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Design and Analysis of District Heating Systems

Volume 4:
Assessment of District Heating for Springfield, Massachusetts

Prepared by
Burns and Roe, Inc.
Oradell, New Jersey

REPORT SUMMARY

SUBJECTS Building energy systems / Cogeneration/waste heat recovery

TOPICS Dual-purpose power plants; District heating; Cogeneration; Design

AUDIENCE Customer service managers / Generation planners

Design and Analysis of District Heating Systems

Volumes 1–4

Rising energy costs and dwindling fuel sources have spurred development of alternative energy-use technologies. One such technology, which reduces waste and increases the use of available energy supplies, is cogeneration of electricity and heat energy. This study evaluates utility cogeneration systems that cost-effectively provide district heating as well as electricity.

BACKGROUND District heating—the centralized production of heat energy and its distribution through pipes to provide space and hot water heating to homes, businesses, and industries within a certain area—is widely used throughout Europe, where dense population and relatively expensive fuel make it a viable technology. The need to conserve oil and gas and the success of European systems, which use hot water to distribute the heat, have sparked U.S. interest in district heating. However, research is necessary to assess the technical and economic feasibility of U.S. applications and to evaluate site-specific designs.

OBJECTIVES
- To assess the application of hot water district heating in the United States.
- To design district hot water systems for three utility sites and to evaluate the technical, economic, and environmental effects of these systems.

APPROACH To identify potentially attractive sites for cogeneration hot water district heating systems, project personnel developed a methodology for assessing potential heat sources and heat loads, analyzing hot water transmission and distribution pipe systems, determining the mode of operation of the system, identifying environmental and institutional issues, and analyzing economic factors. Using this methodology, they studied designs for power plant modifications and transmission/distribution piping systems for district heating in three candidate cities—Lansing, Michigan; Providence, Rhode Island; and Springfield, Massachusetts.

RESULTS The study shows that an economically attractive site for district heating should have a high heat load density, usually between 60 and 90 MW/mi^2; a short distance between the heat source and heat load; a coal-fired or refuse-derived–fuel-fired electrical generating station that could be modified to provide district heat along with electricity; and utility interest in owning and operating the system. Researchers produced site-specific conceptual designs for power plant modifications and transmission/distribution piping systems for the three candidate cities. They also devised plans for implementing the district heating systems and installing them in phases corresponding to increases in district load. In general, heat sources for the systems would be coal-fired or refuse-derived fuel-fired. The environmental assessment produced encouraging results: for example, replacement of numerous uncontrolled heat sources by a central cogeneration plant would improve local air quality. The economic analysis indicated that district heating would supply heat for downtown areas at a lower cost than individual boilers fired with oil or gas.

EPRI PERSPECTIVE

This study is part of EPRI's ongoing research in dual energy-use systems and their application in the United States. A related EPRI report, EM-2864, evaluates European district heating systems. In cooperation with Northeast Utilities, the city of Springfield, Massachusetts, is using the results of this research to carry out a more detailed analysis of the feasibility of district heating. The Lansing Board of Water and Light is using the project results to plan a district heating system for the downtown area.

Volume 1 of this four-volume report is an executive summary; Volumes 2, 3, and 4 are assessments of district heating for Lansing, Michigan; Providence, Rhode Island; and Springfield, Massachusetts, respectively.

PROJECT

RP1276-5
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Design and Analysis of District Heating Systems

Volume 4: Assessment of District Heating for Springfield, Massachusetts

EM-3867, Volume 4
Research Project 1276-5

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ABSTRACT

This report assesses the technical and economic feasibility of implementing a hot water district heating system in Springfield, Massachusetts. It provides conceptual designs for power plant modifications and transmission/distribution systems to satisfy a projected heat load. It includes a system implementation plan with equipment installation phases corresponding to projected increases in heat load. It also calculates the financial implications of such a hot water district heating system. This report is volume 4 of a 4 volume research project entitled "Design and Analysis of District Heating Systems." Volume 1 summarizes the methodology for assessment of district heating technical and economic feasibility and the results of studies performed for the cities of Lansing, Michigan; Providence, Rhode Island; and Springfield, Massachusetts. Volume 2 presents the site specific results for Lansing, Michigan and volume 3 presents the site specific results for Providence, Rhode Island.

ACKNOWLEDGMENTS

This study was performed in close cooperation with Northeast Utilities and the City of Springfield. Messrs. F. B. Hill, R. H. Meyer, F. P. Sabatino, J. J. Shea and C. F. Carlin of the former, and Messrs. J. J. Superneau and A. W. Curto of the latter were particularly helpful. Institutional aspects were investigated by Mr. E. J. Doyle, Jr. of Doyle Associates, Inc.

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SUMMARY

BACKGROUND

This report is submitted under EPRI project RP-1276-5, Evaluation of Dual Energy Use Systems (DEUS) - Design and Analysis of District Heating Systems. It assesses the feasibility of hot water district heating in Springfield, Massachusetts, and develops such a system in conceptual form. The system considers the commercial, industrial and high density residential sections of the city as the heat load and a combination of high temperature hot water boilers, the Solid Waste Energy Recovery Facility and the West Springfield Generating Station as the heat sources.

The study assesses the available heat load, determines the available heat from the heat sources, develops a distribution network, develops a system implementation plan, assesses the environmental impacts, addresses institutional issues, and analyses the economics of the conceptual system.

HEAT LOAD ASSESSMENT

The heat load assessment determined the most suitable areas within the city for inclusion in the hot water district heating system and defined the heat load associated with these areas. Springfield has a population of about 152,000. It has a cold climate, with approximately 6000 heating degree days. The heat load analysis indicated a peak thermal demand of 98 MWt: 19.2 MWt in the commercial district, 31.5 MWt in the industrial district, and 47.3 MWt in the high density residential district.

HEAT SOURCE ANALYSIS

The combination of three heat sources is proposed for the Springfield district heating system.

A total of five approximately 11.7 MWt high temperature hot water boilers would be installed. During the initial phases of district heating development two or three of these boilers would satisfy the heat load. During the later phases and in the fully developed system, they would satisfy the peak loads only, while the West Springfield Generating Station and the Solid Waste Energy Recovery Facility would carry the district heating base load.

The turbine at the proposed Solid Waste Energy Recovery Facility would be adapted for district heating to generate hot water in a heat exchanger using steam from its extraction connection. A peak heat load of approximately 17.2 MWt could be provided at a loss of 2.1 MWe.

Two 50 MW turbines at the West Springfield Generating Station would be modified to extract steam from selected stages for use in new district heat exchangers. Each unit would be capable of supplying 22.2 MWt, with a corresponding loss in electrical generation of about 4.4 MWe.

TRANSMISSION AND DISTRIBUTION ANALYSIS

The proposed hot water district heating system will have a two-pipe closed transmission/distribution system with peak load supply and return temperatures of 250°F and 140°F.

The conduit system would consist of a carbon steel carrier pipe, polyurethane insulation, polyethylene casing, and leak detection system. Supply and return lines would be in the same trench. Installation of the distribution system will be beneath sidewalk areas.

Transmission/distribution system development would be based on a plan developed from an analysis of the heat load characteristics and the heat source alternatives. The objective would be to spread capital expenditures out over the development period, allowing the system to generate revenues to offset investments.

SYSTEM IMPLEMENTATION

The proposed 9-year development of the Springfield district heating system is planned to occur in eight phases, resulting in a system with a peak load rating of 98.64 MWt after 9 years.

In the first year of development, three high temperature hot water boilers would be installed at the City Hall boiler plant after the existing low capacity steam boilers were removed. Two of these generators would satisfy a developed heat load of 23.42 MWt. This phase would require the installation of about 4.5 miles of piping. During the second year, there would be no new heat source or district heating piping addition. Revenues would be collected to finance subsequent development.

In the third year, the district heating system load would be increased by an additional 17.23 MWt which would allow the addition of capacity from the turbine operating at the Solid Waste Energy Recovery Facility. This turbine would be operated as the base loaded heat source, while the high temperature hot water boilers would provide the peak heat loads and serve as backup. This phase requires the installation of supply and return pipes across the Memorial Bridge, together with the additional piping required for the added heat load.

During the fourth year the Unit 1 turbine at the West Springfield Generating Station would be modified and included in the district heating system. The total developed load during this phase would be 50.37 MWt. This unit, together with the turbine at the Solid Waste Energy Recovery Facility, would provide the base load.

Two more high temperature hot water generators would be added during the fifth and sixth years of implementation, together with additional piping necessary to increase the connected heat load to 64.88 MWt.

With the addition of another 24.16 MWt of heat load, the Unit 2 turbine would be included in the district heating system in its seventh year of development, providing a total installed capacity of 120.2 MWt.

In the eight and ninth years of system development, the piping system would be extended to connect remaining loads of 5.06 MWt and 4.54 MWt. In the ninth year, the system would be complete with a maximum connected load of 98.64 MWt.

ENVIRONMENTAL EFFECT

District heating would increase the thermal efficiency of all the turbine cycles operating in the district heating mode. The increased efficiency would result in a reduction in heat rejection to the environment per pound of fuel burned.

The district heating system would also affect air quality. The district heating system would replace numerous uncontrolled point sources with a few more efficient central sources. The net effect of the changes would depend on the changes in fuel use at the West Springfield Generating Station due to the district heating system. In this study it was assumed that the West Springfield Generating Station would be converted to coal and operated as a base loaded plant regardless of district heating, and thus the district heating system would not cause an increase in emissions at the station. During the course of the district heating study, Northeast Utilities plans for converting the Station to coal firing changed, coal conversion is no longer being actively pursued. The emissions from the Solid Waste Energy Recovery Facility are not assessed against the district heating since this plant must be operated regardless of a district heating system. However, the plant is provided with an air pollution control device which ensures that emissions are in conformance with current federal and/or state regulations applicable to this type facility. Emission from the gas-fired high temperature hot water generators may actually increase in the first few years, but in the fully developed system net gas consumption will decrease due to district heating, with a corresponding decrease in emission from gas sources.

INSTITUTIONAL ASSESSMENT

The institutional assessment for the Springfield district heating system examined a variety of options for the ownership, construction, and operation of the Solid Waste Energy Recovery Facility and district heating system. Other factors that were assessed include: system financing options, proposed federal legislation, regulatory and legal aspects, siting laws, and rate allocation. The assessment determined that there are no insurmountable obstacles to district heating in Springfield. However, many questions remain to be answered.

ECONOMIC ANALYSIS

The economic analysis was performed from the viewpoint of using the required revenue approach to determine the necessary charges for district heat. System implementation phases and unit costs of district heat are summarized in Tables S-1 and S-2.

Results of the economic analysis demonstrate that a hot water district heating system will supply heat at lower cost than individual boilers fired with oil (Figure S-1).

An analysis indicated payback periods varying from 3 to 6 years for most consumers for district heating in comparison with 7.5% escalation of oil.

Table S-1

HOT WATER DISTRICT HEATING SYSTEM IMPLEMENTATION STATISTICS

	Phase One	Phase Two	Phase Three	Phase Four	Phase Five	Phase Six	Phase Seven	Phase Eight
Proposed Date On Line	1985	1987	1988	1989	1990	1991	1992	1993
Rated Peak Load (MWt)	23.42	40.65	50.37	61.99	64.88	89.04	94.1	98.64
Cumulative Annual Heat Sales (MWh)	76490	132760	164500	202460	211900	290800	307330	322160
Investment ($1983 x 10^3)								
Heat Source	1408	957	2216	470	470	2216	0	0
Piping	4347	2791	1583	1061	636	1855	741	445
Total	5755	3748	3799	1531	1106	4071	741	445

Table S-2

UNIT COST OF DISTRICT HEAT ($/MBtu)

1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
12.33	12.98	8.08	8.54	8.74	9.36	10.09	10.53	10.99	11.43

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
11.88	12.43	13.07	13.80	14.54	15.44	16.25	17.32	18.75	19.06

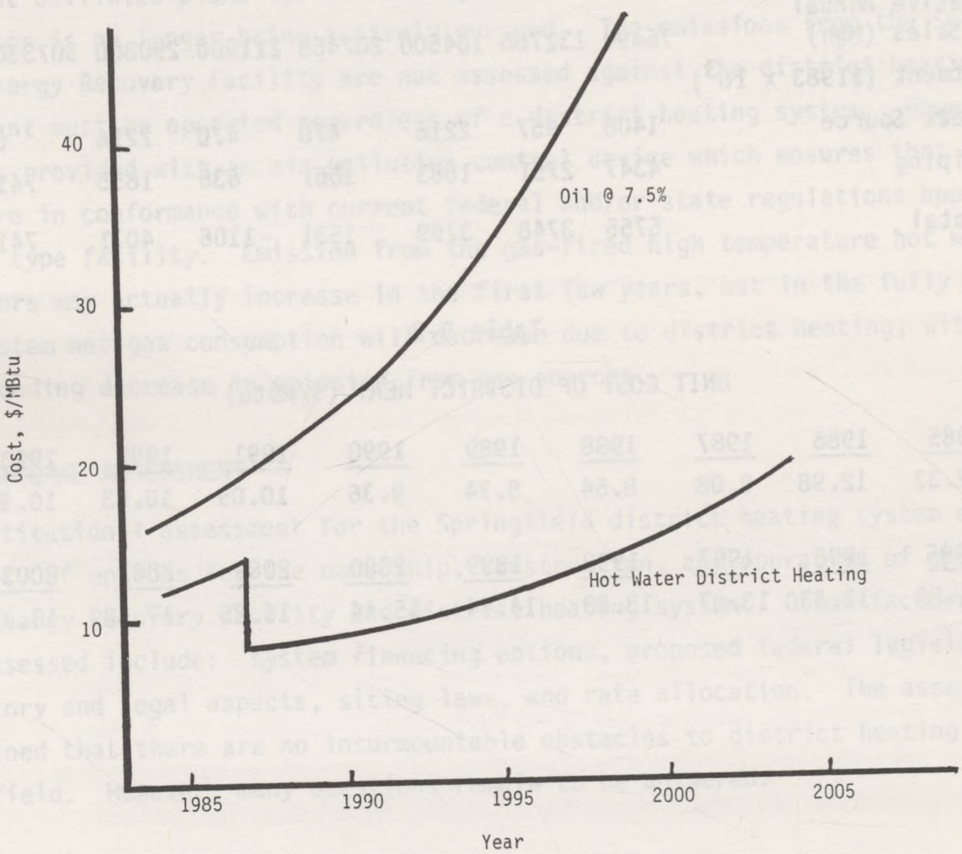


Figure S-1. Projected Heating Cost Comparison

Section 1

INTRODUCTION

This study develops in conceptual form a district heating system for the City of Springfield, Massachusetts. The study was performed in close cooperation with Northeast Utilities, with active participation of city development agencies and prospective customers.

Springfield, with a population of 152,319 is situated on the bank of the Connecticut River. During the 1960's and 1970's, Springfield suffered from a dwindling industrial base, increasing unemployment, and a migration to the suburbs by middle-income residents. The effects were particularly noticeable in the downtown area. From 1972 to 1977, Springfield's central business district suffered a 15.7% loss in the number of retail establishments and a 13.6% decline in employment.

Springfield has embarked upon an ambitious revitalization effort designed to attract commercial and retail interests, as well as residents to populate the downtown neighborhoods. These efforts have been supported by sources such as the Community Development Block Grant program, Economic Development Administration, Urban Development Action Grant program, and the Commonwealth of Massachusetts.

Springfield's leaders recognize that the municipality must continue its revitalization efforts if the city's renaissance is to be successful and that implementation of a district heating project would be an asset. The district heating concept has the potential to provide the low cost energy necessary to enhance Springfield's efforts in housing rehabilitation, commercial stabilization and industrial expansion.

The major components of a district heating system are the energy sources, transmission and distribution system, and users. The major heat sources considered are high temperature hot water (HTHW) boilers, a prospective solid waste energy recovery facility (SWERF) and two units of the West Springfield Generating Station (WSGS).

Section 2 presents an assessment of the heat load, based on consumption records for existing buildings and city block maps of the prospective service areas. Section 3 characterizes the available heat sources and provides the composition and capital cost estimate of the ultimate heat source configuration. Section 4 presents the conceptual hot water transmission and distribution networks and assesses their costs. Section 5 describes the system implementation plan, and Section 6 discusses system operation and plant dispatch. Section 7 assesses the environmental impact of the prospective district heating system, and Section 8 provides an institutional assessment.

Section 9 presents the results of an economic analysis of the hot water district heating system based on budgetary capital costs, and operation and maintenance cost estimates.

Section 2

HEAT LOAD ASSESSMENT

INTRODUCTION

Major factors in a heat load assessment are the area heat load density and the proximity of the load to the heat source. For the progressive development of a district heating system in Springfield, it is assumed that HTHW boilers are the initial heat source, followed by the SWERF and two units at the WSGS. An area of adequate density to serve as a district heating load exists.

DEFINITION OF THE SERVICE AREA

Springfield is in southwestern Massachusetts, on the east side of the Connecticut River. The climate is cold, with approximately 6000 heating degree days. The outdoor temperature profile is shown in Figure 2-1. The outdoor design temperature is 3°F.

The primary heating district, closest to the heat sources, is the downtown central business area of about 157 acres. The HTHW boilers will be located in the City Hall boiler plant. The SWERF will be southwest of this district, and the WSGS is to the northwest, both on the other side of the river. The most favorable expansions for the district heating system would be to the north and east to the industrial district, and to the south to the high density residential areas. The entire prospective service area (Figure 2-2) occupies about 1210 acres.

METHODOLOGY FOR DETERMINING HEAT LOAD

The peak heat load estimate is based on block maps for each of the 75 assessor's blocks within the service area and building information such as area, height, condition, heating system type, fuel consumption, building function and construction type. All buildings within the potential service area are included in the heat load assessment. They include residential, commercial, institutional, public, hospital, public housing and other structures but no large factories.

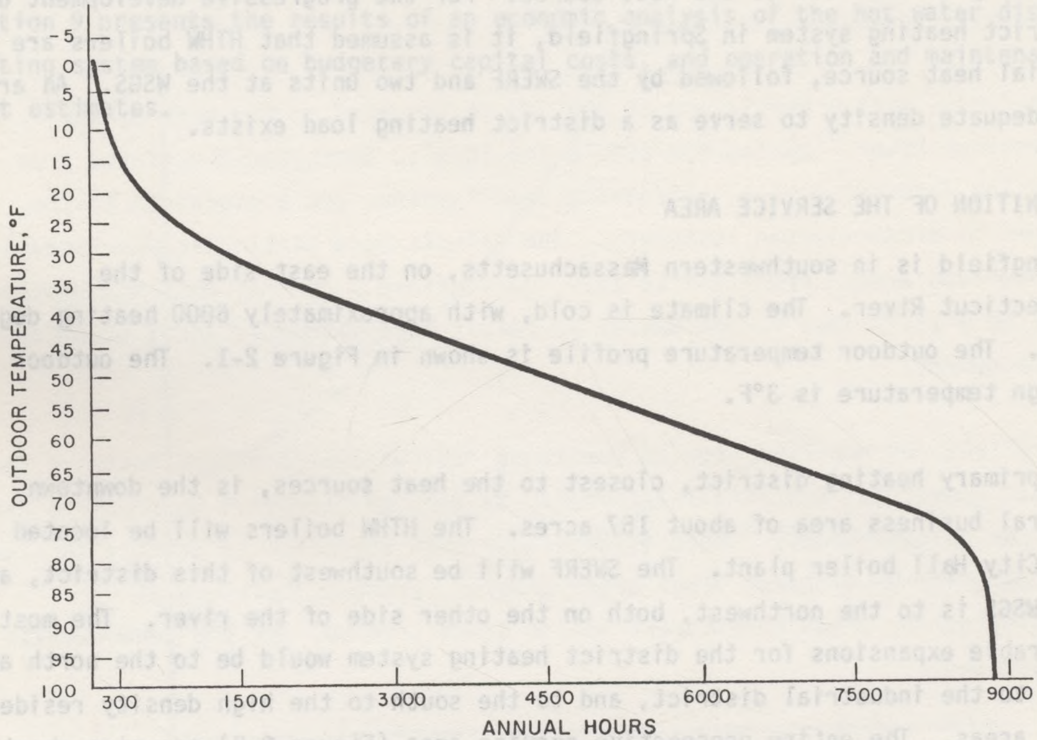


Figure 2-1. Outdoor Temperature Profile

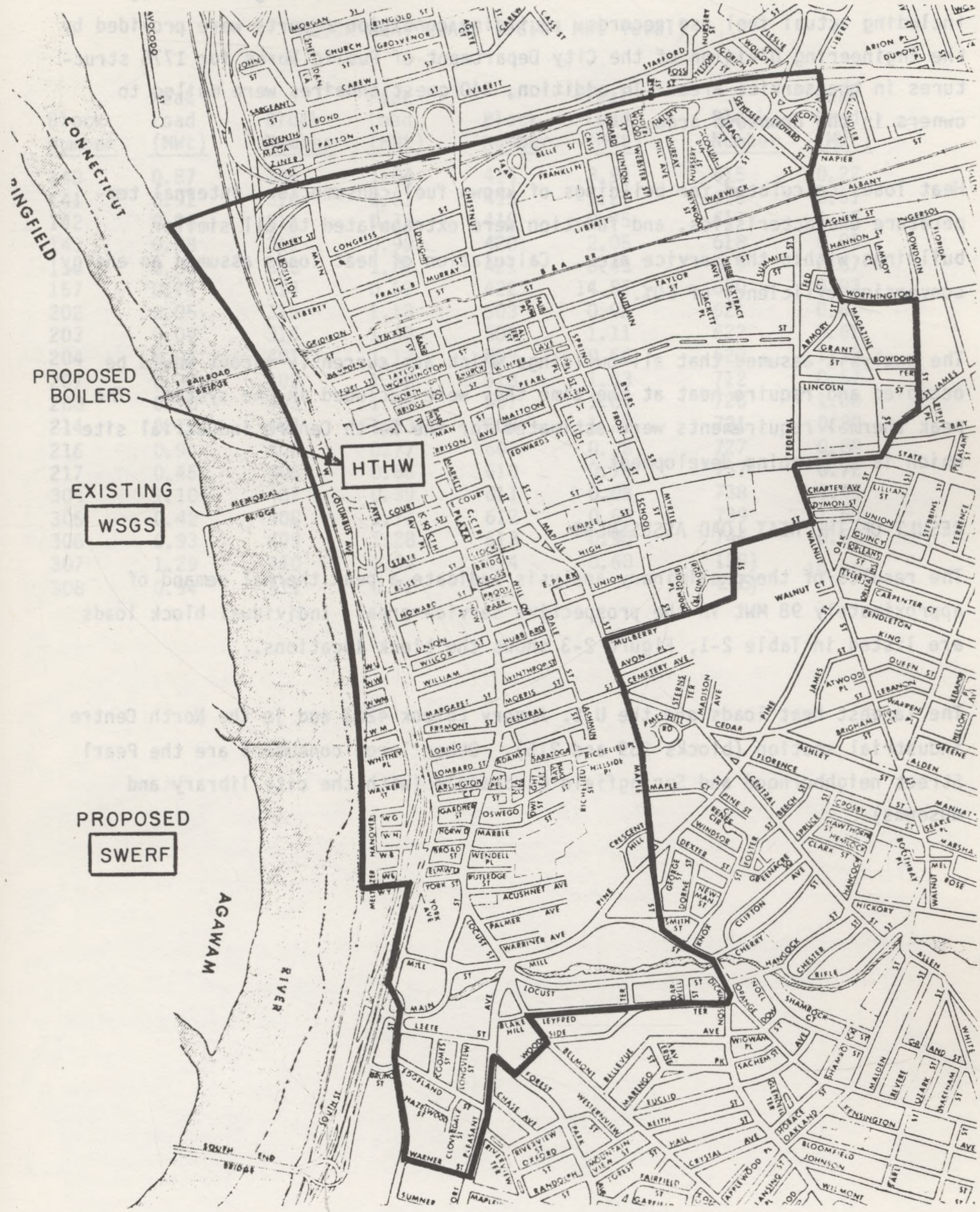


Figure 2-2. Prospective Service Area

Selected major users in the service area were interviewed to gather data, including actual fuel use records. Building condition reports were provided by the Engineering Division of the City Department of Public Works for 1775 structures in the service area. In addition, 340 questionnaires were mailed to owners in the downtown area.

