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FEASIBILITY OF A LARGE DISTRICT HEATING — COGENERATION SYSTEM FOR THE MINNEAPOLIS-ST. PAUL AREA*

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ABSTRACT

The Department of Energy, Minnesota Energy Agency, Northern States Power Company, and other local government and private organizations are cooperatively performing an in-depth application study to determine the feasibility of district heating for a large northern U.S. city. A Swedish firm, Studsvik, has developed an overall scenario and has attempted to show the potential of a fully implemented system. The proposed system would be about 2600 MW(t) and cover a significant portion of both Minneapolis and St. Paul. This study has 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 study — both sponsored by Northern States Power Company. The overall conclusions that can be drawn at the present time are: (1) the concept is technically feasible, (2) it has great value from the fuel conservation aspect, and (3) the economics are viable with an appropriate financing system.

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INTRODUCTION

District heating is a process in which thermal energy from a central source (either a heat-only unit or a cogeneration plant that produces both electricity and thermal energy) is distributed to commercial, industrial, and residential consumers for space heating and domestic hot water needs. From a historical standpoint, district heating was first implemented in the United States over 100 years ago. After a period of rapid growth, the expansion of steam district heating systems slowed in the late 1940's when inexpensive oil and natural gas became available for heating purposes. District heating technology is now being reassessed because of rapidly escalating energy prices and our country's increasing dependence on imported oil. Northern States Power Company (NSP), the U.S. Department of Energy (DOE), the Minnesota Energy Agency (MEA), and other local government and private organizations are cooperatively performing an in-depth application study to determine the feasibility of hot water district heating for a large U.S. metropolitan area — namely, Minneapolis-St. Paul, Minnesota.

The program to assess district heating for the Twin Cities area consists of a number of coordinated studies focusing on technical, economic, environmental, and institutional issues. This paper will present the results of several phases of the program that have been completed or are near completion — these include the Studsvik district heating study and a power plant retrofit study.

STUDSVIK DISTRICT HEATING STUDY

This study[1] is a joint effort based on current Swedish district heating technology and experience, adopted where necessary to U.S. conditions. U.S. participants supplied the basic data and economic criteria while Studsvik Energiteknik carried out the analysis. The objective of Studsvik's analysis was to determine the feasibility of district heating for the Twin Cities and not to develop a detailed step-by-step plan for the network nor do detailed engineering and economic calculations. The major efforts were concentrated in three areas: (1) Assessment of the heating loads which could be connected over a 20-year period; (2) Determination of a feasible implementation schedule to connect the loads and bring cogeneration plants and peak load boilers on line; and (3) Examination of the overall economics based on alternative methods of financing.

Heat Load

The cold climate (more than 8,000 heating degree days) combined with the large population of the Minneapolis-St. Paul area give rise to a fairly large concentrated heat load. The metropolitan area contains two separate downtown areas about seven miles apart (Fig. 1). Around these core areas are industrial sites and residential housing which practically makes the area one continuous metropolitan region having a population of more than one million people.

Natural gas presently supplies the majority of the heat load in the region. Current heat demands within the entire region were forecast from records of gas consumption, existing district heating system heat demands, and consumer heating oil requirements. This analysis was carried out for 32 subareas in the Twin Cities and surroundings. The subareas were classified into five types of relatively homogeneous areas as indicated in Table I and the corresponding map in Fig. 2. Due to the complication of integrating the existing steam district heating systems in Minneapolis and the University of Minnesota into a hot water system within the time frame and work scope of the study, these areas were excluded. Also some large industries for which insufficient data were available were excluded. This case is referred to as Scenario A with a heat load of 2,600 MW(t).

A potential heat load of 2000 MW(t) was estimated for outlying residential areas. Scenario B assumes that this load with a 70% connection would also be supplied by the regional district heating system giving a maximum demand of 4,000 MW(t) (2,600 + 1,400).

Implementation Schedule

The heat load connection rate for Scenarios A and B are assumed to be approximately 130 MW(t) and 200 MW(t)/y respectively, over a 20-year period (see Fig. 3). Initially, the main system would develop in the high-density downtown areas which have a heat density of more than 50 MW(t)/km^2. The system would spread to the medium-density industrial and commercial apartment buildings and to high density residential multiple-family houses having heat densities of 25 to 50 MW(t)/km^2. Initially, the Minneapolis and St. Paul systems would develop independently. Eventually, when the systems become sufficiently large, an interconnecting pipeline would connect the two regions.

