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Bob Tenell

DISTRICT HEATING AND COOLING SYSTEMS FOR COMMUNITIES THROUGH POWER PLANT RETROFIT AND DISTRIBUTION NETWORKS

PHASE I - IDENTIFICATION AND ASSESSMENT

FINAL REPORT

VOLUME I - EXECUTIVE SUMMARY

SEPTEMBER 1979

WISCONSIN STATE ENERGY OFFICE

PREPARED FOR:

U. S. DEPARTMENT OF ENERGY
CHICAGO OPERATIONS OFFICE
UNDER CONTRACT EM-78-C-02-4981

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1.0 INTRODUCTION

Two functions of the Department of Energy are to investigate and disseminate information on efficient use of energy. As part of this effort, DOE sponsored the District Heating and Cooling System (DHCS) for Communities through Power Plant Retrofit and Distribution Networks, Phase I Identification and Assessment Study. The study assesses the preliminary technical, economic and institutional feasibility of district heating systems achieved by retrofitting existing utility power plants in three Wisconsin cities: Green Bay, Janesville/Beloit and Madison.

District heating is the use of one or more central heat sources to supply the low to moderate thermal needs of a community through a distribution system. The central heat source can be a heat-only boiler or a cogeneration (e.g., power plant producing both electric and thermal energy) facility. This type of system is becoming the dominant mode of operation in urban areas of the Scandinavian and Soviet Bloc countries.

The results of this study, which was performed over a nine-month period, are contained in this report. The Phase I study was performed by the following team of state agencies, industries and utilities:

Contractor: Wisconsin Office of State Planning and Energy
Madison, Wisconsin

Subcontractors: Honeywell Inc.
Energy Resources Center
Minneapolis, Minnesota

American Hydrotherm Corporation
New York, New York

Wisconsin Public Service Commission
Madison, Wisconsin

Madison Gas and Electric Co.
Madison, Wisconsin

Wisconsin Power and Light Co.
Madison, Wisconsin

Wisconsin Public Service Corporation
Green Bay, Wisconsin

Manitowoc Public Utilities
Manitowoc, Wisconsin

Wisconsin Electric Power Co.
Milwaukee, Wisconsin

Results of the study are published in three volumes:

- Volume I - Executive Summary,
- Volume II - Detailed Results,
- Volume III - Appendices.

Volume I is a brief synopsis of the project and its results. Volume II contains the assumptions that were used, a description of the approach and detailed results. Volume III, the Appendices, contains detailed background information used during the study.

2.0 STATEMENT OF THE PROBLEM

In a conventional utility power plant, about 35 percent of the usable energy derived from fuel burned is transformed into electricity. In a typical cogeneration facility, such as one found in Sweden, 20 to 25 percent of the fuel burned is transformed into electricity and 45 to 55 percent is transformed into thermal energy. Thus, in a cogeneration facility 65 to 80 percent of the fuel burned is transformed into usable energy forms compared with 35 percent from a conventional (electric only) power plant.

The energy conservation potential of a cogeneration facility is obvious. Space and water heating needs supplied through more efficient cogeneration district heating systems will free considerable supplies of scarce fossil fuels (natural gas and/or fuel oil) for other uses. The long-term economic benefits include more stable costs for space and water heating needs, since these costs would be tied to the price of coal at the electric generating station rather than to the more rapidly escalating prices of natural gas and fuel oil. In an area with air pollution problems (such as a nonattainment area), a cogeneration district heating system might well enhance that area's ability to attract new industry. At present, an industry that depends on burning coal to supply its heat energy needs probably would not be allowed to locate in a nonattainment area. However, if these heat needs could be supplied by a district heating system, the industry would not have to burn coal and could locate in the nonattainment area.

To examine the feasibility of the district heating concept, the Department of Energy initiated a seven-phase program entitled "District Heating and Cooling Systems for Communities through Power Plant Retrofit and Distribution Networks." The initial phases of the program are aimed at identifying and evaluating potential sites, institutional problems and financial arrangements.

Later phases are aimed at detailed design and construction of promising projects. Final phases are aimed at initial testing, start-up and operational evaluation of the demonstration project.

This project contains the results of the Phase I Identification and Assessment Study for the State of Wisconsin.

3.0 OBJECTIVES

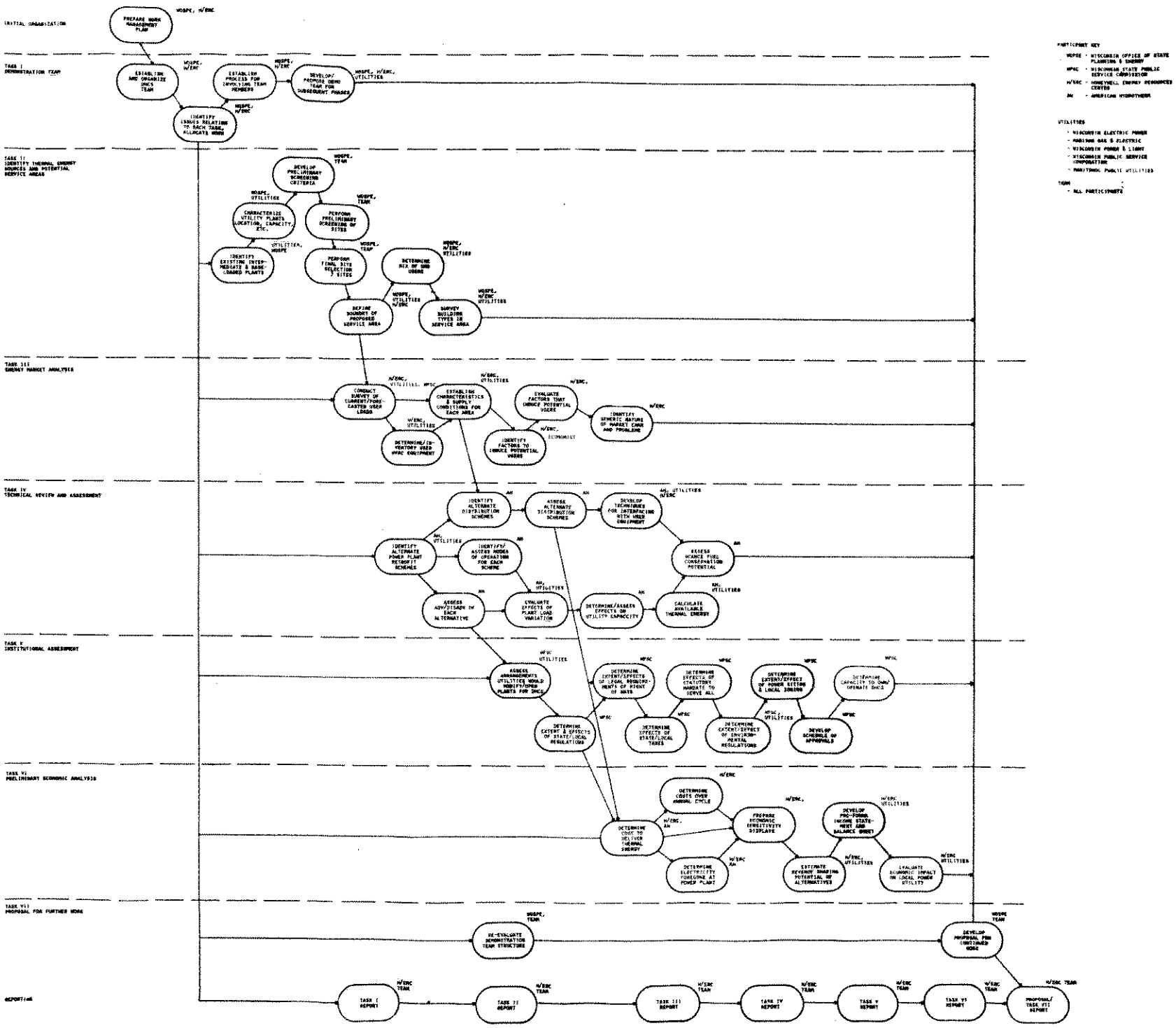
The Phase I Identification and Assessment Study was aimed at surveying the State of Wisconsin to identify potential sites for a district heating system and evaluating these sites in terms of their technical, institutional and economic merits. Specific objectives of the study were to:

- Identify candidate plants and service areas,
- Perform an energy market analysis for selected areas,
- Identify and evaluate plant retrofit and distribution alternatives for the selected service areas,
- Identify and evaluate institutional problems within the infrastructure,
- Perform an economic analysis for the candidate sites, and
- Select the most promising site for further study.

4.0 APPROACH

The overall methodology employed on the Phase I study is illustrated in Figure 1. Team members responsible for each task/subtask are also identified.

The overall approach consisted of surveying the State of Wisconsin to identify all existing intermediate and base-loaded electric generating facilities. Once identified, screening criteria were developed to narrow the list to the three most promising sites. For each of the three sites, an extensive market analysis was performed to identify and characterize thermal loads and survey potential users on their views and concerns regarding the concept. Parallel to this effort, each of the three sites was evaluated on its technical and institutional merits. The technical evaluation centered on identifying and evaluating utility plant retrofit schemes and distribution system alternatives to service the identified thermal market. The institutional analysis evaluated potential barriers such as environmental, distribution system right-of-way, and legal issues within the infrastructure of the state, city and community. Finally, all previous aspects of the analysis were combined to determine the economic viability of each site.


INITIAL ORGANIZATION
PREPARE WORK MANAGEMENT PLAN
WDSPE, H/ERC
TASK I DEMONSTRATION TEAM
ESTABLISH AND ORGANIZE DMCS TEAM
ESTABLISH PROCESS FOR INVOLVING TEAM MEMBERS
DEVELOP/PROPOSE DEMO TEAM FOR SUBSEQUENT PHASES
IDENTIFY ISSUES RELATING TO EACH TASK, ALLOCATE WORK
WDSPE, H/ERC
WDSPE, H/ERC, UTILITIES
TASK II IDENTIFY THERMAL ENERGY SOURCES AND POTENTIAL SERVICE AREAS
DEVELOP PRELIMINARY SCREENING CRITERIA
CHARACTERIZE UTILITY PLANTS LOCATION, CAPACITY, ETC.
PERFORM PRELIMINARY SCREENING OF SITES
IDENTIFY EXISTING INTERMEDIATE & BASE-LOADED PLANTS
PERFORM FINAL SITE SELECTION 7 SITES
DETERMINE MIX OF END USERS
DEFINE BOUNDRY OF PROPOSED SERVICE AREA
SURVEY BUILDING TYPES IN SERVICE AREA
WDSPE, TEAM
WDSPE, UTILITIES
WDSPE, TEAM
WDSPE, TEAM
WDSPE, H/ERC UTILITIES
WDSPE, UTILITIES H/ERC
WDSPE, H/ERC UTILITIES
TASK III ENERGY MARKET ANALYSIS
CONDUCT SURVEY OF CURRENT/FORECASTED USER LOADS
ESTABLISH CHARACTERISTICS & SUPPLY CONDITIONS FOR EACH AREA
EVALUATE FACTORS THAT INDUCE POTENTIAL USERS
IDENTIFY GENERIC NATURE OF MARKET CHAR AND PROBLEMS
DETERMINE/INVENTORY USED HVAC EQUIPMENT
IDENTIFY FACTORS TO INDUCE POTENTIAL USERS
H/ERC, UTILITIES, HPSC
H/ERC, UTILITIES
H/ERC, ECONOMIST
H/ERC
TASK IV TECHNICAL REVIEW AND ASSESSMENT
IDENTIFY ALTERNATE DISTRIBUTION SCHEMES
ASSESS ALTERNATE DISTRIBUTION SCHEMES
DEVELOP TECHNIQUES FOR INTERFACING WITH USER EQUIPMENT
ASSESS NCANCE FUEL CONSERVATION POTENTIAL
IDENTIFY ALTERNATE POWER PLANT RETROFIT SCHEMES
IDENTIFY/ASSESS MODES OF OPERATION FOR EACH SCHEME
ASSESS ADV/DISADV OF EACH ALTERNATIVE
EVALUATE EFFECTS OF PLANT LOAD VARIATION
DETERMINE/ASSESS EFFECTS ON UTILITY CAPACITY
CALCULATE AVAILABLE THERMAL ENERGY
AH, UTILITIES H/ERC
AH
AH, UTILITIES
AH
AH, UTILITIES
AH
AH, UTILITIES
AH
AH, UTILITIES
TASK V INSTITUTIONAL ASSESSMENT
ASSESS ARRANGEMENTS UTILITIES WOULD MODIFY/OPER PLANTS FOR DMCS
DETERMINE EXTENT/EFFECTS OF LEGAL REQUIREMENTS OF RIGHT OF WAYS
DETERMINE EFFECTS OF STATUTORY MANDATE TO SERVE ALL
DETERMINE EXTENT/EFFECT OF POWER SITING & LOCAL ZONING
DETERMINE CAPACITY TO OWN/OPERATE DMCS
DETERMINE EXTENT & EFFECTS OF STATE/LOCAL REGULATIONS
DETERMINE EFFECTS OF STATE/LOCAL TAXES
DETERMINE EXTENT/EFFECT OF ENVIRONMENTAL REGULATIONS
DEVELOP SCHEDULE OF APPROVALS
HPSC UTILITIES
HPSC
HPSC
HPSC
HPSC
HPSC
HPSC
HPSC, UTILITIES
HPSC
TASK VI PRELIMINARY ECONOMIC ANALYSIS
DETERMINE COSTS OVER ANNUAL CYCLE
DETERMINE COST TO DELIVER THERMAL ENERGY
PREPARE ECONOMIC SENSITIVITY DISPLAYS
DEVELOP PRO-FORMA INCOME STATEMENT AND BALANCE SHEET
DETERMINE ELECTRICITY FOREGONE AT POWER PLANT
ESTIMATE REVENUE SHARING POTENTIAL OF ALTERNATIVES
EVALUATE ECONOMIC IMPACT ON LOCAL POWER UTILITY
H/ERC
H/ERC, AH
H/ERC, AH
H/ERC, UTILITIES
H/ERC, UTILITIES
H/ERC, UTILITIES
H/ERC UTILITIES
TASK VII PROPOSAL FOR FURTHER WORK
RE-EVALUATE DEMONSTRATION TEAM STRUCTURE
DEVELOP PROPOSAL FOR CONTINUED WORK
WDSPE, TEAM
WDSPE TEAM
REPORTING
TASK I REPORT
TASK II REPORT
TASK III REPORT
TASK IV REPORT
TASK V REPORT
TASK VI REPORT
PROPOSAL/TASK VII REPORT
H/ERC TEAM
PARTICIPANT KEY
WDPSE - WISCONSIN OFFICE OF STATE PLANNING & ENERGY
HPSC - WISCONSIN STATE PUBLIC SERVICE COMMISSION
H/ERC - HONEYWELL ENERGY RESOURCES CENTER
AH - AMERICAN HYDROTHERM
UTILITIES
- WISCONSIN ELECTRIC POWER
- MADISON GAS & ELECTRIC
- WISCONSIN POWER & LIGHT
- WISCONSIN PUBLIC SERVICE CORPORATION
- MANITOWOC PUBLIC UTILITIES
TEAM
- ALL PARTICIPANTS

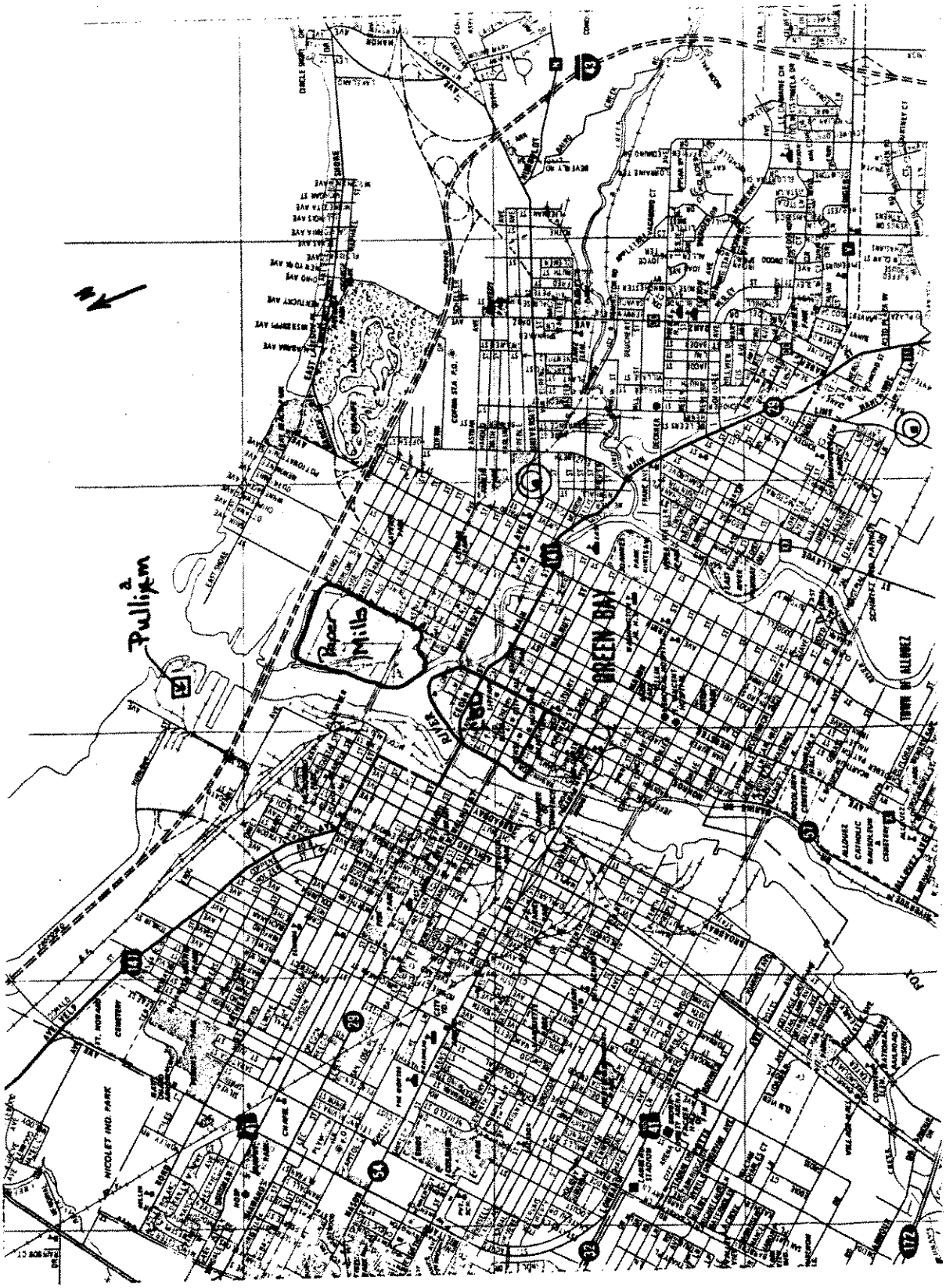


Figure 2. Green Bay Area

5.0 RESULTS

5.1 SITE SELECTION

Eighteen existing intermediate/base-loaded generating plants were identified and characterized by location, capacity, ownership, fuel type and capacity factor. To select the most promising sites, the following criteria were developed:

- Thermal density of the potential heat load and its characterization,
- Remaining expected lifetime of the generating units,
- Potential environmental benefits accruing to the area through cogeneration,
- Reliability and/or backup capability for the DHCS,
- Facility load factor.