Heat loads calculated for buildings of known fuel consumption, internal temperature characteristics, and function were extrapolated to all similar buildings within the service area. Calculation of heat loads assumed an energy conversion efficiency of 60%.

The analysis assumed that all buildings which are currently vacant would be occupied and require heat at the time they were included in the system. The peak thermal requirements were estimated for the North Centre industrial site which is undergoing development.

RESULT OF THE HEAT LOAD ASSESSMENT

The results of the preliminary analysis indicate a peak thermal demand of approximately 98 MWt in the prospective service area. Individual block loads are listed in Table 2-1, Figure 2-3 shows the block locations.

The largest heat loads are the U.S. Armory (block 422) and in the North Centre industrial section (blocks 139 and 215). Other large consumers are the Pearl Street neighborhood and Springfield Quadrangle (with the city library and museums).

Table 2-1

BLOCK HEAT LOADS (98.64 MWt Total)

Block Number	Peak Load (MWt)	Block Number	Peak Load (MWt)	Block Number	Peak Load (MWt)	Block Number	Peak Load (MWt)
140	0.87	309	1.94	414	3.94	615	0.22
141	0.91	310	0.81	415	1.29	616	0.51
142	0.98	311	0.73	419	0.75	617	2.15
143	0.88	312	0.99	420	2.05	618	0.80
156	0.31	313	1.08	421	0.45	619	0.87
157	0.75	314	0.52	422	14.85	620	0.93
202	0.05	315	1.13	503	0.92	621	0.61
203	0.09	316	1.48	508	1.11	622	0.61
204	0.04	401	1.12	509	0.55	623	1.13
207	0.31	402	1.50	518	1.63	712	0.57
208	0.10	403	1.05	607	1.04	720	1.00
214	0.13	404	1.23	608	1.29	721	0.30
216	0.90	405	0.77	609	0.28	727	0.88
217	0.45	406	0.86	610	0.79	737	0.72
304	1.10	407	0.39	611	0.08	738	0.41
305	0.42	408	1.77	612	0.69	739	1.65
306	0.93	409	1.28	613	0.98	744	0.53
307	1.29	410	1.34	614	0.60	139) 215)	19.60
308	0.94	411	0.42				

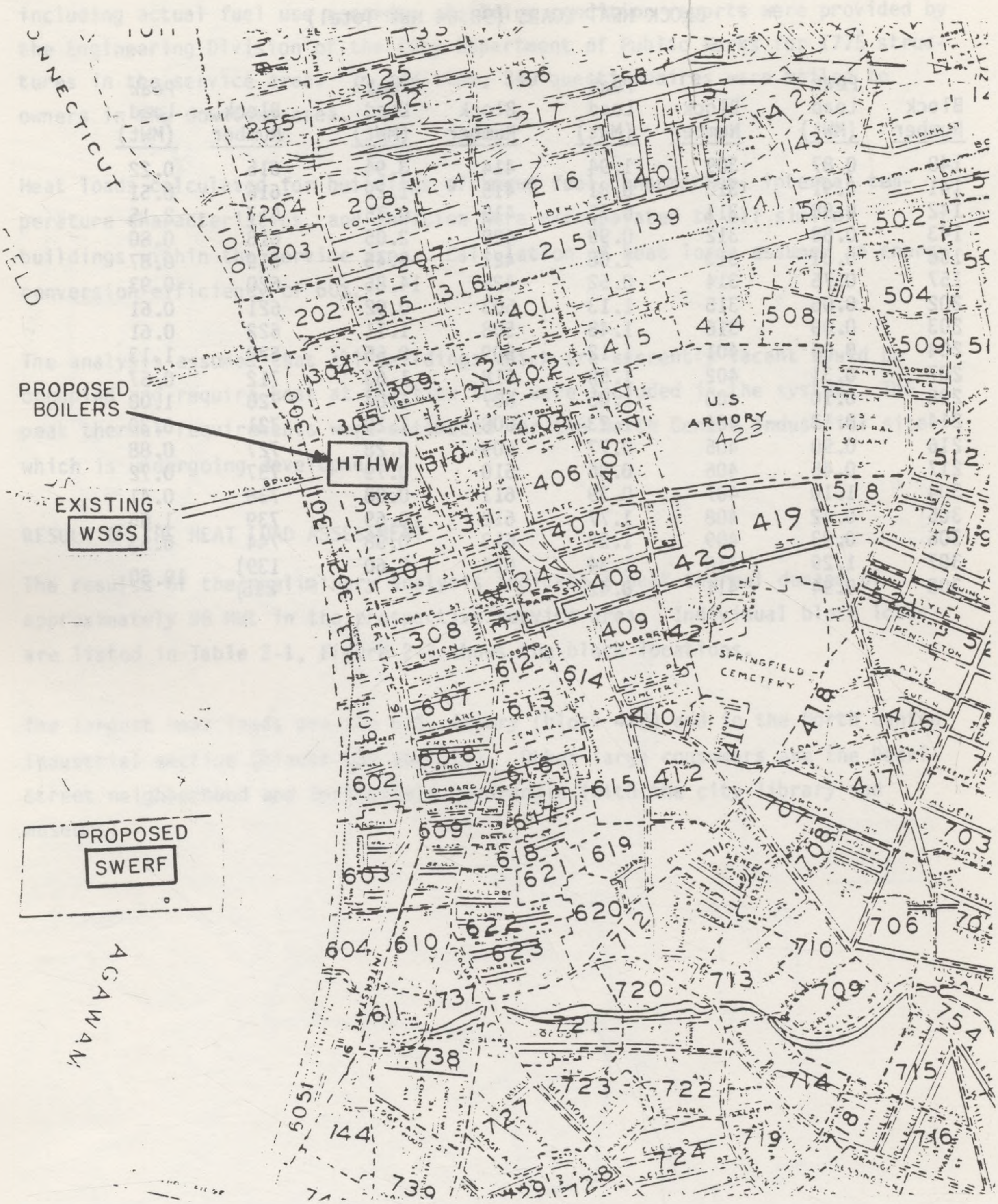


Figure 2-3. Block Locations

Section 3

HEAT SOURCE ANALYSIS

INTRODUCTION

This section develops in a conceptual form the heat sources necessary for providing district heat in the form of hot water for Springfield. Three potential energy sources were investigated in sufficient detail to choose the best combination to supply the required energy in the most economical and reliable manner:

- Constructing natural gas fired high temperature hot water boilers.
- Modifying the turbine at the planned SWERF (before installation).
- Modifying the turbines at the WSGS.

NATURAL-GAS-FIRED HIGH TEMPERATURE HOT WATER (HTHW) BOILERS

To minimize capital expenditures for providing hot water district heat during the development stage of the system, HTHW boilers can be installed. Subsequently the boilers can be used for peaking and backup for the main energy sources.

The HTHW boilers would be located at the City Hall boiler plant where there will be sufficient room for the three initial units if the existing three small steam boilers are removed. The coal bunker areas adjacent to the boiler plant could be adapted to house two more units.

HTHW boilers are available in modules which require minimal field construction time. The proposed units are of the forced recirculation type with the following characteristics:

Generator capacity	40,000,000 Btu/hr
Heating capacity	11.72 MWt
Design pressure	275 psig
Outlet temperature	250°F
Return temperature	140°F
Water flow rate	364,000 lb/hr
Boiler efficiency at full load	78.1%

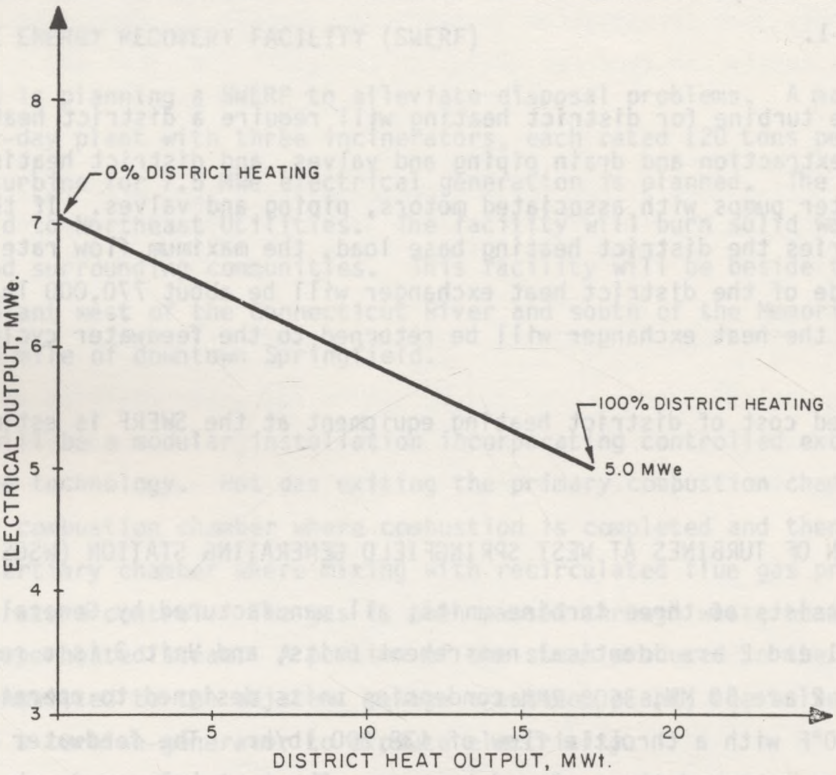


Figure 3-1. SWERF Turbine Performance

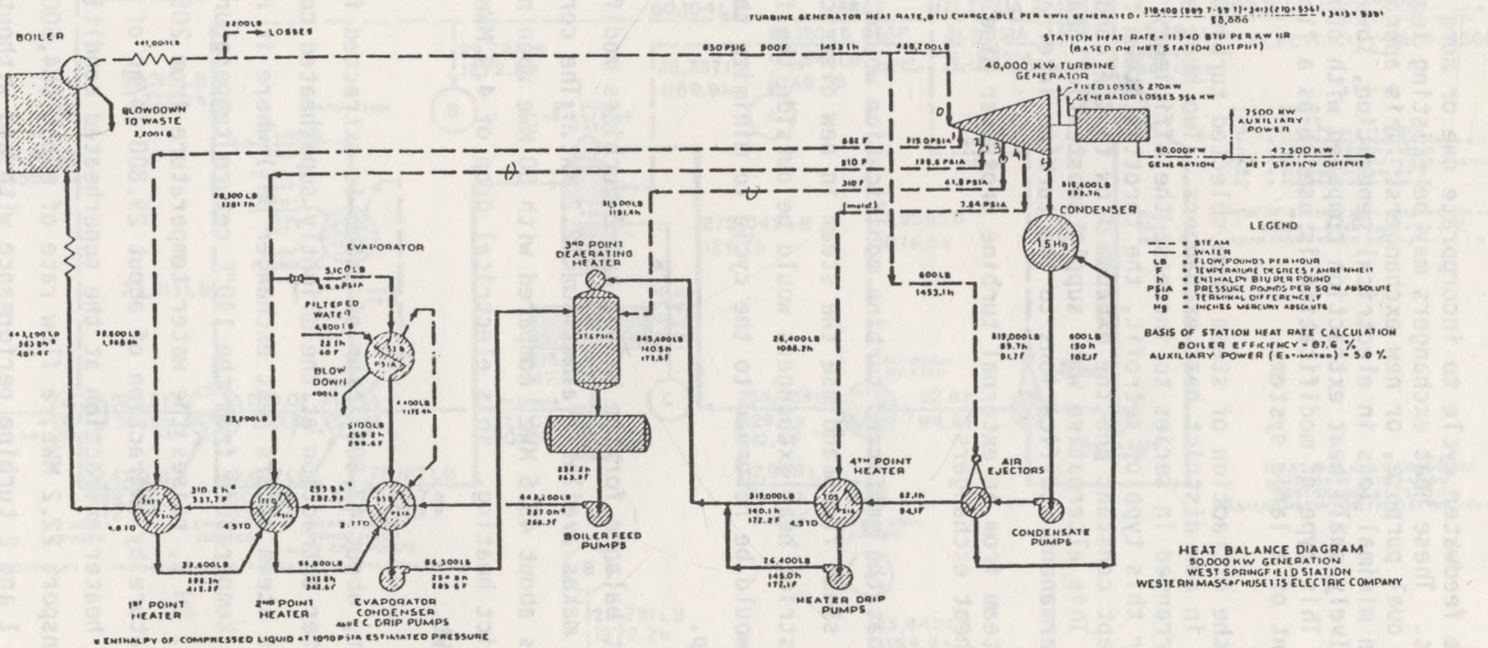


Figure 3-2. Unit 1 and 2 Original Heat Balance

following alternatives were considered:

- Modify the feedwater cycle to incorporate one or more district heat exchangers. These heat exchangers may be existing feedwater heaters serving a dual purpose, or new exchangers. This approach typically results in minimal loss in electrical generation, lowest capital costs and relatively small heat extraction compared with other retrofit schemes. This type of modification is useful as a first phase in the development of a large system.

- Maximize the extraction of steam from selected turbine stages and use the steam in new district heat exchangers. Two heat exchangers are usually arranged in series to increase the efficiency of heat extraction. For this type of retrofit, the throttle steam flow to the turbine is kept constant and the exhaust flow to the condenser is reduced. This alternative will supply substantial heat but may require permanent modifications to the turbine internals.

- Extract steam from an external turbine crossover pipe for use in district heat exchangers.

Analyses indicate that the preferred turbine modification would be to maximize selected extraction steam flows and use the steam in new district heat exchangers. The district heat exchangers would be outside the feedwater cycle, but the condensate would be returned to the cycle to minimize thermal loss and the need for make-up.

Figure 3-3 is a heat balance for the Unit 1 and 2 turbines modified for district heating. This mode makes available a maximum 22.2 MWt. The corresponding electrical output is about 45.6 MWe, compared with 50 MWe when no steam is being extracted for district heating. This electrical drop of 4.4 MWe translates to 1 MWe for every 5 MWt.

To produce this heat, about 43,800 lb/hr of steam is extracted from the 3rd point feedwater heater extraction at the slightly superheated condition of 263°F and 31.9 psia. This steam enters heat exchanger DH 1 where it raises the district heating water temperature from the 140°F return temperature to 205°F. The second stage heater, DH 2, raises the water temperature from 205°F to the 250°F supply temperature by extraction of about 29,800 lb/hr of steam from the 2nd point feedwater heater extraction at the superheated condition of 488°F and 121.5 psia. To transport 22.2 MWt, a flow rate of about 684,500 lb/hr of water is necessary. Unit 1 and 2 turbine performance with and without steam extraction for district heating is shown in Table 3-1. Electrical output as a func-

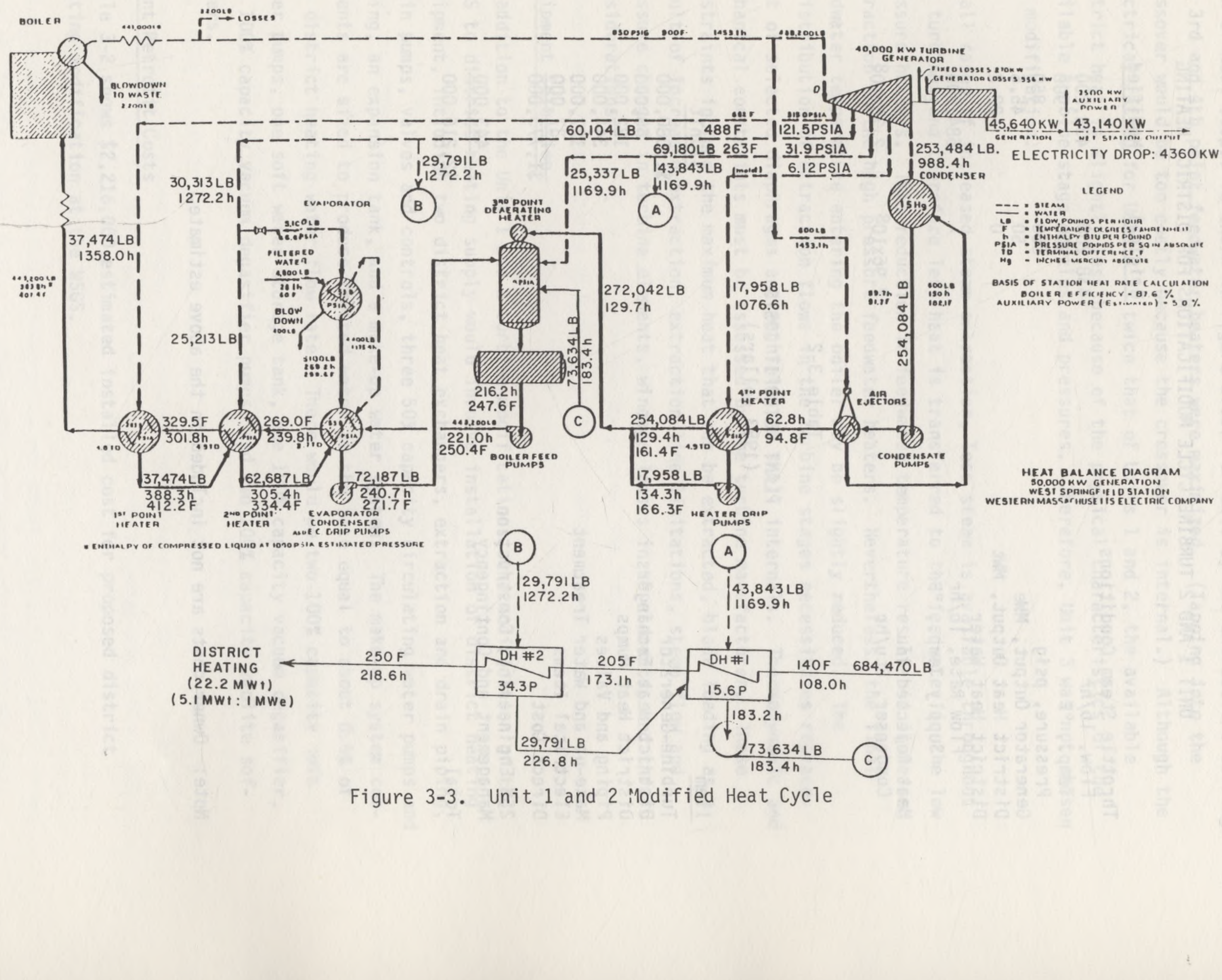


Figure 3-3. Unit 1 and 2 Modified Heat Cycle

Table 3-1

UNIT 1 AND 2 TURBINE CYCLE MODIFICATIONS FOR DISTRICT HEATING

	Original	Modified
Throttle Steam Conditions		
Flow, lb/hr	438,200	438,200
Temp., °F	900	900
Pressure, psig	850	850
Generator Output, MWe	50	45.6
District Heat Output, MWt	0	22.2
District Heat Water		
Flow Rate, lb/hr	-	684,500
Supply Temp., °F	-	250
Heat Rejected in Condenser, Btu/hr	2.96×10^8	2.35×10^8

Table 3-2

PLANT RETROFIT COSTS
(1983 dollars)

Item	$/Unit
Turbine-Generator	$1,080,000
District Heat Exchangers	63,000
District Heat Pumps	122,000
Piping and Valves	344,000
Make-up and Water Treatment	127,000
Electrical Items	37,000
Direct Cost	$1,773,000
25% Engineering, Construction Management and Contingency	443,000
Total	$2,216,000

Note: Owner costs are not included in the above estimate.

tion of heat output is shown in Figure 3-4. For Unit 3, the extractions serving the 3rd and 4th point feedwater heaters were maximized. (Tapping into the crossover would be too costly because the crossover is internal.) Although the electrical rating for Unit 3 is twice that of Units 1 and 2, the available district heat is slightly less because of the physical characteristics of the available turbine stage nozzles and pressures. Therefore, Unit 3 was not chosen for modification.

In all cases of increased steam extraction, less steam is available throughout the turbine, and therefore less heat is transferred to the feedwater in the low pressure heaters. This reduction in feedwater temperature results in increased extraction in the high pressure feedwater heaters. Nevertheless, the final feedwater temperature entering the boiler may be slightly reduced. The redistribution of extraction flows in the turbine stages necessitates replacement of selected diaphragms and machining of shell internals. Thermodynamic and mechanical constraints must be assessed by the turbine manufacturer. These constraints include the maximum heat that can be extracted, blade loading as a result of increased extraction, extraction line limitations, steam flow and pressure changes in turbine elements, windage losses in LP elements, and thrust considerations.

Equipment Selection

In addition to the Unit 1 and 2 turbine modifications, the modification of the WSGS to district heating supply would involve installation of district heating equipment, including two district heat exchangers, extraction and drain piping, drain pumps, valves and controls, three 50% capacity circulating water pumps and piping, an expansion tank, and a make-up water system. The make-up system components are sized to produce treated water at the rate equal to about 0.5% of the district heating water flow rate. There would be two 100% capacity soft water pumps, one soft water storage tank, one 100% capacity vacuum degasifier, two 100% capacity vacuum degasifier pumps, and two 100% capacity zeolite softeners.

Plant Retrofit Costs

Table 3-2 shows $2,216,000 estimated installed cost for proposed district heating modification at the WSGS.