For Scenario A, it has been assumed that all cogeneration capacity could be located at existing sites within the metropolitan area, i.e., at High Bridge for St. Paul and Riverside for Minneapolis with some energy interchange after the construction of the interconnecting pipeline. For Scenario B, new units were assumed at an out-of-town site. This site was assumed to be King, located about 17 miles from downtown St. Paul (see Fig. 1).

Table II tabulates the assumed cogeneration plants. The largest and most modern existing turbines would be converted first, i.e.; High Bridge No. 6, Riverside No. 8, and High Bridge No. 5. The last cogeneration plant to be introduced for Scenario A is a new boiler turbine unit with a rating of 335 MW(t) and 190 MW(e) during cogeneration operation and 240 MW(e) for electric only operation. This unit should be located at Riverside to be near the load, but may have to be located at High Bridge due to site conditions.

The total heat from the cogeneration units summarized in Table II is 1,516 out of a maximum 2,600 MW(t) demand for Scenario A. The cogeneration units would provide about 60% of the peak capacity of the system and supply almost 90% of the annual thermal energy demand. The remaining load would be provided by peak-load oil-fired boilers.

Economic Analysis

Table III summarizes the total investments needed for Scenario A for the entire 20-year period in terms of 1978 dollars. The total cost includes the transmission and distribution system, cogeneration and peak load plants, and building heating system conversions. It can be seen that the system is highly capital intensive with over 50% of the investment in transmission and distribution lines. For this reason, it is important that as the system develops consumers must be connected early to start generating revenues as soon as possible. Out of a total investment of $625 million, about 80% would normally be financed by the utility and the rest by building owners. Figure 4 shows the calculated net saving in 1978 dollars for the reference cases for both municipal and private utility financing.

Fuel Savings

Figure 5 shows the fuel consumed for district heating. This includes additional coal that is needed to generate electricity sacrificed through conversion of electric-only plants to cogeneration units. The figure also shows the fuel that would be required to supply thermal energy to the same consumers by individual oil- and/or gas-fired boilers. 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 equal to 18 million barrels of oil equivalent. 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 than for Scenario A.

RETROFIT OF HIGH BRIDGE GENERATING PLANT TO COGENERATION STUDY

Northern States Power Company's existing power plants are the designated heat sources for both the Studsvik and the St. Paul district heating studies. The power plants are ideally located close to the heat load and use coal as the basic fuel. Conversion of existing power plant turbine units to cogeneration is used wherever possible in district heating applications as the conversion of an existing unit is lower in cost than building new units or installing new heat-only boilers. The technical feasibility of converting the existing units to cogeneration is therefore important to the development of the district heating system.

Units 3, 5, and 6 were selected for conversion to cogeneration. The selection is based on the high availability of these units and the projected low maintenance cost to maintain the high availability. Unit 4 is similar to Unit 3 but was not recommended for conversion due to its lower availability and the high cost projected to improve its availability. In addition, the base loaded thermal capacity of Unit 4 was not required to meet system thermal demand.

Cogeneration System Design

The conceptual system design is shown schematically in Fig. 6. Unit 3 is converted to a back pressure operation by removal of a portion of the low pressure blading. It is not amenable to steam extraction due to the single casing turbine design. Unit 3 will be operated in a thermal base loaded condition to heat the return water from 150°F to 190°F. Units 5 and 6 are converted to condensing tail operation by the installation of a variable steam by-pass in the external crossover piping between the high pressure and low pressure casings. Condensing tail operation permits the unit to be operated in the summer in the "Electric Generation" mode without loss of electrical capacity. These units will operate in series with Unit 3 to heat the water to a maximum of 300°F for the peak thermal demand of the system. An emergency heat exchanger supplied with boiler steam is used when a cogeneration unit is not available.

Capital and Operating Costs

A detailed capital cost estimate is shown in Table IV. The costs are based on 1978 equipment prices and labor rates and include indirect costs such as engineering and construction management. Included in the estimate are costs required to convert Units 3, 5, and 6 and also the estimated costs for major repairs or maintenance required to extend the life of these units. The costs are production costs at the High Bridge Station and do not include amortization costs of the distribution system or other distribution costs such as pumping power.

Based on the system thermal cogeneration output of 444 MW(e) and the $9,000,000 conversion costs, the unit cost of cogeneration is approximately 20 $/kWt. When the $3,000,000 maintenance cost required to extend the life of the units is added, the unit cost of cogeneration is 27 $/kWt.