After two levels of screening, three sites were determined to have the greatest potential for DHCS retrofit modifications:

- Green Bay--served by the Pulliam Plant,
- Janesville/Beloit--served by the Rock River and Black Hawk Plants,
- Madison--served by the Blount Street Plant.

5.1.1 Green Bay

The geographical areas selected (Figure 2) include the Central Business District (CBD) and the Industrial Area (three paper mills) located across the Fox River from the power plant. The CBD offers a concentration of multistory retail stores, office buildings, hotels and city-county buildings. The area is currently being renovated and offers great potential for future markets for a DHCS. The three paper mills are concentrated in a small area

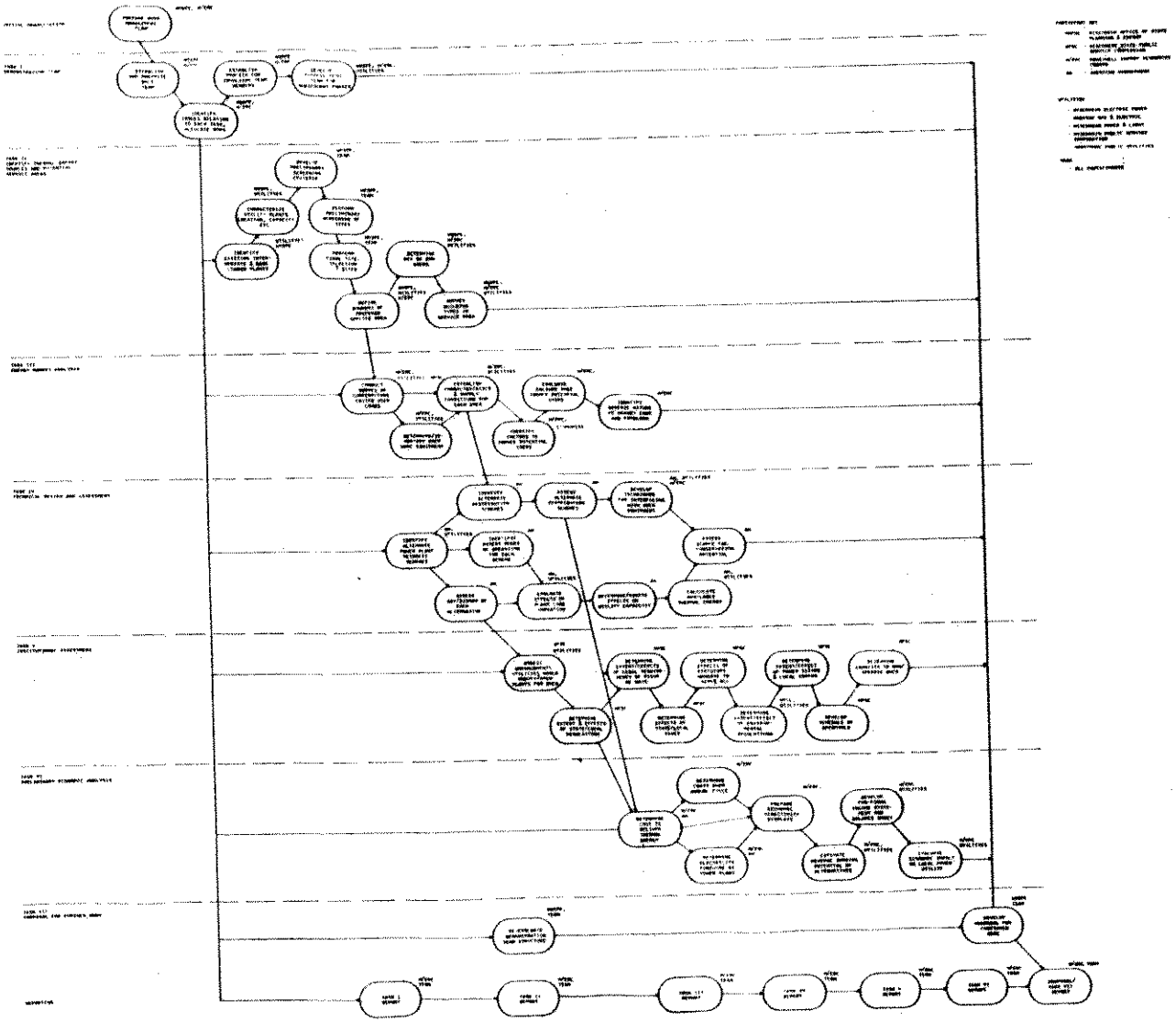


Figure 1. Phase 1 Study Approach, District Heating and Cooling Systems for Communities through Power Plant Retrofit and Distribution Networks

and use a large amount of process steam and process hot water. Boiler makeup water is extracted from the city water system and process water from the Fox River.

Thermal requirements for this service area were derived using actual gas consumption data (1977-1978) obtained from the Wisconsin Public Service Corporation and from discussions with representatives of the paper mills.

Consumption data were converted to load data by using an efficiency factor of 75 percent.

The thermal loads (Btu x 10^9/year) for Green Bay are:

Current		Future	
CBD	238.7	CBD	64.0
Industrial	3465.0		

The peak hour demand (Btu x 10^6/hour) is:

Current		Future	
CBD	89.0	CBD	38.0
Industrial	401.00		

The types and percentages of fuel currently consumed are:

Area	Fuel	Percentage
CBD	Natural Gas	100
Industrial	Natural Gas	17
	No. 6 Fuel Oil	17
	Coal	66

In the vast majority (82 percent) of the buildings, natural gas-fired boilers are the source of space heating. Of those, about 66 percent use steam for distribution and 34 percent use hot water.

Gas-fired hot water heaters are used in a majority of the buildings. In buildings that have a large hot water requirement (i.e., hotel/motels), steam or hot water heat exchangers are used.

The majority of the air conditioning equipment consists of small window units, which is indicative of the general age of the buildings. Larger department stores and the shopping plaza have central electric chillers. One building had a central absorption unit, but it was scheduled to be taken out because of operational problems.

5.1.2 Janesville/Beloit

The cities of Janesville and Beloit were analyzed together because of the close geographical locations of both the communities and power plants.

The areas selected for detailed analyses are illustrated in Figure 3 and include the Janesville CBD and areas to the south of it, the Beloit CBD and areas near it, and the industrial area east of Beloit.

The thermal market in this selected area can be described as:

- Beloit thermal loads that are very close to the Black Hawk Power Plant--these loads include the Beloit CBD, industry and Beloit College, and are appropriate for consideration of a very compact distribution network.

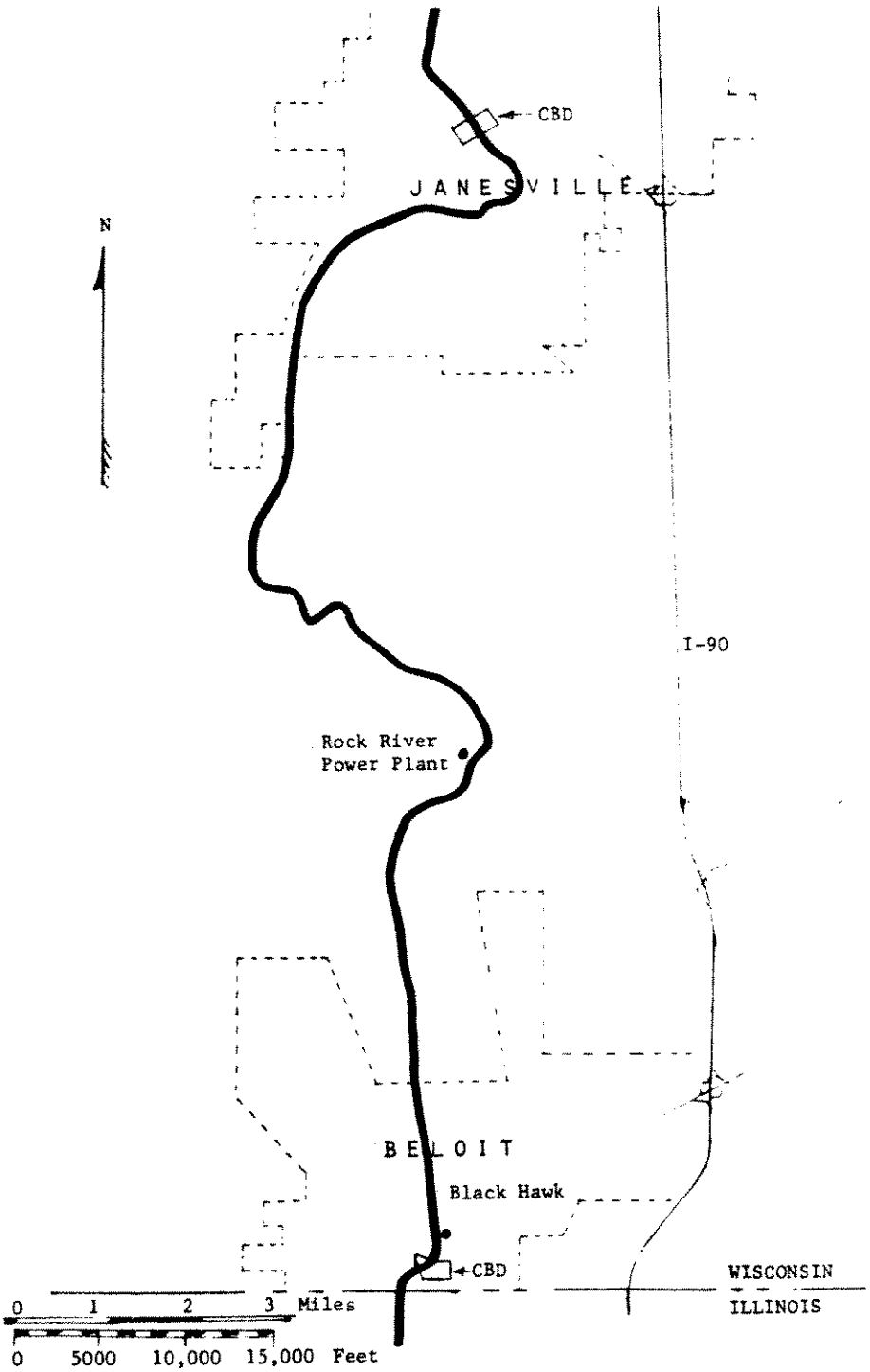


Figure 3. Janesville/Beloit Service Area

- South-of-Janesville thermal loads that are applicable to a network off a pipe from the Rock River Power Plant, with or without a connection to Black Hawk--these loads include the Janesville CBD, industry, and schools.
- Additional thermal loads north and east of Beloit (called Beloit "other")--these loads include industry, schools and a hospital.

The thermal loads (Btu x 10^9/year) for Janesville/Beloit are:

Current		Future	
Janesville CBD	31.9	Janesville Industry	1010.0
Janesville Industry	1192.6		
Beloit CBD	27.6		
Beloit Industry	1131.4		

The peak hour demand (Btu x 10^6/hour) is:

Current		Future	
Janesville CBD	12.0	Janesville Industry	250.0
Janesville Industry	295.0		
Beloit CBD	11.0		
Beloit Industry	416.0		

The types and percentages of fuel currently consumed are:

Fuel	Percentage
Coal	35
Natural Gas	65

Space and process heating in 90 percent of the "blocks" (i.e., CBD block, industrial plant, or school, etc.) is provided by natural gas-fired boilers. Five percent use natural gas-fired space heaters and five percent use coal

boilers plus gas space heaters. Oil is the predominant backup fuel for the boilers (50 percent of the blocks), LP gas is used as backup in 14 percent of the cases, coal is used as backup in five percent of the cases, and 27 "blocks" have no backup.

Hot water is provided by gas hot water heaters and steam-to-water heat exchangers on a 50/50 ratio.

The majority of the air conditioning equipment consists of small window units. Larger businesses have central electric chillers. Two "blocks" use central absorption units.

5.1.3 Madison--Served by the Blount Street Plant

The areas selected for detailed analysis (Figure 4) include the Central Business District (plus those buildings heated by the Capitol Heating Plant) and the University of Wisconsin campus. The CBD area encompasses about 100 city blocks of multistory commercial retail and hotel/motel buildings and includes those buidlilngs (i.e., office) served by the Capitol Heating Plant. The University of Wisconsin occupies an area about the size of the CBD. The campus contains about a 150 multistory classroom, office and dormitory buildings.

The current thermal load was derived using natural gas consumption data and steam supply data (1977-1978) supplied by Madison Gas and Electric Company. Load data for the Capitol Heating Plant and the University of Wisconsin were derived by assuming that 1000 pounds of steam equals 10^6 Btu. Almost 100 percent of the buildings in the central business district have natural gas-fired boilers. Of these, about 80 percent have steam distribution systems; the remainder have hot water.

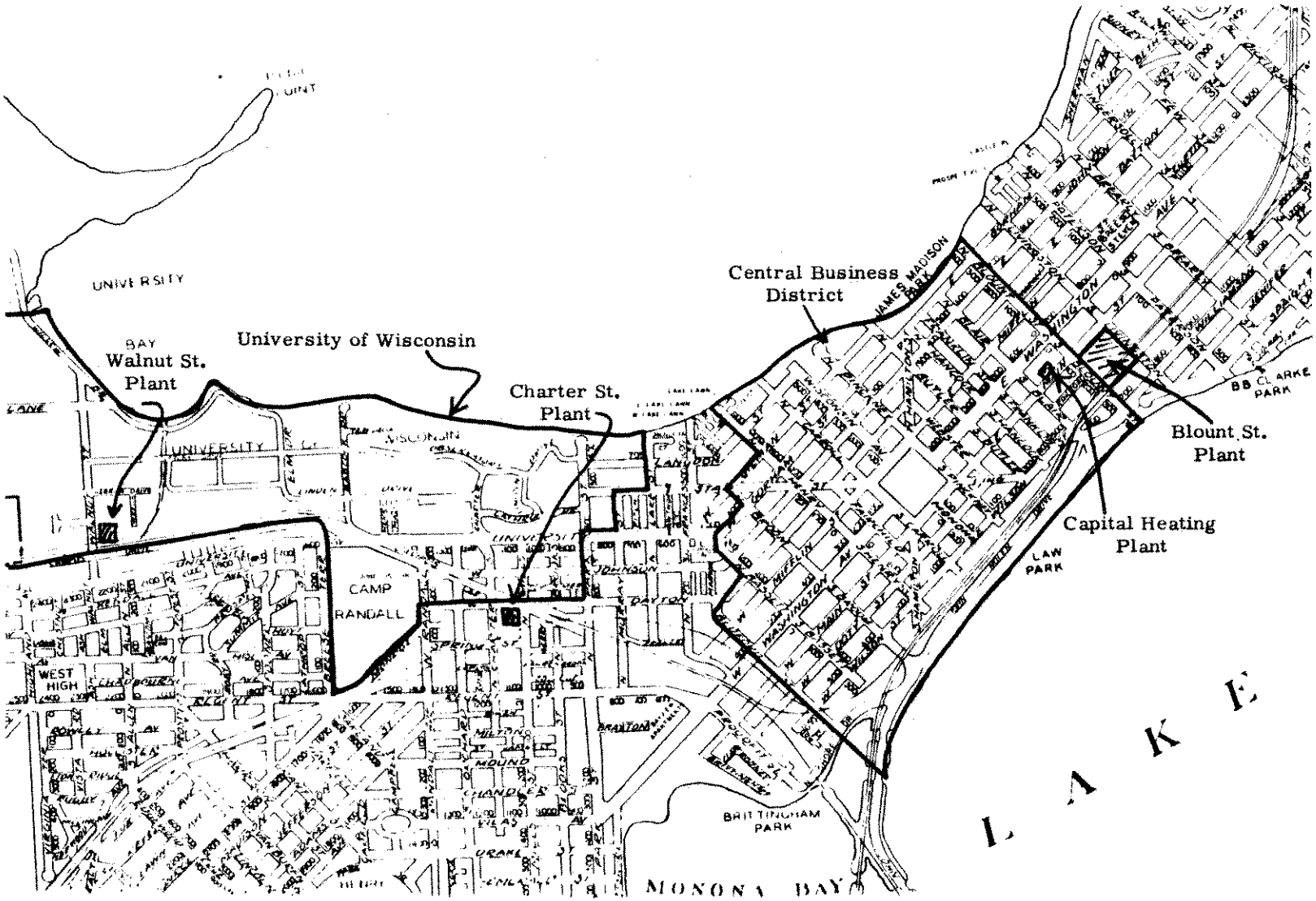


Figure 4. Madison Service Area

The thermal loads (Btu x 10^9/year) for Madison are:

Current		Future	
CBD (includes Capitol Heating Plant)	609.1	CBD	27.8
University	1637.0		

The peak hour demand (Btu x 10^6/hour) is:

Current		Future	
CBD (includes Capitol Heating Plant)	281.2	CBD	8.8
University	580.0		

The types and percentages of fuel currently consumed are:

Area	Fuel	Percentage
CBD	Natural Gas	100
Capitol	Natural Gas	65
	No. 6 Fuel Oil	7
	Coal	28
University of Wisconsin	Natural Gas	39
	Coal	38
	No. 5 Fuel Oil	6.5
	No. 2 Fuel Oil	16.5

Gas-fired hot water heaters are used in the majority of buildings. In buildings having a large hot water requirement (i.e., hotel/motel), steam or hot water heat exchangers are used.

