to convert from dollars to dollars per million Btu consumed.

Table 9.9. Heat consumption and heat rate for the Twin Cities, Scenario A, base case

Year	Coinciding demand (MW)	Consumed energy (TWhr)	Rate[a] (\$/MWhr)	Rate[a] (\$/10^6 Btu)
1980	0.0	0.0000	10.55	3.09
1981	94.0	0.2317	12.77	3.74
1982	194.0	0.4782	15.08	4.42
1983	349.0	0.8603	16.21	4.75
1984	529.0	1.3040	17.25	5.05
1985	721.0	1.7773	18.30	5.36
1986	902.0	2.2234	19.75	5.79
1987	1084.0	2.6721	20.78	6.09
1988	1274.0	3.1404	22.20	6.50
1989	1428.0	3.5200	24.11	7.06
1990	1524.0	3.7567	25.56	7.49
1991	1656.0	4.0820	27.42	8.04
1992	1792.0	4.4173	29.73	8.71
1993	1907.0	4.7008	31.57	9.25
1994	2047.0	5.0459	34.33	10.06
1995	2247.0	5.5389	36.58	10.72
1996	2324.0	5.7287	39.30	11.51
1997	2432.0	5.9949	42.33	12.40
1998	2514.0	6.1970	45.46	13.32
1999	2596.0	6.3991	48.45	14.20
2000	2621.0	6.4608	51.59	15.12

[a]Current dollars.

9.4.9 Municipal financing (Tables 9.12 and 10.12) and private financing (Tables 9.13 through 9.15 and 10.13 through 10.15)

The values appearing in these tables are explained in detail in Chap. 8.

9.4.10 Comparative analysis (Tables 9.16 and 10.16)

These tables compare the revenue requirement with the actual revenue estimate. Columns 2 through 6 are related to municipal financing and columns 7 through 11 to private utility financing.

Table 9.10. Income statement[a] ($\$ \times 10^6$) for the Twin Cities, Scenario A, base case

Year	Gross revenue	Operating costs	Operating income
1980	0.00	0.00	0.00
1981	2.96	2.85	0.10
1982	7.21	6.15	1.06
1983	13.95	6.41	7.54
1984	22.49	10.27	12.23
1985	32.52	13.98	18.54
1986	43.91	18.65	25.26
1987	55.52	23.74	31.78
1988	69.71	29.54	40.17
1989	84.85	35.86	48.99
1990	96.03	41.17	54.86
1991	111.95	47.16	64.78
1992	131.34	54.11	77.24
1993	148.40	60.73	87.68
1994	173.21	69.52	103.69
1995	202.62	80.26	122.36
1996	225.11	88.94	136.18
1997	253.79	98.92	154.86
1998	281.70	107.86	173.84
1999	310.05	117.49	192.56
2000	333.33	124.83	208.49

[a]Current dollars.

Columns 2 and 3 give the difference between operating income (column 4 of Table 9.10) and the total revenue requirement (column 7 of Table 9.12) in current dollars and in 1978 dollars. Column 4, "Present worth," is obtained by dividing column 2 by

$$(1 + R65)^N ,$$

where N is year minus 1980 and R65 is 0.065, or 6.5%. Columns 5 and 6 are the accumulated sums of columns 3 and 4. The figures in column 6 are the values denoted by "net saving" for municipal financing.

Table 9.11. Income statement[a] ($\$/10^6$ Btu) for the Twin Cities, Scenario A, base case

Year	Gross revenue	Operating costs	Operating income
1980	0	0	0
1981	3.74	3.61	0.13
1982	4.42	3.77	0.65
1983	4.75	2.18	2.57
1984	5.05	2.31	2.75
1985	5.36	2.31	3.06
1986	5.79	2.46	3.33
1987	6.09	2.60	3.48
1988	6.50	2.76	3.75
1989	7.06	2.98	4.08
1990	7.49	3.21	4.28
1991	8.04	3.39	4.65
1992	8.71	3.59	5.12
1993	9.25	3.79	5.46
1994	10.06	4.04	6.02
1995	10.72	4.25	6.47
1996	11.51	4.55	6.96
1997	12.40	4.83	7.57
1998	13.32	5.10	8.22
1999	14.20	5.38	8.82
2000	15.12	5.66	9.46

[a]Current dollars.

Columns 7 through 11 correspond to columns 2 through 6, except that operating income and total revenue requirement are different for private utility financing (column 5 of Table 9.15), and the interest factor used in computing the present worth is R12 = 0.1088 (10.88%) instead of R65 = 0.065.

Table 9.12. Municipal financing[a] ($\$ \times 10^6$) for the Twin Cities, Scenario A, base case

Year	Book depreciation	Book depreciation reserve, first of year	Net investment	Return requirement	Property taxes	Total revenue requirement
1980	0.00	0.00	0.00	0.00	0.00	0.00
1981	1.33	0.00	33.71	2.19	0.00	3.52
1982	2.57	1.33	64.26	4.18	0.00	6.74
1983	4.12	3.90	96.33	6.26	0.00	10.38
1984	5.99	8.01	138.57	9.01	0.00	14.99
1985	7.89	14.00	177.48	11.54	0.00	19.42
1986	10.00	21.89	219.79	14.29	0.00	24.28
1987	12.18	31.88	261.36	16.99	0.00	29.16
1988	14.52	44.06	304.46	19.79	0.00	34.31
1989	16.42	58.58	334.74	21.76	0.00	38.17
1990	17.80	74.99	351.18	22.83	0.00	40.63
1991	19.97	92.79	391.36	25.44	0.00	45.41
1992	22.31	112.76	432.88	28.14	0.00	50.44
1993	24.91	135.07	483.73	31.44	0.00	56.36
1994	28.71	159.98	567.70	36.90	0.00	65.61
1995	32.24	188.69	635.32	41.30	0.00	73.54
1996	36.55	220.93	730.90	47.51	0.00	84.06
1997	39.22	257.48	769.81	50.04	0.00	89.26
1998	40.95	296.71	776.87	50.50	0.00	91.45
1999	42.98	337.66	792.15	51.49	0.00	94.47
2000	43.71	380.64	768.72	49.97	0.00	93.67

[a]Current dollars.

Table 9.13. Private financing[a] ($ × 10^6) for the Twin Cities, Scenario A, base case

Year	Beginning of year gross plant revenue	Book depreciation reserve	Deferred tax reserve	Investment credit reserve	Beginning of year net plant income	Property taxes
1980	0.00	0.00	0.00	0.00	0.00	0.00
1981	33.71	0.00	0.00	0.00	33.71	0.00
1982	65.59	1.33	0.80	3.24	63.46	0.00
1983	100.23	3.90	2.30	6.17	94.03	0.00
1984	146.58	8.01	4.40	9.22	134.17	0.00
1985	191.48	14.00	7.38	13.26	170.11	0.00
1986	241.68	21.89	11.07	16.96	208.73	0.00
1987	293.24	31.88	15.50	20.98	245.86	0.00
1988	348.52	44.06	20.61	24.92	283.85	0.00
1989	393.32	58.58	26.37	28.99	308.37	0.00
1990	426.17	74.99	32.44	31.83	318.74	0.00
1991	484.16	92.79	38.47	33.34	352.90	0.00
1992	545.64	112.76	45.10	37.14	387.79	0.00
1993	618.80	135.07	52.28	41.06	431.45	0.00
1994	727.68	159.98	60.27	45.88	507.43	0.00
1995	824.01	188.69	69.89	53.90	565.43	0.00
1996	951.84	220.93	80.50	60.31	650.41	0.00
1997	1027.29	257.48	93.05	69.95	676.75	0.00
1998	1073.57	296.71	105.86	74.15	671.01	0.00
1999	1129.81	337.66	118.06	75.60	674.09	0.00
2000	1149.36	380.64	129.91	78.04	638.81	0.00

Table 9.14. Private financing[a] ($\$ \times 10^6$) for the Twin Cities, Scenario A, base case

Year	Return on equity	Return on debt	Book depreciation	Tax depreciation	Deferred taxes
1980	0.00	0.00	0.00	0.00	0.00
1981	2.25	1.42	1.33	2.87	0.80
1982	4.24	2.67	2.57	5.45	1.50
1983	6.28	3.95	4.12	8.15	2.10
1984	8.96	5.64	5.99	11.72	2.98
1985	11.36	7.14	7.89	14.99	3.69
1986	13.94	8.77	10.00	18.53	4.43
1987	16.42	10.33	12.18	22.01	5.11
1988	18.96	11.92	14.52	25.60	5.76
1989	20.60	12.95	16.42	28.10	6.07
1990	21.29	13.39	17.80	29.41	6.03
1991	23.57	14.82	19.97	32.73	6.63
1992	25.90	16.29	22.31	36.13	7.18
1993	28.82	18.12	24.91	40.29	7.99
1994	33.90	21.31	28.71	47.22	9.62
1995	37.77	23.75	32.24	52.67	10.61
1996	43.45	27.32	36.55	60.72	12.56
1997	45.21	28.42	39.22	63.87	12.80
1998	44.82	28.18	40.95	64.44	12.20
1999	45.03	28.31	42.98	65.80	11.85
2000	42.67	26.83	43.71	63.91	10.49

[a]Current dollars.

9.5 Economic Results

9.5.1 Base case

Output from the economic program for the base case is shown in Tables 9.5 through 9.16. Figure 9.10 shows the calculated annual net savings in 1978 dollars for the reference cases for municipal utility

Table 9.15. Private financing[a] ($\$ \times 10^6$) for the Twin Cities, Scenario A, base case

Year	Investment credit: General	Investment credit: Flow through	Income taxes	Total revenue requirement
1980	0.00	0.00	0.00	0.00
1981	3.37	0.13	-1.88	7.16
1982	3.19	0.26	-0.38	13.52
1983	3.46	0.41	0.78	20.28
1984	4.64	0.60	1.43	20.03
1985	4.49	0.79	3.25	37.04
1986	5.02	1.00	4.54	45.70
1987	5.16	1.22	6.18	54.15
1988	5.53	1.45	7.64	62.88
1989	4.48	1.64	9.95	68.82
1990	3.29	1.78	11.78	71.79
1991	5.80	2.00	10.90	79.70
1992	6.15	2.23	12.26	87.86
1993	7.32	2.49	13.16	97.83
1994	10.89	2.87	13.04	114.59
1995	9.63	3.22	17.11	127.89
1996	13.30	3.66	17.16	146.68
1997	8.12	3.92	23.71	153.57
1998	5.55	4.10	26.28	153.90
1999	6.74	4.30	25.44	156.06
2000	3.21	4.37	27.70	150.25

[a]Current dollars.

and private utility financing (solid lines) and for certain variations from the reference cases. Figure 9.11 shows the accumulated present worth of net savings expressed in 1978 dollars. In this figure, conversions from the year of operation to 1978 were made using the appropriate average interest rates for the two cases, that is, 6.5%/year for municipal financing and 10.88%/year for utility financing, and the proper inflation factor.