CONCLUSIONS

Studsvik has developed an implementation scenario for a large regional hot water district heating system. The analysis concluded that the concept is technically feasible, has great value from a fuel conservation aspect, and can achieve viable economics with an appropriate financing system. The 2,600 MW(t) system servicing a significant portion of the two cities would be economically viable with joint municipal-private financing. Typical utility financing alone may not be a viable option for such a large system. However, a possible scenario using utility financing could service the more attractive high heat load density regions, but not the lower heat load density areas.

Northern States Power Company has examined retrofitting the existing High Bridge Power Plant to serve as a heat source for district heating. The results indicate that 300°F hot water can be supplied without a substantial loss in generating capacity at an estimated capital cost of 20 $/kWt. This is less than the capital cost of a new oil or gas fired boiler at approximately 40 $/kWt.

In summary, the preliminary analysis of the feasibility of a district heating system for the Minneapolis-St. Paul area is nearing completion, and the results show that significant savings in oil and natural gas are possible. It is uncertain, however, as to what type of financing (i.e., utility, municipal, or some combination of these) would be most suitable to implement such a system. This question and others need to be resolved in order to bring about the successful development and growth of cogeneration/district heating systems which can be a significant benefit to both local and national interests.

REFERENCES

1. Studsvik Energiteknik AB, Minneapolis-St. Paul District Heating Study, ORNL/TM-6830, September 1979.

TABLE I AREA TYPES AND HEAT DEMAND

Type of Area		Minneapolis (MW_t)	St. Paul (MW_t)	Total (MW_t)
1.	Very dense downtown areas with existing DH systems (>70 MW/km^2)	206	60	266
2.	Other large customers needing special consideration	100	191	291
3.	Dense downtown area (>50 MW/km^2)	313	244	557
4.	Medium density districts with commercial buildings and multi-family apartment buildings (25-50 MW/km^2)	1000	286	1286
5.	Residential areas with two-family and four family houses (10-25 MW/km^2)	370	195	565
6.	Total load, including special customers	1989	976	2965
7.	SCENARIO A TOTAL	1781	840	2621
	<u>Additions for Scenario B</u>			
8.	Large customers needing special consideration	48	51	99
9.	Residental areas (10-25 MW/km^2)	1105	826	1931
10.	Total additions	1153	877	2030
11.	SCENARIO B (potential)	2934	1717	4651
12.	SCENARIO B with 70% connection of item 10	2588	1454	4042

TABLE II COGENERATION PLANTS

Power Plant Unit	Original Electrical Output MW_e	Cogeneration Output 1) MW_e	MW_t	Conversion Cost ($ Million)	Start of Operation (year) 4)
Existing Units					
High Bridge No. 3	62	48	117	3.3	10
High Bridge No. 4	62	48	117	3.3	6
High Bridge No. 5	102	64	157	4.0	3
High Bridge No. 6	156	98	240	4.5	2
Riverside No. 6	62	48	110	3.3	2
Riverside No. 7 2)	55	52	110	0.0	7
Riverside No. 8	216	127.5	330	5.5	2
Total	716	485.5	1181	23.9	
New Units	Maximum Electric Output MW_e			Extra Cost 3) ($ Million)	
High Bridge 9 or Riverside No. 9 (Scenario A)	240	190	335	29	12
King (Scenario B)	900	2 x 400	2 x 350	72	18
TOTAL, SCENARIO A	956	675.5	1 516	53	
TOTAL, SCENARIO B	1616	885.5	1 881	96	

1) Simultaneous maximum electrical and maximum thermal power output.

2) New back pressure turbine installed in existing building to match existing boiler. Value of additional electrical power gained is estimated to equal cost, therefore no charge to district heating system.

3) Additional cost due to economy of scale as compared to normal large capacity units at remote sites.

4) Assuming start of distribution system construction in year 0

TABLE III. DISTRICT HEATING SYSTEM INVESTMENTS, Scenario A. (1978 Dollars).

