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COOLING

DISTRICT HEATING AND COOLING SYSTEM FOR COMMUNITIES
THROUGH POWER PLANT RETROFIT AND DISTRIBUTION
NETWORK

Final Report, Phase 1

MASTER

June 1979

Work Performed Under Contract No. EM-78-C-02-4980

Minnesota Energy Agency
Saint Paul, Minnesota

U. S. DEPARTMENT OF ENERGY

Division of Industrial Energy Conservation

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Final Report

Phase 1

**Minnesota Energy Agency
150 East Kellogg Boulevard
Saint Paul, Minnesota
55101**

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RB

PREFACE

Minnesota has actively pursued district heating research and development since 1975. The Minnesota Project, which is described in this report, is an essential part of that research and development effort. If the work initiated through the Minnesota Project can be successfully completed, it will lead to the construction of at least one demonstration district heating system in the state and will provide both valuable information and a timely stimulus to a number of Minnesota communities where district heating might prove to be an economically attractive alternative to increasingly scarce and expensive energy sources.

The Minnesota Project started with a survey of all steam turbine power plants in the state to identify those plants that could be retrofitted for district heating. Those plants -- 39 in all -- were subsequently matched with potential service areas in nearby communities. The most promising power plant/service area pairs were then subjected to further study, including an assessment of retrofit schemes and an assessment of pertinent economic and institutional issues. As a result of this screening and assessment process, which was carried out between September 1, 1978, and May 1, 1979, three especially promising communities were chosen to be carried into Phase 2 of the study -- Red Wing, Moorhead, and Fergus Falls.

The project team was headed by the Minnesota Energy Agency, who served as prime contractor to the DOE, and included KVB, Inc., who conducted the technical assessment of retrofit schemes, and Touche Ross and Company, who carried out the assessment of economic and institutional issues. Other members of the team included Fjärrvärmebyrå ab, a leading Swedish distribution system design firm who developed distribution schemes for nine Minnesota communities as part of the project, and Metcalf and Eddy, an architect/engineer firm who assisted KVB and Fjärrvärmebyrå in adapting European district heating technology to Minnesota conditions.

The study completed by this team is a good study. We are excited to be involved in DOE's district heating demonstration project and are pleased to report the progress made during Phase 1.

Algernon Johnson
Director
Minnesota Energy Agency

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1. INTRODUCTION AND SUMMARY

Project Scope and Objectives

This study of district heating in Minnesota is part of the Minnesota Energy Agency's effort to encourage the application of district heating as an energy conserving measure. The study was funded by the United States Department of Energy as part of its program to demonstrate the use of heat produced as a by-product of electrical generation in existing condensing electric power plants as a source for district heating. Phase 1 of this program, the results of which are reported herein, entailed a survey and analysis of potential demonstration sites with the objective of identifying the most attractive site(s) for actual implementation. This study has been, in some respects, patterned after an earlier study of Swedish cities performed by the Swedish District Heating Society. That survey has proven valuable in directing the expansion of an already highly successful district heating program in Sweden.

To achieve the objective stated above, the DOE established a program to identify district heating and cooling opportunities and to assess the technical, economic, and legal feasibility of retrofitting an existing power plant and constructing a thermal distribution network to supply thermal energy to an identified service area. The program, as outlined by the DOE in RFP EM-78-R-02-0008, set out the following agenda of work:

1. Establish demonstration teams with, or with access to, expertise and information necessary for evaluating technical, legal, economic, and marketing issues related to the utilization of heat derived as a by-product of power generation to supply district heating and cooling.
2. Identify areas that potentially can be serviced by a district heating and cooling system created by retrofitting nearby base or intermediate-loaded electric generating plants.
3. Assess the impediments to establishing district heating and cooling systems in jurisdictions already served by existing utilities.

4. Determine how a district heating and cooling system can be established under existing law without acquiring an obligation to expand to meet a utility-type obligation to serve all customers demanding service.
5. Establish that any impediments to constructing thermal distribution networks to supply thermal energy to a multiplicity of customers can be overcome.
6. Establish that such demonstration systems will substitute scarce fuels currently used for space heating and cooling with heat derived as a by-product of electric power generation and assess the energy conservation and the fuel substitution effect of each system.
7. Establish techniques and arrangements for allocating electrical and thermal production to optimize plant utilization.
8. Establish cost allocation techniques for apportioning production costs to thermal and electrical services.
9. Establish ownership and operating arrangements consistent with technological and institutional considerations.

Summary

The Minnesota Project began with a survey of the existing power plants in Minnesota. This survey identified and categorized the existing thermal power plants, the potential associated district heating service areas and the characteristics of these service areas. The power plants ranged from the 1550 MWe of Sherco 1 and 2 units of Northern States Power to the 3-5 MWe municipally owned and operated units of the cities of Madison and Blue Earth.

A process was developed to determine the most attractive combination of service areas and sources. As the number of prospective sites was narrowed, the amount of detailed investigation was increased so that progressively more information was available on the more attractive sites.

Due to the requirements and goals of this program, all power plants that were not base or intermediate loaded (i.e., 3000 hours or more per year at 65% load factor) in the past three years were excluded from further consideration. Also, some units were presently serving in a cogeneration mode as sources for steam district heating systems and thus could not serve as a power plant retrofit demonstration. It should be noted, however, that neither of the above criteria is fundamentally adverse to the success of modern district heating; indeed, the latter might in some instances be a highly positive factor.

Following this initial survey, a pairing of communities and power plants was made in order to make a rough check of "thermal electric balance." It became immediately apparent that pairs such as Prairie Island 1 and 2 (1100 MWe) and Hastings or Red Wing (40 MWe) were not practical. This process showed that Black Dog, High Bridge, Riverside, Alan King, Sherco, Monticello, and Prairie Island (all Northern States Power Company generating stations) were all excellent potential sources for Twin Cities district heating but could not be effectively matched with smaller nearby communities.

Site visits were then made and initial conceptual designs were drafted for distribution systems in each community. These site visits served as the basis for detailed examination of Swedish district heating distribution technology as it would apply to Minnesota conditions. The results of the service area evaluation indicated that nine sites were potentially viable from the standpoint of distribution system economics and conversion technology. The

range in estimated implementation costs was fairly small, and none of the nine sites was especially attractive or unattractive.

Further investigation into the characteristics of the nine power plants indicated more basic factors for site selection. These include preferences of the owner utility, fuel type, emission compliance status and the nature of the existing source for district heating. These factors eliminated four of the nine subject sites. The remaining five were subject of an initial study of institutional and market factors, as well as more extensive technical and economic evaluation. As a result of these evaluations, Rochester and Duluth were eliminated, primarily due to factors relating to the presence of an existing steam system in these cities, leaving the cities of Moorhead, Red Wing, and Fergus Falls to be examined in detail.

No major difficulties with plant retrofit have been identified at these three sites, although the numerous options require extensive analysis. Presently, it appears that a progressive approach to conversion, where applicable, may have a favorable impact on the overall economics. Also, although power plant derating is a concern, it is also possible to increase short term power plant capacity through the use of thermal storage in the district heat system.

Detailed economic analyses of the three proposed district heating systems were completed as part of the study. These analyses considered the distribution system cost, construction and hook-up phasing, power plant retrofit alternatives and phasing, as well as ownership options. Overall economic viability will, of course, depend on many factors outside the system itself. Primarily, these are the future prices and availability of alternative sources of energy. It appears that district heating through the retrofit of existing power plants may be economically attractive in some Minnesota cities. District heating will be capital intensive, and the economic success will be dependent on successful technology transfer and the resolution of institutional issues. Neither of these present serious problems at the present time.

2. A. SITE IDENTIFICATION PROCESS

Identification Process and Initial Inventory

Level 1: Initial Inventory

The site identification process employed in this study was a five-step process which started with a survey of all electric generating plants in Minnesota to identify potential retrofit opportunities. This initial survey identified all steam turbine power plants currently in operation in the state. Diesel and gas turbine generating plants were, for the purposes of this study, eliminated from further consideration at this point because the technology for capturing waste heat from these types of plants is substantially different from steam extraction techniques, and it was decided that the examination of such technology fell outside the scope of the present study. The initial survey identified 39 steam turbine generating plants and their associated service areas. These plants, which are listed in Exhibit 2-1, were scattered around the state and ranged in size from 1550 MWe (Sherco 1 and 2) down to 3 MWe (Madison).

This initial survey, and the inventory of potential sites which resulted from it, constituted the first step (Level 1) of the identification process. A description of the process, including screening levels, constraints, and the number of sites remaining after each screening, is presented in Exhibit 2-2 and Exhibit 2-3. As the number of prospective sites was narrowed, the level of analytical effort was increased so that progressively more information was collected and assessed pertaining to the more attractive sites. The process which lead to the final selection of Moorhead, Red Wing, and Fergus Falls is discussed in detail below.

Level 2: Load and Retrofit Constraints

The second step in the site identification process (Level 2) involved screening the 39 sites in the initial inventory to determine which of them met certain criteria stipulated in the DOE guidelines for the program. To qualify

Exhibit 2-1

Inventory of Steam Turbine Power Plants in Minnesota

<u>Plant Name</u>	<u>Potential Service Area(s)</u>
1. Laskin	Aurora, Hibbing, Virginia
2. Clay Boswell	Grand Rapids, Duluth
3. Hibbard	Duluth
4. Hibbing	Hibbing
5. Virginia	Virginia
6. Two Harbors	Two Harbors
7. Moorhead	Moorhead
8. Detroit Lakes	Detroit Lakes
9. Hoot Lake	Fergus Falls
10. Alexandria	Alexandria
11. Litchfield	Litchfield
12. Willmar	Willmar
13. Minnesota Valley	Granite Falls
14. Ortonville	Ortonville
15. Madison	Madison
16. Monticello	Monticello, St. Cloud, Minneapolis-St. Paul
17. Sherburne	Becker, St. Cloud, Minneapolis-St. Paul
18. Elk River	Elk River
19. Luverne	Luverne
20. Worthington	Worthington
21. Fox Lake	--
22. Wilmarth	Mankato
23. Blue Earth	Blue Earth

Exhibit 2-1 (Continued)

Inventory of Steam Turbine Power Plants in Minnesota

<u>Plant Name</u>	<u>Potential Service Area(s)</u>
24. Fairmont	Fairmont
25. New Ulm	New Ulm
26. Sleepy Eye	Sleepy Eye
27. Springfield	Springfield
28. Albert Lea	Albert Lea
29. Red Wing	Red Wing
30. Prairie Island	Hastings, Red Wing, Minneapolis-St. Paul
31. Austin-Downtown	Austin
32. Austin-North Broadway	Austin
33. Rochester-North Broadway	Rochester
34. Rochester-Silver Lake	Rochester
35. Owatonna	Owatonna
36. King	Stillwater, Minneapolis-St. Paul
37. Black Dog	Minneapolis-St. Paul
38. High Bridge	Minneapolis-St. Paul
39. Riverside	Minneapolis-St. Paul

Exhibit 2-2

Screening Process (Level Constraints)

Constraints	Level 1	Level 2	Level 3	Level 4	Level 5
1. Steam Turbine Plant	●				
2. Base/Intermediate Loaded		●			
3. Retrofit Opportunity		●			
4. Non-Metro Area		●			
5. Thermal/Electric Balance			●		
6. Source/Service Area Distance			●		
7. Emission Compliance				●	
8. Fuel Type				●	
9. Owner Commitment				●	
10. No Current District Heating					●

Exhibit 2-3

Screening Levels

as a potential retrofit opportunity a plant had to be base or intermediate loaded (3000 hours or more per year at 65% load during any twelve consecutive months since January 1, 1975) and could not currently be operating in a cogeneration mode. It should be noted in passing, however, that neither of these constraints is fundamentally adverse to the successful implementation of a district heating system. In fact, the expansion or modification of existing systems might prove especially attractive. These two constraints should be viewed, rather, as specific to the guidelines of the demonstration program, the primary thrust of which is to demonstrate the feasibility of retrofitting a power plant where waste heat is not now put to use. Details on all 39 power plants are presented in Appendix F.

Base or intermediate loading. The program guidelines required that the project consider only base or intermediate loaded power plants as candidate sources for district heating retrofit. A plant was to be considered at or greater than intermediate load if it operated for over 3,000 hours at an equivalent capacity factor of 65% during any twelve month period in the previous four calendar years.

While a non-intermediate loaded power plant might, in a specific instance, be an extremely attractive source for district heat retrofit, a conversion of this plant would not serve to demonstrate the methods, advantages, and problems of retrofitting a more heavily utilized plant. Furthermore, energy savings could not be demonstrated by comparing pre-modification data with post-modification data.

The data pertaining to loading were obtained from the Electrical World directory of utilities as well as from direct communications with power plant operators. It should be noted that the loading constraint was applied on a unit basis within a multi-unit plant. Hence, in some instances a plant will be considered as qualifying even though some units in the plant are peak or standby units. In these cases, only the qualifying unit is considered for initial retrofit. However, all factors relating to all other units will be considered in assessing overall suitability.

Retrofit opportunity. Minnesota has a number of steam district heating systems still in operation. Several of these are supplied by automatic extraction or back pressure steam turbines. An assessment of these systems was

beyond the scope of this report.¹ Since these existing cogeneration supplied steam systems are already utilizing this by-product energy, there appeared to be no retrofit opportunity at these sites that fell within the program guidelines. It should be clearly noted, however, that this exclusion is based on the requirements and the nature of this demonstration project. On an individual and local basis, a number of these existing steam district heat systems are very attractive sites for the introduction of modern hot water distribution system technology.

Twin Cities area exclusion. A third constraint was applied to candidate sites at this step. Because a separate district heating study is being conducted in the Twin Cities, all candidate plants located within the seven-county metropolitan area were excluded from further consideration.

The screening at Level 2 narrowed the candidate sites from 39 to 15. The results of the Level 2 screening are presented in Exhibit 2-4.

Level 3: Thermal/Electric Balance

The screening at Level 3 entailed pairing the candidate power plants -- those remaining after the Level 2 screening -- with nearby potential service areas to determine whether or not the two were compatible. In doing so, it became immediately apparent that such pairs, for example, as Prairie Island 1 and 2 (1100 MWe) and Red Wing (25 MWt) or Hastings (25 MWt) were not balanced. The same pairing process revealed that two other pairs -- Sherco 1 and 2 (1400 MWe) and Becker (5 MWt) and Monticello (550 MWe) and Monticello (15 MWt) -- were also incompatible.

Also considered at this level were source/service area distances. It is obvious that the ideal load is concentrated, continuous, and nearby. Where source/service area distances appeared to be too great, those sites were eliminated from further analysis. It should be noted, however, that the plants at Prairie Island, Sherburne, and Monticello, while they are not in balance with the small communities nearest to them, could be attractive district heating

¹ This information is contained in "Report on Minnesota Municipal District Heating Study," July, 1978. Prepared by Pfeifer and Shultz for the Minnesota Energy Agency.

Exhibit 2-4

Results of Level 2 Screening

Power Plant	Base or Inter- mediate Loading	Retrofit Opportunity	Not Twin Cities	All 3 Preceding
Blue Earth	●		●	
Fairmont	●		●	
New Ulm	●		●	
Sleepy Eye	●		●	
Springfield	●		●	
Albert Lea		●	●	
Red Wing	●	●	●	●
Prairie Island	●	●	●	●
Monticello	●	●	●	●
Sherburne	●	●	●	●
Austin	●		●	
Austin Northeast	●	●	●	●
Owatonna	●	●	●	●
Rochester			●	
North Broadway			●	
Rochester				
Silver Lake	●	●	●	●
Black Dog	●	●		
High Bridge	●	●		
King	●	●		
Riverside	●	●		
Aurora-Laskin	●	●	●	●

Power Plant	Base or Inter- mediate Loading	Retrofit Opportunity	Not Twin Cities	All 3 Preceding
Clay Boswell	●	●	●	●
Hibbing	●		●	
Hibbard	●	●	●	●
Two Harbors		●	●	
Virginia	●		●	
Hoot Lake	●	●	●	●
Moorhead	●	●	●	●
Alexandria			●	
Detroit Lakes	●		●	
Litchfield			●	
Willmar	●		●	
Minnesota Valley	●	●	●	●
Ortonville	●	●	●	●
Madison			●	
Elk River		●	●	
Luverne			●	
Worthington			●	
Fox Lake		●	●	
Willmarth	●	●	●	●

sources for the Twin Cities. The Twin Cities service area, however, was excluded from this study for the reasons mentioned above. The nine sites remaining after Level 3 screening are listed below and shown in Exhibit 2-5.

<u>Power Plant</u>	<u>Owner</u>	<u>Service Area</u>
Hoot Lake	Otter Tail	Fergus Falls
Wilmarth	Northern States Power	Mankato
Hibbard	Minnesota Power & Light	Duluth
Silver Lake	City of Rochester	Rochester
Northeast	City of Austin	Austin
Red Wing	Northern States Power	Red Wing
Owatonna	Owatonna Public Utilities	Owatonna
Ortonville	Otter Tail Power	Ortonville
Moorhead	Moorhead Public Service	Moorhead

Level 4: Retrofit and Distribution Analysis

The nine sites remaining after Level 3 screening were subjected to a more detailed assessment at Level 4. The nine power plants/service areas are described briefly below.

Hoot Lake/Otter Tail Power Company. The Hoot Lake plant of Otter Tail Power is located about one mile east of the central business district. Two of the three units are in compliance with emissions regulations. Unit 1 is out of compliance in particulates and is not being operated. All units are operating under somewhat restrictive cooling water temperature standards. Unit 3 has an external cross-over, 2-cylinder turbine which offers a variety of retrofit opportunities. Fergus Falls has limited supplies of Canadian natural gas.

Wilmarth/NSP. The Wilmarth plant is located on the Minnesota River approximately 1.5 miles northeast of the central business district of Mankato. It is currently in compliance with emission regulations while firing coal at reduced loads. In the future, the plant may require modification for particulate and/or opacity control. The routing from the plant to the central business district passes a solvent extraction oil plant similar to that at Red Wing. The thermal and electric loads will be approximately in balance.

Hibbard/Minnesota Power and Light. The Hibbard plant is located on the Duluth Harbor/St. Louis River about three miles south of the central business

Exhibit 2-5

Sites Remaining After Level 3 Screening

district. It is in compliance with emissions regulations. However, this compliance was achieved by the conversion of the pulverized coal boilers to oil firing. The plant is not now able to fire coal. The plant is located adjacent to a major commercial coal transshipment facility and all varieties of coal are shipped through the Duluth harbor.

Duluth has a high (200 psi) pressure steam system serving a portion of downtown. This system has no condensate return. It is supplied by four pulverized coal boilers in the downtown area. These boilers are out of compliance with emission regulations for particulates. The Duluth area has been designated a non-attainment area for particulates and SOx.

Silver Lake/Rochester Public Utility Department. The Silver Lake plant is located on the south fork of the Zumbro River adjacent to the high density central business district of Rochester. This four-unit, coal fired plant is used solely for electrical generation. Emission controls are provided on all units with electrostatic precipitators. The central business district is presently served by two district heating steam systems; the municipal system originating from the North Broadway plant and the privately owned Franklin Institute.

Austin-Northeast/Austin Utilities. The Northeast plant, a single unit 30 MW condensing turbine for electrical generation, is located approximately two miles northeast of the central business district. Coal is the primary fuel for the Northeast plant. The central business district is currently served by a steam district heating system from the Austin-Downtown steam plant. Geo. Hormel Meat Packing and Processing is the major industrial load located in the potential service area.

Red Wing/NSP. The Red Wing plant is located on the Mississippi River one-half mile south of the central business district of Red Wing. It is currently in compliance with emission regulations, but only marginally, having only multiclone dust collectors. The fuel burned is a mixture of Western (Montana) coal, Eastern (Illinois) coal, and wood chips. The city of Red Wing is fairly compact, being constrained by the bluffs and the river. An industrial load exists at the south end of the business district -- near the power plant. The city is served by natural gas distributed by NSP from domestic supplies. The size and configuration of the town and power plant would allow a number of retrofit concepts with good balance.

Owatonna/Owatonna Public Utilities. The Owatonna Plant is located on the Straight River adjacent to the central business district of Owatonna. Oil and natural gas, primarily oil, are the fuels burned. The plant is not equipped to burn, store, or control emissions from coal. The business district is presently served by a steam district heating system from the plant. Five older, smaller turbines provide good backup capability for the newest (1969), largest (20 MWe) condensing turbine.

Ortonville/Otter Tail Power. The Ortonville plant is located in the town of Ortonville, population 3600, on the Minnesota-South Dakota border. While both town and plant are small, the location of the plant and its up-to-date compliance with emission regulations and use of Western coal make it a technically interesting source. It is also a well-balanced combination. It is a single unit plant and thus any conversion would have to consider the cost of additional backup sources. Ortonville is served by a municipal electric company, hence, Otter Tail Power does not have a utility infra-structure in place.

Moorhead/Moorhead Public Service Department. The Moorhead Municipal Power plant is located on the Red River of the North at the west end of the central business district. It consists of five units, only the largest (22 MWe) of which is operating. This unit is quite new and meets all emissions regulations firing lignite. The electricity produced is being sold to the Missouri Basin Power Coop. Due to the configuration of the plant it might be convertible to cross-compound operation. With the exception of a dairy north of the plant there is no industrial load within range of the plant. The business-commercial area stretches east from the plant. Two small colleges are also candidate loads. Fargo, North Dakota, is directly across the Red River from the plant and could represent an attractive load outside Minnesota. The area is served by Canadian natural gas. Overall, there appears to be a good opportunity for thermal-electric balance.

As part of the Level 4 screening, visits were made to each of the nine sites and, based on data collected during these visits, potential service areas were delineated in each community. These service areas are illustrated in Exhibits 2-6 through 2-14. Preliminary district heating distribution networks were then prepared for each community by Fjärrvärmebyrån ab. These distribution networks are delineated in Exhibit 2-15 through Exhibit 2-23.

Exhibit 2-7

Mankato Service Area

Exhibit 2-8

Duluth Service Area

Exhibit 2-9

Rochester Service Area

Austin Service Area

Exhibit 2-11

Red Wing Service Area

Exhibit 2-12

Owatonna Service Area

Exhibit 2-13

Ortonville Service Area

Exhibit 2-15

Preliminary Distribution System (Fergus Falls)

Preliminary Distribution System (Mankato)

Exhibit 2-17

Preliminary Distribution System (Duluth)

2-24

Exhibit 2-18

Preliminary Distribution System (Rochester)

Exhibit 2-19

Preliminary Distribution System (Austin)

Exhibit 2-20

Preliminary Distribution System (Red Wing)

Red Wing

Legend

□ Floor Area 2000-5000 m²/Block

■ Floor Area >5000 m²/Block

— Distribution Network

FVB

FJÄRRVÄRMEBYRÅN AB
Västerås, Sweden
KRAFTLINJEGATAN 14B, 721 36 VÄSTERÅS
SWELEN 021-14 40 55

Exhibit 2-21

Preliminary Distribution System (Owatonna)

Exhibit 2-22

Preliminary Distribution System (Ortonville)

Exhibit 2-23

Preliminary Distribution System (Moorhead)

In the assessment of the physical extents of the proposed distribution areas, consideration was given to present and anticipated loading densities and the geographical locations of the generation plants in relation to the consumer areas. Obstacles in the form of highways, waterways, industrial concentrations, etc. affecting the pattern of costs were also taken into account.

The resulting assessments revealed that the distribution areas are usually confined to regions consisting of general and commercial buildings (downtown) and isolated districts with high loading densities, provided that these are geographically located so that it will be economically attractive to run district heating mains to them. Such isolated districts usually comprise areas of multi-family dwellings (apartment houses), shopping centers, industrial plants, schools and the like.

Districts comprising single-family houses are not expected to be included in the distribution areas, due primarily to the fact that the distribution costs in such areas are many times higher than in districts with high loading densities. But this does not preclude districts consisting of single-family houses being connected to the district heating system at a future date. If the economic conditions should change due to drastic increases in the cost of natural gas, for instance, connection of such districts may become attractive, and the district heating network can be then supplemented by ring mains through the districts, without necessarily overloading the mains network now proposed for areas with high loading densities.

As a result of the Level 4 screening, four of the nine remaining sites were eliminated from further consideration:

1. Wilmarth/NSP
2. Ortonville/Otter Tail Power Company
3. Owatonna/Owatonna Public Utilities
4. Austin-Northeast/Austin Utilities

It was felt that only one power plant owned by NSP and only one power plant owned by Otter Tail Power should be part of the final five. Mankato and Ortonville were felt to be less desirable district heating opportunities than Red Wing and Fergus Falls and were thus eliminated. Both Owatonna and Austin have existing steam systems using extraction turbines. The program requires a

retrofit of an existing power plant. The retrofit of an extraction steam turbine was not considered appropriate. In addition, Owatonna is presently an oil fired power plant.

Level 5: Final Selection

The remaining five sites were subjected to further study of institutional and market factors as well as more extensive technical and economic evaluation. As a result of this effort, Rochester and Duluth were eliminated from further consideration, primarily due to factors relating to the presence of an existing steam system in each city. The steering committee agreed that detailed analyses were not warranted in either city.

Rochester. The city owns the power plant and a steam district heating and cooling system. St. Mary's Hospital has a cogenerating facility that meets basically all of its electrical, cooling and heating needs. Franklin Station, presently owned by Mayo Medical Clinic, Kahler Hotel and Rochester Methodist Hospital, provides the majority of electrical, cooling and heating needs of its three owners through cogeneration.

The characteristics of the power plant present initial barriers to co-generated district heating. Power plant representatives indicated that they are currently nearing their peak output in the winter. Cogeneration would compound this problem because a temporary derate, at a minimum, would be required during the winter. The situation is further complicated because the city has a back-up power agreement with Dairyland Cooperative which requires the city to maintain its power rating. Given the current near capacity situation and the contractual requirement it appears that any energy plan which impacts generation capacity faces substantial economic and institutional barriers.

In addition, the generating capacity problem also appears to limit the potential market to those customers who do not currently get their heat from cogeneration. Servicing the heating needs of current cogenerators would necessitate serving their electrical needs; which does not seem possible.

The city also owns the district steam heating system. This system services a substantial share of the market not serviced by the two existing cogenerating facilities. Their volume for the fiscal year ended in May of 1978

was approximately $200,000 \times 10^6$ BTU's. This includes approximately 15% cooling use. The current district heating market is the major potential market available to a cogeneration district heating system. Capital expenditures in excess of two million dollars have recently been made by the city to bring their steam heating system into compliance with pollution standards. If the city were to phase out their district steam system for a hot water cogeneration system, the debt service cost associated with these expenditures would have to be recovered through cogeneration revenues. This recent major capital expenditure also creates at least two significant institutional problems. First, it will be difficult to convince the people who made the decision to upgrade the steam system that the system should now be phased out. Regardless of the economic benefit, people are reluctant to consider such recent improvements as a sunk cost before the investment has been recovered or the useful life exhausted. Secondly, it will potentially make it more difficult to obtain a final approval because the decision makers may be leary of having to explain to the public why the recently improved system should be phased out.

The 15% cooling load provided by the steam district system would have to be converted to electrical since current hot water temperature designs in the summer are not sufficient to meet cooling needs. This would be an additional capital expenditure related to cogeneration.

St. Mary's Hospital and Franklin Station represent substantial thermal markets. Assuming that the city could overcome the problems caused by lack of electrical capacity, it is still not clear that they could obtain these markets. The hospitals need highly reliable systems and hospital management believes that this need can be met most effectively by in house systems. In addition, they have cogenerating facilities on site that utilize steam. A switch to a central hot water cogeneration system would mean that they would be faced with having to absorb the costs of retrofitting, distribution lines and conversion to hot water heating. It is unlikely that increased efficiencies related to a larger cogenerating facility would cover these costs.

In summary, Rochester has the following potential market and institutional barriers:

1. Limited available electrical capacity.

2. Limited market potential.
3. Abnormal cogeneration costs related to recent capital improvements and the existence of steam air-conditioning.
4. Significant potential institutional barriers.
5. Competing cogenerating facilities owned and operated by the largest potential users.

Duluth. Duluth is served by Minnesota Power and Light Company, who owns the power plant. A steam district heating system is owned by the city and managed by a cooperative of users.

The characteristics of the power plant present initial barriers to cogenerated district heating. The boilers are currently gas and oil fired. MP&L has performed two feasibility studies on conversion to coal; both studies indicated that it was not economically justified to convert for electrical generation alone. The plant would have to be converted to coal to meet demonstration site guidelines which would mean that the district heating company would have to recover the additional conversion costs not allocated to electrical generation. In addition, the power plant may be used only as a peaking plant after the addition of Boswell #4 to the MP&L system in May of 1980. This also could have a significant adverse impact on economic feasibility.

The current steam district heating company also presents a major barrier to cogenerated district heating. The current system was purchased by the city for approximately \$700,000 in 1978. In addition, the district heating company is already committed to make a substantial capital expenditure to bring the steam plant into pollution control compliance. The capital expenditures involved in the pollution compliance and plant purchase will be in excess of three million dollars. These expenditures and expenditure commitments create substantial economic and institutional barriers which make it unlikely that a commitment could be obtained to convert to a hot water cogeneration system.

The steam system is managed by a cooperative of steam users and the steam company has multiple year contracts with many customers. The steam company services the majority of the market in the dense downtown district. The majority of buildings using steam have no condensate return and many do not have facilities for boilers or large heat exchangers. The steam system does not have a condensate return due to the availability of make-up water from Lake

Superior. Thus the cost of converting these buildings would appear to be very high, making the economics questionable.

In addition it became apparent that:

1. The cogenerated district heating company would have to replace the current district heating company to obtain a sufficient market.
2. Current energy supply contracts would have to be renegotiated with users.
3. Building conversion costs would be higher than other sites due to the existence of single-pipe steam systems.
4. Some building conversions would be very costly due to the lack of available space for heat exchangers.

In summary, Duluth has the following potential market and institutional barriers:

1. The power plant is fired by gas and oil.
2. The power plant may become a peaking plant within MP&L's system.
3. Large capital expenditures on the current district heating system would have to be absorbed by the cogenerating system.
4. Significant institutional barriers exist because of the commitment to upgrade the current steam system.
5. Current energy contracts would have to be renegotiated.
6. User/managers of the current system would have to be persuaded that a cogenerating system would be more beneficial than their current system.
7. Building conversion costs would be higher due to existing single pipe systems and lack of space.
8. Other energy alternatives appear to exist which may be more economically and institutionally feasible.

As a result of the Level 5 screening, three cities were selected for detailed technical, institutional, and economic assessments:

1. Moorhead
2. Red Wing
3. Fergus Falls

The locations of these three potential demonstration sites are shown in Exhibit 2-24. A detailed discussion of each of these three sites is presented later in this report.

Sites Remaining After Level 5 Screening

2. B. ENVIRONMENTAL IMPACT ASSESSMENT

The three finalist sites are not located in non-attainment areas and, hence, are not affected by attainment maintenance strategies and plans. Environmental concerns of two types do exist, however: the operating emission effects and construction impact.

The effect of large scale district heating on air quality has been investigated in Sweden and, by Oak Ridge National Laboratory, in the U.S. The Swedish results show a general reduction in ground level SOx concentrations with district heating. However, these results are for conditions quite different from the U.S. sites. The Oak Ridge National Laboratory (unpublished) work also indicates that ground level air quality will be improved, but shows an effect from forecast fuel displacement. Applying these studies and the sub-contractor's power plant emissions experience, it appears that no detrimental air quality effects are likely. The absolute reduction in fuel consumed, as well as the reduction in fuel oil use, indicates a reduction in NOx. The power plants involved also use low sulfur coal and are in compliance with state opacity and particulate standards. Hence, the overall results in all three communities should be beneficial or neutral. This may be especially true in Moorhead and Fergus Falls where indications are that widespread conversion to electric heat may be expected without district heating.

Construction effects are similar to those of other in-ground work. General construction noise, construction equipment emissions, fugitive dust, and welding emissions are to be expected. Small quantity water spills are also likely. After construction is completed -- experience has shown -- only minimal maintenance or repair work is required. However, some trenching is likely for new connections. Water leaks or spills are also possible during operation. The water is highly treated and less biologically active than domestic water. However, it is hot, and a large spill could damage local root systems. Expansion cooling would normally limit this to a very small area. It may be noted that the district heating system will reduce use of gas and oil and hence will reduce the frequency of catastrophic explosions, uncontrolled fires and oil spills.

3.A. TECHNICAL ASSESSMENT

Overview

The technical assessment activities carried out as part of this project included the assessment of retrofit opportunities at each potential site. This assessment identified base and intermediate loaded units and also identified potential retrofit strategies. Each of these retrofit strategies was reviewed and -- in case of the power plants at Moorhead, Red Wing, and Fergus Falls -- analyzed in detail to determine the most advantageous retrofit scheme for each plant. Four types of retrofit strategies were assessed:

1. Back Pressure Conversion
2. Added Extraction
3. Cross Compounding
4. Use of Regenerative Heaters

The assessment of retrofit opportunities also considered thermal/electric balancing, emission control and compliance, and the need for modifications to peripheral equipment.

Distribution networks were developed for nine communities as part of the technical assessment process. While both steam and hot water systems were initially considered, it was decided rather early in the process, for reasons of thermodynamic efficiency, to restrict distribution network design to hot water systems. Fjärrvärmebyrån ab developed the preliminary distribution networks for the nine communities and, together with Metcalf and Eddy, estimated the costs for installing the distribution networks.

The requirements for building heating system conversions -- to make existing building systems compatible with district heating -- were determined for three types of heating systems: (1) hot water systems, (2) steam systems, and (3) warm-air systems. The costs of converting these systems were also estimated and are presented in the discussion below.

Retrofit Strategies

There are two conventional approaches to retrofitting steam electric power plants for district heating. These involve either the extraction of steam before complete expansion to condenser conditions or the removal of low-pressure stages for conversion to "back pressure" operation. A less conventional approach is to use boiler flue gas energy through modification or removal of air preheater or economizer sections. This latter approach will not offer the energy efficiencies theoretically available in the more conventional retrofit schemes, but might be of economic interest in situations where the load and source are not easily balanced.

All of the retrofit strategies discussed below involve complex interactions between the proposed source and the magnitude of the load and extent of the distribution system. From the standpoint of the source, all the load characteristics will influence the retrofit scheme selected (load, load duration relations, and distribution media characteristics). The size of the boiler/turbine, turbine cross-over point (if any), steam conditions, water system capacity, regeneration, reheat stages, condenser cooling system, emissions and site status will, in turn, affect decisions on load size and distribution area. The discussion of retrofit strategies below presents general retrofit procedures. Site-specific analyses of retrofit schemes appear later in this report.

Single Point Extraction Turbines

Straight condensing turbines are used in most small and older power plants. These are designed to take steam at throttle pressure and exhaust it to a condenser operating below atmospheric pressure. The exhaust pressure approximates the vapor pressure of the condensed water at its average temperature. The normal exhaust pressures range from 1.5 to 3 inches of Hg absolute. These turbines are widely used in electric generating plants, but account for less than ten percent of the steam turbines being sold to industrial power plants. Many condensing turbines, especially those used in industrial plants, are equipped with an extraction feature, which can be automatic or fixed. With automatic extraction, great flexibility is permitted in supplying both process steam and

electrical generation. Retrofit of a straight condensing turbine to either manual or automatic extraction is usually mechanically simple, provided the physical construction of the turbine casing and the staging are such that easy access is permitted at the desired expansion point.

Cross Compound Condensing Turbines

Cross compound condensing turbines are essentially two turbine/generator sets connected in series to the steam flow. The low pressure turbine/generator generally runs at half the speed (rpm's) of the high pressure turbine/generator. This design was developed so that the large blades revolving at lower speed in the low pressure turbine could be designed for greater efficiency. A unique aspect of this type of turbine for district heating is that access to the steam in the crossover connection pipe is extremely easy. Pure back pressure operation may be accomplished without windage losses. With reduced summer demand, if district cooling is not employed, full electrical output can easily be attained by simple valve positioning.

An advantage of extracting steam from a condensing turbine is that a large electrical generator is on spinning reserve and available for meeting temporary electrical grid upsets. In this configuration the turbine can also be counted as spinning reserve to meet utility commission agreements. The potential disadvantages of retrofitting a condensing turbine for extraction include potential increase in low-pressure turbine windage losses and potential cooling problems on blading (on high extraction), turbine blade instability, turbine rotor torsional damping, and deterioration of throttle response and control. If full extraction is run (minimum electrical generation) and the turbine is essentially run in a back pressure mode, problems can occur with thermal load-following unless some blades are removed. Other factors to consider include structural integrity of the casing. Because each of these potential changes is turbine specific, even model specific, the manufacturer should be consulted for guidance in handling modifications.

Extraction has some impact on boiler operation as well. Boiler furnace heat absorption can be reduced by higher feedwater temperatures. If extracted steam is taken from a first stage reheater or superheater, other heat transfer surfaces must be oversized. Additional spray attemperation or altering of heat

surfaces (tube removal) may be necessary to keep final steam temperatures within the limits allowed by the turbine blading. Meeting full electrical load in the minimum extraction mode may require such items as superheater/reheater splitter dampers and other techniques, or firing changes to raise steam temperatures.

Multiple Extraction Condensing Turbines

In the regenerative cycle commonly found in modern steam power plants a number of extraction ports at differing stages of expansion in the turbine serve feedwater heaters. The purpose of this modification to the basic Rankine cycle is to improve ideal efficiency. The number of stages of regenerative heating is usually determined by trading off improvements in efficiency against increases in cost and complexity. Commonly, four to eight stages are used. It would be possible to modify one or more of these heaters to serve as a source for the district heating water. Multiple extraction can also be added or retrofitted to a straight noncondensing turbine. The advantages of retrofitting with a multiple extraction configuration are much the same for a single extraction turbine. A spinning reserve commitment is maintained and, with limited extractions, nearly full electrical output can be obtained, especially in the case of turbines designed with multiple extraction. The disadvantages are that blade cooling, efficiency, and blade loading profiles might be adversely impacted.

The thermal power available would be considerably lower than for back pressure conversion. Also, along with a reduction in cycle efficiency, some boiler effects are likely. This modification should be low in cost and should not materially affect peak plant capacity. It will be most attractive when the thermal load is of the same order of magnitude as the electrical load.

Back Pressure (noncondensing) Turbines

Many very old turbines and some industrial turbines may be designed as noncondensing turbines, i.e., steam is exhausted from the turbine at higher than ambient air pressure. Retrofitting a condensing turbine into a back pressure turbine generally involves removing final stage blades to terminate the steam expansion at the desired pressure and temperature conditions. It is

particularly important that the turbine be reanalyzed in the new mode to assess the effect of the change on mechanical stability, structural integrity of the case, shaft thrust loading, and other performance and reliability parameters that could be affected. One major disadvantage of this retrofit scheme is that the electrical output of the unit is permanently reduced. The turbine controls, speed governors and load regulators must also be changed. The boiler thermal surfaces must also be reexamined in light of the higher feedwater temperature.

A variation on the back pressure conversion is the addition of cross compounding. For this technique, an existing turbine is converted to back pressure operation and a new condensing "tail" turbine is added. This approach offers the advantages of maintaining capacity and heat rate while offering the maximum flexibility in operations. It also will be a relatively expensive conversion option when a new unit must be added. However, since most power plants under consideration consist of more than one unit, one of these units might be converted to a tailing unit. In such a system the older boilers could also serve as peaking units if converted to oil.

There is considerable operating experience with back pressure retrofits. For example, Consolidated Edison Company of New York, which owns and operates the largest steam district heating system in the U.S. and one of the largest in the world, has employed such back pressure retrofits. Any site considered for a back pressure retrofit must usually be grid connected because the electrical output that is permanently lost must be made up elsewhere in the system. The only case where this requirement would not apply would be in an isolated service area that has an electrical supply in excess of service area demand.

Other Retrofit Schemes

Another retrofit scheme that could be employed in certain cases would be to extract heat in the form of steam directly from the boiler. Possible techniques could include replacement of an airheater with evaporation surfaces, using the economizer surface, or using portions of the superheater or reheater surfaces. The connections would be valves that would permit steam extraction

from the boiler instead of at the turbine. Thermodynamically, this type of connection is not as efficient as extraction from the turbine, but in some cases it could be extremely economical as a demonstration retrofit. In the absence of summer district cooling load, full electrical output could be obtained by returning extraction valves to a closed position. This retrofit scheme also allows all spinning reserve commitments to be met since full electrical output can easily be regained by valve repositioning. Detailed analyses of the influence of such a retrofit on boiler surface requirements must be performed to assess the impact of direct steam extraction.

Additional Retrofit Considerations

Any turbine retrofit should also consider the addition of peripheral equipment: (1) heat exchangers, (2) accumulators, and (3) controls.

Heat exchangers. In most modern heat distribution connections to power plants, an inplant master heat exchanger is employed because it is generally too expensive to transport boiler quality water throughout a thermal grid. The amount of water purification needed to prevent scaling and corrosion is thus reduced, as is the temperature of the thermal medium. Some older steam systems generating low-pressure/low-temperature steam may send boiler water directly into the steam systems. Many of these older systems do not return condensate. The water purification requirements for these older boilers are such that the additional costs for a master heat exchanger may be more than the cost of water treatment. The retrofit opportunities considered in the Minnesota Project will probably require an inplant master heat exchanger.

Accumulators. Accumulators are used to maintain system pressure so as to avoid severe condensation with steam distribution or to keep water as a liquid in hot water distribution systems. These large thermal reservoirs are generally pressure controlled, using steam or inert gases. An additional function of accumulators can be peak shaving. In essence, the boilers or hot water generators can be run at increased capacity at night, with the accumulator serving as a thermal reservoir to meet morning peaks of thermal and electrical delivery requirements.

Controls. Controls to couple the demand of the thermal distribution network to the boiler must be incorporated into any retrofit scheme. For steam distribution, the system may respond to pressure changes as a result of increased or decreased demand. For hot water systems, the supply temperature is generally increased or decreased based on return temperature measurements at a constant pumping rate. Another potential mode not generally in use would be fixed temperature at variable flow rate.

Computer Simulation. The SYNTHA II simulation program was used to analyze the thermodynamics of retrofit alternatives. This simulation program allows retrofit modifications to the boiler or turbine to be made "on paper" and then calculates new mass and energy balances for all pertinent thermodynamic cycles. Samples of SYNTHA II output are presented in Appendix A.

Distribution Systems

The thermodynamics involved in district heating systems are relatively straight forward, at least insofar as distribution is concerned. There are two basic types of distribution systems, steam and hot water, with variations possible within each basic type. There are, as one might expect, advantages and disadvantages to each type, so care must be taken to determine the "best" system for each application. Basically, steam systems possess those qualities expected of a vapor phase transmission system. Hot water systems use liquid transmission and simple heat transfer at the point of use. Many factors will affect the economics and operation of the system. Of these factors, transport distance and thermal demand density are probably the most critical.

Transport Media

Steam. Steam systems essentially use steam enthalpy for pumping work and thermal transport. Mechanical steam compression could, in principle, be used to provide some or all of the pumping work, but in practice this is seldom done. Since saturated steam is usually used in steam distribution networks, the delivery temperature is determined by the pressure. Although the energy available in the form of latent heat actually decreases as the pressure and temperature increase, the specific volume of the steam decreases at the same time, and this decrease more than compensates for the decrease in latent heat, so that higher pressures allow the use of smaller pipe sizes to deliver the same thermal heat rate. Saturated steam at 200 psig (848°R) has a latent heat of 837.2 Btu/lb and a density of 0.47 lb/ft³. As this steam gives up its latent heat in a change of phase, it yields a useful heat of 394 Btu/ft³. Steam may thus be thought of as a "low Btu" gas. At a reduced pressure of 100 psig and saturated conditions, steam has a useful energy of 260 Btu/ft³. In comparison, natural gas at 100 psig and 500°R has an "energy content" (based on heat value) of about 6800 Btu/ft³. Low Btu producer gas, with a heating value of 180 Btu/ft³ at standard conditions, represents an energy content of about 1200 Btu/ft³ at 100 psig and 500°R. As an energy transport medium, therefore, steam compares poorly with even the poorest of chemical transport agents.

Hot water. Since hot water systems do not have energy stored in a phase change, the energy available for end-use is entirely dependent on system conditions. For example, a two-pipe system (with 300°F supply and 150°F return, with a ten-mile, two-foot diameter pipe, using a velocity of 2.5 m/sec will deliver about 300,000 Btu/sec. About 9000 HP would be required for pumping in a ten-mile two-pipe system. Because the effective transported thermal power in this case is about 400,000 HP, the transport pumping power is a relatively minor fraction. The pressure drop (pumping power) and thermal loss (owing to heat transfer) are essentially linear functions of length, so the pumping power per unit length will remain relatively constant at increasing supply of distances.

Three ranges of hot water temperature have been used conventionally to describe hot water systems. Low temperature water (LTW) -- 100°F-200°F -- usually involves the direct use of power plant condenser reject heat. Medium temperature water (MTW) -- 200°F-300°F -- is the most widely used, especially in Scandinavia where the water temperature is allowed to vary with the season. High temperature water (HTW) -- above 300°F -- is being studied but has not yet been used on a widespread commercial basis.