Table 9.16. Comparative analysis of financing methods ($ × 10^6) for the Twin Cities, Scenario A, base case

Year	Municipal financing					Private financing				
	Difference		Present worth	Accumulated difference (1978 dollars)	Accumulated present worth	Difference		Present worth	Accumulated difference (1978 dollars)	Accumulated present worth
	Current dollars	1978 dollars				Current dollars	1978 dollars			
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	-3.42	-2.91	-2.83	-2.91	-2.83	-7.05	-6.01	-5.17	-6.01	-5.17
1982	-5.68	-4.59	-4.41	-7.51	-7.24	-12.46	-10.08	-8.24	-16.09	-13.41
1983	-2.84	-2.19	-2.07	-9.69	-9.32	-12.75	-9.80	-7.61	-25.89	-21.02
1984	-2.76	-2.03	-1.89	-11.72	-11.21	-16.80	-12.31	-9.04	-38.19	-30.06
1985	-0.89	-0.62	-0.57	-12.34	-11.78	-18.50	-12.91	-8.98	-51.11	-39.04
1986	0.97	0.65	0.59	-11.69	-11.20	-20.44	-13.63	-8.95	-64.73	-47.99
1987	2.61	1.67	1.48	-10.02	-9.71	-22.37	-14.27	-8.83	-79.00	-56.82
1988	5.86	3.58	3.12	-6.44	-6.59	-22.71	-13.87	-8.08	-92.87	-64.90
1989	10.82	6.34	5.41	-0.10	-1.18	-19.83	-11.62	-6.37	-104.50	-71.27
1990	14.23	8.01	6.68	7.91	5.50	-16.94	-9.54	-4.90	-114.03	-76.17
1991	19.38	10.48	8.54	18.39	14.05	-14.91	-8.06	-3.89	-122.10	-80.07
1992	26.79	13.92	11.10	32.31	25.15	-10.62	-5.52	-2.50	-127.62	-82.57
1993	31.32	15.63	12.18	47.94	37.32	-10.15	-5.07	-2.16	-132.69	-84.73
1994	38.08	18.25	13.90	66.19	51.23	-10.90	-5.23	-2.09	-137.91	-86.82
1995	48.82	22.49	16.74	88.68	67.96	-5.53	-2.55	-0.96	-140.46	-87.77
1996	52.11	23.16	16.78	111.84	84.74	-10.51	-4.67	-1.64	-145.13	-89.41
1997	65.60	27.88	19.83	139.73	104.57	1.30	0.55	0.18	-144.58	-89.23
1998	82.39	33.64	23.38	173.37	127.95	19.94	8.14	2.53	-136.43	-86.70
1999	98.09	38.47	26.14	211.84	154.09	36.50	14.31	4.17	-122.12	-82.53
2000	114.82	43.26	28.73	255.10	182.82	58.25	21.95	6.00	-100.17	-76.52

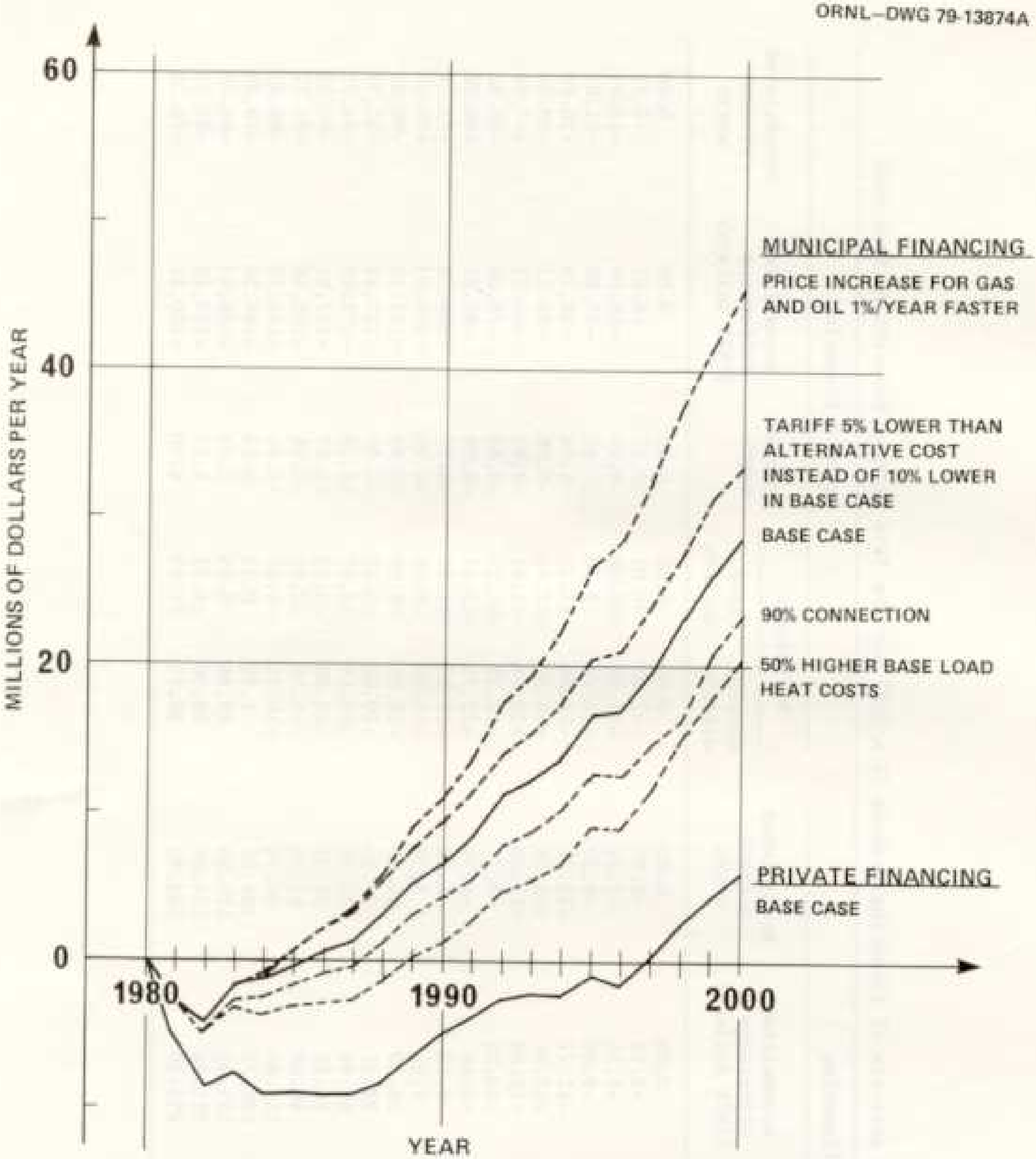

Fig. 9.10. Annual net savings in 1978 dollars, Scenario A.

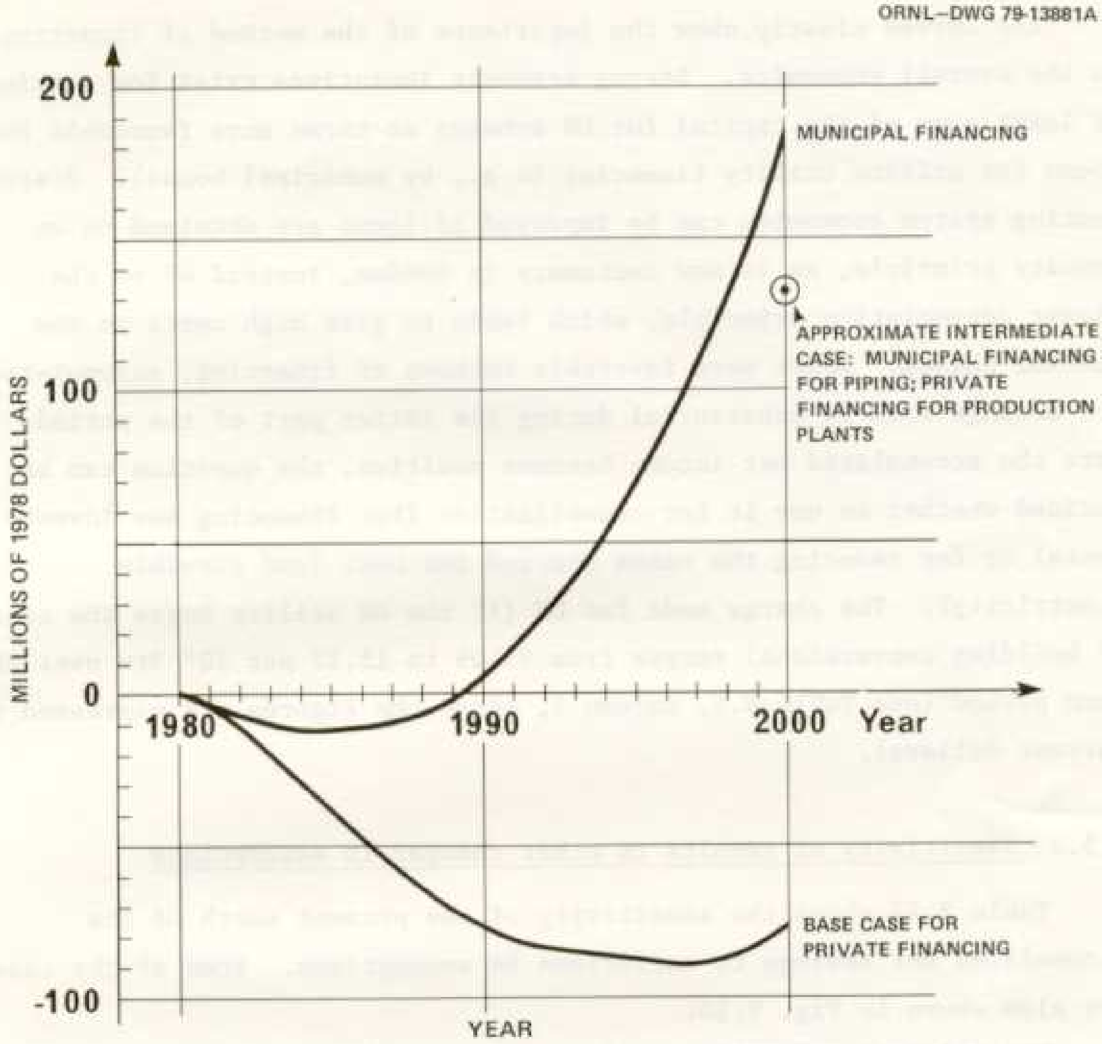

Fig. 9.11. Accumulated present worth of net savings for base case, Scenario A.

The results show that with municipal financing net savings soon become positive, and the present worth of the net savings accumulated by the end of the period is considerable, +\$183 million (in 1978 dollars). Under private utility financing, annual costs take much longer to break even with savings. The accumulated net saving does not become positive during the period considered. The residual net negative value at the end of the period is about -\$77 million (in 1978 dollars). Under an intermediate form of financing (i.e., private utility financing for production plants and municipal financing for transport and distribution systems) a net positive accumulated saving would result. By interpolation, this is estimated to amount to about \$132 million (in 1978 dollars).