	Total Cost (Million $)	Unit Cost* ($/kW)
Cogeneration plants	55	21
Peak load boilers	66	25
Production plant total	121	46
Hot water transport	104	40
Hot water distribution	274	105
Transport and distribution total	378	145
Production, transport, distribution	499	191
Building conversion	126	48
System total	625	239

*Based on 2621 MW(t) Maximum System Demand

TABLE IV. CAPITAL CONVERSION COSTS

Equipment	Retrofit Cost	Maintenance Cost
Structures and Improvements	$ 30,000	--
Boiler Plant Equipment	4,105,000	$2,450,000
Turbine-Generator Units	2,880,000	--
Accessory Electric Equipment	315,000	--
Total Direct Costs	7,330,000	2,450,000
Indirect Costs	620,000	200,000
	7,950,000	2,650,000
Contingency	1,050,000	350,000
Total	$ 9,000,000	$3,000,000

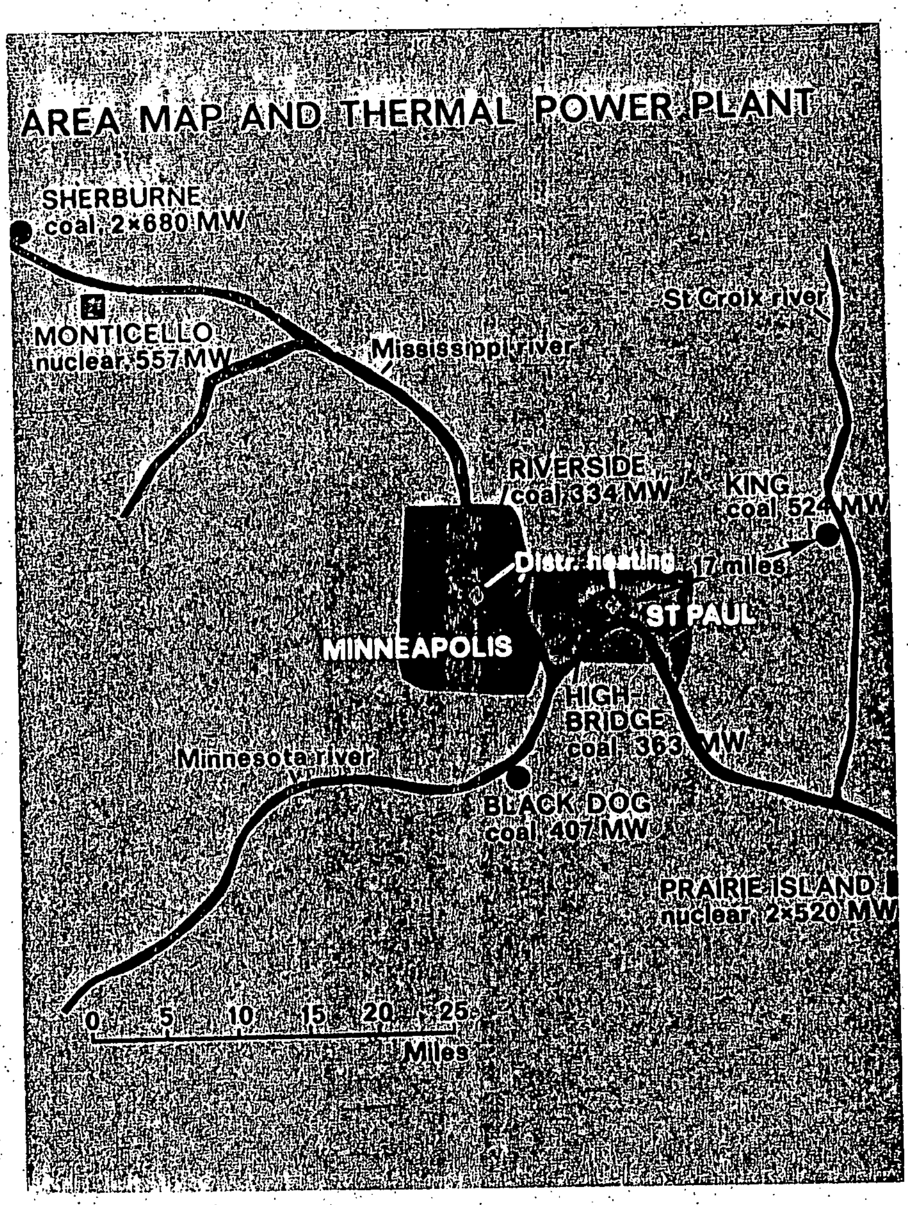

Fig. 1. Area map with main thermal power plants.