The majority of the air conditioning equipment consists of electric window units or central chillers. One building, a hospital, contained a central absorption unit.

5.2 FACTORS TO INDUCE POTENTIAL SUBSCRIBERS

To determine what factors would induce potential users to subscribe to the DHCS, interviews were conducted in the communities of Green Bay, Janesville/Beloit, and Madison with building owners, managers, operators and directors.

Economics was the consideration most often mentioned that would induce potential users to subscribe to the DHCS. Capital expenditures for building conversions should be projected to produce a payback ranging from three to five years. Financial expenditures with paybacks longer than this period would receive less attention. Factors that would help to achieve this payback criteria for a DHCS and circumstances where it would be relaxed included:

- Tax Credits were often mentioned by private businesses/corporations as a means to help offset initial retrofit costs.
- Low interest loans were often mentioned as a method to help achieve the financing objective. As opposed to tax credits, this vehicle would also benefit nonprofit organizations.
- The Federal Government should consider financing a portion of the DHCS installation.
- Because of the bleak outlook for energy, energy-related expenditures appear to be receiving higher priority in business decisions. Because of this factor, most people would be willing to relax payback criteria from three to five years.
- The better the business climate at the time, the more relaxed the economic payback.
- Those persons who lived in the community and owned/operated businesses in the community appeared more inclined to support the DHCS concept because of possible benefits to the community.
- Reduced pollution was a welcomed benefit; however, those interviewed seemed unable to place a value on this benefit because it was intangible and difficult to quantify.

Additional information about DHCS--hot it works, what it would cost, what current users think about it--would greatly add to the general public's acceptance of the DHCS concept. Based on the small sample of people interviewed, this would be a significant factor in inducing potential users to subscribe to the DHCS system.

Reliability was not deemed to be a significant factor as perceived by the users. This is not to say that they are not concerned, but rather that they would view a project such as this to be reliable because the system will be designed as such. They also view the thermal energy as coming from the utility, which they generally consider to be as reliable as possible.

Having the streets torn up for installation of the DHCS distribution system was determined not to be a significant factor that would deter potential users. Businessmen commented that ripped up streets make it inconvenient for customers, thus business tends to suffer. Industry views this potential problem even less signficantly. As long as supplies can be received and products shipped, there is no problem.

5.3 INSTITUTIONAL ASSESSMENT

An institutional assessment was accomplished by analyzing the impact of all statutes, codes, ordinances, regulations and other external factors that may impact the establishment of a DHCS in Wisconsin. Conclusions reached are:

- The reform-minded utility regulatory climate in Wisconsin ensures that a DHCS system will be supported. Institutional impediments can be expected, however, when a multitude of agencies are to give approvals before the DHCS can proceed. An example is intervention of the Federal Highway Administration, which is expected to oppose a river bridging in Green Bay using the existing bridge.

- The State regulations often override local regulations, as in the case of siting and taxes due to the existing State laws and the support of the utility customers.
- It appears that institutional problems would be minimized if the DHCS were owned/operated by an existing utility. However, eventual rules of PURPA may favor setting up an independent DHCS that purchases heat from the electric utility.
- State-backed utility bonds are an option that opens the way financially for an independently owned DHCS system, should this alternative prove preferable.
- The Public Service Commission of Wisconsin believes the main test of DHCS viability is economic, not institutional. If energy can be delivered at a cost that is competitive with that of No. 6 fuel oil, success appears likely. If it cannot be competitive with No. 6 fuel oil, but only with No. 2 oil, the risks are greater but reduced by the effects of marginal cost-based pricing for natural gas.

5.4 DISTRICT HEATING SYSTEM ALTERNATIVES

Seven district heating system alternatives were developed by designing preliminary power plant retrofit schemes and distribution/transmission networks to serve the identified loads. Similar retrofit modifications were proposed for the Pulliam, Rock River and Blount Street Power Plants. The major portion of extracted energy was obtained at the crossover point just before the low-pressure condensing turbine. Additional smaller energy inputs extracted from the high- or intermediate-pressure turbine were used to bring the DHCS distribution system temperature up to the desired operating temperature. The modification proposed for the Black Hawk Power Plant, with no existing condensing turbine, was to extract all the required DHCS energy directly from the single turbine used. Backup heat-only peaking boilers were suggested or proposed in each modification.

A medium-temperature (250°F to 350°F) or high-temperature (above 350°F) hot water distribution system (operating pressures between 150 and 300 psig) was proposed as the DHCS distribution system in each instance. Such a hot water distribution system has many advantages:

- It is a completely closed circuit, with supply and return mains maintained under pressure. There are no losses due to flashing, and very little makeup water is required. Corrosion within the system is minimized. Because the system is closed circuit, the heat not utilized in the terminal heat transfer equipment is returned to the high-temperature water boilers or heat exchangers.
- Such a system can be designed for large temperature drops; thus smaller pipe sizes and less pumping capacity can be employed.
- Operation and temperature control are easily maintained. Uniform temperature is easily maintained, not only for normal operation, but also during peak loads, abnormal operating schedules, and for long periods of banked loads such as overnight or on weekends.
- Piping may slope up or down to suit the terrain, reducing the amount of excavation required and eliminating all drip points and return pump locations, as compared to steam.
- There are lower distribution piping costs since pipe sizes are generally smaller than in a steam system or low-temperature water system of the same capacity. Fewer specialties are required with elimination of steam traps, pressure-reducing valves, separators, flash tanks, condensate receivers and return pumps, as compared to steam.
- Lower operating costs result from better utilization of heat and reduced maintenance.
- Such a system can be considered a safer heat transfer agent then high-pressure steam.
- There is a tremendous "flywheel" effect in the heat storage in such a system, which acts to even out fluctuations in the load.

No technical problems with any of the designs are foreseen. A brief description of each of the alternatives is given below along with the amount of heat being supplied to the selected service area, estimated installed costs and the potential scarce fuel (natural gas, oil) savings. The distribution system costs do not include costs for user modifications to his building or plant, nor for supply and return piping between the building and the distribution system. Both proposed Green Bay distribution systems include the cost ($1,000,000) of a separate pipe bridge across the Fox River.

5.4.1 Green Bay

5.4.1.1 CBD and Three-Mill Alternative--Includes three paper mills (located across the Fox River from the power plant) and the Central Business District, which is located immediately south of the paper mills (Figure 5). The distance from the Green Bay Pulliam Plant to the southern boundary of the CBD is approximately two miles.

- Heat Supplies 3540.85×10^9 Btu/year
- System Costs
  - Plant Retrofit $3,000,000
  - Distribution System $8,000,000
- Scarce Fuel Savings 1418.3×10^9 Btu/year

The difference between the heat supplied and the thermal loads (page 5-3) is due to the 158 hours that the heat supply is interrupted since full power is needed and the 22 days of holidays and planned shutdowns. Capital costs for a 100 million Btu/hour standby oil- or gas-fired water heater to provide enough heat for the downtown area during the interruption hours are included. The quantity of heat that would be sold from the standby-fired water heater is not included since this would be replacing oil- or gas-fired building boilers.

Heat was taken from the Pulliam 8 unit by removing steam from one extraction point (183 psia) and the crossover point (89.7 psia) and condensing it in high-temperature water distribution system heat exchangers. The rate of heat removal varied throughout the year from a February average of 478 million Btu/hour to an August average of 409 million Btu/hour. The corresponding rate of power lost varied from 37.3 to 31.1 MW.

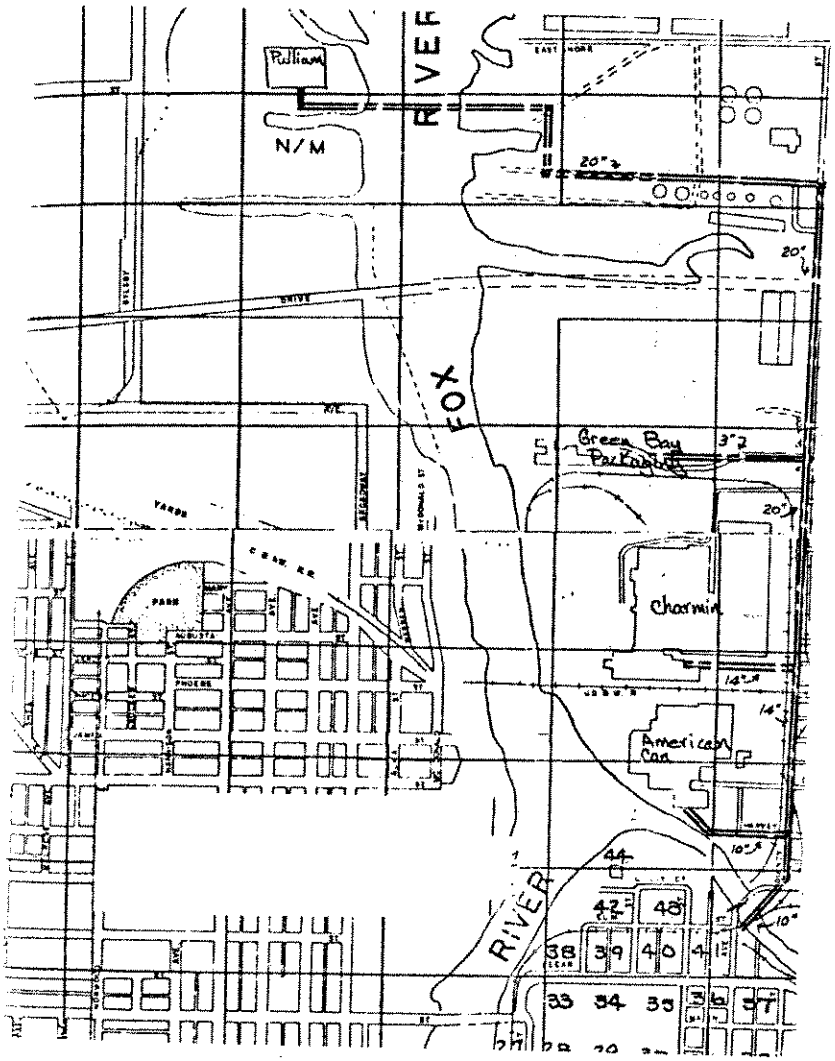


Figure 5. Green Bay Distribution System with Northern River Crossing

5.4.1.2 CBD and Two-Mill Alternative--Includes the two smaller paper mills and the CBD. The largest paper mill was omitted.

- Heat Supplied — 1418.33×10^9 Btu/year
- System Costs
  - Plant Retrofit — $2,200,000
  - Distribution System — $6,500,000
- Scarce Fuel Savings — 1418.3×10^9 Btu/year

Heat was removed from Pulliam 8 as described above. The rate of heat removal varied throughout the year from a February average of 215 million Btu/hour to an August average of 146 million Btu/hour. The corresponding rate of power lost varied from 17.2 to 11.7 MW.

5.4.2 Janesville/Beloit

5.4.2.1 Rock River to Industrial Park Alternative--Includes a proposed (i.e., no current tenants) industrial park located near the Rock River Power Plant.

- Heat Supplied — 1234.80×10^9 Btu/year
- System Costs
  - Plant Retrofit — $1,500,000
  - Distribution System — $5,200,000
- Scarce Fuel Savings — 1481.8×10^9 Btu/year

Heat was taken from the Rock River 1 or 2 unit by removing steam from one extraction point (183 psia) and the crossover point (89.7 psia) and condensing it in high-temperature water distribution system heat exchangers. The rate of heat removal averaged 150 million Btu/hour throughout the year with a power loss of 10.36 MW.

5.4.2.2 Black Hawk to Beloit Alternative--Includes large industrial users in and near Beloit, Wisconsin.

- Heat Supplied 670.41×10^9 Btu/year
- System Costs
  - Plant Retrofit $1,500,000
  - Distribution System $14,300,000
- Scarce Fuel Savings 84.0×10^9 Btu/year

Heat was taken from the Black Hawk 3 and 4 units by removing steam from three extraction points (298 psia, 123 psia, and 42.7 psia) and condensing it in high-temperature water distribution system heat exchangers. The rate of heat removal varied from a February average of 93.7 million Btu/hour to an August average of 62.9 million Btu/hour. The corresponding rate of power lost varied from 6.23 to 4.18 MW.

5.4.2.3 Rock River to Janesville and Beloit Alternative--Includes heavy users near Janesville and Beloit, with all energy extracted from the Rock River Power Plant.

- Heat Supplied 1928.61×10^9 Btu/year
- System Costs
  - Plant Retrofit $2,500,000
  - Distribution System $67,200,000
- Scarce Fuel Savings 2314.3×10^9 Btu/year

Heat was removed from the Rock River 1 or 2 unit by removing steam from two extraction points (201 psia and 89.7 psia) and the crossover point (28.0 psia). The rate of heat removal varied from a February average of 362 million Btu/hour to an August average of 139.7 million Btu/hour. The corresponding rate of power lost varied from 24.9 to 9.8 MW.

5.4.3 Madison

5.4.3.1 CBD and Capitol Heating Complex--Includes portions of the Central Business District and the buildings heated by the Capitol Heating Plant.

- Heat Supplied 215.10×10^9 Btu/year
- System Costs
  - Plant Retrofit $1,000,000
  - Distribution System $3,500,000
- Scarce Fuel Savings 258.1×10^9 Btu/year

Heat was removed from the Blount Street 6 or 7 unit by removing steam from two extraction points (305 psia and 150 psia) and the crossover point (59.2 psia). The rate of heat removal varied from a February average of 61.5 million Btu/hour to an August average of 4.7 million Btu/hour. The corresponding rate of power lost varied from 4.92 to 0.38 MW.

5.4.3.2 University of Wisconsin--Includes complex of buildings (approximately 150) at the University of Wisconsin.

- Heat Supplied 1176.05×10^9 Btu/year
- System Costs
  - Plant Retrofit $2,400,000
  - Distrubtion System $14,200,000
- Scarce Fuel Savings 1411.3×10^9 Btu/year

Heat was taken from the Blount Street 6 or 7 unit as described above. The rate of heat removal varied from a January average of 252 million Btu/hour to an August average of 26.5 million Btu/hour. The corresponding rate of power lost varied from 20.2 to 2.1 MW.

5.5 EFFECT ON UTILITIES CURRENT AND FUTURE OPERATION

For all of the alternatives considered, the cogeneration turbine was a "must run" turbine, and the electrical output from that unit was fully dependent on the amount of heat that was taken off to the district heating system.

During cogeneration operation, the power output from the retrofitted turbine is reduced and the lost power must be made up by other units.

The peak power demand cogeneration operation is considered an "interruptible" operation. Therefore, there would be no effect on the reserve capacity of the utility. As an example, the Green Bay operation would have a range of "interruption" hours per year from 42 (year 1980) to 329 (year 1990).

5.6 ECONOMIC ANALYSIS

With the background information developed during the study, the economic analysis was structured to assess the viability of each alternative from a viewpoint that would economically induce building owners to convert to the DHCS. This was accomplished by selecting a customer base rate for thermal energy that was lower than competitive fuels in each of the three areas. The analysis centered on either the local utility or municipality financing the plant retrofit and distribution networks. For two alternatives, joint financing between the utility and municipality was analyzed.

For each of the three sites and each of the alternatives analyzed, yearly fixed revenue requirements necessary to retire the cost of the capital

investment were determined. Yearly fuel costs at the power plant, based on coal escalating at a real rate of 4.0 percent and oil at 4.1 percent, were calculated. These were added to yearly operation and maintenance costs of the system to determine total revenue requirements.

Gross income for each of the three sites was determined by selecting a customer rate structure and escalating it at a rate equal to that expected for the fuel that would be displaced. In each of the three sites, the fuel that would be displaced is natural gas. The customer rate for thermal energy from the DHCS was selected by taking 90 percent of the current charge per Btu for natural gas at each site. This 10 percent reduction was selected as a means of providing an incentive for customers to convert their buildings to DHCS. The customer rate was escalated at the real rate expected for natural gas (7.0 percent), and the gross yearly income was determined.

Annual savings were then determined by subtracting total yearly revenue requirements from gross income. Accumulated annual savings (in 1979 dollars) were then plotted on a yearly basis. Thus the results obtained depict the economic viability of the DHCS for each alternative while considering:

- Capitalization structure of the utility or municipality,
- Installed cost of the DHCS,
- Thermal load supplied,
- Fuel, operation and maintenance costs,
- Income based on a competitive energy charge rate, and
- Income based on a charge rate that provides incentive for owners to convert their buildings.

A summary of the results for each of the three sites and each of the alternatives analyzed is illustrated in Figures 6 through 12. The summary results depict the accumulated net present worth or annual savings as a function of the year of operation for each financing alternative considered. Table I summarizes the major assumptions used in the economic analysis.