The curves clearly show the importance of the method of financing to the overall economics. Strong economic incentives exist for seeking at least some of the capital for DH schemes at terms more favorable than those for private utility financing (e.g., by municipal bonds). District heating system economics can be improved if loans are obtained on an annuity principle, as is now customary in Sweden, instead of on the linear depreciation principle, which tends to give high costs in the initial phases. Under more favorable methods of financing, accumulated net savings will be substantial during the latter part of the period. Once the accumulated net income becomes positive, the question can be decided whether to use it for consolidation (for financing new investments) or for reducing the rates charged for heat (and possibly electricity). The charge made for DH (if the DH utility bears the costs of building conversions) ranges from \$3.09 to 15.12 per 10^6 Btu over the same period (see Table 9.9, column 5, where the figures are expressed in current dollars).

9.5.2 Sensitivity of results to other changes in assumptions

Table 9.17 shows the sensitivity of the present worth of the accumulated net savings to variations in assumptions. Some of the cases are also shown in Fig. 9.10.

One critical assumption projects the cost level for the transport and distribution systems. The cost level we used, characteristic for the Stockholm area, is considerably higher than that for other regions in Sweden. If actual costs were 20% lower, the accumulated net savings would increase by about \$44 million (in 1978 dollars), as shown by case 2 of Table 9.17.

With respect to the connection rate, we assumed that 100% of all the present consumers within the supply area for Scenario A would connect, although the actual connection rate will probably be lower. In case 3, we have shown the influence of a connection rate 10% lower than in the base case, but the transport and distribution systems would still be built

Table 9.17. Sensitivity of net accumulated savings ($\$ \times 10^6$) to changes in assumption, Scenario A

Case	Net accumulated saving		Change from base case	
	Municipal financing	Private utility financing	Municipal financing	Private utility financing
1. Base case	182.8	-76.5		
2. 20% lower transmission and distribution costs	227.2	-32.5	+44.4	+44.0
3. 90% connection without change in transmission and distribution costs[a]	127.2	-103.1	-55.6	-26.6
4. 50% instead of 60% of all buildings converted	189.6	-62.2	+6.8	+14.3
5. 1%/year faster oil and gas cost increases	308.1	-13.7	+125.3	+62.8
6. 50% higher base-load energy costs	81.3	-131.8	-101.5	-55.3
7. District heating rate at 5% instead of 10% below fuel cost	234.3	-48.7	+51.5	+27.8
8. Includes the effect of property taxes (4.5% for the private utility finance)		-133.3		-56.8
9. Extends the economic analysis another 10 years for a total of 30 years	501.0	11.88	+318.2	+88.4

[a]1978 dollars.

[b]Pessimistic assumption because transmission and distribution systems would be cheaper with 90% connection.

for the load corresponding to the full 100% connection despite the lower heat demand. That pessimistic assumption reduces the accumulated net savings by $56 million and $27 million for municipal and private financing respectively.

In connection with the assumption of 100% connection for Scenario A, one should also note that we have neglected the probable net load increase due to new establishments within the area to some big industries and to two of the existing steam DH systems. The influence of additional loads from such sources would tend to compensate, at least in part, for the effect of an overly optimistic assumed connection rate.

If the cost for building conversions charged to the DH system is only 50% instead of 60% (as in the base case), net accumulated savings would increase by $7 to 14 million (1978 dollars)* (case 4).

One of the most critical sensitivities is that of oil and gas prices projected for the future. Because the NSP staff considers its long-range predictions of oil and gas price increases to be on the low side, we have shown by case 5 the influence of a 1%/year faster increase in these prices. This increases the net accumulated savings substantially, that is, by $125 million and $63 million for municipal and private financing respectively. Higher assumed gas and oil prices almost eliminate the negative savings (loss) for the private utility financing case.

Case 6 illustrates the influence of a 50% higher level of coal costs, as might be the case for cities having to rely on eastern coal. This reduces net savings by $101 million and $55 million respectively. This case does not really apply to the Twin Cities area.

Case 7 shows the effect of reducing the average cost incentive to consumers (i.e., the difference between the charge for heat and the cost of alternative fuel) from 10 to 5%. This increases the accumulated net savings achieved by the utility by $52 million and $28 million, respectively, assuming that all consumers still connect.

Case 8 deals with the effect of property taxes on the transmission and distribution systems for the private ownership option. Property taxes

*All references to money in the rest of this section are to 1978 dollars.

for a private utility are estimated at about 4.5% of the gross revenues from the plant annually. This reduces the net savings by $57 million.

Finally, case 9 extends the economic analysis another 10 years for a total of 30 years. This extension is based on the following assumptions: (1) no system expansion takes place after 20 years; (2) no reinvestments are considered for the converted cogeneration plants; and (3) after the year 2000, fuel prices follow inflation, contrary to their trend during the period 1980-2000, when they are assumed to rise faster than inflation. A 30-year period yields accumulated net savings of $501 million and $12 million respectively. The total energy savings during this longer period is equivalent to 60 million barrels of oil. These examples give some indication of the degree to which changes in the conditions can influence the overall financial results.

Despite the deviations that various changes in assumptions (cases 2 through 8) produce, the broad picture given by the base case seems to be representative, that is, it shows substantial positive net accumulated savings with municipal financing and a small net negative accumulated savings with full private financing. An intermediate solution with private financing of production plants and municipal financing of transport and distribution should give significant positive net accumulated savings.

9.5.3 Other factors influencing results

The influence of some other factors on net savings that have not been evaluated quantitatively but have been indicated qualitatively are shown in Table 9.18. These factors consider the following points: (1) no credit has been taken for existing boiler plants in the area, some of which could probably be used for peak-load and reserve purposes; (2) we have assumed that sites would be available for locating new peak-load and reserve boilers at the various junctions of transport pipes in the area, which probably will only be partially true; and (3) we have neglected the savings that, in practice, could be made by installing hot water accumulators to decrease the daily peak loads, thus reducing heat-only boiler capacity and making more effective use of cogeneration capacity.

None of these factors individually produces large changes in the net savings, and the conservative and optimistic aspects of these simplifying assumptions should approximately balance. Hence, the net influence on the overall results should be relatively small.

Table 9.18. Simplified assumptions that tend to give conservative or optimistic results compared with expectations, Scenario A

Assumption	Result
For consumer connections	
100% connection of present consumers in Scenario A area	Optimistic
Neglecting net load growth due to new construction on vacant sites, etc.	Conservative
Neglecting load from some large industries and two of existing steam DH systems	Conservative
For heat-only boilers	
Neglecting use of existing boilers at 3rd Street plant in St. Paul, at larger industries, and in larger buildings	Conservative
Finding sites for new oil-fired boilers at all major line junctions	Optimistic
For heat storage	
Neglecting use of heat accumulators, which cut daily load peaks and improve flexibility of cogeneration plants	Conservative

10. RESULTS, SCENARIO B

10.1 Assumptions for Technical and Economic Calculations

10.1.1 Expansion period

The objective of Scenario B is to justify the extension of the distribution system to incorporate a greater part of residential areas with mainly one-family houses and medium load densities (i.e., 10 to 20 MW/km^2). The total coincident demand amounts to 2588 MW(t) for Minneapolis and 1454 MW(t) for St. Paul [4042 MW(t)], assuming that 70% of the consumers in the additional areas connect to the system.

The investment in the distribution system for the additional areas is estimated for two alternative assumptions:

1. conventional technology of the type practiced in Sweden (i.e., prefabricated culverts);

2. newer technology of the type introduced in some DH systems in recent years (e.g., temperature-resistant plastic pipes); the total cost for these pipes and installations is assumed to be 70% of the corresponding cost for conventional pipes in accordance with current experiences and projections in Sweden.

To create the necessary additional cogeneration capacity, a site outside the metropolitan area had to be used. Therefore, King, 17 miles from downtown St. Paul, was selected for the investigation. This replaces the new unit R9 for the Riverside site in Scenario A. The buildup and the power plant expansion program are discussed further in Sect. 5.5 and Chap. 4.

The development of the system is summarized in Figs. 9.1 to 9.3 and in Fig. 4.6.

10.1.2 Energy prices, inflation factor, and annual costs for operation and maintenance

The energy price evaluation, inflation estimates, and annual costs for operation and maintenance have been treated in the same way as for Scenario A (see Sect. 9.1).

The rates for selling DH for the part of the load corresponding to Scenario A were calculated in the same manner as before. For the additional DH load for Scenario B, the fuel cost for alternative heat production in individual boilers was based on an average boiler efficiency of 58% instead of 70% because the additional load was substantially for one-family houses with small domestic boilers. Because these would burn firm gas or, later, light fuel oil, the costs for interruptible gas and building oil for Scenario A were multiplied by 1.25 for the additional Scenario B part of the load to reflect the higher cost of the fuel for individual furnaces and boilers in one-family houses.

10.2 Transmission Lines, Preliminary Design

A preliminary layout of a system was made for the networks in Minneapolis and St. Paul, as well as for the interconnector between the two cities, and the transmission line from King. The system layout was fed into the computer program to calculate the dimensions of the transmission lines in the system. The necessary input data and the interpretation of the results from the computer program are briefly discussed in Sect. 9.2 and Chap. 7.

The locations of the DH nodes for Scenario B are presented in Fig. 9.7 for Minneapolis and in Fig. 10.1 for St. Paul. The coincident heat loads for each node are listed in Table 10.1.

The network for the transmission lines is presented in Figs. 10.2 and 9.10, and the detailed technical data are presented in Table 10.2. Comments to Table 10.2 are given in Sect. 9.2.

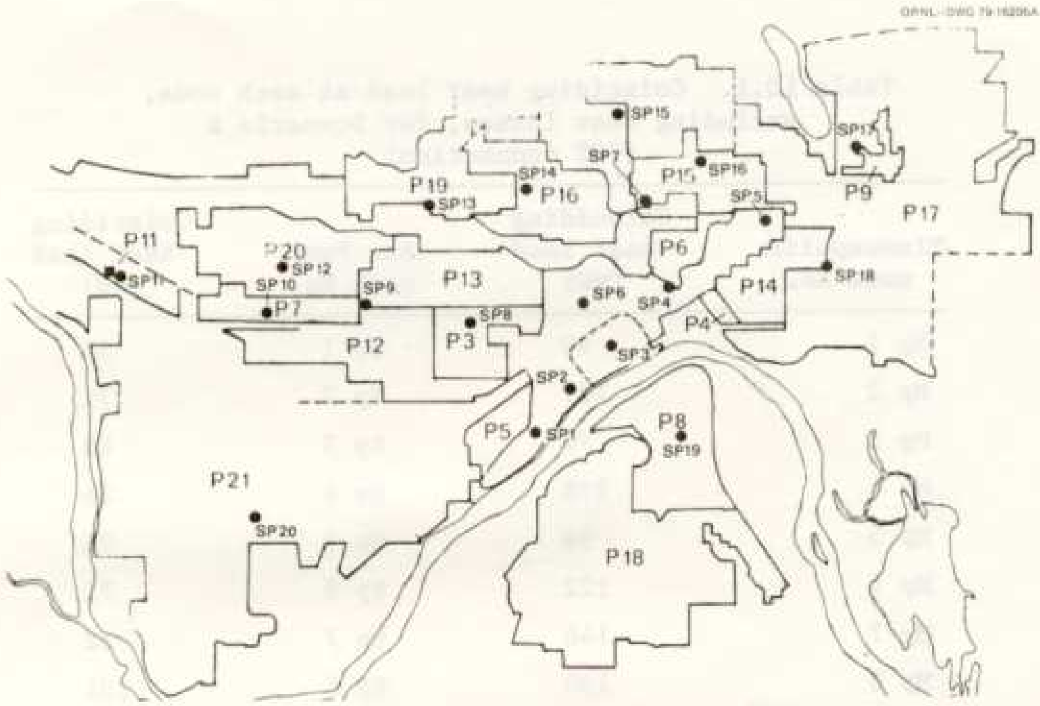

Fig. 10.1. District heating nodes in St. Paul, Scenario B.