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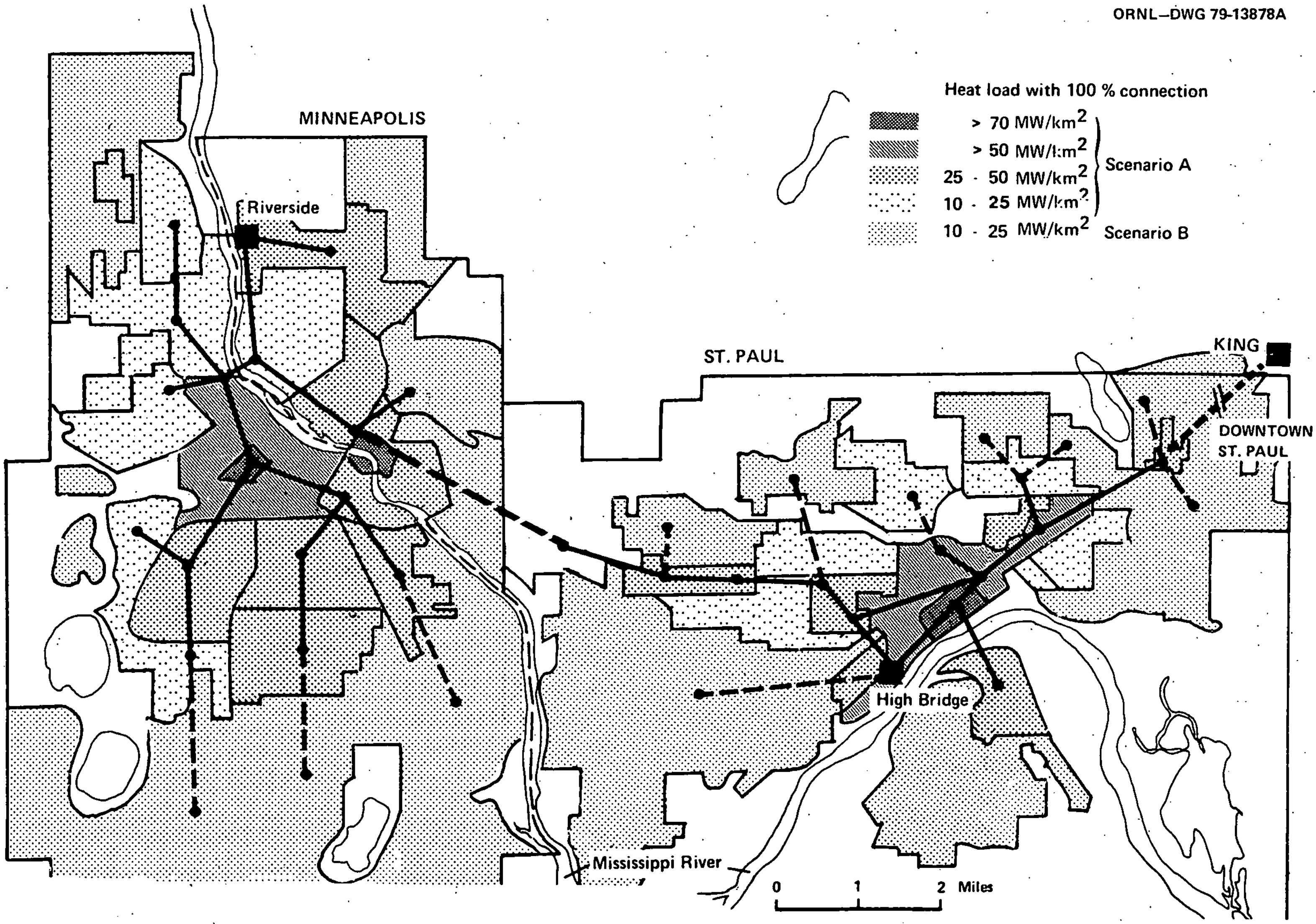

Fig. 2. Heat load densities and possible regional piping systems.