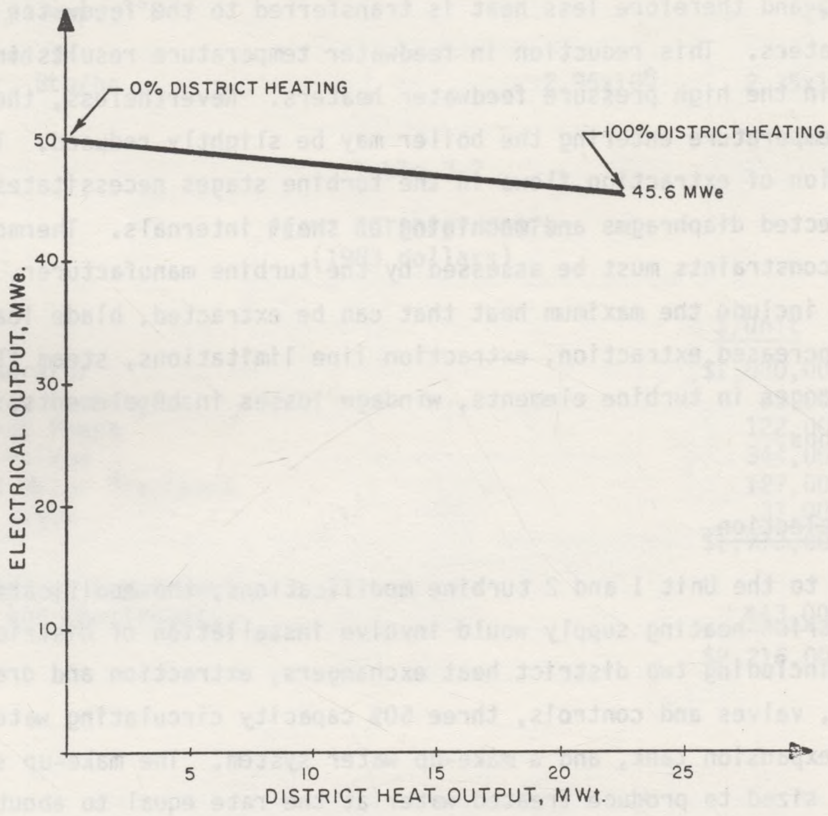


Figure 3-4. Modified Unit 1 and 2 Turbine Performance

Section 4

TRANSMISSION AND DISTRIBUTION SYSTEM

GENERAL

This section develops in conceptual form a transmission and distribution system to integrate the Springfield heat load with the available heat sources. Development of the transmission and distribution system would be performed in phases to coincide with development of the heat sources. The transmission and distribution system is designed as a two pipe closed system for district heating water circulated by horizontal split case pumps located at each heat source.

PIPING SYSTEM DESIGN

District heating piping sizes are determined by the heat load and the water temperature drop in the system, which depend on the type of heat supply control. Simplest and most widely used in a central temperature control system in which the required amount of heat is provided by varying the temperature in the supply network at the heat source as a function of the outdoor temperature.

A large temperature drop between supply and return lines minimizes the flow rate of circulating water, piping size and pumping power. On the other hand, a high temperature of the supply water requires higher steam extraction pressure, which results in reduced plant electrical generation. Therefore, the economics of both the power plant and the piping system must be considered. The piping system for the district heating system is designed for peak supply temperature of 250°F and return temperature of 140°F.

As discussed in the Assessment of European District Heating Technology (EPRI EM-2864, February 1983), there are several types of piping system designs available for district heating systems. Conduit design is considered best suited to the proposed system. The conduit system consists of a thin-walled carbon steel carrier pipe, polyurethane insulation, polyethylene casing, and a leak detection system.

The effects of accelerated corrosion of carbon steel piping in the 200°F range require that the supply piping be physically protected against outside water contact. Equally important, the pipe insulation must be protected from moisture penetration that would increase the thermal conductivity of the insulation. The insulation must also be protected against mechanical abuse, ultraviolet degradation, erosion and other environmental hazards. The polyurethane foam insulation must be protected against mechanical damage from weathering, handling abuse, field bending, casing pressures, water pressure, saddle-bearing forces, ground movement and damage in storage. The most economic and reliable method for providing the piping system with protection against the above problems is to use a shop-fabricated conduit design with a polyethylene casing.

A shop-fabricated conduit system can be fully shop tested, is less expensive to install, is easier to install causing less disruption of the district heating site, and can be manufactured with a high degree of quality control resulting in a product of high reliability. Polyethylene is the preferred casing material because it will not corrode in the underground environment, has excellent water-resisting properties, is easy and cost effective to install, and is light weight and easy to repair if physically damaged.

Polyurethane foam is preferred because of its low thermal conductivity (0.18 Btu/in./hr/ft^2/°F) which provides excellent thermal efficiency of the conduit system. During manufacture of the conduit, the foam is poured between the carrier pipe and the casing in a liquid form and expands to occupy the space between the carrier pipe and the casing. The foam bonds itself to the pipe and casing walls, providing a structurally stable insulation that will not shift, settle or shrink with time to create voids. The conduit requires no special hardware for fastening the insulation in place.

The prefabricated conduit is installed by butt-welding the carrier pipe sections together; the joint is then coated with an elastic sealing compound. A steel fitting coated with a thick layer of polyethylene is bolted around the joint. For large diameter pipe, an aluminum jacket is placed around the joint and riveted in place instead of a bolted steel fitting. Polyurethane is then poured through holes in the aluminum to insulate the joint. The holes in the aluminum jacket are plugged, and a shrink sleeve is placed over the aluminum and heated to fit tightly.

The conduit is manufactured and shipped to the field in lengths of 20 feet or more. All fittings and valves are also preinsulated and shipped in the form of a finished conduit section. Figure 4-1 shows the conduit design.

The small customer branches are conduits of the same designs, with flexible copper carrier pipe delivered in coils. Such conduit has the advantages of being flexible and requiring fewer joints.

To protect the system and facilitate service, a combined alarm and fault locator system is built into the conduit during manufacture. The alarm system consists of two copper wires molded into the foam insulation during manufacture of the conduit. As the conduit sections are installed, the wires are connected, forming a continuous circuit through the piping system. The copper wires are connected to alarm/control boxes at either central or remote locations. The wires carry a low voltage current. When moisture enters the piping system, it completes the circuit between the two wires and triggers an alarm. The alarm system not only detects the leak but, by measuring resistance, locates the leak.

Two different schemes were investigated for the location of the conduit: below the streets and below the sidewalks. Installing the conduit below the sidewalks has the advantage of requiring shallow excavation, typically resulting in a less expensive system than street installations. Sidewalk installations require less excavation and backfill, cause minimum disruption of traffic in congested areas, and usually involve fewer interferences with other underground utilities. Examination of available utility maps for Springfield determined that a minimum number of interferences with other utilities would occur if the district heating pipes were installed beneath the sidewalks.

The proposed technique is to install the supply and return piping side-by-side in a single trench beneath the sidewalk. The trenches will usually be less than 5 feet deep and require no shoring. The conduit is laid directly in the trench on a 4-inch sand bed. The excavation provides for a clearance of 6 inches between conduits and 6 inches between the conduit and trench wall. The conduit is covered with at least 18 inches of homogeneous stone-free sand. The sidewalk bed and pavement are installed directly over this sand. Figure 4-2 shows the recommended conduit installation, conduit diameters and required trench sizes for different size carrier pipes.

To minimize the cost of expansion provisions, the steel piping system expansion will be accommodated by a European technique utilizing the mechanical plasticity

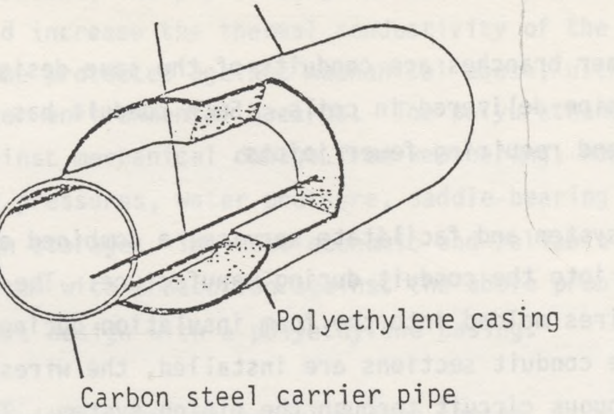
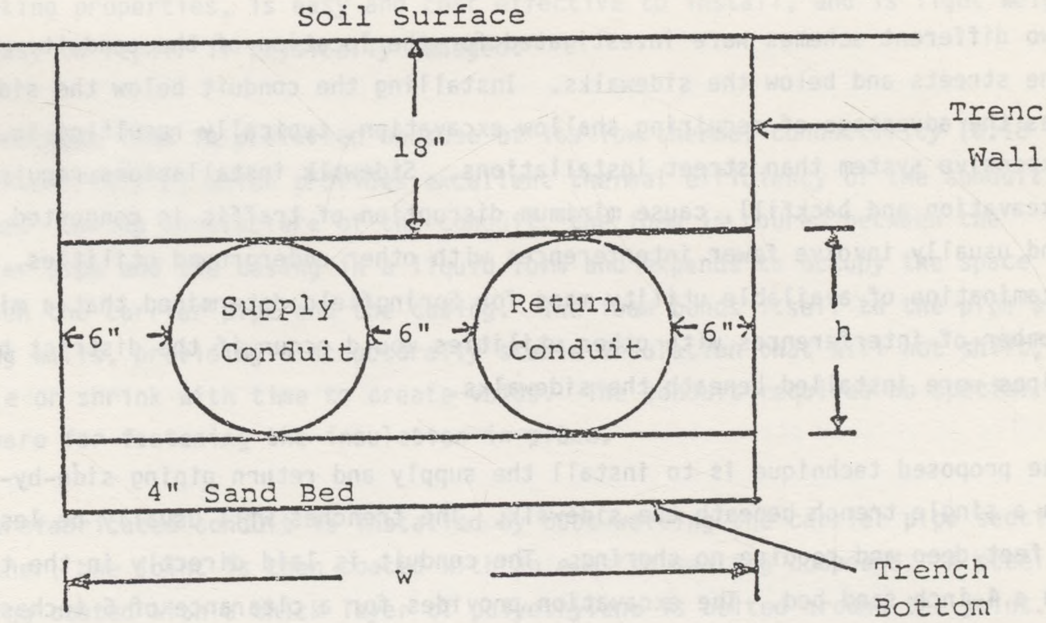


Figure 4-1. District Heating Conduit



Pipe Size (inches)	Conduit Dia. (h) (inches)	Installation Envelope (wxh)
2	6	30 x 6
2½	6	30 x 6
3	7	32 x 7
4	9	36 x 9
5	10	38 x 10
6	11	40 x 11
8	14	46 x 14
10	18	54 x 18

Figure 4-2. Conduit Installation

of the pipe at stress ranges up to the elastic limits. A steel pipe is anchored at one end, and heated from the installation temperature of 65°F to about 120°F. The pipe is then anchored at the opposite end; this does not change the physical state of the pipe, and the tension in the steel will be zero. When the temperature of the pipe is increased to the operating temperature of 250°F, a compressive stress will be generated in the steel pipe within allowable structural limits. When the temperature is reduced, a tensile stress within the allowable limits will be generated. Special pipe fittings allow the system to be installed in accordance with this procedure.

Expansion loops or pipe offsets are not recommended because of the narrow access route that is available. Mechanical expansion joints of the slip, bellows, or ball/swivel type are not recommended because of their maintenance and installation requirements.

PIPE ROUTING

To determine the optimal routing for the district heating piping, utility maps showing the locations of the existing underground utilities were examined, together with maps showing the blocks for which heat loads were determined. The required piping diameters and lengths between the various nodes were than calculated.

Figure 4-3 shows the proposed transmission system throughout the district heating service area, and Table 4-1 lists the associated pipe sizes and lengths. The principal transmission pipes will be routed along Main and Chestnut Streets in the north-south direction, with others in Pearl, Liberty, and State Streets in the east-west direction. Between nodes 1' and 1 there will be a pair of nominal 16-inch pipes. The pipes on Memorial Bridge over the Connecticut River will be 12-inch diameter.

Hot water will pass from the transmission mains through a distribution network to the building systems. Although it has been assumed that distribution piping would be located under the sidewalks, some piping may be routed through the basements of adjacent buildings in order to minimize system cost.

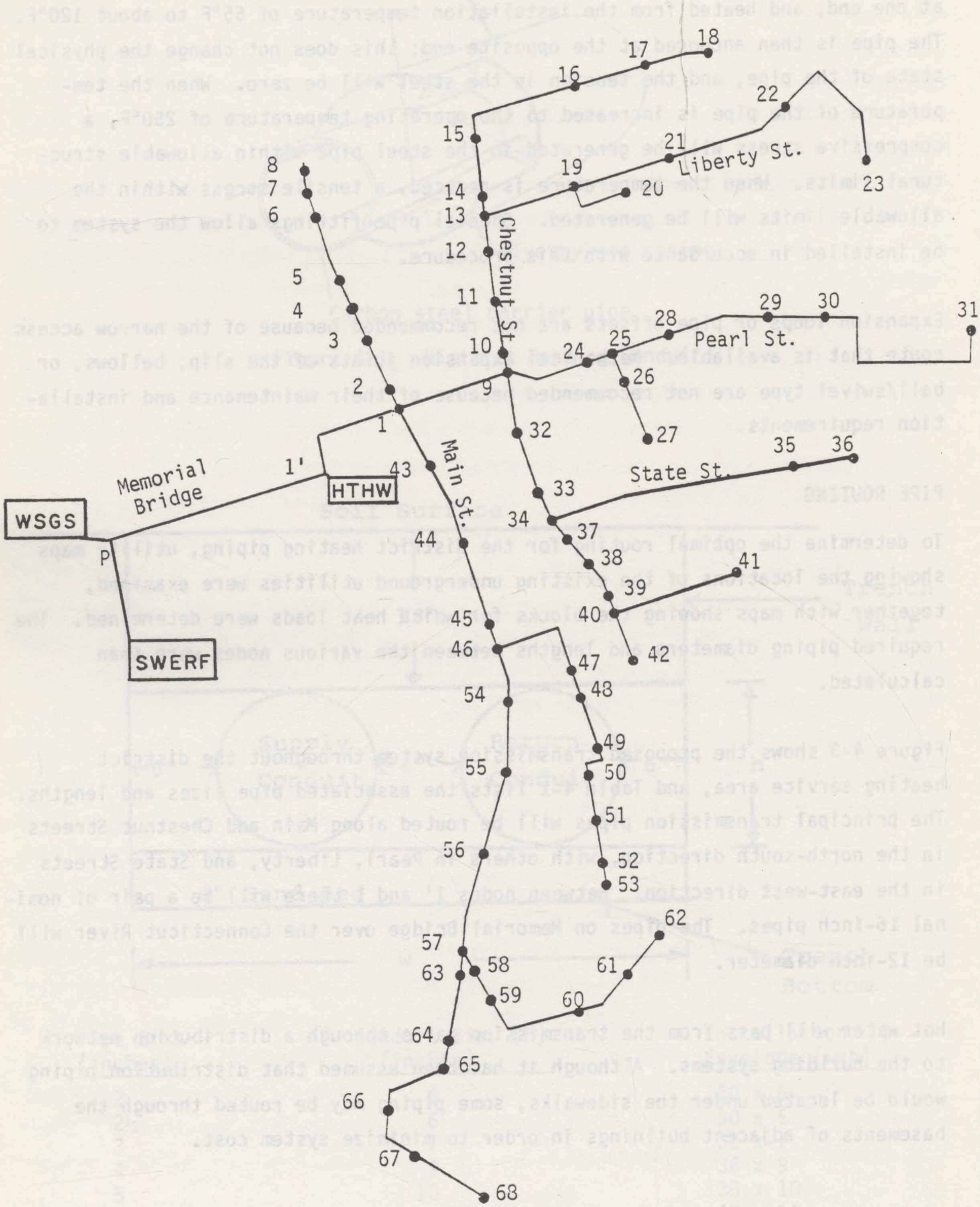


Figure 4-3. Schematic of Transmission System

Table 4-1

TRANSMISSION PIPING SYSTEM DIMENSIONS

Nodes	Length (ft)	Nominal Dia(in.)	Nodes	Length (ft)	Nominal Dia(in.)
SWERF-P	1500	8	6-7	250	0.75
P-1'	1875	12	7-8	250	0.75
1'-1	1500	16	13-19	875	8
1-43	625	8	19-20	625	8
43-44	813	8	19-21	938	4
44-45	813	8	21-22	1250	3
45-46	250	8	22-23	1438	2
1-9	1125	12	46-47	1063	5
9-32	625	8	47-48	313	5
32-33	625	8	48-49	500	4
33-34	313	8	49-50	375	4
9-10	188	8	50-51	438	4
10-11	500	8	51-52	438	2.5
11-12	500	8	52-53	188	2
12-13	375	8	34-37	250	4
34-35	2375	6	37-38	313	4
35-36	563	2	38-39	438	4
9-24	750	5	39-40	188	3
24-25	250	5	40-41	1250	2.5
25-26	313	2.5	40-42	500	2
26-27	625	1.5	46-54	500	5
25-28	563	4	54-55	688	5
28-29	1060	4	55-56	813	5
29-30	563	2	56-57	938	5
30-31	2125	1.25	57-58	250	4
13-14	188	2	58-59	313	3
14-15	563	2	59-60	1000	2.5
15-16	1250	2.5	60-61	625	2.5
16-17	750	1.5	61-62	500	2
17-18	563	1.25	57-63	250	4
1-2	188	4	63-64	313	3
2-3	500	2.5	64-65	250	3
3-4	375	2	65-66	750	3
4-5	313	1	66-67	563	2.5
5-6	625	0.75	67-68	750	2.5

TRANSMISSION AND DISTRIBUTION SYSTEM COSTS

Estimates of piping system costs were developed by individually estimating the cost of each component and installation step. The cost estimate includes:

- Removal of existing sidewalk surface
- Excavation of the trench
- Hauling of excavated and backfill material
- Spreading and compaction of backfill material
- Prefabricated conduit and field joints
- Pipe installation and testing
- Isolation valves, fittings and specialties
- Contingency for problems with underground construction

Costs for piping and other materials are based on budget estimates received from vendors. Costs for earthwork and labor are based on reference sources for the construction industry. The transmission and distribution piping costs for the entire district heating system are estimated at $10,120,000 and $3,339,000 respectively, a total of $13,459,000.

Section 5

SYSTEM IMPLEMENTATION

The development of the Springfield district heating system is projected to occur over a 9-year period that will allow capital expenditures to be spread out in incremental investments and the system to generate revenues to offset the required capital investments. This development period will also provide the required lead time for system engineering, design and construction.

The general procedure will be to develop the heat load at average increment of about 11 MWt per year. When sufficient heat load is developed, heat sources will be brought on line. The development sequence and corresponding capital costs are summarized in Tables 5-1 through 5-3.

In 1985, transmission and distribution piping would be installed to provide heat for parts of the central business district and industrial district. The initial connected load would be about 23.42 MWt. This would require about 4.5 miles of pipe including piping from the City Hall boiler plant to the end of Pearl Street (node 31) and from the intersection of Pearl and Chestnut Streets (node 9) to nodes 18 and 34, as well as extensions from this main route to nodes 4 and 27. Three HTHW boilers would be installed in the City Hall boiler plant. Two boilers would operate to supply heat to the network described, the third would be a spare. The total installed capacity would be 35.16 MWt. Annual district heat sales for this phase are estimated at 76,490 MWht.

In 1986, there would be no additions to the district heating system. Instead, revenues will be collected to help offset the 1987 capital expenditures. Total heat sales would remain 76,490 MWht.

In 1987, the turbine at the SWERF would be connected to the district heating system to supply an additional 17.2 MWt capability (52.36 MWt total). this would require a capital expenditure for heating equipment as well as for piping across Memorial Bridge. The district heating network would be extended by the addition of a piping section between nodes 34 and 36 on State Street. The load would be 40.65 MWt, and the total annual district heat sales would be 132,762 MWht.

TRANSMISSION AND DISTRIBUTION SYSTEM COSTS

Estimates of piping system costs were developed by individually estimating the cost of each component and installation step. The cost estimate includes:

- Removal of existing sidewalk surface
- Excavation of the trench
- Hauling of excavated and backfill material
- Spreading and compaction of backfill material
- Prefabricated conduit and field joints
- Pipe installation and testing
- Isolation valves, fittings and specialties
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Table 5-1

DEVELOPMENT STRATEGY

Construction Year	Transmission Sys. Construction From	To	Blocks Served	HTHW Unit Construction	SWERF	WSGS	Connected Load (MWt)
1985	HTHW 1 9 1 9 9 25	1 9 31 4 18 34 27	156,157,207,214, 216,217,304,305, 309,313,315,316, 401,402,403,404, 405,406,414,415, 508,509	Unit 1 Unit 2 Unit 3	-	-	23.42
1986	-	-	Same as above	-	-	-	23.42
1987	SWERF P 34	P 1' 36	419,422,518	-	SWERF turbine	-	40.65
1988	1 46	46 49	306,307,308,310, 311,312,410,411, 612,613,614	-	-	Unit 1	50.37
1989	34 40 50	42 41 53	314,407,408,409, 420,421,615,616, 617,618,619,621	Unit 4	-	-	61.99
1990	46 5	56 8	202,203,204,208, 607,608,609	Unit 5	-	-	64.88
1991	13 19	23 20	139,140,141,142, 143,215,503	-	-	Unit 2	89.04
1992	57	68	610,611,727,733, 738,739,744	-	-	-	94.1
1993	57	62	620,622,623,712, 720,721,202,203,	-	-	-	98.64

Table 5-2

CAPACITY ADDITION AND HEAT LOAD DEVELOPMENT

Year	Addition	Capability (MWt) Installed	Available	Load (MWt) Developed	Connected
1985	35.16	35.16	23.44	23.42	23.42
1986	0	35.16	23.44	0	23.42
1987	17.2	52.36	40.64	17.23	40.65
1988	22.2	74.56	52.36	9.72	50.37
1989	11.72	86.28	64.08	11.62	61.99
1990	11.72	98.00	75.80	2.89	64.88
1991	22.2	120.2	98.00	24.16	89.04
1992	-	120.2	98.64	5.06	94.1
1993	-	120.2	98.64	4.54	98.64

Table 5-3

CAPITAL COST SUMMARY

Projected Investment ($1983 x 10^3)

Year of Expenditure	1985	1986	1987	1988	1989	1990	1991	1992	1993	Total
HTHW Station	1408	0	0	0	470	470	0	0	0	2,348
SWERF	0	0	957	0	0	0	0	0	0	957
Power Plant Retrofits	0	0	0	2,216	0	0	2,216	0	0	4,432
Transmission System	3,555	0	2,208	1,254	668	538	1,038	567	292	10,120
Distribution System	792	0	583	329	393	98	817	174	153	3,339
Total	5,755	0	3,748	3,799	1,531	1,106	4,071	741	445	21,196

In 1988, one turbine at the WSGS would be modified to supply 22.2 MWt of district heat (74.56 MWt total). The district heating piping system would be extended by a section on Main Street between nodes 1 and 46 with a branch between nodes 46 and 49. during this phase, the HTHW boilers would operate mostly in the peaking mode. The connected load during this phase would be 50.37 MWt, and the estimated heat sales would be 164,508 MWht.