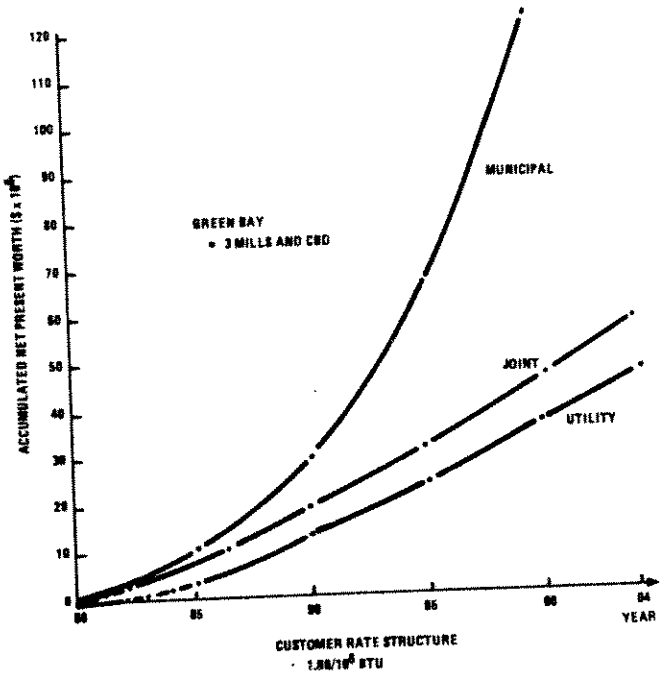


Figure 6. Accumulated Net Present Worth versus Year, Green Bay, Three Mills and CBD

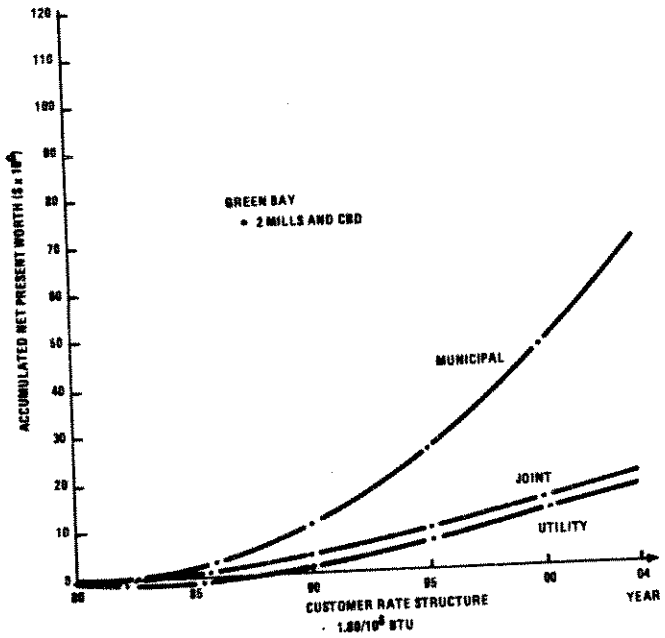


Figure 7. Accumulated Net Present Worth versus Year, Green Bay, Two Mills and CBD

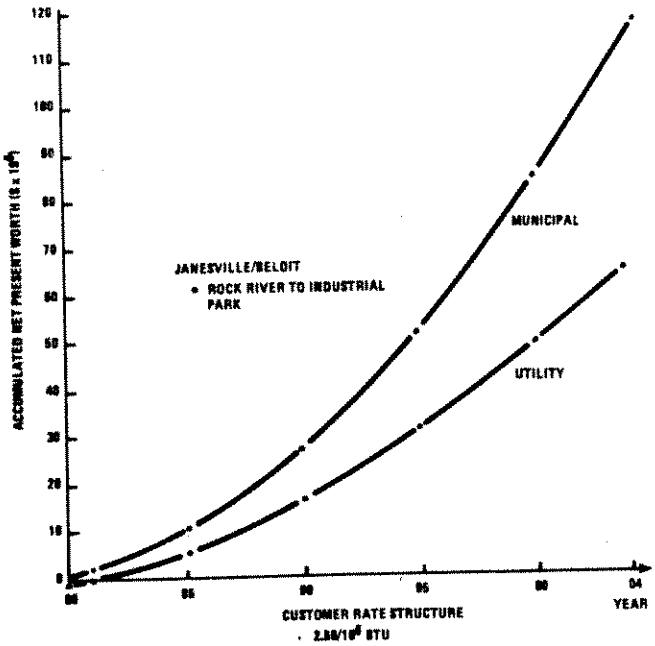


Figure 8. Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Industrial Park

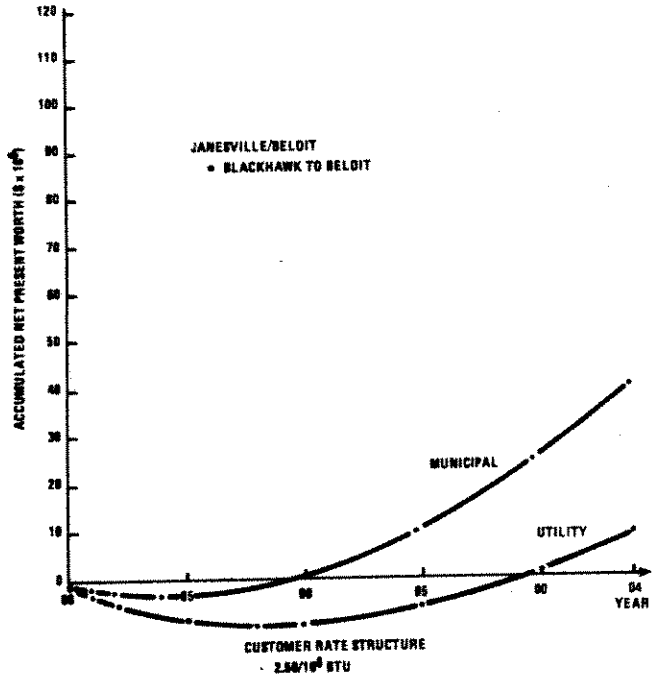


Figure 9. Accumulated Net Present Worth versus Year, Janesville/Beloit, Black Hawk to Beloit

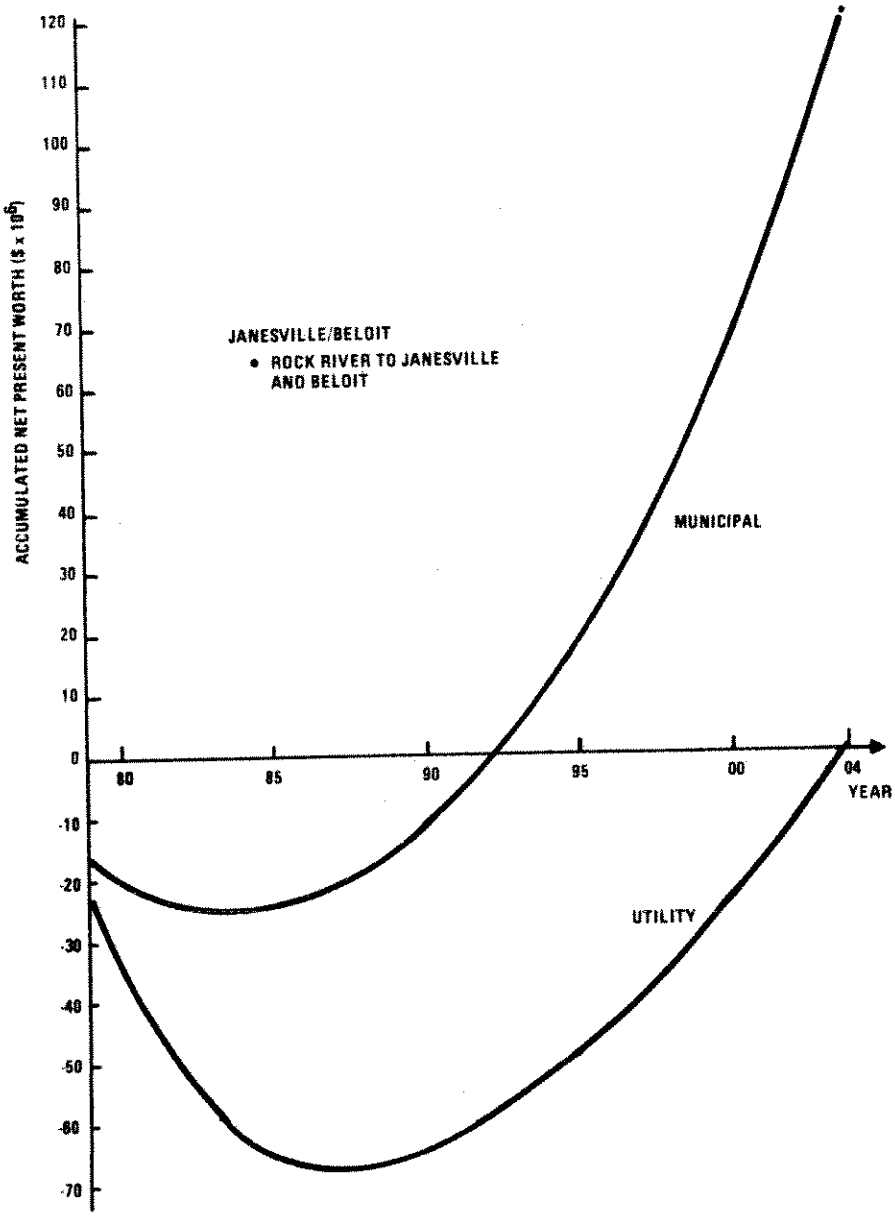


Figure 10. Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Janesville and Beloit

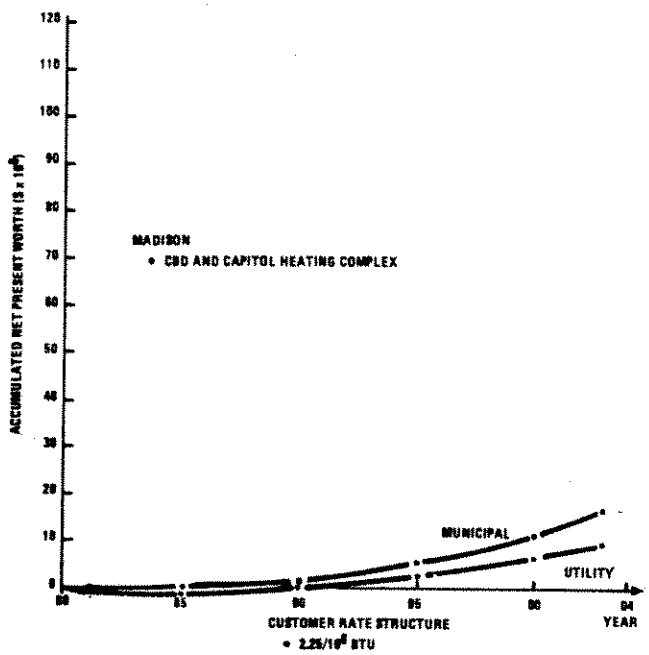


Figure 11. Accumulated Net Present Worth versus Year, Madison, CBD and Capitol Heating Complex

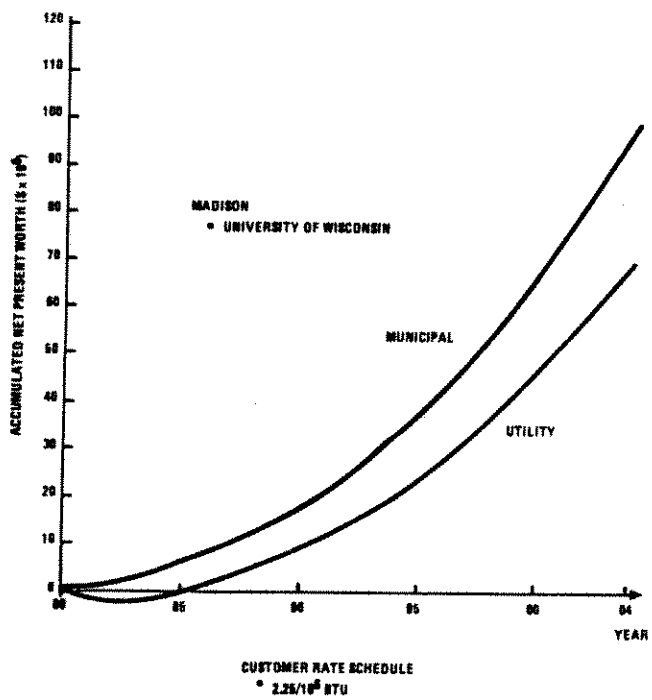


Figure 12. Accumulated Net Present Worth versus Year, Madison, University of Wisconsin

Table I. Major Assumptions in Economic Analysis

PERIOD OF ANALYSIS	25 YEARS
INFLATION RATE	7.0 PERCENT PER YEAR
ANNUAL INVESTMENTS FOR CAPITAL EQUIPMENT	OCCUR IN FIRST YEAR
MAINTENANCE, DISTRIBUTION SYSTEM	1.0 PERCENT OF COST
INSURANCE, DISTRIBUTION SYSTEM	0.2 PERCENT OF COST
OPERATION, DISTRIBUTION SYSTEM	BASED ON PUMP SIZED TO PUMP FLUID
OPERATION/MAINTENANCE - TURBINE RETROFIT	UTILITY SIMULATION MODEL
CAPITALIZATION INPUTS	EACH UTILITY
INCOME FROM SALE OF HEAT	BASE RATE 90 PERCENT OF RATE FOR NATURAL GAS IN AREA
CAPACITY CHARGES FOR LOST ELECTRICAL GENERATION CAPACITY	CUSTOMERS TREATED AS INTERRUPTIBLE LOADS
LOSS OF REVENUE FROM GAS SALES	NOT CONSIDERED IN OVERALL ECONOMICS
BUILDING CONVERSION COSTS	NOT CONSIDERED IN OVERALL ECONOMICS

The most promising site is Green Bay, where a large industrial process load as well as a commercial building heat and hot water load are all located within two miles of the Pulliam Power Plant. The large industrial load and low capital investment resulting from a small DHCS size combine to make the economics attractive. Positive net annual savings would be realized in two years (three-mill alternative) and seven years (two-mill alternative), based on highly competitive thermal rates, and would provide incentive for building owners to convert. This period could be reduced even further by considering municipal or joint financing mechanisms, although this would increase the institutional problems encountered.

Because of the concentration of estimated loads and the short distribution system, the most economically attractive alternative analyzed was the industrial park to be located near the Rock River Power Plant in the Janesville/Beloit area. At present, no industries have been identified as park occupants.

The next most promising site analyzed was Madison. The two alternatives included (1) a portion of the CBD and buildings heated by the Capitol Heating Plant and (2) the University of Wisconsin complex of buildings. Both analyses assumed that all customers would come on line during the first year of system operation. This would be an optimistic assumption for the CBD. In reality, the buildings would come on line over a time-phased period. Combined with the lack of any large industrial loads, this would tend to make the economics less desirable than illustrated.

The University of Wisconsin currently has two central boiler plants and a steam distribution system. Because of its distance from the Blount Street Power Plant, a substantial investment ($16,600,000) would be required to transport hot water to the central plants for distribution to the buildings. Costs for converting each building would also be substantial. These costs were not included in the economic analysis performed. Combined with a time-phased building conversion plan, these costs would represent a less desirable economic outlook.

The two remaining alternatives analyzed for the Janesville/Beloit have scattered concentrations of loads requiring extensive and costly distribution systems. The results of the economic analysis illustrate this situation, depicting long periods where the system would have negative accumulated savings.

COO-4981-1

DISTRICT HEATING AND COOLING SYSTEMS FOR COMMUNITIES THROUGH POWER PLANT RETROFIT AND DISTRIBUTION NETWORKS

PHASE I - IDENTIFICATION AND ASSESSMENT

FINAL REPORT

VOLUME II - DETAILED RESULTS

SEPTEMBER 1979

WISCONSIN STATE ENERGY OFFICE

PREPARED FOR:

U. S. DEPARTMENT OF ENERGY
CHICAGO OPERATIONS OFFICE
UNDER CONTRACT EM-78-C-02-4981

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FOREWORD

District heating is the use of one or more central heat sources to supply the low to moderate temperature energy needs (space and water heating) of an area through a distribution system. The central heat source can be either a heat-only boiler or an electric cogeneration (i.e., production of electric and thermal energy at a single site) facility. The heat is usually distributed through a system of underground insulated pipes to buildings that require the energy. The energy is delivered in the form of steam or high temperature, high pressure hot water and transferred to the buildings through one or more heat exchangers.

In many places in Europe, cogeneration facilities are used to produce both heat and electrical energy. In fact, this is becoming the dominant mode of space and domestic hot water heating in the urban areas of West Germany and the Scandinavian and Soviet bloc countries.

A cogeneration facility uses fuel much more efficiently than a conventional electric generating facility, which produces only electricity. In a typical Swedish cogeneration facility, between 20 and 25 percent of the fuel energy is transformed into electricity adn 45 to 55 percent of the fuel energy is delivered to the district heating system. Thus, in a cogeneration facility about 70 to 75 percent of the input fuel energy can be transformed into usable energy forms (electricity and hot water for space and/or water heating) compared with 30 to 35 percent usable energy (electricity) from a conventional power plant.

The energy conservation potential of a cogeneration facility is obvious. Space and water heating needs supplied through more efficient cogeneration district heating systems will free considerable supplies of scarce fossil fuels (natural gas and/or fuel oil) for other uses. The long-term economic benefits include more stable costs for space and water heating needs since these costs would be tied to the price of coal at the electric generating station rather than the

more rapidly escalating prices of natural gas and fuel oil. In an area with air pollution problems (such as a nonattainment area), a cogeneration district heating system might well enhance that area's ability to attract new industry. At present, an industry that depends on burning coal to supply its heat energy needs probably would not be allowed to locate in a nonattainment area. However, if these heat needs could be supplied by a district heating system, the industry would not have to burn coal and could locate in the nonattainment area.

To examine the feasibility of the district heating concept, the Department of Energy initiated a seven-phase program entitled "District Heating and Cooling Systems for Communities through Power Plant Retrofit and Distribution Networks." The initial phases of the program are aimed at identifying and evaluating potential sites, institutional problems and financial arrangements. Later phases are aimed at detailed design and construction of promising projects. Final phases are aimed at initial testing, startup and operation evaluation of the demonstration project.

This report contains the results of the Phase I Identification and Assessment Study for the State of Wisconsin. Study results are presented in three volumes:

- Volume I, Executive Summary,
- Volume II, Detailed Results,
- Volume III, Appendices.