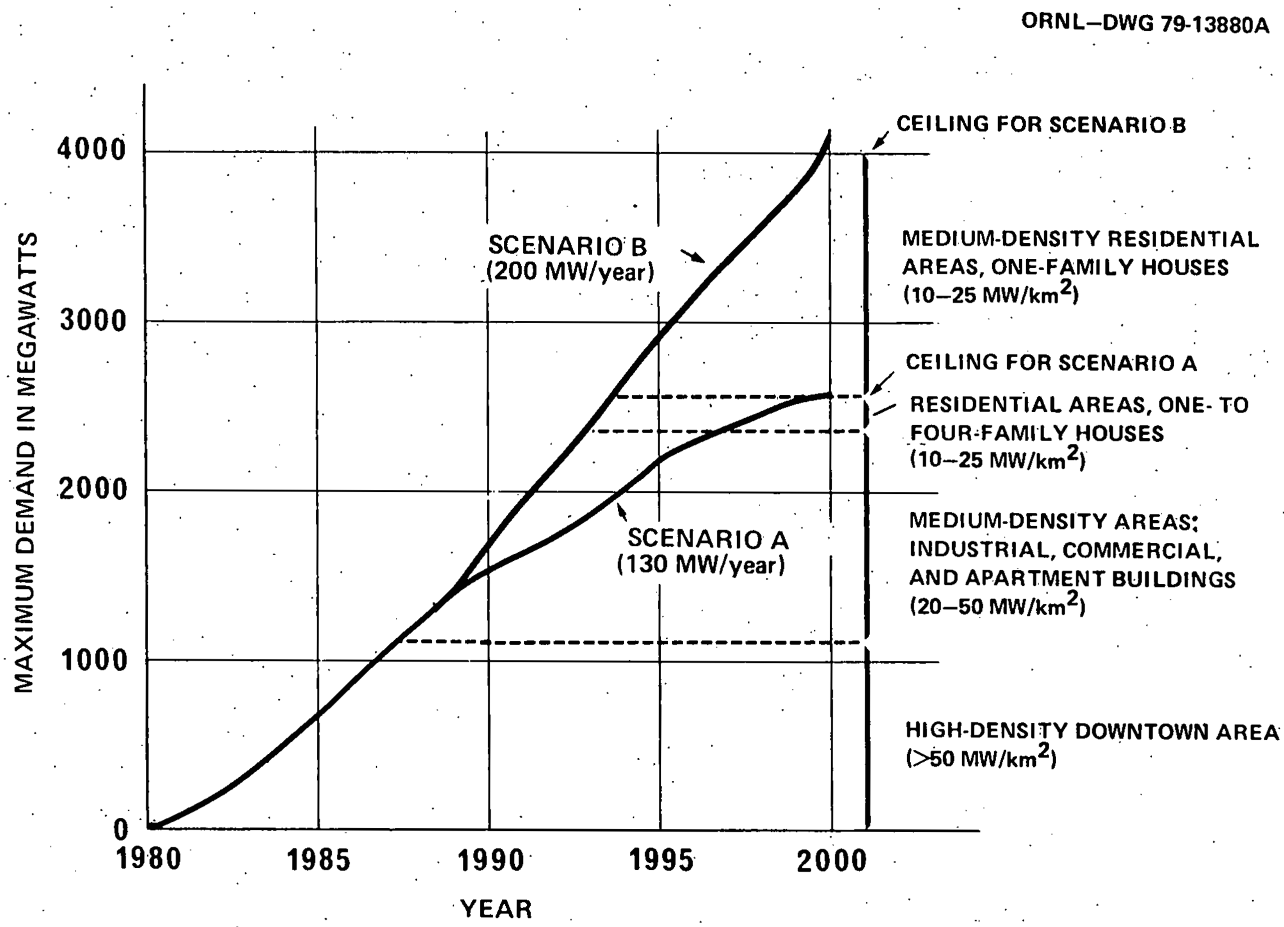

Fig. 3. Assumed load connection rates for Scenarios A and B.