In 1989, another HTHW boiler would be added at City Hall (86.28 MWt total). Piping would be installed from nodes 34 to 41 and 42, and from 50 to 53. Total connected load would reach 61.99 MWt, and total heat sales would be 202,458 MWht.

In 1990, a fifth and last HTHW boiler would be installed at City Hall (98 MWt total). Two sections of district heating piping would be added on Main Street (between nodes 5 and 8 and between nodes 54 and 56), bringing the connected load to 64.88 MWt. Total heat sales would be 211,897 MWht.

In 1991, the second turbine at the WSGS would be modified, and the 22.2 MWt output would be added to the system for a total capacity of 120.2 MWt. At the same time, the Liberty Street piping extension (between nodes 13 and 23) would be added to increase the heat load by 24.16 MWt. The total connected load would be 89.04 MWt, and the total heat sales would be 290,804 MWht.

In 1992, a section of piping will be installed between nodes 57 and 68, with an increase in heat load of 5.06 MWt. Thus the maximum rated heat load would then be 94.1 MWt and the heat sales would be 307,330 MWht.

In 1993, the last piping section, between nodes 57 and 62, would be installed, with a heat load addition of 4.54 MWt. The system would be complete, with a maximum connected heat load of 98.64 MWt and total estimated heat sales of 322,157 MWht. In this phase and thereafter, the system would operate with the SWERF and WSGS turbines as the base loaded energy sources and with the HTHW boilers supplying backup and peak loads.

Section 6
SYSTEM OPERATION AND PLANT DISPATCH

SYSTEM OPERATION

During a year, the actual heat demanded by the connected load varies inversely with the outdoor temperature. In order to determine the annual heat generation required by a district heating system, a heat load duration curve is required.

Using an outdoor minimum design temperature of 3°F, an indoor design temperature of 65°F, and the annual temperature profile, the annual heat load duration curves were developed for each phase of implementation (Figure 6-1 through 6-8). Total annual heat consumption at the ultimate connected peak load of 98.64 MWt is calculated to be approximately 322,160 MWht.

The heat load duration affects operation of a cogenerating unit since the maximum extraction for district heating which occurs at 100% heat load reduces electrical generation to its minimum. As the heat load decreases, steam extraction also decreases, resulting in higher electrical generation.

In the completed district heating system, the mode of operation of the system depends on the system load demand. In summer, when the load is generally constant and equal to the domestic hot water load, the system would operate at supply and return temperatures of 160°F and 104°F. The summer load is about 7.3 MWt, with a duration of about 3160 hours.

Planned maintenance on the modified WSGS units and the SWERF equipment should occur in summer. The HTHW heaters need not be used in summer since maintenance of the WSGS turbines and the SWERF can be staggered. For the purposes of this study, a maintenance downtime of 1 month for the SWERF has been assumed. Summer load can be carried entirely by the SWERF turbine.

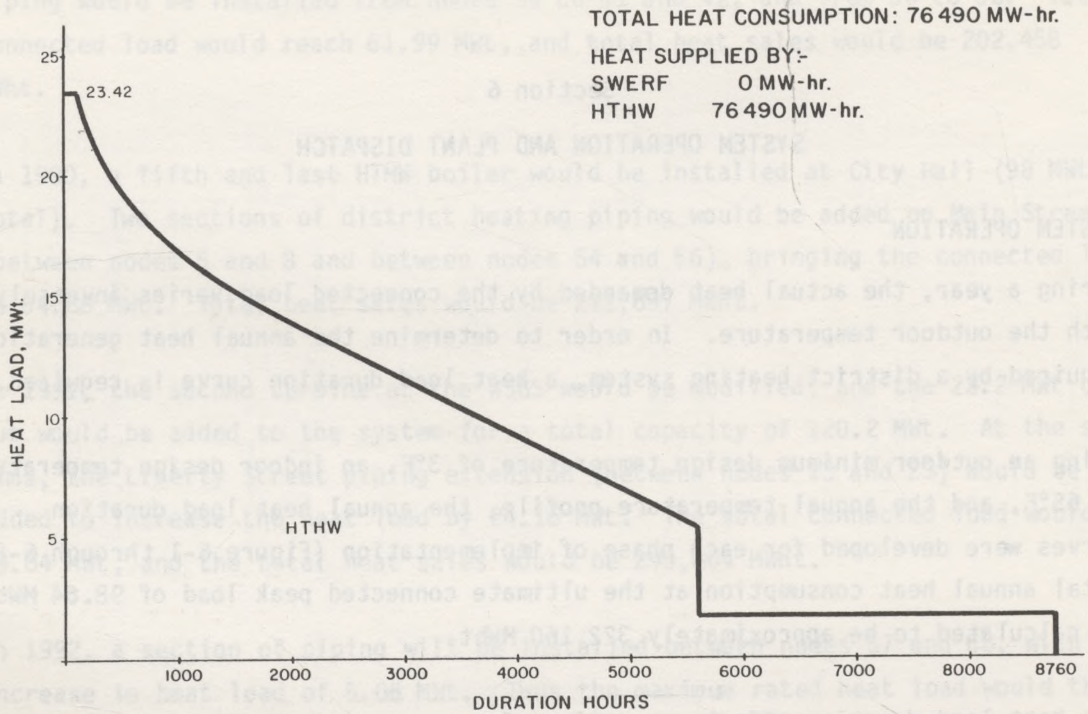

Figure 6-1. Heat Load Duration Curve for 1985 and 1986

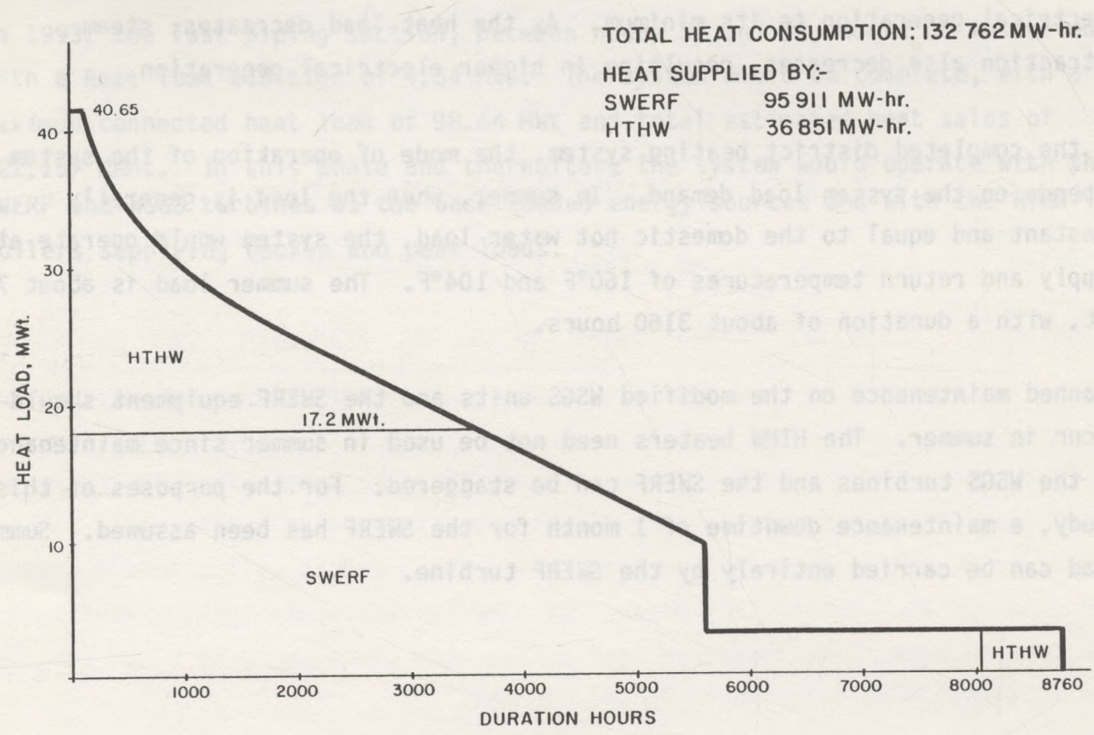

Figure 6-2. Heat Load Duration Curve for 1987

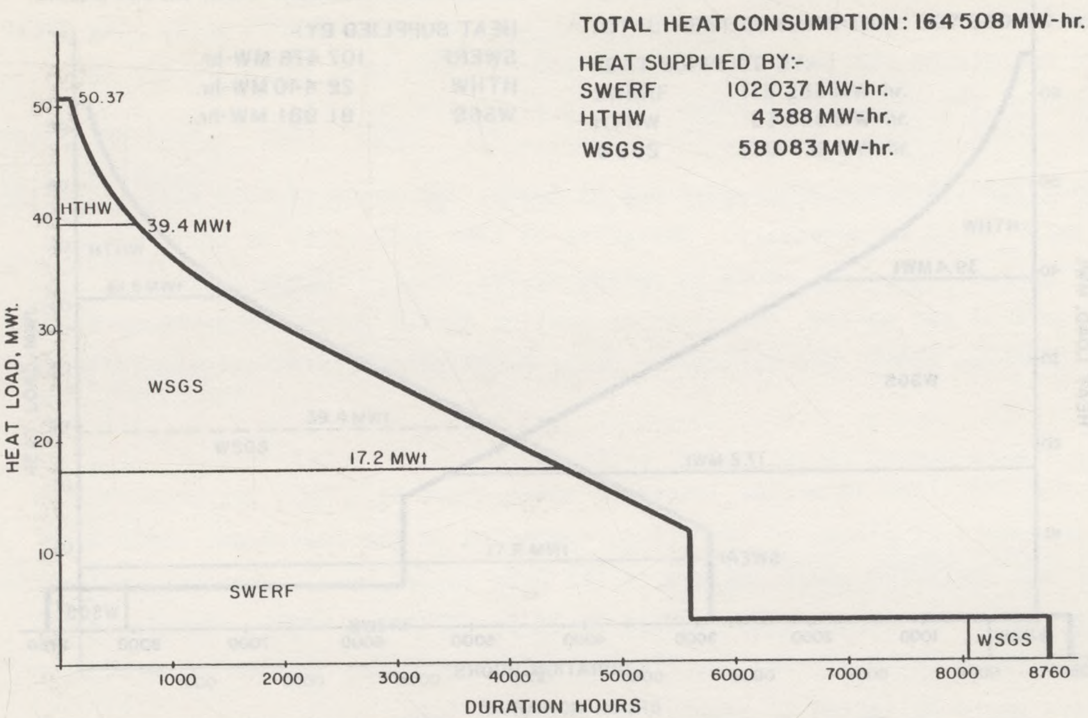

Figure 6-3. Heat Load Duration Curve for 1988

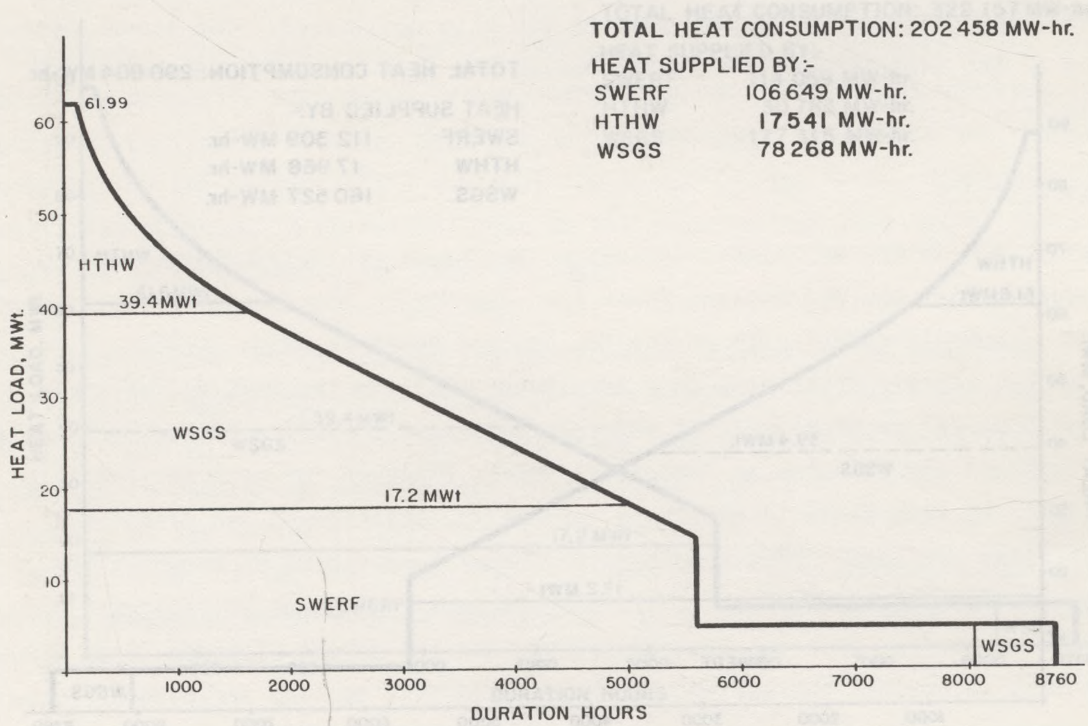

Figure 6-4. Heat Load Duration Curve for 1989

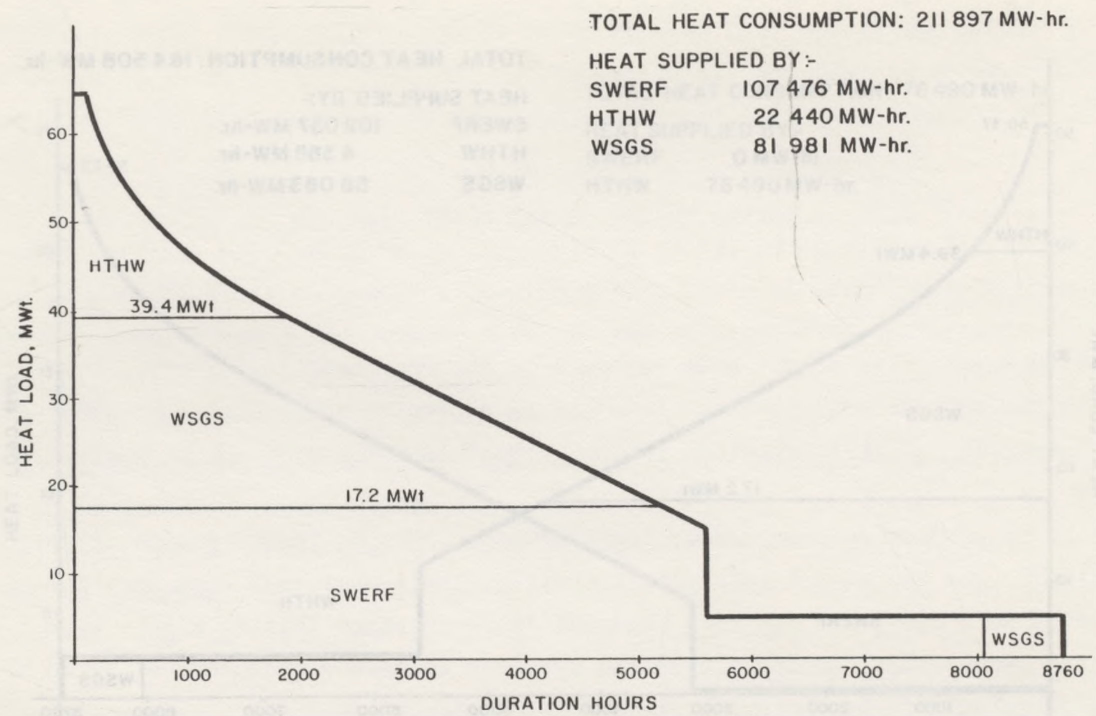

Figure 6-5. Heat Load Duration Curve for 1990

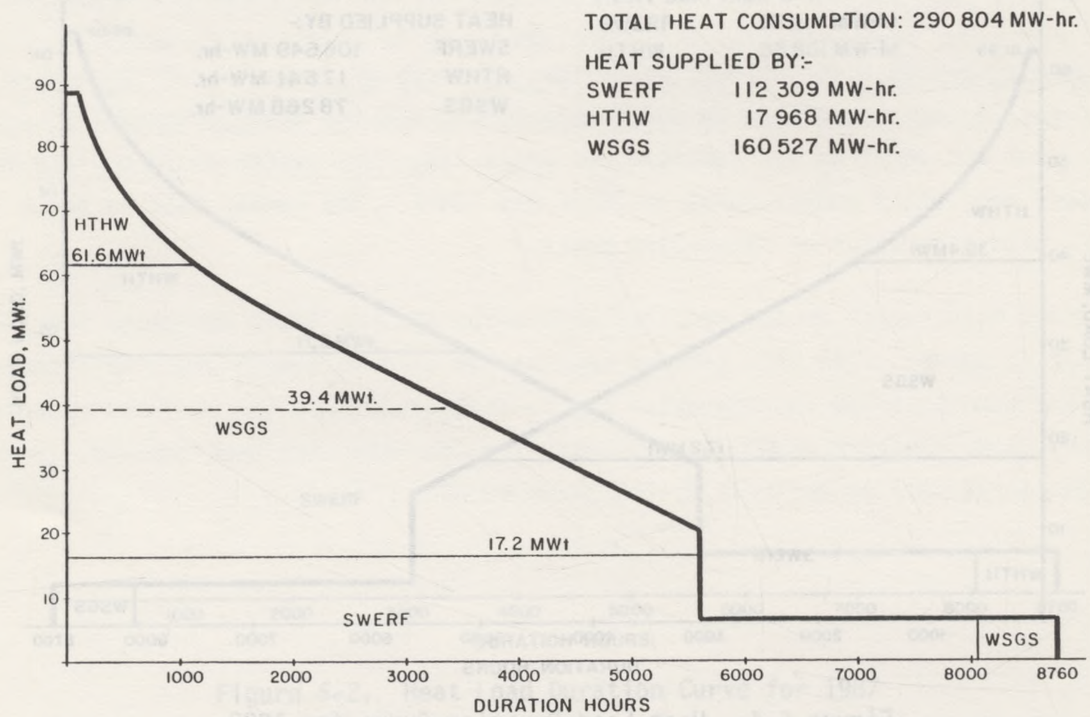

Figure 6-6. Heat Load Duration Curve for 1991

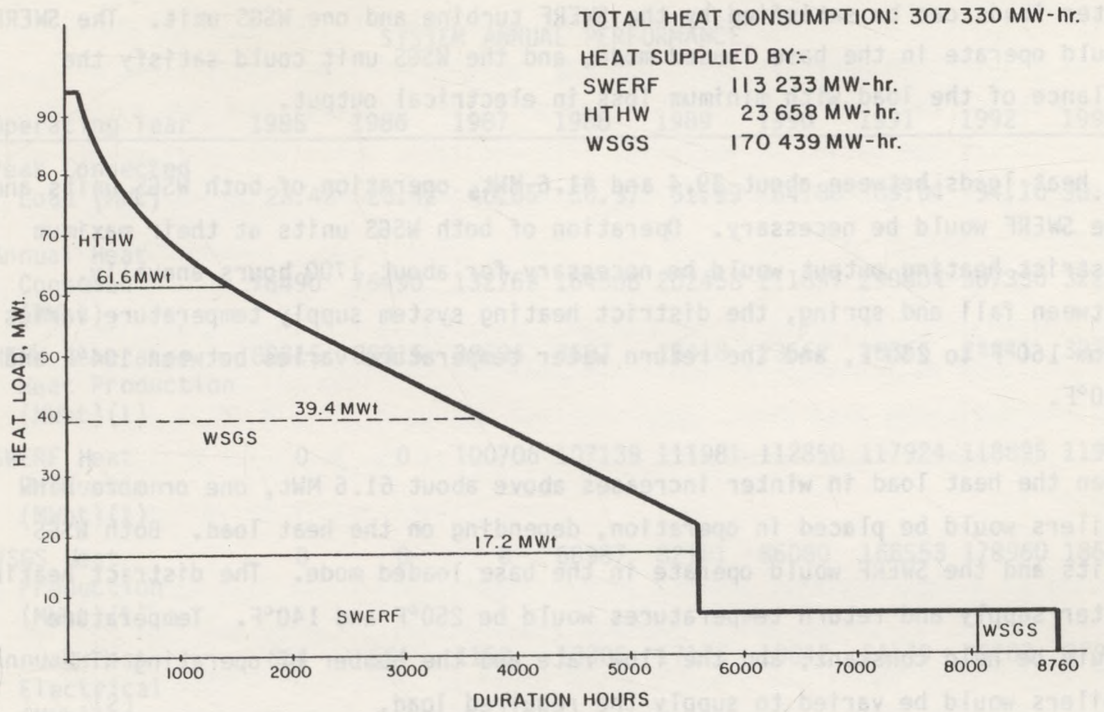

Figure 6-7. Heat Load Duration Curve for 1992

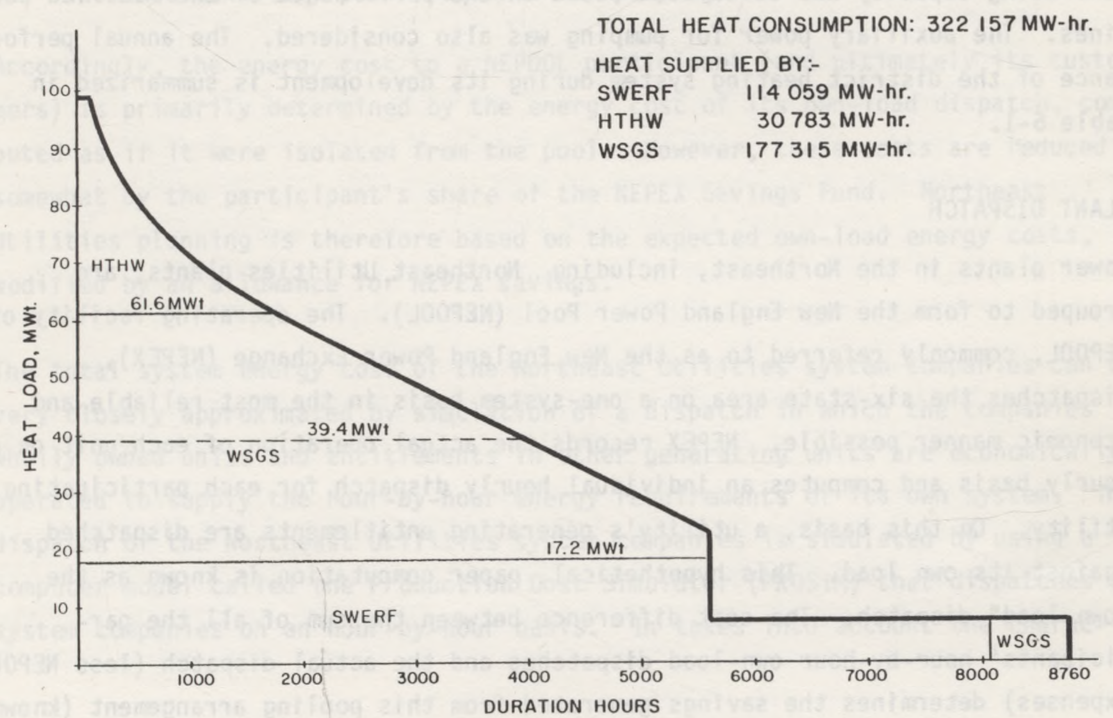

Figure 6-8. Heat Load Duration Curve for 1993

During spring and fall, up to about 39.4 MWt space heating and domestic hot water loads can be satisfied by the SWERF turbine and one WSGS unit. The SWERF would operate in the base loaded mode, and the WSGS unit could satisfy the balance of the load with minimum loss in electrical output.