The Phase I study was performed by the following team of state agencies, industries and utilities:

Contractor: Wisconsin Office of State Planning & Energy
Madison, Wisconsin

Subcontractors:

Honeywell Inc.
Energy Resources Center
Minneapolis, Minnesota

American Hydrotherm Corporation
New York, New York

Wisconsin Public Service Commission
Madison, Wisconsin

Madison Gas and Electric Co.
Madison, Wisconsin

Wisconsin Power & Light Co.
Madison, Wisconsin

Wisconsin Public Service Corporation
Green Bay, Wisconsin

Manitowoc Public Utilities
Manitowoc, Wisconsin

Wisconsin Electric Power Co.
Milwaukee, Wisconsin

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SECTION 1.0 INTRODUCTION

1.1 OBJECTIVES

The Phase I Identification and Assessment Study was aimed at surveying the State of Wisconsin to identify potential sites for a district heating system and evaluating these sites in terms of their technical, institutional and economic merits. Specific objectives of the study were to:

- Identify candidate plants and service areas,
  Perform an energy market analysis for selected areas,
- Identify and evaluate plant retrofit and distribution alternatives for the selected service areas,
- Identify and evaluate institutional problems within the infrastructure, and
- Perform an economic analysis for the candidate sites.

1.2 APPROACH

The overall methodology employed on the Phase I study is illustrated in Figure 1. Team members responsible for each task/subtask are also identified.

The overall approach consisted of surveying the State of Wisconsin to identify all existing intermediate and base-loaded electric generating facilities. Once identified, screening criteria were developed to narrow the list to the three most promising sites. For each of the three sites, an extensive market analysis was performed to identify and characterize thermal loads and survey potential users on their views and concerns on the concept. Parallel to this effort, each of the three sites was evaluated on its technical

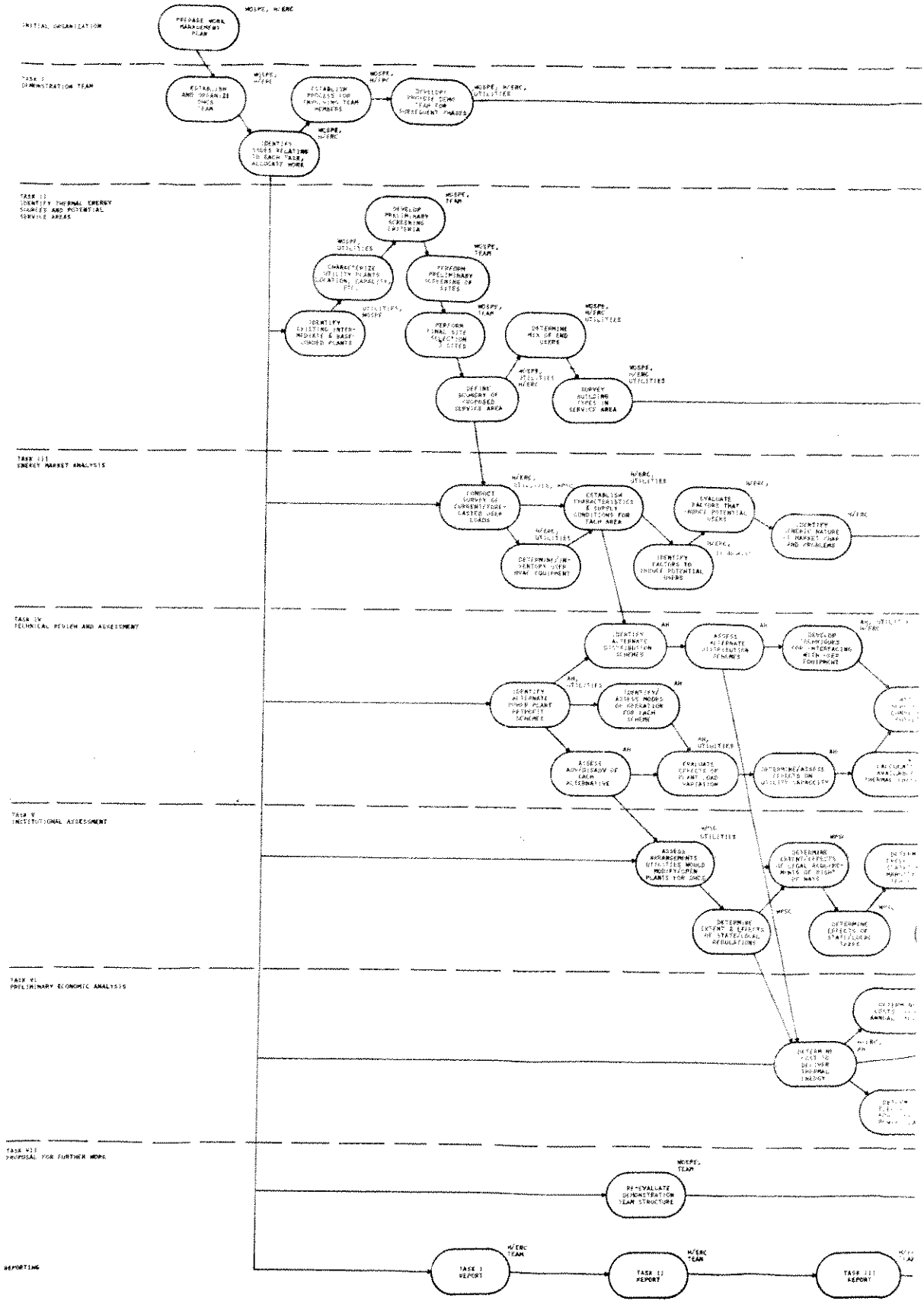
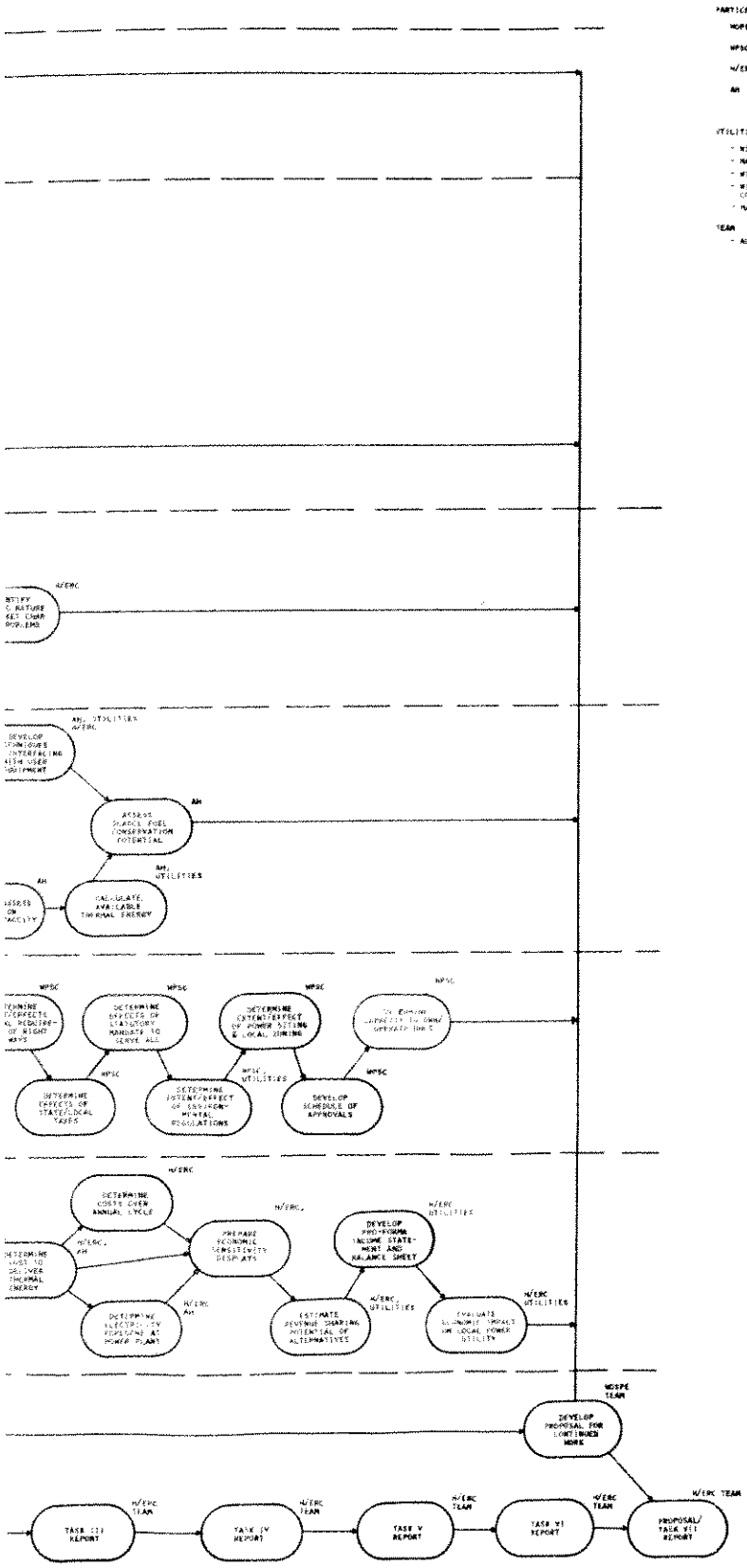


Figure 1. Phase 1 Study Approach, District Heating and Cooling Sys
Retrofit and Distribution Networks



ooling Systems for Communities through Power Plant

and institutional merits. The technical evaluation centered on identifying and evaluating utility plant retrofit schemes and distribution system alternatives to service the identified thermal market. The institutional analysis evaluated potential barriers such as environmental, distribution system right-of-way and legal issues within the infrastructure of the state, city and community. Finally, all previous aspects of the analysis were combined to determine the economic viability of each site.

SECTION 2.0 SITE SELECTION

2.1 INTRODUCTION

This section describes the process by which the team members selected existing intermediate/base-loaded electric generating stations with the greatest potential as heat sources for a District Heating and Cooling System (DHCS) as well as the results of this process.

2.2 SPECIFIC OBJECTIVES

The specific subtasks to be accomplished included:

- Identify all existing intermediate/base-loaded electric generating plants in Wisconsin.
- Develop preliminary screening criteria to prescreen these candidate sites.
- Perform the preliminary screening of these candidate sites.
- Characterize each site surviving the preliminary screening as to location, ownership, size, equipment, etc.
- Perform the final site selection using more detailed data.
- Define the proposed DHCS service area for each remaining final site.
- Determine the mix of end users within each service area.
- Survey the building types within each service area.

These subtasks were reviewed by team members during a review meeting and performed during two working meetings and the period between those meetings.

2.3 APPROACH

Task II objectives were primarily accomplished through the cooperative efforts of all team members during two working meetings. The team was comprised of members of the Wisconsin Office of State Planning and Energy, the Honeywell Energy Resources Center, American Hydrotherm Corporation, the Wisconsin Public Service Commission, and the five participating Wisconsin utilities: Wisconsin Power & Light Company, Wisconsin Public Service Corporation, Wisconsin Electric Power Company, Madison Gas & Electric Company, and Manitowoc Public Utilities. Team decisions were made by consensus. During discussion prior to consensus, development objections and/or reservations were addressed as directly and clearly as possible. The perspectives and information of every member of the team were also shared during the discussion.

2.4 IDENTIFICATION OF EXISTING INTERMEDIATE/BASE-LOADED PLANTS

The Wisconsin Office of State Planning and Energy (WOSPE) identified all existing intermediate/base-loaded electric generating plants in Wisconsin. The approximate location of each of these plants is shown in Figure 2. A summary of the operating characteristics of these plants is shown in Table I. No electric generating plants owned and operated by Northern States Power Company--a Minnesota-based utility that serves a small portion of northwestern Wisconsin--were included in this list. Northern States Power had indicated to WOSPE that they were presently investigating district heating potential in Minnesota and were not interested in participating in the Wisconsin program at this time.

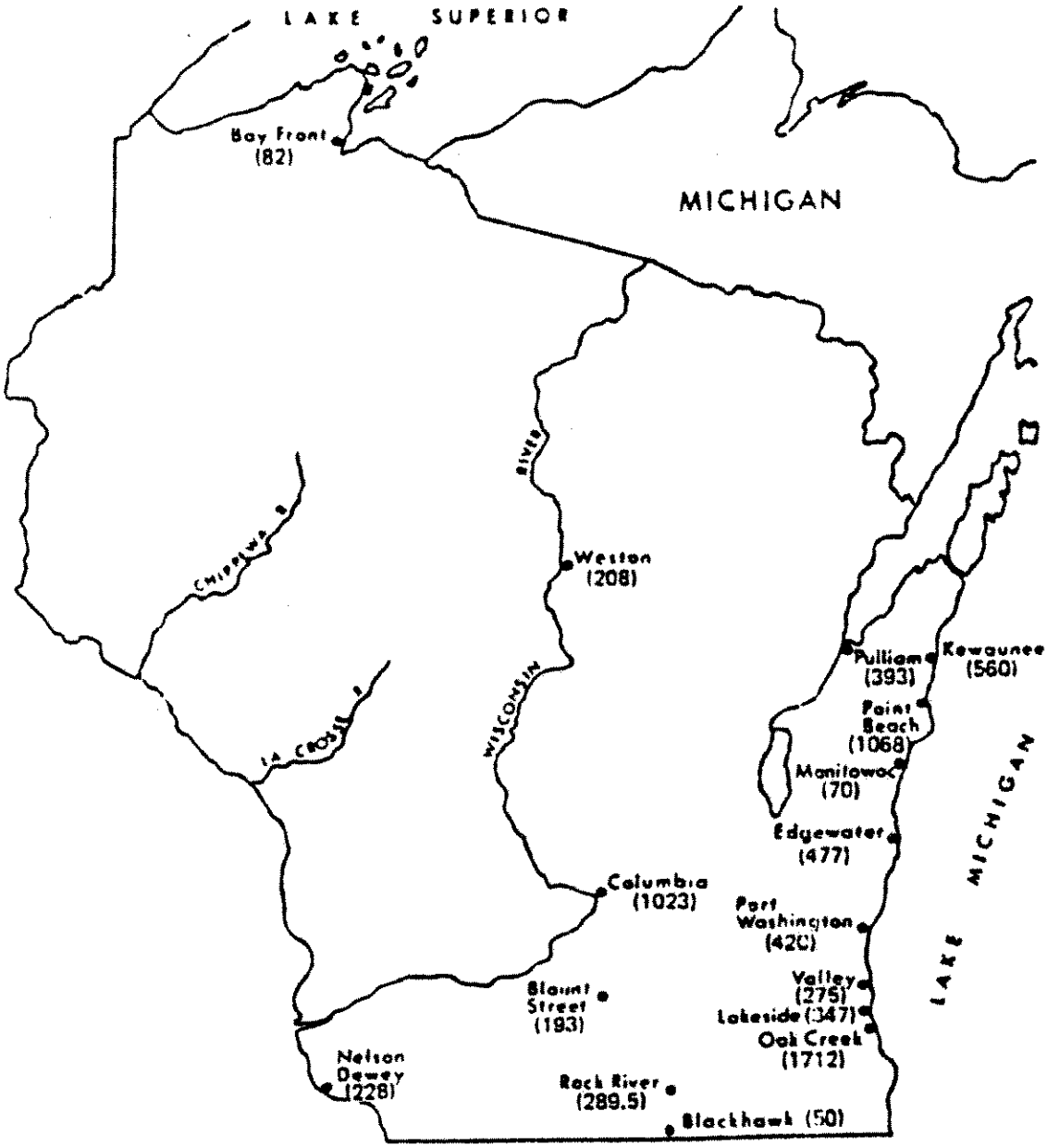


Figure 2. Major Power Plants in Wisconsin (Net Capacity, MW)

Table I. Existing Intermediate/Base-Loaded Electric Generating Plants in Wiscsonsin

FOSSIL-FUELED STEAM GENERATING PLANTS				
NAME OF PLANT	OPERATING UTILITY	CAPACITY (mW) 12/31/77	mW HR. GEN. 1977	CAPACITY FACTOR (PERCENT)
SOUTH OAK CREEK	WEPCO	1,170	4,852,453	47
NORTH OAK CREEK	WEPCO	550	1,717,044	39
COLUMBIA	*	556	2,952,208	61
EDGEWATER UNITS 1, 2, 3	WP&L	126	345,893	31
EDGEWATER UNIT 4	**	351	1,886,841	61
PORT WASHINGTON	WEPCO	400	1,355,956	39
PULLIAM	WPSC	392.5	1,764,971	51
LAKESIDE	WEPCO	310.8	243,544	9
VALLEY	WEPCO	269.7	1,126,692	48
NELSON DEWEY	WP&L	227.2	1,186,913	60
BLOUNT STREET	MG&E	194	427,389	25
ROCK RIVER	WP&L	150	546,870	42
WESTON	WPSC	135	608,460	51
BAY FRONT	LSDP	82.2	109,615	15
BLACK HAWK	WP&L	50	133,856	31
MANITOWOC	MUNICIPAL	69	207,994	34
NUCLEAR-FUELED STEAM GENERATING PLANTS				
†POINT BEACH		1,006	7,309,147	83
††KEWAUNEE		535	3,546,342	76

WEPCO - WISCONSIN ELECTRIC POWER COMPANY
WP&L - WISOCNSIN POWER AND LIGHT COMPANY
WPSC - WISCONSIN PUBLIC SERVICE COMMISSION
MG&E - MADISON GAS & ELECTRIC COMPANY
LSDP - LAKE SUPERIOR DISTRICT POWER COMPANY

*JOINTLY OWNED BY WP&L (39.3%), WPSC (38.9%) AND MG&E (21.8%)
**JOINTLY OWNED BY WP&L (68.2%) AND WPSC (31.8%)
†JOINTLY OWNED BY WEPCO (50%) AND WISCONSIN MICHIGAN POWER COMPANY (50%)
††JOINTLY OWNED BY WPSC (41.2%), WP&L (41.0%) AND MG&E (17.8%)

2.5 SCREENING CRITERIA

Preliminary screening criteria were developed prior to an initial organizational and team working meeting. These criteria were discussed and supplemented during a subsequent team meeting. The resulting list of selection criteria was divided into two categories: primary criteria and secondary criteria. The primary criteria were those judged to be of greatest importance in the selection of a potential cogeneration facility for a DHCS. The secondary criteria were those of either secondary importance in the selection process or of such a detailed nature as to be more useful in the technical analysis. The selection criteria are shown in Table II, which also indicates the criteria of greatest importance in the final site selection process.