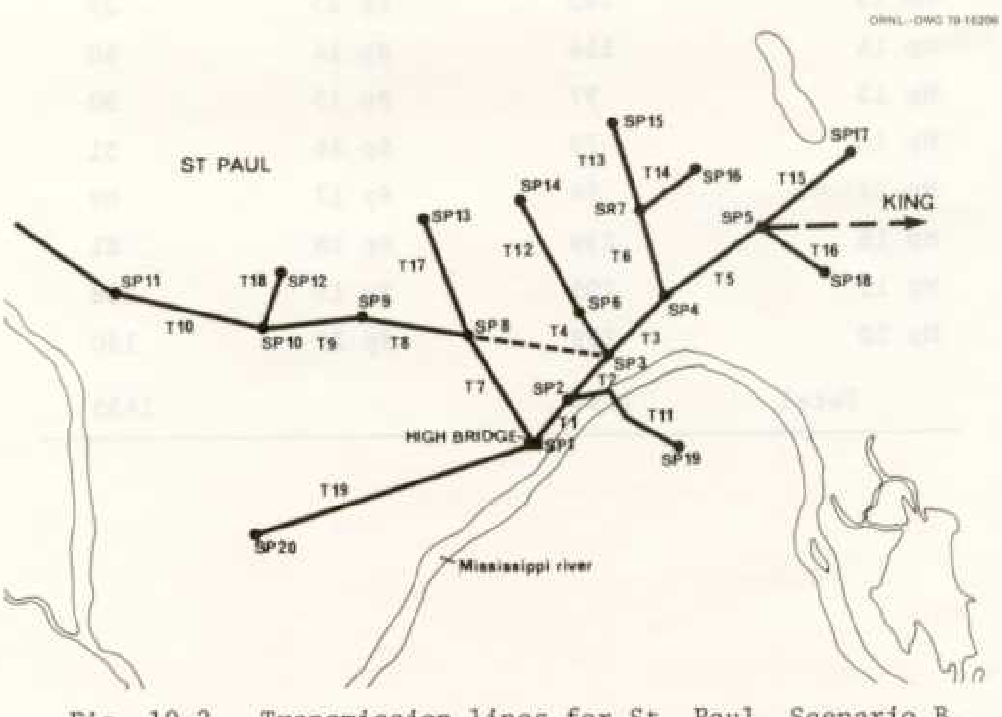

Fig. 10.2. Transmission lines for St. Paul, Scenario B.

Table 10.1. Coinciding heat load at each node, excluding heat losses, for Scenario B (70% connection)

Minneapolis node No.	Coinciding heat load (MW)	St. Paul node No.	Coinciding heat load (MW)
Mp 1	49	Sp 1	35
Mp 2	127	Sp 2	71
Mp 3	70	Sp 3	60
Mp 4	278	Sp 4	86
Mp 5	96	Sp 5	71
Mp 6	122	Sp 6	71
Mp 7	146	Sp 7	32
Mp 8	100	Sp 8	101
Mp 9	93	Sp 9	47
Mp 10	168	Sp 10	135
Mp 11	41	Sp 11	46
Mp 12	54	Sp 12	53
Mp 13	183	Sp 13	28
Mp 14	114	Sp 14	40
Mp 15	97	Sp 15	30
Mp 16	79	Sp 16	51
Mp 17	94	Sp 17	89
Mp 18	239	Sp 18	81
Mp 19	205	Sp 19	138
Mp 20	239	Sp 20	190
Total	2594		1455

Table 10.2. Transmission lines, Scenario B

Transmission line	Distance	Tunnel	Culvert		Maximum heat load[a] (MW)	Length (km)	Size (m)		Heat losses[b] (MW)	Investments ($ × 10^6)		Pump capacity [MW(e)]
			Downtown	Residential			Optimum	Standard		Including pumps	Excluding pumps	
T1	Sp1-Sp2	X			236[b]	0.9		0.55[b]	0.10		2.4[b]	0.16[b]
T2	Sp2-Sp3	X			177[b]	1.0		0.45[b]	0.09		2.4[b]	0.15[b]
T3	Sp3-Sp4		X		498[b]	1.3		0.75[b]	0.20		3.5[b]	0.36[b]
T4	Sp3-Sp6	X			50	0.8	0.25	0.25	0.04	1.93	1.60	0.05
T5	Sp4-Sp5		X		589[b]	1.8		0.80[b]	0.29		5.3[b]	0.51[b]
T6	Sp4-Sp7		X		52	1.4	0.24	0.25	0.07	1.56	1.17	0.11
T7	Sp1-Sp8	X			432[b]	2.0		0.70[b]	0.26		6.2[b]	0.56
T8	Sp8-Sp9	X			787[b]	1.9		0.90[b]	0.34		6.9[b]	0.64[b]
T9	Sp9-Sp10	X			765[b]	1.3		0.90[b]	0.23		4.7[b]	0.43[b]
T10	Sp10-Sp11	X			677[b]	2.1		0.85[b]	0.36		7.4[b]	0.67[b]
T11	Sp2-Sp19	X			63	2.9	0.28	0.30	0.17	6.40	5.94	0.20
T12	Sp6-Sp14	X			18	1.3	0.15	0.15	0.04	2.72	2.40	0.04
T13	Sp7-Sp15		X		14	1.3	0.13	0.15	0.04	1.11	0.78	0.04
T14	Sp7-Sp16		X		23	1.2	0.17	0.20	0.05	1.14	0.81	0.06
T15	Sp5-Sp17		X		41	2.5	0.22	0.25	0.13	2.38	1.94	0.17
T16	Sp5-Sp18		X		37	2.1	0.21	0.25	0.11	1.99	1.59	0.13
T17	Sp8-Sp13	X			13	1.8	0.13	0.20	0.07	3.59	3.25	0.05
T18	Sp10-Sp12	X			24	1.3	0.18	0.20	0.05	2.77	2.44	0.05
T19	Sp1-Sp20	X			87	4.8	0.32	0.35	0.34	10.88	10.23	0.42
TSPM	Sp11-Mp6	X			656[b]	5.0		0.85[b]	0.09		17.5[b]	1.34[b]
T01	Mp1-Mp2			X	491[b]	2.8		0.75[b]	0.42		5.6[b]	0.78[b]
T02	Mp2-Mp3		X		946	0.8	0.89	0.90	0.14	3.42	2.68	0.56
T03	Mp3-Mp4	X			783	2.0	0.87	0.90	0.36	8.23	7.23	0.88
T04	Mp4-Mp12	X			407	1.7	0.65	0.65	0.22	5.61	4.96	0.45
T05	Mp3-Mp5			X	44	1.2	0.23	0.25	0.06	1.06	0.73	0.07
T06	Mp2-Mp6	X			531[b]	2.4		0.80[b]	0.36		7.9[b]	0.72[b]
T07	Mp6-Mp7		X		44	1.6	0.27	0.30	0.10	1.85	1.45	0.15
T08	Mp3-Mp8			X	88	1.8	0.32	0.35	0.13	1.80	1.40	0.17
T09	Mp8-Mp9			X	42	1.5	0.23	0.25	0.08	1.24	0.91	0.08
T010	Mp4-Mp10	X			248	2.5	0.52	0.55	0.28	7.07	6.42	0.46
T011	Mp10-Mp11			X	128	2.1	0.38	0.40	0.17	2.39	1.90	0.26
T012	Mp12-Mp13	X			230	1.4	0.50	0.50	0.14	4.00	3.53	0.24
T013	Mp13-Mp14		X		146	1.5	0.39	0.40	0.12	2.32	1.85	0.25
T014	Mp12-Mp13	X			153	1.4	0.42	0.45	0.13	3.68	3.26	0.18
T015	Mp1-Mp16			X	36	2.5	0.21	0.25	0.13	1.81	1.44	0.13
T016	Mp10-Mp17			X	43	1.2	0.23	0.25	0.06	1.05	0.73	0.07
T017	Mp15-Mp18			X	109	2.8	0.35	0.35	0.20	2.90	2.37	0.31
T018	Mp14-Mp19			X	94	2.8	0.33	0.35	0.20	2.73	2.23	0.27
T019	Mp11-Mp20			X	109	2.8	0.35	0.35	0.20	2.90	2.37	0.31
TK	King-Sp5			X	700[b]	24.0		0.85[b]	4.08		55.8[b]	7.96[b]
TM2	Sp3-Sp8	X	X		419[b]	1.9		0.70[b]	0.27		4.6[b]	0.49[b]

[a] According to computed optimum size.

[b] Manual calculation on the basis of the computed results.

10.3 Costs of the Local Distribution System

The local distribution system costs are estimated from actual costs in Stockholm for similar load densities and consumer loads (Fig. 5.7). The costs used for each district are given in Table 10.3.

10.4 Explanations of Tables 10.4-10.16.

Tables 10.4 through 10.16 are explained in Sect. 9.4.

10.5 Economic Results

10.5.1 Base case, Scenario B

The purpose of Scenario B is to determine whether or not it is justifiable to extend the distribution system to residential areas with mainly one-family houses and medium load densities (i.e., 10 to 20 MW/km^2).

The initial load growth rates for Scenarios A and B are the same, the controlling factor being a desire to limit the negative net savings in the initial years. During the latter part of the period, Scenario B covers considerably greater connection rates than Scenario A.

The plant extension program is shown schematically in Fig. 10.1. As indicated in the text, the cogeneration capacity at King was assumed to be subdivided between two production units, each having an electrical output of 450 MW with cold condensation and 400 MW with 50% steam extraction for DH. A 50% steam extraction provides 350 MW of heat for DH from each of the units.