At heat loads between about 39.4 and 61.6 MWt, operation of both WSGS units and the SWERF would be necessary. Operation of both WSGS units at their maximum district heating output would be necessary for about 1700 hours annually. Between fall and spring, the district heating system supply temperature varies from 160°F to 250°F, and the return water temperature varies between 104°F and 140°F.

When the heat load in winter increases above about 61.6 MWt, one or more HTHW boilers would be placed in operation, depending on the heat load. Both WSGS units and the SWERF would operate in the base loaded mode. The district heating water supply and return temperatures would be 250°F and 140°F. Temperature would be held constant, and the flow rate and the number of operating HTHW boilers would be varied to supply the required load.

Using the cumulative durations of the various heat loads, the lost electrical generating capacity was calculated based on the performance of the modified turbines. The auxiliary power for pumping was also considered. The annual performance of the district heating system during its development is summarized in Table 6-1.

PLANT DISPATCH

Power plants in the Northeast, including Northeast Utilities plants, are grouped to form the New England Power Pool (NEPOOL). The operating facility of NEPOOL, commonly referred to as the New England Power Exchange (NEPEX), dispatches the six-state area on a one-system basis in the most reliable and economic manner possible. NEPEX records the actual operation of each unit on an hourly basis and computes an individual hourly dispatch for each participating utility. On this basis, a utility's generating entitlements are dispatched against its own load. This hypothetical, paper computation is known as the "own-load" dispatch. The cost difference between the sum of all the participants' hour-by-hour own-load dispatches and the actual dispatch (less NEPOOL expenses) determines the savings generated from this pooling arrangement (known as NEPEX Savings Fund).

Table 6-1

SYSTEM ANNUAL PERFORMANCE

Operating Year	1985	1986	1987	1988	1989	1990	1991	1992	1993
Peak Connected Load (MWt)	23.42	23.42	40.65	50.37	61.99	64.88	89.04	94.10	98.64
Annual Heat Consumed (MWht)	76490	76490	132762	164508	202458	211897	290804	307330	322157
HTHW Generator Heat Production (MWht)(1)	80315	80315	38694	4607	18418	23562	18866	24841	32322
SWERF Heat Production (MWht)(1)	0	0	100706	107139	111981	112850	117924	118895	119762
WSGS Heat Production (MWht)(1)	0	0	0	60987	82181	86080	168553	178960	186180
Annual Lost Electrical (MWh)(2)	664	664	1152	13305	17176	18042	34149	36202	37924

(1) Includes 5% transmission line loss

(2) Includes auxiliary power required for pumping

Accordingly, the energy cost to a NEPOOL participant (and ultimately its customers) is primarily determined by the energy cost of its own-load dispatch, computed as if it were isolated from the pool. However, these costs are reduced somewhat by the participant's share of the NEPEX Savings Fund. Northeast Utilities planning is therefore based on the expected own-load energy costs, modified by an allowance for NEPEX savings.

The total system energy cost of the Northeast Utilities system companies can be very closely approximated by simulation of a dispatch in which the companies' wholly owned units and entitlements in other generating units are economically operated to supply the hour-by-hour energy requirements of its own system. This dispatch of the Northeast Utilities system companies is simulated by using a computer model called the Production Cost Simulator (PROSIM) that dispatches the system companies on an hour-by-hour basis. In takes into account the characteristics of all units and entitlements available to the system companies, with regard to their heat rates, capabilities, seasonal deratings, forced outage rate, maintenance schedules, and minimum running and down times. The model accounts for capacity additions, retirements, or deratings that are assumed to occur during the period of analysis. All available units and entitlements are economically dispatched to meet the projected profile of system hourly load levels.

Cost parameters important in production simulation are also incorporated in PROSIM, such as variable operation and maintenance expenses, and fossil and nuclear fuel cost estimates. The resultant output of PROSIM is an estimate of the total monthly and annual fuel cost expense of the Northeast Utilities system companies.

PROSIM is a deterministic (versus probabilistic) model and will handle any electric utility system which includes conventional, standby and cold storage thermal units, nuclear units, and hydro units of the run of river, pondage, and pumped storage types. The program is used primarily as a planning device for production cost evaluations in the areas of capacity expansion planning, fuel budgeting, forecasting, and operation and maintenance evaluation.

First, PROSIM dispatches conventional hydro against the highest load level hours, recognizing the constraints of limited hydro energy available during each day of each month. Second, pumped hydro energy is dispatched on an economic basis in accordance with the pumping to generation cost ratios. This cost ratio is a function of the system's available thermal generating resources. The pumped hydro dispatch is solved using a weekly cycle, in accordance with the dispatch practice adopted by NEPOOL and predicated by the design size of the Northfield Mountain facility. Finally, thermal units are dispatched against the remaining hourly load levels on a priority costing basis, and with an appropriate consideration to their operational characteristics and limitations.

The complete PROSIM model consists of the following sub-routines or models, in addition to the main program which accesses these subroutines and controls the preparation of the output summary information: load model, operating reserve, overhaul schedule, equivalent forced outage rates, conventional hydro dispatch, pumped hydro dispatch, and thermal unit dispatch.

The incremental costs of generation for the thermal units such as those at the WSGS differ for each plant. The incremental costs of generation are based on the operating characteristics of each plant and the associated operating and maintenance costs.

If the WSGS is converted to coal, it will have a low incremental cost of operation and will become a base-loaded plant. The plant would be dispatched continuously at full load. As a result, the conversion of Units 1 and 2 for district heating would not impact on the hours of operation of the units. The impact of the district heating system would be that the electrical generation from the plant would be reduced and the lost power would have to be replaced by another plant at a cost equal to the incremental cost of power for the pool corresponding to the system load.

The analysis of the district heating system considers the cost for replacing this power as a penalty against the district heating system. The estimated electrical capacity reductions for WSGS Units 1 and 2 are shown in Tables 6-2 and 6-3.

If the WSGS was considered for conversion to district heating operation as a non-base-loaded plant, the analysis would be more complicated. A typical load duration curve for the operation of the plant as a pure electric plant would have to be developed. This load duration curve would then be compared with the load duration curve of the plant operating as a cogeneration plant. This analysis would probably show that there were some periods during which the district heating system reduced the electrical output of the units, and others when the district heating system required the station to run at a higher load than the pure electric case. Since the pure electric case represents the most efficient operation from the pool viewpoint, any change in operation would be a decrease in dispatch efficiency, and a penalty would be charged against the district heating system. This penalty would differ depending on the change in operation required. If the plant were required to decrease load, the penalty would be equal to the incremental fuel cost for the particular system load. If the plant were required to run at a high load, the penalty would be equal to the incremental cost associated with the WSGS.

Table 6-2

WSGS UNIT 1 ESTIMATED ELECTRICAL CAPACITY REDUCTION (MWe)

Year	1985-1987	1988	1989	1990	1991	1992	1993
January	0	4.4	4.4	4.4	4.4	4.4	4.4
February	0	2.3	3.7	3.9	4.4	4.4	4.4
March	0	1.8	3.0	3.3	4.4	4.4	4.4
April	0	0	0.3	0.4	1.9	2.2	2.5
May	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0
July	0	0.7	0.9	0.9	1.3	1.4	1.5
August	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0
October	0	0	0.9	1.0	2.7	3.1	3.4
November	0	1.3	2.4	2.6	4.4	4.4	4.4
December	0	3.3	4.4	4.4	4.4	4.4	4.4

Table 6-3

WSGS UNIT 2 ESTIMATED ELECTRICAL CAPACITY REDUCTION (MWe)

Year	1985-1990	1991	1992	1993
January	0	4.4	4.4	4.4
February	0	2.2	2.8	3.5
March	0	1.4	2.0	2.4
April	0	0	0	0
May	0	0	0	0
June	0	0	0	0
July	0	0	0	0
August	0	0	0	0
September	0	0	0	0
October	0	0	0	0
November	0	0.5	1.0	1.4
December	0	4.1	4.4	4.4

Section 7

ENVIRONMENTAL ASSESSMENT

Installation of a district heating system in Springfield will cause the replacement of numerous uncontrolled small point sources with several large sources of emission. The latter will be more efficient than the individual units and will have control systems to reduce overall emissions.

The proposed district heating system will reduce the overall fuel consumption within the city because of the higher efficiencies of the central sources when compared to the individual point sources. The conversion of the WSGS to a cogenerating mode will increase its cycle efficiency and further reduce the overall fuel consumption within the city. It will also cause rejection of less heat to the environment per pound of fuel burned.

Elimination of area source emissions in downtown Springfield would, in and of itself, substantially improve air quality in the city. The net effect will depend upon changes in fuel use at WSGS due to the district heating system. At present, the station output cycles with demand. Serving a district heating system from this operating mode would increase emissions from the station, negating much of the air quality benefit gained from decreasing area source emissions. For the purposes of this study, it was assumed that WSGS would be converted to coal and run base loaded. It should be noted that coal conversion plans at the WSGS are uncertain at this time.

Assuming that the plant emissions remained unchanged, the impact of the district heating system would be a reduction in area point source emissions. The point sources in question are the individual residential, commercial and industrial customers that would convert to district heat supply. The energy consumption for the service area indicated the following fuel mix:

Fuel oil	83%
Coal	8%
Natural gas	8%
Electricity	1%

Table 7-1

PROJECTED DISPLACED FUEL

Year	Annual Heat Consumption (MWht)	Displaced Oil Consumption (10^3 gal)	Displaced Coal Consumption (tons)	Net Displaced Gas Consumption (10^7 cu ft) (1)
1985	76,490	2636	1392	-30.99
1986	76,490	2636	1392	-30.99
1987	132,762	4575	2416	-10.65
1988	164,508	5669	2994	5.37
1989	202,458	6976	3685	1.14
1990	211,897	7302	3857	-0.64
1991	290,804	10021	5293	4.89
1992	307,330	10590	5594	3.07
1993	322,157	11101	5864	0.53

(1) Adjusted for HTHW generator gas consumption

The reduction in emissions due to fuel displacement was calculated and assumed to be evenly spread across the service area. The projected displaced fuel for the development stages is shown in Table 7-1. When completed in 1993, the district heating system would have an annual load of approximately 322,160 MWht and displace about 11.1 million gallons of fuel oil and 5860 tons of coal per year. At the same time, the net natural gas consumption would decrease by about 5.3 million cubic feet per year. All gas used for district heating would be burned at substantially increased conversion efficiency.

Neither the Massachusetts Department of Environmental Quality Engineering nor the Lower Pioneer Valley Regional Planning Agency had sufficiently detailed information on fuel use by location to develop an accurate emission grid. Therefore, it was decided to calculate the emission reduction due to the total fuel displacement. The analysis was keyed to sulfur dioxide emissions and concentrations, since that pollutant will show the greatest incremental effect. Emission from natural gas firing was found to be negligible. Using emission factors from AP-42 (Compilation of Air Pollutant Emission Factors, U.A. EPA, 1980) it was determined that 11.1 million gallons of oil at 0.3% sulfur release 262.1 tons of sulfur dioxide. Additionally, 111.4 tons of sulfur dioxide would be released by burning 5860 tons of coal at 1% sulfur. The total sulfur dioxide emission reduction would be 373.5 tons per year.

This emission reduction must be converted to ground level concentrations to estimate the air quality improvement. Several techniques are available to do this, most of which require details that are not available for the present sources of pollution. However, EPA offers one method which gives a reasonable approximation for concentrations within the study area and does not require detailed emission data. This method uses the equation:

$$C = 18 \frac{Q}{U} (\Delta X)^{1/4}$$

where:

C = maximum ground level concentration from area source (g/m^3)

Q = average emission rate ($g/m^2/sec$)

U = average wind speed for period of concern (m/sec)

ΔX = length of a side of the square that contains the bulk of emissions (m)

Most of the emissions in the service area can be represented by a square with ΔX = 2500 m. Based on air quality measurements in the area, the wind speed on days with elevated sulfur dioxide levels averages 4-5 m/sec. Using these values in the above equation, the area source contribution to the high 24-hour sulfur dioxide averages would be 89-115 $\mu g/m^3$. Therefore, elimination of these area source emissions could reduce the maximum sulfur dioxide levels by that amount.

These air quality improvements assume that emissions from WSGS would not be affected by the district heating system. If emissions at the station were to increase, annual concentrations might actually go up. However, this would probably not be a problem with a "typical" district heating system. The WSGS is not well designed for dispersion, and strongly affects the air quality in downtown Springfield. The added dispersion from most power plants (with respect to replaced area sources) is likely to more than compensate for an increase in emissions.

Section 8
INSTITUTIONAL ASSESSMENT

OWNERSHIP OPTIONS AND FINANCIAL CONSIDERATIONS

Ownership Options

Many options are available for construction and operation of the SWERF and establishment of a district heating system in Springfield, each with advantages and disadvantages. The options selected for discussion herein are not exhaustive and, no doubt, alternatives could be suggested. Other combinations of entities beyond those considered are possible, but disadvantages would arise when departing from the single entity arrangement.

NORTHEAST UTILITIES OR A NEW SUBSIDIARY TO FINANCE, OWN AND OPERATE THE DISTRICT HEATING SYSTEM.

Representatives of Northeast Utilities indicated an interest in establishment of a district heating system in Springfield. The prospective district heating system may make it economically feasible to upgrade their WSGS to a base load operation by converting from oil to coal. However, even when firing coal the units may displace more efficient units when required to run to supply the district heating system, and penalty charges would be assessed to protect Northeast's electric customers. Northeast's present capital commitments would make it difficult to undertake a large new project with substantial funding required for district heating.

They indicated some interest in the concept of an unregulated subsidiary funded independently of their present capitalization. This possibility was mentioned in the most preliminary fashion. The restrictions on such a course have not been explored and could be formidable under the public utility laws of Massachusetts.

Because operation of a SWERF and administration of a waste disposal business differ so from running an electric utility company, Northeast Utilities is unlikely to participate in this segment of the project.

Regardless of the final ownership, Northeast Utilities has assured the officials of Springfield that they will cooperate with the project to the fullest extent possible. The modification of the WSGS to provide hot water service for a district heating system will depend, however, on financial and contractual arrangements adequate to cover the investment, increased operating expenses, and incremental fuel costs.

The Massachusetts Legislature periodically considers a statute that would impose rate and other regulations on district heating utilities. Such a law would impose on Northeast Utilities an additional regulatory burden for district heating. Regardless of whether district heating rates are regulated, the allocation of capital, operating, and fuel costs between electric power and hot water production would impose a regulatory burden on Northeast Utilities in electric rate cases. Such regulatory burdens would not accrue to the city under municipal ownership and would not, or at least not to the same degree, be imposed on other optional ownerships.

This option has only a fair to poor chance of realization because of the reluctance of electric utilities to go into the district heating business.

SPRINGFIELD TO FINANCE, OWN, AND OPERATE THE DISTRICT HEATING SYSTEM, SELLING ELECTRICITY TO AND BUYING HOT WATER FROM NORTHEAST UTILITIES' WSGS

Officials of the Public Works Department said that the city is virtually precluded from undertaking the district heating project. Among the obstacles are the bonding and taxing limits imposed by Proposition 2-1/2 (passed in 1980); the delays inherent in complying with the state statutes that require competitive bidding for supplies, materials and replacement parts costing $2,000; and the constraints of civil service employment rules that make the hiring, promoting and replacing of competent technical, construction, operating and maintenance personnel extremely difficult.

Another constraint on municipal ownership would be caused by the city's annual budget process. If the City Council in a given year should refuse to authorize adequate capital and operating funds, the extension of district heating service to new customers or the expansion of service to existing customers would be delayed. Even the continuing operation of the system could be put in jeopardy in case of budget crisis.

Only minimal offsetting advantages would accrue to city ownership such as the right to use the streets and other public property for installation of facilities without the need for franchises or siting permits. Some economies might be possible by the use of the same maintenance and construction forces as are used for the water and sewer systems. Also, the profits from the sale of electricity to Northeast Utilities and heating service to consumers would supplement tax revenues. The city would benefit, however, under other entity options by reduced waste disposal expenses and possible franchise fees.

ENTREPRENEUR TO FINANCE, OWN AND OPERATE THE DISTRICT HEATING SYSTEM, INCLUDING THE HTHW BOILER PLANT AND SWERF, SELLING ELECTRICITY TO AND BUYING HOT WATER FROM NORTHEAST UTILITIES' WSGS.

Having an independent entrepreneur undertake the project would have a number of advantages. Under present law, an entity established for this purpose would be free of some of the constraints that Northeast Utilities and the city would encounter. An entrepreneur would be free to organize in one of several ways, including a general partnership with limited partners or a new or existing corporation. Likewise, he would be free to finance the facilities by a variety of means. The city has expressed willingness to cooperate by applying for HUD/UDAG grants and, if feasible, to devote some Block Grant funds to this purpose.

Officials of two large Springfield financial institutions indicated that they know of entrepreneurs who might be attracted to this project. They offered to assist in finding such a person or organization and in structuring the financial package.

In attracting an entrepreneur, the city would be offering assured revenues from waste tipping fees, and Northeast Utilities would buy the cogenerated electric power on a long-term contract.

The principal disadvantages of this option are the burdens an independent entity might have in building up a construction, operating and maintenance organization and the delay in the start of cash flow that would have to be covered in the original capitalization.

District heating projects under construction in Lawrence/Haverhill, MA, and

Trenton, NJ, are excellent examples of the entrepreneurial method of organizing a district heating enterprise. The Lawrence/Haverhill project includes waste recovery facilities, the Trenton project does not. However, the Trenton project has city and other government buildings as initial customers.

NON-PROFIT CORPORATION ESTABLISHED BY CITY AND COMMUNITY LEADERS TO FINANCE, OWN AND OPERATE THE DISTRICT HEATING SYSTEM, INCLUDING THE HTHW BOILER PLANT AND SWERF, SELLING ELECTRICITY TO AND BUYING HOT WATER FROM NORTHEAST UTILITIES' WSGS.

The concept of establishing a non-profit corporation to undertake the construction and operation of the district heating system has a number of advantages, although it may not be as easily carried out as the independent entrepreneurial option. The operating margin of a non-profit corporation need not be as great as that of the utility or an entrepreneur, so the tipping fees to the city and the heating rates to the consumers would probably be lower. With lower fees and rates, the activities of the two enterprises would probably grow more rapidly. With lower rates, district heating service would also compete with oil and gas heating more successfully.

To form a non-profit corporation to undertake this project, a major leadership effort would be required by government and community leaders. Also, substantial funds would be needed to cover organizing and planning expenses. Some preliminary planning has been done and, if a second HUD feasibility study grant is forthcoming, money would be available to cover some portions of these initial costs.

In St. Paul, MN, the non-profit corporation scheme has been successfully used to undertake a district heating project which is on a scale larger than that proposed for Springfield. Based on this, the non-profit corporation option would appear preferable to the others, except the entrepreneur. This option is heavily dependent on the willingness of the leaders of Springfield to expend the considerable effort required in its formation and initial funding.

ENTREPRENEUR FINANCING, OWNING AND OPERATING THE SWERF, AND A NON-PROFIT CORPORATION FINANCING, OWNING AND OPERATING THE DISTRICT HEATING SYSTEM

Under this scheme the independent organization to fund, own, and operate the SWERF would have expertise in this field. This option would bring the SWERF on line in a shorter time. With a non-profit corporation funding, owning, and operating the district heating system, lower and more competitive heating rates might result. Under this option, the non-profit corporation would buy hot water from the SWERF operator and Northeast Utilities' WSGS.

For this option to succeed, it would be necessary to obtain substantial take-or-pay consumer commitments initially so that revenue in early years would support the engineering and administrative manpower that would be required. Some additional difficulty would arise in having to bring into operation two new entities.

Springfield District Heating and Waste Recovery Authority to be established by the Massachusetts Legislature and provided with start-up funds to cover some of the planning, organizing and administration costs.

The authority concept has substantial appeal, particularly if it were to bring seed money to the project. It would have advantages similar to those of the non-profit corporation option. In addition, raising of capital funds might be more readily accomplished. However, it is improbable that the legislature would establish a new authority for the narrow purpose of waste recovery and district heating in Springfield alone. It is conceivable that a state-wide authority could be created, but from Springfield's point of view such an entity would have disadvantages in terms of delays and political complications. Also, it would probably take the legislature two or three annual sessions to bring such a proposition to a favorable vote.

NORTHEAST UTILITIES OR A NEW SUBSIDIARY COMPANY TO MANAGE AND OPERATE THE ENTIRE PROJECT UNDER CONTRACT WITH THE CITY OR AN INDEPENDENT ENTITY, INCLUDING OR EXCLUDING THE SWERF.

The concept of contracting with Northeast Utilities to manage the project would appear to have some attraction, since their Western Massachusetts Electric operating company is conveniently located and has substantial technical organization in place. It is doubtful, however, if the utility would view this idea sewers, and utility facilities.

Major advantages of the UDAG program are flexibility and an expeditious review process. Funds are awarded to local governments, which can then lend or grant them to private or municipal developers. Flexibility in management of funds is designed to promote stronger working relationships among the local government, the commercial and industrial sectors, and the public in overcoming development problems. The rapid review process is another positive aspect of the program. Applicants can reasonably expect a decision on a proposal within two months of its submission. The review process is further enhanced by having four separate dates each year for filing applications.

Action Grant projects are selected on the basis of a national competition. A major eligibility criterion is a firm financial commitment from the private sector. The program is meant to catalyze increased investment in distressed communities by private sector involvement. Such investments must be firm before a grant can be approved.

Action Grants can be used for energy conservation or alternative energy supply projects, including district heating, which are technically feasible and have sufficient economic viability to attract the private investment required under the UDAG program. The minimum is \$2.5 private to \$1 Action Grant, but the higher the ratio of private investment to UDAG requested, the more competitive the application will be. As in other Action Grant applications, a partially guaranteed loan or a revenue bond (but not a local government general obligation bond) can qualify as private investment. Accordingly, the capitalization of any development entity must clearly be private in nature, with no obligation running entirely (100% guarantee) to a municipality, public authority or the general funds of a governmental entity in case of default of a project. The private investor must be at risk for the project, not the public participants, although public financial participation is not discouraged. Additionally, there should be new, permanent jobs created as a result of the project, although it is recognized that high technology, energy related projects do not create as many jobs as do some other investments.