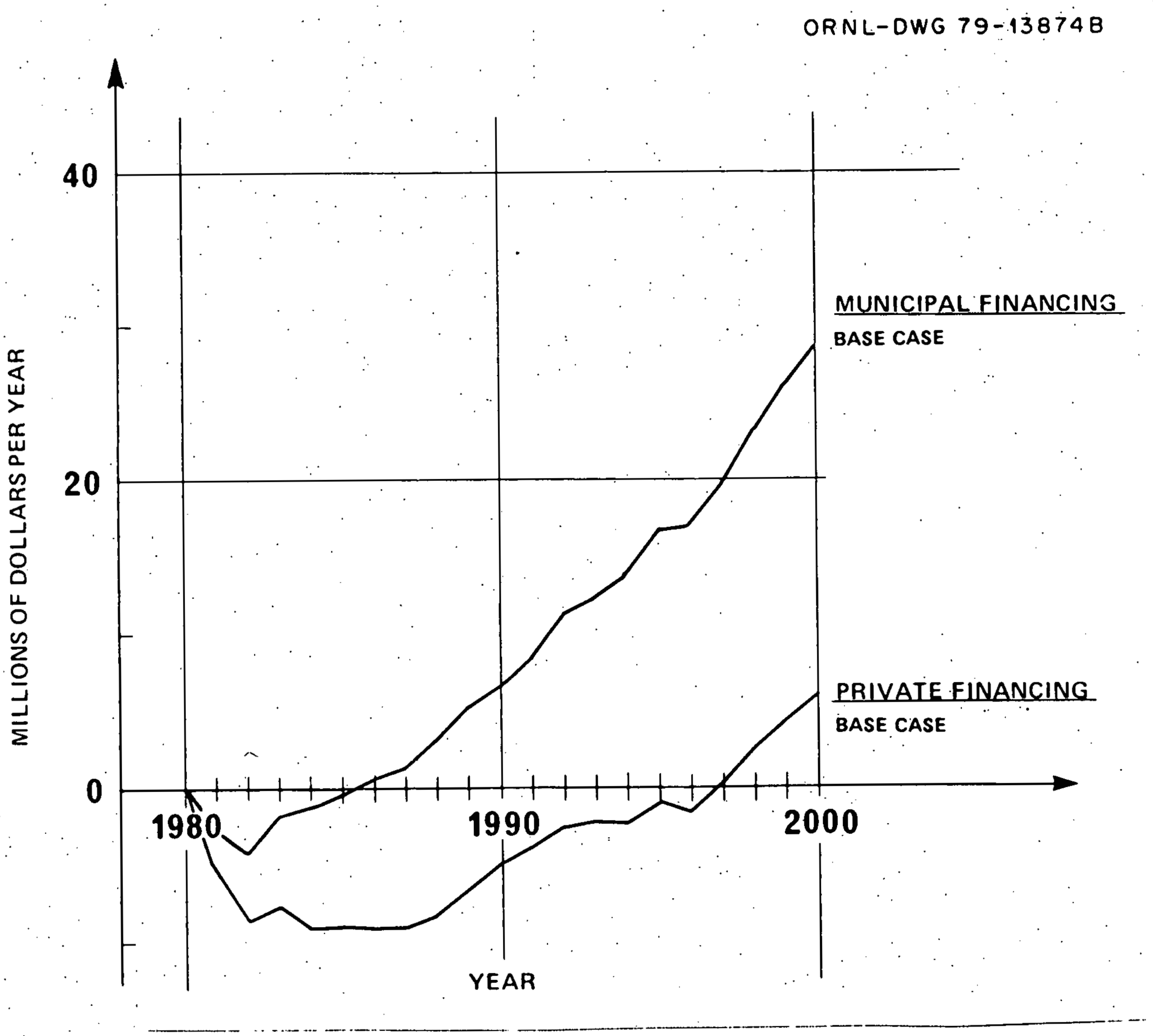

Fig. 4. Annual net savings in 1978 dollars.

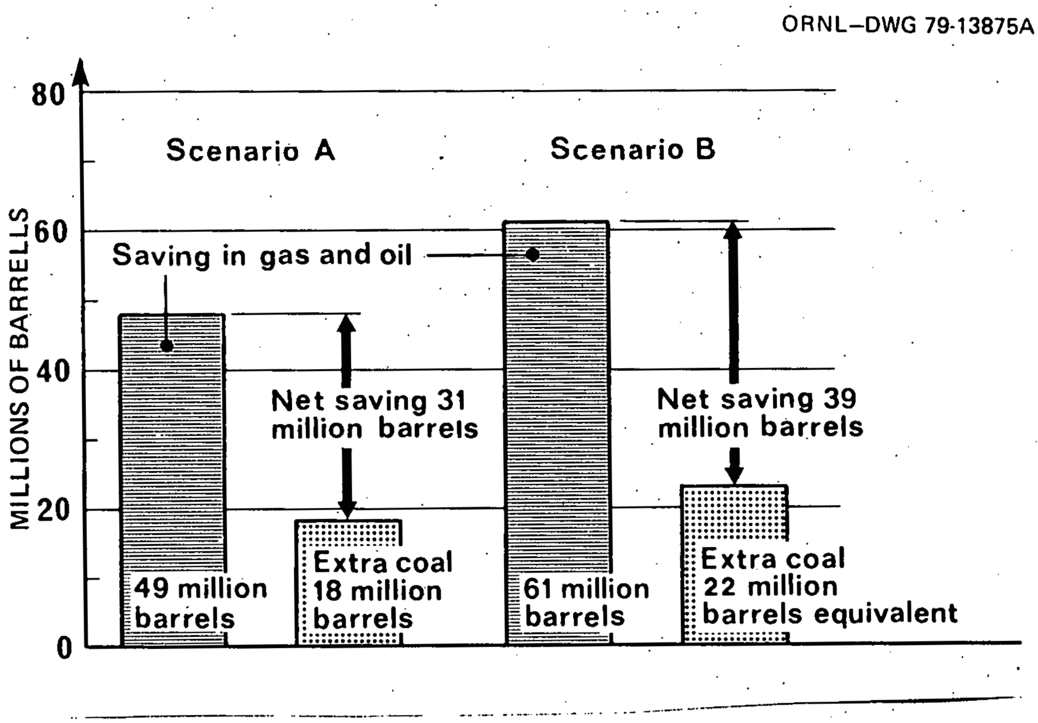

Fig. 5. Fuel savings due to district heating, 1980 to 2000, Scenario A and B.