Since a phase change is not employed in hot water systems, the temperature drop between the supply and return lines is a direct measure of the heat delivered. The higher the temperature of the water, the more deliverable heat per cubic foot in the form of temperature drop. For example, in a HTW system with a 200°F ΔT (supply to return), each cubic foot delivers 11,400 Btu. For a MTW system designed with a 100°F ΔT , each cubic foot delivers 5,400 Btu. Thus, at the same flow velocity, the higher the temperature, the smaller the delivery pipe can be without reducing the heat rate. For any water system, the operating pressure must be held above saturation to avoid flashing of the water to steam. In Scandinavian systems the pressure is maintained at about 150 psig, with winter peak supply temperatures around 270°F.

Distribution Networks

Steam distribution networks. Steam pipe systems can be once-through or they can return condensate. The thermodynamics of returning condensate are well known, but until recently fuel costs have been so low that condensate return

systems have not been generally employed. Since steam at any reasonable supply pressure has temperatures of 350°F and higher, insulation of the pipe to prevent large thermal losses becomes extremely important. Condensate return lines have the advantage of being very small, since the density ratio of the liquid compared to the vapor can be as high as 500:1. Condensate lines are not generally insulated, which is of benefit in terms of installation costs. Because steam systems use saturated steam, steam supply lines must be trapped at the low points so the condensate can be removed. This condensate can be put into the municipal sewage or storm sewer systems, or it can be added to the condensate return system if one is employed. One advantage of the relatively high delivery temperature of steam systems is that soil moisture which might otherwise damage the pipes will evaporate from around the pipes. Evaporation of trapped moisture will extend the life of both the insulation and the pipe itself.

Hot water distribution networks. A two-pipe hot water system has received the widest use in operating hot water district heating systems and has been evaluated in detail in Phase 1 of this study. With a large summer cooling load and a small domestic hot water and industrial load that could be heated electrically by each user, a two-pipe system could deliver chilled water in the cooling season. The pipes used in such a system differ widely in their construction. Some pipes are prefabricated with an insulating cover. Some pipes are constructed as a pipe within a pipe: insulation is incorporated between the inner and outer pipes, and an insulating layer covers the outer pipe. The outer pipe then either is used as a sacrificed corrosion vessel or is constructed of cement to reduce maintenance costs.

Where variable supply and return temperatures are employed and the thermal transport is over long distances, expansion and contraction of the pipe must be considered. Two methods of supporting the pipe are generally employed to deal with this phenomenon. The first method uses U expansion joints and floating, sliding or roller-mounted supports. A second method, which is currently receiving large-scale deployment, is prestressed pipe. In this latter case the pipe is initially stretched to accommodate the expected expansion and is either mounted on fixed supports or buried. This "stressing" eliminates the cost and maintenance expenses associated with expansion links. On a test basis for single-

family residences near the outer fringes of thermal distribution systems, some plastic pipe has also been employed.

In two-pipe systems a "loop" network configuration is generally desirable. In a loop the supply and return flows run in the same direction and the entire loop returns to a central point on the main distribution line. If any major break occurs in the loop, the pipe can simply be capped off and the flow reversed in the upstream segment, giving very little service interruption to customers. Since the "end users" depend on the ΔT between the supply and return pipes, the running of these flows in the same direction permits a nearly constant ΔT , even though the total temperature varies with the distance from the pumping station.

Two-pipe systems can be installed in tunnels or cement culverts, or they can be enclosed in a conduit and buried. A typical installation is illustrated in Exhibit 3-1. The illustration shows two pipes in separate support pipes buried in a trench. Pipes up to sixteen inches can be buried in this manner in stable soil conditions.

District Cooling

Cogenerated thermal energy may be used to provide for district cooling in much the same manner as district heating. The system can assume differing forms depending on the thermodynamics and economics of each particular case. There are two principal schemes for providing cooling: (1) cooling provided by inbuilding coolant generation, and (2) cooling provided by central plant coolant generation. Both schemes allow for the use of either absorption chillers or steam turbine chillers.

The applicability of these district cooling schemes is largely dependent on local climatic conditions. In Minnesota the cooling season is short and, therefore, annual cooling demand is relatively small (approximately 400 hrs/yr). However, during this short cooling season cooling loads can be quite high, with ambient dry-bulb temperatures over 100°F and wet-bulb temperatures over 70°F not unusual.

If cooling is to be provided by inbuilding coolant generation, the thermal energy generated at approximately a 4:1 ratio to lost electricity will

Exhibit 3-1

Two-Pipe Hot Water System

generate chilled water in an absorption chiller -- at the user end -- with a coefficient of performance of about 0.6-0.8. This means an effective cooling coefficient of performance of ~ 3.2 based on lost electricity. Since the alternative of using existing electrically driven mechanical chillers yields a coefficient of performance on generated electricity of ~ 4 , it is clear that this type of district cooling will not materially save energy. The cost of electrical capacity and distribution might affect the economics slightly, but not the energy balance. At the very least this approach to district cooling would require very high annual usage -- considerably higher than is typical in Minnesota -- to offset the present investment in electrical chillers.

A similar energy balance problem obtains when distributing chilled water from a central plant, except that a turbine chiller might be used in a central plant. This would allow slightly more efficient chilled water generation based on the amount of fuel expended. However, the distribution system would require at least three pipes (one being a common return). This added expense might be economically justifiable in warm climates and areas having dense cooling loads, but it does not appear to be justifiable in Minnesota.

Options for Distribution Networks

It has been clearly shown -- especially in Sweden, but also elsewhere -- that hot water systems with variable temperature sendout have demonstrated advantages over steam systems. Energy transport losses are inherently much lower for hot water systems due to the higher effective energy density of hot water. A hot water system also allows for the use of variable sendout temperatures and thus makes for easier system optimization under varying thermal and electrical loads. The construction and maintenance of a hot water distribution system will also be less expensive in most cases than the construction and maintenance of a steam distribution system because the piping is smaller and less expensive, because a hot water system has no trapping requirements, and because a hot water system is easier to maintain. Steam systems might be attractive for limited areas with dense industrial loads, but the advantages of hot water for district heating are obvious and, therefore, it was decided to concentrate on variable temperature hot water distribution in this study.

Physical Extent of the Distribution Areas

In the assessment of the physical extent of the proposed distribution areas, consideration was given to the present and expected future loading density and the geographical locations of the generation plants in relation to the consumer areas. Obstacles such as highways, waterways, and industrial concentrations that might affect installation costs were also taken into account.

The resulting assessments revealed that the distribution areas are usually confined to regions consisting of general and commercial buildings (downtown) and isolated districts with high loading densities, provided that these are geographically located so that it will be economically attractive to run district heating mains to them. Such isolated districts usually comprise areas of multi-family dwellings, shopping centers, industrial plants, schools and other institutions.

Districts comprising single-family houses are not expected to be included in the distribution areas, due primarily to the fact that the distribution costs in such areas are many times higher than in districts with high loading densities. But this does not preclude districts consisting of single-family houses being connected to the district heating system at a future date. If economic conditions should change -- due, for instance, to drastic increases in the cost of natural gas -- connection of such districts may become attractive, and the district heating network can be then supplemented by ring mains through the districts, without necessarily overloading the main network now proposed for areas with high loading densities.

Thermal Demand for District Heating

The thermal demand for the heating of buildings varies within very wide limits and is dependent on factors such as the relationship between the volume of a building and the total area of its confining walls, the insulation, the ventilation requirements, and the presence of heat recovery equipment. Modern office buildings with a high standard of insulation and efficient heat recovery equipment are typical of buildings with a low thermal demand, i.e., below 50 W/m^2 .

Older dwellings, such as old school buildings, with poor insulation, single-glazed windows and high rates of ventilation often have a thermal demand in the order of 150-175 W/m². Studies of the thermal demands of individual buildings were outside the scope of Phase 1 of this project. Until such studies are made, the mean value of the thermal demand was assumed to be 125 W/m² of floor area. Adjustments to this mean estimate were made for buildings with very special thermal demands, such as certain industrial plants and hospital complexes.

The thermal demands were mapped out and quantified by using available maps and by visually inspecting the buildings within the planned distribution areas. Allowances for special heat demands were made on the basis of interviews with the appropriate owners.

The annual thermal energy demand for the heating of buildings is usually calculated from statistical particulars of the annual utilization time of the heating plants. Statistical information in Sweden indicates that the utilization times vary between about 1700 and 2300 hours per year. A comparison of the climatic conditions prevailing in northern Sweden with those in Minnesota indicates that the conditions are probably roughly the same in both countries, and this has been confirmed by investigations carried out on other occasions. A provisional value assumed in this evaluation is a utilization time of 2000 hours per year.

The accuracy of the estimate of the thermal energy demand is of minor significance at this stage of the analysis, since the main purpose of Phase 1 is to rank the proposed towns in their order of suitability for district heating. The accuracy of estimated investment costs is also not of major significance at this point. An increase or decrease in the thermal demand by 15-20% has only a marginal effect on the investment costs for the distribution system.

However, subsequent examination should devote more attention to the thermal demand in each individual case, particularly for sizing the subscriber installations and allowing detailed calculations of the future annual heating cost facing the individual subscriber. In this study, it was assumed that 100% of the buildings in the relevant areas would be connected to the district heating network.

Installation of the Distribution Network

The proposed networks of distribution mains plotted on the maps presented later in this report are supported by reconnoitering visits at all of the locations. The aim was to determine an economically optimized pattern of the network, taking into account not only the major centers of thermal loading, but also the prevailing traffic conditions, the standard of road surfacing, and the flexibility of the main network with respect to future extensions to the distribution areas.

It was assumed that the pipe networks would be in accordance with the well-proven Scandinavian technology, using pipeline materials of the same types as those long used in Sweden and other countries. Prefabricated double-wall pipes are best suited for the distribution networks envisaged in the towns studied in this study. These pipes are prefabricated elements consisting of a welded or drawn steel tube insulated with polyurethane foam and enclosed in a tubular casing of polyethylene. The elements are delivered in 40-foot lengths and are welded together in the pipe trenches. Special polyethylene elements are used for jointing the tubular casings. All types of pipe fittings, such as bends, tees, and reducers are available as prefab components.

The pipes are usually laid at a depth of 2-1/2 to 3 feet below surface and should preferably be run below walkways, reservations between the lanes of expressways, or the like. Service lines are run to each subscriber and isolation of the service line is arranged immediately outside the basement foundation wall of the relevant building. Inspection shafts are arranged at more important branch points in the network, and pipe fittings and equipment for the control and maintenance of the network should be located at these points.

It is assumed that the piping will be run in accordance with the method in which thermal expansions of the pipes are prevented or restricted, to the maximum extent possible, by friction between the soil and the pipe, within the limitations of the associated stresses in the material. A system of this nature reduces appreciably the need for expansion compensators and the associated investment and maintenance costs.

A supervisory alarm system for indicating and recording any leakage of moisture into the insulation layer of the pipes should be provided for the entire

system. The ingress of moisture into the insulation layer may be due either to leakage through the tubular casing, which thus allows ground-water to seep in, or leakage of the pipe, which causes the insulation to be saturated by the medium flowing through the pipe. Unless such leakage is detected and corrected in time, both types of faults may have serious consequences in the form of corrosion of the pipes.

The installation procedures used in deploying pipe for the distribution network do not require especially complicated excavation or construction work. A typical installation procedure is described below:

- Step 1: In preparation for digging the pipe trench, the existing pavement and curbing are removed. Temporary bridges and security devices are then put in place to maintain the continuity and safety of pedestrian and vehicular traffic.
- Step 2: The ground is now ready for trench excavation, which in most cases will require only a backhoe. (In Red Wing, Fergus Falls, and Moorhead, all excavation can be done with a backhoe.) In some instances, depending on soil conditions and the depth of the trench, permanent shoring may be necessary. Also at this time any utility pipes or cables that conflict with the district heating piping should be moved.
- Step 3: When all preparatory work is completed, piping can be laid. A typical trench cross-section is shown in Exhibit 3-2. First, the trench drainage pipe is laid and the trench is backfilled with six inches of gravel. A foundation of sand is then laid about three inches deep. The district heating pipes are placed on this foundation.
- Step 4: The pipe sections are connected with welded joints, and the welds are checked by x-ray. The system is then given a water pressure test. If the system functions as expected, backfilling and restoration of the pavement can proceed.
- Step 5: The trench is first backfilled with sand -- immediately surrounding the pipes -- and then the road subbase is prepared with gravel. The first layer of pavement, the binder course, follows the gravel and that is followed by the final layer of pavement. Curbs are then replaced and the roadway is ready for normal use.

Exhibit 3-2

Trench Cross Section

Distribution Network Investment Costs

The investment costs for a two-pipe hot water system have been calculated by Fjärrvärmebyrån (Vasteras, Sweden) and Metcalf and Eddy, Inc. (Chicago). A comparison of the investment costs in the U.S. and Sweden indicates that the estimates, made independently, are roughly the same.

The calculation procedure consisted of detailed cost calculations for all relevant pipe sizes, assuming "medium-difficult" conditions. The prices per linear foot thus obtained were later used for calculating the total cost of the proposed networks for Red Wing, Moorhead, and Fergus Falls, making individual allowances for exceptional conditions, such as intersections with waterways, highways, very busy city streets, and other difficult situations. These site-specific investment costs are presented later in this report. Estimated costs per linear foot of installed piping are presented in Exhibit 3-3.

Exhibit 3-3

Estimated Costs of District Heating Distribution Piping (Installed)

<u>Number and Size of Pipes</u>	<u>Fjarrvarmebyran Installed Costs</u>	<u>Pipe Material Only (2 Pipes)</u>	<u>Metcalf & Eddy⁽¹⁾ Installed Costs</u>
2 x 1-1/4"	\$ 55/foot	\$ 8.00/foot	\$ 77/foot
2 x 1-1/2"	\$ 58/foot	\$ 9.70/foot	\$ 77/foot
2 x 2"	\$ 63/foot	\$ 9.80/foot	\$ 77/foot
2 x 2-1/2"	\$ 69/foot	\$11.00/foot	\$ 77/foot
2 x 3"	\$ 75/foot	\$12.40/foot	\$ 77/foot
2 x 4"	\$ 82/foot	\$15.00/foot	\$ 77/foot
2 x 6"	\$104/foot	\$24.80/foot	\$ 95/foot
2 x 8"	\$125/foot	\$35.00/foot	\$114/foot
2 x 10"	\$146/foot	\$50.50/foot	\$142/foot
2 x 12"	\$166/foot	\$60.00/foot	\$162/foot
2 x 16"	\$207/foot	\$87.00/foot	\$214/foot

Building System Conversions

A major expense to be considered as part of the overall cost of a district heating system is the cost associated with the conversion of users' systems to make them compatible with district heating. The following discussion identifies types of user systems and outlines procedures to follow in determining conversion alternatives. Also presented below are average cost estimates for converting building systems of different types. Site-specific building conversion cost estimates for the three potential demonstration communities will be developed in Phase 2.

Types of Heating Systems

Building heating systems are generally fueled by gas, oil, or coal. From the perspective of heating system compatibility with district heating, however, it is the heating medium which will determine the cost and complexity of the conversion, not fuel type. The three types of building heating media most commonly found in Minnesota are hot water, steam, and warm air. Each of these heating systems can be modified to make it compatible with district heating.

Hot water systems. A hot water heating system in its simplest form consists of a hot water boiler, a compression or expansion tank, circulating pump(s), and radiators or convectors all piped together in a circuit. There are many variations and elaborations of this basic system: some systems may use multiple boilers for better efficiency and reliability; instead of radiators, fan-coil air-handling units may be used (air forced through a coil heated by the hot water); and a heat exchanger for heating domestic water may be added. But there is rarely anything more complex in such systems than the components mentioned above, and all these systems operate in essentially the same manner.

Another system that for the purposes of this discussion can be considered a hot-water system is one in which a steam boiler is connected to steam-to-hot-water heat exchangers that produce hot water for space heating and sometimes for domestic hot water. This type of system is usually used for a heating system

requiring several heating zones, each with a different water temperature, or when steam boilers are required to provide steam for purposes in addition to heating.

Steam systems. A steam heating system usually consists of a steam boiler and radiators, or convectors, connected together. The radiators may not even be piped in a complete circuit: only one pipe may carry steam to and return condensate from each radiator, which is known as a one-pipe system. The most common steam system in Minnesota, however, is a two-pipe system in which there are separate pipes for steam supply and condensate return. As in the hot-water systems, many variations of the basic system can be found: multiple boilers may be used; fan-coil air handling units and/or domestic water heat exchangers may be connected; and condensate may be returned by gravity or pumped. There are very few variations more complex than this, although steam used for special processes may require additional equipment.

Warm-air systems. A warm-air system consists of a furnace with an integral blower section, ductwork for supply and return air (or just supply air), and air diffusers and/or registers. The ductwork may include supply ductwork from the fan outlet to the heated space and return air ductwork from the heated space to the fan inlet, or there may be only a supply duct to the heated space with the air required to find its way back to the fan inlet through doorways and other openings. Often there is a separate fan connected to the return air ductwork to draw air from the heated space and feed it to the inlet of the supply fan. Generally, some air from the outdoors is also fed to the inlet side of the supply fan. Most furnaces are used for comparatively small heating areas, but larger areas may be broken into smaller areas with a separate furnace for each area.

Methods of Converting Customers' Systems to District Heat

Most modern district heating systems are designed to distribute 260°F-300°F water. Most building hot water heating systems in the U.S. are generally designed for a maximum temperature of 200°F and, therefore, must be modified to be compatible with these higher temperature/pressure requirements. Steam

systems and fuel-fired warm air systems must obviously be modified in order to be compatible with hot water district heat. It is essential, therefore, to provide each customer with a heat exchanger, that has a primary side suitable for high temperature and pressure hot water and a secondary side compatible with the lower temperature and pressure water circulated through it to be used in the customer's system as it exists, or in some cases as modified. This type of heat exchanger is available but to date is manufactured only in Europe and Scandinavia. Such a heat exchanger is also relatively expensive so other modifications to customers' systems must be as inexpensive as possible to keep total costs down.

A similar type of heat exchanger is also used in Europe and Scandinavia for heating of domestic water. The district heating water is passed through this second exchanger (connected in series to the first) just before leaving the building. This procedure extracts the last bit of usable heat from the district heating water and reduces the temperature of the water returning to the power plant.

Hot Water conversion. A typical hot-water system already has all required parts properly connected; except for the heat exchanger(s) and perhaps some control devices, all that remains is to disconnect the system from the existing boiler and connect it to the secondary side of the heat exchanger(s). Depending on the customer's preference, the boiler(s) may be removed (at a price) or may be left in place for possible back-up service. To determine the capacity of the heat exchanger(s) and controls that will replace the boiler(s) in any building, an assessment of the building's construction and heating load must be made. When the building was originally designed, the heating requirements were determined based on the original construction and load. Radiators and/or air-handling units were sized and the heating-water temperature was selected based on these requirements. An energy audit might show that these requirements have changed, that insulation and storm windows have been added, or that room sizes and radiators have been modified. New heating requirements can take into account structural modifications and changes in load. In this way the heat exchanger(s) can be properly sized and the necessary heating-water temperature can be determined. Depending on the specific type and design of the

building's heating equipment and the building's load, it might be possible to use 150°F or 160°F average-temperature water at design outdoor conditions and still get adequate heat out of existing radiators and air-handling units even though the system was designed to use higher temperature water. Minor building modifications such as additional insulation, more radiators, or changes in piping or control systems may also enable a customer to use lower temperature water.

Converting an existing hot-water heating system to district heat consists of the following steps:

- Step 1: Inspect the present boiler(s) and determine such factors as annual fuel usage and system efficiency to find the building net heat loss. Tabulate the sizes and types (nameplate data if possible) of all pieces of heating equipment including piping, radiators, convectors, and coils.
- Step 2: Proportion the actual heat loss (indicated by the fuel usage) to each heating area or zone of the building. From this figure, calculate the heat output required from each heating terminal (radiator, fan-coil or air-handling unit) in every zone, and select the water temperature ranges and flow rates that will produce this required heat output. (Obviously, there will be a number of temperature ranges and corresponding flow rates to meet the design heating requirements, so the combination that is finally selected must be the most economical for both the customer and the district heating system owner.)
- Step 3: Determine whether or not any minor modifications to the building or heating system would result in a significant reduction in the total heating requirements, and how economical such modifications would be for the customer.
- Step 4: Investigate the domestic hot-water system and determine whether or not the customer will bear the cost of converting the system to district heat.
- Step 5: Select heat exchanger or exchangers and other equipment as required (valves, control devices, piping, pumps, etc.) to meet the criteria established under 1, 2, 3, and 4 above and prepare the installation plans. These plans should include any demolition and removal of existing equipment as required by the customer. As previously discussed, it may be advantageous to leave existing equipment in place to save removal costs and/or to use in the very unlikely case of failure of the district heating system.

Steam conversion. Converting an existing steam heating system to be compatible with district heating is somewhat more involved than converting a hot water system and generally requires more equipment and engineering work. Generating steam in a heat exchanger supplied with 250°F district heating water would be very difficult at best, requiring a very large heat transfer surface area due to the rather small temperature difference (260°-212°). Such a conversion scheme must be considered impractical. Modifying a steam heating system to use hot water as the heating medium instead of steam can often be accomplished, however, without excessive effort or expense. In a steam system the radiators, coils, and convectors, are likely to be large enough so that if hot water of 200°F, 190°F, or even less is supplied to them, each unit will produce sufficient heat for its zone. The supply piping to the radiators or coils in one-pipe or two-pipe systems is generally large enough for supplying adequate hot (200°F) water for sufficient heat output from these units. However, return piping must be added to one-pipe systems, and in some zones of a two-pipe system, larger pipes may have to be installed for the returns. Steam traps must also be removed from the heating terminals and piping, and air vents must be added to purge any air trapped by the hot water. The only equipment missing entirely in a steam system -- and required in a hot-water system -- is a compression/expansion tank and pump(s) for circulating the water. The existing control systems will also have to be modified to operate the circulating pumps and/or control valves. Any other existing equipment, such as condensate return pumps and boiler feed pumps, must be by-passed and/or removed. This method of converting an existing steam heating system to district heating requires the same basic steps (1 through 5) as listed for converting a hot water system with a small amount of additional work in step 2:

Step 1: Determine the net building heat loss and tabulate sizes of radiators, coils, convectors and piping (supply and return).

Step 2: Proportion the actual heat loss to each zone and determine the heat output required from each heating terminal. After calculating the water temperature ranges and flow rates required to produce this heat output when using hot water instead of steam as the heating medium, check the size of the return piping (and supply piping, too) to see if it can handle the rate of flow that appears to be the most economical choice.

If the pressure drop in the piping is excessive so that a very high-pressure pump would be required, some sections of the piping must be changed to reduce the pressure drop.

- Step 3: Determine the economics of any minor building modifications.
- Step 4: Investigate the domestic hot-water heating system.
- Step 5: Select heat exchanger or exchangers, compression tank(s), circulating pump(s), and other equipment as required (valves, control devices, etc.) to meet the criteria established above.

Converting a steam system to district heating is obviously more expensive than converting a hot-water system due to the additional equipment (pump(s), tank(s), and perhaps piping) required. Moreover, to convert the steam boiler to hot-water, if it is to remain for back-up service, would require additional (although minor) changes in piping and control trim. If steam is required in limited quantities for some process that cannot be converted to hot-water or electrical energy, another expense might be an electric or fuel-fired steam generator. It is expected, however, that there will be very few cases where steam will actually be required. For these cases, generating steam in a district heating exchanger might be carefully reassessed.

Warm-air conversions. Fuel-fired (or electric) warm-air heating systems do not lend themselves particularly well to district heating. To be usable in a district heating system, a heating unit must distribute or radiate heat extracted from circulated 160°F (or somewhat higher) hot water. The easiest way to accomplish this in a warm-air system is to remove the fuel-fired heat exchanger or a section of ductwork at the fan and install a hot-water coil in the air stream. However, warm-air furnaces are generally designed to be as compact as possible so it is not very likely that hot water coils could be fit in either the ductwork or the furnace itself. If there is not enough space in either place to install a hot water coil with sufficient heat output when supplied with 160°F hot water, then the furnace must be replaced with an appropriate air-handling unit to accommodate such a coil. If the furnace remains intact after installing the coil and/or air-handling unit in the ductwork, it could be used as back-up for the district heating system.

A typical warm-air heating system has little of the equipment required in a hot-water district heating system. In fact, the only equipment usable for conversion is the ductwork/air distribution system, and possibly the fan section and some controls. To select the additional equipment and complete the conversion to district heating requires, once again, the same basic steps as for steam and hot water systems with some changes and additions:

- Step 1: Determine such factors as annual fuel usage and system efficiency to find the net building heat loss. List the dimensions and air flow characteristics of the furnace fan section and registers or diffusers.
- Step 2: Proportion the actual heat loss to each furnace unit and select a coil and/or air-handling unit that will provide the required heat when supplied with 160°F hot water from the secondary side of the district heating exchanger. The coil selection must take into account the temperature and flow of the hot water as well as air flow. After the coil has been selected and located, supply and return piping must be sized and installed between the coil and the district heating exchanger.
- Step 3: Check for past or needed building modifications to see if energy consumption has been or can be reduced.
- Step 4: Determine whether or not the domestic water heating system can be converted to district heat.
- Step 5: Select heat exchanger(s), compression tank(s), circulating pump(s), and other equipment as required (valves, control devices, etc.) to meet the criteria established under 1, 2, 3, and 4 above, and design the complete conversion. The plans should include any demolition and removal of existing equipment, and any minor (insulation, etc.) building modifications.

Metering

In existing district heating systems metering is generally done only for large users or for large blocks of users. Frequently, charges are based simply on volume of heated space. In new systems, however, it is probable that individual building metering will be necessary to comply with state law and to provide equitable cost allocation to customers. Several integrating meters are on the market. These integrate the temperature difference between supply and return, as well as flow rate, to determine thermal usage. Such meters are usually

located at the control heat exchanger in the building. They are quite expensive, however, -- costing \$600 and up -- so they would represent a major cost component of any conversion, especially conversions of smaller systems.

In summary, converting the three common types of existing heating systems requires the basic steps of determining the net building heat loss; identifying the existing heating units and calculating the output of each when supplied with 160°F to 210°F hot water; designing minor building modifications to most economically utilize existing equipment; and selecting equipment as required to complete the installation of a converted hot-water system. Once the basic conversion is complete with a heat exchanger, compression tank, circulating pump, and heating terminals, refinements may be made at any time. These may include multiple zone circulating systems (or air-handling systems).

Estimated Conversion Costs

Converting any heating system to district heating requires a heat exchanger capable of handling 250°F district heating water on the primary side and producing 160°F to 210°F on the secondary side. The existing heating system then utilizes this secondary water, or is modified as required in order to utilize it. The cost of each conversion must include, at maximum, the cost of a heat exchanger and the costs of any required system modifications.

Hot water. The estimated average cost per kilowatt for converting existing hot-water heating systems is shown in Exhibit 3-4. These costs were generated based on the following information and assumptions:

1. Heat exchanger outputs and prices are based on information from AGA-CTC Varmevaxlare AB of Sweden. The Swedish FOB prices were doubled to account for shipping, customs, overhead, and profit for the importer.
2. Heat exchanger ratings were reduced to 80% of listed output to compensate for building distribution system design.
3. Ratings of heat exchangers were based on a primary ΔT of 248°F (120°C) $\rightarrow$ 158°F (70°C) and a secondary ΔT of 176°F (80°C) $\rightarrow$ 140°F (60°C).
4. Installation costs for the heat exchangers were taken from 1979 edition of "Building Cost File" published by Van Nostrand as installation costs of equivalent size steel boilers.

Exhibit 3-4

Building Heating System Conversion Costs (Hot Water)

5. It was assumed that each heat exchanger installation would require: 30 feet of primary piping, 100 feet of secondary piping, pipe insulation, control devices, and valves (three for the secondary and two for the primary). Pipe sizes were based on the inlet and outlet nozzles of the heat exchangers.
6. Labor and materials costs were taken from the 1979 edition of "Building Cost File" and marked up 25% for profit, overhead and contingencies.
7. Since it was the intent of this study to determine the minimum reasonable costs for converting existing systems to district heating, no allowances were made for the removal of any existing equipment as this would not be required for the conversion to be completed.
8. The cost of meters has not been included in the estimates.

Steam. The estimated average cost per kilowatt for converting existing steam heating systems is shown in Exhibit 3-5. These costs were determined in the same way as the costs for hot-water conversions, and basic assumptions included those listed above (1 through 8), but additional information and assumptions were required to cover all conditions of converting a steam system:

9. Ratings for the AGA-CTC heat exchangers were reduced 20% below the nominal ratings listed for hot-water conversions. This accounted for the possibility that the existing heating units in a converted steam system may require hot water of a higher temperature than 160°F for proper heat output. (The ratings for hot-water conversions were based on a 160°F average water temperature in the secondary side of the exchanger.).
10. In addition to the equipment listed for a hot-water conversion, the following equipment is required: a circulating pump (multiple units used in larger installations), and an expansion/compression tank and fittings. It was assumed that some existing return piping may have to be replaced with a larger size, so the cost of some 200 or so feet of insulated secondary piping was added to account for this. Obviously, this amount of piping replacement is insufficient for one-pipe steam systems where return piping must be completely installed. This type of steam system is likely to require much more piping so costs will probably be much higher.

Warm-air. The estimated average cost per kilowatt for converting existing warm-air heating systems is shown in Exhibit 3-6. These costs were calculated based on the assumptions and statements 1 through 10 above and, in addition, the following:

Exhibit 3-5

Building Heating System Conversion Costs (Steam)

Exhibit 3-6

Building Heating System Conversion Costs (Warm Air)

11. The ratings for the heat exchangers are the same as those used for the hot-water conversions. However, warm-air furnaces are not normally available in capacities above about 200 kilowatts, although multiple units may be used to heat larger areas. This type of arrangement can most often be converted to district heat by using a separate heat exchanger/air-handling unit combination to replace each furnace. In some cases, it may be possible to use one large heat exchanger and multiple air-handling units, but this would probably require a lot of additional secondary water circulation piping.
12. In addition to the equipment listed for a steam system conversion, it is assumed that an air-handling unit/hot-water coil combination will be required for each furnace that is converted. Labor and material costs for the installation of the units were taken from "Building Cost File" and marked up 30% for overhead, profit, and contingencies. To this amount was added the cost of converting an equivalent size steam system to obtain total conversion costs.

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3. B. MARKET ANALYSIS

Overview

An energy market analysis was conducted to determine the potential market for a central district heating system in five cities (Duluth, Rochester, Fergus Falls, Moorhead, and Red Wing). These five cities were the cities determined to be the most attractive candidates for a cogeneration district heating demonstration project during Task 2 of this project.

For each of these five cities, the market analysis of the potential demonstration sites began with a review of the preliminary distribution lines laid out as part of the Task 2 effort. This initial effort was designed to identify the potential market to be served and to evaluate the distribution network designed to service the market. A preliminary fact finding visit was made to each of the five cities to review the type and density of the buildings along the preliminary distribution line, to become familiar with the city, to develop a systematic approach to the market analysis and to identify factors that would expand or reduce the scope of the market analysis effort. During the preliminary visit an attempt was made to:

- 0 Identify the type and location of potential users.
- 0 Identify present energy suppliers who could be displaced by a co-generated thermal energy source
- 0 Review potential energy alternatives already being investigated in the city.

The visits to Duluth and Rochester resulted in the identification of various factors which raised serious questions about the feasibility of these sites. The project team gathered additional information and recommended that these two sites not be studied in any greater detail. Based upon a review of the project team's findings, the steering committee unanimously voted to eliminate these two sites from additional study. This reduced the viable demonstration sites to three: Moorhead, Fergus Falls, and Red Wing.

The information collected during the visits to the remaining cities was used to develop a market analysis plan. One city, Moorhead, was selected as a

pilot city for testing the market analysis approach and methodology. The results of the site-specific market analyses are discussed later in this report.

Market Analysis

Objectives and Methodology

The objectives of the energy market analyses conducted for the three selected cities were:

- 0 To develop initial estimates of the potential market for a central district heating system.
- 0 To determine the major service requirements of potential district heating customers.
- 0 To identify factors or problems which could have a significant impact on the market penetration of the district heating product.

In order to accomplish these major objectives, it was necessary to understand and collect data regarding potential users of the district heating system. The information required included:

- 0 Current levels of consumption of thermal energy.
- 0 Thermal energy consumption patterns.
- 0 Location relative to potential distribution lines.
- 0 Current thermal energy equipment systems, including type of fuel and its cost.
- 0 Kinds of thermal energy desired.
- 0 Suppliers of current fuel.
- 0 Key variables in the decision to switch to cogenerated district heating.

The market analysis methodology consisted of three basic steps: (1) preliminary visit, (2) detailed surveying, and (3) selected market interviews. The detailed tasks required in each step determined the level of effort and the results affected the scope of tasks included in subsequent steps. Preliminary visits were made to all cities.

Preliminary Visit

The preliminary visit to each city included:

- 0 Driving the proposed distribution line.
- 0 Driving areas near the proposed distribution line.

- 0 Discussing future expansion with city planners.
- 0 Reviewing the proposed distribution line with city planners.
- 0 Collecting city background information from the Chamber of Commerce.
- 0 Discussing the cogeneration concept with the local power plant production personnel.
- 0 Discussing the current operations and future power plant plans with power plant representatives.
- 0 Discussing cogeneration concept, current operations and future plans with potential major competitors of cogenerated district heating.
- 0 Gathering names of local people who could provide significant input.
- 0 Discussing existing energy alternatives with informed individuals.
- 0 Discussing the cogeneration concept and potential use with some possible major users.

Based upon the results of these initial fact gathering steps a survey methodology and plan was developed for each city.

Detailed Surveying

The detailed surveying process consisted of the development, distribution and collection of survey questionnaires. The questionnaire development process included defining required results, reviewing questionnaires used in prior studies, preparing a draft questionnaire, reviewing the draft questionnaire with the project steering committee and other project team members and test sampling. The final questionnaire used to gather the market data is included in Appendix B of this report.

The survey population in each city was defined as all buildings except single family dwellings located along the distribution line. Single family dwellings were excluded because of the assumed high cost of conversion relative to energy use. Empty buildings and cold storage locations along the primary distribution line were not surveyed. All potentially large users and all buildings over approximately 3000 gross square feet within this population were surveyed. In addition, potential major users near the preliminary distribution line and potential high density areas off the distribution line were surveyed.

During the survey process, locations found to have electrical base-board resistance heating systems were excluded from the population. These buildings were excluded due to the probable need to install entire new heating systems which would make them uneconomical to convert.

In planning the market survey the population was broken into districts to create manageable survey areas and to provide segments of data for financial analysis. The division into districts was done on a combination of geographical dispersion and apparent market density. When additional buildings were added to the potential market through line revisions, the new data were either considered as part of a primary district or became a separate district.

A door-to-door method was adopted for survey distribution. Building owners or managers were located, given a brief description of cogenerated district heating, informed of the importance of their participation and encouraged to return the surveys. All surveys had a return envelope attached for convenience. This surveying process was followed for all buildings except major apartment buildings in Moorhead. In order to insure proper compilation of the market associated with the apartment buildings, each series of apartment buildings was mapped out and their heat distribution system, heat source, and input fuel type were determined by the surveyors. Average consumption data was obtained through the current energy supplier and projected across all the apartment buildings. The data related to these apartment buildings is considered as part of the data base in the summary of results presented in subsequent sections.

As surveys were distributed each building was classified by type in order to provide a basis for analyzing the returns by building type. As surveys were returned, they were checked off and the original building classification reviewed. The classification scheme used is presented in Exhibit 3-7.

Selected Market Interviews

The returned surveys were analyzed and summarized. All significant potential users who did not return the survey were contacted a second time and a market interview was conducted in order to acquire a base amount of data. These individuals were also encouraged to complete and return their surveys.

Exhibit 3-7

Building Classification Scheme

<u>Classification</u>	<u>Identifying Characteristics</u>
Large Commercial	Greater than 10,000 g.s.f. Heating system on 8-10 hours a day Use includes office buildings, stores, and government administrative offices
Small Commercial	10,000 g.s.f. or less Heating system on 8-10 hours a day Use includes office buildings, stores, and government administrative offices
Industrial	Heating system on up to 24 hours a day Use is directly associated with some pro- duction facility, does not include administrative support heat requirements
Multi-Unit Residential	Group of two or more individual units
Public and Institutional	Heating system use sporadic or constant Building size normally large Uses include hospital, church, school, and theater

In addition to those major potential users who did not return their survey, other major users were selected to be contacted and interviewed. These were selected based upon a review of the completed survey and the interviews were designed to provide supplemental information about:

- 0 Unusual thermal energy requirements.
- 0 Consumption patterns.
- 0 Questions not fully answered on survey.
- 0 Variables they would consider in deciding to switch to district heating.

The procedure generally followed was to contact the individual to set a meeting, ask specific questions, and then attempt to encourage the individual to present his views regarding district heating. The questions addressed to the individuals were designed to elicit responses for items such as capital costs, fuel costs, maintenance costs, reliability factors and disruption effects. Most interviews led to discussions of other factors. These interviews were held in each city and they were conducted over a spectrum of users. The main problem encountered was that potential users could not quantify their opinions.

Comparative Results

The differences dealt with in this section include potential market, type of market, types of buildings, types of heating systems and potential fuel displacement.

Potential thermal market. Moorhead has the largest market with a potential market approximately two times that of Red Wing and two and one-half times that of Fergus Falls. Moorhead and Fergus Falls are similar in that a minor percentage of each potential market is process use, whereas Red Wing has a substantial potential process market. Differences in thermal market size and characteristics are presented in Exhibit 3-8.

Percentage market comparisons. Moorhead and Fergus Falls are very similar in their percentage breakdowns. The dominant potential market in Moorhead is educational which is reflected in the high percentage for the Public and Institutional category. The Multi-Unit Residential percentage was also high and represents mostly student housing supporting the educational institutions.

Exhibit 3-8

Potential Thermal Market Comparisons

In Fergus Falls, the dominant potential market is the hospitals and that is reflected in the high percentage of the Public and Institutional category. The Multi-Unit Residential is also high and represents mainly rest homes supporting Lake Region Hospital. In Red Wing, the dominant potential market is process.

Each city has a dominant characteristic that accounts for a major percentage of the potential thermal market. Moorhead is educational, Fergus Falls is health care, and Red Wing is process. All cities have approximately the same percentage of the total potential market related to their dominant characteristic and each city has approximately the same percentage of its total represented by the commercial category. Differences in percentage market comparisons are presented in Exhibit 3-9.

Percentage of heating market by heating system. Moorhead is dominated by the hot water/steam systems of the college and university. The hot water use is related mostly to multi-unit residential units. Fergus Falls is dominated by hot water/steam and steam due to the hospitals. The hot water percentage is related to the rest homes and partially to renovations in the downtown area. Red Wing is dominated by steam which is related to the fact that it is an older community. Differences in percentage heating system share are presented in Exhibit 3-10.

Potential annual fuel displacement. Moorhead has twice the market that Red Wing has and two and one-half times the market of Fergus Falls. Using Moorhead as the base, the following relative statements can be made:

1. Moorhead has the highest potential fuel oil displacement as a percentage of market.
2. Red Wing has the lowest potential fuel oil displacement as a percentage of market.
3. Red Wing has the highest potential natural gas displacement as a percentage of market.
4. Fergus Falls has the lowest potential natural gas displacement as a percentage of market.
5. Displacement of propane is restricted to Red Wing.
6. Displacement of lignite is restricted to Fergus Falls.

Differences in annual fuel displacement are presented in Exhibit 3-11.

Exhibit 3-9

Percentage Market Comparisons by Process and Building Type

Exhibit 3-10

Percentage of Heating Market by Heating System

Exhibit 3-11

Potential Annual Fuel Displacement

<u>City</u>	<u>Gas (CCF)</u>	<u>#2 Fuel Oil (Gal)</u>	<u>#6 Fuel Oil (Gal)</u>	<u>Propane (Gal)</u>	<u>Lignite (Ton)</u>
Moorhead	3,561,897	1,702,535	638,246	--	--
Red Wing	2,253,703	168,553	--	520,403	
Fergus Falls	1,016,406	968,323	--	--	6,996

Market Penetration Analysis

As part of the overall market analysis an attempt was made to determine users' assumptions and reasons for preferring thermal over traditional energy supplies. The vast majority of interviewees were not sure about their preferences. The most frequent response was that thermal energy would be preferred if it were cheaper.

Relative cost seemed to be the dominant variable in an individual's preference. If thermal energy were cheaper, then most would consider switching depending upon the initial capital outlay. Most would be encouraged to switch if it did not involve capital financing by themselves. Some would switch with subsidized capital financing and few were willing to switch given that they had to absorb the initial capital outlay. Most respondents broke the cost factor into three elements: fuel costs, capital cost and operating and maintenance costs.

Fuel cost refers to current energy price versus the price of thermal energy. Estimates ranged from seven percent a year inflation on current fuels to 25%. The respondents talked of availability of fuel in making their predictions and, obviously, the ones with higher inflation predictions preferred thermal energy. The respondents expressed desires for price guarantees as protection against "unfair" price increases after capital expenditures had been made. Respondents could not set a price for hot water thermal energy because insufficient information existed concerning capital costs and changes in operating and maintenance costs. A few respondents acknowledged that deregulation of current fuel prices would drastically alter their inflation predictions.

Capital cost refers to the initial outlay of funds required to convert to hot water district heating. The consensus seemed to be that the user did not want to absorb this initial cost outlay. A few respondents referred to low cost financing being made available. A negligible number of respondents discussed the value of their current equipment, potential tax write-offs, potential investment credit effects, return on investment, investment paybacks, and depreciation benefits.

Operating and maintenance costs were the least mentioned items in the cost analysis. Respondents felt they did not know enough about hot water district heating to make statements regarding the impact of district heating on these costs.

Reliability was not a significant concern to most respondents (excluding hospitals, nursing homes and process users). This appeared to be associated with people's opinion of the reliability of electrical power. In cases where people remembered power outages, they questioned reliability, for others reliability was not questioned.

Stability was an important factor and it relates not only to price as stated earlier but also to supply. Along with price guarantees, respondents would like to see supply guarantees so they would not be left without a heating energy source. Another factor brought up by a few individuals was the concept of energy conservation. Only in cases where financial stability and security seemed to exist did respondents address the social issue of energy conservation.

A final and interesting concept brought up by several individuals involved the subsidizing of the project. These individuals would not have an interest if the project were subsidized because that would presumably mean that it could not support itself.

Based upon these responses we have concluded that:

- 0 The system would have a greater probability of success if capital costs are not absorbed by the user.
- 0 In marketing the product, it will be necessary to demonstrate that the thermal energy alternative is less expensive than current alternatives.

3.C. INSTITUTIONAL ASSESSMENT

Overview

Institutional issues have been divided into two distinct groups depending on the degree to which each issue might present a problem for the implementation of district heating and cooling systems. Group 1 issues are those which might pose significant barriers to the development of district heating and cooling systems. Group 2 issues do not appear to present significant barriers, but represent concerns which may need further clarification and analysis in Phase 2 of this study. These latter issues involve laws and regulations which will impact district heating both administratively and economically but which do not present serious impediments to implementation at this time.

Group 1: Potentially Significant Institutional Issues

- 0 Selection of an Owner/Operator
- 0 Decision Process for Utility Investment in Cogeneration District Heating
- 0 Hookup Policy
- 0 Allocation of Costs/Benefits Between Electrical Generation and District Heating
- 0 Moorhead Public Service Plant Lease and Purchased Power Agreements
- 0 Pricing Policy
- 0 Profit Motivation for a City-Owned District Heating System
- 0 Capital Structure
- 0 Types of Debt Available

Group 2: Institutional Issues Having Less Significant Impact

- 0 Start-up and Construction Permits and Authorizations
- 0 Franchise Agreements
- 0 Taxation
- 0 Zoning and Redevelopment Plans
- 0 Regulation of the District Heating Business

- 0 Displacement Effects on Existing Energy Suppliers and Their Customers
- 0 Adequacy of Existing Coal Contracts

Considerable care and effort has been devoted to identifying and analyzing institutional issues, but it is conceivable that other significant issues may be identified in subsequent phases of this project. These issues will be dealt with when they arise. Certain issues discussed below are not relevant to all sites. The applicability of each will be made clear in the detailed discussion of the three "final" sites.

Potentially Significant Institutional Issues
(Group 1)

Selection of Owner/Operator

The ownership options which were considered in this study include: ownership by a new company; ownership by an existing utility; joint ownership between an existing utility and another entity; and formation of a co-op of users. Because the existing electric utilities already own the plants required for district heating, the most reasonable assumption at this time is that those utilities would own and operate the district heating systems. Justification for the selection of site-specific ownership and operating assumptions will be presented later in this report.

Decision Process for Utility Investment

The evaluation process for an investment in district heating will vary for each of the utilities considered as potential owners. Their required returns, challenge of the economics, emphasis on institutional concerns, and corporate approval process all reflect their individual management goals and objectives. This decision process and the identification of the critical variables assessed are important factors in the determination of the overall feasibility of any district heating development.