An energy UDAG application would contain the following:
Project Description - Provide a description of the community in terms of its existing and projected land use mix and zoning. The description should include

a space heating market study of the building stock and related heating systems in the proposed service area. There should be maps that show the heat load density and significant detail on potential large customers within the service area. Finally, there should be a discussion of the utility service that exists within the area with specific emphasis on how the space heating load is served currently.

Development Plan - A time-phased integrated development plan for all phases of the project with key milestones identified would provide additional substantiation.

Engineering Design - The design should include all aspects of the district heating system, the piping system, the energy source and the conversion of the building heating systems. The expansion potential of the system without federal financing subsidies and the scarce fuel savings beyond the segment for which funding is sought should be estimated.

Economic Feasibility - Plans for financing the proposed district heating system should be outlined, including amounts, sources, and timing. The economic feasibility assessment should include all project costs and estimating assumptions, cash flow, capital amortization, and internal rate of return, both with and without the UDAG requested. The applicant should submit letters of intent from building owners to convert to the system at the energy prices used in the feasibility study as an indication of the project's economic viability. The applicant should also address the long term supply stability of the energy source of the proposed system.

Environmental and Legal - The project may be subject to local, county, or state environmental statutes and/or the national environmental protection laws. Provide an assessment of the applicable environmental regulations for the proposed system. Include in the development plan all task and key milestones denoting the successful completion of environmental-associated requirements. There should also be evidence that all legal requirements have been met or are scheduled and integrated into the development plan.

REGULATORY AND LEGAL ASPECTS

Introduction

This section provides a brief description of the laws and programs of the State of Massachusetts governing the regulation of public energy utilities and their probable direct or indirect impacts on the proposed Springfield project. To be considered are the siting of energy generating and transmission facilities, the municipal franchising of public energy utilities, and the prescription of rates to be charged by utilities, including attendant problems of cost allocations, rate base and operating expense determinations, and rate of return allowances.

The powers of regulatory agencies in most states are extensive and reach most aspects of the organization, operation and financing of the business of a public utility. Most regulatory commissions are granted supervisory authority over public utilities as well as specific powers. In addition to regulating rates, most commissions regulate the construction of utility facilities, transfer of assets and local franchises, initiation and abandonment of service, and standards of service. Also, they are empowered to regulate capitalization, issuance of securities, mergers and consolidations, and affiliated interest transactions and to prescribe a system of accounts to be followed by the utilities.

In examining the regulatory and legal aspects of district heating in Massachusetts, considerable guidance is provided in a report prepared for the U.S. Department of Energy by a Chicago law firm and issued in January 1981. This Massachusetts report, one of 50 state studies and an overview study, examines the laws of the state governing the regulation of public utilities, the siting of energy generating and transmission facilities, the municipal franchising of public utilities, and the regulation of rates.

Regulation of Public Utilities

The authority to regulate public utilities in Massachusetts is vested in the Department of Public Utilities (DPU), supervised by three commissioners appointed by the governor for 4-year terms. Municipalities are given a limited role in the regulation of public utilities. In general, the role of the municipality in Massachusetts is limited to the exercise of police power and to authorizing initiation of service by a new gas or electric company, if the municipality is already served by such a utility. The DPU is responsible for regulating and has supervisory authority over all gas and electric companies. The

Massachusetts report does not mention district heating utilities as does the companion report on nearby Rhode Island where utility regulatory jurisdiction "...encompasses a wide variety of utility functions, including generation, manufacture, production, transmission, distribution or furnishing of natural or manufactured gas, steam, electrical or nuclear energy, heat, light or power."

Siting of Energy Facilities

Massachusetts has enacted an electric power facilities siting law, and created the Energy Facilities Siting Council as a state agency responsible for implementing the siting law. The Council approves long-range forecasts for facilities which are required to be submitted by all gas and electric companies, and issues permits for the construction of such facilities after finding that the proposed construction is consistent with the approved long-range forecast. Upon application by a gas or electric company showing that it has been impeded in its efforts to obtain necessary permits from other state agencies or local governmental units, the Council may issue a certificate of environmental impact and public need which supersedes all other state and local restrictions that would delay or prevent the construction, operation or maintenance of the proposed facility.

Whether the Council and the siting law it administers would have jurisdiction over the SWERF and district heating system is not clear. The language of the law refers to electric and gas companies, so the question might arise, if a new district heating entity were formed that would generate electricity in the SWERF whether it would be considered an electric utility subject to the law.

Franchising of Public Utilities

The authority to grant franchises for the use of public streets and places in connection with providing utility services in Massachusetts is vested in municipalities. To be granted a franchise, the statutes require that a public utility must file a petition with the local governing body, after which a public hearing must be held. There are statutory criteria governing whether or not a franchise should be awarded.

Specifically, municipalities are empowered to "authorize the laying of pipes and conduits for the transmission of steam or hot water for heating, cooling and mechanical power, for private use..." A separate statutory provision states specifically that corporations organized for the purpose of generating and furnishing steam or hot water may lay pipeline only with the written consent of the local authorities.

Franchising authority is not limited to certain classes of cities. The statutes do not limit the type of entities which may be franchised, but the franchising power is limited to entities providing electricity, steam, hot water or other enumerated services.

Certain procedures have been established by statute governing the grants of franchises for the construction of electric facilities, but no specific procedures have been established with respect to other franchise grants. Local home rule charters and ordinances must be consulted to determine the procedure in obtaining a franchise.

No specific criteria for evaluating franchise requests have been established by statute or reported judicial decision. A franchisee need not obtain a certificate of convenience and necessity from the state before seeking a franchise, and franchises need not be awarded competitively to the highest bidder. No maximum term for a franchise has been established by statute or by judicial decision, nor are perpetual franchises specifically sanctioned or prohibited. Municipalities have been neither authorized nor forbidden to grant exclusive franchises by statute or reported judicial decision.

Rate Regulation

Currently, district heating rates are not regulated by the DPU in Massachusetts. However, there is the ever-present possibility that the Legislature may extend the regulation of rates to steam and hot water service that now applies to electric and gas services. Such regulation of district heating does occur in Rhode Island and New York.

The regulation of electric and gas service requires that no change in rates can be made until an amended rate schedule is filed, hearings are held, and a decision is made by the DPU. Rate changes may be suspended for a period not to exceed six months while the hearing procedures and submissions of briefs and reply briefs are carried out and the commissioners weigh the evidence before reaching a decision.

In relation to rate regulation, the utility is required to keep financial records according to a uniform system of accounts. In Massachusetts the Federal Energy Regulatory Commission (FERC) system of accounts is employed. Also, the DPU may order a utility to establish and maintain a depreciation reserve fund that it deems adequate.

The Massachusetts statutes give the DPU authority to "supervise" the rates of certain municipally owned utilities. Rates charged by a municipality may not be fixed at less than production cost as determined by the DPU and may not yield more than eight percent per year, after operating cost, interest, sinking fund provision and depreciation. Inherent in rate regulation are the DPU policies and practices relating to rate base determination, valuation of property, test periods, allowed expenses, treatment of amounts in construction work in progress, and other related accounting and financial matters.

Of overriding concern under rate regulation is the method used by the DPU for determining the rate of return to be allowed a regulated utility. The Massachusetts DPU, in specifying the overall rate of return in a given case, focuses heavily on the cost of equity as well as the cost of service and finds that the discounted cash-flow method of determining reasonableness is preferable. Other factors considered in determining rate of return allowed include the utility capital structure, risk, quality of service, efficiency of management and nature of operations.

The regulatory climate for utilities in Massachusetts could, of course, be examined herein in far greater depth. Until such time as the DPU is empowered to regulate district heating utilities, this brief overview may suffice.

Under present Massachusetts law which does not provide for the regulation of rates for steam or hot water, the sale of heat by Northeast Utilities to the district heating entity would not be subject to state rate regulation, as such. Northeast Utilities, however, would encounter a measure of regulation in electric rate cases when the method and reasonableness of the allocation of operating and fuel costs between electric generation and steam or hot water for district heating at the WSGS is examined. Also, it is likely that a contract for heat between Northeast Utilities and the district heating entity would require filing with and approval by the DPU.

As an example of the indirect regulation of district heating, Boston Edison reports that in past years when their unregulated street steam system was supplied from non-condensing electric turbines, the question of cost allocation always arose in electric rate cases, with intervenors on behalf of both the steam customers and the electric customers challenging the utility's computations. Boston Edison also reports that for the past several years, at the instigation of the Building Owners and Managers Association of Boston, legislation has been proposed that would authorize the DPU to regulate district heating. Each year it has been defeated in committee.

Another district heating system now operating in Massachusetts is Cambridge Electric Light Company's comparatively small system. Of their 41 steam customers, Harvard University, that owns and maintains its own piping in the streets from the campus to the power plant, is the largest. The steam is supplied from cogeneration sources.

In Lawrence, construction has been started on a district heating system that will include a waste recovery plant, a cogeneration power plant and a district heating system. The heat distribution medium will be steam which will be supplied initially to several industries and two housing projects. Most of the electric power will be sold to New England Power Company under PURPA rates. Some small electricity sales will continue to be made within the Arlington Mills Complex, an industrial park where the power plant is located. The understanding of the management of the Lawrence project is that the sale of steam will not be subject to rate regulation. They recognize, however, that under applicable provisions of Massachusetts law, retail sales of electricity may be subject to retail rate regulation, but they do not believe their project will be subject to DPU financial or organizational regulation. The DPU, under Chapters 164 and 94, has the authority to regulate electric rates if a cogenerator or district heating entity engages in retail sales of electricity, as will occur in Lawrence.

Federal Regulation

Section 210(e) of the PURPA Act of 1978 provides the FERC with authority to promulgate regulations exempting certain cogeneration and small power production facilities from various state and federal public utility regulatory laws. Under the regulations promulgated by FERC under Section 210, cogeneration and small power production facilities satisfying certain specified criteria ("qualifying facilities") are exempt from regulation under the Public Utility Holding Company Act of 1935, wholesale rate regulation under the Federal Power Act, as amended, and certain Massachusetts regulatory laws.

The Springfield SWERF cogenerating plant will be owned and operated by an entity other than Northeast Utilities, and, therefore, will be considered a qualifying facility under PURPA and be exempt from the forms of public utility regulation mentioned above. The sale of the cogenerated electric power to Northeast Utilities would be subject to PURPA regulations promulgated by the Massachusetts DPU and the Western Massachusetts Electric Company's filed Power Purchase Schedule tariff MDPU 477. Under the provisions of MDPU 477, the owner of the SWERF would be paid for electricity furnished to the utility in accordance with avoided cost on an on-peak and off-peak hours basis. The avoided costs are recomputed quarterly. For the December 1982 through February 1983 they were:

On-peak	primary	5.35¢/kWh
On-peak	secondary	5.57¢/kWh
Off-peak	primary	4.00¢/kWh
Off-peak	secondary	4.16¢/kWh

The MDPU 477 filed by Western Massachusetts Electric as required by the DPU provides a minimum range for the pricing of sale of power from the project owner to the utility. Nothing in the PURPA rules, however, precludes the cogenerating entity and the utility from negotiating a mutually satisfactory agreement outside the scope of the filed buy-back tariff.

Section 9

ECONOMIC ANALYSIS

The economic analysis of hot water district heating in Springfield was performed from the viewpoint of municipal ownership except for the modification of the Northeast Utilities' WSGS. The analysis determined the annual carrying charges for each investment phase, the composite carrying charges for all investment phases, the unit cost of district heat, and the pay-back period for specific customer retrofit categories.

The analysis uses the required revenue approach to determine the necessary charges for district heating. The annual carrying charges for the district heating investment are calculated based on a debt to equity ratio, return rates, book life, tax information, and insurance rates, both typical of municipal ownership and for Northeast Utilities. The method was used to develop the total system costs and compare these costs with the total quantity of heat sold to determine the minimum required charges for district heat. The total system costs are comprised of fixed expenses, operating expenses, replacement electricity, and gross receipt taxes.

The capital costs were derived in 1983 dollars and then escalated to the year of expenditure at a rate of 6.5%. The capital costs include all direct and indirect costs associated with the power plant retrofits and the transmission and distribution systems.

The annual carrying charges were based on the assumption that the entire system would be owned by a municipal-type entity and that heat would be purchased from the WSGS and the SWERF. The project would be financed using 100% debt except for the modifications of the WSGS (phases 3B and 6B). The cost of municipal debt is 7%. The income tax and property tax rates for a municipality are 0%, and the insurance rate is 0.5%. The analysis is conducted for a 30-year book life.

The annual carrying charges for phases 3B and 6B were based on the assumption that Northeast Utilities would modify their WSGS to sell district heat to the municipality at a rate equal to the carrying charges for the modification plus the replacement electricity costs. The plant modification is assumed to be financed with a weighted cost of capital equal to 14.38%. The income tax rate for the utility is 46%, the insurance rate is 0.5%, and the gross receipts tax is 4%. The utility is assumed to take advantage of accelerated tax depreciation on the modification over a 15-year period.

The annual carrying charges for the eight phases of implementation are presented in Tables 9-1 through 9-10; the composite annual carrying charges are presented in Table 9-11.

The operating expenses for the district heating system are comprised of replacement electricity costs, fuel costs, refuse heat costs, pumping costs, operating and maintenance manpower, and operating and maintenance materials. The replacement electricity costs are charged against the district heating system to compensate for the reduction in electrical output at the WSGS caused by the district heating modification. The replacement electricity costs are \$51.44/MWh in 1983 dollars. The fuel costs charged to the system represent the cost of natural gas burned in the high temperature hot water boilers. The gas costs are \$5.13/MBtu in 1983 dollars. The refuse heat costs in the analysis are for heat purchased from the SWERF. The cost of refuse heat is \$4.81 MWt in 1983 dollars. Both gas and refuse heat costs are escalated at 7.5%. Pumping costs for transmission, distribution costs, and condensate return are also calculated using \$51.44/MWh in 1983 dollars. Electric power costs are escalated at 7.5% per year. Operating and maintenance manpower for the system is estimated to cost \$35,000 per man-year in 1983 dollars, including overhead and benefits, escalated at an annual rate of 6.5%. Operating and maintenance material costs are estimated to be equal to 3% of the capital costs of the heat source and 1% of the capital costs of the piping on an annual basis, escalated at 6.5%. The quantities of replacement electricity and pumping power were determined from the load duration curves for the respective phases of development.

The economic analysis developing the cost of district heating is presented in Table 9-12; Figure 9-1 shows item H graphically.

An analysis to determine the period in which commercial heating customers would recover their retrofit expenses was performed for two different cases and several different original building heating systems. One case assumes the customer does not finance the retrofit, the other that he finances the retrofit at an annual rate of 12% for 20 years. The equipment is depreciated over a 5-year period using an accelerated depreciation and an expensing deduction in the first year. Customer maintenance and repair costs for the district heating equipment are not included. Maintenance expenses should be lower for district heating equipment than for existing heating equipment. The payback period is based on the after tax savings in annual energy costs. This analysis assumes a tax rate of 50%. The analysis was performed for an energy escalation rate for oil of 7.5%; it was determined that over 80% of the existing heating systems in Springfield burn oil.

The unit cost of district heat is compared with the unit cost of oil, adjusted for combustion efficiency, in Figure 9-2. The consumer payback periods for different types of conversions are developed in Tables 9-13 through 9-17 for 7.5% oil escalation. The payback period depends on the type of existing system and varies form 3 to 6 years for most consumers.

Results of the economic analysis demonstrate that a hot water district heating system will supply heat at lower cost than individual boilers fired with oil.

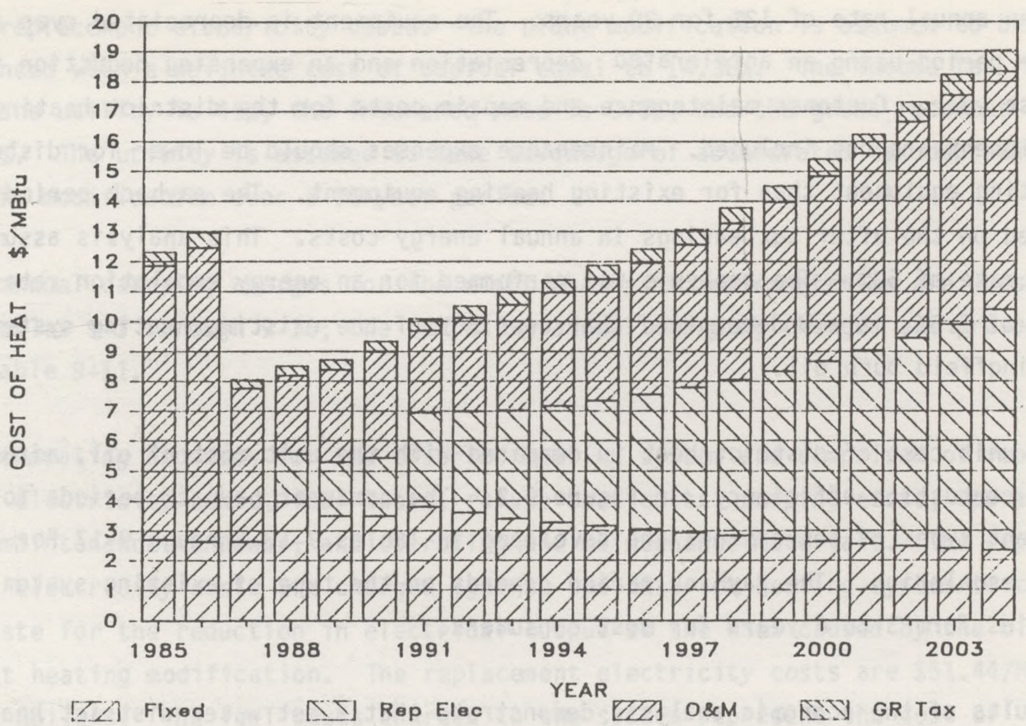

Figure 9-1. Unit Cost of District Heat

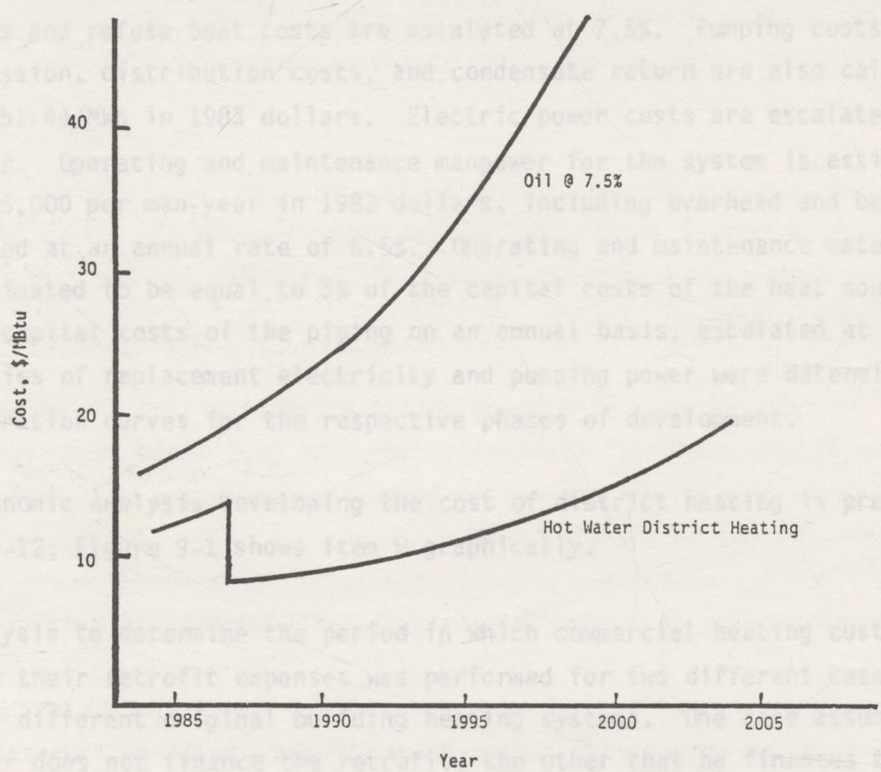

Figure 9-2. Projected Heating Cost Comparison

Table 9-1

ANNUAL CARRYING CHARGES, PHASE ONE

Investment for Phase	1
Initial Operation	1985
Cost Basis	1983
Capital Cost - $1000	
Heat Source	1408
Piping	4347
Total	5755
Escalation - $1000	570
AFDC - $1000	218
Total Cost - $1000	6543
Start of Evaluation	1985

Economic Factors			
Preferred Stock Ratio	0	Book Life - Yrs	30
Return on Preferred Stock - %	0	Income Tax Rate - %	0
Common Stock Ratio	0	Tax Credit - %	0
Return on Common Stock - %	0	Tax Life - Yrs	30
Debt Ratio	1	Accelerated Tax Depreciation	0
Debt Cost - %	7	Property Tax - %	0
Weighted Cost of Capital - %	7	Insurance Rate - %	0.5

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	6543	6325	6107	5888	5670	5452	5234	5016	4798	4580
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	458	443	427	412	397	382	366	351	336	321
Book Depreciation	218	218	218	218	218	218	218	218	218	218
Tax Depreciation	218	218	218	218	218	218	218	218	218	218
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	33	33	33	33	33	33	33	33	33	33
Annual Carrying Charges	709	694	678	663	648	632	617	602	587	571

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	4362	4144	3926	3708	3489	3271	3053	2835	2617	2399
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	305	290	275	260	244	229	214	198	183	168
Book Depreciation	218	218	218	218	218	218	218	218	218	218
Tax Depreciation	218	218	218	218	218	218	218	218	218	218
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	33	33	33	33	33	33	33	33	33	33
Annual Carrying Charges	556	541	526	510	495	480	465	449	434	419

Table 9-2

ANNUAL CARRYING CHARGES, PHASE TWO

Investment for Phase	2	Economic Factors			
Initial Operation	1987	Preferred Stock Ratio	0	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	0	Income Tax Rate - %	0
Capital Cost - $1000		Common Stock Ratio	0	Tax Credit - %	0
Heat Source	957	Return on Common Stock - %	0	Tax Life - Yrs	30
Piping	2791	Debt Ratio	1	Accelerated Tax Depreciation	0
Total	3748	Debt Cost - %	7	Property Tax - %	0
Escalation - $1000	924	Weighted Cost of Capital - %	7	Insurance Rate - %	0.5
AFDC - $1000	161				
Total Cost - $1000	4833				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	4833	4672	4511	4350	4189	4027	3866	3705
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	0	0	338	327	316	304	293	282	271	259
Book Depreciation	0	0	161	161	161	161	161	161	161	161
Tax Depreciation	0	0	161	161	161	161	161	161	161	161
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	24	24	24	24	24	24	24	24
Annual Carrying Charges	0	0	524	512	501	490	478	467	456	445