Figure 5.6 shows the main hot water transmission network, with additional pipelines for Scenario B marked by dashed lines. Tables 10.4 through 10.16 show the economic program for the base case of Scenario B. Figure 10.3 shows the annual calculated net savings in 1978 dollars for the reference case with municipal utility and private utility financing (solid lines) and certain variations from the reference cases. Figure 10.4 shows the accumulated net savings expressed in 1978 dollars for the base case. Conversion from the year of operation to 1978 is made using the average interest rate applicable for the two cases (6.5%/year for

Table 10.3. Cost[a] of local distribution system ($\$ \times 10^6$), conventional technology for Scenario B

DH area	Cost	DH area	Cost
M1	0	P1	1.4
M2	0	P2	6.9
M3	8.4	P3	5.7
M4	7.7	P4	2.4
M5	4.4	P5	4.7
M6	25.3	P6	3.4
M7	20.0	P7	1.2
M8	13.0	P8	7.6
M9	18.0	P9	3.5
M10	13.6	P10	0
M11	8.9	P11	0.7
M12	3.0	P12	12.5
M13	16.9	P13	11.6
M14	7.9	P14	5.6
M15	6.6	P15	6.9
M16	18.7	P16	10.1
M17	18.7	P17	78.3
M18	187.0	P18	29.9
M19	2.8	P19	9.6
M20	2.4	P20	14.6
M21	6.8	P21	91.9
M22	29.0		
M23	13.2		

[a]1978 dollars.

Table 10.4. Annual energy savings, in equivalent barrels of oil, for Scenario B, base case (old technology, 70% connection)

Year	Oil	Gas	Coal	Total	Accumulated
1980	0	0	0	0	0
1981	-151,402	177,013	0	25,611	25,611
1982	-240,716	365,325	-39,175	85,434	111,044
1983	-84,295	657,208	-246,966	325,947	436,992
1984	-147,028	996,169	-355,200	493,941	930,933
1985	-174,257	1,357,727	-497,668	685,802	1,616,734
1986	-219,210	1,698,571	-607,062	872,300	2,489,034
1987	-264,409	2,041,299	-696,657	1,080,233	3,569,267
1988	-312,824	2,408,506	-807,801	1,287,881	4,857,148
1989	-355,544	2,736,169	-918,114	1,462,511	6,319,659
1990	-400,175	3,077,013	-1,011,420	1,665,418	7,985,077
1991	-464,136	3,564,740	-1,150,144	1,950,461	9,935,538
1992	-529,523	4,060,000	-1,312,176	2,218,301	12,153,839
1993	-646,951	4,515,714	-1,436,676	2,432,088	14,585,927
1994	-883,765	5,018,506	-1,526,538	2,608,203	17,194,130
1995	-1,223,405	5,634,286	-1,613,685	2,797,196	19,991,326
1996	-788,730	6,018,442	-1,864,489	3,365,223	23,356,549
1997	-1,095,479	6,460,974	-1,831,248	3,534,247	26,890,796
1998	-901,222	6,854,545	-1,988,013	3,965,311	30,856,107
1999	-994,575	7,248,117	-2,035,182	4,218,360	35,074,467
2000	-1,156,265	7,611,558	-2,097,524	4,357,770	39,432,237
21 years	-11,034	72,502	-22,036	39,432	39,432

Table 10.5. Annual investments[a] ($\$ \times 10^6$), Scenario B, base case (old technology, 70% connection)

Year	Consumer equipment	Local network	Base-load plants	Transmission lines	Heat-only plants	Total
1980	0.00	0.00	0.00	0.00	0.00	0.00
1981	5.19	4.07	5.28	12.94	4.87	32.35
1982	5.75	4.93	4.94	13.63	0.00	29.25
1983	9.17	8.14	9.89	8.73	0.00	35.93
1984	11.16	12.46	0.00	14.32	10.57	48.51
1985	12.57	14.04	0.00	10.88	12.17	49.66
1986	13.61	20.70	4.95	12.72	4.56	56.54
1987	13.99	19.61	5.17	10.43	5.30	54.51
1988	16.21	25.44	0.00	6.19	14.23	62.07
1989	14.59	25.24	0.00	16.89	13.19	69.90
1990	16.38	50.07	5.86	18.70	5.36	96.38
1991	23.02	78.87	0.00	33.43	21.31	156.64
1992	24.54	86.18	0.00	32.59	22.58	165.89
1993	23.90	87.18	0.00	46.91	0.96	158.96
1994	28.00	119.59	0.00	46.62	24.83	219.05
1995	35.01	135.74	0.00	50.50	31.60	252.85
1996	24.13	109.91	81.00	27.86	0.18	243.08
1997	29.12	124.78	0.00	19.22	12.76	185.89
1998	27.00	107.22	88.16	6.98	0.21	229.57
1999	28.11	111.64	0.00	16.65	9.21	165.62
2000	27.07	113.86	0.00	1.67	22.98	165.58

[a]Current dollars.

Table 10.6. Replacement cost of system[a] ($\$ \times 10^6$) Scenario B, base case (old technology, 70% connection)

Year	Consumer equipment	Local network	Base-load plants	Transmission lines	Heat-only plants	Total
1980	0.00	0.00	0.00	0.00	0.00	0.00
1981	5.19	4.07	5.23	12.94	4.87	32.35
1982	11.22	9.22	10.51	27.27	5.14	63.35
1983	20.98	17.84	20.95	37.43	5.41	102.60
1984	33.17	31.18	21.98	53.59	16.25	156.16
1985	47.40	46.77	23.07	67.14	29.23	213.60
1986	63.22	69.66	29.10	82.99	35.15	280.13
1987	80.09	92.43	35.59	97.18	42.05	347.34
1988	99.82	121.94	37.16	107.65	58.13	424.69
1989	118.61	152.32	38.73	129.08	73.76	512.49
1990	139.86	208.64	46.18	153.07	82.15	629.90
1991	168.63	296.09	48.07	192.80	106.84	812.43
1992	200.10	394.44	50.05	233.31	113.81	1,011.71
1993	232.21	497.81	52.10	289.80	140.26	1,212.19
1994	269.72	637.77	54.24	348.28	170.83	1,480.84
1995	315.72	799.50	56.45	412.97	209.40	1,794.03
1996	351.34	938.51	139.50	455.85	217.19	2,102.39
1997	396.54	1,106.25	145.89	495.94	239.90	2,384.52
1998	439.72	1,258.61	240.00	523.16	249.90	2,711.38
1999	485.97	1,422.15	249.90	561.38	289.42	2,988.82
2000	532.86	1,594.01	260.09	585.95	303.38	3,276.29

[a]Current dollars.

Table 10.7. Heat production capacity and demand, Scenario B, base case (old technology, 70% connection)

Year	Heat-only boilers (MW)			Capacity (MW)		Demand (MW)			Overcapacity	
	Decentralized	Centralized	Total	Cogeneration	Total	Heat	Losses	Total	(MW)	(%)
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	96.6	96.6	240.0	336.6	94.0	2.6	96.6	240.0	248.4
1982	0.0	96.6	96.6	397.0	493.6	194.0	5.5	199.5	294.2	147.5
1983	0.0	96.6	96.6	837.0	933.6	349.0	9.8	358.8	574.9	160.2
1984	0.0	276.8	276.8	837.0	1,113.8	529.0	14.8	543.8	570.0	104.8
1985	0.0	474.3	474.3	837.0	1,311.3	721.0	20.3	741.3	570.0	76.9
1986	0.0	545.0	545.0	954.0	1,499.0	902.0	27.0	929.0	570.0	61.4
1987	0.0	623.6	623.6	1,064.0	1,687.6	1,084.0	33.6	1,117.6	570.0	51.0
1988	0.0	825.8	825.8	1,064.0	1,889.8	1,279.0	40.8	1,319.8	570.0	43.2
1989	0.0	1,005.5	1,005.5	1,064.0	2,069.5	1,453.0	46.5	1,499.5	570.0	38.0
1990	0.0	1,075.8	1,075.8	1,181.0	2,256.8	1,634.0	52.8	1,686.8	570.0	33.8
1991	0.0	1,343.8	1,343.8	1,181.0	2,524.8	1,893.0	61.8	1,954.8	570.0	29.2
1992	0.0	1,616.5	1,616.5	1,181.0	2,797.5	2,156.0	71.5	2,227.5	570.0	25.6
1993	0.0	1,627.7	1,627.7	1,181.0	2,808.7	2,398.0	80.7	2,478.7	330.0	13.3
1994	0.0	1,904.5	1,904.5	1,181.0	3,085.5	2,665.0	90.5	2,755.5	330.0	12.0
1995	0.0	2,243.1	2,243.1	1,181.0	3,424.1	2,992.0	102.1	3,094.1	330.0	10.7
1996	0.0	2,244.9	2,244.9	1,531.0	3,775.9	3,196.0	110.9	3,306.9	469.0	14.2
1997	0.0	2,371.0	2,371.0	1,531.0	3,902.0	3,431.0	121.0	3,552.0	350.0	9.9
1998	0.0	2,373.0	2,373.0	1,881.0	4,254.0	3,640.0	130.0	3,770.0	484.0	12.8
1999	0.0	2,457.1	2,457.1	1,881.0	4,338.1	3,849.0	139.1	3,988.1	350.0	8.8
2000	0.0	2,658.4	2,658.4	1,881.0	4,539.4	4,042.0	147.4	4,189.4	350.0	8.4

Table 10.8. Heat production and operating costs,[a] Scenario B, base case (old technology, 70% connection)

Year	Production capacity (MW)		Energy produced[b] (TWhr)		Operating costs ($/MWhr)		Operation and maintenance costs ($/MWhr)	
	Base load	Heat only	Base load	Heat only	Base load	Heat only	Base load	Heat only
1980	0.0	0.0	0.0000	0.0000	3.55	10.18	0.00	0.00
1981	240.0	96.6	0.0000	0.2548	3.74	11.20	0.00	0.19
1982	397.0	96.6	0.1211	0.4051	10.08	11.94	6.14	0.13
1983	837.0	96.6	0.8039	0.1419	5.58	12.99	1.43	0.38
1984	837.0	276.8	1.1861	0.2474	5.68	14.07	1.32	0.66
1985	837.0	474.3	1.6619	0.2933	5.73	15.23	1.16	1.00
1986	954.0	545.0	2.0906	0.3689	6.10	16.31	1.21	0.95
1987	1,064.0	623.6	2.5217	0.4450	6.47	17.11	1.23	0.94
1988	1,064.0	825.8	2.9834	0.5265	6.78	18.37	1.20	1.10
1989	1,064.0	1,005.5	3.3908	0.5984	7.37	19.98	1.22	1.23
1990	1,181.0	1,075.8	3.8165	0.6735	8.06	21.10	1.35	1.22
1991	1,181.0	1,343.8	4.4265	0.7811	8.49	22.70	1.47	1.37
1992	1,181.0	1,616.5	5.0501	0.8912	9.02	24.63	1.65	1.50
1993	1,181.0	1,627.7	5.5292	1.0888	9.53	25.84	1.82	1.29
1994	1,181.0	1,904.5	5.8751	1.4874	10.14	27.85	2.07	1.15
1995	1,181.0	2,243.1	6.2105	2.0590	10.96	29.47	2.49	1.02
1996	1,531.0	2,244.9	7.5221	1.3274	11.36	32.20	2.54	1.64
1997	1,531.0	2,371.0	7.6738	1.8437	12.11	34.23	2.81	1.30
1998	1,881.0	2,373.0	8.5950	1.5168	12.68	37.00	2.95	1.65
1999	1,881.0	2,457.1	9.0321	1.6739	13.27	39.29	3.07	1.61
2000	1,881.0	2,658.4	9.3088	1.9460	13.90	41.69	3.23	1.56

[a]Current dollars.