2.6 PRELIMINARY SITE SELECTION

Using the selection criteria listed in Table II and the available information about the existing intermediate/base-loaded electric generating plants in Wisconsin, summarized in Table III, the team identified the existing plants having the highest potential for retrofit modificaiton to serve a DHCS. The last five plants in Table III are sited in rural or small town (Bay Front in Ashland, population about 9,000) areas and were immediately eliminated from consideration because of low thermal density. Four generating plants--Weston, Lakeside, Port Washington, and North and South Oak Creek--all showed some promise as DHCS sites, but were eliminated because of special considerations. The Weston Plant, south of Wausau, has a new unit scheduled to begin operation in 1982 as a cogeneration unit, supplying steam to industrial customers nearby. The consensus was that our efforts would be more fruitfully applied to other sites where cogeneration benefits could be higher. The Lakeside Plant was eliminated from further consideration because of its age and resulting high costs of operation as well as

Table II. Site Screening and Selection Criteria

PRIMARY CRITERIA	FINAL SITE SELECTION	TOO DETAILED	SECONDARY IMPORTANCE
THERMAL DENSITY--DISTANCE OF THE LOAD FROM THE GENERATING PLANT, TYPES OF EXISTING HEATING SYSTEMS, FUELS USED, ETC.	X		
REMAINING LIFETIME OF EXISTING GENERATING UNITS--AT LEAST 10 YEARS DESIRABLE	X		
ENVIRONMENTAL CONCERNS--POTENTIAL ENVIRONMENTAL BENEFITS THAT COULD BE DERIVED FROM COGENERATION	X		
UTILITY COMMITMENT TO COGENERATION	X		
RELIABILITY FACTOR--AT LEAST TWO EXISTING UNITS THAT COULD BE MODIFIED (BACKUP CAPABILITY)	X		
LOAD FACTOR--DOES THE PLANT QUALIFY OR COULD A DHCS MODIFIED PLANT QUALIFY UNDER THE DOE CRITERIA AS AN INTERMEDIATE/BASE-LOADED PLANT?	X		
CHANGES IN ECONOMICS CAUSED BY SUCH A PROPOSED MODIFICATION			
SECONDARY CRITERIA			
PLANT CAPACITY			X
PLANT OWNERSHIP			X
HOURLY ELECTRICAL DEMAND ON A WEDNESDAY NEAREST THE 15TH OF THE MONTH FOR EACH WINTER MONTH AND FOR A REPRESENTATIVE MONTH FOR FALL, SPRING AND SUMMER CONDITIONS	X		
TRADEOFF CURVES OF ELECTRICAL OUTPUT VERSUS POTENTIAL HEAT DELIVERY FOR EXISTING TURBINES	X		
MINIMUM TURBINE CHARACTERISTICS THAT WOULD ALLOW A REASONABLE RETROFIT MODIFICATION	X		

Table III. Information about Existing Wisconsin Electric Generating Plants Relating to DHCS Screening Criteria

	DISTANCE TO LOAD (MILES)	TYPE OF LOAD WITHIN 5 MILES	REMAINING LIFETIME (YEARS)	POTENTIAL ENVIRONMENTAL BENEFITS**	UTILITY COMMIT-MENT†	RELI-ABILITY (NO. UNITS)	1977 LOAD FACTOR (PERCENT)
BLOUNT STREET	<1	COMMERCIAL(HD)* RESIDENTIAL(MD)* INSTITUTIONAL(HD)	5-25	YES	YES	5	25
PULLIAM	<2	INDUSTRIAL(HD) COMMERCIAL(HD)	5-25	YES	YES	4	51
BLACK HAWK	<1	INSTITUTIONAL(HD) COMMERCIAL(MD)	5-10	YES	YES	2	31
ROCK RIVER	2-7	INSTITUTIONAL(HD) COMMERCIAL(MD)	10-20	?	YES	2	42
EDGEWATER	1-3	INDUSTRIAL(MD) COMMERCIAL(MD)	5-30	?	YES	2	53
VALLEY	<1	INDUSTRIAL(HD) COMMERCIAL(HD) RESIDENTIAL(HD)	20-25	YES	YES	2	48
MANITOWOC	<2	INDUSTRIAL(MD) COMMERCIAL(MD)	5-15	?	YES	4	34
N&S OAK CREEK	5-7	COMMERCIAL(MD) RESIDENTIAL(LD)*	5-20	YES	YES	4	45
PORT WASHINGTON	1-2	COMMERCIAL(MD) RESIDENTIAL(LD)	5-10	?	YES	2	39
LAKESIDE	2-5	INDUSTRIAL(HD) COMMERCIAL(HD) RESIDENTIAL(MD)	5	YES	YES	-	9
WESTON††	2-4	INDUSTRIAL(MD) COMMERCIAL(MD)	10-15	?	YES	-	51
NELSON DEWEY	-	RURAL	10-20	NO	-	-	60
COLUMBIA	-	RURAL	30	NO	-	-	61
BAY FRONT	1-3	COMMERCIAL(LD) RESIDENTIAL(LD)	5-15	NO	-	-	15
POINT BEACH	-	RURAL	30	NO	-	-	81
KEWAUNEE	-	RURAL	30	NO	-	-	76

*HD -- HIGH DENSITY; MD -- MEDIUM DENSITY; LD -- LOW DENSITY.
**IS THERE POTENTIAL FOR REDUCING OTHER AIR POLLUTION EMISSIONS IN THE AREA BY SUPPLYING THE POLLUTION SOURCES WITH AN ALTERNATE ENERGY SOURCE THROUGH A DHCS?
†FOR THOSE GENERATING PLANTS WHICH DEMONSTRATE SOME POTENTIAL AS A DHCS HEAT SUPPLIER, IS THERE A COMMITMENT BY THE UTILITY OWNER TO THE IDEA OF COGENERATION?
††ONE UNIT AT WESTON, PLANNED FOR OPERATION IN 1982, IS TO BE A COGENERATION UNIT.

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its short expected remaining lifetime. The low thermal density near the Port Washington Plant (population of Port Washington about 9,500) resulted in its elimination. Likewise, the North and South Oak Creek Plants, sited in a predominantly residential area, were quite far from the high density thermal demand centers of Racine (about 7 miles) and downtown Milwaukee (about 10 miles), and they were also eliminated from consideration.

The remaining seven intermediate/base-loaded electric generating plants--Blount Street in Madison, Pulliam in Green Bay, Black Hawk in Beloit, Rock River between Beloit and Janesville, Edgewater in Sheboygan, Valley in Milwaukee and Manitowoc in Manitowoc--were considered to have the highest potential for retrofit modification to serve a DHCS. The utilities were asked to supply additional data on these seven plants at a team meeting for use in the final site selection process.

2.7 FINAL SITE SELECTION

Additional data were obtained from the utilities on each of these seven generating plants and are included in Appendix A. These data, along with maps of the area surrounding each generating plant, were used by team members to perform the final site selection. The team was able to reach a consensus on each decision. The most important criteria used in the final selection process were:

- Load factor--does the plant qualify or would a DHCS modified plant qualify under the DOE criteria as an intermediate/base-loaded plant?
- Thermal density in the surrounding area--residential, commercial and industrial.

- Expected remaining lifetime for the plant.
- Potential environmental advantages--is the plant presently in a nonattainment area?
- Degree of utility commitment.

Two generating plants were eliminated from further consideration during the initial discussion--the Valley Plant in Milwaukee and the Manitowoc Plant. Both of these plants presently supply to their customers heat in the form of steam as well as electricity. The Manitowoc Plant supplies steam to a nearby brewery, and the Valley Plant supplies steam to a district heating system in downtown Milwaukee. Since each plant already supplied the maximum amount of steam to its heat customers, the only feasible retrofit would have been to increase the boiler capacity at each plant in order to increase the steam supply. In the case of Manitowoc, this was not possible because of phsyical limitations. The Valley Plant was prevented from adding boiler capacity because of air pollution restrictions in the Milwaukee area. However, team members agreed that continuing participation of the Manitowoc Municipal Utility and the Wisconsin Electric Power Company in the Wisconsin DHCS Program was imperative. Their experience with existing district heating or heat delivery systems would be very beneficial to our future analysis.

The suggestion was made that the Rock River Plant and the Black Hawk Plant be considered together as potential heat sources for a DHCS, which would serve both Janesville and Beloit as well as an industrial park between the two cities. The consensus was that this idea made a lot of sense since the heat transmission line between the two cities would represent only a small portion of the entire distribution system. The number of potential customers would be larger since both cities would be involved.

With this modification the task of final site selection became relatively straightforward. The three sites with highest potential were selected immediately.

Green Bay--Served by the Pulliam Plant

Much of the potential demand in the Green Bay service area would be represented by industries that would use the heat for process heating as well as space/hot water heating needs. In addition, some commercial and high-density residential users exist in downtown Green Bay, which is in the early stages of a renovation and revitalization effort. Most of the residential housing in Green Bay is scattered single-family units--difficult and expensive to serve with a district heating system.

Madison--Served by the Blount Street Plant

This area probably contains the most diverse mix of potential users of the three service areas. Industrial users would be a relatively small component. There are a number of potential institutional users. The state government buildings in downtown Madision are served by a steam distribution system fed by head-only boilers located less than two blocks from the Blount Street Plant. The University of Wisconsin-Madison campus is less than two miles from the Blount Street Plant. The Madison Area Technical College (MATC) has not made final selection of a site for its new combined campus, which might be a potential user. Like Green Bay, the downtown Madison area is undergoing revitilatization, with the State Street Mall, the Capitol Concourse and the Madison Civic Center being the most prominent changes. In addition to the commercial users that could be served, downtown Madison has some high-density residential development as well.

Janesville/Beloit--Served by the Rock River and Black Hawk Plants

As in Green Bay, the Janesville/Beloit area has little high-density residential development. Commercial demand is comparable to Green Bay, and the industrial demand is probably much less. The industrial concerns of Janesville

and Beloit, generally much smaller than the large paper mills of Green Bay, may be more willing to use a district heating system since their capital investment in in-plant heat delivery systems would be significantly less than that of a major paper mill. In addition, there is an institutional customer, Beloit College, with an existing low pressure steam heating system. Beloit College has already indicated to Wisconsin Power & Light Company that they would be interested in using heat from any potential district heating system.

The Sheboygan area (Edgewater Plant) has the smallest potential heat demand of the final four areas considered and was identified as the first alternate in case an insurmountable difficulty was encountered at an early stage of analysis of the three primary sites.

The team members agreed that no reliable comparative ranking among the three primary sites could be done in the absence of market, technical, institutional and economic analyses. The only meaningful ranking that could be accomplished during the site selection task was what has been done--selection of the three best sites from all the potential sites in Wisconsin.

Preliminary boundaries were developed for the DHCS service areas in Madison and Green Bay. These preliminary service areas are shown in Figures 3a and 3b. Final delineations of these service areas, as well as the more complex Janesville/Beloit service area, will result from the Energy Market Analysis and the Technical Review and Assessment.

2.8 CONCLUSIONS

In summary, three areas in Wisconsin have been identified as having high potential for a DHCS served by heat from an existing electrical generating

Figure 3a. Preliminary Service Area, Madison, Wisconsin

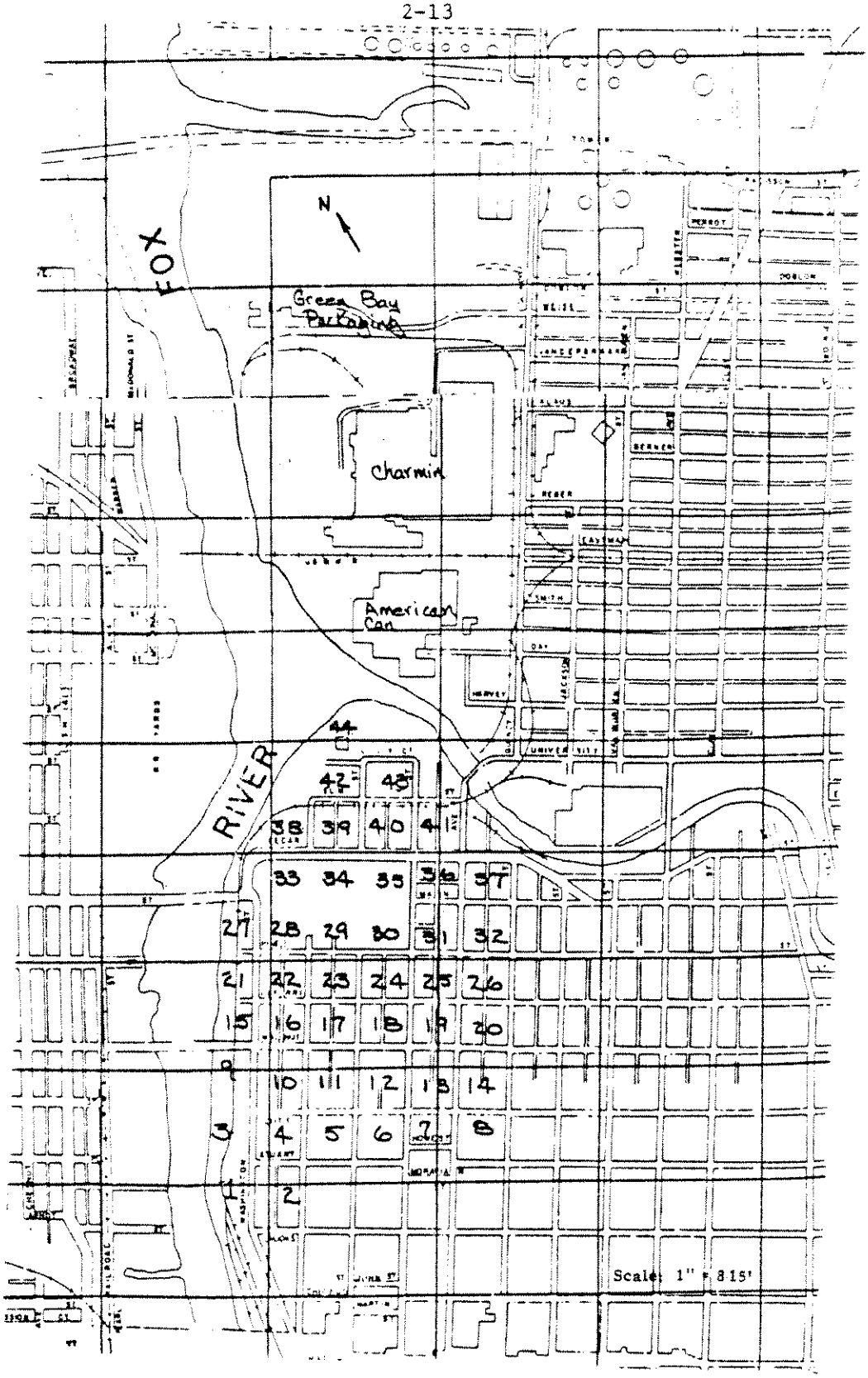


Figure 3b. Preliminary Service Area, Green Bay, Wisconsin

plant. They are Madison, Green Bay and Janesville/Beloit. An additional encouraging factor in each instance is that the utility serving the area is strongly committed to this concept if it can be demonstrated that it is economically and institutionally acceptable.

SECTION 3.0 ENERGY MARKET ANALYSIS

3.1 INTRODUCTION

The results of the energy market analysis are presented in this section and described separately for each of the three selected sites--Green Bay, Janesville/Beloit and Madison. Potential service areas identified are characterized by present and future thermal loads, types of heating, hot water and air conditioning equipment, types of buildings and supply conditions for thermal energy. Finally, all three sites are anlayzed with respect to factors that would induce potential users to subscribe to the DHCS.

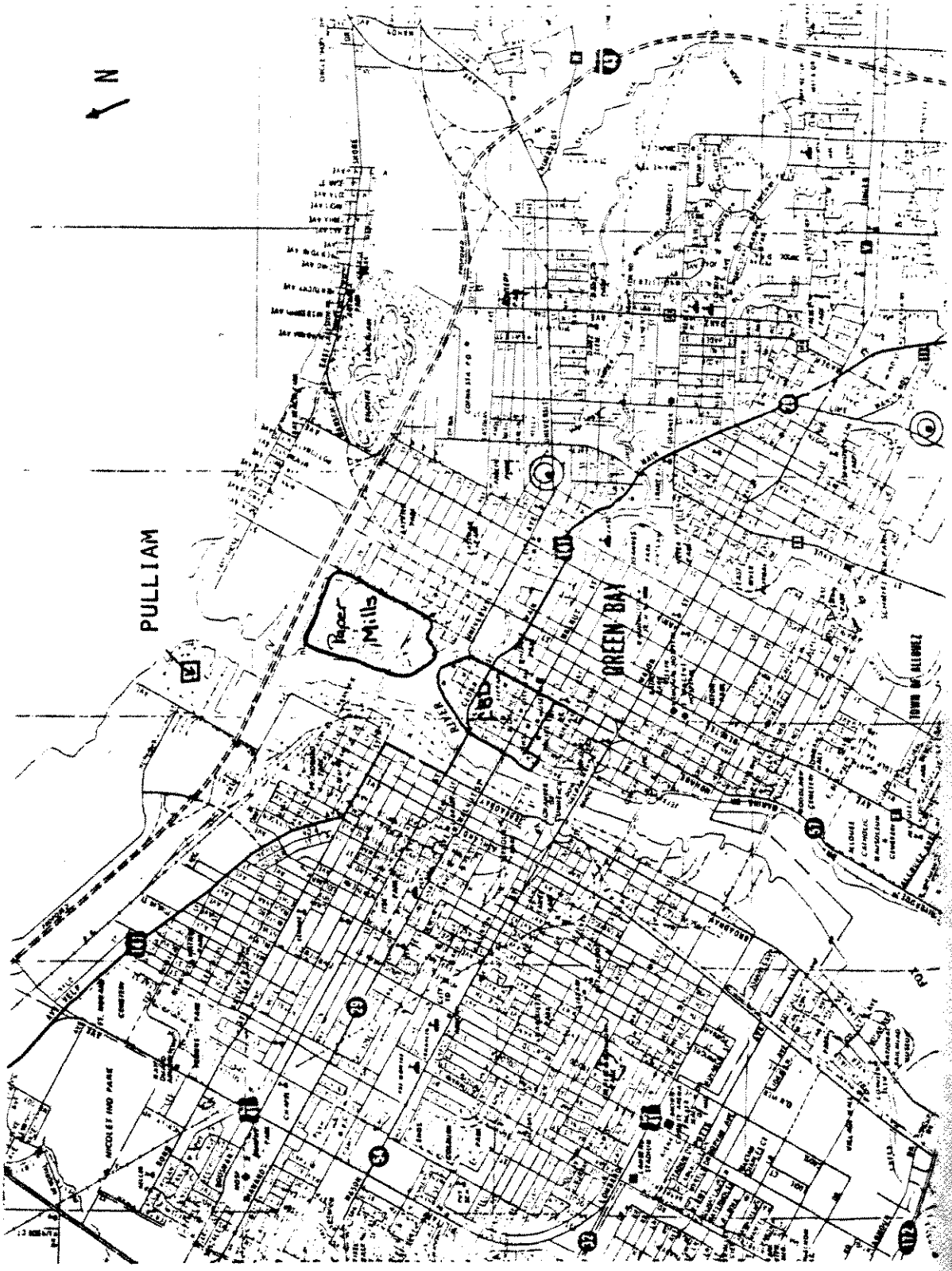
3.2 GREEN BAY

Green Bay is located in Brown County in northeastern Wisconsin at the junction of the Fox and East Rivers, which empty into Green Bay on Lake Michigan (Figure 4). The city covers 44 square miles and has a population of 89,154 (1977 estimate), which is expected to increase to 92,000 by 1980.