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	3544	3383	3222	3061	2900	2739	2578	2416	2255	2094
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	248	237	226	214	203	192	180	169	158	147
Book Depreciation	161	161	161	161	161	161	161	161	161	161
Tax Depreciation	161	161	161	161	161	161	161	161	161	161
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	24	24	24	24	24	24	24	24	24	24
Annual Carrying Charges	433	422	411	400	388	377	366	354	343	332

Table 9-3

ANNUAL CARRYING CHARGES, PHASE THREE A (MUNICIPAL)

Investment for Phase	3 A	Economic Factors			
Initial Operation	1988	Preferred Stock Ratio	0	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	0	Income Tax Rate - %	0
Capital Cost - $1000		Common Stock Ratio	0	Tax Credit - %	0
Heat Source	0	Return on Common Stock - %	0	Tax Life - Yrs	30
Piping	1583	Debt Ratio	1	Accelerated Tax Depreciation	0
Total	1583	Debt Cost - %	7	Property Tax - %	0
Escalation - $1000	519	Weighted Cost of Capital - %	7	Insurance Rate - %	0.5
AFDC - $1000	72				
Total Cost - $1000	2174				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	0	2174	2101	2029	1957	1884	1812	1739
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	0	0	0	152	147	142	137	132	127	122
Book Depreciation	0	0	0	72	72	72	72	72	72	72
Tax Depreciation	0	0	0	72	72	72	72	72	72	72
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	11	11	11	11	11	11	11
Annual Carrying Charges	0	0	0	236	230	225	220	215	210	205

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	1667	1594	1522	1449	1377	1304	1232	1159	1087	1015
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	117	112	107	101	96	91	86	81	76	71
Book Depreciation	72	72	72	72	72	72	72	72	72	72
Tax Depreciation	72	72	72	72	72	72	72	72	72	72
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	11	11	11	11	11	11	11	11	11	11
Annual Carrying Charges	200	195	190	185	180	175	170	164	159	154

Table 9-4

ANNUAL CARRYING CHARGES, PHASE THREE B (UTILITY)

Investment for Phase	3B	Economic Factors			
Initial Operation	1988	Preferred Stock Ratio	0.11	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	11	Income Tax Rate - %	46
Capital Cost - $1000		Common Stock Ratio	0.4	Tax Credit - %	10
Heat Source	2216	Return on Common Stock - %	17	Tax Life - Yrs	15
Piping	0	Debt Ratio	0.49	Accelerated Tax Depreciation	1
Total	2216	Debt Cost - %	13	Gross Receipts Tax %	4
Escalation - $1000	726	Weighted Cost of Capital - %	14.38	Insurance Rate - %	0.5
AFDC - $1000	204				
Total Cost - $1000	3146				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	0	2832	2689	2463	2249	2049	1861	1686
Return on Preferred Stock	0	0	0	34	33	30	27	25	23	20
Return on Common Stock	0	0	0	193	183	167	153	139	127	115
Interest	0	0	0	180	171	157	143	131	119	107
Book Depreciation	0	0	0	94	94	94	94	94	94	94
Tax Depreciation	0	0	0	210	392	364	336	308	280	252
Income Taxes	0	0	0	136	43	40	38	38	38	39
Deferred Taxes	0	0	0	48	132	119	106	93	80	68
Property Tax	0	0	0	126	129	132	136	139	142	146
Insurance	0	0	0	16	16	16	16	16	16	16
Annual Carrying Charges	0	0	0	827	800	756	714	675	638	605

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	1525	1375	1239	1116	1005	908	823	751	692	646
Return on Preferred Stock	18	17	15	14	12	11	10	9	8	8
Return on Common Stock	104	94	84	76	68	62	56	51	47	44
Interest	97	88	79	71	64	58	52	48	44	41
Book Depreciation	94	94	94	94	94	94	94	94	94	94
Tax Depreciation	224	196	168	140	112	84	56	28	0	0
Income Taxes	40	43	47	51	56	63	70	78	87	83
Deferred Taxes	55	42	29	16	3	-10	-23	-35	-48	-48
Property Tax	150	153	157	161	165	169	173	178	182	187
Insurance	16	16	16	16	16	16	16	16	16	16
Annual Carrying Charges	574	546	521	499	480	463	449	438	430	425

Table 9-5

ANNUAL CARRYING CHARGES, PHASE FOUR

Investment for Phase	4	Economic Factors			
Initial Operation	1989	Preferred Stock Ratio	0	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	0	Income Tax Rate - %	0
Capital Cost - $1000		Common Stock Ratio	0	Tax Credit - %	0
Heat Source	470	Return on Common Stock - %	0	Tax Life - Yrs	30
Piping	1061	Debt Ratio	1	Accelerated Tax Depreciation	0
Total	1531	Debt Cost - %	7	Property Tax - %	0
Escalation - $1000	634	Weighted Cost of Capital - %	7	Insurance Rate - %	0.5
AFDC - $1000	74				
Total Cost - $1000	2239				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	0	0	2239	2165	2090	2015	1941	1866
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	0	0	0	0	157	152	146	141	136	131
Book Depreciation	0	0	0	0	75	75	75	75	75	75
Tax Depreciation	0	0	0	0	75	75	75	75	75	75
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	11	11	11	11	11	11
Annual Carrying Charges	0	0	0	0	243	237	232	227	222	216

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	1791	1717	1642	1567	1493	1418	1344	1269	1194	1120
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	125	120	115	110	104	99	94	89	84	78
Book Depreciation	75	75	75	75	75	75	75	75	75	75
Tax Depreciation	75	75	75	75	75	75	75	75	75	75
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	11	11	11	11	11	11	11	11	11	11
Annual Carrying Charges	211	206	201	196	190	185	180	175	169	164

Table 9-6

ANNUAL CARRYING CHARGES, PHASE FIVE

Investment for Phase	5	Economic Factors			
Initial Operation	1990	Preferred Stock Ratio	0	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	0	Income Tax Rate - %	0
Capital Cost - $1000		Common Stock Ratio	0	Tax Credit - %	0
Heat Source	470	Return on Common Stock - %	0	Tax Life - Yrs	30
Piping	636	Debt Ratio	1	Accelerated Tax Depreciation	0
Total	1106	Debt Cost - %	7	Property Tax - %	0
Escalation - $1000	559	Weighted Cost of Capital - %	7	Insurance Rate - %	0.5
AFDC - $1000	57				
Total Cost - $1000	1723				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	0	0	0	1723	1665	1608	1550	1493
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	0	0	0	0	0	121	117	113	109	105
Book Depreciation	0	0	0	0	0	57	57	57	57	57
Tax Depreciation	0	0	0	0	0	57	57	57	57	57
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	9	9	9	9	9
Annual Carrying Charges	0	0	0	0	0	187	183	179	175	171

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	1436	1378	1321	1263	1206	1148	1091	1034	976	919
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	100	96	92	88	84	80	76	72	68	64
Book Depreciation	57	57	57	57	57	57	57	57	57	57
Tax Depreciation	57	57	57	57	57	57	57	57	57	57
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	9	9	9	9	9	9	9	9	9	9
Annual Carrying Charges	167	163	158	154	150	146	142	138	134	130

Table 9-7

ANNUAL CARRYING CHARGES, PHASE SIX A (MUNICIPAL)

Investment for Phase	6 A	Economic Factors			
Initial Operation	1991	Preferred Stock Ratio	0	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	0	Income Tax Rate - %	0
Capital Cost - $1000		Common Stock Ratio	0	Tax Credit - %	0
Heat Source	0	Return on Common Stock - %	0	Tax Life - Yrs	30
Piping	1855	Debt Ratio	1	Accelerated Tax Depreciation	0
Total	1855	Debt Cost - %	7	Property Tax - %	0
Escalation - $1000	1120	Weighted Cost of Capital %	7	Insurance Rate - %	0.5
AFDC - $1000	102				
Total Cost - $1000	3077				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	0	0	0	0	3077	2975	2872	2769
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	0	0	0	0	0	0	215	208	201	194
Book Depreciation	0	0	0	0	0	0	103	103	103	103
Tax Depreciation	0	0	0	0	0	0	103	103	103	103
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	15	15	15	15
Annual Carrying Charges	0	0	0	0	0	0	333	326	319	312

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	2667	2564	2462	2359	2257	2154	2051	1949	1846	1744
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	187	180	172	165	158	151	144	136	129	122
Book Depreciation	103	103	103	103	103	103	103	103	103	103
Tax Depreciation	103	103	103	103	103	103	103	103	103	103
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	15	15	15	15	15	15	15	15	15	15
Annual Carrying Charges	305	297	290	283	276	269	262	254	247	240

Table 9-8

ANNUAL CARRYING CHARGES, PHASE SIX B (UTILITY)

Investment for Phase	6B	Economic Factors			
Initial Operation	1991	Preferred Stock Ratio	0.11	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	11	Income Tax Rate - %	46
Capital Cost - $1000		Common Stock Ratio	0.4	Tax Credit - %	10
Heat Source	2216	Return on Common Stock - %	17	Tax Life - Yrs	15
Piping	0	Debt Ratio	0.49	Accelerated Tax Depreciation	1
Total	2216	Debt Cost - %	13	Gross Receipts Tax - %	4
Escalation - $1000	1338	Weighted Cost of Capital - %	14.38	Insurance Rate - %	0.5
AFDC - $1000	247				
Total Cost - $1000	3801				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	0	0	0	0	3421	3248	2975	2717
Return on Preferred Stock	0	0	0	0	0	0	41	39	36	33
Return on Common Stock	0	0	0	0	0	0	233	221	202	185
Interest	0	0	0	0	0	0	218	207	190	173
Book Depreciation	0	0	0	0	0	0	114	114	114	114
Tax Depreciation	0	0	0	0	0	0	253	473	439	405
Income Taxes	0	0	0	0	0	0	164	52	48	46
Deferred Taxes	0	0	0	0	0	0	58	159	144	128
Property Tax	0	0	0	0	0	0	152	156	160	164
Insurance	0	0	0	0	0	0	19	19	19	19
Annual Carrying Charges	0	0	0	0	0	0	1000	967	913	862

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	2475	2248	2037	1842	1662	1497	1348	1215	1097	994
Return on Preferred Stock	30	27	25	22	20	18	16	15	13	12
Return on Common Stock	168	153	139	125	113	102	92	83	75	68
Interest	158	143	130	117	106	95	86	77	70	63
Book Depreciation	114	114	114	114	114	114	114	114	114	114
Tax Depreciation	372	338	304	270	236	203	169	135	101	68
Income Taxes	45	45	47	49	52	56	62	68	76	84
Deferred Taxes	113	97	82	66	51	35	19	4	-12	-27
Property Tax	168	172	176	181	185	190	195	199	204	210
Insurance	19	19	19	19	19	19	19	19	19	19
Annual Carrying Charges	815	771	730	693	660	630	603	579	559	543

Table 9-9

ANNUAL CARRYING CHARGES, PHASE SEVEN

Investment for Phase	7	Economic Factors			
Initial Operation	1992	Preferred Stock Ratio	0	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	0	Income Tax Rate - %	0
Capital Cost - $1000		Common Stock Ratio	0	Tax Credit - %	0
Heat Source	0	Return on Common Stock - %	0	Tax Life - Yrs	30
Piping	741	Debt Ratio	1	Accelerated Tax Depreciation	0
Total	741	Debt Cost - %	7	Property Tax - %	0
Escalation - $1000	525	Weighted Cost of Capital - %	7	Insurance Rate - %	0.5
AFDC - $1000	44				
Total Cost - $1000	1309				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	0	0	0	0	0	1309	1265	1222
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	0	0	0	0	0	0	0	92	89	86
Book Depreciation	0	0	0	0	0	0	0	44	44	44
Tax Depreciation	0	0	0	0	0	0	0	44	44	44
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	7	7	7
Annual Carrying Charges	0	0	0	0	0	0	0	142	139	136

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	1178	1135	1091	1047	1004	960	916	873	829	785
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	82	79	76	73	70	67	64	61	58	55
Book Depreciation	44	44	44	44	44	44	44	44	44	44
Tax Depreciation	44	44	44	44	44	44	44	44	44	44
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	7	7	7	7	7	7	7	7	7	7
Annual Carrying Charges	133	130	127	123	120	117	114	111	108	105

Table 9-10

ANNUAL CARRYING CHARGES, PHASE EIGHT

Investment for Phase	8	Economic Factors			
Initial Operation	1993	Preferred Stock Ratio	0	Book Life - Yrs	30
Cost Basis	1983	Return on Preferred Stock - %	0	Income Tax Rate - %	0
Capital Cost - $1000		Common Stock Ratio	0	Tax Credit - %	0
Heat Source	0	Return on Common Stock - %	0	Tax Life - Yrs	30
Piping	445	Debt Ratio	1	Accelerated Tax Depreciation	0
Total	445	Debt Cost - %	7	Property Tax - %	0
Escalation - $1000	364	Weighted Cost of Capital - %	7	Insurance Rate - %	0.5
AFDC - $1000	28				
Total Cost - $1000	837				
Start of Evaluation	1985				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	0	0	0	0	0	0	0	0	837	809
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	0	0	0	0	0	0	0	0	59	57
Book Depreciation	0	0	0	0	0	0	0	0	28	28
Tax Depreciation	0	0	0	0	0	0	0	0	28	28
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	4	4
Annual Carrying Charges	0	0	0	0	0	0	0	0	91	89

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	781	754	726	698	670	642	614	586	558	530
Return on Preferred Stock	0	0	0	0	0	0	0	0	0	0
Return on Common Stock	0	0	0	0	0	0	0	0	0	0
Interest	55	53	51	49	47	45	43	41	39	37
Book Depreciation	28	28	28	28	28	28	28	28	28	28
Tax Depreciation	28	28	28	28	28	28	28	28	28	28
Income Taxes	0	0	0	0	0	0	0	0	0	0
Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Property Tax	0	0	0	0	0	0	0	0	0	0
Insurance	4	4	4	4	4	4	4	4	4	4
Annual Carrying Charges	87	85	83	81	79	77	75	73	71	69

Table 9-11

COMPOSITE CARRYING CHARGES, PHASES ONE THROUGH EIGHT

Phase	Year	Investment	Economic Factors			
1	1985	6543	Preferred Stock Ratio	0	Book Life - Yrs	30
2	1987	4833	Return on Preferred Stock - %	0	Income Tax Rate - %	0
3A	1988	2174	Common Stock Ratio	0	Tax Credit - %	0
4	1989	2239	Return on Common Stock - %	0	Tax Life - Yrs	30
5	1990	1723	Debt Ratio	1	Accelerated Tax Depreciation	0
6A	1991	3077	Debt Cost - %	7	Property Tax - %	0
7	1992	1309	Weighted Cost of Capital - %	7.00	Insurance Rate - %	0.05
8	1993	837				
3B	1988	3146				
6B	1991	3801				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Remaining Book Value	6543	6325	10940	15566	17211	18181	23882	24132	23778	22588
Return on Preferred Stock	0	0	0	34	33	30	69	64	59	53
Return on Common Stock	0	0	0	193	183	167	386	360	329	299
Interest	458	443	766	1072	1188	1257	1636	1656	1634	1553
Book Depreciation	218	218	379	546	621	678	895	938	966	966
Tax Depreciation	218	218	379	661	918	947	1275	1511	1477	1415
Income Taxes	0	0	0	136	43	40	203	89	86	85
Deferred Taxes	0	0	0	48	132	119	164	253	224	196
Property Tax	0	0	0	126	129	132	288	295	302	310
Insurance	33	33	57	83	95	103	138	144	148	148
Annual Carrying Charges	709	694	1202	2238	2422	2527	3777	3799	3748	3611

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Remaining Book Value	21426	20292	19187	18110	17062	16042	15050	14087	13152	12246
Return on Preferred Stock	48	44	40	36	32	29	26	24	22	20
Return on Common Stock	272	246	223	201	181	164	148	134	122	112
Interest	1475	1398	1322	1249	1178	1108	1040	974	909	847
Book Depreciation	966	966	966	966	966	966	966	966	966	966
Tax Depreciation	1353	1291	1230	1168	1106	1044	983	921	859	825
Income Taxes	86	89	93	100	109	119	132	146	162	168
Deferred Taxes	167	139	111	82	54	25	-3	-31	-60	-75
Property Tax	317	325	333	342	350	359	368	377	387	396
Insurance	148	148	148	148	148	148	148	148	148	148
Annual Carrying Charges	3480	3355	3237	3125	3018	2919	2825	2738	2656	2582

Table 9-12 (Sheet 1 of 2)

CALCULATED UNIT COST FOR HOT WATER DISTRICT HEAT, 1985-1994

Start of Evaluation	1985		Economic Factors			
Unit Costs	1983	Escalation	Preferred Stock Ratio	0	Book Life - Yrs	30
			Return on Preferred Stock - %	0	Income Tax Rate - %	0
Electricity - $/MWh	51.44	7.5	Common Stock Ratio	0	Tax Credit - %	0
Pumping Power-$/MWh	51.44	7.5	Return on Common Stock - %	0	Tax Life - Yrs	30
Refuse Heat-$/MWt	4.81	7.5	Debt Ratio	1	Accel. Tax Deprec.	0
Gas - $/MBtu	5.13	7.5	Debt Cost - %	7	Insurance Rate - %	0.5
O&M Labor -$/ManYr	35000	6.5	Weighted Cost of Capital - %	7	Gross Receipts Tax-%	4
O&M Materials -% Cost	----	6.5				
Property Taxes - %	0	2.5				

Year	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
A. Annual Quantities										
1. Heat Sales - MWt/yr	76490	76490	132762	164508	202458	211897	290804	307330	322157	322157
2. Refuse Heat - MWt/yr	0	0	100706	107139	111981	112850	117924	118895	119762	119762
3. Gas Consumed - MBtu/yr	350954	350954	169082	20131	80481	102959	82439	108548	141238	141238
4. Electricity Loss - MWh/yr	0	0	0	11877	15419	16203	31625	33535	35128	35128
5. Pumping Energy - Mwh/yr	664	664	1152	1428	757	1839	2524	2667	2796	2796
6. O&M Labor - ManYr/yr	6	6	8	8	8	8	8	8	8	8
7. O&M Material-% year's Inv	0.45%	0.45%	1.00%	1.61%	1.85%	1.00%	1.00%	1.00%	0.00%	0.00%
B. Unit Costs										
1. Replacement Elec. - $/MWh	59.45	63.90	68.70	75.14	80.78	86.83	98.34	105.72	113.65	122.17
2. Pumping Electricity-$/MWh	59.45	63.90	68.70	73.85	79.39	85.34	91.74	98.62	106.02	113.97
3. Refuse Heat - $/MWt	5.56	5.98	6.35	6.72	7.69	8.06	8.91	9.89	10.62	11.60
4. Fuel - $/MBtu	5.93	6.37	6.85	7.36	7.92	8.51	9.15	9.84	10.57	11.37
5. O&M Labor - $1000/ManYr	40	42	45	48	51	54	58	62	66	70
C. Investments - $1000	6543	0	4833	2174	2239	1723	3077	1309	837	0
D. Annual Carrying Charges-$1000/yr										
1. Return on Preferred Stock	0	0	0	34	33	30	69	64	59	53
2. Return on Common Stock	0	0	0	193	183	167	386	360	329	299
3. Interest	458	443	766	1072	1188	1257	1636	1656	1634	1553
4. Book Depreciation	218	218	379	546	621	678	895	938	966	966
5. Tax Depreciation	218	218	379	661	918	947	1275	1511	1477	1415
6. Income Taxes	0	0	0	136	43	40	203	89	86	85
7. Deferred Taxes	0	0	0	48	132	119	164	253	224	196
8. Property Tax	0	0	0	126	129	132	286	295	302	310
9. Insurance	33	33	57	83	95	103	138	144	148	148
Sub- Total	709	694	1202	2238	2422	2527	3777	3799	3748	3611
E. Operating Expenses - $1000/yr										
1. Replacement Electricity	0	0	0	892	1245	1407	3110	3545	3992	4292
2. Refuse Heat	0	0	639	720	861	910	1051	1176	1272	1389
3. Fuel	2081	2237	1158	148	637	876	754	1068	1493	1605
4. O&M Labor	238	254	360	384	409	435	463	494	526	560
5. O&M Materials	29	31	81	122	171	200	243	272	290	309
6. Pumping Cost	39	42	79	105	60	157	232	263	296	319
Sub- Total	2387	2564	2319	2372	3384	3984	5853	6817	7869	8473
F. Gross Receipts Tax-$1000/yr	124	130	141	184	232	260	385	425	465	483
G. Required Revenues- $1000/yr	3220	3388	3661	4794	6038	6772	10016	11041	12082	12568
H. Unit Cost of Heat - $/MBtu										
1. Fixed Expenses	$2.72	$2.66	$2.65	$3.99	$3.51	$3.49	$3.81	$3.62	$3.41	$3.28
2. Replacement Electricity	$0.00	$0.00	$0.00	$1.59	$1.80	$1.95	$3.13	$3.38	$3.63	$3.90
3. Operating Expenses	$9.15	$9.82	$5.12	$2.63	$3.09	$3.56	$2.76	$3.12	$3.53	$3.80
4. Gross Receipts Tax	$0.47	$0.50	$0.31	$0.33	$0.34	$0.36	$0.39	$0.40	$0.42	$0.44
	$12.33	$12.98	$8.08	$8.54	$8.74	$9.36	$10.09	$10.53	$10.99	$11.43

Table 9-12 (Sheet 2 of 2)

CALCULATED UNIT COST FOR HOT WATER DISTRICT HEAT, 1995-2004

Start of Evaluation 1985

Unit Costs	1983	Escalation
Electricity - $/MWh	51.44	7.5
Pumping Power-$/MWh	51.44	7.5
Refuse Heat-$/MWt	4.81	7.5
Gas - $/MBtu	5.13	7.5
O&M Labor -$/ManYr	35000	6.5
O&M Materials -% Cost	----	6.5
Property Taxes - %	0	

Economic Factors

Preferred Stock Ratio	0	Book Life - Yrs	30
Return on Preferred Stock - %	0	Income Tax Rate - %	0
Common Stock Ratio	0	Tax Credit - %	0
Return on Common Stock - %	0	Tax Life - Yrs	30
Debt Ratio	1	Accel. Tax Deprec.	0
Debt Cost - %	7	Insurance Rate - %	0.5
Weighted Cost of Capital - %	7	Gross Receipts Tax-%	4