[b]Equivalent to 10^6 MWhr.

Table 10.9. Heat consumption and heat rate[a] for the Twin Cities, Scenario B, base case (old technology, 70% connection)

Year	Coinciding demand (MW)	Consumed energy (TWhr)	Rate (\$/MWhr)	Rate (\$/10^6 Btu)
1980	0.0	0.0000	10.55	3.09
1981	94.0	0.2317	12.77	3.74
1982	194.0	0.4782	15.08	4.42
1983	349.0	0.8603	16.21	4.75
1984	529.0	1.3040	17.25	5.05
1985	721.0	1.7773	18.30	5.36
1986	902.0	2.2234	19.75	5.79
1987	1084.0	2.6721	20.78	6.09
1988	1279.0	3.1527	22.27	6.52
1989	1453.0	3.5816	24.33	7.13
1990	1634.0	4.0278	26.50	7.76
1991	1893.0	4.6662	29.37	8.61
1992	2156.0	5.3145	32.52	9.53
1993	2398.0	5.9111	35.18	10.31
1994	2665.0	6.5692	38.90	11.40
1995	2992.0	7.3753	41.82	12.25
1996	3196.0	7.8781	45.52	13.34
1997	3431.0	8.4574	49.35	14.46
1998	3640.0	8.9726	53.52	15.68
1999	3849.0	9.4878	57.07	16.72
2000	4042.0	9.9635	62.07	18.19

[a]Current dollars.

Table 10.10. Income statement[a] ($\$ \times 10^6$), Scenario B, base case (old technology, 70% connection)

Year	Gross revenue	Operating costs	Operating income
1980	0.00	0.00	0.00
1981	2.96	2.85	0.10
1982	7.21	6.06	1.15
1983	13.95	6.33	7.62
1984	22.49	10.22	12.28
1985	32.52	13.99	18.53
1986	43.91	18.77	25.13
1987	55.52	23.93	31.59
1988	70.21	29.90	40.30
1989	87.14	36.93	50.21
1990	106.73	44.97	61.76
1991	137.05	55.32	81.73
1992	172.84	67.52	105.31
1993	207.92	80.84	127.08
1994	255.56	100.99	154.57
1995	308.45	128.75	179.70
1996	358.58	128.23	230.35
1997	417.42	156.01	261.40
1998	480.19	165.07	315.12
1999	541.45	185.65	355.80
2000	618.47	210.49	407.99

[a]Current dollars.

Table 10.11. Income statement[a] ($\$/\text{Btu} \times 10^6$), Scenario B, base case (old technology, 70% connection)

Year	Gross revenue	Operating costs	Operating income
1980	0	0	0
1981	3.74	3.61	0.13
1982	4.42	3.71	0.71
1983	4.75	2.16	2.59
1984	5.05	2.30	2.76
1985	5.36	2.31	3.05
1986	5.79	2.47	3.31
1987	6.09	2.62	3.46
1988	6.52	2.78	3.75
1989	7.13	3.02	4.11
1990	7.76	3.27	4.49
1991	8.61	3.47	5.13
1992	9.53	3.72	5.81
1993	10.31	4.01	6.30
1994	11.40	4.50	6.89
1995	12.25	5.11	7.14
1996	13.34	4.77	8.57
1997	14.46	5.40	9.06
1998	15.68	5.39	10.29
1999	15.72	5.73	10.99
2000	18.19	6.19	12.00

[a]Current dollars.

Table 10.12. Municipal financing[a] ($\$ \times 10^6$), Scenario B, base case (old technology, 70% connection)

Year	Book depreciation	Book depreciation reserve first of year	Net investment	Return requirement	Property taxes	Total revenue
1980	0.00	0.00	0.00	0.00	0.00	0.00
1981	1.29	0.00	32.35	2.10	0.00	3.39
1982	2.45	1.29	60.32	3.92	0.00	6.37
1983	4.04	3.74	93.79	6.10	0.00	10.14
1984	5.97	7.78	138.26	8.99	0.00	14.96
1985	8.01	13.75	181.95	11.83	0.00	19.84
1986	10.30	21.76	230.48	14.98	0.00	25.28
1987	12.56	32.06	274.69	17.86	0.00	30.42
1988	15.12	44.62	324.20	21.07	0.00	36.19
1989	17.82	59.74	378.98	24.63	0.00	42.45
1990	21.38	77.56	457.54	29.74	0.00	51.12
1991	26.98	98.94	592.80	38.53	0.00	65.51
1992	32.91	125.92	731.71	47.56	0.00	80.47
1993	38.38	158.84	857.75	55.75	0.00	94.13
1994	45.99	197.21	1,038.43	67.50	0.00	113.48
1995	54.90	243.20	1,245.29	80.94	0.00	135.85
1996	63.16	298.10	1,433.46	93.18	0.00	156.33
1997	69.72	361.26	1,556.19	101.15	0.00	170.87
1998	77.73	430.98	1,716.05	111.54	0.00	189.28
1999	83.64	508.71	1,803.93	117.26	0.00	200.90
2000	89.67	592.35	1,885.87	122.58	0.00	212.25

[a]Current dollars.

Table 10.13. Private financing[a] ($\$ \times 10^6$), Scenario B, base case (old technology, 70% connection)

Year	Beginning of year gross plant	Book depreciation reserve	Deferred tax reserve	Investment credit reserve	Beginning of year net plant	Property taxes
1980	0.00	0.00	0.00	0.00	0.00	0.00
1981	32.35	0.00	0.00	0.00	32.35	0.00
1982	61.61	1.29	0.76	3.11	59.56	0.00
1983	97.53	3.74	2.15	5.79	91.65	0.00
1984	146.04	7.78	4.18	8.98	134.09	0.00
1985	195.70	13.75	7.15	13.23	174.80	0.00
1986	252.24	21.76	10.98	17.39	219.50	0.00
1987	306.76	32.06	15.74	22.02	258.96	0.00
1988	368.82	44.62	21.23	26.21	302.97	0.00
1989	438.72	59.74	27.54	30.91	351.45	0.00
1990	535.10	77.56	34.81	36.12	422.74	0.00
1991	691.74	98.94	43.62	43.62	549.17	0.00
1992	857.63	125.92	55.41	56.58	676.30	0.00
1993	1,016.59	158.84	70.08	69.88	787.67	0.00
1994	1,235.64	197.21	87.26	81.94	951.17	0.00
1995	1,488.49	243.20	108.18	99.24	1,137.11	0.00
1996	1,731.57	298.10	133.21	119.04	1,300.25	0.00
1997	1,917.45	361.26	161.93	137.55	1,394.26	0.00
1998	2,147.03	430.98	192.23	149.74	1,523.82	0.00
1999	2,312.64	508.71	225.01	165.84	1,578.92	0.00
2000	2,478.22	592.35	258.16	175.16	1,627.70	0.00

[a]Current dollars.

Table 10.14. Private financing[a] ($\$ \times 10^6$), Scenario B, base case (old technology, 70% connection)

Year	Return on equity	Return on debt	Book depreciation	Tax depreciation	Deferred taxes
1980	0.00	0.00	0.00	0.00	0.00
1981	2.16	1.36	1.29	2.75	0.76
1982	3.98	2.50	2.45	5.12	1.39
1983	6.12	3.85	4.04	7.95	2.03
1984	8.96	5.63	5.97	11.70	2.98
1985	11.68	7.34	8.01	15.38	3.83
1986	14.66	9.22	10.30	19.45	4.75
1987	17.30	10.88	12.56	23.14	5.49
1988	20.24	12.72	15.12	27.26	6.31
1989	23.48	14.76	17.82	31.81	7.27
1990	28.24	17.76	21.38	38.35	8.82
1991	36.68	23.07	26.98	49.66	11.78
1992	45.18	28.40	32.91	61.16	14.68
1993	52.62	33.08	38.38	71.45	17.18
1994	63.54	39.95	45.99	86.25	20.92
1995	75.96	47.76	54.90	103.09	25.03
1996	86.86	54.61	63.16	118.44	28.72
1997	93.14	58.56	69.72	128.04	30.30
1998	101.79	64.00	77.73	140.84	32.79
1999	105.47	66.31	83.64	147.45	33.15
2000	108.73	68.36	89.67	153.51	33.17

[a]Current dollars.

Table 10.15. Private financing[a] ($\$ \times 10^6$), Scenario B, base case (old technology, 70% connections)

Year	Investment credit		Income taxes	Total revenue requirement
	General	Flow through		
1980	0.00	0.00	0.00	0.00
1981	3.24	0.13	-1.80	6.88
1982	2.93	0.25	-0.28	12.72
1983	3.59	0.40	0.56	19.79
1984	4.85	0.60	1.21	29.00
1985	4.97	0.30	2.96	37.98
1986	5.65	1.03	4.33	47.89
1987	5.45	1.26	6.40	56.82
1988	6.21	1.51	7.73	66.81
1989	6.99	1.78	9.20	77.73
1990	9.64	2.14	9.76	93.46
1991	15.66	2.70	9.30	120.78
1992	16.59	3.29	14.02	148.49
1993	15.90	3.84	19.66	172.97
1994	21.91	4.60	20.90	208.60
1995	25.28	5.49	25.87	249.32
1996	24.83	6.32	33.53	285.39
1997	19.16	6.97	43.70	307.60
1998	23.87	7.77	44.99	337.40
1999	17.68	8.36	54.16	352.05
2000	17.82	8.97	56.88	365.65

[a]Current dollars.