The decision process for most potential owners focuses on the economic analysis. Given a sufficient economic return based on realistic projections, each potential owner indicated that institutional factors could then be considered. At this time, it is the opinion of each of the utilities which have been identified as potential owners that no unqualified opinion can be given regarding the utility's willingness to proceed to implementation until additional analysis has been completed.

Hookup Policy

Hookup refers to physically connecting a customer to a distribution line of the district heating system. Hookup policy issues that must be addressed include: mandatory or voluntary hookup; the assignment of installation and conversion costs; and ownership of the heat exchangers. The final resolution of

these issues is important because the hookup policy resulting from that resolution will have a significant impact on the viability of the district heating company. High start-up costs for the system are anticipated, thus a high hookup rate is essential in order to recover those costs.

It is improbable that a mandatory hookup policy would be politically or institutionally acceptable to the potential customers or to the community in general. Therefore, the hookup decision will almost certainly be left up to the building owners. This latter approach impacts the hookup rate and the economics of the system, due to the high cost of conversion for some buildings and the resultant uncertainty of demand for the system. Because of the high fixed costs for the system (depreciation expense and interest expense), operation of a new district heating system will be uneconomical below some critical level of demand. Accordingly, the hookup policy must be structured to insure that that critical level of demand is either met or exceeded.

The costs of conversion could be borne by either the property owners or the district heating company. Each alternative is discussed below:

Alternative 1: Property owner assumption of conversion costs. If the costs of conversion are assumed by property owners, the connection represents an added expenditure to consider when making the decision of whether to hookup to district heating. Installation and conversion costs will differ for each building owner depending on the type of heating system that is to be converted.

Because each building owner has a different conversion cost which results in different expected returns over the life of the project, the degree of market penetration will be difficult to predict. The assignment of conversion costs to the building owner will increase the perceived risk of the project and may have a negative impact on demand. In order to encourage hookup, incentives such as preferential loans, tax credits or other arrangements may be needed.

One additional problem relates to the perceived high cost of capital for many owners, particularly for owners wishing to own a building for a short period of time. It is not uncommon for building owners to require a payback on their investment in two to five years, implying that their cost of capital is from twenty to fifty percent. Although their actual cost of capital may be much lower, this perception could dissuade owners from purchasing conversion equipment.

Alternative 2: District heating company assumption of conversion costs.

This alternative involves absorption of all conversion costs by the district heating company. The costs would be capitalized and amortized over the life of the equipment. As such, amortization of conversion costs would be another operating cost of the district heating company and would have to be recovered in the rates that customers pay for service.

This would shift the economic burden initially from the building owners to the district heating company. Customers may indirectly pay for conversion through higher rates but that would depend upon the form and structure of rates, the impact of competitive pressures, and the overall marketing strategy.

The district heating consumer might gain if the cost of financing conversion were lower for the district heating firm than for the customer. Because there is likely to be a wide divergence in the cost of capital for various potential customers, the attractiveness of financing conversion through the district heating firm will vary by individual customer. It is quite likely that the cost of capital for the district heating company will generally be less than for individual customers. Should the district heating firm be allowed to finance conversion with a tax-exempt debt offering, all consumers would most likely benefit from such an arrangement.

The negative impact on demand associated with building owner absorption of conversion costs for different systems may be alleviated with this alternative. Customers with a higher-than-average ratio of conversion costs to thermal usage might not connect to the system unless their hookup cost was lowered. Depending on the overall economics, the broadest base of customers might be achieved if the conversion costs for these customers could be spread over all users. The implication for customers with a lower-than-average ratio of hookup costs to thermal usage is that they would trade off their lower cost of conversion for a lower cost of operation due to the spreading of high fixed costs. In structuring the customer base, care will have to be taken to insure that the average conversion cost achieved is economically justified. If conversion costs are paid for all customers, the program will have to be structured to prevent the attraction of a disproportionate share of buildings with high conversion costs.

For the present time it has been assumed that the owners of the heat exchangers will be whoever has incurred the conversion costs. Ownership of a portion of the heating system beyond the meter by the utility presents potential problems in performing maintenance and in building security. However, arrangements might be made where responsibility for equipment maintenance could be placed with the customer, while ownership rests with the utility.

Additional considerations. Potential district heating customers can also be expected to consider other factors in arriving at their final decision relating to hookup. Conversations with several building owners indicated that, given the preliminary nature of the cost and engineering estimates, specific hookup decisions could not be made at this time. Several factors appear to be relevant to the potential customer's hookup decision:

- 0 Alternative fuels and their perceived long-term availability;
- 0 Risk of achieving projected savings associated with conversion;
- 0 Financial stability of district heating firm;
- 0 Reliability of district heating versus alternative fuels;
- 0 Present condition of the heating system;
- 0 Cash flow considerations;
- 0 Whether capital investment recovery for building owners is possible; and
- 0 Identification with energy conservation objectives.

Capital investment recovery for building owners is an important institutional issue because building owners must either absorb the capital outlay or pass it on to tenants through higher rents. Some building owners may not have any way to recover the costs of converting given the restrictions inherent in some building leases. These restrictions can take the form of an obligation on the part of the owner to pass on to tenants any fuel or heating savings while at the same time prohibiting the passing on of any additional capital costs. Therefore, the resolution of this issue could be a significant factor in a building owner's decision.

Given the alternatives and consequences discussed above, the following assumptions for this preliminary phase of the district heating project were selected:

- Assumption 1: Absorption of hookup costs by the district heating company was selected as the most reasonable alternative. This option eliminated a portion of the uncertainty associated with demand and many of the problems related to building owner conversion cost absorption.
- Assumption 2: Voluntary hookup was assumed. Building owner hookup was anticipated to occur if favorable economics could be shown. Voluntary hookup will not result in 100% hookup, as individuals may make decisions based on non-economic factors. Hookup is assumed to be phased in over a three-year period in the financial model with the maximum hookup percentage of 90% obtained three years after a particular segment of the distribution line is placed into service.

Allocation of Costs/Benefits Between Electric Generation and District Heat

The hot water for the district heating system will be produced by an existing public utility or municipal utility utilizing existing generating plants. The price which the utility charges the district heating system for this hot water allocates the costs and benefits of cogeneration between electric customers and district heating customers. There are two basic approaches for determining price of the hot water:

1. A traditional cost-based public service approach to pricing; and
2. A market-based pricing approach which recognizes that economic considerations dictating the feasibility of marketing district heating services in a competitive environment will be used as the pricing criteria.

Allocation of the costs of cogenerating electricity and thermal energy to those respective systems is an important institutional issue because the price of the hot water may be critical to the economic feasibility of the project. Unless agreement can be reached very early in the project's development as to how the hot water will be priced, it is possible that the project will not be undertaken.

The public's perception of the benefits of district heating, their views as to what approach constitutes a "fair" costing, and the specter of electrical consumers subsidizing district heating customers is apt to generate considerable controversy. To some extent, the degree of public acceptability of the project will depend on how these issues are communicated to the public, how well they are understood, and how the pricing issue is resolved.

Under regulatory practice in Minnesota, the Public Service Commission approves rules and cost allocations for public utilities as part of a rate case. Because the Commission decides on issues which are currently before it and does not rule on matters which may arise in the future, it is difficult to predict how the PSC will rule when it is faced with the allocation of costs between electrical generation and district heating.

The potential institutional barrier is really not the inadequacy or unfairness of any one allocation methodology (even though the methodology is probably critical to the system's economic feasibility) but the uncertainty and unpredictability of the process for selecting that method. That process must also be public and must give all impacted parties an opportunity to affect the decision.

Several approaches to the problem of choosing a methodology for allocation of cost/benefits between electrical generation and district heating can be suggested:

- Approach 1: Let the Commission decide what is fair and reasonable when the matter comes up in a rate hearing. If the allocation problem is ignored for the present and the resolution of the issue is left to the rate case process, one outcome might be that the district heating project would never be undertaken. This could occur if:
- 0 The price of the thermal energy appeared to be a major component in total system costs;
 - 0 There was a substantial difference in the effects of the alternative allocation methodologies which, given a particular alternative, could make the price of hot water competitive or uncompetitive with other heat sources; and
 - 0 Potential owners/operators perceived that the risk of the Commission choosing a methodology which resulted in co-generation district heating services to be priced out of the market was too great to justify the investment.

Another possible outcome, however, is that potential investors/operators would not perceive the risk of an adverse allocation ruling to be so great as to prevent system development. Between these two extremes is another possible outcome, that being that the system would not be developed until the economics were favorable enough to render the allocation choice immaterial.

Approach 2: Pass legislation which would mandate definitive authority to the Commission to establish the allocation methodology in advance through its rules hearing process. The Public Service Commission currently has the authority through the rules hearing process to establish the methodology for allocating costs between electrical generating and thermal generation. It does not, however, have a clear mandate to do so because there are no large-scale cogeneration district heating systems in operation in the state. Accordingly, the Commission is unlikely, at the present time, to devote time and resources to the resolution of an issue which does not impact its decisions on current utility rate cases.

This potential barrier to the implementation of a district heating system could be removed if the state legislature were to provide the mandate for a ruling. Legislation could give the Commission a clear directive to establish the allocation methodology within a specified time frame. Then, regardless of the ruling, potential district heating promoters would be able to evaluate the economics of building the system and selling the thermal energy in a competitive environment.

One consequence of this approach is that the entire process could take up to two years to complete. The legislation itself could involve a year or more of delay, and the rules hearing process could take an additional year. This delay may be preferable, however, to the uncertainty of having no established allocation methodology.

Approach 3: Pass legislation which would establish the allocation methodology prior to further system development. This, too, would serve to dispell the uncertainty of not having an established methodology; but it would also take two or more years to pass such legislation. Even then, there would be no assurance that an allocation formula favorable to district heating would be adopted. Overall, the legislature may not be a very good forum for establishing an appropriate methodology.

The most effective alternative for dealing with the cost allocation problem may be for the legislature to direct the PSC to rule on a methodology. The Minnesota Energy Agency is currently discussing this internally, with the PSC, and with Twin Cities utilities.

Pricing Policy

Hot water district heating services must be priced to compete in the marketplace with alternative heat sources, including electricity, which is a co-product of the district heating cogeneration plant. A pricing policy requires the formalization of the characteristics, terms, conditions and corresponding rates for the various services provided by the district heating system in the marketplace. An inappropriate pricing policy may create significant barriers to establishing and maintaining an otherwise feasible district heating system.

Pricing policy issues which could impact the viability of the district heating system include tariff classification, pricing basis, and rate structure.

Tariff classification. A tariff classification is the "product line" of the district heating services which may be obtained by a consumer from the district heating system. Each individual service offering is described by specific terms, conditions, and characteristics of the service.

In order to be effective in a competitive marketplace, the district heating system must offer a flexible range of services under terms and conditions which are mutually consistent with market needs and system needs. The several temperatures, pressures and flow rates which could be available to customers must be evaluated in terms of market impact. The availability of the services must be defined geographically, and the applicability of the service to various end use patterns must be established to properly balance desirable system usages with potential customer usages. Any special conditions or restrictions on system operation, reliability, or safety must be properly identified and specified in the tariff classifications. Tariff classifications designed to promote specific system objectives must be established to assure economic operation of the system. Special contract services designed to meet unique heating needs must also be considered in developing appropriate pricing policies.

A number of examples can be given to illustrate the impact of inappropriate rates classifications:

- 0 Were the district heating utility to fail to distinguish between peak and off-peak services in its service classifications and subsequent pricing policies, on-peak customers might be inappropriately encouraged to use the system and off-peak customers might be effectively discouraged from using the system. This could adversely impact the system load pattern.

- 0 Were the utility to fail to distinguish between density of service areas in its pricing policies and service offerings, growth of district heating may be subsidized in the less dense areas relative to the more dense areas.

If the tariff classification is not properly researched and designed, the district heating system will risk not properly matching its products with the needs of the marketplace, thus jeopardizing market acceptance and rapid system development. It should be noted, however, that since the Minnesota Public Service Commission is not empowered to regulate district heating companies, a district heating company would not be required to submit a tariff to the Commission.

Pricing basis. The pricing basis is the method, or group of methods, employed to determine appropriate market prices for the district heating services defined in the tariff classification. The primary bases of pricing include competitive service-based pricing, cost-based pricing, social cost/benefit pricing and practical-constraint pricing.

Energy prices are the subject of intense local and national scrutiny resulting from the increased cost of energy, supply limitations, and other factors. Energy suppliers, whether directly regulated or not, are typically required to provide the rationale underlying their specific energy prices. The different methods that might be employed in arriving at prices for district heating services will likely produce substantially different prices and, as such, will be closely scrutinized and will be the subjects of considerable controversy. Different price levels will also impact the revenues available and the overall economic viability of the district heating.

The upper level for the prices which may be charged for the various district heating services will be constrained to the prices that consumers will be willing to pay for the service plus any possible direct consumer subsidies which may be available. The lower level of prices is constrained by the operating costs and profit requirements of the system less any system subsidies which may be available.

The "ceiling" price for district heating services is constrained by the competitive price of energy alternatives but is not necessarily equal to the current costs of those alternatives. Longer-term cash flow and discounting

analysis must be conducted to determine "life cycle" costs for both district heating services and competitive services. Considering the fairly broad range of estimates now available for long-term prices of gas, oil, electricity and other energy sources, life cycle costs must necessarily be estimated using several plausible scenarios. In addition, different rates might be established for the different service classifications of each energy source (e.g., industrial rates, commercial rates, promotional rates).

The determination of the price "floor" and intermediate cost-based prices for the various district heating services is complicated in that there are a number of cost-based methods which may be used to develop "product or service" costs and each of the several methods are, in themselves, complex. Although an in-depth discussion of the various costing methods and their effects on service costing is beyond the immediate scope of this discussion, some background may be useful.

The costing methodologies which can be used in determining the costs of various services may be categorized with respect to the types of cost data used in the methodology and the methods employed to properly assign the costs to specific services.

The alternative types of cost data frequently used in pricing/costing studies include:

- 0 Accounting (book) data;
- 0 Current or replacement cost data; and
- 0 Discounted long-run cost estimates.

Methods which are employed in evaluating cost data and properly assigning costs into appropriate service categories include:

- 0 Profit margin contribution analysis of variable costs;
- 0 Full cost (fixed or variable) allocation (there are over twenty methods for determining full cost allocation); and
- 0 Marginal cost allocation

Socio-political influences are also factors which can impact the feasibility of the system. Energy prices, particularly for heating uses in cold climates, are a matter of considerable public interest with regard to the welfare and safety of the public as well as for energy conservation. Many people regard energy pricing as an issue which must be directly addressed in a

socio-political context. Consequently, these form additional bases for pricing energy.

Practical constraints play an important part in establishing specific rates and, to a certain extent, also place limitations upon the underlying pricing methodologies used. The primary practical constraints are those associated with the gathering of statistics needed to utilize a methodology and the types of metering which can be economically employed in the system.

Rate structure. Rate structure refers to the specific prices and billing approaches established for the various district heating services specified in the tariff classification. The prices charged for these services must be consistent with market sensitivity factors so as to attract a sufficient number of customers and to assure the economic viability of the system.

The pricing structure must complement the tariff classification by encouraging desired system usage and discouraging undesirable system usage. For example, if space heating applications had a natural competitive advantage and industrial process applications did not, the district heating company might want to structure rates differently for those industrial process uses in order to make district heating an attractive alternative for both.

In order to properly balance the available supply of district heating services to the demand for services which exist at the various possible prices, a pricing analysis must be undertaken. This pricing analysis or market study must provide information regarding the potential demand for the possible services as well as an estimate of the price sensitivity of that demand. This information, then, would become the basis for determination of an appropriate rate structure.

An inappropriate pricing strategy, particularly at the onset of the new district heating service, could have long-term detrimental effects on the district heating company. Moreover, without some assessment of how potential consumers of the various services would respond to the district heating services offered at the specified prices, the economic feasibility of district heating cannot be assessed.

At this time, it is impossible to specify or recommend appropriate tariff classifications, pricing basis, or rate structure. That analysis and

determination should be included in Phase 2. The key consideration at this point is that the pricing must be such that the market is penetrated quickly. To accomplish that, prices may have to be set on a competitive basis and then allowed to catch up with costs over the longer term.

Profit Motivation for a City-Owned District Heating System

Under public ownership, a district heating utility can be established as an entity either with a profit or a break-even objective. If the project were privately owned, the project would only be undertaken with a profit motivation. Government ownership, on the other hand, would allow the alternative of operating with the objective of breaking even on the initial investment.

If a break even objective is selected for the government-owned district heating company, rates would be set so as to recoup original investments without allowing for a profit. Under this alternative, then, funds would not be available for contributions to the city's general fund. Also system additions would have to be financed from internal cash flows, from additional borrowings, or from funded depreciation.

If a municipally owned district heating utility chooses to make a profit, it must price its services to cover all capital and operating costs, depreciation and a return on investment. If the utility is established with an initial infusion of capital from appropriations, revenues would provide for repayment of that initial contribution. Over time, the enterprise would accumulate earnings from operations just as would a privately held concern. The enterprise would attempt to be completely self-supporting, plan for future replacement needs and, over the long term, might even make a contribution to the owner-government's general fund.

Capital Structure

Capital structure is determined by the mixture of debt and equity components used to finance the start-up costs, expansion, and working capital of the district heating company. The selection of an appropriate balance of debt and equity is an important issue because it has a direct impact on the cost of providing district heating services. The selection process involves consideration of two objectives, presented below.

Attainment of low cost financing. The capital structure determines the amount of risk assumed by the debt and equity holders and influences the returns these groups require. Debt instrument holders have first lien on the company's assets in the event of liquidation. Therefore, their relative risk and expected return is lower than that required by equity holders. Another attractive feature is the fact that interest expense is deductible for tax purposes. This benefit may only be realized if the district heating company is profitable and can utilize the deductions on its tax return. All of these advantages, which have a tendency to lower the cost of debt financing, must be evaluated in light of the second objective involved in capital structure determination.

Selection of a capital structure which is attractive to investors. In order for an investment to be attractive to either debt or equity investors, the company's capital structure should balance risk in a way that attracts debt and equity holders. For example, if a company possesses a high proportion of debt to equity, the risk allocated to either class of capital suppliers might be too great and might deter potential investors. Debt investors may be difficult to attract because of the high risk associated with the significant burden of meeting existing fixed interest payments. Equity may be difficult to issue because, as subordinate claimants, equity holders would incur a greater risk both in terms of the residual remaining in the event of liquidation and in terms of the availability of cash flow for dividend distribution after all fixed interest payments have been met. It will be in the best interest of the district heating company to choose a balance of debt and equity such that capital costs are minimized and potential investors will be attracted.

Types of Debt Available

Debt represents capital loaned to the district heating firm for a specified period of time for a fixed rate of return. Debt claims on the firm do not represent any ownership rights and do not imply any control over the business or input into management decisions.

There are numerous types of debt available in the market today, with different interest rates and obligations on the issuer. Each of these characteristics and their impacts must be considered in the selection of types of debt to issue. The debt used will be a function of owner/utility choice, availability

and the characteristics of the business. Because the amount of debt capital needed is likely to be large, the selection of the types of debt will have significant impact on the costs to the district heating company. It should be noted, however, that many of the debt alternatives available in the market are not appropriate for the financing of a new district heating company. A preliminary assessment has indicated that long-term bonds will be the most likely source of debt financing. Bonds represent a creditor relationship with the corporation and provide a fixed rate of return or interest on specific dates in the future. They have a fixed date of maturity but often can be called under certain conditions prior to that maturity date. In the event of liquidation of the firm, debt holders' claims on assets must be satisfied before those of equity holders, so bond holders' investments are somewhat more secure than those of equity holders. The interest paid on the bonds by the corporation is a deductible expense for income tax purposes. Those bonds which appear to be reasonable given the capital structure assumptions and the characteristics of the business are discussed below.

Mortgage bonds. These are secured by specific tangible assets of the corporation which have a value equal to or exceeding the amount of the bond issue. In the event of default, the trustee for the bondholders can foreclose on the mortgage, sell the asset collateral and use the proceeds to pay the bondholders. Interest paid to bondholders is taxable income to the bondholder.

Debentures. These represent unsecured or general credit bonds of a corporation. Because the earning power of the firm is looked upon as the security of the bonds, the bondholders rank as general creditors in the event of liquidation of the firm. The indenture usually includes a "negative pledge" clause, however, which prohibits the borrower from pledging its assets to other creditors. Debentures are usually used only by well-established credit-worthy firms and might, therefore, be used by an existing utility to capitalize a new district heating system. If the system were owned and operated by a new company, this may not be a feasible debt instrument. Interest paid to bondholders is taxable income to the bondholder.

Industrial development revenue bonds (IDR's). Current law (Minn. Stat. Ch. 474 - Municipal Industrial Development Act) provides that a taxing authority may issue IDR's to finance a load to a non-governmental entity for the purpose of funding industrial development projects and pollution control facilities. These issues are subject to the approval of the Commissioner of the Department of Economic Development. The issuer pays the bond proceeds to the entity being financed and receives, in exchange, a capital note and a pledge of the revenues of that entity

sufficient to satisfy principal and interest payment obligations. Because the security for the bonds is the project revenue stream, uncertainties as to the amount and timing of the cash flows will impact the rates on the bonds. The bondholders' interest income is not subject to federal or state income tax if the bondholder resides in the state where the bonds were issued. The obvious advantage of tax-exempt revenue bonds is that the interest cost to the firm being financed is much lower than if conventional, taxable, debt instruments are employed.

In Minnesota, a municipality can issue IDR's for a firm if the firm's capital expenditures for the six year period extending from three years prior to the issue to the end of the third subsequent year, do not exceed five million dollars. However, this limitation is waived if the IDR issue is to finance facilities for air or water pollution control. At this time it is not clear whether the financing of a district heating system will be subject to the five million dollar limitation.

General obligation bonds (GO's). A taxing authority may issue GO's to finance most types of public improvements. This type of government bond provides a high degree of security to the investor as it is backed by the full faith and credit of the issuer. Thus, the authority pledges the full use of its taxing and other general revenue producing powers to generate funds to meet principal and interest obligations. GO's are attractive to investors residing in the state where the bonds were issued and the interest income is exempt from both federal and state income taxes. Unless the district heating system is owned by a municipality, the issuance of GO's to finance it would not be possible. If they are used to finance a municipal system, rates for GO's typically are two or more percentage points lower than for IDR's.

Special tax or limited tax bonds. In lieu of providing authority to levy an unlimited ad valorem property tax, municipalities and special districts may issue limited tax debt in an amount which can be serviced by a specified mill rate on the affected real property. Accordingly, the amount of debt which can be issued is constrained by the mill rate established by the legislative body.

Special tax bonds differ in that an alternative tax base is utilized for debt service requirements. Special sales taxes, liquor taxes, gross receipt taxes, or special assessment property taxes (on those properties in the district heating market area or located on the distribution lines) could be earmarked for meeting special tax debt service needs.

Either of these types of bonds could conceivably be used in a government-owned district heating company financing package. Both provide bondholders with a degree of security which is somewhat less than for GO's but stronger than for IDR's. However, this type of bond would most likely be used in combination with another type in order to finance the entire amount of capital required.

Revenue bonds. These bonds may be issued by a municipality or special district to finance public acquisitions or improvements which can be supported through user charges. Typical projects include utilities, parking garages, transportation services and recreational facilities. Funds for principal and interest payments are generated from the net revenues (gross revenues less operating and maintenance expenses) of the government owned entity. Revenue bonds do not provide as much security to the investor as do GO's, however, so the rates on these are typically higher. The interest income to bondholders is exempt from state and federal income taxes.

A consequence of raising external debt capital is the involvement of investment bankers, bond counsel, and securities rating agencies in a potential bond offering.

Appendix H discusses the role and involvement of investment bankers, bond counsel and securities rating agencies in a bond offering to finance the proposed district heating projects.

Institutional Issues Having Less Significant Impact
(Group 2)

Start-Up and Construction Permits and Authorizations

Start-up and construction permits include all authorizations required from federal, state, and local administrative and regulatory agencies for implementation of the district heating project. Such permits must usually be obtained prior to commencement of project construction or may be required for a specific phase of the project.

The impact of the permit process may be felt in the actual cost of the permit, the time associated with preparation and processing, and the increased construction costs resulting from the delays in initiating construction. Of these costs, the most significant is the price escalation on new construction which alone could add ten to fifteen percent to construction costs each year.

Operating permits. State Certificate of Need and Certificate of Site Compatibility permits will not be relevant because current statutes do not include hot water district heating systems and because preliminary demonstration project plans do not require the siting of a new power plant (Minn. Stat. #116D and 116C.51-116C.69).

Environmental permits. Environmental permits include those authorizations which certify that the project will not have an adverse effect on air or water quality. Federal agencies, such as the Environmental Protection Agency, have established guidelines which Minnesota state agencies, such as the Pollution Control Agency, have developed into state rulings.

Environmental Assessment Worksheet (EAW)/Environmental Impact Statement (EIS). The normal environmental review process begins with the completion of an Environmental Assessment Worksheet (EAW)--a document which provides a description of the proposed project and an assessment of the potential environmental impact. This document is circulated among state agencies and local governments for comment and review.

An environmental impact statement (EIS) must be prepared if the project is anticipated to have negative environmental impact. This statement includes a project description, the environmental impact, commitments of resources, alternatives, and the responsible agency's response to the significant environmental issues raised during draft and review.

Environmental impact requirements will affect the district heating company primarily through the costs and the delays inherent in the processing and review time. Refer to Appendix C for an illustration of review process timing.

An EAW will likely be required for a new district heating utility due to the scope of the project and potential for environmental impact. However, at this time it is not clear whether an EIS would be required. If an EIS is waived, the permitting process could be reduced by up to six months.

Use of land/easements. This category includes all authorizations needed to allow the construction of permit facilities and laying of pipes in desired locations. Included are easements and permits for right-of-way. Authorizations are granted by city and county agencies, as well as by private land owners when their properties are affected.

Easements. These are agreements between private property owners and the utility allowing access to private property for project construction. Easements must be obtained from the property owners before construction takes place if the lines are to cross the owners' property. The costs involve the legal fees incurred for negotiation and the delays attributable to rerouting or extensive negotiation with non-supportive parties. The time frame is entirely dependent on the number and agreeability of property owners from whom easement must be obtained.

Right of eminent domain. Regulated public utilities in Minnesota are granted the right of eminent domain; because current statutes do not include district heating companies, this right would not apply.

If the existing statutes were amended such that district heating companies became eligible to claim the right of eminent domain, the utility would be able to use private property for utility use, providing that just compensation was provided. Utilities avoid invoking this right, however, due to the lengthy and costly court cases which can ensue. Rather, utilities pursue negotiation of a reasonable settlement with property owners.

Utility permit on trunk highway and permit to use airspace above or sub-surface below trunk highway. The objective of the permit is to enable joint development on highway properties. The district heating company would apply for this permit if it needed to attach pipes to a highway structure or to run pipe under a trunk highway.

Standard applications giving the basic project description and pipe locations are required. The approval can take from two to six months and no significant cost associated with the permits is anticipated.

Railroad permits. The preliminary distribution lines in both Red Wing and Fergus Falls cross railroad property; accordingly, authorizations from the affected railroads will be required. Railroad personnel have indicated that these permits most likely will not significantly impact the district heating company in regard to costs or delays.

Construction/system design permits. Normal city or county construction permits covering the plant retrofit and customer hookup/conversion will be required. These authorizations include building, heating system, construction and other permits required for renovation, remodeling or other changes. System plans must be submitted to the city engineer for review prior to any construction in order to insure that the transmission and distribution lines will not interfere or obstruct other underground systems. The attainment of construction permits is not expected to create any avoidable time delays or result in any substantial costs to the district heating company.

Incorporation/issuance of securities and debt. Establishment of a corporation according to state and federal laws is required before construction if a new entity is created to own and operate the district heating utility. Assuming that existing utilities build the project, this will not be required.

The issuance of debt and/or equity securities most likely will not be a problem as all the potential owners and cities selected for this preliminary phase have a Moody's rating of A or above. These utilities are experienced in applying for the required permits.

A critical factor in assessing the permit process as a potential institutional barrier is the acceptability of the project in terms of environmental impact, routing of transmission and distribution lines, and the need for additional cogeneration capacity. Should the project be assessed as having no adverse environmental consequences, as being properly routed and compatible with state energy conservation objectives, the authorizations will present minimal problems. However, if there is sufficient doubt raised about the impact of the project, the permits may become difficult to obtain due to challenge by public interest groups and other affected concerns.

At this time it is impossible to state categorically that no permitting problems will be encountered. The project team was favorably impressed by the degree of public interest in the project, but no assurances can be provided that

barriers will not be encountered or that public interest groups will not challenge the environmental impact of potential hot water spills or construction disruption.

It is also impossible to state at this time that the project will be able to obtain all needed permits. That determination cannot be made until the project has been completely designed, all permits have been applied for, and the application have either been accepted or rejected. For the three potential demonstration sites, it appears that the application and approval of local permits does not represent a major institutional hurdle. The fact that no new generating facilities are contemplated at this time eliminates the need for most major power plant permits. The costs associated with the various permits are minimal. Optimistic and pessimistic time frames proposed for the entire approval process are presented in Appendix C.

Franchise Agreements

In order to provide services in a particular city, a utility is usually required to obtain a grant of special privileges from the municipal authority. These privileges typically include:

- 0 The right to construct, operate, repair, and maintain utility facilities on public property;
- 0 Permission to operate as a supplier of a specified service for a specified period of time (life of the franchise); and
- 0 Protection from bearing the cost of indiscriminate relocation caused by city mandate.

In return for these privileges, the city may include sections in the franchise which provide for the following:

- 0 Indemnification of the city in case of accidents caused by utility construction or operation;
- 0 Regulation of the rates of a franchisee by a city utility board; and
- 0 Imposition of a franchise fee or a tax on gross earnings of the utility.

The franchise agreement is negotiated with representatives of the city and becomes a legal contract after passage of a municipal ordinance. In return for the privilege to operate in the city, the utility usually agrees to tax pro-

visions and conditions relating to safety and adequacy of service, but often also to reporting requirements, arbitration of labor disputes, and free or special services provided by the city to the utility.

Under current law (Minn. Stat. Ch. 216B - Public Utility Regulation), district heating companies are not considered to be public utilities so franchise provisions may be somewhat different than for existing regulated utilities. However, franchise agreements have the potential to impact the district heating utility significantly in terms of costs and restrictions. These consequences are detailed below:

Costs

- 0 A franchise fee may be assessed on gross earnings; known examples of such fees in the Minneapolis-St. Paul area are from three percent to nearly nine percent.
- 0 A regulatory fee may be required to cover the cost of the review of the utility's compliance with franchise provisions. In Minnesota, this fee is not prevalent.
- 0 The actual cost of negotiating the franchise agreement is minimal and, depending on the city, may cost between \$25 and \$100.
- 0 The costs associated with time delays inherent in processing and preparation may be material if construction is significantly delayed. Given that no major controversies develop, preparation and processing could take from one to six months before final approval is granted.

Restrictions

- 0 Under existing statutes, the rates a franchised district heating company could charge customers would be subject only to the review of a municipal utility board. This regulation of rates could negatively impact the district heating company if it constrained its ability to respond to market factors on a timely basis.
- 0 Most agreements must be re-negotiated every 10 to 25 years as no perpetual franchises are granted in Minnesota (Minn. Stat. 410.09).

As a result of preliminary discussions with the potential utility owners and various city officials, franchises do not appear to represent serious problems. In all of the cities, the utilities and the cities have enjoyed good working relationships and existing franchises are not unduly restrictive.

Taxation

The major taxes which an investor-owned district heating company would be subject to are discussed below:

Property tax. Property taxes in Minnesota are currently calculated by multiplying a percentage (which varies according to property type) by the limited market value (taxable market value) of the property, to arrive at the assessed value. A tax mill rate is then applied to this assessed property value to determine the amount of tax to be paid.

Property held by a public utility is classified as either real property which includes land and buildings; personal property, which includes transmission lines; or attached machinery, which refers to non-movable equipment. Taxes are assessed on 43% of the limited market value for real and personal property and 33-1/3% of the taxable market value for attached machinery.

Because the property tax assessment is fairly complex, for purposes of the preliminary study a single property tax rate has been applied. Analysis has indicated that the aggregate effects of property tax can be reasonably approximated by multiplying the assets' historical cost less depreciation by a percentage rate which is stated in the economic analysis section of this report.

Income tax. Federal and state income taxes will be payable in years in which the utility has taxable income and will be determined in accordance with the statutes existing at that time. For the purposes of this study, the combined tax rate is assumed to be approximately 52% of taxable income.

Employer taxes. State and federal unemployment taxes as well as the employer share of FICA taxes will also be applicable to the district heating company. These taxes are included as part of the overall general and administrative expense of the utility in the economic model.

Other taxes which have been considered but which are not applicable for the three cities studied are:

Sales tax. A four percent sales tax on the dollar amount of energy consumed must be paid by consumers but collected by the district heating utility. It may be worth noting that district heating is, in effect, penalized by current sales tax treatment relative to in-house heating systems. A building owner must pay sales tax on the fuel consumed in the in-house system. A district heating utility also must pay the tax on fuel consumed, and the customer using the thermal energy must pay the tax again on the energy he uses.

Property tax. Property taxes vary proportionally with the entity's investment in real and personal property. Thus, property taxes will be sizeable as the district heating system requires significant capital investment. The amount of the property tax will affect the overall economic viability of the district heating company because it will add to the cost of providing service and will reduce the cash flow for the firm in the start-up years. In the early years the cash flow problem may be magnified by the amount of tax because taxes will be levied on a large investment even though the utility will be generating revenues at a level far less than capacity would permit.

Due to the phasing of system development and the assumption of competitive pricing, revenue may not cover costs until the system is completely in place. If the community is to obtain the benefits from the heat which is otherwise rejected into the air or the rivers, then it may be necessary to grant some type of competitive economic advantage to the district heating system, and exemption from or shifting of property taxes may be a method to consider.

Income tax. The bulk of income taxes will be paid to the federal government and it is assumed that, barring any unforeseen changes, the federal tax will remain applicable. The same remains true of state income taxes but these may be easier to change should any preferential treatment be needed to encourage the development of cogeneration district heating. For the purposes of this study, no alteration in corporate tax rates have been assumed.

Zoning and Redevelopment Plans

Zoning and redevelopment plans are important concerns because they may impact the market development of the district heating company. Site-specific plans for redevelopment and industrial expansion and their effects on the potential market will be discussed later in this report. With the exception of future market opportunities, the planning director in each of the cities believes that zoning or land use plans will not significantly impact district heating development.

The redevelopment and expansion plans, either proposed or underway, in each of the cities have the potential to impact the district heating market. However, further investigation and evaluation of the amount of energy consumption, the compatibility of the prospective heating systems, and the costs of conversion will have to be undertaken in Phase 2 in order to determine the impact on the district heating market.

Regulations of District Heating Companies

In Minnesota, the Public Service Commission currently has authority to regulate investor-owned gas and electric utilities (Minn. Sta. Ch. 216B) but is not empowered to regulate district heating companies. It has the authority to regulate public utility rates and revenues; to approve capital structures; to approve the issuance of securities; to establish depreciation methods and rates; to regulate the expansion of service to new customers; to prescribe standards of service; and to perform other specific regulatory responsibilities. In order for the Commission to have jurisdiction over district heating companies the existing statutes would have to be amended to include them.

The PSC also does not regulate municipally-owned utilities. That function is left to the discretion of the municipality and usually takes the form of oversight review of management decisions and rate setting by a municipal utility board.

The question of regulation of the district heating company is an important institutional issue because it could influence the acceptability of the project to the public and could have a direct impact on the cost of hot water services to its customers. If the district heating company is regulated, that decision may contribute to the establishment of a degree of credibility and public acceptance of the project. However, it will also create additional expenses due to increased administrative cost, rate case preparation, hearings expenses, and regulatory delays.

The impact of regulation will depend on the form and degree of that regulation which would be determined by the amended legislation and any subsequent rules. The impact it will have on the public's acceptance of the project or on the rates paid by customers cannot be precisely measured at this time. If the regulation is extensive it could affect all aspects of the financing and economic feasibility of the project.

Regulation also may impact a utility's decision to implement district heating. If a prospective utility owner is sufficiently concerned about entering a new regulated business and about the risks of that regulation, the decision to commit to the project might be impossible to obtain.

If the district heating company is not regulated, it will theoretically be better able to respond to changes in its economic environment and to allocate resources according to management's perception of where it can obtain the highest return on the investment. Free market economic theory suggests that by allowing the firm to operate in such a manner in a competitive environment, resources will be efficiently allocated and society will be better served in the long run.

A second implication is that without regulation, costs which would have been incurred in complying with regulation (both the company's cost and the state's cost) would be avoided, thus lowering the total cost of providing district heating services. Lower costs could lead to lower district heating rates and an enhanced competitive position for the firm.

The public, however, might not be convinced that a free market economy operates efficiently and rationally, and might be concerned that the district heating company will earn excessive profits or will not serve the customers in an equitable manner. This concern is important because hookup is a long-term decision. Unless potential consumers feel assured that they will be treated fairly, they may be reluctant to convert, thus jeopardizing system development. In the absence of state regulation, other means might have to be developed for dealing with this concern.

The district heating systems contemplated for the three potential demonstration sites might not be faced with this problem though, due to the anticipated mix of customers. Most customers will be commercial users or other large users who will most likely negotiate long-term contracts for service. If that is the case, they will not need the regulatory monitoring which might be appropriate for small residential customers.

Once customers hook up to the district heating system, the firm might have the equivalent of a monopoly position due to the expense that customers would incur in reconverting to another heat source. If abuses developed as a result of this "locking in" effect (e.g., poor service or unjustifiably high rates), it might become appropriate to regulate the firm. It may be more likely, however, that the company's rates would be adequately constrained by the long-term contracts which are common between district heating companies and their customers.

Such contracts, up to twenty years in length, provide a mutually agreeable mechanism whereby certain cost escalations can be passed on to customers. As long as competition exists for heat sources and as long as the district heating company desires to expand, it appears unlikely that regulation of rates would be of much value to the consumer.

If the district heating company is regulated by the PSC, the firm might be in a less favorable position for responding to changes in its environment. Regulation of rates, for example, could prevent management from responding quickly to changes in the economic environment, which might dictate an immediate increase in rates. Under current regulation and application of statutes, a delay of three to four months could be expected for response to a rate request. This restriction of management action could represent increased risk for investors to bear and, consequently, could result in higher equity returns. Accordingly, district heating rates to consumers might be higher under regulation.

Regulation could have a favorable impact on the public's acceptance of the project. If operating income and rates are regulated, it may, at the very least, give the appearance that the interests of the consumer are being protected and that the firm is not being allowed to earn "monopolistic" profits. If the regulation accomplishes its objective and actually lowers the profits and total costs of the district heating system, then consumers will benefit.

Finally, regulation of the firm in a manner similar to current regulation of public utilities will present other problems which are addressed separately in Appendix D.

Displacement Effects on Existing Energy Suppliers and Their Customers

Existing regulated and nonregulated fuel suppliers of natural gas, electricity and fuel oil are likely to be affected by construction of a district heating system, which will act to reduce the space heating market share of the regulated energy suppliers (gas and electric) and the nonregulated suppliers (fuel oil). The general effects of displacement on the various fuel types will be discussed below, while the displacement consequences for the suppliers within each city will be addressed as site specific issues later in this report.

Natural gas suppliers. If total gas sales decline due to the installation of a district heating system, the price of the gas to consumers might be forced higher (independent of other supply/demand factors affecting gas prices). This is because many of the costs of serving gas customers are fixed (distribution system depreciation, interest expense, etc.) and would be spread over a smaller sales base. Also, the reduction in demand may result in an abandonment of pipes, a cost which would have to be absorbed by gas users. However, because natural gas supplies are already insufficient to satisfy consumer demand in Minnesota, it is more likely that the gas which would have been used by district heating customers would be made available to other customers. Costs of displacement may not be significant:

- 0 If the current supply of gas is made available for existing interruptible users not hooked up to the district heating system, gas sales might not decline and prices might be unaffected.
- 0 If lines currently in use can transport gas for uses other than heating and can continue to serve customers who decide not to convert to district heating.
- 0 If new gas customers may be hooked up. This would require some investment in new pipe lines, a cost which most likely would be borne by gas rate payers which desire gas service.

Electricity suppliers. Electrical sales could be lost if there was substantial displacement of electrical heating by district heating, but these losses could be offset somewhat by increased electrical consumption by the district heating pumps and other equipment. Significant loss of electrical sales does not appear to be very likely, however, because of the low usage of that source for commercial heating and the high cost of conversion from electric to district heating. In the event that some electrical sales are displaced, the impact on rates would not be substantial because of the continued usage of the distribution equipment for nonheating purposes.

Fuel oil suppliers. The primary effect on fuel oil suppliers will probably be the substitution of hot water sales for fuel oil sales when oil customers hook up to district heating. A secondary effect will also occur if gas, which is also displaced by hot water, in turn displaces more fuel oil sales. Even if the entire displacement effect came to rest on oil suppliers, the total effect would probably not be felt by a single supplier. There are a few major

oil companies and several local fuel oil suppliers serving each of the cities, though the major oil companies provide service to the large commercial and industrial users. Thus, the main impact of district heating will most likely be felt by the major oil companies and the effect on any one supplier may not be significant.

Although displacement will undoubtedly be a major concern of alternative fuel suppliers, it is impossible to determine the economic impact on key suppliers at the present time. Further investigation of this institutional issue may be appropriate in Phase 2 of the study.

Adequacy of Existing Coal Contracts

For this study, the thermal energy needed for district heating is assumed to be generated by coal-fired electric power plants. Therefore, the adequacy of existing coal contracts is an important issue as a dependable supply of coal is necessary to assure reliable thermal generation. The coal contracts of the electric utilities studied in this phase do not appear to impose any barriers to implementation of district heating at this time. Site-specific discussions of this issue appear later in the report.

3. D. ECONOMIC ANALYSIS

Overview

The preliminary economic analysis of the potential demonstration sites addressed the economic and cost factors which should be considered in selecting a demonstration community. This effort was designed to identify major economic differences between the selected communities and to determine under what conditions a retrofitted district heating system would be economically feasible. This effort also involved the summarization, coordination and analysis of the results of preceeding technical, marketing and institutional analysis.

The economic analysis began with a review of the work on the other project tasks. Based upon this review, the financial and economic data which would result from these tasks was defined. Other data inputs required to complete the economic analysis were defined and work plans were developed to obtain the information.

It was determined that a base case scenario would be developed for each city. The base case represents the project team members consensus of expected financial results for a district heating system in the cities of Moorhead, Red Wing and Fergus Falls. It was also determined that the results of the economic analysis would be presented using traditional financial statements: balance sheets, income statements and cash flow statements.

In addition, key economic factors which should be used in evaluating the economic viability of these systems were also developed. These included:

- 0 Internal cash flow rate of return over the life of the system.
- 0 Annual return on invested capital.
- 0 Annual return on book equity (where appropriate)
- 0 Annual cash return on invested capital

Finally, key assumptions or estimates used in developing the base case were tested to determine their potential impact on the overall economic results. This was accomplished by measuring the impact of a change in these key variables on the economic factors listed above.

Objectives

The primary objective of the Phase 1 economic analysis was to develop summary economic and cost factors that should be considered in selecting a demonstration community and identifying major economic differences between the selected communities. In order to meet this objective it was necessary to define the most reasonable operating scenario for a district heating company in each of the three cities based upon results of Phase 1 technical, marketing and institutional efforts. It should be noted that the preliminary economic analysis was not designed to develop final estimates of costs and revenues.

A second major objective of the Phase 1 economic analysis effort was to identify the major economic factors (cost and revenues) which must be estimated more precisely before a final decision to proceed with construction of the system can be made. These factors were determined by performing sensitivity analysis to assess the impact of different cost and revenue elements on the overall economic results. The results of these sensitivity tests were then utilized to shape the specific scope of the Phase 2 effort.

Another objective of this preliminary economic analysis was to provide information regarding the results of the Phase 1 effort to potential owners, users and other key decision makers in order to obtain their commitment to future involvement. The base case economic analysis provided a reference for identifying and resolving specific local concerns and requirements.

A final objective of the economic analysis work was to provide input which could be used with other data to rank the three cities on the basis of probability of success. Consideration was also given to operational success of the demonstration site and to the probability of replication.

Assumptions Underlying Economic Analysis

In order to understand and use the results of any economic analysis, it is necessary to understand the basic assumptions underlying the analysis. The assumptions which are key to the base case economic analysis of the three potential district heating systems discussed in this report are presented below. These assumptions are classified as to general assumptions which apply to all cities and site-specific assumptions which apply only to the individual city. The site-specific assumptions are discussed later in this report.

General Assumptions

The general assumptions made in the economic analysis of the base cases and the rationale underlying the assumptions are presented below.