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
A. Annual Quantities										
1. Heat Sales - MWt/yr	322157	322157	322157	322157	322157	322157	322157	322157	322157	322157
2. Refuse Heat - MWt/yr	119762	119762	119762	119762	119762	119762	119762	119762	119762	119762
3. Gas Consumed - MBtu/yr	141238	141238	141238	141238	141238	141238	141238	141238	141238	141238
4. Electricity Loss - MWh/yr	35128	35128	35128	35128	35128	35128	35128	35128	35128	35128
5. Pumping Energy - Mwh/yr	2796	2796	2796	2796	2796	2796	2796	2796	2796	2796
6. O&M Labor - ManYr/yr	8	8	8	8	8	8	8	8	8	8
7. O&M Material-% year's Inv	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
B. Unit Costs										
1. Replacement Elec. - $/MWh	131.33	141.18	151.77	163.15	175.39	188.54	202.68	217.89	234.23	251.79
2. Pumping Electricity-$/MWh	122.52	131.71	141.59	152.20	163.62	175.89	189.08	203.26	218.51	234.90
3. Refuse Heat - $/MWt	12.33	13.55	15.14	17.09	18.68	21.25	22.47	25.46	26.62	26.13
4. Fuel - $/MBtu	12.22	13.13	14.12	15.18	16.32	17.54	18.86	20.27	21.79	23.43
5. O&M Labor - $1000/ManYr	75	79	85	90	96	102	109	116	123	131
C. Investments - $1000	0	0	0	0	0	0	0	0	0	0
D. Annual Carrying Charges-$100										
1. Return on Preferred Stock	48	44	40	36	32	29	26	24	22	20
2. Return on Common Stock	272	246	223	201	181	164	148	134	122	112
3. Interest	1475	1398	1322	1249	1178	1108	1040	974	909	847
4. Book Depreciation	966	966	966	966	966	966	966	966	966	966
5. Tax Depreciation	1353	1291	1230	1168	1106	1044	983	921	859	825
6. Income Taxes	86	89	93	100	109	119	132	146	162	168
7. Deferred Taxes	167	139	111	82	54	25	-3	-31	-60	-75
8. Property Tax	317	325	333	342	350	359	368	377	387	396
9. Insurance	148	148	148	148	148	148	148	148	148	148
Sub- Total	3480	3355	3237	3125	3018	2919	2825	2738	2656	2582
E. Operating Expenses - $1000/										
1. Replacement Electricity	4613	4959	5331	5731	6161	6623	7120	7654	8228	8845
2. Refuse Heat	1477	1623	1813	2047	2237	2545	2691	3049	3188	3129
3. Fuel	1726	1855	1994	2144	2305	2477	2663	2863	3078	3309
4. O&M Labor	596	635	676	720	767	817	870	926	987	1051
5. O&M Materials	329	350	373	397	423	451	480	511	544	580
6. Pumping Cost	343	368	396	426	457	492	529	568	611	657
Sub- Total	9083	9791	10584	11465	12350	13405	14353	15572	16636	17570
F. Gross Receipts Tax-$1000/yr	503	526	553	584	615	653	687	732	772	806
G. Required Revenues- $1000/yr	13066	13672	14374	15173	15983	16976	17865	19042	20064	20958
H. Unit Cost of Heat - $/MBtu										
1. Fixed Expenses	$3.17	$3.05	$2.94	$2.84	$2.75	$2.65	$2.57	$2.49	$2.42	$2.35
2. Replacement Electricity	$4.20	$4.51	$4.85	$5.21	$5.60	$6.02	$6.48	$6.96	$7.48	$8.04
3. Operating Expenses	$4.07	$4.39	$4.78	$5.21	$5.63	$6.17	$6.58	$7.20	$7.65	$7.94
4. Gross Receipts Tax	$0.46	$0.48	$0.50	$0.53	$0.56	$0.59	$0.62	$0.67	$0.70	$0.73
	$11.88	$12.43	$13.07	$13.80	$14.54	$15.44	$16.25	$17.32	$18.25	$19.06

Table 9-13

HOT WATER RADIATION CONSUMER RETROFIT PAYBACK

COST COMPARISON FOR:HOT WATER

PRESENT YEAR:	1984
HOOKUP YEAR:	1985
TOTAL CONVERSION COST (PRESENT YEAR):	$55,000
ESCALATION RATE:	6.50%
TOTAL CONVERSION COST (HOOKUP YEAR):	$58,575
PERCENT FINANCED:	100%
CASH INVESTMENT:	$0
TERM OF LOAN (YEARS):	20
INTEREST RATE:	12.00%
ANNUAL PAYMENT:	$7,842
TAX RATE:	50%
EXPENSING DEDUCTION:	$5,000
YEARS OF DEPRECIATION:	5
ACCELERATED DEPRECIATION? (1=YES,0=NO):	1
POTENTIAL END USE ENERGY SAVINGS FROM CONVERSION:	0%
ESTIMATED CURRENT SYSTEM EFFICIENCY:	55%
HEATING EQUIPMENT TYPE:	OIL BOILER

Cost: $55/kWt

	------------ CURRENT ANNUAL FUEL USE ------------			
	PRIMARY	BACKUP	BACKUP	TOTAL
FUEL TYPE:	OIL			
CONSUMPTION (MILLION BTU):	13843			13843
ESTIMATED DH CONSUMPTION (MILLION BTU):				7614
CURRENT FUEL RATE ($/MILLION BTU):	8.43			
FUEL ESCALATION RATE:	7.50%			

YEAR	CURRENT FUEL RATE $/MMBTU	DH FUEL RATE $/MMBTU	CURRENT ENERGY COSTS	I-------- DISTRICT HEATING --------I ENERGY COSTS	CONVERSION AMORTIZATION PRINC.	INTER.	TOTAL COSTS	TAX EFFECTS ($)	DISTRICT HEATING SAVINGS ($)	CUMULATIVE SAVINGS ($)	ENERGY COST SAVINGS ($)
1985	9.06	12.33	125449	93876	813	7029	101718	-5754	17977	17977	31572
1986	9.74	12.98	134857	98825	911	6931	106667	-8657	19533	37510	36032
1987	10.47	8.08	144972	61518	1020	6822	69360	-32690	42921	80431	83453
1988	11.26	8.54	155845	65021	1142	6700	72863	-36437	46545	126977	90824
1989	12.10	8.74	167533	66543	1279	6563	74385	-41588	51560	178536	100990
1990	13.01	9.36	180098	71264	1433	6409	79106	-51212	49780	228316	108834
1991	13.99	10.09	193605	76822	1605	6237	84664	-55273	53668	281984	116783
1992	15.03	10.53	208126	80172	1797	6045	88014	-60955	59157	341142	127954
1993	16.16	10.99	223735	83674	2013	5829	91516	-67116	65103	406245	140061
1994	17.37	11.43	240515	87024	2254	5588	94866	-73952	71697	477942	153491
1995	18.68	11.88	258554	90450	2525	5317	98292	-81393	78868	556811	168104
1996	20.08	12.43	277945	94638	2828	5014	102480	-89147	86319	643130	183308
1997	21.58	13.07	298791	99510	3167	4675	107352	-97303	94136	737265	199281
1998	23.20	13.80	321201	105068	3547	4295	112910	-105919	102371	839637	216132
1999	24.94	14.54	345291	110702	3973	3869	118544	-115360	111387	951023	234588
2000	26.81	15.44	371187	117555	4450	3392	125397	-125120	120670	1071694	253633
2001	28.83	16.25	399026	123722	4984	2858	131564	-136223	131239	1202933	275305
2002	30.99	17.32	428953	131868	5582	2260	139710	-147412	141831	1344764	297085
2003	33.31	18.25	461125	138949	6252	1590	146791	-160293	154041	1498805	322176
2004	35.81	19.06	495709	145116	7002	840	152958	-174876	167875	1666680	350593

PAYBACK (NO FINANCING) IN YEAR: 1987

PAYBACK (WITH FINANCING) IN YEAR: 1987

Table 9-14

TWO PIPE STEAM RADIATION CONSUMER RETROFIT PAYBACK

COST COMPARISON FOR:STEAM-2P
PRESENT YEAR: 1984
HOOKUP YEAR: 1985
TOTAL CONVERSION COST (PRESENT YEAR):$176,000
ESCALATION RATE: 6.50%
TOTAL CONVERSION COST (HOOKUP YEAR):$187,440
PERCENT FINANCED: 100%
CASH INVESTMENT: $0
TERM OF LOAN (YEARS): 20 Cost: $175/kWt
INTEREST RATE: 12.00%
ANNUAL PAYMENT: $25,094
TAX RATE: 50%
EXPENSING DEDUCTION: $5,000
YEARS OF DEPRECIATION: 5
ACCELERATED DEPRECIATION? (1=YES,0=NO): 1
POTENTIAL END USE ENERGY SAVINGS FROM CONVERSION: 13%
ESTIMATED CURRENT SYSTEM EFFICIENCY: 55%
HEATING EQUIPMENT TYPE:OIL BOILER

	CURRENT ANNUAL FUEL USE PRIMARY	BACKUP	BACKUP	TOTAL
FUEL TYPE:	OIL			
CONSUMPTION (MILLION BTU):	13843			13843
ESTIMATED DH CONSUMPTION (MILLION BTU):				5814
CURRENT FUEL RATE ($/MILLION BTU):	8.43			
FUEL ESCALATION RATE:	7.50%			

YEAR	CURRENT FUEL RATE $/MMBTU	DH FUEL RATE $/MMBTU	CURRENT ENERGY COSTS	DISTRICT HEATING ENERGY COSTS	CONVERSION AMORTIZATION PRINC.	INTER.	TOTAL COSTS	TAX EFFECTS ($)	DISTRICT HEATING SAVINGS ($)	CUMULATIVE SAVINGS ($)	ENERGY COST SAVINGS ($)
1985	9.06	12.33	125449	71687	2601	22493	96782	549	29216	29216	53761
1986	9.74	12.98	134857	75466	2914	22181	100561	1463	35760	64976	59391
1987	10.47	8.08	144972	46978	3263	21831	72072	-18925	53974	118950	97994
1988	11.26	8.54	155845	49652	3655	21439	74746	-23220	57878	176828	106192
1989	12.10	8.74	167533	50815	4093	21001	75909	-28702	62921	239750	116718
1990	13.01	9.36	180098	54420	4585	20510	79514	-52584	48000	287749	125678
1991	13.99	10.09	193605	58664	5135	19959	83758	-57491	52356	340105	134941
1992	15.03	10.53	208126	61222	5751	19343	86316	-63780	58029	398135	146904
1993	16.16	10.99	223735	63897	6441	18653	88991	-70593	64152	462286	159839
1994	17.37	11.43	240515	66455	7214	17880	91549	-78090	70876	533162	174060
1995	18.68	11.88	258554	69071	8080	17015	94165	-86234	78154	611317	189483
1996	20.08	12.43	277945	72269	9049	16045	97363	-94816	85767	697083	205677
1997	21.58	13.07	298791	75990	10135	14959	101084	-103921	93786	790869	222801
1998	23.20	13.80	321201	80234	11351	13743	105328	-113612	102260	893130	240967
1999	24.94	14.54	345291	84536	12714	12381	109631	-124187	111473	1004603	260754
2000	26.81	15.44	371187	89769	14239	10855	114863	-135282	121042	1125645	281418
2001	28.83	16.25	399026	94478	15948	9146	119573	-147701	131753	1257398	304548
2002	30.99	17.32	428953	100700	17862	7233	125794	-160511	142649	1400047	328254
2003	33.31	18.25	461125	106107	20005	5089	131201	-174965	154960	1555007	355018
2004	35.81	19.06	495709	110816	22406	2689	135910	-191102	168697	1723704	384893

PAYBACK (NO FINANCING) IN YEAR: 1988

PAYBACK (WITH FINANCING) IN YEAR: 1968

Table 9-15

ONE PIPE STEAM RADIATION CONSUMER RETROFIT PAYBACK

COST COMPARISON FOR:STEAM-1P
PRESENT YEAR: 1984
HOOKUP YEAR: 1985
TOTAL CONVERSION COST (PRESENT YEAR):$500,000
ESCALATION RATE: 6.50%
TOTAL CONVERSION COST (HOOKUP YEAR):$532,500
PERCENT FINANCED: 100%
CASH INVESTMENT: $0
TERM OF LOAN (YEARS): 20
INTEREST RATE: 12.00%
ANNUAL PAYMENT: $71,290
TAX RATE: 50%
EXPENSING DEDUCTION: $5,000
YEARS OF DEPRECIATION: 5
ACCELERATED DEPRECIATION? (1=YES,0=NO): 1
POTENTIAL END USE ENERGY SAVINGS FROM CONVERSION: 15%
ESTIMATED CURRENT SYSTEM EFFICIENCY: 55%
HEATING EQUIPMENT TYPE:OIL BOILER

Cost: $500/kWt

	------------- CURRENT ANNUAL FUEL USE ------------			
	PRIMARY	BACKUP	BACKUP	TOTAL
FUEL TYPE:	OIL			
CONSUMPTION (MILLION BTU):	13843			13843
ESTIMATED DH CONSUMPTION (MILLION BTU):				5537
CURRENT FUEL RATE ($/MILLION BTU):	8.43			
FUEL ESCALATION RATE:	7.50%			

YEAR	CURRENT FUEL RATE $/MMBTU	DH FUEL RATE $/MMBTU	CURRENT ENERGY COSTS	I-------- DISTRICT HEATING --------I ENERGY COSTS	CONVERSION AMORTIZATION PRINC.	INTER.	TOTAL COSTS	TAX EFFECTS ($)	DISTRICT HEATING SAVINGS ($)	CUMULATIVE SAVINGS ($)	ENERGY COST SAVINGS ($)
1985	9.06	12.33	125449	68274	7390	63900	139564	45425	31310	31310	57175
1986	9.74	12.98	134857	71873	8277	63013	143163	58039	49733	81043	62985
1987	10.47	8.08	144972	44741	9271	62020	116031	36282	65223	146265	100231
1988	11.26	8.54	155845	47288	10383	60907	118578	31563	68829	215095	108557
1989	12.10	8.74	167533	48395	11629	59661	119686	25649	73497	288591	119138
1990	13.01	9.36	180098	51828	13024	58266	123119	-35002	21977	310569	128270
1991	13.99	10.09	193605	55870	14587	56703	127161	-40516	25928	336497	137735
1992	15.03	10.53	208126	58307	16338	54953	129597	-47433	31095	367592	149819
1993	16.16	10.99	223735	60854	18298	52992	132144	-54945	36646	404239	162881
1994	17.37	11.43	240515	63290	20494	50796	134581	-63214	42720	446959	177225
1995	18.68	11.88	258554	65782	22954	48337	137072	-72218	49264	496223	192772
1996	20.08	12.43	277945	68827	25708	45582	140118	-81768	56060	552282	209118
1997	21.58	13.07	298791	72371	28793	42497	143662	-91961	63168	615451	226420
1998	23.20	13.80	321201	76413	32248	39042	147704	-102872	70624	686075	244787
1999	24.94	14.54	345291	80511	36118	35172	151801	-114804	78686	764760	264780
2000	26.81	15.44	371187	85494	40452	30838	156785	-127427	86975	851736	285693
2001	28.83	16.25	399026	89980	45306	25984	161270	-141531	96225	947961	309047
2002	30.99	17.32	428953	95904	50743	20547	167195	-156251	105508	1053469	333049
2003	33.31	18.25	461125	101054	56832	14458	172344	-172806	115974	1169443	360071
2004	35.81	19.06	495709	105539	63652	7638	176829	-191266	127614	1297057	390170

PAYBACK (NO FINANCING) IN YEAR: 1990

PAYBACK (WITH FINANCING) IN YEAR: 1994

Table 9-16

FORCED AIR CONSUMER RETROFIT PAYBACK

COST COMPARISON FOR: FORCED AIR
PRESENT YEAR: 1984
HOOKUP YEAR: 1985
TOTAL CONVERSION COST (PRESENT YEAR): $140,000
ESCALATION RATE: 6.50%
TOTAL CONVERSION COST (HOOKUP YEAR): $149,100
PERCENT FINANCED: 100%
CASH INVESTMENT: $0
TERM OF LOAN (YEARS): 20   Cost: $140/kWt
INTEREST RATE: 12.00%
ANNUAL PAYMENT: $19,961
TAX RATE: 50%
EXPENSING DEDUCTION: $5,000
YEARS OF DEPRECIATION: 5
ACCELERATED DEPRECIATION? (1=YES,0=NO): 1
POTENTIAL END USE ENERGY SAVINGS FROM CONVERSION: 0%
ESTIMATED CURRENT SYSTEM EFFICIENCY: 55%
HEATING EQUIPMENT TYPE: OIL BOILER

	------------- CURRENT ANNUAL FUEL USE -------------			
	PRIMARY	BACKUP	BACKUP	TOTAL
FUEL TYPE:	OIL			
CONSUMPTION (MILLION BTU):	13843			13843
ESTIMATED DH CONSUMPTION (MILLION BTU):				7614
CURRENT FUEL RATE ($/MILLION BTU):	8.43			
FUEL ESCALATION RATE:	7.50%			

YEAR	CURRENT FUEL RATE $/MMBTU	DH FUEL RATE $/MMBTU	CURRENT ENERGY COSTS	I-------- DISTRICT HEATING --------I ENERGY COSTS	CONVERSION AMORTIZATION PRINC.	CONVERSION AMORTIZATION INTER.	TOTAL COSTS	TAX EFFECTS ($)	DISTRICT HEATING SAVINGS ($)	CUMULATIVE SAVINGS ($)	ENERGY COST SAVINGS ($)
1985	9.06	12.33	125449	93876	2069	17892	113838	6467	18078	18078	31572
1986	9.74	12.98	134857	98825	2318	17644	118787	6657	22728	40806	36032
1987	10.47	8.08	144972	61518	2596	17366	81480	-17913	45579	86385	83453
1988	11.26	8.54	155845	65021	2907	17054	84982	-21754	49108	135493	90824
1989	12.10	8.74	167533	66543	3256	16705	86505	-27012	54017	189509	100990
1990	13.01	9.36	180098	71264	3647	16314	91225	-46260	42613	232122	108834
1991	13.99	10.09	193605	76822	4084	15877	96783	-50453	46369	278491	116783
1992	15.03	10.53	208126	80172	4575	15387	100133	-56284	51709	330200	127954
1993	16.16	10.99	223735	83674	5124	14838	103635	-62612	57488	387688	140061
1994	17.37	11.43	240515	87024	5738	14223	106985	-69634	63896	451584	153491
1995	18.68	11.88	258554	90450	6427	13534	110411	-77285	70858	522442	168104
1996	20.08	12.43	277945	94638	7198	12763	114599	-85272	78074	600516	183308
1997	21.58	13.07	298791	99510	8062	11899	119472	-93691	85629	686144	199281
1998	23.20	13.80	321201	105068	9029	10932	125030	-102600	93571	779715	216132
1999	24.94	14.54	345291	110702	10113	9848	130664	-112370	102257	881972	234588
2000	26.81	15.44	371187	117555	11327	8635	137516	-122499	111172	993144	253633
2001	28.83	16.25	399026	123722	12686	7276	143683	-134015	121329	1114473	275305
2002	30.99	17.32	428953	131868	14208	5753	151830	-145666	131458	1245931	297085
2003	33.31	18.25	461125	138949	15913	4048	158910	-159064	143151	1389082	322176
2004	35.81	19.06	495709	145116	17823	2139	165077	-174227	156405	1545486	350593

PAYBACK (NO FINANCING) IN YEAR: 1988

PAYBACK (WITH FINANCING) IN YEAR: 1989

Table 9-17

STEAM AIR HANDLER CONSUMER RETROFIT PAYBACK

Cost: $250/kWt

COST COMPARISON FOR:	STEAM AIR HANDLERS
PRESENT YEAR:	1984
HOOKUP YEAR:	1985
TOTAL CONVERSION COST (PRESENT YEAR):	$250,000
ESCALATION RATE:	6.50%
TOTAL CONVERSION COST (HOOKUP YEAR):	$266,250
PERCENT FINANCED:	100%
CASH INVESTMENT:	$0
TERM OF LOAN (YEARS):	20
INTEREST RATE:	12.00%
ANNUAL PAYMENT:	$35,645
TAX RATE:	50%
EXPENSING DEDUCTION:	$5,000
YEARS OF DEPRECIATION:	5
ACCELERATED DEPRECIATION? (1=YES,0=NO):	1
POTENTIAL END USE ENERGY SAVINGS FROM CONVERSION:	13%
ESTIMATED CURRENT SYSTEM EFFICIENCY:	55%
HEATING EQUIPMENT TYPE:	OIL BOILER

	CURRENT ANNUAL FUEL USE			
	PRIMARY	BACKUP	BACKUP	TOTAL
FUEL TYPE:	OIL			
CONSUMPTION (MILLION BTU):	13843			13843
ESTIMATED DH CONSUMPTION (MILLION BTU):				5814
CURRENT FUEL RATE ($/MILLION BTU):	8.43			
FUEL ESCALATION RATE:	7.50%			

YEAR	CURRENT FUEL RATE $/MMBTU	DH FUEL RATE $/MMBTU	CURRENT ENERGY COSTS	DISTRICT HEATING ENERGY COSTS	DISTRICT HEATING CONVERSION AMORTIZATION PRINC.	DISTRICT HEATING CONVERSION AMORTIZATION INTER.	DISTRICT HEATING TOTAL COSTS	TAX EFFECTS ($)	DISTRICT HEATING SAVINGS ($)	CUMULATIVE SAVINGS ($)	ENERGY COST SAVINGS ($)
1985	9.06	12.33	125449	71687	3695	31950	107333	11188	29304	29304	53761
1986	9.74	12.98	134857	75466	4139	31507	111112	14795	38541	67845	59391
1987	10.47	8.08	144972	46978	4635	31010	82623	-6061	56288	124133	97994
1988	11.26	8.54	155845	49652	5192	30454	85297	-10438	60109	184242	106192
1989	12.10	8.74	167533	50815	5815	29831	86460	-16012	65060	249303	116718
1990	13.01	9.36	180098	54420	6512	29133	90065	-48273	41760	291063	125678
1991	13.99	10.09	193605	58664	7294	28352	94309	-53295	46001	337064	134941
1992	15.03	10.53	208126	61222	8169	27476	96867	-59714	51545	388609	146904
1993	16.16	10.99	223735	63897	9149	26496	99542	-66671	57522	446131	159839
1994	17.37	11.43	240515	66455	10247	25398	102100	-74331	64084	510215	174060
1995	18.68	11.88	258554	69071	11477	24168	104716	-82657	71180	581395	189483
1996	20.08	12.43	277945	72269	12854	22791	107914	-91443	78589	659984	205677
1997	21.58	13.07	298791	75990	14397	21249	111635	-100776	86380	746364	222801
1998	23.20	13.80	321201	80234	16124	19521	115879	-110723	94599	840963	240967
1999	24.94	14.54	345291	84536	18059	17586	120182	-121584	103525	944488	260754
2000	26.81	15.44	371187	89769	20226	15419	125414	-133000	112774	1057261	281418
2001	28.83	16.25	399026	94478	22653	12992	130124	-145778	123125	1180386	304548
2002	30.99	17.32	428953	100700	25372	10274	136345	-158990	133619	1314004	328254
2003	33.31	18.25	461125	106107	28416	7229	141752	-173895	145478	1459483	355018
2004	35.81	19.06	495709	110816	31826	3819	146461	-190537	158711	1618194	384893

PAYBACK (NO FINANCING) IN YEAR: 1989

PAYBACK (WITH FINANCING) IN YEAR: 1989