Table 10.16. Comparative analysis of financing methods ($ × 10^6), Scenario B, base case (old technology, 70% connection)

	Municipal					Private				
Year	Difference	1978	Present worth	Accumulated 78	Accumulated present worth	Difference	1978	Present worth	Accumulated 78	Accumulated present worth
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	-3.29	-2.80	-2.72	-2.80	-2.72	-6.78	-5.78	-4.97	-5.78	-4.97
1982	-5.22	-4.22	-4.06	-7.03	-6.78	-11.57	-9.36	-7.65	-15.14	-12.62
1983	-2.52	-1.94	-1.84	-8.96	-8.62	-12.17	-9.36	-7.26	-24.49	-19.89
1984	-2.68	-1.96	-1.84	-10.93	-10.46	-16.72	-12.25	-9.00	-36.74	-28.89
1985	-1.30	-1.91	-0.84	-11.84	-11.30	-19.45	-13.58	-9.44	-50.32	-38.33
1986	-0.15	-0.10	-0.09	-11.94	-11.38	-22.76	-15.17	-9.96	-65.49	-48.29
1987	1.17	0.75	0.67	-11.19	-10.72	-25.23	-16.09	-9.96	-81.58	-58.25
1988	4.12	2.51	2.19	-8.67	-8.53	-26.51	-16.19	-9.44	-97.78	-67.69
1989	7.76	4.55	3.88	-4.13	-4.65	-27.52	-16.13	-8.84	-113.91	-76.52
1990	10.64	5.99	5.00	1.86	0.35	-31.70	-17.85	-9.18	-131.75	-85.70
1991	16.22	8.77	7.15	10.64	7.50	-39.05	-21.12	-10.20	-152.87	-95.90
1992	24.84	12.90	10.29	23.54	17.79	-43.18	-22.43	-10.17	-175.30	-106.07
1993	32.95	16.44	12.81	39.98	30.60	-45.89	-22.90	-9.75	-198.20	-115.82
1994	41.09	19.70	15.00	59.68	45.60	-54.03	-25.90	-10.35	-224.10	-126.17
1995	43.85	20.20	15.03	79.88	60.64	-69.62	-32.07	-12.03	-256.17	-138.19
1996	74.02	32.90	23.83	112.78	84.46	-55.03	-24.46	-8.58	-280.63	-146.77
1997	90.53	38.47	27.36	151.25	111.82	-46.20	-19.64	-6.49	-300.26	-153.26
1998	125.85	51.39	35.71	202.64	147.54	-22.28	-9.10	-2.82	-309.36	-156.09
1999	154.90	60.75	41.28	263.38	188.82	3.74	1.47	0.43	-307.89	-155.66
2000	195.74	73.75	48.98	337.14	237.79	42.33	15.95	4.36	-291.94	-151.30

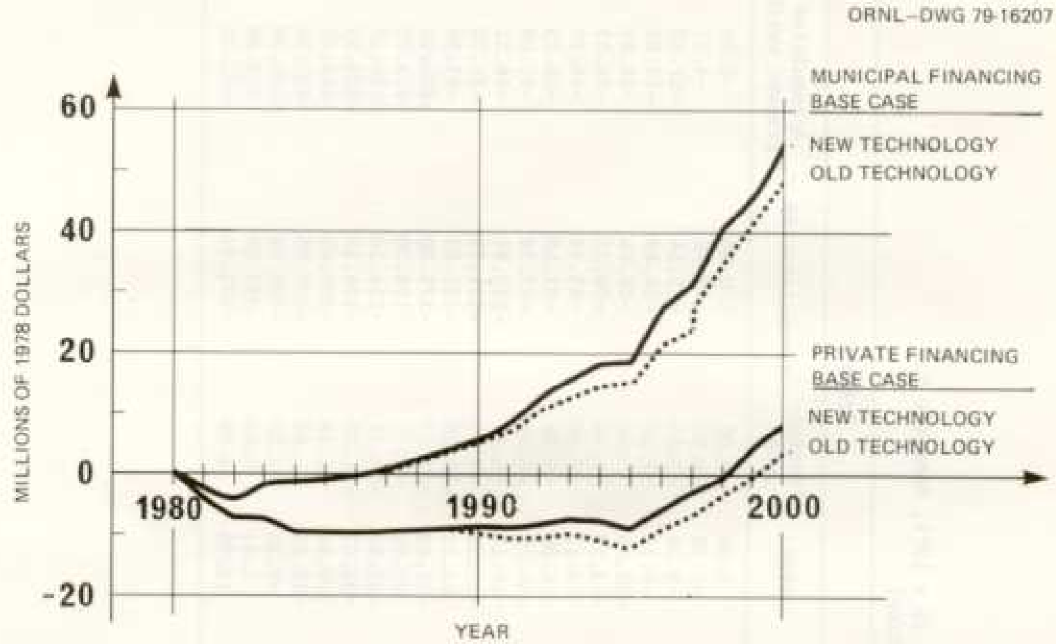

Fig. 10.3. Annual net savings in 1978 dollars, Scenario B.

municipal financing and 10.88%/year for utility financing) and the appropriate inflation factor.

The net accumulated savings for Scenarios A and B are compared with conventional distribution technology in Table 10.17.

Table 10.17. Net accumulated savings for different scenarios

Scenario	Distribution technology for Scenario B	Accumulated net savings[a] ($\$ \times 10^6$)		
		Municipal financing	Private financing	Intermediate financing[b]
A	Conventional	183	-77	132
B	Conventional	238	-151	171
B	New	274	-118	201

[a]1978 dollars.

[b]Private financing for production plants and municipal financing for other investments. Obtained by interpolation.

Scenario B gives larger accumulated positive and negative savings than Scenario A for municipal and private financing, respectively,

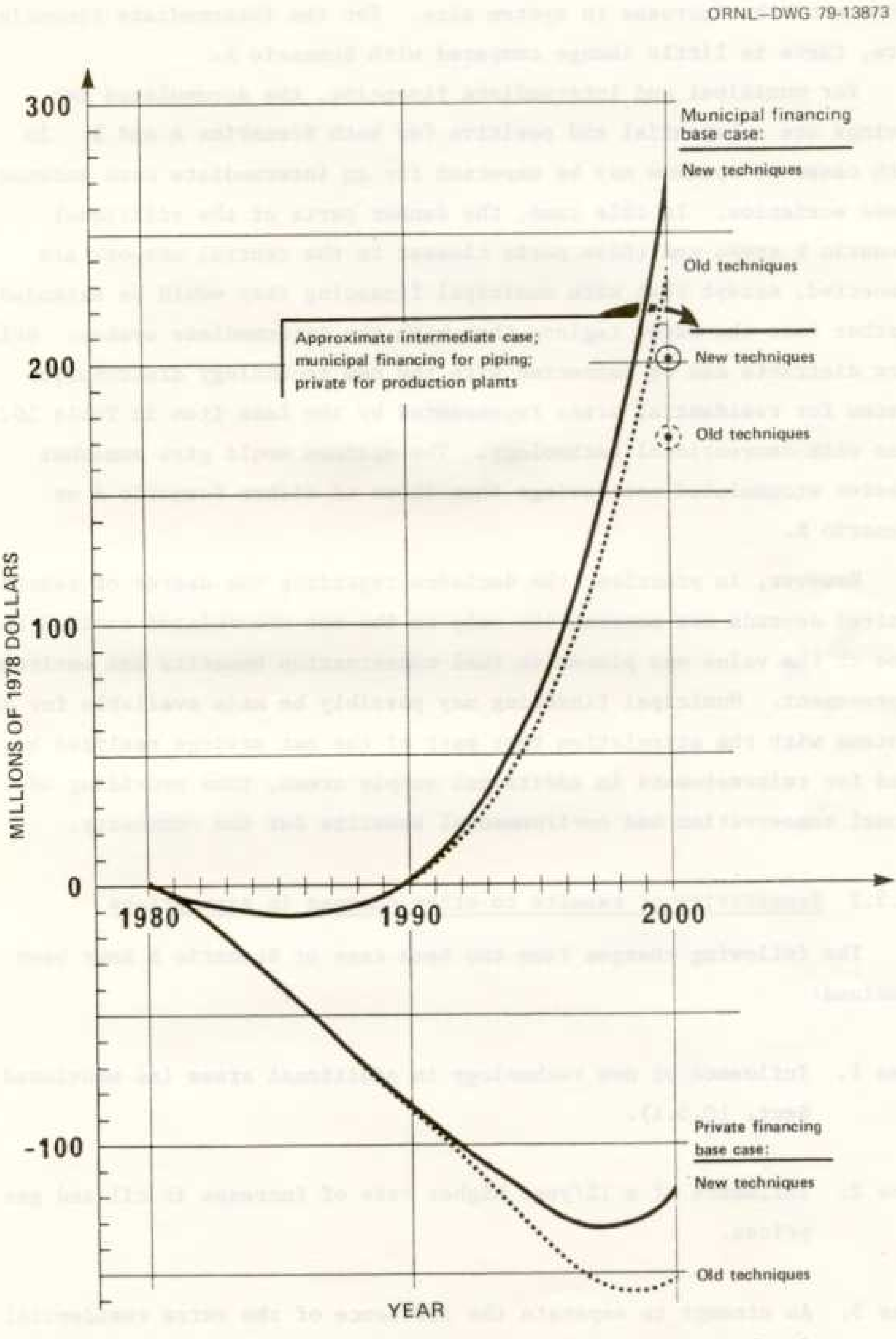

Fig. 10.4. Accumulated present worth of net savings for base case, Scenario B.

because of the increase in system size. For the intermediate financing form, there is little change compared with Scenario A.

For municipal and intermediate financing, the accumulated net savings are substantial and positive for both Scenarios A and B. In both cases an optimum may be expected for an intermediate case between these scenarios. In this case, the denser parts of the additional Scenario B areas and those parts closest to the central network are connected, except that with municipal financing they would be extended further into the outer regions than with the intermediate system. Still more districts can be connected with the new technology distribution system for residential areas represented by the last item in Table 10.16 than with conventional technology. The optimum would give somewhat greater accumulated net savings than those of either Scenario A or Scenario B.

However, in practice, the decision regarding the degree of penetration desired depends not necessarily only on the net accumulated savings but also on the value one places on fuel conservation benefits and environment improvement. Municipal financing may possibly be made available for piping systems with the stipulation that part of the net savings realized be used for reinvestments in additional supply areas, thus providing additional conservation and environmental benefits for the community.

10.5.2 Sensitivity of results to other changes in assumptions

The following changes from the base case of Scenario B have been examined:

Case 1. Influence of new technology in additional areas (as mentioned in Sect. 10.5.1).

Case 2. Influence of a 1%/year higher rate of increase in oil and gas prices.

Case 3. An attempt to separate the influence of the extra residential consumers for Scenario B from the influence of the out-of-town location of the last two cogeneration units needed for that scenario. The extra cost of the transport lines from King to St. Paul has been subtracted.

Case 4. Extension of the computations over a 30-year period instead of only 20 years. The assumptions for Scenario A have been used (see Sect. 9.5.2).

Table 10.18 shows the results of these changes. The influence of the first change is also shown in Table 10.17.

As indicated in Sect. 10.5.1, the influence of newer, cheaper technology distribution systems for low-density residential districts justifies more penetration of the residential areas than conventional

Table 10.18. Sensitivity of net accumulated savings[a] to changes in assumption, Scenario B ($\$ \times 10^6$)

Case	Net accumulated savings		Change from base case	
	Municipal financing	Private utility financing	Municipal financing	Private utility financing
Base case	237.8	-151.3		
1. New distribution technology in additional areas	273.9	-118.6	+36.1	+32.7
2. A 1%/year faster oil and gas cost increase	428.9	-57.9	+191.1	+93.4
3. Cost of King-St. Paul interconnector excluded (town-site location at additional cogeneration plant)	264.6	-128.2	+26.8	+23.1
4. Extends the economic analysis another 10 years for a total of 30 years	818.9	-12.0		
5. Scenario A, base case	182.8	-76.5		

[a]1978 dollars.

technology. However, even without this further improvement, very substantial connection areas can be justified.