Analysis period

Assumption: The economic analysis was developed by projecting revenues and expenses by type for twenty years. The analysis included developing projected:

- 0 Income statements by year
- 0 Balance sheets by year
- 0 Cash flow by year
- 0 Return on investment and/or book equity by year
- 0 Life cycle cash internal rate of return on total capital
- 0 Life cycle cash internal rate of return on equity capital (where appropriate)
- 0 Present value of cash flow using various discount rates

Assumption: The life cycle return analysis assumed that at the end of twenty years the investment had a cash value equal to its book value. No replacement of depreciated assets was considered.

Assumption: A fiscal year beginning April 1st and ending March 31st of the following calendar year was assumed. The adoption of this fiscal year allows the matching of construction expenditures during the construction period of April through September to the revenues produced during the heating season of October thru March.

Assumption: The analysis covered the twenty year period beginning with fiscal year ending March 31, 1982, to reflect an anticipated start of construction in April, 1981.

Ownership and financing

Assumption: The district heating company would be owned, operated and financed by the electric utility. This simplified the development of the economic analysis in terms of developing, financing and operating cost estimates. Other ownership options are possible in each city, but ownership by the utility means that:

- 0 Cost estimates can be based on an existing administrative structure, which means a reasonable level of efficiency can be assumed for administrative functions such as billing, collecting revenues, and personnel practices.
- 0 Utility operating expertise and experience can be assumed.
- 0 There will be coordination between retrofit and district heating operations.
- 0 A stable financial entity can be assumed which makes it possible to project financing costs.

Assumption: The owner/operator in each city was assumed to be:

- 0 Fergus Falls -- Otter Tail Power Company
- 0 Moorhead -- Moorhead Municipal Utility
- 0 Red Wing -- Northern States Power Company

Assumption: For investor owned utilities, total capital will always consist of 50% long-term debt and 50% equity. This is a reasonable approximation of existing utility capital structures.

Assumption: For the municipal utility, the initial construction and operating losses are 100% debt financed.

Assumption: The interest rate on long-term debt will be ten percent and eight percent for investor owned and municipal utilities respectively. These estimates are approximately equal to the estimated current interest rate for these types of utilities.

Assumption: For investor owned utilities long-term debt will be retired over the years as required to maintain a 50% debt ratio.

Assumption: For the municipal utility, debt would be retired over the twenty year period as cash becomes available.

Assumption: Return on owner's equity was not assigned a cost, but the return will be determined based on the present value of cash flows from the investment over a twenty year life.

Marketing and pricing

Assumption: The potential market is as defined by the market study (Task 2) and will not increase or decrease over time.

Assumption: The district heating company will pay the building conversion costs. This assumption was made in order to avoid estimating each building owners cost of capital and to allow for additional flexibility in pricing and marketing. Potential customers of the district heating company have a variety of considerations that they will take into account in determining whether to hookup to the district heating system. One significant decision criteria will be who pays for the conversion of the present heating system. This decision is impacted by many factors such as the availability of financing, opportunity costs, return requirements and perceived risk all of which may differ dramatically between the various potential users. If individual owners were required to pay the conversion costs, it is likely that a significant portion of the potential market may not hookup because of the initial investment required. The conversion costs can economically be born by the utility since it is likely that they will have as low or lower capital costs than most of the potential users of the system. This assumption also allows the district heating company to balance the cost benefit of increase volume with the cost of converting an individual customer.

Assumption: Thermal energy delivered will be priced initially at 110% of the lowest alternative fuel in terms of equivalent energy. This assumption allows the district heating company to charge rates which should provide an immediate economic incentive to hookup. The total energy cost to the users should still be less than under his existing system because of increased fuel efficiencies.

Assumption: The district heating system energy price will be increased by fixed percentages each year which is less than the percentage increase of alternative fuels. This means that in every year of the analysis, the district heating price increase will be under the projected increase in alternative energy cost and the overall advantage of district heating versus alternatives will increase over time. This provides an incentive for the potential user to hookup to the district heating system as quickly as possible.

Assumption: The thermal energy users will sign long-term contracts for the delivery of the energy and that these contracts will allow the district heating company to increase its rates as outlined above even though its costs do not increase at the same rate. This assumption is necessary since costs exceed projected revenues in the early years.

Assumption: Pricing differentials based on volume, cost of service or value of service will not be reflected. This assumption was made to simplify the analysis.

Assumption: Hookup fees equal to approximately 25% of conversion costs will be charged all customers who do not hookup at their first opportunity. Those customers who hookup immediately will not be charged a hookup fee.

Assumption: The district heating company will ultimately penetrate at least 90% of the potential thermal market because of conversion cost absorption and competitive thermal pricing. This market penetration assumption reflects some of the experience encountered in the development of Swedish district heating systems. It was also assumed that customers along the initial (first year) distribution line construction will have a lower initial hookup percentage because some people will adopt a "wait and see" attitude about district heating. In subsequent years, potential users on the first distribution line will hookup in larger percentages. As new distribution lines are constructed, users having observed the results obtained from the first line will hookup at a faster rate.

Construction phasing

Assumption: All investments in fixed assets will be placed in service in the year of construction and there will be no AFDC reflected. Construction of the distribution lines and the power plant retrofit will begin in April, 1981, and will be completed by the first heating season beginning around October, 1981. The impact of not recognizing allowance for funds used during construction is not significant since the assets used generate revenue in the same year they are constructed.

Assumption: The initial distribution line constructed will allow the hookup of the significant users in each town as well as other potential users along that distribution line. Since the construction season is short, the primary goal of the initial distribution line construction is to hookup the most significant users in order to build a revenue base. Thus marketing effort can be directed towards a limited number of users and those users can serve as a demonstration for the rest of the city.

Assumption: Subsequent distribution line phasing will be dependent on distribution line costs, expected revenue and length of line to be placed in service. Consideration was given in the construction phasing decision to minimizing the construction nuisance encountered by the city residents and businessmen by concentrating construction on specific zones rather than on a citywide basis. The construction phasing reflected in the base case could be actually compressed and the final phasing should be a key concern of Phase 2 of this project.

Cost of thermal energy

- Assumption: An incremental cost allocation approach was used in assigning fuel cost to the district heating company. It was also assumed that the electric operations would have no economic gain or loss because of district heating.
- Assumption: One element of the thermal energy cost will be the additional cost of replacing electric energy because of derating. The electrical plant may experience an electrical generation derating resulting from the turbine retrofit and from live steam being extracted from the boiler for thermal peaking requirements. The lost electrical production from the retrofitted turbine must be replaced either by higher variable cost electricity from other generating plants owned by the utility or by the purchase of power. The cost of this derating will be born by the district heating company.
- Assumption: The incremental cost associated with producing at the retrofitted plant rather than a more efficient plant will be born by the district heating company. The electrical plant may be required to produce electricity greater than needed under normal economic dispatch in order to maintain a load on the retrofitted turbine that allows for cogeneration economies. This may result in the production of electricity at a higher variable cost than would have occurred if the thermal demand from the district heating company did not exist. To the extent that this occurs the difference between the variable cost of producing at the plant that would have produced the electricity and the cost of producing at the retrofitted plant will be assigned to the district heating company.
- Assumption: Incremental operating costs at the power plant will be absorbed by the district heating company.
- Assumption: The electrical derating whether on an instantaneous or permanent basis will be covered by generating reserves of the utility and will not require replacement of capacity.

Federal and state taxes

- Assumption: Municipal owned utilities will not be subject to Federal or state taxes.
- Assumption: For investor owned utilities, the beginning operating losses, tax timing differences and investment tax credits generated by the district heating company will be utilized by the utility to shelter electrical production operating income from income taxes.

Assumption: The utilization of tax benefits resulting from district heating operations is a source of cash flow to the district heating company.

Assumption: The utilities can utilize the tax benefit generated by the district heating company.

Inflation rates

Assumption: Gas prices will escalate by 4.3% per annum in excess of the general inflation rate and fuel oil prices will escalate by 3.0% per annum in excess of the general inflation rate. The primary fuels to be displaced by a district heating company are gas and fuel oil. This estimate was on data provided by the Minnesota Energy Agency.

Assumption: Coal costs will escalate at the general inflation rate. This estimate was based on data provided by the Minnesota Energy Agency.

Assumption: All the fuel prices will differ on a city-specific basis and as a result the escalations will be applied to different basis in each city. The current energy costs to which escalation rates were applied were defined at a point in time and do not reflect price changes resulting from recent rate cases or the market reaction to recent price increases initiated by major oil producing nations.

Assumption: General inflation rate will be a constant four percent over the twenty year period. This relatively low rate was used since increases in the general inflation rate will make district heating investment more attractive. This is true since alternative fuel prices escalation rates are defined in excess of the general inflation rate and it has been assumed that district heating prices will escalate as fast or slightly faster than inflation.

Assumption: The general inflation rate has been applied to all operating costs other than depreciation and interest costs. This means that if district heating prices increase at the inflation rate or faster, revenues will increase faster than costs.

Working capital

Assumption: A cash balance of approximately \$50,000 is maintained to adjust for timing differences between cash disbursement on accounts payable and cash receipts on accounts receivable. It was assumed that this cash would earn five percent per year.

Assumption: Revenues are net of bad debts; no provision has been made for uncollectible revenues.

Assumption: Accounts receivable will be collected in 30 days and the amount at March 31st will be equal to the projected energy consumption in the month of March.

Assumption: Accounts payable at year end will be equal to 1/12th of the year's cash operating expenses.

Assumption: A working capital requirement for materials and supplies inventory was not required since the amount is not anticipated to be large and will stay fairly constant over the period of the analysis.

4.A. MOORHEAD

Introduction

Moorhead, Minnesota, population 34,076 (1977 estimate), is situated on the western boundary of the state adjacent to Fargo, North Dakota, in the Red River Valley, 230 miles northwest of Minneapolis-St. Paul. Agriculture and education are the community's economic lifeblood. Agricultural processing by American Crystal Sugar, Anheuser-Busch, Fairmont Foods and others provide a strong economic base. With a major university, Moorhead State (enrollment 6500), a college, Concordia (enrollment 2500), two vocational-technical schools, 12 public and 2 parochial schools the entire community is heavily involved with the educational process.

Technical Assessment

Retrofit Alternatives

Power plant description. The Moorhead power plant is owned and operated by the Public Service Department of the City of Moorhead. The power plant has four operable steam turbines, one gas turbine, and two diesel turbines. The gas and diesel turbines do not fall within the scope of the present study.

Moorhead 3 is a 3 MWe single-cylinder GE turbine with a GE generator. Steam is supplied by a stoker-fired Bros. boiler rated at 30,000 lbs/hr steam flow with throttle conditions of 400 psi/725°F. Since this unit has no stack gas cleanup devices, its emissions control is probably not adequate. The boiler was installed in 1926, and to it the turbine and generator were added in 1940.

Moorhead 4 is a 3 MWe turbine and generator identical to the turbine and generator of unit No. 3. Steam is supplied by a stoker fired Babcock and Wilcox boiler rated at 45,000 lbs/hr steam flow with throttle conditions of 400 psi/725°F. The boiler has no stack gas cleanup devices.

Moorhead 5 is a 6 MWe single-cylinder Brown-Boveri turbine with a 6 MWe Brown-Boveri generator. Steam is supplied by a stoker fired Edgemoor

boiler rated at 45,000 lbs/hr steam flow with throttle conditions of 400 psi/725°F. As is the case with units Nos. 3 and 4, this boiler has no stack cleanup devices.

Moorhead 7 is a 22 MWe single-cylinder Brown-Boveri turbine with a 22 MWe Brown-Boveri hydrogen cooled generator. Steam is supplied by a stoker fired Riley boiler rated at 250,000 lbs/hr steam flow with throttle conditions of 850 psi/900°F. The boiler is equipped with an electrostatic precipitator which provides sufficient emissions control. The boiler of unit No. 7 is fueled by lignite, as are all the other stoker fired boilers in Moorhead. Moorhead 7 was installed in 1970 but not operated commercially until 1977.

In addition to the units described above, the Moorhead plant also has an oil fired package boiler capable of supplying 50,000 lbs/hr steam flow at 400 psi/750°F. The unit is reported to be used only for plant heating but it is considerably oversized for that purpose.

Moorhead's loading and dispatch are somewhat complex due to the plant's participation in the Missouri Basin Power Pool, but it has recently been operated in an intermediate-to-base loaded mode.

Alternatives. The Moorhead power plant is not atypical of municipal power plants in Minnesota. It has a number of relatively small electrical generating units, some more than 50 years old. The number and variety of generating units allows for considerable flexibility in designing district heating retrofit schemes. In the case of Moorhead, those schemes considered in detail were the following:

1. Back pressure conversion of unit No. 7 with (a) peak and back-up provided by units Nos. 3, 4, and 5 plus oil-fired boilers or college boilers.
2. Extraction conversion of unit No. 7 with (a).
3. (1) plus condensing tail modification of turbine units Nos. 3, 4, and 5 plus (a).

4. Back pressure modification of units Nos. 3, 4, and 5 with peak and back-up provided by unit No. 7 plus oil-fired boilers or college boilers.

Retrofit Strategy Assessment

Retrofit strategy 1. The back pressure conversion of unit No. 7 was modeled using the SYNTHA II simulation program. A diagram of the SYNTHA II simulation of unit No. 7 and a summary of the results of the simulation are presented in Exhibits 4-1 and 4-2, respectively. The results of the simulation, program indicate that unit No. 7 is too large to serve as a source for the projected thermal load of 65 MW. What this means is that the permanent electrical output derate caused by the back pressure modification will be increased by an operational derate. This derate will be most severe during the summer, but will also occur during the rest of the year since high-temperature water is used to meet the peak thermal load.

In addition to this problem, two other factors must be considered in assessing this retrofit scheme. First, the boilers for units Nos. 3, 4, and 5 will be required for peak and/or back-up use and thus must be brought into compliance with emission standards. Second, the contractual obligations relating to unit No. 7 might impose severe economic penalties on a permanent derating of the unit.

Overall, this scheme appears to be both thermodynamically and economically a less than desirable one for the present. It should be noted, however, that if future load growth occurs above the current projected level, unit No. 7 might be brought into thermal/electric balance.

Retrofit strategy 2. The results of the analysis of retrofit strategy 1 indicate that an automatic extraction modification to unit No. 7 might be a more attractive modification than a back pressure conversion because automatic extraction would involve no permanent derate, either mechanically or operationally. However, discussions with the manufacturer (Brown-Boveri of Switzerland) have identified a problem with this retrofit strategy. Due to the turbine's single-cylinder design, the modification contemplated here would require a major redesign effort, the cost of which would have to

SYNTHA Analysis Diagram: Moorhead No. 7

Exhibit 4-2

SYNTHA Simulation Results: Moorhead No. 7

Boiler State 864.7 PSIA 900 F
District Heating 55c - 85c (131F - 185F)

	Design 125% Diagram	Design 125%	Extraction After Strategy 4		Back Pressure		Back Pressure
			Full Load	Half Load	Half Load	Full Load	Full Load 100c O.NT
Run 4/14#		17	18	19	20	4/21 # 3	4/21 # 2
Steam flow MLB/Hr	225	225*	225*	89.2*	89.2*	172.9	172.9*
KW	25,987	26,675	24,436	8,250	8,639	15,574	14,156
M Dist. Htg x 10 ⁶ Lb/Hr	0	0	1.0	1.0	1.411	2.653	1.827
MM Dist. Htg Extract Lb/Hr	0	0	56,428	54,551	89,200	172,900	172,900
Q in x 10 ⁹ Btu/Hr	0.2498	0.251	0.251	0.106	0.1057	0.196	0.196
Q Rej to Coolant x 10 ⁹	0.1567	0.160	0.113	0.0237	0	0	0
T Feedwater	368.7		363	295	295	343	343
4th Stg ExH Pres	7.0*	7.0*	10.9*	10.9*	10.9+	10.9+	18.0+
Last Stg ExH Pres	0.735	0.735*	0.735*	9.338*	9.338*	9.34*	16.22*
Flow Water Gov	10,850	7,204	7,204	2,856	2,856	5,536	5,536
4th Stg	13,850	0.1389*	0.1389*	0.1389	0.1389	0.1389	0.1389
Last Stg	12,500	0.4619	0.20203	0.03409	0.1413	0.2617	0.1608
M FWH 1 Extract Lb/Hr	10,850	10,292	15,010	6,171	0	0	0
FWH 2	13,850	13,684	9,810	180	0	4,628	610.7
Deaer	12,500	12,570	12,329	3,904	3,695	8,822	8,596
FWH 2	12,140	11,682	11,663	3,236	3,222	8,058	8,044

Notes:

1. All FWH devices have 10F TTD
2. Condenser has 5F TTD Used as district heating
3. Extraction "piping" has 5% pressure drop

*Input Value
+Input to Insure Pressure Ration >1.0

be borne by the system operator. The cost of this redesign work would be considerably greater than that for a more controlled extraction turbine. Unless new information from the manufacturer identifies a less expensive redesign option, this retrofit strategy must be ruled out. It should be pointed out, moreover, that this retrofit scheme would also require emission control modifications to units Nos. 3, 4, and 5 to bring them into compliance with state and federal standards.

Retrofit Strategy 3. This scheme is a variation of retrofit strategy 1. One way of dealing with the thermal over-capacity of unit No. 7 would be to convert the turbines of units Nos. 3, 4, and 5 to condensing tail operations. Such a conversion would be relatively simple in this particular case since the turbines are low pressure (400 psi) and the existing condensers could be used. Considerable operational flexibility (and complexity) would result from this retrofit strategy. As was the case with retrofit strategies 1 and 2, the boilers of units Nos. 3, 4, and 5 would have to be brought into compliance with emission standards. This scheme would probably be the most expensive retrofit strategy, but it would also allow the most operational flexibility and permit a high degree of energy utilization optimization. While the expense, downtime, and operational complexity of this scheme make it a not especially attractive option for Moorhead, it is a strategy which might be considered in larger plants having a number of generating units.

Retrofit Strategy 4. Because projected load and reliability requirements will make it necessary to modify the boilers of units Nos. 3, 4, and 5 to bring them into compliance with emission standards, the simultaneous modification of these three units to back pressure operation would be an attractive strategy. The three turbines would be relatively simple to modify and are ideally sized to provide base thermal load throughout the year. Thermal peaking and reliability can then be provided by unit No. 7, with only temporary electric derating. The back pressure conversions of units Nos. 3, 4, and 5 have not been modeled yet--due to insufficient data on the

on the turbines--but considerable experience exists relating to this type of conversion and the performance of such retrofitted turbines is known with considerable certainty.

The boilers for units Nos. 3, 4, and 5 must be renovated and, as has been mentioned earlier, stack gas cleanup equipment must be installed. It is possible that these boilers could be brought under the state particulate limit (.616/MMBTU) with mechanical dust collectors and proper operation. The most prudent course of action, however, might be the installation of baghouse filters. These will provide all necessary particulate removal at a cost of approximately \$1.0 million. Whatever course of action is taken, the stack gas cleanup of units Nos. 3, 4, and 5 will constitute the major expense in retrofitting these units for district heating operation. Turbine retrofit costs--estimated to be approximately \$500,000, including header steam modification of No. 7 boiler-- will be relatively inexpensive. It should be noted, furthermore, that except during peak loads the net station electrical capacity will be increased as a result of this retrofit and, therefore, the retrofit costs might be allowable, in part, to revenues other than district heat sales.

Conclusion. A review of the above retrofit strategies indicates that the most attractive scheme, based on current load projections, is retrofit strategy 4. This strategy also provides considerable flexibility for future thermal load growth. Depending on the phasing of the installation of the distribution system, the retrofit would most likely start with the renovation of the three steam boilers and the oil boilers. These boilers will be able to provide initial load and backup requirements. Work on turbine retrofit could then proceed while the initial distribution system is installed. The modification of the boiler of unit No. 7 could be delayed until reliability and peaking demands justify it. The successful integration of the Moorhead State University and Concordia College heating plants into this retrofit scheme could postpone the modification of unit No. 7 indefinitely.

Distribution System

The preliminary distribution system for Moorhead was designed by Fjärrvärmebyrån ab. The distribution system will require a total pipe length of 11,500 meters at an estimated total capital cost of \$5,578,000 in 1979 dollars. Exhibit 4-3 summarizes pipe size, length, and installation costs by individual pipe segments. Distribution costs developed by Metcalf and Eddy are presented in the same Exhibit. The layout of the distribution system is displayed in Exhibit 4-4 and Exhibit 4-5.

Costs shown in the Exhibit cited above include removal of bituminous and/or concrete pavement, excavation and disposal of subsoil, two pre-insulated pipes, purchase and installation of backfill, and replacement of bituminous pavement. Fjärrvärmebyrån prices include all service piping but do not include project design and inspection (estimated to be an additional 15%). Metcalf and Eddy prices do not include service pipe, engineering (4%) or contingencies (15%).

Exhibit 4-3

Distribution System Costs (Moorhead)

Pipe Section	Pipe Diameter d(mm)	Pipe Length (m)	Fjärrvärmebyrån Cost		Metcalf & Eddy Cost (\$ x 10 ³)
			(Krx10 ³)	(\$x10 ³)	
1-2	400	330	990	230.2	231.0
2-4	300	150	360	83.7	79.3
4-5	250	240	504	117.2	111.3
5-6	250	75	157.5	36.6	34.8
6-7	200	135	243	56.5	50.4
7-8	200	75	135	31.4	28.0
8-9	200	100	180	41.9	37.3
9-10	200	160	288	66.9	59.7
10-11	150	150	225	52.3	46.7
11-12	125	240	324	75.3	74.8
12-13	125	150	202.5	47.1	46.7
13-14	100	80	96	22.3	20.2
14-15	100	80	96	22.3	20.2
2-3	250	150	315	73.3	69.6
3-3a	200	250	387	90.0	93.3
3a-3b	100	215	258	60.0	54.3
3a-3c	200	850	1710	397.7	354.4
3c-3d	150	500	750	174.4	155.8
3d-3e	150	170	255	59.3	53.0
3	200	140	252	58.6	52.2
3b	50	190	171	39.8	48.0
3c-3cl	150	650	975	226.7	202.5
3c	65	60	59.4	13.8	15.2
3cl	100	420	504	117.2	303.1
3d	100	500	600	139.5	303.1
3e	65	200	198	46.0	50.5
5	100	130	156	36.3	303.1
6-6a	125	80	108	25.1	24.9
6a-6b	100	80	96	22.3	20.2
6b-6c	80	80	86.4	20.1	20.2
6a, b, c	65	270	267.3	62.2	68.2
7	65	240	237.6	55.3	60.6
8	80	120	129.6	30.1	30.3
10a, b, c, d	65	120	118.8	27.6	30.3
11-11c	125	170	229.5	53.4	53.0
11c	65	160	158.4	36.8	40.4

Exhibit 4-3 Continued

Distribution System Costs (Moorhead)

Pipe Section	Pipe Diameter d (mm)	Pipe Length (m)	Fjärrvärmebyrån Cost		Metcalf & Eddy Cost (\$ x 10 ³)
			(Krx10 ³)	(\$x10 ³)	
11-11a	125	460	621	144.4	143.4
11a-11b	100	50	60	14.0	12.6
11a	100	120	144	33.5	30.3
11b	65	150	148.5	35.5	37.9
12	50	40	36	8.4	10.1
13	50	60	54	12.6	15.2
14	50	210	189	44.0	53.1
15	65	220	217.8	50.7	55.6
4-4a	250	930	1953	454.2	43.2
4a-4b	150	60	90	20.9	18.7
4b-4c	150	60	90	20.9	18.7
4c-4d	125	60	81	18.8	18.7
4d-4e	125	60	81	18.8	18.7
4e-4f	100	270	324	75.3	68.2
4f	80	270	291.6	67.8	68.2
4b	65	210	207.9	48.3	53.1
4c	65	180	178.2	41.4	45.4
4d	65	180	178.2	41.4	45.4
Subtotal			16678.2	3,878.7	4,003.1
Service Pipe			7308.3	1,700.0	
Total			23986.5	\$5,578.0	

Exhibit 4-4
Distribution Network (Moorhead)

Exhibit 4-5
Distribution Network Layout (Moorhead)

FVB FJARRVÄRMEBYRÅN AB Västerås, Sweden KRAFTLINJEGATAN 14B 721 36 VÄSTERÅS SWEDEN 020 14 40 40	DISTRICT HEATING DEMONSTRATION MINNESOTA		
	MOORHEAD		
	DOWN TOWN		
	DISTRIBUTION NETWORK LAYOUT		
Drawn by VÄSTERÅS MARS 1979	Designed by	Checked by	SCALE 1 cm = 24 m
			DESIGN NR 10
			REV b

Market Analysis

The major industrial companies in Moorhead are Steiger Tractor, which has approximately 800 employees, and American Crystal Sugar Company, which has 450 employees. A private college, Concordia, and a state university, Moorhead State, are also in the city. The city's air service is provided through the neighboring Fargo airport. The power plant is municipally owned. Northern States Power supplies natural gas to the area and multiple suppliers service the fuel oil needs. Discussions with various individuals indicated that large oil companies were competing with retailers in fuel oil sales to major users.

Market Analysis Results

For purposes of the market survey, the population was broken into districts to create manageable survey areas and to provide segments of data for financial analysis. The division into districts was done on a combination of geographical dispersion and apparent market density. When additional buildings were added to the potential market through line revisions, the new data were either considered as part of a primary district or became a separate district. Exhibit 4-6 shows the preliminary distribution line for Moorhead as well as the districts into which the population was divided. Exhibit 4-7 presents a brief description of each district and lists the major potential thermal energy users in each.

Because the survey returns were less than 100%, heating system data and market data for a portion of the original survey population was estimated. These estimates were derived by extrapolating the market data and heating system data from the returned surveys. The extrapolation of the data involved stratifying the population into homogeneous building types, doing follow-up on all major missing types, and then extrapolating either by building class based on average of returned members of that class (i.e., a missing large commercial). The individual extrapolations normally involved finding a similar user, but it also included instances of extrapolations using diverse data inputs. The stratified data simplified the extrapolation

Market Analysis Districts (Moorhead)

Exhibit 4-7

Characteristics of Market Districts (Moorhead).

<u>District</u>	<u>Characteristics</u>	<u>Major Potential Thermal Energy Users</u>	<u>Market Estimates</u> (10 ⁶ Btu/yr)
M-1	This district is dominated by Concordia College	Concordia College	78,000
M-2	This district is dominated by Moorhead State University	Moorhead State University Edison Junior High School	117,000 2,900
M-3	This district, near the college and university, consists primarily of student housing	67 separate multi-plexes	
M-4	This district contains the downtown area consisting primarily of commercial establishments. Areas adjacent to the downtown contain schools, churches, public offices, multi-unit residential housing and a process user	Fairmount Foods Company Housing Redevelopment Authority American State Bank	17,900 6,400 3,100
M-5	This geographically dispersed district contains a diverse mix, including a hospital, schools, churches, public offices and a process user	St. Ansgar Hospital North Junior High Coca Cola Bottling Company	19,000 5,300 5,200
M-6	This district contains a multi-unit residential, large motel, schools and commercial establishments	Holiday Inn Moorhead Area Technical Institute South Junior High	8,200 6,300 4,600
M-7	This district contains a large motel and several commercial establishments	Ramada Inn	4,800

procedures, and the follow-up on major users reduced the percentage of market that was extrapolated. Market data in this section is presented by district, by building type and by heating system.

The majority of potential space heating users in each city expressed a preference for steam as the thermal energy source. Generally this preference was directly associated with the use of steam boilers as their current heat source. Potential users perceived that conversion to a district heating system which used steam as the thermal energy medium would be less complex and costly for them.

The market for absorption cooling appears to be very limited and therefore has not been included in the preliminary design. Current cooling use in Moorhead was $27,000 \times 10^6$ Btus in 1978 (one hospital and one school)-- a relatively insignificant use of absorption cooling.

Process user preference regarding thermal energy was very difficult to determine. Users were able to determine if they could use hot water or steam in general but without further information concerning temperature(s), pressure(s) and flow rate(s), they could not specifically determine adaptability. The major process need in Moorhead is Fairmont Foods Company. Fairmont uses thermal energy in dairy products applications. A discussion with the plant manager indicated that they could use hot water in their processing.

Potential Market

The results of the market analysis in Moorhead are presented in the following exhibits. The market estimates were developed using the data base of information developed through survey, observations and interviews conducted with major potential users. The results are for the entire population even though replies were not received from every building. Buildings not represented in the data base were estimated based upon information of similar buildings as discussed earlier. The data presented in the Exhibits represent normalized energy data (i.e., 1978 consumption was adjusted to reflect normal heating degree days). Appendix E explains the methods used to convert 1978 actual usage to normalized energy data.

Presented below are seven Exhibits which summarize the potential thermal energy market in Moorhead. Only 16% of the potential market is extrapolated.

Exhibit 4-8, Potential Thermal Market, is the total annual estimated market by district. The exhibit indicates that 144,444 MWH is the potential annual market.

Exhibit 4-9, Building Count Information, lists the number of buildings in the data base and in the population. This exhibit is intended to show make-up of buildings for site analysis and for building conversion cost inferences.

Exhibit 4-10, Potential Heating Market by Heating System Type and Exhibit 4-11, Potential Heating Market by Building Type, show market projections by district classified by heating system type and building type. The dominant system is the hybrid hotwater/steam and the major users are the schools.

Exhibit 4-12, Potential Heating Market by Building Type and Heating System, shows the cross classification of building type and heating system.

Exhibit 4-13, Actual Data Base Fuel Usage by District - 1978, shows the actual fuel consumed during 1978 in the buildings included in the data base. In addition, the exhibit shows the percentage of energy output supplied by each fuel.

Exhibit 4-14, Potential Annual Fuel Displacement, shows the potential fuel displacement in Moorhead. Data base usage was normalized and then projected across the balance of the population. The major assumption in normalizing the data was that multiple fuel users used fuel oil for above normal heating needs due to the non-availability of gas.

Exhibit 4-8

Potential Thermal Market (Moorhead)

<u>District</u>	<u>10⁶Btu/yr</u>			<u>MWH⁽¹⁾</u>
	<u>Process</u>	<u>Heating</u>	<u>Total</u>	<u>Total</u>
M-1	--	85,263	85,263	24,989
M-2	--	119,926	119,926	35,148
M-3	--	34,534	34,534	10,121
M-4	13,571	88,916	102,487	30,037
M-5	1,390	68,202	69,592	20,396
M-6	--	53,342	53,342	15,634
M-7	--	27,702	27,702	8,119
	<u>14,961</u>	<u>477,885</u>	<u>492,846</u>	<u>144,444</u>

(1) Conversion to MWH is achieved by dividing the Btu total by 3.412×10^6 .

Exhibit 4-9

Building Count Information (Moorhead)

<u>Building Count Along the Distribution Line</u>			
<u>Type</u>	<u>Total</u>	<u>Number in Data Base</u> ⁽¹⁾	<u>% in Data Base</u>
Large Commercial	30	21	70
Small Commercial	93	19	20
Industrial	1	1	100
Multi-Unit Residential	123	122	99
Public and Institutional	<u>95</u>	<u>77</u>	<u>81</u>
TOTAL	<u>342</u>	<u>240</u>	<u>70</u>

(1) The data base includes those buildings and process applications for which adequate information could be obtained from the returned surveys on-site reviews, or other techniques.

Exhibit 4-10

Potential Heating Market by Heating System Type (Moorhead)

<u>District</u>	10 ⁶ Btu/yr				
	<u>Forced Air</u>	<u>Steam</u>	<u>Hot Water</u>	<u>Hot Water/ Steam</u>	<u>Total</u>
M-1	548	3,748	1,606	79,361	85,263
M-2	--	2,791	--	117,135	119,926
M-3	--	94	33,092	1,348	34,534
M-4	33,552	15,087	34,711	5,566	88,916
M-5	10,199	8,927	19,436	29,640	68,202
M-6	2,634	3,749	40,289	6,670	53,342
M-7	8,205	1,503	16,229	1,765	27,702
	<u>55,138</u>	<u>35,899</u>	<u>145,363</u>	<u>241,363</u>	<u>477,885</u>
Percentage	12%	7%	30%	51%	100%

Exhibit 4-11

Potential Heating Market by Building Type (Moorhead)

<u>District</u>	<u>10⁶Btu/yr</u>					<u>Total</u>
	<u>Large Commerical</u>	<u>Small Commercial</u>	<u>Industrial</u>	<u>Multi-Unit Residential</u>	<u>Public and Institutional</u>	
M-1	--	548	--	3,087	81,628	85,263
M-2	--	--	--	--	119,926	119,926
M-3	--	--	--	32,967	1,567	34,534
M-4	22,996	38,480	--	12,534	14,906	88,916
M-5	17,856	10,506	622	811	38,407	68,202
M-6	14,517	1,740	--	23,679	13,406	53,342
M-7	11,138	2,305	--	11,777	2,482	27,702
	<u>66,507</u>	<u>53,579</u>	<u>622</u>	<u>84,855</u>	<u>272,322</u>	<u>477,885</u>
Percentage	14%	11%	-	18%	57%	100%

Exhibit 4-12

Potential Heating Market by Building Type and Heating System (Moorhead)

<u>Classification</u>	<u>10⁶Btu/yr</u>				<u>Total</u>	<u>Percent</u>
	<u>Forced Air</u>	<u>Steam</u>	<u>Hot Water</u>	<u>Hot Water/ Steam</u>		
Large Commercial	13,935	12,605	35,342	4,625	66,507	14
Small Commercial	41,203	6,455	5,921	--	53,579	11
Industrial	--	--	--	622	622	--
Multi-Unit Residential	--	1,630	83,225	--	84,855	18
Public and Institutional	--	15,209	20,875	236,238	272,322	57
	<u>55,138</u>	<u>35,899</u>	<u>145,363</u>	<u>241,485</u>	<u>477,885</u>	100%
Percentage	12%	7%	30%	51%	100%	

Exhibit 4-13

1978 Data Base Fuel Usage by District (Moorhead)

<u>District</u>	<u>Type of Fuel</u>		
	<u>Natural Gas</u> (CCF)	<u>#2 Fuel Oil</u> (Gal)	<u>#6 Fuel Oil</u> (Gal)
M-1	417,485	613,042	-
M-2	710,100	32,296	700,912
M-3	448,346	-	-
M-4	460,926	287,763	-
M-5	269,813	338,056	-
M-6	487,172	125,434	-
M-7	243,049	-	-
Total	<u>3,036,891</u>	<u>1,396,590</u>	<u>700,912</u>

Percentage of Heat Output After
Conversion to Equivalent Base (1)

Gas	55%
#2 Oil	30%
#6 Oil	15%

- (1) Fuels were converted to Btu equivalents and then fuel-specific efficiency factors were applied to arrive at equivalent heat output.

Exhibit 4-14

Potential Annual Fuel Displacement (Moorhead)

	Natural Gas (CCF)	#2 Fuel Oil (Gal)	#6 Fuel Oil (Gal)
1978 Data Base Usage	3,036,891	1,396,590	700,912
Normalization Adjustment ⁽¹⁾	(73,546)	(96,505)	(62,666)
Estimated Normal Fuel Usage of Users Not in the Data Base ⁽²⁾	598,552	402,450	-
Potential Annual Fuel Displacement	<u>3,561,897</u>	<u>1,702,535</u>	<u>638,246</u>

(1) Heating degree days in 1978 were 6.6% above normal which causes above normal fuel usage. In adjusting the fuel usage to normal, process use was unchanged, interruptible gas users and fuel oil users were assumed to have used oil for above normal heating needs, gas only users were assumed to have used gas for above normal use.

(2) Fuel use of non-data base users was estimated utilizing normalized data base information.

Market Advantages and Problems

Dominance of two large potential users. The predominance of two large educational facilities as potential major users creates advantages and problems. One major advantage is that it may be easier to convince two large users to convert to district heating than many smaller users, thus assuring a base load which will improve the probability of economic success. The marketing and pricing strategy can be tailored to maximize the probability of these two users converting, and commitments could be attainable in advance, which should significantly increase potential investor confidence. The schools also provide a stable base for the market. Their enrollment has been steady and is expected to remain so in the future.

The fact that two large users dominate the market could be a problem because markets dominated by a few users are often considered riskier than similar sized markets with no domination. This higher risk is related to the potential of losing a large user. If district heating is to be implemented, long-term commitments should be obtained from large users before the project is undertaken. The real risk for district heating is that the dominant users would not want to participate. At this point, Concordia, Moorhead State, and Independent School District #152 have expressed interest in district heating. The uncertainty will be resolved in later phases when the major users are given sufficient information to make a final commitment.

Moorhead State University's plans to convert to coal. Moorhead State University has been developing plans to convert their heating plant to coal use. This should be a very positive advantage for district heating if timely action is taken. Moorhead State has delayed future action on these plans for a period of one year pending the results of this project. District heating

could be a much lower cost alternative in as much as expected capital outlays for the coal conversion project are in excess of three million dollars. This also may be a major advantage in obtaining state or local funding for the district heating system.

Closeness of concentrated load in Fargo, North Dakota. The city of Fargo, North Dakota, which is situated just across the river from Moorhead appears to be an opportunity for expansion if capacity is available. Fargo appears to have several concentrated areas of potential load. The major problem, besides limited capacity, in serving this load may be the institutional issues associated with crossing state boundaries.

Canadian gas. Moorhead's natural gas supply is imported Canadian gas which is relatively expensive and is not a long-term stable supply. This should enhance the viability and marketability of district heating in Moorhead.

Dispersion of downtown business district and future industrial expansions. Moorhead's downtown business area is not a highly concentrated grouping of commercial establishments but is very dispersed. This dispersion leads to higher capital cost and subsequently higher thermal energy prices which impact the economic viability of district heating. This problem will be further compounded if a low hook-up rate is experienced in this area. In addition, it does not appear that future industrial growth will be a source for expansion of this district heating system. Current industrial development plans put this growth a substantial distance from the proposed distribution line.

Low electricity costs. Currently Moorhead electric rates are relatively low compared to most other Minnesota cities. This is the result of having a municipal electric system which has traditionally utilized very low-cost power from the Bureau of Reclamation. While this source is no longer as dominant, the rates are still relatively low, which means that electric heating is a viable alternative to district heating.

Institutional Assessment

Selection of an Owner/Operator

The Moorhead Public Service Department was assumed to be the owner and operator of the proposed district heating utility because the city currently operates the municipal electric and water systems. In addition, some city officials have indicated that the city would probably favor municipal ownership and operation of any new district heating utility because it would be so closely tied to the operation of the city's power plant.

Decision Process for Utility Investment

The primary decision variable for the City of Moorhead is the preliminary economic analyses prepared in Phase 1 and to be prepared in subsequent phases of this study. If the economics of the project appear attractive, the Public Service Department would be interested in pursuing a more detailed market and institutional analysis. Assuming that the analysis is positive, the Department would recommend the project to the Moorhead Public Service Commission for approval. Following the MPSC review, the Commission would present the project to the City Council for approval. The estimated time frame for approval is at least two months after the initial recommendation by the Public Service Department.

At this time, the Public Service Department is unable to specify any exact criteria by which the project might be evaluated. The superintendent has indicated, however, that the project would be required to generate a positive cash flow from operations within five to ten years after initial development, and that the project would have to demonstrate a very strong likelihood of success over the long term.

Economic feasibility is the critical decision factor. Other concerns include the plant lease and purchase power agreement (addressed below) and the risk of entering a new area of business.

Plant Lease and Purchased Power Agreements

Currently, the Moorhead Public Service Department (MPSD) leases its only operating turbine (22 MWe output) to the Missouri Basin Municipal Power Agency (MBMPA). The contract between MPSD and MBMPA provides that MPSD furnish the plant equipment and labor and MBMPA pay a fixed charge and supply the fuel. The contract will expire in November, 1982, but may be renewed upon agreement by both parties.

MPSD also has a forty-year purchased power agreement with MBMPA which obligates MPSD to purchase all power requirements in excess of its United States Bureau of Reclamation (USBR) allotment from MBMPA. The agreement covering the current block of power expires in 1987 but will be renegotiated to cover Moorhead's power needs at that time.

If the operating turbine at MPSD's power plant is retrofitted and used for a cogeneration district heating system before November, 1982, the district heating utility will need to obtain assurances from MBMPA that the plant will be operated in a cycle which is coincident with the district heating cycle. Although MPSD has a contractual right to re-rate the plant output (thus eliminating any turbine derate problem which might be necessitated by the retrofit), it does not control or schedule the plant electrical operating cycle. MBMPA is participating with several other utilities to construct a 1500 MWe mine-mouth plant (247 MW share for MBMPA) in Wheatland, Wyoming which is scheduled for completion in 1981-1982. At that time, significant excess electrical generating capacity may become available to MBMPA which, coupled with the fact that the plant is expected to have a lower operating cost than the Moorhead plant, may make continued operation of the MPSD plant questionable.

If the project is feasible and the City desires to develop a district heating system after 1982, the contract with MBMPA may or may not be renewed. If it is renewed, the City would need to obtain assurances regarding the planned operating cycle of the plant in order to be sure that sufficient thermal energy is generated. If the contract is not renewed, Moorhead would have the option of selling the electrical output to other utilities. Given that the plant is lignite-fired and has relatively low operating costs, this could be an attractive alternative.

Profit Motivation

Profit versus break-even motivation objectives must be considered in light of existing municipal policies regarding utility operation. Moorhead, where municipal ownership of the district heating company is assumed, operates both electric and water utilities with a profit objective. The electric utility is governed by the city charter rather than a franchise agreement, though provisions are similar to those typically described in a franchise agreement. The provisions which may have significant impact are summarized below.

Transfer Provisions. The utility may transfer up to 20% of its current year's net revenues to the city's general fund and 5% of net revenue to the capital improvement fund. The transfer amounts are voted upon by the City Council and have historically ranged very close to the 25% aggregate limitation. However, transfer amounts are determined only after bond principal, interest and covenant requirements and all operating expenses have been met. Special provisions have been approved by the Council limiting transfer amounts if the above obligations cannot be met.

Rate Provisions. The rates charged are regulated both by the City Council and the Public Service Commission (five members, appointed by the City Council). The PSC is a five-member group responsible for control of the municipal utility's rates, management and operation. The impact of this dual regulation is not expected to pose any greater problems to the utility than would regulation by a state commission.

Given Moorhead's existing pricing and transfer policies, it appears reasonable to assume for this preliminary phase that the government-owned district heating company would operate with the long-term objective of profit motivation. The city may be willing, however, to waive the requirement for the transfer to the General Fund until the utility becomes well established and generates sufficient cash.

Capital Structure

The district heating utility is assumed to be municipally owned, as are the electric and water utilities. Conversations with the Superintendent of the Moorhead Public Service Department indicate the district heating company

would most likely be entirely financed by revenue bonds. It follows that the assumption implicit in this financial model is that capitalization represents 100% debt.

Types of Debt Available

Because the owner of the district heating utility is assumed to be Moorhead's Public Service Department, tax-exempt bonds would most likely be utilized. Local officials have indicated that revenue bonds would probably be issued without any general obligation or special tax features. It is possible that these bonds could be issued by the city with the revenues from the city water and electric utilities also pledged for debt service needs.

A letter from a representative of the City of Moorhead, included as Appendix I, indicates that the electric and water utilities can be pledged and that this option could be exercised if required to secure revenue bond financing. A preliminary legal discussion of this option is included in Appendix H.

Franchise Agreements

The electric utility is municipally owned. Therefore, it does not have a franchise agreement but is governed instead by provisions in the city charter. The utility has very broad powers to operate as a department of the city government.

Taxation

Taxation is not an issue due to the municipally owned district heating utility's tax-exempt status.

Zoning and Redevelopment Plans

Redevelopment and expansion in Moorhead, when considered in light of the preliminary distribution lines, may increase the potential market for district heating services. Planned development and redevelopment are either located on or near the extremities of the proposed distribution lines. They include:

- 0 Commercial and residential development areas are located south of I-94.

- 0 Industrial expansion may continue in the existing industrial park southeast of Moorhead State University.
- 0 Commercial development and residential redevelopment contemplated in the downtown areas and north of the power plant.

Displacement Effects on Existing Suppliers and Their Customers

Based on limited discussions, it appears that the city's fuel oil suppliers consist of several local jobbers and a few major oil company suppliers who dominate the commercial and industrial market. Effects of displacement would be the greatest for the major oil companies. The effect, however, would be spread over all suppliers such that the absolute impact on any one supplier would be minor.

Northern States Power Company provides gas in Moorhead and would be a major fuel supplier influenced by district heating. However, alternate uses and customers for gas most likely could be secured resulting in a relatively insignificant impact on NSP or rates charged to its gas customers.

Adequacy of Existing Coal Contracts

The Moorhead electric utility burns North Dakota lignite and has a five-year contract (three years to expiration) with the Knife River Coal Mining Company for its fuel supply. The two parties have a good working relationship and no problems with contract renewal are anticipated. Should a shortage of North Dakota lignite occur, the plant can use Montana or Wyoming lignite.

Economic Analysis

Site Specific Assumptions

The specific assumptions made in the economic analysis of the base cases for Moorhead and the rationale underlying these assumptions are presented below.

Thermal energy revenues.

Assumption: Average revenues per/MWH were initially estimated at 12.32 per MWH. This was established by taking 110% of the projected 1981 cost of natural gas in Moorhead of \$3.28/MCF times a conversion factor (MCF to MWH) of 3.412. The \$3.28/MCF is the average projected cost of natural gas in Moorhead based upon data provided by the Minnesota Energy Agency.