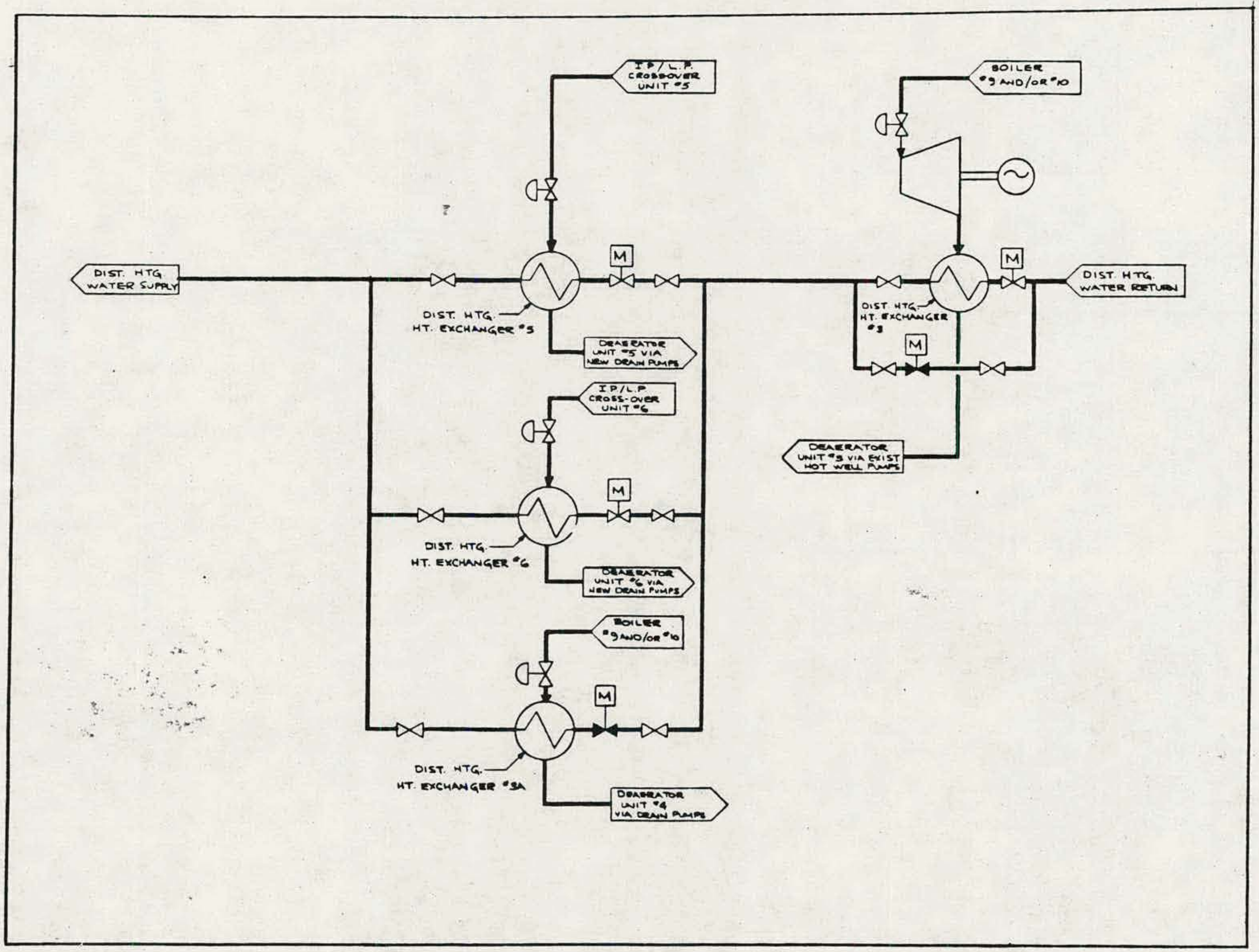

Fig. 6. High bridge cogeneration system.