The principal industry of Green Bay is paper making, with 11 mills of various sizes located in the area. In addition, there are some 25 plants in which food and kindred products are processed for national and foreign markets.

Potential Service Areas

The Pulliam Power Plant is located on the west bank of the Fox River at the point where it flows into Lake Michigan (Figure 4). Because the river is navigable by ships that ply the Great Lakes and the world's seaways, bridges


N
PULLIAM
Paper Mills
GREEN BAY
FOX
RIVER

that are not high enough to permit their passage are either lift or swing-out bridges. This is an important consideration in regard to piping for a DHCS. All bridges on the East River are stationary.

The thermal market in the immediate area of the power plant can be described as follows:

- A few large industries are located on the west bank of the Fox River (the same side as the power plant). These industries are scattered along a six-mile stretch of the river rather than concentrated in one location. Further, the industries are of various types (i.e., steel fabricating, vegetable canning, a paper mill and a cement plant). Some, such as the cement plant, have requirements for high temperature process heat.
- The area adjacent to the power plant and along Lake Michigan has been set aside for a future industrial park. Currently, the area is vacant, but represents a significant future load.
- The area beyond the river bank contains scattered small commercial buildings and some single-family residences. The area further to the west contains primarily single-family residences.
- Immediately across the river from the power plant are three large paper mills concentrated in an Industrial Area that is 3/4 mile long by 1/2 mile wide.
- The area beyond the paper mills and on the same side of the East River contains scattered commercial building and single-family residences.
- The Central Business District (CBD) is located on the northern tip of land between the Fox and East Rivers.
- The area south of the CBD contains scattered small commercial buildings, multifamily and single-family residences.

Areas Selected for Detailed Analysis

The areas selected for detailed analysis are illustrated in Figure 4 and include the Industrial Area (three paper mills) located across the Fox River from the power plant and the Central Business District.

The three paper mills are concentrated in a small area and use a large amount of process steam and process hot water. Boiler makeup water is extracted from the city water system and process water from the Fox River.

The Central Business District offers a concentration of multistory retail stores, office buildings, hotel and city-county buildings. The area is currently being renovated (see future loads) and offers even greater potential for future markets for a DHCS.

The remaining areas briefly surveyed were rejected for further detailed analysis at the present time because of their low thermal densities. The two areas in Green Bay that have a substantial thermal demand are the Central Business District and the paper mills.

Central Business District--Buildings within the Central Business District almost exclusively use natural gas for space and hot water heating. Thermal requirements for this area were derived using actual gas consumption data (1977-1978) supplied by Wisconsin Public Service Corporation of Green Bay.

Load data for the area were computed using an efficiency factor of 75 percent and are summarized by block and month in Table IV. Block numbers correspond to the block numbers on Figure 5.

Table IV. Current Load (Btu x 10^9)

Block	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
1	1.347	1.264	1.024	.897	.476	.311	.316	.327	.389	.545	.626	1.104	8.628
2	1.425	1.156	.874	.550	.168	.012	.004	.007	.019	.130	.251	.372	4.969
3	Vacant Block												
4	.748	.706	.637	.459	.194	.116	.067	.053	.077	.182	.292	.613	4.141
5	.363	.257	.253	.290	.106	.032	.002	.005	.004	.010	.034	.193	1.548
6	.029	.030	.030	.021	.015	.007	.003	.004	.004	.005	.010	.023	.179
7	1.055	1.078	1.181	.851	.623	.526	.389	.161	.234	.426	.537	.962	8.024
8	Load Nill												
9	1.420	1.252	.988	.625	.384	.129	.107	.084	.116	.328	.580	1.124	7.140
10	2.923	2.782	2.354	1.968	.932	.523	.467	.530	.569	.674	1.880	2.037	17.641
11	1.701	1.753	1.883	1.237	.800	.296	.060	.048	.056	.208	.575	1.263	9.881
12	1.588	1.660	1.747	1.119	.737	.377	.053	.046	.053	.124	.448	1.334	9.286
13	.807	.672	.638	.416	.278	.113	.018	.009	.009	.061	.178	.352	3.623
14	.929	.563	.592	.410	.223	.148	.017	.010	.022	.025	.257	.535	3.814
15	.411	.530	.316	.215	.074	.019	.025	.012	.018	.090	.155	.350	2.207
16	3.276	2.781	2.071	1.560	.503	.090	.099	.101	.164	.820	1.168	2.317	14.952
17	2.297	2.064	1.640	1.201	.456	.081	.045	.048	.139	.495	.942	2.015	11.467
18	1.513	1.500	1.192	.918	.524	.550	.751	.588	.544	.365	.491	1.030	10.064
19	.540	.677	.499	.445	.341	.135	.066	.059	.073	.124	.289	.563	3.773
20	.310	.366	.265	.263	.134	.047	.046	.018	.020	.081	.114	.296	1.962
21	.268	.262	.181	.122	.044	.027	.022	.032	.038	.051	.053	.220	1.319
22	1.892	1.766	1.367	.976	.521	.329	.338	.347	.410	.620	.853	1.484	10.904

Table IV. Current Load (Btu x 10^9) concluded

Block	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
23	3.859	3.099	2.581	2.017	1.301	1.092	.860	.846	.797	1.432	1.886	2.459	22.230
24	.365	.386	.330	.268	.177	.060	.025	.022	.025	.026	.215	.341	2.241
25	.426	.476	.325	.233	.178	.065	.035	.028	.026	.070	.164	.348	2.372
26	Load Nill												
27	.706	.651	.570	.501	.309	.278	.248	.251	.256	.242	.332	.393	5.041
28	1.078	1.054	.724	.486	.098	.229	.086	.087	.082	.198	.381	.751	5.328
29	1.836	1.589	1.301	1.064	.594	.335	.236	.308	.405	.629	.935	1.584	10.841
30	1.082	1.255	.813	.775	.348	.019	.006	.004	.010	.017	.206	.765	5.300
31	.813	.583	.620	.475	.314	.058	.011	.005	.274	.402	.300	.423	4.279
32	.467	.508	.449	.189	.095	.018	.011	.010	.012	.062	.119	.407	2.347
33	.706	.651	.570	.501	.309	.241	.248	.251	.256	.243	.332	.393	5.041
34	.706	.651	.570	.501	.309	.241	.248	.251	.256	.243	.332	.393	5.041
35	Vacant Block												
36	.904	.858	.712	.614	.428	.211	.199	.176	.226	.421	.510	.785	6.044
37	.624	.386	.355	.269	.116	.026	.028	.026	.036	.189	.065	.147	2.277
38	1.150	1.058	.918	.794	.490	.382	.404	.397	.404	.384	.531	.668	7.581
39	.565	.422	.242	.307	.046	.051	.009	.009	.017	.104	.173	.292	2.234
40	.439	.413	.301	.217	.050	.023	.025	.023	.030	.072	.137	.335	2.065
41	.452	.343	.486	.212	.055	.033	.007	.006	.015	.060	.119	.415	2.199
42	2.790	2.460	2.130	1.215	.630	.180	.045	.090	.330	.900	1.725	2.490	15.000
43	.694	.705	.524	.425	.144	.022	.002	.002	.028	.093	.216	.436	3.290
44	1.350	1.230	1.065	.608	.315	.090	.023	.045	.165	.450	.863	1.245	7.500
Totals	45.041	41.897	35.318	26.214	13.839	7.522	5.651	5.426	6.608	11.601	19.274	33.257	238.773

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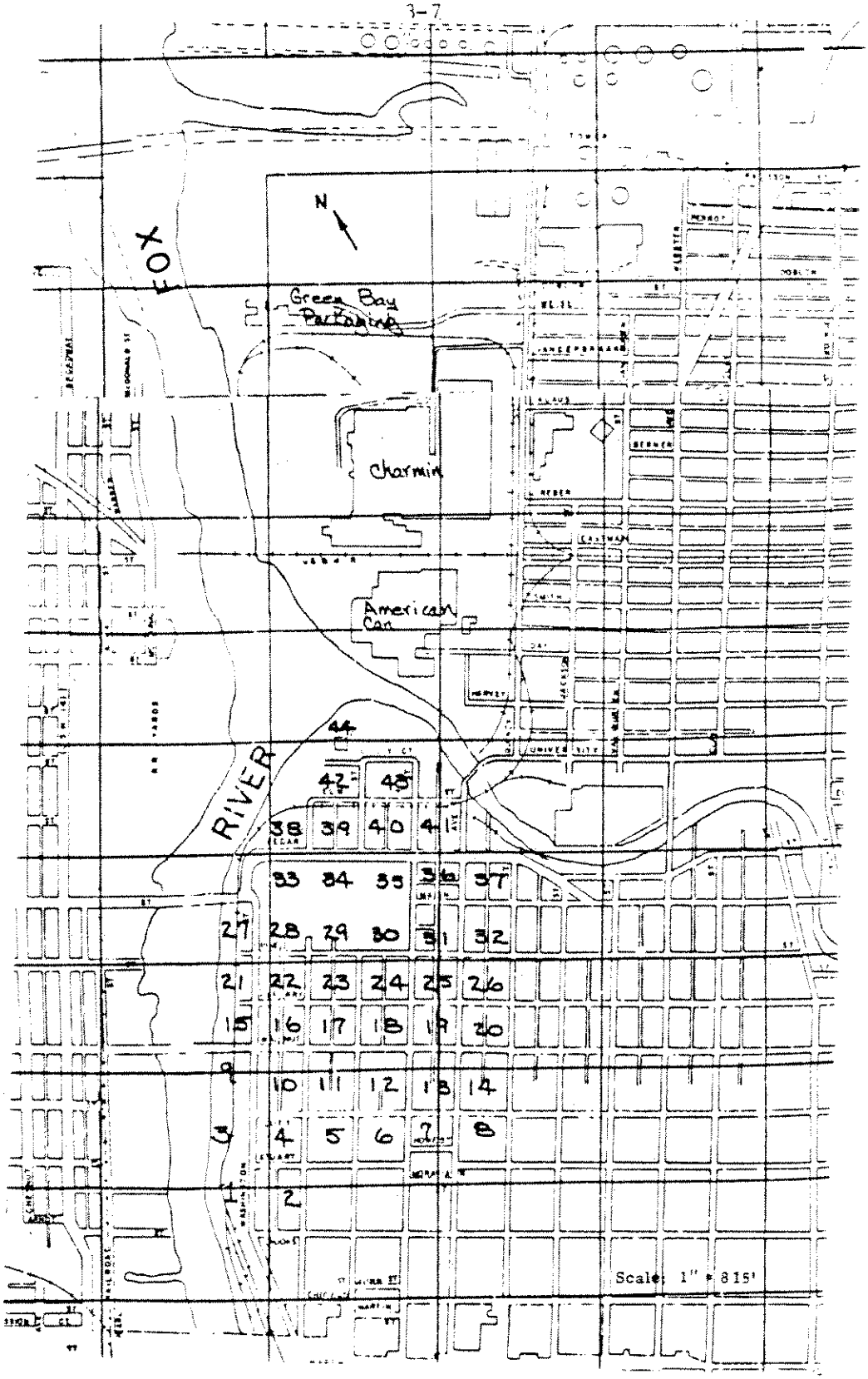


Figure 5. Green Bay Selected Service Area

Peak Hour Demand--Peak hour demand was estimated by determining the peak day load and then calculating the maximum hourly load based on the minimum temperature. During January 1978, the following conditions prevailed for Green Bay.

- Degree-day hours for month 1658
- Maximum degree-day hours for day 66
- Minimum temperature, January 30 -14°

The maximum daily load was determined to be:

$$= \frac{\text{Max. degree-day hours for day}}{\text{degree-day hours for month}} \times \text{monthly load}$$

$$= \frac{66}{1658} \times 45.041 \times 10^9 \frac{\text{Btu}}{\text{day}}$$

The peak hour load can then be estimated:

$$\frac{\text{degree-day hours (based on min. temp.)}}{\text{degree-day hours (max. day for month)}} \times \frac{\text{max. daily load}}{24}$$

$$= \left(\frac{79}{66}\right)\frac{\text{DD}}{\text{DD}} \left(\frac{1 \text{ day}}{24 \text{ hours}}\right) (1.79295 \times 10^9 \frac{\text{Btu}}{\text{day}}) = 0.0894 \times 10^9 \frac{\text{Btu}}{\text{hour}}$$

Industrial Area

Three paper mills, Green Bay Packing, Inc., Charmin Paper, Inc., and American Can Company, are located in a concentrated area immediately north of the downtown business district (Figure 5).

Each of the three plants operate 24 hours per day, seven days per week, with shutdown occurring only on scheduled maintenance days and during holidays. Plant shutdown time is approximately 22 days per year.

The mills require a substantial amount of steam and hot water for process use. Since a substantial amount of the steam is used in processes where the condensate is not returned, there is a large requirement for boiler makeup water. Currently, makeup water is taken from the city water system at an average yearly temperature of 50°F.

There also is a large requirement for hot water for process use. Water for this use is taken from the Fox River at an average yearly temperature of 45°F and heated to 140°F.

Water requirements for the paper mills were obtained from data available at Wisconsin Public Service Corporation and conversations with paper mill representatives. Because individual data is proprietary, only totals are given. Water consumption includes:

- Boiler makup - 1.20×10^6 gallons/day
- Process water - 9.00×10^6 gallons/day

Based on boiler makeup water being heated to 300°F and process water to 140°F, the water consumption can be translated into the following thermal loads:

- Boiler makeup - 2.5×10^9 Btu/day
- Process water - 7.125×10^9 Btu/day

The load is constant with respect to month, except for holidays and scheduled plant shutdown periods.

Peak Hour Demand--Since the paper mills operate continuously except for holidays and scheduled plant shutdown period, the peak hour demand is the average load over the day:

- Boiler makeup - 0.104×10^9 Btu/hour
- Process water - 0.297×10^9 Btu/hour

Cooling Load--Little emphasis was initially placed on the potential cooling load for two reasons. First, it was estimated to be low in comparison to the space heating and hot water load. Second, the majority of the space cooling load was estimated to be supplied by small electric window units and central electric chillers (a fact later borne out by the HVAC analysis). In this case, a sizable retrofit cost would be experienced in switching to absorption cooling equipment.

Rather than expending time and effort identifying all cooling loads, only large loads in buildings amenable to central absorption systems were identified. For Green Bay, this consisted of one large shopping plaza having:

- Cooling load - 25×10^6 Btu/hour
- Operational schedule - April 15 to September 30,
  10:00 a.m. to 9:00 p.m., Monday-Saturday;
  11:00 a.m. to 5:00 p.m., Sunday

Forecasted Future Load--A substantial future load exists for the Green Bay Central Business District. Appendix B contains a detailed analysis of this load, its magnitude and distribution. A summary of the additional load, on a block by block, month by month basis, is contained in Table V. The peak hourly load is estimated to be 0.038×10^9 Btu/hour.

Load Summary--A summary of the current and forecasted loads and peak hour loads are summarized in Table VI.

Table V. Future Load Data (Btu x 10^9)

Block	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
1													
2													
3													
4													
5													
6													
7	1.621	1.417	1.249	.734	.400	.149	.076	.099	.228	.557	1.019	1.451	9.242
8													
9	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
10	.783	.688	.602	.354	.191	.070	.034	.045	.108	.267	.490	.700	4.326
11													
12													
13													
14													
15	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
16	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
17	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
18													
19													
20													
21	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
22	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289

Table V. Future Load Data (Btu x 10^9) concluded

Block	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
23	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
24	.246	.246	.189	.111	.060	.022	.011	.014	.034	.084	.154	.220	1.358
25	.246	.246	.189	.111	.060	.022	.011	.014	.034	.084	.154	.220	1.358
26													
27	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
28	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
29													
30													
31	.369	.324	.284	.167	.090	.033	.016	.021	.051	.126	.231	.330	2.037
32	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
33													
34													
35	.369	.324	.284	.167	.090	.033	.016	.021	.051	.126	.231	.330	2.037
36													
37	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
38													
39	.429	.377	.330	.194	.106	.040	.020	.026	.061	.147	.270	.384	2.443
40	.429	.377	.330	.194	.106	.040	.020	.026	.061	.147	.270	.384	2.443
41	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
42													
43	.369	.324	.284	.167	.090	.033	.016	.021	.051	.126	.231	.330	2.037
44	1.621	1.417	1.249	.734	.400	.149	.076	.099	.228	.557	1.019	1.451	9.242
Totals	11.450	10.108	8.806	5.177	2.805	1.035	0.512	0.674	1.591	3.913	7.177	10.240	63.991

Table VI. Load Summary, Green Bay

	BTU x 10^9												
Load	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
CBD	45.04	41.90	35.32	26.21	13.84	7.52	5.65	5.43	6.61	11.60	19.27	33.26	238.77
Industrial	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	3465.00
TOTAL	333.79	330.65	324.07	314.96	302.59	296.27	294.40	294.18	295.36	300.35	308.02	322.01	3703.77
Future CBD	11.45	10.11	8.81	5.18	2.81	1.04	.51	.67	1.59	3.91	7.18	10.24	63.99

Peak Hour Demand

Current

- CBD 089. x 10^6 BTU/Hr
- Industrial 401. x 10^6 BTU/Hr

Future

- CBD 038. x 10^6 BTU/Hr

Fuel Used

CBD	Natural Gas	100%
Industrial	Natural Gas	17%
	#6 Fuel Oil	17%
	Coal	66%

The building types within the CBD are nearly all commercial (retail store, the shopping plaza, office buildings, etc.). A small number (4 out of 140) are hotels/motels. Currently there is only one high-rise residential build in the service area.