Assumption: The average revenue per MWH was escalated by the assumed inflation rate of 4% per year. This compares to the projected total inflation rate for gas and oil of 8.3% (4.3% differential) and 7.0% (3.0% differential) per year.

Assumption: Exhibit 4-15 is a graphical presentation which shows by year the projected cost of alternative fuels (oil and natural gas), coal and district heating thermal energy. This Exhibit illustrates that the district heating system average revenues per MWH could be increased at a substantially higher rate and still provide lower cost to its customers. A significant energy cost savings not displayed on Exhibit 4-15 is that the district heating thermal price is for delivered energy, while the alternative fuel costs must be divided by the efficiency of the buildings heating system (65-75%) to get actual energy cost.

Assumption: Average revenues per MWH have not been maximized relative to alternative fuel costs in the base case for the following reasons:

- 0 Total revenues will be maximized in the early years by showing a discernable cost savings immediately which will encourage hookups.
- 0 Contractual relationships which provide a stable revenue base will be encouraged since the projected pricing policy guarantees resistance to alternative energy cost inflation.

Exhibit 4-15

Projected Alternative Energy Costs
and District Heating Costs

A potential revenue reserve is available to cover unexpected or underestimated costs.

Assumption: Thermal energy sales in MWH's were developed by year based upon the construction phasing and hookup rates shown on Exhibit 4-16. This assumes that the first year's construction would be from the plant to the colleges who will have committed to hooking-up prior to the start of construction. This accounts for the 100% hookup of the potential market in the first year. For all other construction phases it was assumed that 90% of the potential market would eventually hookup. The overall hookup rate achieved after 1988 is 94%

Purchased energy expense.

Assumption: The estimated purchased energy costs were calculated based upon the following assumptions regarding plant operations:

- 0 Upgrading three small turbines will provide 6 MW electrical of capacity after retrofit. Only the three small turbines will be retrofitted.
- 0 Boiler (header steam) from the main turbine will be used for peaking and system back-up.
- 0 Electricity generated by the three small turbines will displace electricity from the large turbine which would have been operating at 100% capacity in 1982 without district heating.

Assumption: An average cost of \$3.16 per MWH thermal was calculated for 1982 as follows:

- 0 Total incremental fuel costs associated with producing annual thermal energy requirements in a cogeneration environment on three small turbines was calculated.
- 0 An estimated amount was determined for the additional fuel required based upon use of header steam for peaking and back-up 30% of the time.
- 0 An amount for lost revenue on the lease plant due to use of header steam was determined.
- 0 The total cost of the components was divided by the thermal MWH produced to arrive at a cost per MWH in 1979. This number was inflated by 4% per year to arrive at a \$3.16/MWH in 1982.

Assumption: The average cost by MWH was escalated by the assumed inflation rate of coal of 4% per year.

Assumption: Exhibit 4-15 also contains a graphical presentation of the average thermal fuel cost per million BTU assumed in the base case. This graph illustrates that this fuel cost follows the projected cost of coal.

Operating and maintenance expense.

Assumption: Fixed operating expense of \$225,000 was estimated for 1979 based upon adding eight employees as follows: 3 boiler operators; 1 engineer, 1 meter reader and 1 manager. This amount was then escalated at the 4% general inflation rate.

Assumption: Variable operating costs of \$.80/MWH was estimated to cover maintenance @ 1% of distribution investment, electrical costs and miscellaneous variable costs. This was also escalated at the 4% general inflation rate.

Depreciation expense.

Assumption: A full years depreciation was assumed for all new assets in the year placed in service.

Assumption: Straight line depreciation with a 25-year life was assumed for distribution retrofit and conversion assets.

Assumption: Straight line depreciation with a 10-year life was assumed for service equipment assets.

Interest expense.

Assumption: This expense was calculated by extending the assumed rate of 8% times the simple average of the outstanding debt at the beginning and end of the year.

Fixed assets/construction costs

Assumption: The engineering estimate of the cost of bringing the three small turbines into air quality compliance and retrofitting them for cogeneration is \$1,500,000 in 1979 dollars. It is also assumed that all the work

Exhibit 4-16

Preliminary Base Case Economic Analysis
Thermal Energy Construction Phases and Hookup Assumptions

<u>Construction Phase</u>	<u>Potential Thermal Energy Market (MWH's)</u>	<u>Assumed Hook-Up Rate</u>	<u>Maximum MWH's Hooked-Up</u>
1982 - Plant to Colleges	58,607	100% in 1982	58,607
1983 - Downtown and Student Housing and Large Users adjacent to Downtown	44,222	25% in 1983 30% in 1984 35% in 1985	39,800
1984 - Remainder of area adjacent to Downtown and Northern Leg of Proposed Distribution Line	29,307	35% in 1984 30% in 1985 25% in 1986	26,376
1985 - Southern Leg of Proposed Distribution Line	8,119	35% in 1985 30% in 1986 25% in 1987	7,307
1986 - Northwest Leg of Proposed Distribution Line	4,189	35% in 1986 30% in 1987 25% in 1988	3,770
Total	<u>144,444</u>		<u>135,860</u>

will be completed in the first year (1982) and a 6% inflation rate was used to reach \$1,711,000 cost in that year.

Assumption: The engineering estimate of the cost of the total distribution system in 1979 dollars was \$6,871,000 including design costs. It was assumed that work will proceed following the construction phasing shown on Exhibit 4-16, and a 6% construction cost inflation rate was used to determine specific construction each year.

Assumption: Building conversion costs were based upon the following estimate of conversion costs in 1979 dollars and 6% inflation rate:

- 0 \$20.00/KW for hot water
- 0 \$23.00/KW for steam and steam/hot water
- 0 \$30.00/KW for forced air

Assumption: Service Equipment was estimated at \$50,000 in 1982 with a 20% addition each year and a 6% inflation rate.

Base Case Results

The results of the base case economic analysis for Moorhead are presented below. The project teams consensus of expected operating results are presented in Exhibit 4-17 to Exhibit 4-22. These projections are based upon the assumptions presented previously and are intended to be used only to determine whether further study of Moorhead as a potential demonstration site is justified.

Exhibit 4-17. This Exhibit presents projected statements of income for the 20 years, 1982 to 2001. This Exhibit also shows by year the average capital investment, return on average capital investment, and the annual thermal energy sales (MWH). The base case results indicate that, after depreciation and interest, the system will show a loss for the first nine years but that by the end of twenty years there will be a net income on average capital investment of 34.99%.

Exhibit 4-18. This Exhibit presents projected balance sheets for the 20 years, 1982 to 2001. Shown here is the build-up of the system over the first five years with total capital expenditure of \$11,366,000 for plant retrofit, distribution system and conversion costs.

The total capital or debt required would be \$11,475,000. This Exhibit also indicates that cash would be available for debt repayment (accumulated cash reductions) beginning in 1987 and that the entire \$11,475,000 would be paid off by the end of 2001. In addition, the system would have excess cash of approximately \$1,500,000 at the end of 2001.

Exhibit 4-19. This Exhibit presents cash flow statements for the 20 years, 1982 to 2001. This Exhibit indicates that operations will generate positive cash flows beginning in 1985 which will be used to provide working capital, purchase capital expenditures and reduce the capital investment. This Exhibit also shows the cash available for debt service if cash from operations was not used to reduce the capital investment (debt). The Exhibit shows that the investment will have a one-time coverage through 1986 and will not achieve a two-times coverage until 1996. Typically, a two-times debt coverage is required for investor grade bonds. The assumption is that revenues from either the water or electric utility must also be pledged to guarantee an adequate debt coverage.

Exhibit 4-20. This Exhibit presents projected net income and cash from operations for the twenty year period. The difference between net income and cash flow is accounted for primarily by depreciation expense.

Exhibit 4-21. This Exhibit presents a summary schedule showing the calculation of the net cash flow on the investment for the twenty-year period. The internal return shown is the rate which when used as a discount factor, yields a present value of zero for the cash flow.

Exhibit 4-22. This Exhibit presents the internal rate of return analysis of the cash flows calculated in Exhibit 4-21. This Exhibit also shows the present value of the cash flows assuming an 8% and a 10% discount rate. Assuming that 8% is the cost of capital for the city this exhibit indicates that the investment would have a "real" value to the city of approximately \$1,500,000.

Results of the base case economic analysis indicate that Moorhead is potentially a viable demonstration community for a cogeneration hot water district heating system. The internal rate of return of 9.75% would appear to be adequate for a municipal system. In addition, the base case results indicate that debt will be fully retired by the end of twenty years assuming no contribution to the general fund or reserve build-up. Inclusion of these considerations would tend to reduce cash flow somewhat but not enough to make

Exhibit 4-7

CITY OF MOORHEAD

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED STATEMENTS OF INCOME

	FOR THE FISCAL YEARS ENDING MARCH 30TH									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
OPERATING REVENUE										
Thermal energy	\$ 721,963	\$ 892,413	\$1,242,100	\$1,667,260	\$1,895,357	\$2,020,795	\$2,118,119	\$2,202,356	\$2,290,667	\$2,383,053
OPERATING EXPENSES:										
Purchased energy	185,179	229,199	318,678	427,040	486,664	517,669	543,456	565,194	586,932	611,388
Operations and maintenance	271,881	291,961	323,988	361,356	386,330	404,976	422,219	439,104	456,690	474,943
Depreciation	208,461	304,146	385,745	434,271	464,270	467,901	470,104	471,607	473,201	474,893
Total operating expenses	665,521	825,306	1,028,411	1,222,667	1,337,264	1,390,546	1,435,779	1,475,905	1,516,823	1,561,224
OPERATING INCOME	56,442	67,107	213,689	444,593	558,093	630,249	682,340	726,451	773,844	821,829
Interest on cash balances	1,246	2,957	3,232	2,683	2,330	2,402	2,500	2,500	2,500	2,500
Hookup charges and miscellaneous income	747	1,775	50,715	96,110	41,698	15,792	6,400	1,500	1,500	1,500
	1,993	4,732	53,947	98,793	44,028	18,194	8,900	4,000	4,000	4,000
INCOME BEFORE INTEREST CHARGE	58,435	71,839	267,636	543,386	602,121	648,443	691,240	730,451	777,844	825,829
INTEREST CHARGE	207,000	516,000	702,000	829,000	895,000	913,212	899,599	878,698	851,575	818,200
NET INCOME (LOSS)	(\$ 148,565)	(\$ 444,161)	(\$ 434,364)	(\$ 285,614)	(\$ 292,879)	(\$ 264,769)	(\$ 208,359)	(\$ 148,247)	(\$ 73,731)	\$ 7,629
AVERAGE CAPITAL INVESTMENT	\$5,100,718	\$6,079,355	\$7,965,092	\$9,192,603	\$9,728,357	\$9,677,180	\$9,270,418	\$8,830,849	\$8,380,833	\$7,930,626
RETURN ON AVERAGE CAPITAL INVESTMENT	(2.91)%	(7.31)%	(5.45)%	(3.11)%	(3.01)%	(2.74)%	(2.25)%	(1.68)%	(.88)%	.09%
ANNUAL THERMAL ENERGY SALES (MWH)	58,600	69,665	93,180	120,290	131,530	134,810	135,865	135,865	135,865	135,865

Exhibit 4-17 (Continued)

CITY OF MOORHEAD

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED STATEMENTS OF INCOME

	FOR FISCAL YEARS ENDING MARCH 30TH									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
OPERATING REVENUE										
Thermal energy	<u>\$2,478,160</u>	<u>\$2,577,340</u>	<u>\$2,679,238</u>	<u>\$2,786,569</u>	<u>\$2,897,979</u>	<u>\$3,014,822</u>	<u>\$3,135,741</u>	<u>\$3,260,736</u>	<u>\$3,391,166</u>	<u>\$3,527,030</u>
OPERATING EXPENSES:										
Purchased energy	635,844	660,299	687,472	714,645	743,176	773,066	804,315	836,922	869,530	904,854
Operations and maintenance	493,930	513,718	534,239	555,629	577,853	600,945	625,004	649,997	675,992	703,021
Depreciation	471,678	472,521	473,407	474,349	475,348	476,407	477,528	478,719	479,979	481,314
Total operating expenses	<u>1,601,452</u>	<u>1,646,538</u>	<u>1,695,118</u>	<u>1,744,623</u>	<u>1,796,377</u>	<u>1,850,418</u>	<u>1,906,847</u>	<u>1,965,638</u>	<u>2,025,501</u>	<u>2,089,189</u>
OPERATING INCOME	<u>876,708</u>	<u>930,802</u>	<u>984,120</u>	<u>1,041,946</u>	<u>1,101,602</u>	<u>1,164,404</u>	<u>1,228,894</u>	<u>1,295,098</u>	<u>1,365,665</u>	<u>1,437,841</u>
Interest on cash balances	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	29,893
Hookup charges and miscellaneous income	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	
	<u>4,000</u>	<u>4,000</u>	<u>4,000</u>	<u>4,000</u>	<u>4,000</u>	<u>4,000</u>	<u>4,000</u>	<u>4,000</u>	<u>4,000</u>	<u>29,893</u>
INCOME BEFORE INTEREST CHARGE	<u>880,708</u>	<u>934,802</u>	<u>988,120</u>	<u>1,045,946</u>	<u>1,105,602</u>	<u>1,168,404</u>	<u>1,232,894</u>	<u>1,299,098</u>	<u>1,369,665</u>	<u>1,467,734</u>
INTEREST CHARGE	<u>777,927</u>	<u>729,970</u>	<u>673,583</u>	<u>607,910</u>	<u>531,931</u>	<u>444,573</u>	<u>344,689</u>	<u>231,089</u>	<u>102,387</u>	<u>17,026</u>
NET INCOME (LOSS)	<u>\$ 102,781</u>	<u>\$ 204,832</u>	<u>\$ 314,537</u>	<u>\$ 438,036</u>	<u>\$ 573,671</u>	<u>\$ 723,831</u>	<u>\$ 888,205</u>	<u>\$1,068,009</u>	<u>\$1,267,278</u>	<u>\$1,484,760</u>
AVERAGE CAPITAL INVESTMENT	<u>\$7,482,401</u>	<u>\$7,036,751</u>	<u>\$6,591,574</u>	<u>\$6,146,964</u>	<u>\$5,703,070</u>	<u>\$5,259,848</u>	<u>\$4,817,320</u>	<u>\$4,375,417</u>	<u>\$3,934,287</u>	<u>\$4,243,417</u>
RETURN ON AVERAGE CAPITAL INVESTMENT	<u>1.37%</u>	<u>2.91%</u>	<u>4.78%</u>	<u>7.13%</u>	<u>10.06%</u>	<u>13.76%</u>	<u>18.44%</u>	<u>24.41%</u>	<u>32.21%</u>	<u>34.99%</u>
ANNUAL THERMAL ENERGY SALES (MWH)	135,865	135,865	135,865	135,865	135,865	135,865	135,865	135,865	135,865	135,865

Exhibit 4-18

CITY OF MOORHEAD
PRELIMINARY BASE CASE ECONOMIC ANALYSIS
PROJECTED BALANCE SHEETS

	AS OF MARCH 30TH									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
FIXED ASSETS:										
Plant retrofit	\$1,711,000	\$1,711,000	\$1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000
Distribution system	2,582,000	4,794,220	6,460,518	7,221,566	7,754,340	7,754,340	7,754,340	7,754,340	7,754,340	7,754,340
Building conversion	793,514	946,920	1,292,517	1,714,875	1,900,448	1,957,840	1,977,403	1,977,403	1,977,403	1,977,403
Service equipment	50,000	60,600	71,836	83,746	96,371	109,753	123,938	138,974	154,912	171,806
	<u>5,136,514</u>	<u>7,512,740</u>	<u>9,535,871</u>	<u>10,731,187</u>	<u>11,462,159</u>	<u>11,532,933</u>	<u>11,566,681</u>	<u>11,581,717</u>	<u>11,597,655</u>	<u>11,614,549</u>
Accumulated provision for depreciation	208,461	512,607	898,352	1,332,623	1,796,893	2,264,794	2,734,898	3,206,505	3,679,706	4,154,599
Net fixed assets	<u>4,928,053</u>	<u>7,000,133</u>	<u>8,637,519</u>	<u>9,398,564</u>	<u>9,665,266</u>	<u>9,268,139</u>	<u>8,831,783</u>	<u>8,375,212</u>	<u>7,917,949</u>	<u>7,459,950</u>
CURRENT ASSETS:										
Cash	49,834	68,482	60,829	46,486	46,098	50,000	50,000	50,000	50,000	50,000
Accounts receivable	86,636	107,090	149,052	200,071	227,443	242,495	254,174	264,283	274,880	285,966
Total current assets	<u>136,470</u>	<u>175,572</u>	<u>209,881</u>	<u>246,557</u>	<u>273,541</u>	<u>292,495</u>	<u>304,174</u>	<u>314,283</u>	<u>324,880</u>	<u>335,966</u>
TOTAL	<u>\$5,064,523</u>	<u>\$7,175,705</u>	<u>\$8,847,400</u>	<u>\$ 9,645,121</u>	<u>\$ 9,938,807</u>	<u>\$ 9,560,634</u>	<u>\$ 9,135,957</u>	<u>\$ 8,689,495</u>	<u>\$ 8,242,829</u>	<u>\$ 7,795,916</u>
CAPITALIZATION:										
Capital investment	\$5,175,000	\$7,725,000	\$9,825,000	\$10,900,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000
Accumulated earnings (deficit)	(148,565)	(592,726)	(1,027,090)	(1,312,704)	(1,605,583)	(1,870,352)	(2,078,711)	(2,226,958)	(2,300,689)	(2,293,060)
Accumulated cash reductions						(119,705)	(340,396)	(642,238)	(1,018,449)	(1,476,550)
Capital account balance	<u>5,026,435</u>	<u>7,132,274</u>	<u>8,797,910</u>	<u>9,587,296</u>	<u>9,869,417</u>	<u>9,484,943</u>	<u>9,055,893</u>	<u>8,605,804</u>	<u>8,155,862</u>	<u>7,705,390</u>
CURRENT LIABILITIES -										
Accounts payable	38,088	43,431	49,490	57,825	69,390	75,691	80,064	83,691	86,967	90,526
TOTAL	<u>\$5,064,523</u>	<u>\$7,175,705</u>	<u>\$8,847,400</u>	<u>\$ 9,645,121</u>	<u>\$ 9,938,807</u>	<u>\$ 9,560,634</u>	<u>\$ 9,135,957</u>	<u>\$ 8,689,495</u>	<u>\$ 8,242,829</u>	<u>\$ 7,795,916</u>

Exhibit 4-18 (Continued)

CITY OF MOORHEAD

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED BALANCE SHEETS

	AS OF MARCH 30TH									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
FIXED ASSETS:										
Plant retrofit	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000	\$ 1,711,000
Distribution system	7,754,340	7,754,340	7,754,340	7,754,340	7,754,340	7,754,340	7,754,340	7,754,340	7,754,340	7,754,340
Building conversions	1,977,403	1,977,403	1,977,403	1,977,403	1,977,403	1,977,403	1,977,403	1,977,403	1,977,403	1,977,403
Service equipment	133,714	148,097	156,983	166,402	176,386	186,970	198,188	210,080	222,685	236,047
	<u>11,582,457</u>	<u>11,590,840</u>	<u>11,599,726</u>	<u>11,609,145</u>	<u>11,619,129</u>	<u>11,629,713</u>	<u>11,640,931</u>	<u>11,652,823</u>	<u>11,665,428</u>	<u>11,678,790</u>
Accumulated provision for depreciation	4,576,277	5,038,198	5,500,369	5,962,809	6,425,531	6,888,556	7,351,898	7,815,581	8,279,622	8,744,042
Net fixed assets	<u>7,006,180</u>	<u>6,552,642</u>	<u>6,099,357</u>	<u>5,646,336</u>	<u>5,193,598</u>	<u>4,741,157</u>	<u>4,289,033</u>	<u>3,837,242</u>	<u>3,385,806</u>	<u>2,934,748</u>
CURRENT ASSETS:										
Cash	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	1,548,877
Accounts receivable	297,379	309,281	321,509	334,388	347,757	361,779	376,289	391,288	406,940	423,244
Total current assets	<u>347,379</u>	<u>359,281</u>	<u>371,509</u>	<u>384,388</u>	<u>397,757</u>	<u>411,779</u>	<u>426,289</u>	<u>441,288</u>	<u>456,940</u>	<u>1,972,121</u>
TOTAL	<u>\$ 7,353,559</u>	<u>\$ 6,911,923</u>	<u>\$ 6,470,866</u>	<u>\$ 6,030,724</u>	<u>\$ 5,591,355</u>	<u>\$ 5,152,936</u>	<u>\$ 4,715,322</u>	<u>\$ 4,278,530</u>	<u>\$ 3,842,746</u>	<u>\$ 4,906,869</u>
CAPITALIZATION:										
Capital investment	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000
Accumulated earnings (deficit)	(2,190,279)	(1,985,447)	(1,670,910)	(1,232,874)	(659,203)	64,628	952,833	2,020,842	3,288,120	4,772,880
Accumulated cash reductions	(2,025,309)	(2,675,464)	(3,435,032)	(4,317,256)	(5,334,527)	(6,501,192)	(7,831,620)	(9,341,221)	(11,049,167)	(11,475,000)
Capital account balance	<u>7,259,412</u>	<u>6,814,089</u>	<u>6,369,058</u>	<u>5,924,870</u>	<u>5,481,270</u>	<u>5,038,436</u>	<u>4,596,213</u>	<u>4,154,621</u>	<u>3,713,953</u>	<u>4,772,880</u>
CURRENT LIABILITIES -										
Accounts payable	94,147	97,834	101,808	105,854	110,085	114,500	119,109	123,909	128,793	133,989
TOTAL	<u>\$ 7,353,559</u>	<u>\$ 6,911,923</u>	<u>\$ 6,470,866</u>	<u>\$ 6,030,724</u>	<u>\$ 5,591,355</u>	<u>\$ 5,152,936</u>	<u>\$ 4,715,322</u>	<u>\$ 4,278,530</u>	<u>\$ 3,842,746</u>	<u>\$ 4,906,869</u>

Exhibit 4-19

CITY OF MOORHEAD

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED CASH FLOW STATEMENTS

	FOR THE FISCAL YEARS ENDING MARCH 30TH									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
SOURCE OF CASH:										
Net income (loss)	(\$ 148,565)	(\$ 444,161)	(\$ 434,364)	(\$ 285,614)	(\$ 292,879)	(\$ 264,769)	(\$ 208,359)	(\$ 148,247)	(\$ 73,731)	\$ 7,629
Depreciation	208,461	304,146	385,745	434,271	464,270	467,901	470,104	471,607	473,201	474,893
Increase in:										
Accounts receivable	(86,636)	(20,454)	(41,962)	(51,019)	(27,372)	(15,052)	(11,679)	(10,109)	(10,597)	(11,086)
Accounts payable	38,088	5,342	6,060	8,335	11,566	6,301	4,374	3,627	3,276	3,559
Cash from operations	11,348	(155,127)	(84,521)	105,973	155,585	194,381	254,440	316,878	392,149	474,995
Capital investment	5,175,000	2,550,000	2,100,000	1,075,000	575,000					
TOTAL	\$5,186,348	\$2,394,873	\$2,015,479	\$ 1,180,973	\$ 730,585	\$ 194,381	\$ 254,440	\$ 316,878	\$ 392,149	\$ 474,995
USE OF CASH:										
Construction expenditures	\$5,136,514	\$2,376,225	\$2,023,132	\$ 1,195,316	\$ 730,973	\$ 70,774	\$ 33,749	\$ 15,036	\$ 15,938	\$ 16,894
Reduction of capital investment						119,705	220,691	301,842	376,211	458,101
Cash working capital	49,834	18,648	(7,653)	(14,343)	(388)	3,902				
TOTAL	\$5,186,348	\$2,394,873	\$2,015,479	\$ 1,180,973	\$ 730,585	\$ 194,381	\$ 254,440	\$ 316,878	\$ 392,149	\$ 474,995
CASH AVAILABLE FOR DEBT SERVICE:										
Reduction of capital expenditures						\$ 119,705	\$ 220,691	\$ 301,842	\$ 376,211	\$ 458,101
Interest expense on unreduced debt	\$ 207,000	\$ 516,000	\$ 702,000	\$ 829,000	\$ 895,000	918,000	918,000	918,000	918,000	918,000
Total cash available for debt service	\$ 207,000	\$ 516,000	\$ 702,000	\$ 829,000	\$ 895,000	\$ 1,037,705	\$ 1,138,691	\$ 1,219,842	\$ 1,294,211	\$ 1,376,101
Average unreduced debt balance	\$2,587,500	\$6,450,000	\$8,775,000	\$10,362,500	\$11,187,500	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000
Cash available for debt service as a percentage of average unreduced debt balance	8.00%	8.00%	8.00%	8.00%	8.00%	9.04%	9.92%	10.63%	11.28%	11.99%

Exhibit 4-19 (Continued)

CITY OF MOORHEAD

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED CASH FLOW STATEMENTS

	FOR THE FISCAL YEARS ENDING MARCH 30TH									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
SOURCE OF CASH:										
Net income (loss)	\$ 102,781	\$ 204,832	\$ 314,537	\$ 438,036	\$ 573,671	\$ 723,831	\$ 888,205	\$ 1,068,009	\$ 1,267,278	\$ 1,484,760
Depreciation	471,678	472,521	473,407	474,349	475,348	476,407	477,528	478,719	479,979	481,314
Increase in:										
Accounts receivable	(11,413)	(11,902)	(12,228)	(12,879)	(13,369)	(14,022)	(14,510)	(14,999)	(15,652)	(16,304)
Accounts payable	3,621	3,687	3,974	4,047	4,230	4,415	4,609	4,800	4,884	5,196
Cash from operations	566,667	669,138	779,690	903,553	1,039,880	1,190,631	1,355,832	1,536,529	1,736,489	1,954,966
Capital investment										
TOTAL	\$ 566,667	\$ 669,138	\$ 779,690	\$ 903,553	\$ 1,039,880	\$ 1,190,631	\$ 1,355,832	\$ 1,536,529	\$ 1,736,489	\$ 1,954,966
USE OF CASH:										
Construction expenditures	\$ 17,908	\$ 18,983	\$ 20,122	\$ 21,329	\$ 22,609	\$ 23,966	\$ 25,404	\$ 26,928	\$ 28,543	\$ 30,256
Reduction of capital investment	548,759	650,155	759,568	882,224	1,017,271	1,166,665	1,330,428	1,509,601	1,707,946	1,924,833
Cash working capital										1,498,877
TOTAL	\$ 566,667	\$ 669,138	\$ 779,690	\$ 903,553	\$ 1,039,880	\$ 1,190,631	\$ 1,355,832	\$ 1,536,529	\$ 1,736,489	\$ 1,954,966
CASH AVAILABLE FOR DEBT SERVICE:										
Reduction of capital expenditures	\$ 548,759	\$ 650,155	\$ 759,568	\$ 882,224	\$ 1,017,271	\$ 1,166,665	\$ 1,330,428	\$ 1,509,601	\$ 1,707,946	\$ 1,924,710
Interest expense on un-reduced debt	918,000	918,000	918,000	918,000	918,000	918,000	918,000	918,000	918,000	918,000
Total cash available for debt service	\$ 1,466,759	\$ 1,568,155	\$ 1,677,568	\$ 1,800,224	\$ 1,935,271	\$ 2,084,665	\$ 2,248,428	\$ 2,427,601	\$ 2,625,946	\$ 2,842,710
Average un-reduced debt balance	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000	\$11,475,000
Cash available for debt service as a percentage of average un-reduced debt balance	12.78%	13.67%	14.62%	15.69%	16.87%	18.17%	19.59%	21.16%	22.88%	24.77%

Exhibit 4-20

Preliminary Economic Analysis Cogenerated District Heating System
Projected Net Income and Cash From Operations

Exhibit 4-21

Preliminary Economic Analysis Calculation of
Net Cash Flow to/from Investors
"Base Case"

Year	From Operations	Used For Capital Expenditure	Used For Working Capital	Interest Expense	Net To/(From) Investor
1982	11,348	(5,136,514)	(49,834)	207,000	(4,968,000)
1983	(155,127)	(2,376,225)	(18,648)	516,000	(2,034,000)
1984	(84,521)	(2,023,132)	7,653	702,000	(1,398,000)
1985	105,973	(1,195,316)	14,343	829,000	(246,000)
1986	155,585	(730,973)	388	895,000	320,000
1987	194,381	(70,774)	(3,902)	913,212	1,032,917
1988	254,440	(33,749)		899,599	1,120,290
1989	316,878	(15,036)		878,698	1,180,540
1990	392,149	(15,938)		851,575	1,227,786
1991	474,995	(16,894)		777,927	1,276,301
1992	566,667	(17,908)		729,970	1,326,686
1993	669,138	(18,983)		673,583	1,380,125
1994	779,690	(20,122)		607,910	1,432,951
1995	903,553	(21,329)		531,931	1,490,134
1996	1,039,880	(22,609)		444,573	1,549,202
1997	1,190,631	(23,966)		344,689	1,611,238
1998	1,355,832	(25,404)		231,089	1,675,117
1999	1,536,529	(26,928)		102,387	1,740,690
2000	1,736,489	(28,543)		17,026	1,810,333
2001	1,954,966	(30,256)			1,941,736
2002	Book Value				4,722,880

Internal Rate of Return = 9.75%

Exhibit 4-22

Internal Rate of Return Analysis of Discrete Cashflows
(Base Case)

Year	Time Period	Cash			Discounted Cashflows		
		Outflows	Inflows	Netflows	at 8.0%	at 10.0%	at 9.75%
1982	(1)	\$4,968,000	\$	\$-4,968,000	\$-4,600,000	\$-4,516,365	\$-4,526,652
1983	(2)	2,034,000		-2,034,000	-1,743,828	-1,680,994	-1,688,660
1984	(3)	1,398,000		-1,398,000	-1,109,778	-1,050,340	-1,057,534
1985	(4)	246,000		- 246,000	- 180,817	- 168,021	- 169,557
1986	(5)	0	320,000	320,000	217,787	198,695	200,968
1987	(6)	0	1,032,917	1,032,917	650,915	583,057	591,071
1988	(7)	0	1,120,290	1,120,290	653,680	574,889	584,118
1989	(8)	0	1,180,540	1,180,540	637,811	550,734	560,850
1990	(9)	0	1,227,786	1,227,786	614,201	520,705	531,477
1991	(10)	0	1,276,301	1,276,301	591,177	492,073	503,397
1992	(11)	0	1,326,686	1,326,686	568,996	464,999	476,783
1993	(12)	0	1,380,125	1,380,125	548,070	439,754	451,926
1994	(13)	0	1,432,951	1,432,951	526,897	415,079	427,539
1995	(14)	0	1,490,134	1,490,134	507,336	392,403	405,103
1996	(15)	0	1,549,202	1,549,202	488,377	370,871	383,746
1997	(16)	0	1,611,238	1,611,238	470,309	350,657	363,657
1998	(17)	0	1,675,117	1,675,117	452,736	331,417	344,487
1999	(18)	0	1,740,690	1,740,690	435,610	313,083	326,171
2000	(19)	0	1,810,333	1,810,333	419,480	296,008	309,085
2001	(20)	0	1,941,736	1,941,736	416,600	288,631	302,068
2002	(21)	0	4,772,880	4,772,880	948,171	644,973	676,537
Total		\$8,646,000	\$26,888,890	\$18,242,910	\$1,513,743	\$ -187,675	\$ -3,404

The present value of the cashflows at 8.00% is \$1,513,743
The present value of the cashflows at 10.00% is \$- 187,675
The internal rate of return is 9.75%

Moorhead unattractive as a demonstration community. Reserve and general fund requirements should be defined more specifically in Phase 2.

Under private investor ownership this return and higher interest rates would be substantially less because of income and property taxes all other things remaining equal. A long construction period and the subsequent delay in reaching full revenue potential would indicate that revenue/MWH would have to be increased if private ownership were assumed. This might be feasible given the differential between the assumed district heating prices and alternative fuels illustrated in Exhibit 4-15.

Another significant consideration which could be addressed in Phase 2 is whether Moorhead can or will commit over \$11,000,000 to this project. The projected results appear encouraging, but there still may be a high level of perceived risk given that cogeneration hot water district heating systems are not a proven economical venture in this country. Therefore, it is possible that the City may require more tangible assurances that revenues will be sufficient to meet debt service requirements. This assurance could be obtained by financing part of the construction through direct Federal or state grants or by contributions from major users such as Moorhead State University.

Sensitivity Analysis

Sensitivity analysis was performed on significant assumptions to test the relative importance of these assumptions on the financial projections presented in the "Base Case" analysis.

Exhibit 4-23 summarizes the sensitivity analyses performed for Moorhead. All input to the base case analysis remained the same except for the specific data subjected to sensitivity analysis. The Exhibit shows the base case assumption and the new assumption used in the sensitivity analysis. The internal rate of return for 20-year analysis, calculated in the same manner as in the "base case" analysis, is shown for the sensitivity change.

Exhibit 4-23

CITY OF MOORHEAD
PRELIMINARY ECONOMIC ANALYSIS
SENSITIVITY ANALYSIS

Sensitivity Number	Base Case Assumption	Sensitivity Assumption	Sensitivity Assumption Internal rate of return(1)	Present value under Base Case rate of return (9.75%)	Present value at 8% rate of return
1)	Interest rate of 8% on 100% debt financing of investment	Interest rate of 10% on 100% debt financing of investment.	9.5%	(\$ 264,875)	\$1,155,700
2)	Interest rate of 8% on 100% debt financing of investment	Interest rate of 9% on 100% debt financing of investment.	9.5%	(238,885)	1,192,119
3)	Fuel operating and maintenance expense of \$225,000 in 1982 inflated at 4% per year	Fixed operating and maintenance expense of \$281,250 in 1982 (25% increase).	8.3%	(1,185,891)	83,892
4)	Hookups phased over 7 years	Maximum hookup and construction in the first year, 1982.	9.6%	(140,922)	1,436,896
5)	Construction costs estimated at \$8,750,000 in 1982 dollars	Construction cost estimated at \$10,937,500 in 1982 dollars (25% increase).	6.8%	(2,647,488)	(1,267,192)
6)	Energy cost, operations and maintenance cost inflated at 4%. 6% construction inflation rate.	Energy cost, operations and maintenance costs inflated at 8%. Construction inflation rate of 12%. No increase in revenue growth.	negative	(5,041,666)	(\$4,655,764)
7)	As detailed above in 2, 5, and 6	Sensitivity assumption numbers 2, 5, and 6 plus revenue increased at base case alternative fuel costs growth rate.	12.3%	2,941,915	5,987,252

(1) Rounded to nearest 1/4 of one percent.

The present value of the investment measured under the "base case" return of 9.75% is also shown. A positive number indicates that the sensitivity change increased the value of the investment over the base case results presented even after reflecting the time value of money of 9.75%. A negative number indicates that the sensitivity change reduced the value of the investment over the base case results after reflecting a 9.75% time value of money. The absolute change reflected is a measure of the relative importance of the sensitivity change after adjusting for the time value of money.

Also presented is the present value of the sensitivity change measured against an 8% return, which is the assumed minimum return required by the City of Moorhead on a debt financed investment at 8%. Over the period of the analysis, any sensitivity change still resulting in a positive number would make the investment attractive if a break-even return of 8% were required. Any negative present value would indicate that, if that sensitivity change were actually to occur, the investment should not be made.

Sensitivity Number 1. Tests the impact of an interest cost of 10% if current municipal bond rates rise or if investors perceived additional risk in the investment.

Sensitivity Number 2. Tests the impact of an interest cost of 9%. Exhibit 4-24 shows the projected cash from operations under this change compared to the "base case" cash from operations. Cash from operations is used to provide working capital, internally fund expenditures and reduce debt (payback of investment).

Sensitivity Number 3. Tests the importance of a 25% underestimate of operations and maintenance cost on cash flow. Since these costs impact cash flow their impact on present value of the investment is significant.

Sensitivity Number 4. Tests the importance of deferral of construction costs which results in higher construction costs in later years because of inflation to debt carrying costs and the loss of hookup charges. The small difference in present value indicates that the construction phasing is appropriate in matching these factors.

Sensitivity Number 5. Tests the sensitivity of construction cost estimates. If the base case assumptions are appropriate, cost overruns of 25% could be incurred in construction and still allow for a greater than breakeven on the investment if the required return is 8%. Exhibit 4-24 shows the projected cash from operations under this change compared to the base case cash from operation.

Sensitivity Number 6. Tests the impact of the assumed inflation rate of 4% for general inflation and 6% for construction inflation if these inflation rates are doubled. Revenues have been held constant even though there is significant revenue potential. Exhibit 4-24 shows the projected cash from operations under this change compared to the "base case" cash from operations.

Sensitivity Number 7. Combines sensitivity numbers 2, 5, and 6 and charging revenues at the lowest projected alternative fuel price during the period of the analysis. The sensitivity shows that significant deviations from projected costs can occur and still be overcome by charging alternative fuel costs. Exhibit 4-25 shows the projected cash from operations under these changes to the "base case" cash from operations.

Exhibit 4-24

Preliminary Economic Analysis Cogenerated District
Heating System Projected Cash From Operations

Exhibit 4-25

Preliminary Economic Analysis Cogenerated District
Heating System Projected Cash From Operations

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4.B. RED WING

Introduction

Red Wing, Minnesota, population/4,097 (1976 estimate), is a river community located on the banks of the Mississippi in Goodhue County, 50 miles southeast of the Minneapolis-St. Paul metropolitan area. It is one of Minnesota's oldest cities, dating from the 1850's. Over a century of growth, Red Wing has developed into a city with a good mix of industrial and agricultural manufacturing and processing. A major industrial activity is leather processing and footwear manufacture. Agricultural processing, including malting and soybean oil extraction, adds significantly to the industrial base.

Technical Assessment

Retrofit Alternatives

Power Plant Description. The Red Wing power plant, which was constructed in 1948, is owned and operated by Northern States Power Company (Minnesota). Steam is supplied by two Foster Wheeler three-drum, bent-tube boilers rated at 125,000 lbs/hr each (625 psi/825°F). The boilers are fired by Detroit rotorgrate spreader stokers designed for Illinois bituminous coal. Western Precipitation multi-clone dust collectors were installed on each boiler in 1949. Electrical power is generated by two identical GE 16-stage impulse turbines during air-cooled generation. The turbines are fed by a common header connected to both boilers.

The turbines are a single cylinder design but differ somewhat from conventional design in that the low-pressure housing is separable from the high pressure housing. The turbines were designed in this manner to allow greater flexibility in construction for different applications. According to General Electric, numerous variations of this model turbine have been built, including units capable of operating under high back pressure with controlled extraction. The split-housing design, and the operational flexibility such a design allows, makes these turbines attractive candidates for steam extraction or back-pressure retrofit.

At the present time, Red Wing units Nos. 1 and 2 are ranked behind the following NSP power plants in load dispatch:

<u>NSP Plant</u>	<u>Fuel</u>
1. Prairie Island 1 and 2	Nuclear
2. Monticello	Nuclear
3. Sherco 1 and 2	Coal
4. Alan King	Coal
5. Black Dog	Coal
6. High Bridge	Coal
7. Riverside	Coal
8. Minnesota Valley	Coal

Northern States Power reports that the plant is in excellent condition and is expected to continue in operation for the foreseeable future. NSP also reports that they anticipate no difficulties in guaranteeing the City of Red Wing a thermal supply for thirty years. Because NSP will add no new capacity to its system for 4-6 years, the loading of Red Wing 1 and 2 can be expected to increase over the short term and then stabilize at approximately its present level.

NSP is actively experimenting with alternate fuels at Red Wing and is currently burning a mix of 70% coal (Eastern and Western) and 30% wood chips. An expected increase in the availability of wood wastes could have a positive effect on the plant's status in load dispatch. The power plant site has adequate space for all additional equipment required to retrofit the plant, as well as space for increased coal storage if that proves necessary.

Alternatives. The Red Wing power plant is in essentially thermal/electric balance with the community that permits a number of workable retrofit schemes. In addition to this essential balance, the GE turbines at Red Wing were designed to be easily retrofitted; thus several schemes were considered in some detail. These schemes were:

1. Use of header steam for peaking and standby supply.

2. (1) plus modification of the regenerative, low pressure extraction feedwater heaters on both turbines.
3. (1) plus increased fixed extraction flow from heater extraction ports on both turbines.
4. (1) plus conversion of one turbine to back pressure operation.
5. (1) plus conversion of one turbine to controlled extraction.

Retrofit Strategy Assessment

Retrofit strategy 1. This scheme involves increased de-superheating throttling, and steam to hot water heat exchanger. Both boilers are currently fed to a common header, so that only one installation is necessary. This modification will allow the supply of peak thermal load whenever either boiler is available at 50% load. Because of this flexibility, reliability criteria are easily met. This type of modification is not unusual and involves straight-forward engineering and construction.

Retrofit strategy 2. This scheme involves an unusual approach to retrofit originally suggested by Hans Nyman. It involves use of the existing low pressure feedwater heater as district heating heat exchangers. Although only relatively small amounts of energy can be extracted, in this case less than 6 MW, the approach has some interesting features. Primarily it offers a very low cost initial conversion, and one that could be accomplished in a short time. Although the base load of the service areas is slightly higher than what would be desirable for this retrofit scheme, it could nevertheless serve the initial phases of construction. The major disadvantage of this scheme is that the removal of two feedwater heaters will reduce feedwater temperature significantly. This reduction causes an increase in superheater temperatures. From the results obtained in computer simulations, it appears this increase will be significant and would probably require increased de-superheating capacity.

Retrofit strategy 3. It is often possible to enlarge fixed extraction openings to increase extraction flows. Depending on blade and housing designs and materials, this modification may allow significant extraction capacity to be added. A brief consideration of this scheme by the manufacturer indicated that such a modification could be made to the units at Red Wing. It appears, however, that the available capacity would be only marginally improved over scheme 2, although the need for de-superheating would be reduced.

Retrofit strategy 4. In discussion with representatives of GE and as a result of studies of the turbine design, it was found that Red Wing turbines had been designed to be easily modified for different purposes. The base turbine was constructed in a manner that allowed the manufacturer to easily build in many different options. While both units were installed as conventional condensing turbines, this design feature allows relatively simple approaches to turbine modifications. In particular, the casing is designed with a vertical as well as a horizontal split. The unit was offered with both high back pressure and controlled extraction options and both options, reportedly, have been designed and built. Hence, conversion of this unit to back pressure operation would involve only site-specific engineering. The manufacturer is confident about the performance of the modified unit. A back pressure conversion would allow a base load of approximately 30 MW--higher than desirable for the projected load.

Retrofit strategy 5. For reasons outlined in (4) above, conversion to controlled extraction appears to be relatively simple. This modification would offer ideal flexibility for the projected load and would involve no permanent derating of the unit. Discussions with the manufacturer indicate that the retrofit might allow an increase in peak electrical output through the refinement of turbine blading.

Conclusions. The basic turbine retrofit schemes were extensively modeled using the SYNTHA II simulation program. SYNTHA II simulation and a summary of results are presented in Exhibits 4-26 and 4-27, respectively.

Exhibit 4-26

SYNTHA Analysis Diagram: Red Wing

4-59

Exhibit 4-27

SYNTHA Simulation Results: Red Wing

Boiler State: 615 PSIA 825 F
District Heating: 55c - 85c (131F - 185F) Except Δ 180 F Out

Run 4/14+

	Design 110% Diagram	Design Program 3/22 Run 2	Extract After Strategy 4		Back Pressure	
			Full Load	Half Load	Full Load	Half Load
			7	9	4	6
Steam Flow MLB/Hr	118	119*	119	55.6*	119	55.6
KW	12,650	12,928	12,371	5,697	9,704	4,680
M Dist Htg x 10 ⁶ Lb/Hr	0	0	0.3784	0.3784*	1.819	0.903
Temp: Dist Htg Out	-	-	180 Δ	180 Δ	185	185
M Dist Htg Extract Lb/Hr	0	0	19,192	19,192	119,000	55,600
Q in x 10 ⁹ Btu/Hr			0.164	0.0811	164.164	0.0811
Q Rej to Coolant x 10 ⁹ Btu/hr		0.87	0.07067	0.0267	0	0
T feedwater	345	345	345	287	345	287
4th Stg ExH Pres	6.9	6.9*	9.34*	9.34*	10.0*	10.0*
Last Stg ExH Pres	0.735	0.735*	0.735*	0.735*	9.34*	99.34
Flow Factor Stg 1		0.005222	0.005222*	0.00243	0.005222*	0.00243
Stg 4		0.09127	0.09127*	0.09127*	0.09127*	0.09127*
Stg 5		0.2556	0.1557	0.1979	0.1979	0.0987
M FWH 1 Extract Lb/Hr	5,970	6,801	6,672	2,348	0	0
FWH 2	5,740	5,740	3,671	2,484	4,072	0
Deaer	4,775	4,898	5,133	1,529	3,960	1,243
FWH 4	9,155	7,299	1,773	2,800	7,308	2,781

* Input Value
+ Arbitrary Input to insure
pres. ratio >1.0

$\nabla \Sigma > \Phi \leq \Omega \wedge \eta > \xi \Omega \wedge \cdot \Pi \ell \downarrow \uparrow \text{ET} \rightarrow \Theta \leftarrow \Delta \leftarrow \Delta$

Although considerable work remains to be done in the detailed thermodynamic analysis, a few conclusions may be drawn. The feedwater heater modification is probably feasible and should operate without undue disruption of the cycle. It was also found that this modification allows the thermal distribution system to be used as a storage medium during the summer to provide increased peak electrical output.