Case 2 shows the influence of a 1%/year faster rate of increase in oil and gas prices. The results show that the net accumulated savings increase by substantial amounts (i.e., \$191 million and \$93 million 1978 dollars) for municipal and private financing respectively.

Case 3 suggests that the difference in economics between out-of-town and in-town locations is small. In part, this is because the out-of-town extensions are made near the end of the period considered. Therefore, the additional investment on the St. Paul-King line only affects the capital charges during the last years. However, even for an earlier construction date of the interconnector, the effects on economics would still have been only moderate.

Case 4 indicates that the accumulated net savings increase rapidly as the period under study is extended from 20 to 30 years. For example, the accumulated net saving for municipal financing increases from \$238 million to \$819 million (1978 dollars), thus changing the substantial negative accumulated net saving for private financing to a nearly positive saving. The general trend of these results agrees with expectations due to the progressive impact of fuel savings at increasing fuel prices. However, one should bear in mind that the 30-year figures are more uncertain than the 20-year results because of the difficulty in projecting long-term fuel costs. Moreover, the policy of plant retirement and replacement would have to be studied in greater detail if more accurate information on 30-year results is desired. For that reason, the 20-year results have been retained as the base case.

11. FUEL SAVINGS

Figure 11.1 shows the fuel consumed by DH, including the coal needed to produce electricity by the cold condensing mode to replace that sacrificed through cogeneration. The figure also shows the fuel required to supply the same consumers by individual boilers burning mainly gas and/or oil. These numbers have been computed using simplified assumptions, but the order of magnitude should be correct.

For Scenario A, the net result over the period 1980 to 2000 is a savings equivalent to 31 million barrels of oil and an additional replacement of gas and oil by coal equivalent to 18 million barrels. Thus, a total of 49 million barrels of the most limited fuel types is replaced. For Scenario B, the total net fuel savings over the period is about 30% greater. Federal Energy Administration predictions of gas supplies (Fig. 11.2) illustrate the importance of such savings.

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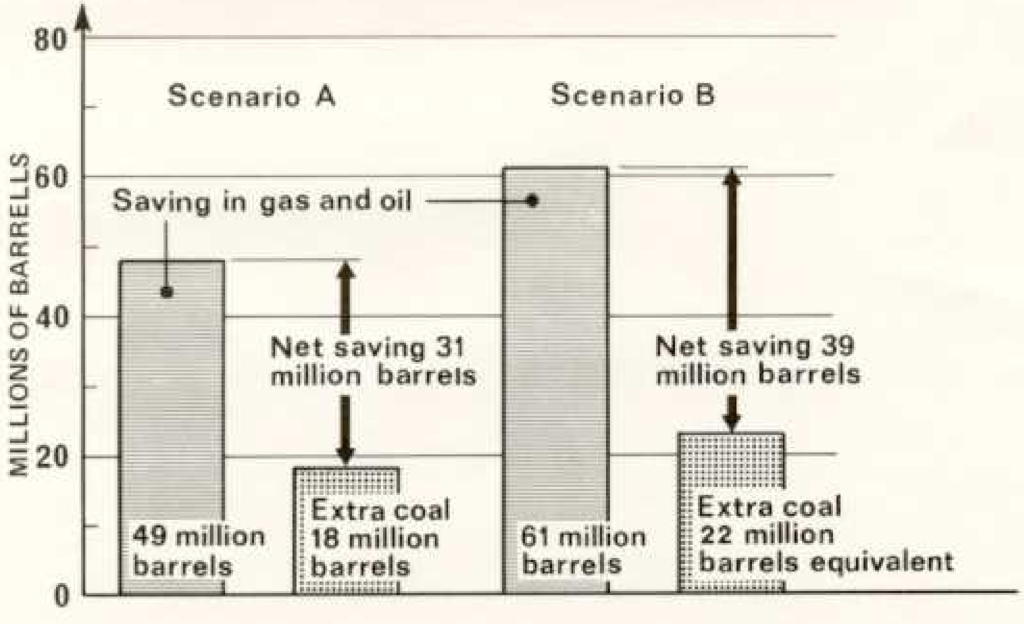

Fig. 11.1. Fuel savings due to district heating, 1980–2000, Scenarios A and B.

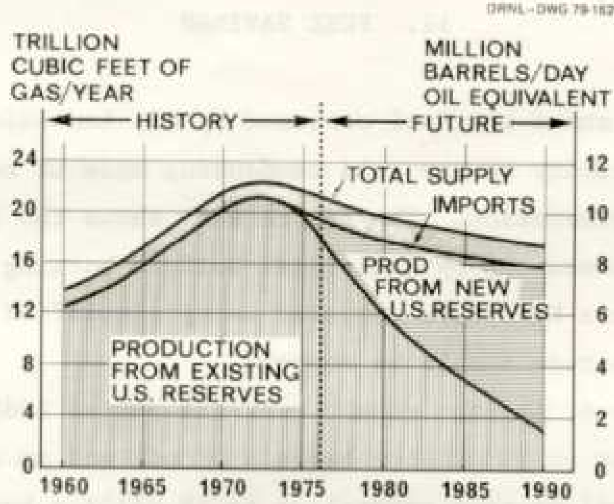

Fig. 11.2. Federal Energy Administration predictions of gas supplies.

12. ENVIRONMENTAL EFFECT

Because studies on the environmental effects of introducing DH in the Twin Cities are separate, this report does not deal with them except for some qualitative remarks. Conversion of the cogeneration units on sites within the city may prolong the economic life of these units and thus later increase the air pollution from them although it is currently already high. Cogeneration in itself reduces the heat emitted to the river.

The relatively low-level emissions to the atmosphere from many individual boilers will be avoided. This will be of increasing importance because the large consumers, in the absence of DH, will likely increasingly convert to oil, and oil burning pollutes the air more than gas does.

Figure 12.1 shows the influence of DH on the sulfur dioxide content of the air at street level in several medium-sized Swedish towns. The air of Västerås and other cities with a high proportion of DH contains much less sulfur dioxide than that of cities of comparable size in which most of the homes are heated by oil-fired boilers. Moreover, city streets are relieved of the oil transport vehicles for individual liquid fuel boilers.

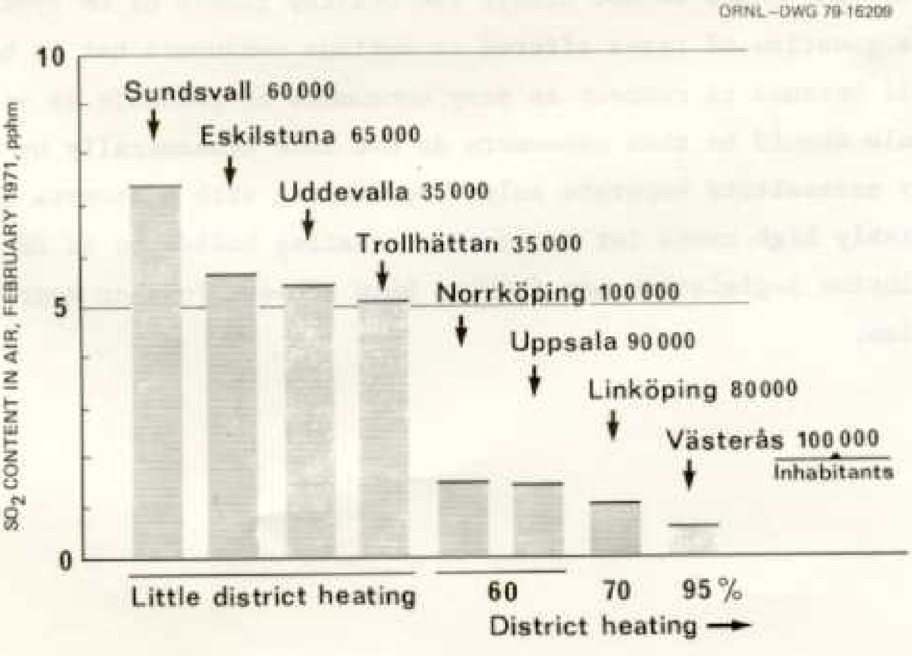

Fig. 12.1. Sulfur dioxide concentration of air in eight medium-sized Swedish towns, February 1971.

13. INSTITUTIONAL ISSUES

Institutional issues are being studied by others in another task; therefore, only a few general remarks are included in this report.

A promoter for the DH system has to be identified. This promoter could be referred to as the DH utility, which would be expected to own and operate the transport pipes and production plants built specifically for heat production. With regard to cogeneration plants, the DH utility could buy excess heat from the electric utility at rates that match the real cost of the excess heat for the utility, even when the electric utility owns the heat utility. This sale has to be established on a long-term basis with correction clauses for escalating fuel prices. Different rates can apply at different times of the year to reflect operating conditions of the system.

Different plants must be licensed to operate, with account taken of overall environmental impacts, so that the DH utility knows what plants to include in its expansion program.

Local taxes for transmission and distribution lines should reflect the significant fuel conservation and overall benefit to the environment by DH, so that taxes do not hinder the healthy growth of DH systems.

The question of rates offered to various consumers has to be studied in detail because to connect as many consumers as possible is vital. The basic rule should be that consumers do not lose economically by connection. This may necessitate separate rules for dealing with customers having demonstrably high costs for converting existing buildings to DH systems. Air pollution legislation may further help achieve full or nearly full connection.

14. CONCLUDING REMARKS

The objective of the present study is to present an outline of an overall plan to heat all or most of the Minneapolis-St. Paul region by DH, mostly from cogeneration power stations fueled by inexpensive western coal. Converted turbines at existing power stations are proposed for heat production, while new cogeneration units will be needed toward the end of the development period. For distribution we propose a hot water system based on modern technology widely practiced in Europe.

The report suggests that the overall scheme is entirely feasible; that the economics are sound, given an appropriate system of financing; and that very large savings in the fuels with limited reserves (natural gas and oil) would result. The savings would be equivalent to 49 million barrels of oil for Scenario A and 30% more than that for Scenario B during the 20-year development period.

In parallel with the present study, several studies have been initiated to provide more accurate information on some of the costs. Subjects being studied include turbine conversion costs, costs of new out-of-town cogeneration plants, costs of a DH network for part of the St. Paul area, and building conversion costs. When the results of these are available and have been analyzed and compared, several of the costs cited in the present study can be adjusted. This and other refinements could lead to revisions in the overall economics, although they are probably not major enough to change the overall conclusions.

In conclusion, the report suggests that most of the Twin Cities area can be connected to DH; that such connection would greatly save scarce fuels, natural gas and oil; and that its overall economics would be sound.

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