This mode of operation would occur in the following manner. During night hours the temperature of the district heating water would be raised to near winter peak temperatures by use of the feedwater heaters and/or the boilers. During periods of high electrical demand, the low pressure extraction ports on the turbine may be throttled or closed and the feed water heat supplied by the district heating water as its temperature is lowered to normal summer operating temperature, e.g., 200°F. It is estimated that approximately 14 MWH could be stored in this manner and recalled at about 2-4 MW. Since this technique allows a district heating system to directly couple to electrical generation in a reverse mode, it is potentially of considerable significance and should be examined more thoroughly. In Red Wing, the nature of the base load is such that it appears that the feedwater heaters are somewhat small for district heating conversion. Nevertheless this is considered a viable option. Retrofit strategy 3 was felt to be less desirable than retrofit strategy 2 due to the much higher expense and downtime involved, with only marginal improvement in performance. Similarly, retrofit strategy 4 was thought to be significantly less attractive than retrofit strategy 5 due to the improper balance and permanent derating that results.

Retrofit strategies 2 and 5 will allow a high degree of operational flexibility, a high confidence level, and no permanent derate, all of which are important to the plant owner. The feedwater heater modification is interesting for the reasons mentioned and should be considered on other installations where more favorable balance conditions exist.

As previously discussed, the boilers have a common header and are the obvious choices for peak and standby operation. Under peak load, the total electrical capacity is estimated to be 19 MWe, an operational

derate of 3 MWe depending on the uprating resulting from the turbine retrofit.

It should be noted that the boilers at Red Wing are usually kept in a banked or hot idle mode when the plant is not operationg. In this mode, the boiler will provide 2-3 MWt thermal output, which now is wasted. This idling output will be utilized as the base load for the plant. This source should be considered in any intermediate loaded power plant, especially those that are stoker fired.

Distribution System

The preliminary distribution system for Red Wing was designed by Fjärrvärmebyrån ab. The distribution system will require a total pipe length of 3,600 meters at an estimated total capital cost of \$2,055,000. Exhibit 4-28 summarizes pipe size, length, and installation costs by individual pipe segments. Distribution costs developed by Metcalf and Eddy are presented in the same Exhibit. The layout of the distribution system is displayed in Exhibit 4-29, and Exhibit 4-30.

Costs shown in the Exhibit cited above include removal of bituminous and/or concrete pavement, excavation and disposal of subsoil, two pre-insulated pipes, purchase and installation of backfill, and replacement of bituminous pavement. Fjärrvärmebyrån prices include all service piping but do not include project design and inspection (estimated to be an additional 15%). Metcalf and Eddy prices do not include service pipe, engineering (4%) or contingencies (15%).

Exhibit 4-28

Distribution System Costs (Red Wing)

Pipe Section	Pipe Diameter d(mm)	Pipe Length (m)	Fjärrvärmebyrån Cost		Metcalf & Eddy Cost (\$x10 ³)
			(Krx10 ³)	(\$x10 ³)	
1-2	250	1180	2,478.0	576.3	534.2
2-3	250	113	237.3	55.2	52.5
3-4	200	118	212.4	49.4	44.0
4-5	200	175	315.0	73.0	65.3
5-6	200	96	172.8	40.2	35.8
6-7	100	120	144.0	33.5	30.3
7-8	100	120	144.0	33.5	30.3
8-9	32	72	56.2	13.1	18.2
2-2a	125	96	129.6	30.1	29.9
2a-2b	100	120	144.0	33.5	30.3
2b-2c	100	216	259.2	60.3	54.5
2c-2d	50	60	54.0	12.6	15.2
3-3a	125	96	129.6	30.1	29.9
3a-3b	125	120	162.0	37.7	37.4
3b-3c	100	252	302.4	70.3	53.7
3c-3d	50	48	43.2	10.0	12.1
3c-3e	40	96	80.6	18.7	24.3
4-4a	125	96	129.6	30.1	29.9
4a-4b	125	120	162	37.7	37.4
4b-4c	125	204	275.4	64.0	65.1
4c-4d	50	60	54	12.6	15.2
4c-4e	50	48	43.2	10.0	12.1
Subtotal			5,728.5	1,332.2	1,267.6
Service Pipe			3,008.0	699.5	
Total			8,737.5	\$2,032.0	

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Red Wing

Legend

- Floor Area 2000-5000 m²/Block
- Floor Area >5000 m²/Block
- Distribution Network

FVB

FJÄRRVARMEBYRÅN AB
Västerås, Sweden
KRAFTLINJEGATAN 14B, 721 36 VÄSTERÅS
SWEDEN 021-14 40 65

Market Analysis

The major industrial companies in Red Wing are the Red Wing Shoe Company, having approximately 1,000 employees; Riviera Products, having approximately 400 employees; and S.B. Foot Tanning Company, having approximately 400 employees. Two large grain and seed processors, ADM and Fleischmann Malting Company, also are in the area. The city's air service is provided by the Twin Cities' airport. The power plant is owned by NSP who is also the supplier of natural gas. Multiple suppliers service fuel oil needs. Gas Supply, Inc., is the major propane supplier.

Market Analysis Results

Shown in Exhibit 4-31 is a map of the revised preliminary distribution line. The Red Wing market was highly compressed, thus there was no need to separate the market into districts. Exhibit 4-32 presents a brief description of the market, including major potential thermal energy users. A review of the table shows that the major potential users are the process user, school, hotel and an industrial application.

Because the survey returns were less than 100%, heating system data and market data for a portion of the original survey population was estimated. These estimates were derived by extrapolating the market data and heating system data from the returned surveys. The extrapolation of the data involved stratifying the population into homogeneous building types, doing follow-up on all major missing types, and then extrapolating either by building class based on average of returned members of that class (i.e., a missing large commercial). The individual extrapolations normally involved finding a similar user, but it also included instances of extrapolations using diverse data inputs. The stratified data simplified the extrapolation procedures, and the follow-up on major users reduced the percentage of market that was extrapolated. Market data in this section is presented by district, by building type, and by heating system.

The majority of potential space heating users in each city expressed a preference for steam as the thermal energy source. Generally this preference

Exhibit 4-31

Market Area (Red Wing)

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Exhibit 4-32

Characteristics of Market (Red Wing)

<u>Characteristics</u>	<u>Major Thermal Energy Users</u>	<u>Market Estimates (10⁶Btu/yr)</u>
The potential market in Red Wing is highly compressed, thus there was no need to divide the market into districts. The market in Red Wing contains many older commercial establishments in the downtown area, churches on the fringe of the downtown area, public offices, a large process user, industrial application, schools and a YMCA.	Fleischmann Malting Company	152,900
	Center High School	11,000
	YMCA	7,000
	Red Wing Shoe Company	
	Main Plant	4,300

was directly associated with the use of steam boilers as their current heat source. Potential users perceived that conversion to a district heating system which used steam as the thermal energy medium would be less complex and costly for them.

Process user preference regarding thermal energy was very difficult to determine. Users were able to determine if they could use hot water or steam in general but without further information concerning temperature(s), pressure(s) and flow rate(s), they could not specifically determine adaptability.

There are two major process users in Red Wing -- ADM and Fleischmann Malting Company. ADM uses high pressure steam in their application and could not utilize hot water. Their plant manager indicated that hot water could be used in about 30% of their applications but an internal study indicated that it would not be economically feasible to run dual systems. Their plant manager also indicated that cogenerated steam thermal energy would not be sufficient for their high pressure needs, which require high pressure steam directly off the boiler. Fleischmann Malting Company requires heat to lower the moisture content of grain from 45% to 4% and to heat germinating rooms. The majority of their need relates to the drying process, which involves pulling hot air over the grain. They currently heat ambient air directly over a flame and pull that heated air over the grain. Their current fuel use is interruptible natural gas and propane; they do not use fuel oil because it affects the quality of the grain. Fleischmann's believes that their entire process is adaptable to hot water heating.

The market for absorption cooling appears to be insignificant in Red Wing.

Potential Market

The results of the market analysis in Red Wing are presented in the following Exhibits. The market estimates were developed using the data base of information developed through survey, observations and interviews conducted with major potential users. The results are for the entire population even

though replies were not received from every building. Buildings not represented in the data base were estimated based upon information of similar buildings as discussed earlier. The data presented in the Exhibits represent normalized energy data (i.e., 1978 consumption was adjusted to reflect normal heating degree days). Appendix E explains the methods used to convert 1978 actual usage to normalized energy data.

Presented below are seven Exhibits which summarize the potential thermal market in Red Wing. The extrapolation of market data in Red Wing was minor. Only 13% of the potential market had to be extrapolated. The majority of the extrapolation related to commercial establishments; in terms of space heating, approximately 33% of the potential market had to be extrapolated.

It is assumed that the entire Fleischmann Malting Company's process market is adaptable to hot water year round. Their current efficiency in fuel conversion was assumed to be 90%, and their consumption was normalized since they heat ambient air. Total annual consumption was normalized even though Fleischmann processes fairly consistently throughout the year. This normalization may tend to understate the potential market but is assumed reasonable at this stage. Humidity effects which could be important in their drying process were not considered.

Exhibit 4-33, Potential Thermal Market, is the total annual estimated market. The exhibit indicates that 73,555 Mwh is the potential annual market. The process need has a utilization rate substantially higher than the normal space heating needs. The specific rate has not been determined in this phase of the project.

Exhibit 4-34, Building Count Information, lists the number of building in the data base and in the population. This exhibit is intended to show make-up of buildings for site analysis and for building conversion cost inferences.

Exhibit 4-35, Potential Heating Market by Heating System Type and Exhibit 4-36, Potential Heating Market by Building Type, show normalized market data by heating system type and building classification. The dominant system is steam and the major users are commercial establishments.

Exhibit 4-37, Potential Heating Market by Building Type and Heating System, shows the cross classification of building type and heating system. Commercials used in order of importance: steam, hot water and forced air. The public and institutional use steam. The use of steam is indicative of older buildings. The fact that hot water is used in 30% of the commercial establishments is indicative of some modernization in the downtown area.

Exhibit 4-38, Actual Data Base Fuel Usage by District - 1978, shows the actual fuel consumed during 1978 by the members of the data base. In addition, the exhibit shows the percentage of energy output supplied by each fuel.

Exhibit 4-39, Potential Annual Fuel Displacement, shows the potential fuel displacement in Red Wing. Data base usage was normalized and then projected across the balance of the population. The major assumption in the normalization was that multiple fuel users used fuel oil for above normal heating needs due to the non-availability of gas. Fleischmann Malting Company was assumed to have used propane for above normal use.

Exhibit 4-33

Potential Thermal Market (Red Wing)

<u>Process</u>	<u>10⁶ Btu/yr</u>		<u>MWH(1)</u>
	<u>Heating</u>	<u>Total</u>	<u>Total</u>
152,900	98,070	250,970	73,555

(1) Conversion to MWH is achieved by dividing the Btu total by 3.412×10^6 .

Exhibit 4-34

Building Count Information (Red Wing)

<u>Building Count Along the Distribution Line</u>			
<u>Type</u>	<u>Total</u>	<u>Number in Data Base (1)</u>	<u>% in Data Base</u>
Large Commercial	25	16	64%
Small Commercial	105	45	43%
Industrial	1	1	100%
Multi-Unit Residential	2	2	100%
Public and Institutional	<u>12</u>	<u>10</u>	<u>83%</u>
TOTAL	<u>145</u>	<u>74</u>	<u>51%</u>

(1) The data base includes those buildings and process applications for which adequate information could be obtained from the returned surveys, on-site reviews, or other techniques.

Exhibit 4-35

Potential Heating Market by Heating System Type (Red Wing)

	<u>10⁶ Btu/yr</u>				
	<u>Forced Air</u>	<u>Steam</u>	<u>Hot Water</u>	<u>Hot Water/ Steam</u>	<u>Total</u>
	<u>18,150</u>	<u>50,906</u>	<u>27,609</u>	<u>1,405</u>	<u>98,070</u>
Percentage	19%	52%	28%	1%	100%

Exhibit 4-36

Potential Heating Market by Building Type (Red Wing)

	<u>10⁶ Btu/yr</u>					
	<u>Large Commercial</u>	<u>Small Commercial</u>	<u>Industrial</u>	<u>Multi-Unit Residential</u>	<u>Public and Institutional</u>	<u>Total</u>
	<u>38,666</u>	<u>28,106</u>	<u>4,465</u>	<u>3,997</u>	<u>22,836</u>	<u>98,070</u>
Percentage	39%	29%	5%	4%	23%	100%

Exhibit 4-37

Potential Heating Market by Building Type and Heating System

<u>Classification</u>	<u>10⁶Btu/yr</u>				<u>Total</u>	<u>Percent</u>
	<u>Forced Air</u>	<u>Steam</u>	<u>Hot Water</u>	<u>Hot Water/ Steam</u>		
Large Commercial	6,952	18,112	13,602	--	38,666	39
Small Commercial	11,198	8,191	8,717	--	28,106	29
Industrial	--	4,465	--	--	4,465	5
Multi-Unit Residential	--	--	3,997	--	3,997	4
Public and Institutional	--	20,138	1,293	1,405	22,836	23
	<u>18,150</u>	<u>50,906</u>	<u>27,609</u>	<u>1,405</u>	<u>98,070</u>	100%
	19%	52%	28%	1%	100%	

Exhibit 4-38

1978 Data Base Fuel Usage (Red Wing)

Type		
<u>Natural Gas</u>	<u>#2 Fuel Oil</u>	<u>Propane</u>
(CCF)	(Gal)	(Gal)
<u>1,916,756</u>	<u>150,674</u>	<u>707,846</u>

Percentage of Heat Output After
Conversion to Equivalent Base (1)

Gas	70%
#2 Oil	6%
Propane	24%

- (1) Fuels were converted to Btu equivalents and then fuel-specific efficiency factors were applied to arrive at equivalent heat output.

Exhibit 4-39

Potential Annual Fuel Displacement

	<u>Natural Gas</u> (CCF)	<u>#2 Fuel Oil</u> (Gal)	<u>Propane</u> (Gal)
1978 Data Base Usage	1,916,756	150,674	707,846
Normalization Adjustment (1)	(21,321)	(38,615)	(187,443)
Estimated Normal Fuel Usage of Users Not in the Data Base (2)	358,268	56,494	--
Potential Annual Fuel Displacement	<u>2,253,703</u>	<u>168,553</u>	<u>520,403</u>

- (1) Heating degree days in 1978 were 10.1% above normal which causes above normal fuel usage. Process use in Red Wing was adjusted since outside air is heated in the particular application. The adjustment assumptions were that gas only users used gas for above normal needs, gas and oil users used oil for above normal use and the gas and propane user used propane for above normal use.
- (2) Fuel use of non-data base users was estimated utilizing normalized data base information, the process used was not considered as part of the base in this estimation process.

Market Advantages and Problems

Size of industrial load. Fleischmann represents 60% of the potential market in Red Wing, and this is advantageous if they decide to convert to district heating. Currently, Flieschmann is very interested in the concept of district heating. A commitment to participate and the potential for signing a long-term contract would substantially reduce risks associated with variable annual hookup percentages. A stable base would be available from which to expand district heating to space heating users. The administrative costs of the district heating company should be reduced by serving less users per energy unit produced.

Need for year round commitment. Fleischmann uses low-cost gas during non-peak times and high cost propane when they are interrupted during peak gas use. This essentially means that they use propane during the winter months and gas during the other months. The economic analysis of the Red Wing district heating market indicates that the process use needs to be a year round customer. This means that a contract would have to be signed with Fleischmann for year around use. Without such a contract it might be advantageous for Fleischmann to use hot water during the winter and low-cost gas other times of the year. This also means that substantial amounts of natural gas would be displaced during the summer months when it could have the most unfavorable impact on the gas supplier.

Alternative energy plans. Fleischmann is within the same corporate group as ADM, another large industrial processor in Red Wing. ADM and NSP are currently discussing the possibility of utilizing high pressure steam off the power plant boilers at NSP. ADM would utilize this steam in their process and there is potential for utilizing the excess steam production for space heating and/or for part of Fleischmann's needs. This arrangement would be cost effective only in the winter months when ADM utilizes high cost fuel oil and Fleischmann's utilizes high cost propane. District heating would not provide lower cost energy for ADM, whereas the use of NSP boilers could be beneficial to both ADM and Fleischmann. It is possible that Fleischmann would decline to participate in district heating thus sacrificing some fuel cost saving at their plant but maximizing total fuel cost savings for the entire corporation. This problem should be dealt with by studying both alternatives and determining which is the better alternative for the power plant, the users and society as a whole. If district heating were found to be the best alternative, then advance commitments would have to be obtained from Fleischmann's.

Market growth. Fleischmann also provides the potential for market growth. They currently are operating near capacity and their long-term planners are considering increasing capacity by 60% in five years. The existence of a low-cost, stable energy source could provide the additional incentive required to finalize the decision. The benefits of such market growth to the economic viability of the district heating system could be significant.

Stability of potential market. Current zoning plans indicated that the potential for other expansion growth is limited although the zoning could be changed to provide additional markets and the potential for fuel conservation.

Red Wing is a relatively unstable downtown area. The downtown area in Red Wing is currently in a transition stage. Some businesses are contemplating moving out to malls while others are renovating. It is not clear which, if either, will be the dominant trend. This instability makes the space heating market more risky in Red Wing. This problem may not be crucial to the viability of district heating in Red Wing since process use is the major use. Some of the riskiness could probably be reduced by obtaining long-term commitments.

Institutional Assessment

Selection of Owner/Operator

For this preliminary stage of the study, the owner of the district heating company in Red Wing is assumed to be Northern States Power Company. The utility is assumed to operate the prospective district heating system for the following reasons:

1. The utility is the existing owner of the coal-fired electrical generating facility and has experience in operating a district heating system. Accordingly, it should be most capable of extending its expertise into operation of a new district heating venture.
2. An existing utility could organize faster and develop a district heating system faster than a newly created entity.
3. There may be efficiencies in operating the two utilities jointly, such that costs for the district heating company may be lower if it was owned and operated by the electric utility. Ownership and operation by the same company will eliminate the redundancies in management which might occur if a separate entity was set up to operate the district heating company. Other operating efficiencies might result from utilization of existing personnel.
4. The utility has obtained public and private acceptance in Red Wing, such that its operation of the new district heating company would positively impact the response to implementation of district heating.
5. It should be easier for an existing utility to raise needed capital.
6. Hiring practices, including job descriptions, candidate recruitment, and utility personnel selection, will be most efficiently handled by a company with power plant and district heating operating experience.
7. If the district heating company is owned and operated by an existing electric utility, opportunities for present personnel to transfer into the new district heating company will exist. Such a change would be less dramatic than hiring all new employees.

Decision Process for Utility Investment

The critical decision variable at Northern States Power is the demonstration of economic feasibility. The Research Department at NSP will analyze the market forecasts, conversion costs, expected returns and other economic variables it considers important. If these results are positive and returns on equity approximate currently earned returns on the electric utility, then other aspects of the study will be evaluated. Legal implications, the PSC's response to guidelines for cost allocation methodology, and preliminary pricing estimates will also be considered. Finally, when the results of Phase 1 have been examined sufficiently, and assuming that a recommendation can be made to proceed, the Research Department will submit the project for approval to the Officers Committee and to the Board of Directors for the final review.

Capital Structure

For the purposes of this preliminary study, the district heating utility is assumed to be owned by Northern States Power Company, which owns the electric and gas utilities in Red Wing. Therefore, the district heating company has a strong probability of reflecting a capital structure identical to that of NSP, since the same sources of permanent financing would most likely be available. Currently, NSP's capital structure approximates a 50/50 debt and equity mix. For this study this mix has been utilized within the financial model.

Types of Debt Available

NSP personnel and Red Wing city officials have indicated that IDR's might be a feasible financing alternative pending further project information and legal opinion as to the appropriateness of their use. In the event that the amount of IDR issuance was limited or inappropriate, conventional utility financing is assumed.

Franchise Agreements

Currently, Northern States Power is operating in Red Wing without an electric franchise agreement with the city but does have a gas franchise. No franchise or regulatory fees are levied on the utility. Other rights and restrictions typically cited in franchise agreements are present in the agreement between the city and the utility.

Taxation

Further investigation of the possibility of and methods for granting a competitive advantage through preferential taxation may be required for Phase 2.

Zoning and Redevelopment

A shopping mall is being constructed three miles west of downtown and may attract new or existing businesses to the detriment of the downtown market. Two factors which may significantly reduce this possibility are that (1) the mall development is currently delayed due to financial considerations, and (2) that a development director has been hired to direct a campaign for renovation and development of the downtown area. Because the effects of these variables on future development are unclear, their ultimate impact on district heating cannot be determined at this time.

The only other major development planned to be completed over the next five years involves one thousand additional residential units in the southern part of the city. This location, however, is not in the proximity of the preliminary distribution lines.

The redevelopment and expansion plans, either proposed or underway, in each of the cities have the potential to impact the district heating market. However, further investigation and evaluation of the amount of energy consumption, the compatibility of the prospective heating systems, and the costs of conversion will have to be undertaken in Phase 2 in order to determine the impact on the district heating market.

Displacement Effects on Existing Energy Suppliers

In Red Wing, NSP provides both electricity and natural gas. Even though displacement would be a certainty, it is impossible to determine, at this time, how it might affect NSP's decision to construct a competing district heating system. Propane sales will also be displaced, assuming hookup of a key industrial user.

Adequacy of Existing Coal Contracts

Due to the fact that the Red Wing plant is a rather small plant, its volume of coal use does not justify negotiation of a long term coal contract. Conversations with NSP's fuel procurement personnel have indicated that the plant's coal supply will continue to be purchased on the spot market and that no difficulties in obtaining coal or wood chips are expected.

Economic Analysis

Site Specific Assumptions

The specific assumptions made in the economic analysis of base case for Red Wing and the rationale underlying these assumptions are presented below.

Thermal energy revenues.

Assumption: Average revenue per MWH for the first year of operation was estimated at \$12.42 per MWH. This amount was established by taking 110% of the projected 1981 cost of natural gas in Red Wing of \$3.31/MCF times a conversion factor (MCF to MWH) of 3.412. The \$3.31/MCF is the average projected cost of natural gas in Red Wing based upon data provided by the Minnesota Energy Agency.

Assumption: The average revenue per MWH was escalated by the rate of 6% per year. This compares to a projected total inflation rate for gas and oil of 8.3% (4.3% differential) and 7.0% (3.0% differential) per year.

Exhibit 4-40 is a graphical presentation of the various significant price and cost relationships assumed for Red Wing. The projected price of alternative fuels (oil and natural gas) and district heating are shown by year as well as the projected coal cost and thermal energy cost to the company. This Exhibit illustrates that the company could increase their average revenue at a higher rate than the projected 6% rate and still provide lower cost energy to its customers. The area under the projected alternative fuel cost line and the assumed district heating price line represents long-term energy savings to the system user. A significant energy cost savings not displayed on Exhibit 4-40 is that the district heating thermal price is for delivered energy while the alternative fuel costs must be divided by the efficiency of the buildings heating system (65-75%) to get actual energy cost.

Assumption: Average revenue per MWH has not been maximized relative to alternative fuel costs case for the following reasons:

Exhibit 4-40

Project Alternative Energy Costs
and District Heating Costs

- 0 Total revenues will be maximized in the early years by showing a discernable cost savings immediately which will will encourage hookups.
- 0 Contractual relationships which provide a stable revenue base will be encouraged since the pricing policy guarantees a lower than alternative energy cost inflation rate.
- 0 A potential revenue reserve is still available to cover unexpected or underestimated costs.

Assumption: Thermal energy sales in MWH's were developed by year based upon the construction phasing and hookup rates shown on Exhibit 4-41. It was assumed that the first year construction would be to the large process load who will have committed to hookup prior to the start of construction. It was assumed that 90% of the potential market excluding process user would eventually hookup. The overall hookup rate, assuming 100% hookup of the process user and 90% of the remaining potential market, is 96%. The maximum hookup percent will be reached in the year 1985 when 70,679 MWH of the estimated potential market of 73,555 will be connected to the system.

Purchased energy expense.

Assumption: The estimated purchase energy costs were calculated based upon the following assumptions regarding plant operations.

- 0 Electrical generation now being run on two identical turbines will be shifted entirely to the retrofitted turbine.
- 0 During the heating season, there will be electrical generation of 6 MW to produce cogeneration efficiencies. This approximates the present plant operations during the heating months using one turbine.
- 0 During the rest of the year, there will be 10 hours of electrical generation of 6 MW to produce cogeneration efficiencies and 14 hours of header steam used to provide the remaining thermal energy required.

Exhibit 4-41

City of Red Wing
Preliminary Base Case Economic Analysis Thermal
Energy Construction Phase and Hookup Assumptions

<u>Construction Phase</u>	<u>Potential Thermal Energy Market (MWH's)</u>	<u>Assumed Hook-Up Rate</u>	<u>Maximum MWH's Hooked-Up</u>
1982 - Plant to Fleischmann's Malting	44,812	100% in 1982	44,812 ⁽¹⁾
Other potential users on distribution line	4,631	25% in 1982 30% in 1983 35% in 1984	4,140 ⁽¹⁾
1983 - Balance of downtown business district	24,142	35% in 1983 30% in 1984 25% in 1985	21,727
Total	<u>73,555</u>		<u>70,679</u>

(1) Economic analysis adjusted for part year consumption in 1982.

- 0 When there is no electrical generation the boilers are banked. This is done to allow for rapid return to the grid if necessary. The banked boilers produce 3 MW of thermal energy through header steam extraction which can be utilized by the District Heating System at no cost.

Assumption: An average cost of \$3.05 per MWH thermal was calculated for 1982 assuming fuel cogeneration efficiencies. In that year, the end of construction coincides with the beginning of the heating season and higher levels of electric generation.

Assumption: An average cost of \$3.50 per MWH thermal was calculated for 1983 as follows.

- 0 Total incremental costs associated with thermal energy requirements in a cogeneration environment during the heating system were estimated.
- 0 The cost of producing approximately 3,000,000 KWH of additional electrical energy at a higher variable cost because of running this plant rather than a large base loaded plant in order to obtain cogeneration efficiencies was estimated. This cost was determined by calculating the incremental fuel cost for this plant over the Sherco plant fuel cost.
- 0 The cost of header steam for 14 hours a day outside the heating season was calculated. This calculation reflected the use of thermal energy delivered by banked boilers.

Assumption: 1982 and 1983 thermal costs were determined based on December 1978 costs and inflated at the general inflation rate of 4.0%.

Assumption: Current operating plant characteristics were based on 1977 experience due to unusual plant operating characteristics in 1978 because of experimentation with fuel alternatives and boiler repairs.

Assumption: The average cost per MWH was escalated by the assumed general inflation rate of coal (4% per year) over the period of analysis.

Assumption: Exhibit 4-40 also contains a graphical presentation of the average thermal fuel cost per million BTU's assumed in the base case. This graph illustrates that average thermal fuel cost follows the projected cost changes in coal prices.

Operating and maintenance expense.

Assumption: Fixed operating expense was estimated for 1981 at \$180,000. This amount is composed of \$150,000 for 6-7 new employees as follows: 2-3 people for night operations as boiler attendants, shift workers, etc., 1 person for night maintenance, 1-2 people for night coal handling, 1 engineer, 1 meter reader and 1 manager. General and administrative expense including rent, billings and supplies was estimated at \$30,000. This amount was then escalated at the 4% general inflation rate.

Assumption: Variable operating expense of \$.60/MWH was to cover maintenance of the distribution system at 1% of distribution investment, electrical cost for the pumps, water treatment and miscellaneous variable costs. This amount was escalated at the 4% general inflation rate and multiplied by the MWH of consumption.

Property taxes.

Assumption: Property (ad valorem) taxes were estimated based on the Minnesota Department of Revenue formula for calculation of the market value by the unit value computation.

Assumption: It was assumed that the unit value calculation was based on a gas distribution company formula. This formula uses asset cost depreciated over time (to a limit of 55% of original cost) to determine 75% of the market value for tax purposes. The average operating income for the prior three years capitalized at 8% determines the remaining 25% of the market value.

Assumption: The calculated market value was then multiplied by the assessed valuation and multiplied by the projected tax rate of \$72.5¢/\$1,000 market value in 1982. The tax rate was developed by multiplying the 1978 tax rate by the general inflation rate to bring it up to a fiscal year 1982 rate.

Assumption: In the years after 1982, the tax rate was increased by the general inflation rate of 4.0% each year and multiplied by the calculated assessed value under the unit value calculation in that year.

Depreciation expense.

- Assumption: A full years depreciation was assumed for all new assets in the year placed in service was assumed.
- Assumption: A 25-year life was assumed for the turbine retrofit, distribution network and conversion assets.
- Assumption: A 10-year life was assumed for the service equipment assets.
- Assumption: Depreciation calculated on a straight line basis was used for financial statement presentation.
- Assumption: Depreciation calculated on a 200% declining method was used for calculating income tax benefit. The tax timing difference between straight line and accelerated depreciation has been reflected as deferred taxes.

Interest expense.

- Assumption: Interest expense was calculated by multiplying the assumed rate of 5% by the simple average of the beginning and ending capital account balance which has a 50% debt component. This equates to a 10% interest rate on the debt portion.

Fixed assets/construction costs.

- Assumption: The engineering estimate for retrofitting an existing turbine to controlled extraction is \$1,000,000 in 1979 dollars. It is also assumed that the actual retrofit effort will be completed in the first year (1982). A 6% construction inflation rate was used to reach a \$1,140,000 cost in year 1982.
- Assumption: The engineering estimate of the total distribution system in 1979 dollars was \$2,300,000 including design costs. It was assumed that the distribution network will be constructed in the phasing shown on Exhibit 4-41. A 6% compound construction cost inflation rate was used to determine the specific construction cost each year.
- Assumption: Building conversion costs were based upon the following estimates of conversion costs in 1979 dollars and a 6% inflation rate:
- o \$20.00/KW for hot water

- o \$23.00/KW for steam and steam/hot water
- o \$30.00/KW for forced air

Assumption: Service equipment was estimated at \$50,000 in 1982 with 20% additions each year and a 6% inflation rate.

Base Case Results

The results of the base case economic analysis for the City of Red Wing are presented below. The project teams consensus of expected operating results are presented in Exhibit 4-42 to Exhibit 4-47. These projections are based upon the assumptions presented above and are intended to be used only to determine whether further study of Red Wing as a potential demonstration site is justified.

Exhibit 4-42. This Exhibit presents projected statements of income for the 20 years, 1982 to 2001. This Exhibit also shows by year the average capital investment, return on average capital investment and the annual thermal energy sales (MWH). The base case results indicate that after depreciation and interest the system will show a loss for the first two years and by the end of twenty years there will be a net income of approximately \$600,000. After the initial loss years the return on average book equity ranges from 1.18% to 100.33%. The book return on equity exceeds 13% for the first time after nine years in 1990.

Exhibit 4-43. This Exhibit presents projected balance sheets for the 20 years, 1982 to 2001. This Exhibit shows the building up of the system over the first five years with total capital expenditure of \$4,361,080 for plant retrofit, distribution system and building conversions.

The total capital required would be \$4,000,000. This Exhibit also indicates that cash would be available for return on capital (accumulated cash reduction) beginning in 1983 and that a total of \$7,803,168 would be paid to investors by the end of 2001.

Exhibit 4-44. This Exhibit presents projected cash flow statements for the 20 years, 1982 to 2001. This Exhibit also shows the cash return on capital investment by year. This Exhibit indicates that operations will generate positive cash flows beginning in 1983. The total cash return, including interest, ranges from 9.30% in 1982 to 64.85% in 2001.

Exhibit 4-45. This Exhibit presents projected net income and cash from operations for the twenty year period. The difference between net income and cash flow is accounted for primarily by depreciation expense.

Exhibit 4-46. This Exhibit presents a summary schedule showing the calculation of internal cash flow to and from the equity investors. The internal rate of return earned on these equity cash flows is 10.94%.

Exhibit 4-47. This Exhibit shows the internal rate of return analysis of the cash flows calculated in Exhibit 4-46. This exhibit also shows the present value of the cash flows assuming a 13% and a 15% discount rate. This indicates that the present value of the cash flows would have to be increased by \$298,410 to achieve a 13% return on equity. This can be accomplished either by increasing cash from operations or reducing capital expenditures.

The results of the base case economic analysis indicate that Red Wing is potentially a viable demonstration community for a cogeneration hot water district heating system. The base case internal rate of return of 10.94% in equity appears somewhat less than acceptable but the assumptions are conservative enough to indicate that it still has good potential as a demonstration site. Key variables which could potentially impact the return on equity include:

- 0 Lower interest cost which might be obtained from a form of tax exempt financing
- 0 Increased leverage (i.e., a higher percent of debt in the capital structure)
- 0 Contributions in aid of construction
- 0 Larger hookup charges
- 0 Increased revenues; revenues matching closer to alternative fuel prices
- 0 Lower operating costs particularly thermal energy costs

A major consideration which should be addressed in Phase 2 is whether it will be possible to accelerate projected cash returns so investors will not have to rely upon receiving a majority of this return more than ten years after they make the investment. Even though projected results appear encouraging

Exhibit 4-42

CITY OF RED WING
PRELIMINARY BASE CASE ECONOMIC ANALYSIS
PROJECTED STATEMENT OF INCOME

	For fiscal years ending March 30th									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
OPERATING REVENUE:										
Thermal energy	\$ 187,004	\$ 734,774	\$ 899,912	\$1,045,342	\$1,108,246	\$1,174,684	\$1,245,363	\$1,320,283	\$1,399,444	\$1,482,845
OPERATING EXPENSES:										
Purchased energy	45,923	195,270	234,648	267,873	278,475	289,784	301,093	313,108	325,830	338,552
Operations and maintenance	164,034	196,014	209,482	222,063	230,947	240,185	249,779	259,768	270,172	280,970
Property taxes	56,603	88,504	95,170	102,553	112,509	116,351	117,946	118,807	120,382	122,185
Depreciation	111,471	171,325	177,777	182,818	184,080	185,418	186,837	188,341	189,934	191,624
Income tax (benefit)	(137,967)	(39,808)	13,168	58,213	69,236	95,546	125,767	157,482	189,958	223,865
Total operating expenses	240,064	611,305	730,245	833,520	875,247	927,284	981,422	1,037,506	1,096,276	1,157,196
OPERATING INCOME	(53,060)	123,469	169,667	211,822	232,999	247,400	263,941	282,777	303,168	325,649
OTHER INCOME:										
Interest on cash balances	2,665	2,469	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Hookup charges	2,665	4,900	33,300	24,000						
	2,665	7,369	35,800	26,500	2,500	2,500	2,500	2,500	2,500	2,500
INCOME BEFORE INTEREST CHARGE	(50,395)	130,838	205,467	238,322	235,499	249,900	266,441	285,277	305,668	328,149
INTEREST CHARGES:										
Interest on debt portion of capital account	64,891	157,052	183,520	175,498	162,282	152,604	141,510	131,344	122,023	113,480
NET INCOME (LOSS)	(\$ 115,286)	(\$ 26,214)	\$ 21,947	\$ 62,824	\$ 73,217	\$ 97,296	\$ 124,931	\$ 153,933	\$ 183,645	\$ 214,669
AVERAGE BOOK EQUITY	\$1,271,179	\$1,561,118	\$1,859,615	\$1,810,278	\$1,728,742	\$1,627,240	\$1,531,736	\$1,441,119	\$1,354,912	\$1,272,741
RETURN ON AVERAGE BOOK EQUITY	(9.07%)	(1.68%)	1.18%	3.47%	4.24%	5.98%	8.16%	10.68%	13.55%	16.87%
ANNUAL THERMAL ENERGY SALES (MWH)	15,057	55,791	64,464	70,679	70,679	70,679	70,679	70,679	70,679	70,679

Exhibit 4-42 (Continued)

CITY OF RED WING

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED STATEMENT OF INCOME

	For the fiscal years ending March 30th									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
OPERATING REVENUE:										
Thermal energy	\$1,571,901	\$1,666,610	\$1,766,268	\$1,872,287	\$1,984,666	\$2,104,114	\$2,229,922	\$2,363,505	\$2,505,570	\$2,656,116
OPERATING EXPENSES:										
Purchased energy	351,981	366,117	380,960	396,509	412,059	428,315	445,278	462,947	481,324	500,407
Operations and maintenance	292,202	303,909	316,049	328,703	341,850	355,511	369,744	384,530	399,908	415,898
Property taxes	123,761	129,230	138,070	147,633	157,838	168,901	181,025	196,218	210,657	226,401
Depreciation	188,415	189,253	190,141	191,083	192,082	193,140	194,261	195,451	196,712	198,048
Income tax (benefit)	262,902	298,995	335,279	373,580	414,432	457,806	503,222	550,380	602,944	655,881
Total operating expenses	1,219,261	1,287,504	1,360,499	1,437,508	1,518,261	1,603,673	1,693,530	1,789,526	1,891,545	1,996,635
OPERATING INCOME	352,640	379,106	405,769	434,779	466,405	500,441	536,392	573,979	614,025	659,481
OTHER INCOME:										
Interest on cash balances	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Bookup charges	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
INCOME BEFORE INTEREST CHARGE	355,140	381,606	408,269	437,279	468,905	502,941	538,892	576,479	616,525	661,981
INTEREST CHARGES:										
Interest on debt portion of capital account	105,735	98,746	92,384	86,533	80,978	75,537	70,152	64,811	57,022	54,290
NET INCOME (LOSS)	\$ 249,405	\$ 282,860	\$ 315,885	\$ 350,746	\$ 387,927	\$ 427,404	\$ 468,740	\$ 511,668	\$ 559,503	\$ 607,691
AVERAGE BOOK EQUITY	\$1,195,224	\$1,122,267	\$1,052,782	\$ 986,132	\$ 921,233	\$ 857,241	\$ 793,565	\$ 730,404	\$ 667,762	\$ 605,705
RETURN ON AVERAGE BOOK EQUITY	20.87%	25.20%	30.00%	35.57%	42.11%	49.86%	59.07%	70.05%	83.79%	100.33%
ANNUAL THERMAL ENERGY SALES (MWH)	70,679	70,679	70,679	70,679	70,679	70,679	70,679	70,679	70,679	70,679

Exhibit 4-43

CITY OF RED WING
PRELIMINARY BASE CASE ECONOMIC ANALYSIS
PROJECTED BALANCE SHEETS

	As of March 30th									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
ASSETS										
FIXED ASSETS:										
Plant retrofit	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000
Distribution system	1,349,000	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300
Building conversions	172,780	312,317	445,526	541,780	541,780	541,780	541,780	541,780	541,780	541,780
Service equipment	50,000	60,600	71,836	83,746	96,371	109,753	123,938	138,974	154,912	171,806
	<u>2,711,780</u>	<u>4,192,217</u>	<u>4,336,662</u>	<u>4,444,826</u>	<u>4,457,451</u>	<u>4,470,833</u>	<u>4,485,018</u>	<u>4,500,054</u>	<u>4,515,992</u>	<u>4,532,886</u>
Accumulated provision for depreciation	111,471	282,796	460,573	643,391	827,471	1,012,889	1,199,726	1,388,067	1,578,001	1,769,625
Net fixed assets	<u>2,600,309</u>	<u>3,909,421</u>	<u>3,876,089</u>	<u>3,801,435</u>	<u>3,629,980</u>	<u>3,457,944</u>	<u>3,285,292</u>	<u>3,111,987</u>	<u>2,937,991</u>	<u>2,763,261</u>
CURRENT ASSETS:										
Cash	56,617	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Accounts receivable	22,441	88,173	107,989	125,441	132,990	140,962	149,444	158,434	167,933	177,941
Total current assets	<u>79,058</u>	<u>138,173</u>	<u>157,989</u>	<u>175,441</u>	<u>182,990</u>	<u>190,962</u>	<u>199,444</u>	<u>208,434</u>	<u>217,933</u>	<u>227,941</u>
TOTAL	<u>\$2,679,367</u>	<u>\$4,047,594</u>	<u>\$4,034,078</u>	<u>\$3,976,876</u>	<u>\$3,812,970</u>	<u>\$3,648,906</u>	<u>\$3,484,736</u>	<u>\$3,320,421</u>	<u>\$3,155,924</u>	<u>\$2,991,202</u>
LIABILITIES AND CAPITAL ACCOUNTS										
CAPITALIZATION:										
Capital investment	\$2,600,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000
Accumulated earnings (deficit)	(115,286)	(141,500)	(119,553)	(56,729)	16,488	113,784	238,715	392,648	576,293	790,962
Accumulated cash reduction		(98,742)	(201,746)	(380,860)	(663,932)	(957,379)	(1,268,176)	(1,598,712)	(1,950,584)	(2,325,711)
Net capital investment	<u>2,484,714</u>	<u>3,759,758</u>	<u>3,678,701</u>	<u>3,562,411</u>	<u>3,352,556</u>	<u>3,156,405</u>	<u>2,970,539</u>	<u>2,793,936</u>	<u>2,625,709</u>	<u>2,465,251</u>
CURRENT LIABILITIES:										
Accounts payable	22,213	39,574	42,167	47,374	51,828	53,860	55,735	57,640	59,699	61,809
DEFERRED CREDITS:										
Accumulated deferred income taxes	58,500	138,422	207,506	265,593	311,349	345,723	369,925	384,753	390,939	389,154
Accumulated deferred investment tax credit	113,940	109,840	105,704	101,498	97,237	92,918	88,537	84,092	79,577	74,988
Total deferred credits	<u>172,440</u>	<u>248,262</u>	<u>313,210</u>	<u>367,091</u>	<u>408,586</u>	<u>438,641</u>	<u>458,462</u>	<u>468,845</u>	<u>470,516</u>	<u>464,142</u>
TOTAL	<u>\$2,679,367</u>	<u>\$4,047,594</u>	<u>\$4,034,078</u>	<u>\$3,976,876</u>	<u>\$3,812,970</u>	<u>\$3,648,906</u>	<u>\$3,484,736</u>	<u>\$3,320,421</u>	<u>\$3,155,924</u>	<u>\$2,991,202</u>

Exhibit 4-43 (Continued)

CITY OF RED WING

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED BALANCE SHEETS

	1992	1993	1994	1995	As of March 30th		1998	1999	2000	2001
					1996	1997				
ASSETS										
FIXED ASSETS:										
Plant retrofit	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000	\$1,140,000
Distribution system	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300	2,679,300
Building conversions	541,780	541,780	541,780	541,780	541,780	541,780	541,780	541,780	541,780	541,780
Service equipment	139,714	148,097	156,983	166,402	176,386	186,970	198,188	210,080	222,685	236,047
	<u>4,500,794</u>	<u>4,509,177</u>	<u>4,518,063</u>	<u>4,527,482</u>	<u>4,537,466</u>	<u>4,548,050</u>	<u>4,559,268</u>	<u>4,571,160</u>	<u>4,583,765</u>	<u>4,597,127</u>
Accumulated provision for depreciation	1,908,040	2,086,692	2,265,598	2,444,773	2,624,229	2,803,987	2,984,062	3,164,478	3,345,252	3,526,405
Net fixed assets	<u>2,592,754</u>	<u>2,422,465</u>	<u>2,252,465</u>	<u>2,082,709</u>	<u>1,913,237</u>	<u>1,744,063</u>	<u>1,575,206</u>	<u>1,406,682</u>	<u>1,238,513</u>	<u>1,070,722</u>
CURRENT ASSETS:										
Cash	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Accounts receivable	188,628	199,993	211,952	224,674	238,160	252,494	267,591	283,621	300,668	318,734
Total current assets	<u>238,628</u>	<u>249,993</u>	<u>261,952</u>	<u>274,674</u>	<u>288,160</u>	<u>302,494</u>	<u>317,591</u>	<u>333,621</u>	<u>350,668</u>	<u>368,734</u>
TOTAL	<u>\$2,831,382</u>	<u>\$2,672,478</u>	<u>\$2,514,417</u>	<u>\$2,357,383</u>	<u>\$2,201,397</u>	<u>\$2,046,557</u>	<u>\$1,892,797</u>	<u>\$1,740,303</u>	<u>\$1,589,181</u>	<u>\$1,439,456</u>
LIABILITIES AND CAPITAL ACCOUNTS										
CAPITALIZATION:										
Capital investment	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000	\$4,000,000
Accumulated earnings (deficit)	1,040,367	1,323,227	1,639,112	1,989,858	2,377,785	2,805,189	3,273,929	3,785,597	4,345,100	4,952,791
Accumulated cash reduction	(2,724,723)	(3,149,806)	(3,601,408)	(4,083,034)	(4,599,680)	(5,154,693)	(5,750,168)	(6,387,742)	(7,071,907)	(7,803,168)
Net capital investment	<u>2,315,644</u>	<u>2,173,421</u>	<u>2,037,704</u>	<u>1,906,824</u>	<u>1,778,105</u>	<u>1,650,496</u>	<u>1,523,761</u>	<u>1,397,855</u>	<u>1,273,193</u>	<u>1,149,623</u>
CURRENT LIABILITIES -										
Accounts payable	63,995	66,606	69,590	72,735	75,978	79,393	83,003	86,973	90,989	95,224
DEFERRED CREDITS:										
Accumulated deferred income taxes	380,921	366,094	345,206	320,320	294,205	267,914	241,603	215,335	189,113	162,939
Accumulated deferred investment tax credit	70,822	66,357	61,917	57,504	53,109	48,754	44,430	40,140	35,886	31,670
Total deferred credits	<u>451,743</u>	<u>432,451</u>	<u>407,123</u>	<u>377,824</u>	<u>347,314</u>	<u>316,668</u>	<u>286,033</u>	<u>255,475</u>	<u>224,999</u>	<u>194,609</u>
TOTAL	<u>\$2,831,382</u>	<u>\$2,672,478</u>	<u>\$2,514,417</u>	<u>\$2,357,383</u>	<u>\$2,201,397</u>	<u>\$2,046,557</u>	<u>\$1,892,797</u>	<u>\$1,740,303</u>	<u>\$1,589,181</u>	<u>\$1,439,456</u>

Exhibit 4-44

CITY OF RED WING
PRELIMINARY BASE CASE ECONOMIC ANALYSIS
PROJECTED CASH FLOW STATEMENTS

	For the fiscal years ending March 30th									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
SOURCE OF CASH:										
Net income (loss)	(\$ 115,286)	(\$ 26,214)	\$ 21,947	\$ 62,824	\$ 73,217	\$ 97,296	\$ 124,931	\$ 153,933	\$ 183,645	\$ 214,669
Depreciation	111,471	171,325	177,777	182,818	184,080	185,418	186,837	188,341	189,934	191,624
Deferred income tax	58,500	79,922	69,084	58,087	45,756	34,374	24,202	14,828	6,186	(1,785)
Deferred investment tax credit	113,940	(4,100)	(4,136)	(4,206)	(4,261)	(4,319)	(4,381)	(4,445)	(4,515)	(4,589)
Increase in:										
Accounts receivable	(22,441)	(65,732)	(19,816)	(17,452)	(7,549)	(7,972)	(8,482)	(8,990)	(9,499)	(10,008)
Accounts payable	22,213	17,361	2,593	5,207	4,454	2,032	1,875	1,905	2,059	2,110
Cash from operations	168,397	172,562	247,449	287,278	295,697	306,829	324,982	345,572	367,810	392,021
Capital investment	2,600,000	1,400,000								
TOTAL	\$2,768,397	\$1,572,562	\$ 247,449	\$ 287,278	\$ 295,697	\$ 306,829	\$ 324,982	\$ 345,572	\$ 367,810	\$ 392,021
USE OF CASH:										
Construction expenditures	\$2,711,780	\$1,480,437	\$ 144,445	\$ 108,164	\$ 12,625	\$ 13,382	\$ 14,185	\$ 15,036	\$ 15,938	\$ 16,894
Reduction of capital investment		98,742	103,004	179,114	283,072	293,447	310,797	330,536	351,872	375,127
Cash working capital	56,617	(6,617)								
TOTAL	\$2,768,397	\$1,572,562	\$ 247,449	\$ 287,278	\$ 295,697	\$ 306,829	\$ 324,982	\$ 345,572	\$ 367,810	\$ 392,021
CASH RETURN ON INVESTMENT:										
Reduction of capital investment		\$ 98,742	\$ 103,004	\$ 179,114	\$ 283,072	\$ 293,447	\$ 310,797	\$ 330,536	\$ 351,872	\$ 375,127
Interest expense	\$ 64,891	157,052	183,520	175,498	162,282	152,604	141,510	131,344	122,023	113,480
Total cash return on capital investment	\$ 64,891	\$ 255,794	\$ 286,524	\$ 354,612	\$ 445,354	\$ 446,051	\$ 452,307	\$ 461,880	\$ 473,895	\$ 488,607
Average capital investment	\$2,542,357	\$3,122,236	\$3,719,230	\$3,620,556	\$3,457,484	\$3,254,481	\$3,063,472	\$2,882,238	\$2,709,823	\$2,545,480
Cash return on capital investment	9.30%	10.86%	11.49%	12.42%	12.57%	13.03%	13.68%	14.40%	15.23%	16.17%

Exhibit 4-44 (Continued)

CITY OF RED WING

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED CASH FLOW STATEMENTS

		For the fiscal years ending March 30th									
		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
SOURCE OF CASH:											
Net income (loss)		\$ 249,405	\$ 282,860	\$ 315,885	\$ 350,746	\$ 387,927	\$ 427,404	\$ 468,740	\$ 511,668	\$ 559,503	\$ 607,691
Depreciation		188,415	189,253	190,141	191,083	192,082	193,140	194,261	195,451	196,712	198,048
Deferred income tax	(	8,233)	(14,827)	(20,888)	(24,886)	(26,115)	(26,291)	(26,311)	(26,268)	(26,222)	(26,174)
Deferred investment tax credit	(	4,166)	(4,465)	(4,440)	(4,413)	(4,395)	(4,355)	(4,324)	(4,290)	(4,254)	(4,216)
Increase in:											
Accounts receivable	(	10,687)	(11,365)	(11,959)	(12,722)	(13,486)	(14,334)	(15,097)	(16,030)	(17,047)	(18,066)
Accounts payable		2,186	2,610	2,985	3,147	3,242	3,415	3,610	3,971	4,016	4,234
Cash from operations		416,920	444,066	471,724	502,955	539,255	578,979	620,879	664,502	712,708	761,517
Capital investment											
TOTAL		\$ 416,920	\$ 444,066	\$ 471,724	\$ 502,955	\$ 539,255	\$ 578,979	\$ 620,879	\$ 664,502	\$ 712,708	\$ 761,517
USE OF CASH:											
Construction expenditures	\$	17,908	\$ 18,983	\$ 20,122	\$ 21,329	\$ 22,609	\$ 23,966	\$ 25,404	\$ 26,928	\$ 28,543	\$ 30,256
Reduction of capital investment		399,012	425,083	451,602	481,626	516,646	555,013	595,475	637,574	684,165	731,261
Cash working capital											
TOTAL		\$ 416,920	\$ 444,066	\$ 471,724	\$ 502,955	\$ 539,255	\$ 578,979	\$ 620,879	\$ 664,502	\$ 712,708	\$ 761,517
CASH RETURN ON INVESTMENT:											
Reduction of capital investment	\$	399,012	\$ 425,083	\$ 451,602	\$ 481,626	\$ 516,646	\$ 555,013	\$ 595,475	\$ 637,574	\$ 684,165	\$ 731,261
Interest expense		105,735	98,746	92,384	86,533	80,978	75,537	70,152	64,811	37,022	54,290
Total cash return on capital investment	\$	504,747	\$ 523,829	\$ 543,986	\$ 568,159	\$ 597,624	\$ 630,550	\$ 665,627	\$ 702,385	\$ 741,187	\$ 785,551
Average capital investment		\$2,390,448	\$2,244,533	\$2,105,563	\$1,972,264	\$1,842,465	\$1,714,301	\$1,587,129	\$1,460,808	\$1,335,524	\$1,211,408
Cash return on capital investment		21.12%	26.01%	25.84%	28.81%	32.44%	36.78%	41.94%	48.08%	55.50%	64.85%

Exhibit 4-45

Preliminary Economic Analysis Cogenerated District
Heating System Projected Cash From Operations (Base Case)

Exhibit 4-47

Internal Rate of Return Analysis of Discrete Cashflows
(Base Case)

Year	Time Period	Cash			Discounted Cashflows		
		Outflows	Inflows	Netflows	at 13.0%	at 15.0%	at 11.0%
1982	(1)	\$1,357,643	0	\$-1,357,643	\$-1,201,454	\$-1,180,559	\$-1,223,102
1983	(2)	663,736	0	- 663,736	- 519,803	- 501,880	- 538,703
1984	(3)	0	62,475	62,475	43,298	41,078	45,681
1985	(4)	0	120,969	120,969	74,192	69,164	79,686
1986	(5)	0	178,145	178,145	96,690	88,569	105,720
1987	(6)	0	195,371	195,371	93,840	84,464	104,453
1988	(7)	0	217,864	217,864	92,606	81,903	104,936
1989	(8)	0	242,235	242,235	91,119	79,187	105,112
1990	(9)	0	267,758	267,758	89,133	76,114	104,673
1991	(10)	0	294,898	294,898	86,874	72,894	103,859
1992	(11)	0	324,209	324,209	84,521	69,687	102,866
1993	(12)	0	353,971	353,971	81,664	66,160	101,180
1994	(13)	0	383,744	383,744	78,348	62,369	98,820
1995	(14)	0	416,186	416,186	75,196	58,819	96,553
1996	(15)	0	452,286	452,286	72,317	55,584	94,530
1997	(16)	0	491,209	491,209	69,505	52,493	92,491
1998	(17)	0	532,107	532,107	66,630	49,447	90,263
1999	(18)	0	574,621	574,621	63,676	46,432	87,815
2000	(19)	0	621,834	621,834	60,980	43,693	85,613
2001	(20)	0	669,477	669,477	58,100	40,905	83,038
2002	(21)	0	574,812	574,812	44,145	30,540	64,231
Total		\$2,021,379	\$6,974,171	\$4,952,792	\$-298,410	\$-512,924	\$-10,270

The present value of the cashflows at 13.00% is \$-298,410

The present value of the cashflows at 15.00% is \$-512,924

The internal rate of return is 10.94%

Exhibit 4-46

City of Red Wing Preliminary Economic Analysis
Calculation of Net Cash Flow to/From Equity Investors (Base Case)

<u>Year</u>	<u>From Operations</u>	<u>Used For Construction Expenditure</u>	<u>Used for Working Capital</u>	<u>Debt Capital Increase/ (Decrease) (1)</u>	<u>Net Cash To/(From) Equity Investor</u>
1982	168,397	(2,711,780)	(56,617)	1,242,357	(1,357,643)
1983	172,562	(1,480,437)	6,617	637,522	(663,736)
1984	247,449	(144,445)		(40,529)	62,475
1985	287,278	(108,164)		(58,145)	120,969
1986	295,697	(12,625)		(104,927)	178,145
1987	306,829	(13,382)		(98,076)	195,371
1988	324,982	(14,185)		(92,933)	217,864
1989	345,572	(15,036)		(88,301)	242,235
1990	367,810	(15,938)		(84,114)	267,758
1991	392,021	(16,894)		(80,229)	294,898
1992	416,920	(17,908)		(74,803)	324,209
1993	444,066	(18,983)		(71,112)	353,971
1994	471,724	(20,122)		(67,858)	383,744
1995	502,955	(21,329)		(65,440)	416,186
1996	539,255	(22,609)		(64,360)	452,286
1997	578,979	(23,966)		(63,804)	491,209
1998	620,879	(25,404)		(63,368)	532,107
1999	664,502	(26,928)		(62,953)	574,621
2000	712,708	(28,543)		(62,331)	621,834
2001	761,517	(30,256)		(61,784)	669,477
2002	Book Value				574,812

Internal Rate of Return = 10.94% (2)

(1) 50% of change in net capital investment during the year.

(2) Assumed required return on weighted equity with common and prepared stock components is 13%.

there still may be a high level of perceived risk given that cogeneration hot water district heating systems are not a proven economical venture in this country and the bulk of the return is not projected until late in the project life. The longer it is projected before an investor begins to receive significant returns the more likely he is to require a very high risk premium as part of his cost of capital. It is possible that investors may require more tangible assurances that revenues will be sufficient to meet investor requirements, in order for private capital to be committed.

Under public (municipal) ownership the return would be substantially greater because of the elimination of income and property taxes, and the lower interest expense all other things remaining equal. This option should be explored in more depth during Phase 2.

Sensitivity Analysis

Sensitivity analysis was performed on significant assumptions to test the relative importance of these assumptions on the financial projections presented in the "Base Case" analysis.

Exhibit 4-48 summarizes the sensitivity analyses performed for Red Wing. All input to the base case analysis remained the same except for the specific data subjected to sensitivity analysis. The exhibit shows the base case assumption and the new assumption used in the sensitivity analysis.

The present value of the investment measured under the "base case" return of 10.94% on equity cash flows is also shown. A positive number indicates that the sensitivity change increased the value of the equity investment over the base case results. A negative number indicates that the sensitivity change reduced the value of the equity investment versus the base case results. The absolute change reflected is a measure of the relative importance of the sensitivity change after adjusting for the time value of money.

Also presented is the present value of the sensitivity change measured against a 13% return on equity investment which is the assumed minimum return required by a private investor owned utility on its equity investment. Over the period of the analysis, any sensitivity change

Exhibit 4-48

CITY OF RED WING
PRELIMINARY ECONOMIC ANALYSIS
SENSITIVITY ANALYSIS

SENSITIVITY ANALYSIS					
Sensitivity Number	Base Case Assumption	Sensitivity Assumption	Sensitivity Assumption Internal rate of return(1)	Present value under Base Case rate of return 10.94%	Present value at 13% rate of return
1)	Interest cost of 10% on a capital structure with 50% debt	Interest cost of 8% on a capital structure with 50% debt. (Approximates tax free municipal bond rate)	11.25%	19,114	(283,582)
2)	Interest cost of 10% on a capital structure with 50% debt	Interest cost of 12% on a capital structure with 50% debt.	10.00%	(168,073)	(450,644)
3)	Interest cost of 10% on a capital structure with 50% debt	Interest cost of 8% on a capital structure with 80% debt.	15.00%	420,924	173,142
4)	Interest cost of 10% on a capital structure with 50% debt	Interest cost of 12% on a capital structure with 80% debt.	12.25%	121,424	(94,153)
5)	Annual consumption equal to the assumed hookup rate times a potential market of 73555 MWH	Annual consumption equal to the assumed hookup rate times a potential market of 69877 MWH, (73555 x 95%)	9.75%	(233,243)	(499,099)
6)	Fixed and variable operating costs were estimated at \$155,000 and \$.60/MWH respectively in 1982 and inflated at the general inflation rate for each year	Fixed and variable operating and maintenance costs increased by 25% over the base case assumption	9.25%	(311,729)	(570,553)

(1) Rounded to nearest 1/4 of one percent.

4-103

Exhibit 4-48 (Continued)

CITY OF RED WING

PRELIMINARY ECONOMIC ANALYSIS

SENSITIVITY ANALYSIS

4-104

SENSITIVITY ANALYSIS			Internal rate of Sensitivity Assumption return on(1)	Present value of sensitivity assumption at Base Case return 10.94%	Present value of sensitivity at 13%
Sensitivity Number	Base Case Assumption	Sensitivity Assumption			
7)	Hookup rate of 90% of potential market other than the large process user	Hookup rate 75% of potential market other than the large process load.	9.00%	(331,984)	(577,233)
8)	Hookup 90% of the potential market other than the large process user in the first four years of operation	Hookup 90% of the potential market other than the large process load in the first eight years of operation.	10.25%	(149,378)	(439,457)
9)	Thermal energy priced at 110% of lowest alternative fuel cost in 1982 and inflated at 6% each year	Thermal energy priced at the lowest alternative fuel price using a 4.3% and 3.0% escalation over a 4% general inflation rate for gas and oil respectively.	16.50%	1,112,722	585,307
10)	Purchased energy costs inflated at 4% per year	Purchased energy costs inflated at 6% per year.	9.25%	(314,771)	(560,107)
11)	Thermal energy priced at 110% of lowest alternative fuel cost in 1982 and inflated at 6% each year	Thermal energy priced at 110% of lowest alternative fuel cost in 1982 and increased by cost increases in purchased energy, operations and maintenance expenses and property taxes.	9.25%	(278,323)	(504,597)
12)	Construction phased over 2 years. Hookups phased over 4 years	Construction and hookups occur in first year	10.50%	(87,799)	(386,127)
13)	Construction costs estimated at \$4,247,779 in 1982 dollars for retrofit distribution system and conversions	Construction costs underestimated by 25% in 1982 dollars, \$5,309,740	8.00%	(617,089)	(893,234)

(1) Rounded to nearest 1/4 of one percent.

resulting in a positive present value in this column would make the investment investment attractive if an equity cost of 13% was required. Any negative present value will indicate that the required return will not be achieved over the period of the analysis.

The market value used in determining property taxes has been assumed to be calculated by the unit value formula developed by the Minnesota Department of Revenue. This formula weighs asset cost and capitalized operating income in determining a market value. Market value is construed to be the price a willing buyer would pay to a willing seller in a free market. A two-step formula is then used for determining property taxes.

- 0 Market value time assessment percentage (approximately 40%) equals valuation for utility property.
- 0 Assessed valuation times the mill rate equals property taxes.

In the sensitivity analysis performed, property taxes reflected were the taxes calculated for the "base case" when the sensitivity change only impacted the capitalized operating income component of the unit value calculation. The impact of not reflecting the change in tax is nominal.

Sensitivity Number 1. Tests the impact of an interest cost of 8% on a capital structure with 50% debt. The lower interest rate raises the internal rate of return of the "base case" analysis if a lower interest rate were obtained. A lower interest rate could probably be obtained if tax free municipal debt were issued. A lower interest rate would still not make the investment attractive if a 13% return was required.

Sensitivity Number 2. Tests the impact of an interest cost of 12% on a 50% debt capital structure. The return would lower the "base case" results presented and would not be attractive if a 13% return on equity capital was required.

Sensitivity Number 3. Tests the effect of an interest cost of 8% on a capital structure with 80% debt. By leveraging the investment through use of lower cost debt the overall return on equity is increased over the "base case" results displayed. The investment would also appear attractive if a 13% return was required on equity.

Sensitivity Number 4. Tests the impact of an interest rate of 12% on a 80% debt capital structure. By leveraging the investment through increased amounts of debt the overall return on equity is increased even with a higher interest rate than used in the "base case." Further leaveraging would probably not be possible because the equity percentage must cover initial start-up losses. The investment would still not generate a 13% return on equity but the present value of the difference.

Sensitivity Number 5. Tests the impact of an over-estimation of the potential thermal consumption. If actual thermal consumption is only 95% of the annual amount used in the "base case" the change will produce the "base case" return.

Sensitivity Number 6. Tests the impact if operations and maintenance expense was underestimated by 25% in the "base case" analysis.

Sensitivity Number 7. Tests the sensitivity of the hookup rate percentage used in the base case for the potential market other than the large process user.

Sensitivity Number 8. Tests the sensitivity of a lower incremental hookup each year than used in the "base case." Based on the negative present value, a potential user who elects to defer entering the district system should probably have to pay a percentage greather than 25% of the conversion cost used in the "base case."

Sensitivity Number 9. Tests the impact of using projected alternative fuel prices using 8.3% gas (4.3% differential) and 7.0% oil (3.0% differential) inflation increases to price thermal energy delivered. If the lowest fuel price was used to price thermal energy the investment would be attractive if a 13% return was required on this investment. Exhibit 4-49 shows the cash from operations that would be generated using alternative fuel prices to price thermal energy compared to the "base case" cash from operations. Cash from operations is used to provide working capital, internally fund capital expenditures, repay debt and provide a cash return to equity investors..

Sensitivity Number 10. Tests whether a thermal pricing approach passing on only cash operating cost increases would increase the value of the investment. Future revenues will probably have to be increased faster than operating costs.

Sensitivity Number 11. Tests the impact of a 6% increase in coal costs on the base case results.

Sensitivity Number 12. Tests the impact of one year construction and hookup on the "base case" analysis. Based on the negative present value under a 10.94% return the phasing of construction used in the "base case" appears appropriate.

Sensitivity Number 13. Tests the impact of a 25% construction cost underestimation on the base analysis.

The results of the "base case" analysis and sensitivity analysis have identified areas of additional study which have been incorporated in the Phase 2 proposal.

Exhibit 4-49

Preliminary Economic Analysis Cogenerated District
Heating System Projected Cash From Operations

4.C. FERGUS FALLS

Introduction

Fergus Falls, Minnesota, population 12,050 (1976 estimate), is an agricultural processing center for the Red River Valley. Located in west central Minnesota on the Otter Tail River, 180 miles northwest of Minneapolis-St. Paul and 50 miles southeast of Fargo, North Dakota, Fergus Falls is also the gateway to a large recreational area containing 1,300 lakes in Otter Tail county. As the county seat of Otter Tail County, Fergus Falls serves as a regional medical and educational center and possesses a number of agriculture-related businesses, including dairy processing, baking, fertilizer production, flour milling and rendering.

Technical Assessment

Retrofit Alternatives

Power plant description. The Hoot Lake power plant, which was built in the late 1940's, is owned and operated by the Otter Tail Power Company. The plant has three conventional Rankine cycle turbines with a total output capacity of 127 MWe. Hoot Lake 1 is a 7.5 MWe single cylinder, 14-stage Allis Chalmers turbine with an air-cooled Allis-Chalmers generator. The turbine is driven by steam supplied by a Combustion Engineering spreader stoker fired boiler rated at 95,000 lbs/hr steam flow with throttle conditions at 400 psi/825°F. This boiler, like the other two in the plant, is fired entirely by lignite. At the present time this boiler, which is equipped with a cyclone dust collector, is reported to be out of compliance with State particulate emissions standards. The future of Hoot Lake 1 cannot be determined until a decision is made whether or not to modify the unit to improve its emissions control.

Hoot Lake 2 is a base-loaded 53.5 MWe single-cylinder GE reheat turbine with a GE generator. Steam is supplied by a pulverized coal-fired Combustion Engineering boiler rated at 400,000 lbs/hr steam flow with throttle conditions of 1460 psi/1000°F. The boiler is designed for single-stage reheat to 1000°F. The boiler is equipped with an electrostatic precipitator

and is reported to be in compliance with all state and federal emissions regulations. Hoot Lake 2 was installed in 1957.

Hoot Lake 3, which like Hoot Lake 2 is base-loaded, is a 66 MWe Westinghouse two-cylinder, non-reheat turbine with a Westinghouse generator. The turbine is driven by steam supplied by a Babcock and Wilcox pulverized coal fired boiler rated at 625,000 lbs/hr steam flow with throttle conditions of 1250 psi/950⁰F. The external crossover steam conditions vary with load, but at 60 MWe the temperature is 230⁰F with three percent moisture. The boiler is equipped with an electrostatic precipitator and is reported to be in compliance with all state and federal emissions standards. Hoot Lake 3 was installed in 1961.

All three units are reported to be in good operating condition, with the exception of the aforementioned particulate problems at Hoot Lake 1. A unit essentially identical to Hoot Lake 3 -- located in Rosario, Mexico--- has been converted to crossover extraction, and considerable design information and operating experience related to this plant could be obtained and applied to Hoot Lake 3.

Alternatives. The Hoot Lake power plant has two clear opportunities for district heating retrofit opportunities -- units Nos. 1 and 3. Hoot Lake No. 2, due to reheat conditions, appears to be a less attractive retrofit alternative. The retrofit schemes considered in detail were the following:

1. Conversion of Hoot Lake No. 3 to extraction at the crossover.
2. Use of Hoot Lake No. 1 in a back pressure mode (as emission compliance permits).
3. Addition of capability to use header steam from units Nos. 2 and 3 as topping or backup capacity.

Retrofit Strategy Assessment

Retrofit strategy 1. The conversion of unit No. 3 to extraction at the crossover was modeled using the SYNTHA II simulation of unit No. 3 and

a summary of the results of the simulation are presented in Exhibits 4-50 and 4-51, respectively. Hoot Lake 3 uses a Westinghouse two-cylinder external crossover turbine. Discussions with the manufacturer and the SYNTHA simulation indicate that the steam conditions at the crossover are within bounds for district heating supply over a range of loads. Also the supply available is considerably greater than that of the projected load.

It was also found that an essentially identical unit, installed at the El Rosario Station, 50 km south of Tijuana, has been modified to provide extraction steam for desalinization. This retrofitted unit has been operated in their extraction mode for over 15 years and has a completed documented operational history. Hence the crossover extraction retrofit is available as an engineered and proven option.

Retrofit strategy 2. Hoot Lake 1 has less certain retrofit possibilities due to the emissions status of its boiler. The 7.5 MWe AC turbine would be an ideal candidate for back pressure modification and would provide a balanced thermal supply. However, Otter Tail Power must provide the MPCA with assurances that the unit will meet state particulate and opacity standards by July or remove the unit from operation. At the present time, the utility has not made a decision on the future of unit No. 1 and its suitability as a district heating source remains in doubt.

Conclusions. The Hoot Lake Plant can be retrofitted to serve as a district heating source. There are two units available of equal interest, although fundamentally different in approach. The conversion of unit No. 3 is probably the most attractive option. Combined with the connection of header steam from unit No. 2 for reliability and peaking service, a satisfactory source is provided. However, Otter Tail Power has a winter electrical peak, roughly correspondent with the expected thermal peak. Thus the operational derate in unit No. 3 will have a negative capacity impact on the electrical utility. For this reason, and also because of the poor unit balance of unit No. 3, the unit No. 1 retrofit is of interest. If Otter Tail Power would bring unit No. 1 up to emission standards, the back pressure conversion of unit No. 1 would provide a well balanced source and an increase in peak capacity. The thermal load following inherent in back pressure turbines

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Exhibit 4-51

SYNTHA Simulation Results: Fergus Falls No. 3

Boiler Out: 950F, 1265 PSIA

4-113

	Data Item	Design	Crossover Extract 55c 85c	Crossover Extract	Crossover + HP Extract 230F	Crossover + HP Extract 260F
Streamflow x 10 ⁶ Lb/Hr MWe	M 1 Summ	0.5436 69.5	0.5436 66.3	0.5384 65.6	0.5361 63.58	0.5313 59.6
M Dist. Htg x 10 ⁶ Lb/Hr	M 3	0	1.101	1.101	1.01	1.01
T Dist Htg IN F	T 3	-	131	150	150	150
T Dist Htg OUT F	T 4	-	185	214.5	230	260
Q in x 10 ⁹ Btu/Hr	Sumry	0.689	0.687	0.684	0.684	0.685
Q Rej x 10 ⁹ Btu/Hr	Condens	0.349	0.299	0.288	0.298	0.258
M xover extract Lb/Hr	M 53	0	62,124	77,368	74,635	68,772
P Xover PSIA	P 6	23.67	19.9	18.7	17.9	16.2
M HP Extract Lb/Hr	M 54	0	0	0	15,824	47,918
T Feedwater	T 35	413	413	412	408	399
M Htr 1	M 44	37,417	32,027	29,548	28,788	27,107
M Htr 2	M 45	18,193	16,247	15,180	15,318	15,570
M DEAER	M 46	26,188	32,889	33,533	33,177	32,511
M Htr 4	M 47	23,971	23,474	23,335	23,343	23,242
M Htr 5	M 48	36,556	34,908	34,581	34,280	33,625

would fit nicely with the unit peak characteristics. Hence, both unit No. 1 and unit No. 3 retrofits must be considered as options in Phase 2.

Distribution System

The preliminary distribution system for Fergus Falls was designed by Fjärrvärmebyrån ab. The distribution system will require a total pipe length of 12,500 meters at an estimated total capital cost of \$5,085,000 in 1979 dollars. Exhibit 4-52 summarizes pipe size, length, and installation costs by individual pipe segments. Distribution costs developed by Metcalf and Eddy are presented in the same Exhibit. The layout of the distribution system is displayed in Exhibit 4-53 and Exhibit 4-54.

Costs shown in the Exhibit cited above include removal of bituminous and/or concrete pavement, excavation and disposal of subsoil, two pre-insulated pipes, purchase and installation of backfill, and replacement of bituminous pavement. Fjärrvärmebyrån prices include all service piping but do not include project design and inspection (estimated to be an additional 15%). Metcalf and Eddy prices do not include service pipe, engineering (4%) or contingencies (15%).

Exhibit 4-52

Distribution System Costs (Fergus Falls)

Pipe Section	Pipe Diameter d (mm)	Pipe Length (m)	Fjärrvärmebyrån Cost		Metcalf & Eddy Cost (\$x10 ³)
			(Krx10 ³)	(\$x10 ³)	
1-2	300	1500	3600	837.2	787.7
2-3	300	750	1800	418.6	382.5
3-4	250	180	378	87.9	83.5
4-4a	65	400	390	90.7	101.0
4a	50	210	189	44.0	53.1
4-5	250	280	588	136.7	129.9
5-6	250	120	252	58.6	54.2
6-9	250	270	570	132.6	121.8
9-10	250	110	231	53.7	51.1
10-11	200	240	432	100.5	84.2
11-12	125	120	162	37.7	32.9
12-13	125	260	351	81.6	81.0
13-14	80	360	389	90.5	90.9
14-15	80	250	270	62.8	63.1
5	50	120	108	25.1	30.3
6	25	100	75	17.4	25.3
9	80	120	130	30.2	30.3
10-10a	100	140	168	39.1	35.3
10a	50	180	162	37.7	45.4
10a1	40	90	76	17.7	22.7
10a-10b	125	270	365	84.9	84.2
10b-10c	80	130	140	32.6	32.8
10c	40	180	151	35.1	45.4
10b-10d	80	110	120	27.9	27.8
10d	65	260	258	60.0	65.7
10d1	50	400	360	83.7	101.0
11-11a	125	140	189	44.0	43.6
11a-11b	65	110	109	25.3	28.0
11a	50	360	324	75.3	90.9
11b	40	210	177	41.2	53.1
12	40	180	151	35.1	45.4
13	50	300	270	62.8	75.8
15	40	210	176	40.9	53.1
2	80	960	1037	241.2	24.2
3-3a	200	1780	3204	745.1	66.4
3a-3b	125	160	216	50.2	49.9
3b-3c	125	120	162	37.7	37.4
3a	150	240	360	83.7	22.8
3a1	40	120	101	23.5	30.3
3b	50	100	90	20.9	25.3
3c	50	80	72	16.7	20.2
3c1	125	280	378	87.9	87.2
Subtotal			18,731	4,356.0	3,417.0
Service Pipe			3,134	728.8	
Total			21,865	\$5,085.0	

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Distribution Network Layout (Fergus Falls)

Market Analysis

The major service and industrial companies in the area are Otter Tail Power Company, which has 380 employees, and Medallion Kitchens, Inc., which has 210 employees. The city's air service is provided by the Fargo, North Dakota airport 70 miles west of Fergus Falls. The power plant is owned by Otter Tail Power Company. Great Plains Natural Gas Company supplies the natural gas, and multiple suppliers service the fuel oil needs. The State Hospital normally purchases its lignite on one year contracts that are dependent on Otter Tail Power Company suppliers due to transportation economies.

Market Analysis Results

For purposes of the market survey, the population was broken into districts to create manageable survey areas and to provide segments of data for financial analysis. The division into districts was done on a combination of geographical dispersion and apparent market density. When additional buildings were added to the potential market through line revisions, the new data were either considered as part of a primary district or became a separate district. Exhibit 4-55 shows the preliminary distribution line for Fergus Falls as well as the districts into which the population was divided. Exhibit 4-56 presents a brief description of each district and lists the major potential thermal energy users in each.

Because the survey returns were less than 100%, heating system data and market data for a portion of the original survey population was estimated. These estimates were derived by extrapolating the market data and heating system data from the returned surveys. The extrapolation of the data involved stratifying the population into homogeneous building types, doing follow-up on all major missing types, and then extrapolating either by building class based on average of returned members of that class (i.e., a missing large commercial). The individual extrapolations normally involved finding a similar user, but it also included instances of extrapolations using diverse data inputs. The stratified data simplified the extrapolation procedures, and the follow-up on major users reduced the percentage of market that was extrapolated. Market data in this section is presented by district, by building type and by heating system.

Market Analysis Districts (Fergus Falls)

Exhibit 4-56

Characteristics of Market Districts (Fergus Falls)

<u>District</u>	<u>Characteristics</u>	<u>Major Potential Thermal Energy Users</u>	<u>Market Estimates 10⁶Btu/yr</u>
F-1	This district contains schools, multi-unit residentials and the YMCA.	Senior high school Riverside Heights Apartments	9,000 2,700
F-2	This district is the main downtown area that contains mostly commercial establishments. The district also contains churches, multi- unit residentials and a process user.	Con-Agra, Inc. River Inn Hotel	5,600 2,700
F-3	This district is the southern downtown area containing commercial establishments, govern- ment offices and churches. In addition, the area directly south contains Lake Region Hospital	Lake Region Hospital Otter Tail County Court House	18,000 4,500
F-4	This district is west of the Lake Region Hospital and contains two rest homes	Pioneer Home Broen Home	6,000 6,000
F-5	This district is dominated by the State Hospital	State Hospital	93,000

The majority of potential space heating users in each city expressed a preference for steam as the thermal energy source. Generally this preference was directly associated with the use of steam boilers as their current heat source. Potential users perceived that conversion to a district heating system which used steam as the thermal energy medium would be less complex and costly for them.

Process user preference regarding thermal energy was very difficult to determine. Users were able to determine if they could use hot water or steam in general but without further information concerning temperature(s), pressure(s) and flow rate(s), they could not specifically determine adaptability. The major process user in Fergus Falls is Con-Agra, Inc.. Con-Agra uses heat to temper wheat from November through March. The plant manager stated that they could use hot water in their processing.

Potential Market

The results of the market analysis in Fergus Falls are presented in the following Exhibits. The market estimates were developed using the data base of information developed through survey, observations and interviews conducted with major potential users. The results are for the entire population even though replies were not received from every building. Buildings not represented in the data base were estimated based upon information of similar buildings as discussed earlier. The data presented in the Exhibits represent normalized energy data (i.e., 1978 consumption was adjusted to reflect normal heating degree days). Appendix E explains the methods used to convert 1978 actual usage to normalized energy data.

Presented below are seven Exhibits which summarize the potential thermal energy market in Fergus Falls. The extrapolation represents 25% of the potential market in Fergus Falls. The percentage is high due to the poor return from the commercial establishments in the downtown area.

Exhibit 4-57, Potential Thermal Market, is the annual estimated market by district. The Exhibit indicates that 64,870 Mwh is the potential annual market.

Exhibit 4-58, Building Count Information, lists the number of buildings in the data base and in the population. This Exhibit is intended to show make-up of buildings for site analysis and for building conversion cost inferences.

Exhibit 4-59, Potential Heating Market by Heating System Type and Exhibit 4-60, Potential Heating Market by Building Type, show normalized market data by district for heating system type and building classification. The dominant system is the hybrid hot water/steam and the major users are the hospitals.

Exhibit 4-61, Potential Heating Market by Building Type and Heating System, shows the cross classification of building type and heating system. The State Hospital has a hybrid system and Lake Region Hospital and the senior high school have steam systems.

Exhibit 4-62, Actual Data Base Fuel Usage by District - 1978, shows the actual fuel consumed during 1978 by the members of the data base. In addition, the Exhibit shows the percentage of energy output supplied by each fuel.

Exhibit 4-63, Potential Annual Fuel Displacement, shows the potential fuel displacement in Fergus Falls. Data base usage was normalized and then projected across the balance for the population. The major assumption in the normalization was that multiple fuel users used fuel oil for above normal heating needs due to the non-availability of gas. For the State Hospital, it was assumed that oil and lignite were used equally for above normal use.

Exhibit 4-57

Potential Thermal Market (Fergus Falls)

<u>District</u>	<u>Btu's - 10⁶/yr</u>		<u>Mwh ⁽¹⁾</u>	
	<u>Process</u>	<u>Heating</u>	<u>Total</u>	<u>Total</u>
F-1		18,354	18,354	5,379
F-2	5,600	54,932	60,532	17,741
F-3	--	37,779	37,779	11,072
F-4	--	11,709	11,709	3,432
F-5	--	92,965	92,965	27,246
	<u>5,600</u>	<u>215,739</u>	<u>221,339</u>	<u>64,870</u>

(1) Conversion to Mwh is achieved by dividing the Btu total by 3.412×10^6

Exhibit 4-58

Building Count Information (Fergus Falls)

<u>Building Count Along the Distribution Line</u>			
<u>Type</u>	<u>Total</u>	<u>Number In⁽¹⁾ Data Base</u>	<u>% In Data Base</u>
Large Commercial	17	9	53%
Small Commercial	109	40	37%
Industrial	3	1	33%
Multi-Unit Residential	6	4	66%
Public and Institutional	<u>38</u>	<u>24</u>	<u>63%</u>
TOTAL	<u>173</u>	<u>78</u>	<u>45%</u>

(1) The data base includes those buildings and process applications for which adequate information could be obtained from the returned surveys, on site reviews, or other techniques.

Exhibit 4-59

Potential Heating Market by Heating System Type (Fergus Falls)

<u>District</u>	<u>10⁶Btu/yr</u>				<u>Total</u>
	<u>Forced Air</u>	<u>Steam</u>	<u>Hot Water</u>	<u>Hot Water/ Steam</u>	
F-1	--	11,823	3,809	2,722	18,354
F-2	12,866	13,544	19,736	8,786	54,932
F-3	4,106	25,854	6,065	1,754	37,779
F-4	--	--	10,604	1,105	11,709
F-5	--	--	--	92,965	92,965
Total	<u>16,972</u>	<u>51,221</u>	<u>40,214</u>	<u>107,332</u>	<u>215,739</u>
Percentage	8%	24%	19%	49%	100%

Exhibit 4-60

Potential Heating Market by Building Type (Fergus Falls)

<u>District</u>	<u>Large Commercial</u>	<u>Small Commercial</u>	<u>Industrial</u>	<u>Multi-Unit Residential</u>	<u>Public and Institutional</u>	<u>Total</u>
F-1	--	--	--	4,932	13,422	18,354
F-2	12,902	23,496	--	3,766	14,768	54,932
F-3	6,730	6,991	2,008	--	22,050	37,779
F-4	--	--	--	11,709	--	11,709
F-5	--	--	--	--	92,965	92,965
	<u>19,632</u>	<u>30,487</u>	<u>2,008</u>	<u>20,407</u>	<u>143,205</u>	<u>215,739</u>
Percentage	9%	14%	1%	10%	66%	100%

Exhibit 4-61

Potential Heating Market by Building Type and Heating System (Fergus Falls)

<u>Classification</u>	<u>10⁶Btu/yr</u>				<u>Total</u>	<u>Percent</u>
	<u>Forced Air</u>	<u>Steam</u>	<u>Hot Water</u>	<u>Hot Water/ Steam</u>		
Large Commercial	3,394	14,336	1,902	--	19,632	9%
Small Commercial	11,570	2,428	16,489	--	30,487	14%
Industrial	2,008	--	--	--	2,008	1%
Multi-Unit Residential	--	--	16,473	3,934	20,407	10%
Public and Institutional	--	34,457	5,350	103,398	143,205	66%
Total	<u>16,972</u>	<u>51,221</u>	<u>40,214</u>	<u>107,332</u>	<u>215,739</u>	100%
Percentage	8%	24%	19%	49%	100%	

Exhibit 4-62

1978 Actual Data Base Fuel Usage by District (Fergus Falls)

<u>District</u>	<u>Type</u>		
	<u>Natural Gas</u> (CCF)	<u>#2 Fuel Oil</u> (Gal)	<u>Lignite</u> (Ton)
F-1	147,038	99,200	--
F-2	188,749	132,721	--
F-3	225,697	157,463	--
F-4	60,004	21,300	--
	--	471,947	7,811
	<u>621,488</u>	<u>882,631</u>	<u>7,811</u>

Percentage of Heat Output After
Conversion to Equivalent Base (1)

Gas	24%
#2 Oil	46%
Lignite	30%

- (1) Fuels were converted to Btu equivalents and then fuel-specific efficient factors were applied to arrive at equivalent heat output.

Exhibit 4-63

Potential Annual Fuel Displacement (Fergus Falls)

	Natural Gas (CCF)	#2 Fuel Oil (Gal)	Lignite ton
1978 Data Base Usage	621,488	882,631	7,811
Normalization Adjustment ⁽¹⁾	(13,751)	(129,616)	(815)
Estimated Normal Fuel Usage of Users not in the Data Base ⁽²⁾	408,669	215,308	-
Potential Annual Fuel Displacement	<u>1,016,406</u>	<u>968,323</u>	<u>6,996</u>

(1) Heating degree days in 1978 were 15% above normal which causes above normal fuel usage. In adjusting the fuel usage to normal, process use was unchanged, interruptible gas users and fuel oil users were assumed to have used oil for above normal heating needs, gas only users were assumed to have used gas for above normal use, and it was assumed that the State Hospital reduced coal and oil equally.

(2) Fuel use of non-data base users was estimated utilizing normalized data base information, data related to the process user and the State Hospital was not utilized in the estimating process.

Market Advantages and Problems

Reluctance of energy supplier. A potential disadvantage in Fergus Falls is that the source supplier of thermal energy, Otter Tail Power Company, has had prior poor experience with district heating. Otter Tail Power pulled out of two district heating markets in North Dakota. The markets were money losers and Otter Tail Power had to incur major costs to abandon the markets. The ultimate ramification of their prior experience is that there may not want to be a supplier in Fergus Falls. Another consideration is that Otter Tail Power may feel that the venture is very risky, based upon actual experience, and thus require a much higher rate of return. They would be willing to supply the thermal energy, but the selling price would not be competitive with alternative fuels. This problem can be partially dealt with by obtaining long-term commitments from major customers. Currently, insufficient information exists for Otter Tail Power Company to make a long-term decision.

Dominant user. Fergus Falls has a dominant user, the State Hospital. This can be an advantage or a problem depending upon their decision to participate. If they would choose not to participate this could make Fergus Falls an unfavorable demonstration site. The advantages include:

- 0 Potentially more effective marketing effort directed at one user; alternative marketing plans would apply to the balance of the market.
- 0 Potential for reduced administrative costs.
- 0 Stable base for implementation and growth.

A disadvantage associated with the State Hospital is that it is not a taxpaying entity. The potential for tax benefits related to equipment abandonments is not available. Incentives must be provided to equalize the tax effects between tax and non-tax paying customers.

Reliability. A potential problem in Fergus Falls is the increased reliability needs associated with providing heat to health care institutions. Health care facilities require more reliable heating systems and the hospitals currently have back-up systems utilizing steam. There would be additional costs to convert the backups to hot water.

Renovation of the downtown area. The downtown area is undergoing a substantial amount of renovation. This renovation indicates that businesses are willing to remain in the downtown area thus increasing the stability of the market.

Potential growth. The existence of a stable, low-cost fuel might induce agricultural drying processes to site in Fergus Falls. In addition, a dairy processor is situated a short distance off the distribution line, this represents potential market growth for the district heating company. However, planned industrial development is remote from the plant and distribution lines and would not be a viable market.

Major building owner. One independent contractor is involved both as an owner and contractor in the downtown renovation program now underway. The independent contractor indicated that he intended to divest himself of the renovated buildings when the market allowed him a reasonable return. He anticipated that this would always precede the exhaustion of the useful life of the district heating system. Long-term contract commitments and additional investment could be barriers to his participation to the extent he perceives them having a negative impact on his ability to sell the buildings at a profit. This problem will have to be discussed with the individual contractor in order to convince him district heating will not impair the value of his property.

Institutional Assessment

Selection of Owner/Operator

For this preliminary stage of the study, the owner of the district heating company in Fergus Falls is assumed to be Otter Tail Power Company. The utility is assumed to operate the prospective district heating system for the following reasons:

1. The utility is the existing owner of the coal-fired electrical generating facility. Accordingly, it should be most capable of extending its expertise into operation of a new district heating venture.
2. An existing utility could organize faster and develop a district heating system faster than a newly created entity.
3. There may be efficiencies in operating the two utilities jointly, such that costs for the district heating company may be lower if it was owned and operated by the electric utility. Ownership and operation by the same company will eliminate the redundancies in management which might occur if a separate entity was set up to operate the district heating company. Other operating efficiencies might result from utilization of existing personnel.
4. The utility has obtained public and private acceptance in Fergus Falls, such that its operation of the new district heating company would positively impact the response to implementation of district heating.
5. It should be easier for an existing utility to raise needed capital.
6. Hiring practices, including job descriptions, candidate recruitment, and utility personnel selection, will be most efficiently handled by a company with power plant and district heating operating experience.
7. If the district heating company is owned and operated by an existing electric utility, opportunities for present personnel to transfer into the new district heating company will exist. Such a change would be less dramatic than hiring all new employees.

Decision Process for Utility Investment

Otter Tail Power Company is the assumed owner for this preliminary phase of the study. Due to the utility's previous experience in steam district heating in Jamestown and Devils Lake, North Dakota, the utility officials are quite concerned about entering the district heating business again. The two North Dakota systems were abandoned in 1975 at substantial cost to the utility.

The rate of return on equity and regulatory rules regarding cost allocation methodology are other important concerns for Otter Tail Power. Economic feasibility must be supported with expected returns on equity exceeding the returns currently realized for the operations of the electric utility. Specific regulatory guidelines for an acceptable cost allocation methodology at the power plant must also be obtained and evaluated because of the significant impact on Otter Tail's allowable returns.

Once these and other decision factors have been assessed, the Planning and Control Department at Otter Tail will review the project and present it to the corporate officers for internal challenge. Final approval must come from the Board of Directors. No difficulties relating to legal restrictions in the corporate charter have been identified at this time or are anticipated. The time required for the decision process is estimated at six months, given the resolution of all economic issues in subsequent phases in this study.

Taxation

Further investigation of the possibility of and methods for granting a competitive advantage through preferential taxation may be required for Phase 2.

Zoning and Redevelopment Plans

There are four primary areas where redevelopment or industrial expansion is occurring:

1. West of the city the existing commercial area is expanding. The impact on district heating will be minimal as this is far removed from proposed distribution lines.

2. In the downtown area near preliminary lines there is a high rise apartment complex in the proposal stage of planning.
3. Northeast of the city an apartment complex is proposed which is located adjacent to preliminary distribution lines.
4. West of the state hospital an existing industrial park may undergo further development; this area could potentially be hooked up to existing lines connecting the hospital.

In Fergus Falls, three of the four major areas where further development is planned have potential positive impact on the market of the cogeneration district heating company.

Displacement Effects on Existing Energy Suppliers

The downtown area is predominantly heated by natural gas which is provided by Great Plains Natural Gas Company. The remaining market is served largely by oil and coal suppliers (lignite used by state hospital). There is probably sufficient demand to absorb the gas which would be made available by district heating displacement, and the oil displaced would likely impact all area suppliers to some extent.

Adequacy of Existing Coal Contracts

Conversations with Otter Tail Power Company personnel have indicated that the adequacy of their coal contract is not considered to be a significant problem. Knife River Coal Mining Company currently has a contract to supply the Hoot Lake plant with North Dakota lignite until 1981; a renewal of the coal contract for the life of the plant is being considered at this time.

Otter Tail Power Company and Knife River Coal Mining Company have enjoyed a good working relationship for some time. Otter Tail is a co-owner of the Big Stone power plant in South Dakota with Montana-Dakota Utilities, the parent of Knife River Coal Mining Company. Knife River Coal Mining Company has also agreed to supply the Big Stone plant and the Coyote plant located in North Dakota (partially owned by Otter Tail).

Economic Analysis

Site Specific Assumptions

The specific assumptions made in the economic analysis of the base case for Fergus Falls and the rationale underlying these assumptions are presented below.

Thermal energy revenues

- Assumption: Average revenues per/MWH were initially estimated at 14.38 per MWH. This was established by taking 110% of the projected 1981 cost of natural gas in Fergus Falls of \$3.83/MCF times a conversion factor (MCF to MWH) of 3.412. The \$3.83/MCF is the average projected cost of natural gas in Fergus Falls based upon data provided by the Minnesota Energy Agency.
- Assumption: The average revenue per/MWH was escalated by 6% per year. This compares to a projected total inflation rate for gas and oil of 8.3% (4.3% differential) and 7.0% (3.0% differential) per year.
- Assumption: Exhibit 4-64 is a graphical presentation which shows by year the projected cost of alternative fuels (oil and natural gas), coal and district heating thermal energy. This exhibit illustrates that the district heating system's average revenues per/MWH could be increased at a higher rate and still provide lower cost to the customers. A significant energy cost savings not displayed on Exhibit 4-64 is that the district heating thermal price is for delivered energy while the alternative fuel costs must be divided by the efficiency of the buildings heating system (65-75%) to get actual energy cost.
- Assumption: Average revenue per MWH has not been maximized relative to alternative fuel costs in the base case for the following reasons:
- 0 Total revenues will be maximized in the early years by showing a discernable cost savings immediately which will encourage hookups.
 - 0 Contractural relationships which provide a stable revenue base will be encouraged since the projected pricing policy guarantees resistance to alternative energy cost inflation.

Exhibit 4-64

Projected Alternative Energy Costs and
District Heating Costs

- 0 A potential revenue reserve is available to cover unexpected or underestimated costs.

Assumption: Thermal energy sales in MWH's were developed by year based upon the construction phasing and hookup rates shown on Exhibit 4-65. This assumes that the first year's construction would be from the plant to the State Hospital who will have committed to hooking-up prior to the start of construction. This user plus potential users on the initial distribution line account for the 100% hookup of the potential market in the first year. For all other construction phases it was assumed that 90% of the potential market would eventually hookup. The overall hookup rate achieved after 1987 is approximately 95%.

Purchased energy expense

Assumption: The estimated purchased energy costs were calculated based upon the following assumptions regarding plant operations:

- 0 Retrofitting an existing base loaded turbine for controlled extraction at the crossover point.
- 0 Boiler (header steam) will be used for system backup.
- 0 The plant will continue to be base loaded over the period of the economic analysis.

Assumption: An average cost of \$2.82 per MWH thermal was calculated for 1982 as follows:

- 0 Total incremental fuel costs associated with producing annual thermal energy requirements in a cogeneration environment was reflected in the analysis.
- 0 The incremental fuel cost was calculated by multiplying the calculated electrical derating caused by thermal energy production times estimated electrical fuel cost of 9.65/MWH in 1978. This amount was inflated by four percent each year to 1982.
- 0 The displacement of a base loaded turbine electrical generation must be replaced by intermediate or peaking plants which have a higher variable fuel cost per KW of generation. It was estimated that approximately 8,650,000 KWH of generation should be replaced by the Ortonville generating plant which has a .23 cent higher variable fuel cost per KWH.
- 0 A MAPP back-up demand was reflected in the analysis as a charge to the district heating system for capacity loss due to the cogeneration requirements.

Exhibit 4-65

Preliminary Base Case Economic Analysis
 Thermal Energy Construction Phases and
 Hook-up Assumptions

<u>Construction Phase</u>	<u>Potential Thermal Energy Market (MWH's)</u>	<u>Assumed Hook-up Rate</u>	<u>Max. MWH's Hooked-up</u>
1982 - Plant to State Hospital plus other users on line	31,508	100% in 1982	31,508
1983 - Downtown District north of the river	17,441	25% in 1983 30% in 1984 35% in 1985	15,967
1984 - Area south of the river to the hospital	11,072	35% in 1984 30% in 1985 25% in 1986	9,966
1985 - Two nursing homes south of the river and north leg off existing distribution net- work on Springen	4,549	35% in 1985 30% in 1986 25% in 1987	4,095
Total	<u>64,870</u>		<u>61,536</u>

- Assumption: The average cost by MWH was escalated by the assumed inflation rate of coal of four percent per year.
- Assumption: Exhibit 4-64 also contains a graphical presentation of the average thermal fuel cost per million BTU assumed in the base case. This graph illustrates that this fuel cost follows the projected cost of coal. In year 1982 the cost of thermal energy is 90% of the cost of coal.

Operating and maintenance expense

- Assumption: Fixed operating expense of \$100,000 was estimated for 1979 based upon adding five employees as follows: three operating personnel; one engineer; one meter reader and one manager. General and administrative expense for rent, billing and supplies was estimated at \$50,000. The total expense of \$150,000 was then escalated at the four percent general inflation rate.
- Assumption: Variable operating costs of \$1.70/MWH were estimated to cover maintenance at one percent of distribution system investment, electrical costs and miscellaneous variable costs. Variable operating costs were also escalated at the four percent general inflation rate.

Property taxes

- Assumption: Property (ad valorem) taxes were estimated based on the Minnesota Department of Revenue formula for calculation of the market value by the unit value computation.
- Assumption: It was assumed that the unit value calculation was based on a gas distribution company formula. The formula sets asset cost depreciated over time (to a limit of 55% of original cost) equal to 75% of the market value of the assets. The operating income for the prior three years is capitalized at eight percent comprises the remaining 25% of the market value.
- Assumption: The capitalized market value was then multiplied by the assessed valuation and multiplied by the projected tax rate of \$124.27/\$1,000 in 1982. The tax rate was developed by multiplying the 1978 tax rate by the general inflation rate to bring it up to 1981.
- Assumption: In the years after 1982, the tax rate was increased by the general inflation rate of four percent each year and multiplied by the calculated assessed value under the unit value calculation in that year.

Depreciation expense

- Assumption: A full year's depreciation was assessed for all assets in the year placed in service.
- Assumption: A 25 year life was assumed for the turbine retrofit, distribution network and conversion assets.
- Assumption: A 10 year life was assumed for the service equipment assets.
- Assumption: Depreciation calculated on a straight line basis was used for financial statement presentation.
- Assumption: Depreciation calculated on a 200% declining method was used for calculating income tax benefit. The tax timing difference between straight line and accelerated depreciation has been reflected as deferred taxes.

Interest expense

- Assumption: Interest expense was calculated by multiplying the assumed rate of five percent by the simple average of the beginning and ending capital account balance which has a 50% debt component. This equates to a ten percent interest rate on the debt portion.

Fixed assets/construction costs

- Assumption: The engineering estimate for retrofitting an existing turbine to controlled extraction is \$1,500,000 in 1979 dollars. It is also assumed that the actual retrofit effort will be completed in the first year (1982). A six percent construction inflation rate was used to reach a \$1,700,000 cost in year 1982.
- Assumption: The engineering estimate of the total distribution system in 1979 dollars was \$5,600,000 including design costs. It was assumed that the distribution network will be constructed in the phasing shown on Exhibit 4-65. A six percent compound construction cost inflation rate was used to determine the specific construction cost based on 1979 dollars matched to the construction period.
- Assumption: Building conversion costs were based upon the following estimates of conversion costs in 1979 dollars and six percent inflation rate:
- 0 \$20.00/KW for hot water
 - 0 \$23.00/KW for steam and steam/hot water
 - 0 \$30.00/KW for forced air

Assumption: Service equipment was estimated at \$50,000 in 1982 with 20% additions each year and a six percent inflation rate.

Base Case Results

The results of the base case economic analysis for the City of Fergus Falls are presented below. The project teams consensus of expected operating results are presented in Exhibit 4-66 to Exhibit 4-71. These projections are based upon the assumptions presented above and are intended to be used only to determine whether further study of Fergus Falls as a potential demonstration site is justified.

Exhibit 4-66. This Exhibit presents projected statements of income for the 20 years, 1982 to 2001. This exhibit also shows by year the average equity portion of the capital investment, return on average book equity and the annual thermal energy sales (MWH). The base case results indicate that the system will generate operating income in 1983 but will not cover operating expenses and interest charges until 1992. By the end of twenty years there will be a net income of approximately \$370,000. After the initial loss years, the return on average book equity ranges from .94% to 33.33%. The approximate return on equity for the utility exceeds 13% for the first time after sixteen years in 1998.

Exhibit 4-67. This Exhibit presents projected balance sheets for the 20 years, 1982 to 2001. This exhibit shows the build up of the system over the first six years with total capital expenditure of \$9,155,797 for plant retrofit, distribution system, building conversions and service equipment in the first six years.

The total capital required would be \$8,240,000. This exhibit also indicates that cash would be available for return on capital (accumulated cash reduction) beginning in 1986 and that a total of \$6,446,585 would be paid to investors by the end of 2001. Due to substantial initial losses, positive retained earnings are only reached in the last year of the analysis, in year 2001.

Exhibit 4-68. This Exhibit presents projected cash flow statements for the 20 years, 1982 to 2001. This exhibit also shows the cash return on average capital investment by year. This exhibit indicates that operations will generate positive cash flows because of substantial depreciation expense in the first year. However, cash flow available for return of capital first occurs in year 1986. The total cash return, including interest, ranges from 2.50% in 1982 to 34.55% in 2001.

Exhibit 4-69. This Exhibit presents projected net income and cash from operations for the twenty year period. The difference between net income and cash flow is accounted for primarily by depreciation expense.

Exhibit 4-70. This Exhibit presents a summary schedule showing the calculation of internal cash flow from/to the equity investors. The internal rate of return on these equity cash flows is .32%.

Exhibit 4-71. This Exhibit presents the internal rate of return analysis of the equity cash flows calculated on Exhibit 4-70. This Exhibit also shows the present value of the cash flows assuming a 13% and a 15% discount rate. This indicates that the present value of the cash flows would have to be increased by \$3,099,256 to reach a 13% return. This can be accomplished either by increasing cash from operations or reducing capital outlay.

The results of the base case economic analysis indicate that Fergus Falls is not presently a viable demonstration community for a cogeneration hot water district heating system. The base case internal rate of return of .32% on equity would not be acceptable to generate private investment. The major factor impacting the projected results is the substantial distribution line investment relative to the potential thermal market. Locating a significant process load near the proposed distribution network or plant could dramatically improve the projected results.

Under public (municipal) ownership the return would be substantially greater because of the elimination of income and property taxes, and lower interest expense all other things remaining equal. Other changes that might favorably impact the economic analysis include:

- 0 Lower interest cost which might be obtained from a form of tax exempt financing.
- 0 Contributions in aid of construction.
- 0 Larger hookup charges.
- 0 Increased revenues; revenues matching closer to alternative fuel prices.
- 0 Lower operative costs particularly thermal energy costs.

Exhibit 4-66

CITY OF FERGUS FALLS

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED STATEMENTS OF INCOME

	FOR FISCAL YEARS ENDING MARCH 30th									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
OPERATING REVENUE -										
Thermal energy	\$ 453,076	\$ 547,794	\$ 729,512	\$ 963,764	\$1,096,150	\$1,183,946	\$1,255,330	\$1,330,401	\$1,410,397	\$1,494,701
OPERATING EXPENSES:										
Purchased energy	88,851	105,317	137,686	178,350	199,300	211,067	219,682	228,297	237,528	246,758
Operations and maintenance	203,247	219,176	244,757	275,693	294,892	309,036	321,380	334,232	347,618	361,511
Property taxes	220,742	268,235	300,233	326,780	337,249	343,954	346,900	345,605	343,762	341,127
Depreciation	249,835	302,457	337,739	366,989	370,747	372,817	374,236	375,739	377,333	379,021
Income tax (benefit)	(244,336)	(348,551)	(321,300)	(261,798)	(228,263)	(194,252)	(160,621)	(121,293)	(80,699)	(38,613)
Total operating expenses	518,339	546,634	699,115	886,014	973,925	1,042,622	1,101,577	1,162,580	1,225,542	1,289,804
OPERATING INCOME	(65,263)	1,160	30,397	77,750	122,225	141,324	153,753	167,821	184,855	204,897
OTHER INCOME:										
Interest on cash balances	2,720	3,000	2,929	2,788	2,639	2,500	2,500	2,500	2,500	2,500
Hookup charges			21,500	39,000	16,750	5,000				
	2,720	3,000	24,429	41,788	19,389	7,500	2,500	2,500	2,500	2,500
INCOME BEFORE INTEREST CHARGE	(62,543)	4,160	54,826	119,538	141,614	148,824	156,253	170,321	187,355	207,397
INTEREST CHARGES - interest on debt portion of capital account	144,791	305,657	331,434	342,041	333,512	309,669	286,373	264,546	244,519	226,132
NET INCOME (LOSS)	(\$ 207,334)	(\$ 301,497)	(\$ 276,608)	(\$ 222,503)	(\$ 191,898)	(\$ 160,845)	(\$ 130,120)	(\$ 94,225)	(\$ 57,164)	(\$ 18,735)
AVERAGE BOOK EQUITY	\$2,950,000	\$3,064,709	\$3,386,433	\$3,552,905	\$3,520,405	\$3,324,202	\$3,123,480	\$2,928,232	\$2,742,507	\$2,565,388
RETURN ON AVERAGE BOOK EQUITY	(7.03%)	(9.84%)	(8.17%)	(6.26%)	(5.45%)	(4.84%)	(4.17%)	(3.22%)	(2.08%)	(.73%)
ANNUAL THERMAL ENERGY SALES (MWH)	31,507	35,944	45,143	56,262	60,394	61,536	61,536	61,536	61,536	61,536

Exhibit 4-66 (Continued)

CITY OF FERGUS FALLS
PRELIMINARY BASE CASE ECONOMIC ANALYSIS
PROJECTED STATEMENTS OF INCOME

	FOR THE FISCAL YEARS ENDING MARCH 30th									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
OPERATING REVENUE -										
Thermal energy	\$1,584,543	\$1,679,924	\$1,780,842	\$1,887,299	\$2,000,524	\$2,120,519	\$2,247,898	\$2,382,661	\$2,526,039	\$2,677,417
OPERATING EXPENSES:										
Purchased energy	256,604	267,065	277,526	289,218	300,294	312,601	324,908	337,831	351,369	365,522
Operations and maintenance	375,964	391,026	406,646	422,928	439,844	457,420	475,733	494,757	514,543	535,117
Property taxes	338,926	341,563	360,861	381,834	403,502	427,084	450,932	477,707	506,087	538,332
Depreciation	375,813	376,652	377,540	378,482	379,480	380,538	381,660	382,851	384,110	385,446
Income tax (benefit)	7,758	50,552	86,519	122,963	162,245	202,907	246,799	292,252	340,592	390,293
Total operating expenses	<u>1,355,065</u>	<u>1,426,858</u>	<u>1,509,092</u>	<u>1,595,425</u>	<u>1,685,365</u>	<u>1,780,550</u>	<u>1,880,032</u>	<u>1,985,398</u>	<u>2,096,701</u>	<u>2,214,710</u>
OPERATING INCOME	<u>229,478</u>	<u>253,066</u>	<u>271,750</u>	<u>291,874</u>	<u>315,159</u>	<u>339,969</u>	<u>367,866</u>	<u>397,263</u>	<u>429,338</u>	<u>462,707</u>
OTHER INCOME:										
Interest on cash balances	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Hookup charges	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>
INCOME BEFORE INTEREST CHARGE	<u>231,978</u>	<u>255,566</u>	<u>274,250</u>	<u>294,374</u>	<u>317,659</u>	<u>342,469</u>	<u>370,366</u>	<u>399,763</u>	<u>431,838</u>	<u>465,207</u>
INTEREST CHARGES - interest on debt portion of capital account	<u>209,335</u>	<u>194,014</u>	<u>179,962</u>	<u>166,907</u>	<u>154,431</u>	<u>142,221</u>	<u>130,160</u>	<u>118,174</u>	<u>106,237</u>	<u>94,347</u>
NET INCOME (LOSS)	<u>\$ 22,643</u>	<u>\$ 61,552</u>	<u>\$ 94,288</u>	<u>\$ 127,467</u>	<u>\$ 163,228</u>	<u>\$ 200,248</u>	<u>\$ 240,206</u>	<u>\$ 281,589</u>	<u>\$ 325,601</u>	<u>\$ 370,860</u>
AVERAGE BOOK EQUITY	<u>\$2,397,068</u>	<u>\$2,236,996</u>	<u>\$2,083,550</u>	<u>\$1,935,347</u>	<u>\$1,790,224</u>	<u>\$1,646,709</u>	<u>\$1,504,311</u>	<u>\$1,362,529</u>	<u>\$1,221,229</u>	<u>\$1,080,398</u>
RETURN ON AVERAGE BOOK EQUITY	<u>.94%</u>	<u>2.75%</u>	<u>4.53%</u>	<u>6.59%</u>	<u>9.12%</u>	<u>12.16%</u>	<u>15.97%</u>	<u>20.67%</u>	<u>26.67%</u>	<u>34.33%</u>
ANNUAL THERMAL ENERGY SALES (MWH)	<u>61,536</u>	<u>61,536</u>	<u>61,536</u>	<u>61,536</u>	<u>61,536</u>	<u>61,536</u>	<u>61,536</u>	<u>61,536</u>	<u>61,536</u>	<u>61,536</u>

Exhibit 4-67

CITY OF PERGUS FALLS

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED BALANCE SHEETS

	AS OF MARCH 30th									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
ASSETS										
FIXED ASSETS:										
Plant retrofit	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000
Distribution system	4,044,000	5,276,780	6,007,120	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215
Building conversions	376,871	433,129	556,756	715,152	777,554	795,829	795,829	795,829	795,829	795,829
Service equipment	50,000	60,600	71,836	83,746	96,371	109,753	123,938	138,974	154,912	171,806
	<u>6,170,871</u>	<u>7,470,509</u>	<u>8,335,712</u>	<u>9,049,113</u>	<u>9,124,140</u>	<u>9,155,797</u>	<u>9,169,982</u>	<u>9,185,018</u>	<u>9,200,956</u>	<u>9,217,850</u>
Accumulated provision for depreciation	249,835	552,292	890,031	1,257,020	1,627,767	2,000,584	2,374,820	2,750,559	3,127,892	3,506,913
Net fixed assets	<u>5,921,036</u>	<u>6,918,217</u>	<u>7,445,681</u>	<u>7,792,093</u>	<u>7,496,373</u>	<u>7,155,213</u>	<u>6,795,162</u>	<u>6,434,459</u>	<u>6,073,064</u>	<u>5,710,937</u>
CURRENT ASSETS:										
Cash	58,812	61,200	55,964	55,556	50,000	50,000	50,000	50,000	50,000	50,000
Accounts receivable	54,369	65,735	87,541	115,652	131,538	142,074	150,639	159,648	169,248	179,364
Total current assets	<u>113,181</u>	<u>126,935</u>	<u>143,505</u>	<u>171,208</u>	<u>181,538</u>	<u>192,074</u>	<u>200,639</u>	<u>209,648</u>	<u>219,248</u>	<u>229,364</u>
TOTAL	<u>\$6,034,217</u>	<u>\$7,045,152</u>	<u>\$7,589,186</u>	<u>\$7,963,301</u>	<u>\$7,677,911</u>	<u>\$7,347,287</u>	<u>\$6,995,801</u>	<u>\$6,644,107</u>	<u>\$6,292,312</u>	<u>\$5,940,301</u>
LIABILITIES AND CAPITAL ACCOUNTS										
CAPITALIZATION:										
Capital investment	\$5,900,000	\$7,075,000	\$7,765,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000
Accumulated earnings (deficit)	(207,334)	(508,831)	(785,439)	(1,007,942)	(1,199,840)	(1,360,685)	(1,490,805)	(1,585,030)	(1,642,194)	(1,660,929)
Accumulated cash reduction					(190,597)	(432,067)	(702,520)	(988,714)	(1,294,030)	(1,621,293)
Net capital investment	<u>5,692,666</u>	<u>6,566,169</u>	<u>6,979,561</u>	<u>7,232,058</u>	<u>6,849,563</u>	<u>6,447,248</u>	<u>6,046,675</u>	<u>5,666,256</u>	<u>5,303,776</u>	<u>4,957,778</u>
CURRENT LIABILITIES - accounts payable										
	<u>42,738</u>	<u>49,395</u>	<u>55,099</u>	<u>61,818</u>	<u>67,891</u>	<u>71,588</u>	<u>73,997</u>	<u>75,678</u>	<u>77,409</u>	<u>79,116</u>
DEFERRED CREDITS:										
Accumulated deferred income taxes	131,113	268,234	399,566	520,911	618,444	692,997	746,296	780,025	795,733	794,841
Accumulated deferred investment tax credit	167,700	161,354	154,960	148,514	142,013	135,454	128,833	122,148	115,394	108,566
Total deferred credits	<u>298,813</u>	<u>429,588</u>	<u>554,526</u>	<u>669,425</u>	<u>760,457</u>	<u>828,451</u>	<u>875,129</u>	<u>902,173</u>	<u>911,127</u>	<u>903,407</u>
TOTAL	<u>\$6,034,217</u>	<u>\$7,045,152</u>	<u>\$7,589,186</u>	<u>\$7,963,301</u>	<u>\$7,677,911</u>	<u>\$7,347,287</u>	<u>\$6,995,801</u>	<u>\$6,644,107</u>	<u>\$6,292,312</u>	<u>\$5,940,301</u>

Exhibit 4-67 (Continued)

CITY OF FERGUS FALLS
PRELIMINARY BASE CASE ECONOMIC ANALYSIS
PROJECTED BALANCE SHEETS

	AS OF MARCH 30th									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
<u>ASSETS</u>										
FIXED ASSETS:										
Plant retrofit	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000
Distribution system	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215	6,550,215
Building conversions	795,829	795,829	795,829	795,829	795,829	795,829	795,829	795,829	795,829	795,829
Service equipment	139,714	148,097	156,983	166,402	176,386	186,970	198,188	210,080	222,685	236,047
	<u>9,185,758</u>	<u>9,194,141</u>	<u>9,203,027</u>	<u>9,212,446</u>	<u>9,222,430</u>	<u>9,233,014</u>	<u>9,244,232</u>	<u>9,256,124</u>	<u>9,268,729</u>	<u>9,282,091</u>
Accumulated provision for depreciation	3,832,728	4,198,780	4,565,084	4,931,658	5,298,512	5,665,668	6,033,142	6,400,957	6,769,129	7,137,681
Net fixed assets	<u>5,353,030</u>	<u>4,995,361</u>	<u>4,637,943</u>	<u>4,280,788</u>	<u>3,923,918</u>	<u>3,567,346</u>	<u>3,211,090</u>	<u>2,855,167</u>	<u>2,499,600</u>	<u>2,144,410</u>
CURRENT ASSETS:										
Cash	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Accounts receivable	190,145	201,591	213,701	226,476	240,063	254,462	269,748	285,919	303,128	321,290
Total current assets	<u>240,145</u>	<u>251,591</u>	<u>263,701</u>	<u>276,476</u>	<u>290,063</u>	<u>304,462</u>	<u>319,748</u>	<u>335,919</u>	<u>353,128</u>	<u>371,290</u>
TOTAL	<u>\$5,593,175</u>	<u>\$5,246,952</u>	<u>\$4,901,644</u>	<u>\$4,557,264</u>	<u>\$4,213,981</u>	<u>\$3,871,808</u>	<u>\$3,530,838</u>	<u>\$3,191,086</u>	<u>\$2,852,728</u>	<u>\$2,515,700</u>
<u>LIABILITIES AND CAPITAL ACCOUNTS</u>										
CAPITALIZATION:										
Capital investment	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000	\$8,240,000
Accumulated earnings (deficit)	(1,638,286)	(1,576,734)	(1,482,446)	(1,354,979)	(1,191,751)	(991,503)	(751,297)	(469,708)	(144,107)	226,753
Accumulated cash reduction	(1,971,217)	(2,345,779)	(2,740,840)	(3,160,343)	(3,612,030)	(4,097,878)	(4,622,075)	(5,186,802)	(5,794,466)	(6,446,585)
Net capital investment	<u>4,630,497</u>	<u>4,317,487</u>	<u>4,016,714</u>	<u>3,724,678</u>	<u>3,436,219</u>	<u>3,150,619</u>	<u>2,866,628</u>	<u>2,583,490</u>	<u>2,301,427</u>	<u>2,020,168</u>
CURRENT LIABILITIES - accounts payable	<u>80,956</u>	<u>83,302</u>	<u>87,084</u>	<u>91,161</u>	<u>95,300</u>	<u>99,756</u>	<u>104,295</u>	<u>109,188</u>	<u>114,330</u>	<u>119,911</u>
DEFERRED CREDITS:										
Accumulated deferred income taxes	779,561	750,384	708,424	658,333	605,672	550,915	495,638	440,338	385,073	329,857
Accumulated deferred investment tax credit	102,161	95,779	89,422	83,092	76,790	70,518	64,277	58,070	51,898	45,764
Total deferred credits	<u>881,722</u>	<u>846,163</u>	<u>797,846</u>	<u>741,425</u>	<u>682,462</u>	<u>621,433</u>	<u>559,915</u>	<u>498,408</u>	<u>436,971</u>	<u>375,621</u>
TOTAL	<u>\$5,593,175</u>	<u>\$5,246,952</u>	<u>\$4,901,644</u>	<u>\$4,557,264</u>	<u>\$4,213,981</u>	<u>\$3,871,808</u>	<u>\$3,530,838</u>	<u>\$3,191,086</u>	<u>\$2,852,728</u>	<u>\$2,515,700</u>

Exhibit 4-68

CITY OF PERGUS FALLS

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED CASH FLOW STATEMENTS

	FOR THE FISCAL YEARS ENDING MARCH 30th									
	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
SOURCE OF CASH:										
Net income (loss)	(\$ 207,334)	(\$ 301,497)	(\$ 276,608)	(\$ 222,503)	(\$ 191,898)	(\$ 160,845)	(\$ 130,120)	(\$ 94,225)	(\$ 57,164)	(\$ 18,735)
Depreciation	249,835	302,457	337,739	366,989	370,747	372,817	374,236	375,739	377,333	379,021
Deferred income tax	131,113	137,121	131,332	121,345	97,533	74,553	53,299	33,729	15,708	(892)
Deferred investment tax credit	167,700	(6,346)	(6,394)	(6,446)	(6,501)	(6,559)	(6,621)	(6,685)	(6,754)	(6,828)
Increase in:										
Accounts receivable	(54,369)	(11,366)	(21,806)	(28,111)	(15,886)	(10,536)	(8,565)	(9,009)	(9,600)	(10,116)
Accounts payable	42,737	6,657	5,704	6,721	6,072	3,697	2,409	1,681	1,731	1,707
Cash from operations	329,682	127,026	169,967	237,995	260,067	273,127	284,638	301,230	321,254	344,157
Capital investment	5,900,000	1,175,000	690,000	475,000						
TOTAL	\$6,229,682	\$1,302,026	\$ 859,967	\$ 712,995	\$ 260,067	\$ 273,127	\$ 284,638	\$ 301,230	\$ 321,254	\$ 344,157
USE OF CASH:										
Construction expenditures	\$6,170,870	\$1,299,638	\$ 865,203	\$ 713,403	\$ 75,026	\$ 31,657	\$ 14,185	\$ 15,036	\$ 15,938	\$ 16,894
Reduction of capital investment					190,597	241,470	270,453	286,194	305,316	327,263
Cash working capital	58,812	2,388	(5,236)	(408)	(5,556)					
TOTAL	\$6,229,682	\$1,302,026	\$ 859,967	\$ 712,995	\$ 260,067	\$ 273,127	\$ 284,638	\$ 301,230	\$ 321,254	\$ 344,157
CASH RETURN ON INVESTMENT:										
Reduction of capital investment					\$ 190,597	\$ 241,470	\$ 270,453	\$ 286,194	\$ 305,316	\$ 327,263
Interest expense	\$ 144,791	\$ 305,657	\$ 331,434	\$ 342,041	333,512	309,669	286,373	264,546	244,519	226,132
Total cash return on capital investment	\$ 144,791	\$ 305,657	\$ 331,434	\$ 342,041	\$ 524,109	\$ 551,139	\$ 556,826	\$ 550,740	\$ 549,835	\$ 553,395
Average capital investment	\$5,796,333	\$6,129,418	\$6,772,865	\$7,105,810	\$7,040,811	\$6,648,406	\$6,246,962	\$5,856,466	\$5,485,016	\$5,130,777
Cash return on capital investment	2.50%	4.99%	4.89%	4.81%	7.44%	8.29%	8.91%	9.40%	10.02%	10.79%

Exhibit 4-68 (Continued)

CITY OF FERGUS FALLS

PRELIMINARY BASE CASE ECONOMIC ANALYSIS

PROJECTED CASH FLOW STATEMENTS

	FOR THE FISCAL YEARS ENDING MARCH 30th									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
SOURCE OF CASH:										
Net income (loss)	\$ 22,643	\$ 61,552	\$ 94,288	\$ 127,467	\$ 163,228	\$ 200,248	\$ 240,206	\$ 281,589	\$ 325,601	\$ 370,860
Depreciation	375,813	376,652	377,540	378,482	379,480	380,538	381,660	382,851	384,110	385,446
Deferred income tax	(15,280)	(29,177)	(41,960)	(50,091)	(52,661)	(54,757)	(55,277)	(55,300)	(55,265)	(55,216)
Deferred investment tax credit	(6,405)	(6,382)	(6,357)	(6,330)	(6,302)	(6,272)	(6,241)	(6,207)	(6,172)	(6,134)
Increase in:										
Accounts receivable	(10,781)	(11,446)	(12,110)	(12,775)	(13,587)	(14,399)	(15,286)	(16,171)	(17,209)	(18,162)
Accounts payable	1,842	2,346	3,782	4,079	4,138	4,456	4,539	4,893	5,142	5,581
Cash from operations	367,832	393,545	415,183	440,832	474,296	509,814	549,601	591,655	636,207	682,375
Capital investment										
TOTAL	\$ 367,832	\$ 393,545	\$ 415,183	\$ 440,832	\$ 474,296	\$ 509,814	\$ 549,601	\$ 591,655	\$ 636,207	\$ 682,375
USE OF CASH:										
Construction expenditures	\$ 17,908	\$ 18,983	\$ 20,122	\$ 21,329	\$ 22,609	\$ 23,966	\$ 25,404	\$ 26,928	\$ 28,543	\$ 30,256
Reduction of capital investment	349,924	374,562	395,061	419,503	451,687	485,848	524,197	564,727	607,664	652,119
Cash working capital										
TOTAL	\$ 367,832	\$ 393,545	\$ 415,183	\$ 440,832	\$ 474,296	\$ 509,814	\$ 549,601	\$ 591,655	\$ 636,207	\$ 682,375
CASH RETURN ON INVESTMENT:										
Reduction of capital investment	\$ 349,924	\$ 374,562	\$ 395,061	\$ 419,503	\$ 451,687	\$ 485,848	\$ 524,197	\$ 564,727	\$ 607,664	\$ 652,119
Interest expense	209,335	194,014	179,962	166,907	154,431	142,221	130,160	118,174	106,237	94,347
Total cash return on capital investment	\$ 559,259	\$ 568,576	\$ 575,023	\$ 586,410	\$ 606,118	\$ 628,069	\$ 654,357	\$ 682,901	\$ 713,901	\$ 746,466
Average capital investment	\$4,794,138	\$4,473,992	\$4,167,101	\$3,870,696	\$3,580,449	\$3,293,419	\$3,008,624	\$2,725,059	\$2,442,459	\$2,160,798
Cash return on capital investment	11.67%	12.71%	13.80%	15.15%	16.93%	19.07%	21.75%	25.06%	29.23%	34.55%

Exhibit 4-64

Projected Net Income and Cash Flow Operations (Base Case)

Exhibit 4-70

Preliminary Economic Analysis

Calculation of Net Cash Flow To/From Equity Investors (Base Case)

Year	Cash Flow				Net Cash To/(From) Equity Investor
	From Operations	Used For Construction Expenditures	Used For Working Capital	Debt Capital Increase/ (Decrease) ⁽¹⁾	
1982	329,682	(6,170,870)	(58,812)	2,846,333	(3,053,667)
1983	127,026	(1,299,638)	(2,388)	436,752	(738,248)
1984	169,967	(865,203)	5,236	206,695	(483,305)
1985	237,995	(713,403)	408	126,249	(348,751)
1986	260,067	(75,026)	5,556	(191,248)	(650)
1987	273,127	(31,657)		(201,157)	40,313
1988	284,638	(14,185)		(200,287)	70,166
1989	301,230	(15,036)		(190,209)	95,985
1990	321,254	(15,938)		(181,240)	124,076
1991	344,157	(16,894)		(172,999)	154,264
1992	367,832	(17,908)		(163,641)	186,283
1993	393,545	(18,983)		(156,505)	218,057
1994	415,183	(20,122)		(150,386)	244,675
1995	440,832	(21,329)		(146,018)	273,485
1996	474,296	(22,609)		(144,230)	307,457
1997	509,814	(23,966)		(142,800)	343,048
1998	549,601	(25,404)		(141,995)	382,202
1999	591,655	(26,928)		(141,569)	423,158
2000	636,207	(28,543)		(141,032)	466,632
2001	682,375	(30,256)		(140,629)	511,490
2002	Book Value				1,010,084

Internal Rate of Return of Equity and Cash Flows = .32%

- (1) Calculated by taking 50% of the change in the net capital investment account each year.

Exhibit 4-71

Fergus Falls Economic Analysis Internal Rate of
Return Analysis of Discrete Cashflows (Base Case)

Year	Period	Cash			Discounted Cashflows		
		Outflows	Inflows	Netflows	at 13.0%	at 15.0%	at 1.0%
1982	(1)	\$3,053,667	0	\$-3,053,667	\$-2,702,362	\$-2,655,363	\$-3,038,477
1983	(2)	738,248	0	- 738,248	- 578,157	- 558,222	- 730,921
1984	(3)	483,305	0	- 483,305	- 334,955	- 317,781	- 476,128
1985	(4)	348,751	0	- 348,751	- 213,896	- 199,400	- 341,863
1986	(5)	650	0	- 650	- 352	- 323	- 633
1987	(6)	0	40,313	40,313	19,363	17,428	39,124
1988	(7)	0	70,166	70,166	29,825	26,378	67,759
1989	(8)	0	95,985	95,985	36,106	31,377	92,231
1990	(9)	0	124,076	124,076	41,303	35,270	118,630
1991	(10)	0	154,264	154,264	45,444	38,131	146,760
1992	(11)	0	186,283	186,283	48,564	40,040	176,340
1993	(12)	0	218,057	218,057	50,307	40,756	205,391
1994	(13)	0	244,675	244,675	49,954	39,766	229,317
1995	(14)	0	273,485	273,485	49,413	38,651	255,044
1996	(15)	0	307,457	307,457	49,160	37,785	285,299
1997	(16)	0	343,048	343,048	48,540	36,660	316,742
1998	(17)	0	382,202	382,202	47,859	35,516	351,138
1999	(18)	0	423,158	423,158	46,892	34,193	386,831
2000	(19)	0	466,632	466,632	45,760	32,788	424,452
2001	(20)	0	511,490	511,490	44,389	31,252	462,941
2002	(21)	0	1,010,084	1,010,084	77,574	53,667	909,663
Total		\$4,624,621	\$4,851,375	\$ 226,754	\$-3,099,256	\$-3,161,415	\$- 120,346

The present value of the cashflows at 13.00% is \$-3,099,256

The present value of the cashflows at 15.00% is \$-3,161,415

The internal rate of return is .32%

However, it is unlikely changes in these factors would improve the economics enough to make Fergus Falls as attractive a demonstration site as either Red Wing or Moorhead. Therefore, no additional sensitivity tests were conducted for Fergus Falls.

5. RECOMMENDATIONS AND CONCLUSIONS

The results and conclusions discussed below are both general and site-specific and are drawn from all aspects -- technical, economic, marketing, institutional -- of the study. For more detailed observations related to Moorhead, Red Wing, and Fergus Falls, refer to the body of this report.

Technical/Economic

1. A statewide survey methodology to assess the potential viability of district heating system was developed and applied. This approach should be utilized on, at least, a Northern Tier regional basis to identify initial candidates for replication.
2. Swedish district heating expertise (a retrofit technology) was analyzed, modified, and applied in detail to U.S. cities for the first time. This application requires careful coordination, team selection, and technical initiation, but it is of the utmost importance to the rapid development of an economically successful system to draw upon a proven, reliable technical base.
3. In Sweden the distribution systems and end user conversions were retrofitted to existing cities, but new power plants were constructed as heat sources. In the Minnesota Project, power plant retrofit concepts to modify existing systems were developed.
4. In the initial demonstration projects, to assure satisfactory, reliable system performance, European equipment, particularly in regard to building conversions, will most likely be employed. When a significant market develops in the U.S., local equipment manufacturers should be able to compete favorably with the imported equipment.
5. The power plant retrofit schemes developed in this program were tailored to U.S. utility profiles of summer electrical peak and winter thermal peaks rather than the European experience of coincidental electrical and thermal peaks in the winter. One retrofit option based on the thermal storage potential of the district heating system can provide more electrical capacity than possible prior to retrofit.

6. Many sites within Minnesota because of energy density and cold climate appear to be technically and economically feasible sites for district heating. The best of these sites appear to have very favorable economic potential.

Moorhead

1. The power plant retrofit can be accomplished with near ideal thermal-electric balance over the annual use profiles of electrical and thermal energy. Some details of the retrofit remain to be determined.
2. Large loads (two colleges) in near proximity to the plant will provide a strong start-up incentive and minimize start-up losses.
3. Construction of the initial phase could begin in 1980. Depending upon Phase 2 results of the power plant analyses, commercial operation could begin in 1980-81 heating season.
4. The return on investment for municipal ownership appears to be attractive.

Red Wing

1. The power plant is unusually attractive due to past experience with the model turbines involved. The manufacturer will work with NSP to finalize turbine details.
2. The downtown business area is relatively compact and well laid for district heating retrofit. A large industrial load exists.
3. Construction of the initial phase could begin in 1980 with commercial operation by the end of 1980. The rate of return for NSP ownership appears to be in an acceptable range based on NSP pricing suggestions.

Fergus Falls

1. The power plant retrofit is relatively simple and considerable experience has been obtained with a similar turbine unit. Another possibly attractive retrofit scheme requires further analysis.
2. The distribution service area is farther from the power plant than in the other cities and overall economics are not as favorable.
3. This city and power plant could serve as an ideal site for replication prototyping and should be pursued at a level that supports this position.

4. Construction could begin in 1981 dependent upon the results and experiences in the other cities.

Marketing/Institutional

1. With competitive pricing there appears to be little problem in marketing district heating. Large industrial or institutional customers will require site-specific marketing efforts.
2. Major institutional difficulties, if any, center on the cost allocation between thermal and electrical power. Various types of present and potential future regulations may apply and decision in this area can control the viability of district heating system economics.
3. There are no known insurmountable obstacles in the environmental, franchising, or permitting areas.

Sensitivity of Economics to Alternative Fuel Price Escalation Rates

The base case economic analysis for all three cities was developed in light of certain general assumptions regarding the future cost of fuels such as natural gas, oil and coal. Specifically, it was assumed that:

1. Coal would have a differential escalation rate of 0% over the general inflation rate.
2. Natural gas would have a differential escalation rate of 4.3% over the general inflation rate.
3. Oil would have a differential escalation rate of 3.0% over the general inflation rate.

Since buildings which were heated by electricity did not represent a significant part of the potential market, it was not necessary to estimate an escalation rate for electricity.

The overall economic viability of any new energy technology demonstration project is influenced to a great extent by the actual escalation rates for these fuels. While recent events would indicate the base case assumption are somewhat conservative, it is important to understand the sensitivity of basic economic parameters to different fuel escalation rates. Therefore, general sensitivity tests were performed which show the relative impact of fuel escalation rates on the projects internal rate of return for the cities of Red Wing and Moorhead.

The following key assumptions were used in developing the sensitivity of differences in scarce fuel and coal escalation rates over the "base case" escalation rates used in the economic analysis for the City of Red Wing.

1. General inflation rate of 4%.
2. Initial scarce fuel cost equal to \$4.00/MMBtu and increased at the general inflation rate plus the scarce fuel escalation rates.
3. Initial purchased thermal energy cost was increased at the general inflation rate plus the escalation rates for coal.
4. Thermal energy price to customers equal to 100% of alternative scarce fuel prices.
5. The remaining base case assumptions for the City of Red Wing such as operating and construction costs, market size and penetration and financing structure were unchanged.

The results of the sensitivity tests for the City of Red Wing are presented on Exhibits 5-1 and 5-2.

Exhibit 5-1 shows that as long as scarce fuel prices escalate at rates greater than coal escalation, the opportunity to earn a reasonable return on equity and corresponding to have a viable project exists.

Exhibit 5-2 shows that if scarce fuels have a differential escalation rate greater than 6% the economic viability of the system is almost assured.

The following key assumptions were used in developing the sensitivity of differences in scarce fuel and coal escalation rates over the "base case" escalation rates used in the economic analysis for the City of Moorhead.

1. General inflation rate of 4%.
2. Initial scarce fuel cost equal to \$4.00/MMBtu and increased at the general inflation rate plus the scarce fuel escalation rates.
3. Initial purchased energy cost was increased at the general inflation rate plus the escalation rates for coal.
4. Thermal energy price to customers equal to 100% of alternative scarce fuel prices.

Exhibit 5-1

Sensitivity of Return on Investment to Scarce Fuel Price Escalation Rates (Red Wing)

Exhibit 5-2

Sensitivity of Return on Investment to Alternative Coal Price Escalation Rates (Red Wing)

5. The remaining base case assumptions for the City of Moorhead such as operating and construction costs, market size and penetration and financing structure were unchanged.

The results of the sensitivity tests for the City of Moorhead are presented on Exhibits 5-3 and 5-4.

Exhibits 5-3 and 5-4 also show that as long as scarce fuel prices escalate at rates greater than coal escalation, the opportunity for an economically viable project exists and that the higher the scarce fuel escalation rate is the more assurance exists for economic success.

Exhibits 5-1 to 5-4 clearly demonstrate the relative impact of scarce fuel and coal escalation rates on the economic analysis results presented for the cities of Red Wing and Moorhead.

In pricing thermal energy at 100% of alternative scarce fuel prices a significant cost savings to users has been assumed. The alternative fuel cost must be divided by the efficiency of the building heating system (.65-.75) to get actual energy cost while the thermal energy cost is for actual delivered energy.

In comparing the cities, Red Wing is less sensitive to change in the scarce fuel escalation rate than Moorhead because of property and income taxation and a different financing structure than Moorhead.

Exhibit 5-3

Sensitivity of Return on Investment to Scarce Fuel Price Escalation Rates (Moorhead)

Exhibit 5-4

Sensitivity of Return on Investment to Coal Price
Escalation Rates (Moorhead)