Future additional loads within the CBD (projected by 1985) will be a mixtur of commercial, hotel/motel and multifamily. No future loads are specified for the industrial park area. Currently, there is no construction in this area. Projections for the near future (by 1985) would be speculative since no tenants have been identified.

HVAC Inventory--Data characterizing the type and age of heating, hot water and air conditioning equipment were collected and analyzed for 28 buildings (approximately 20 percent of total) in the Central Business District. Detailed data are contained in Appendix C. A summary of the types of HVAC equipment is contained in Table VII; the age distribution in Table V.

The vast majority (82 percent) of the buildings have natural gas-fired boilers as a source of space heating. Of these, about 66 percent use stea for distribution and 34 percent use hot water. These results seem to correlate with the general age of the buildings in the Central Business District. Many of the buildings date back to the early 1900s (Figure 6). Steam was used in most large buildings built before 1960. Since then many new buildings have been designed for hot water space heating.

Gas-fired hot water heaters are used in a majority of the buildings. In buildings having a large hot water requirement (i.e., hotels/motels), stea or hot water heat exchangers are used.

The majority of the air conditioning equipment consists of small window units, which is indicative of the general age of the buildings. Larger

Table VII. HVAC Inventory Summary

	Number	Percentage
• Heat Source		
Boiler	23	82
Gas Forced Air	4	14
Electric	1	4
• Distribution		
Steam	14	50
Hot Water	9	32
Air	5	18
• Hot Water		
Steam Exchanger	5	18
Hot Water Exchanger	8	29
Gas	15	54
• Air Conditioning		
Electric	27	96
Absorption	1	4

Table VIII. Heating System Age Summary

Age	Number	Percent
0-5	7	23
6-10	5	17
11-15	2	7
16-20	5	17
21-25	4	13
26-30	5	17
31	4	13

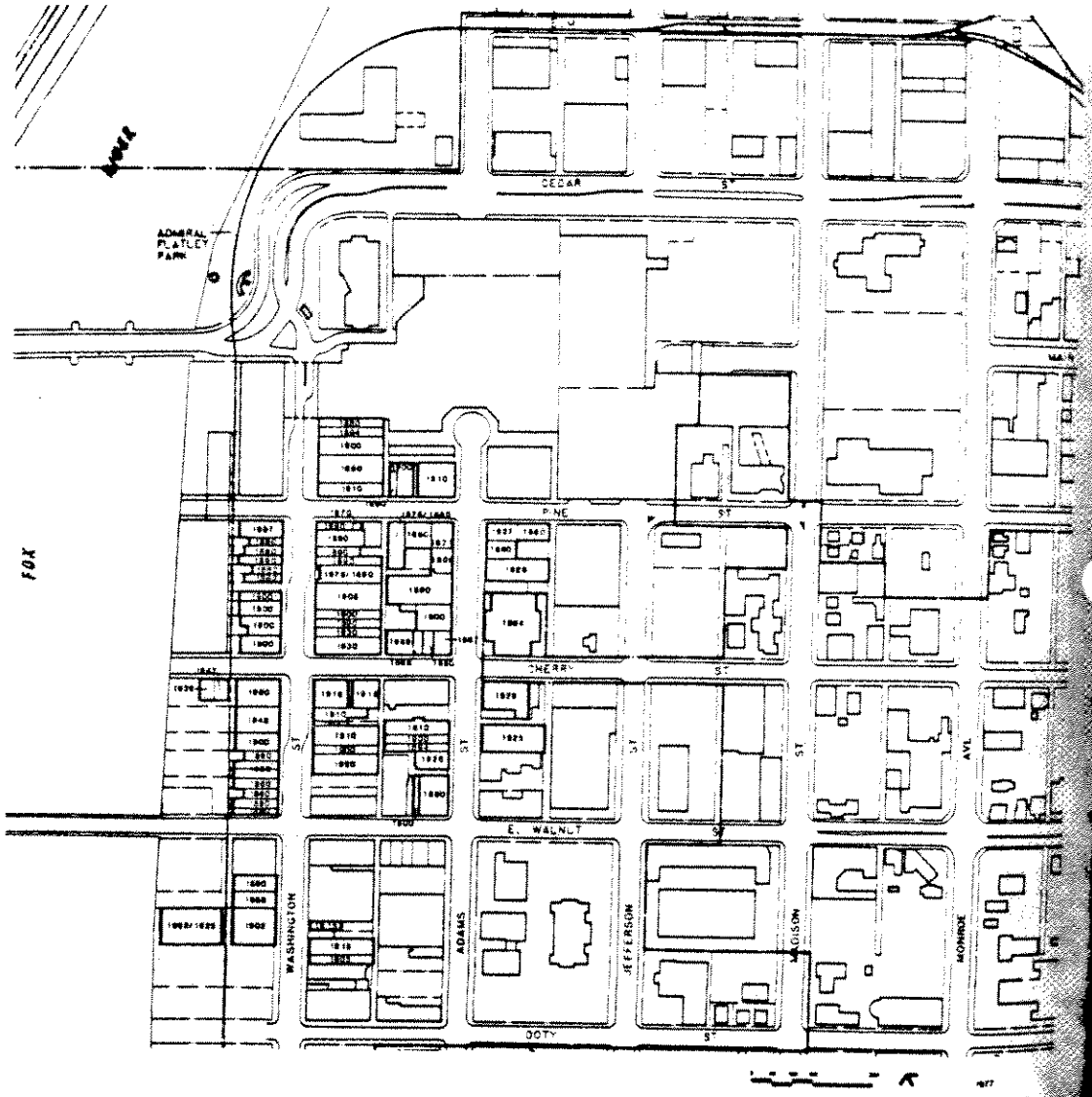


Figure 6. Building Age, Green Bay CBD

department stores and the shopping plaza have central electric chillers. One building contains a central absorption unit, but it is scheduled to be removed because of operational problems.

3.3 JANESVILLE/BELOIT

The Janesville/Beloit area is located in southern Wisconsin along the Rock River which flows southward into Illinois. The cities are in Rock County, population 132,000 (1970), and are separated by 10 miles. The 1977 population of Janesville is 49,656 and Beloit, 36208.

Potential Service Areas

Two power plants exist in the service area, the Black Hawk Plant in Beloit and the Rock River Plant midway between the two cities. Figure 7 shows the location of the two cities in relation to each other, the Central Business Districts (CBDs) and the power plants.

The thermal market in this area can be described as:

- Industry in the vicinity of Janesville,
- Industry in Beloit,
- Industry along the freeway east of Beloit,
- Janesville CBD,
- Beloit CBD,
- Schools,
- Residential areas.

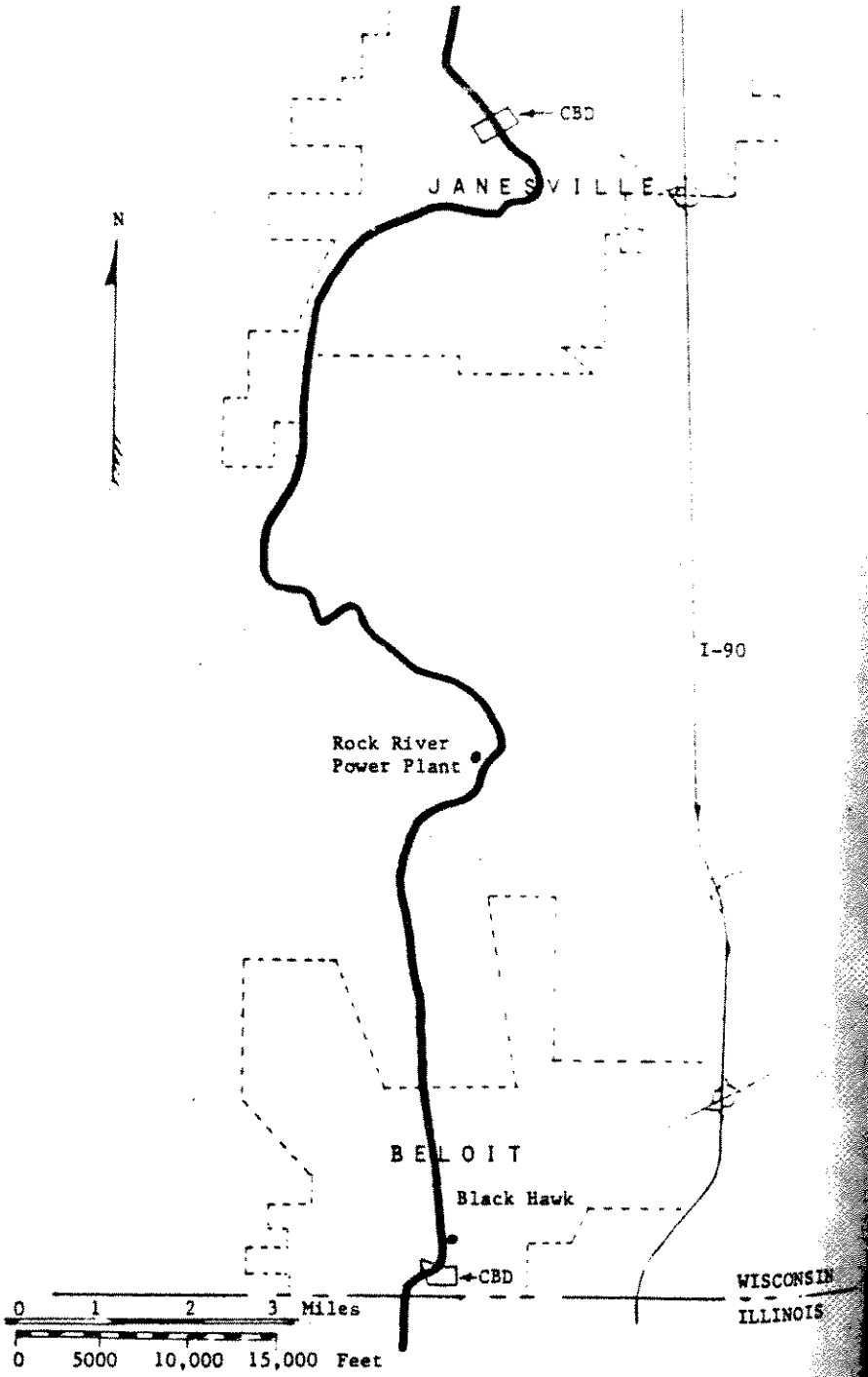


Figure 7. Janesville/Beloit Area

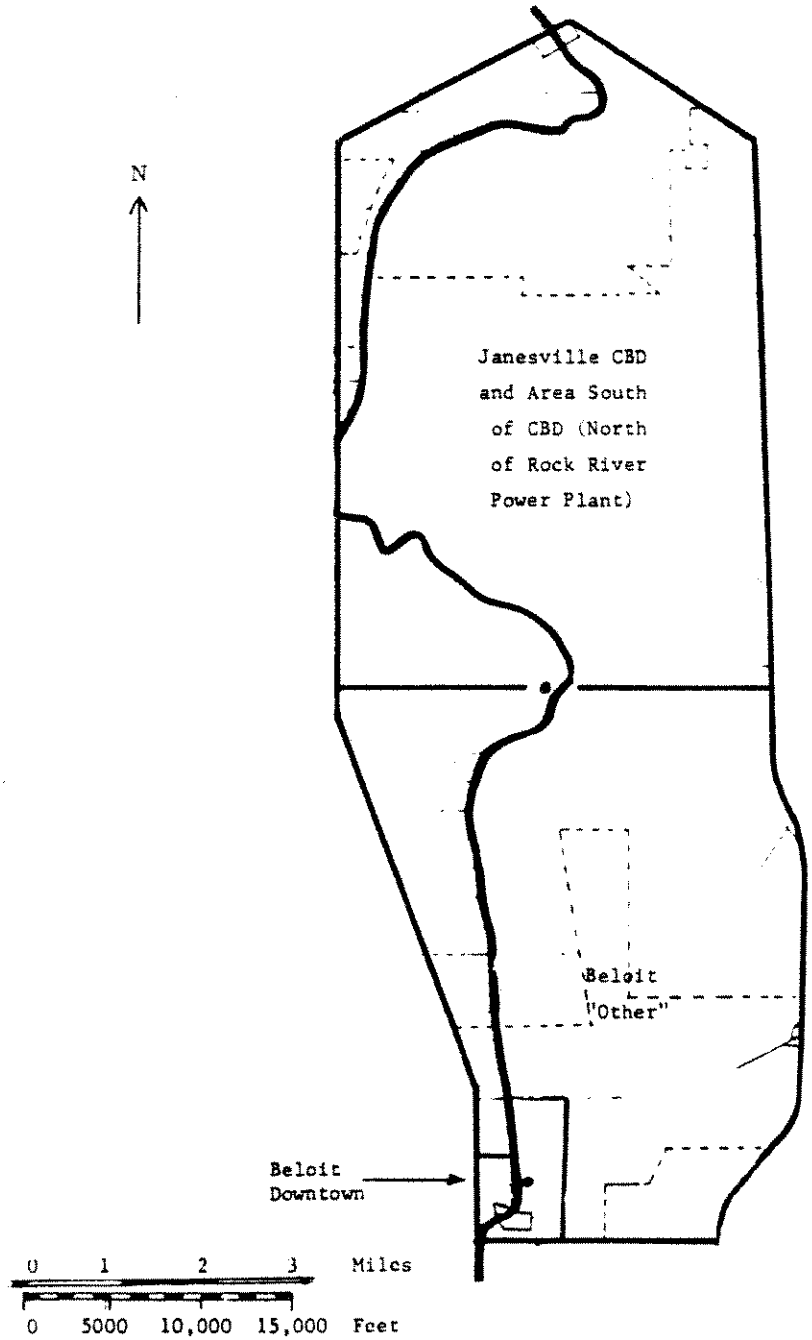


Figure 8. Selected Subareas

Table IX. Current Load at Janesville/Beloit (Btu x 10^9)

Block	J	F	M	A	M	J	J	A	S	O	N	D	Total	Remarks
1	0.62	0.50	0.26	0.14	0.02	0.02	0.01	0.01	0.03	0.13	0.38	0.48	2.6	J-CBD
2	0.33	0.26	0.15	0.09	0.02	0.03	0.02	0.02	0.04	0.11	0.27	0.29	1.6	J-CBD
3	0.59	0.50	0.27	0.18	0.08	0.03	0.04	0.04	0.07	0.17	0.50	0.50	3.0	J-CBD
4	0.75	0.68	0.37	0.20	0.06	0.02	0.02	0.03	0.07	0.20	0.65	0.62	3.7	J-CBD
5	1.04	0.96	0.65	0.47	0.26	0.17	0.17	0.20	0.23	0.41	0.98	0.95	6.5	J-CBD
6	0.47	0.61	0.32	0.20	0.10	0.06	0.08	0.08	0.11	0.21	0.50	0.49	3.2	J-CBD
7	0.91	0.64	0.11	0.53	0.06	0.02	0.02	0.02	0.05	0.21	0.68	0.73	4.0	J-CBD
8	1.07	0.86	0.52	0.35	0.16	0.14	0.14	0.12	0.18	0.32	0.83	0.90	5.6	J-CBD
9	0.33	0.26	0.17	0.12	0.02	0.01	0.01	0.01	0.02	0.11	0.28	0.32	1.6	J-CBD
10	0.4	0.4	0.3	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.2	0.4	2.0	
11	4.7	3.6	0.8	0.8	0.6	0.8	0.8	0.3	0.8	0.7	3.8	5.7	23.2	
12	0.7	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0	0.1	0.4	0.7	3.4	
13	102.7	91.5	81.4	76.3	58.0	46.8	36.6	36.6	39.7	75.3	85.4	100.7	831.0	
14	2.6	3.2	2.4	1.4	1.1	0.8	0.8	0.8	0.8	1.0	1.8	2.4	19.0	
15	1.5	1.6	1.5	1.3	0.8	0.5	0.2	0.2	0.2	0.4	0.7	1.1	9.8	
16	1.6	1.7	1.2	0.9	0.4	0.1	0.1	0.1	0.2	0.5	1.1	1.6	9.2	
17	2.9	3.5	3.2	2.3	0.9	0.5	0.3	0.4	0.5	0.5	0.7	2.0	17.4	
18	15	15	15	15	15	15	15	15	15	15	15	15	180	
19	6.3	6.5	6.6	5.4	4.7	4.6	4.1	4.0	5.8	4.9	6.5	6.2	65.4	
20	0.8	1.0	0.8	0.6	0.3	0.1	0.0	0.0	0.0	0.1	0.3	0.7	4.6	
21	0.7	0.7	0.5	0.2	0.1	0.0	0.0	0.0	0.0	0.1	0.4	0.6	3.4	
22	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.9	

NOTE: J-CBD = Janesville Central Business District

Table IX. Current Load at Janesville/Beloit (Btu x 10^9) concluded

Block	J	F	M	A	M	J	J	A	S	O	N	D	Total	Remarks
23	1.6	1.4	1.2	0.8	0.7	0.5	0.4	0.4	0.8	1.0	1.4	1.6	11.7	
24	2.1	2.0	1.6	0.7	0.4	0.0	0.0	0.0	0.0	0.5	1.2	1.6	10.0	
25	1.9	1.7	1.5	0.9	0.5	0.0	0.0	0.0	0.0	0.7	1.1	1.6	9.8	
26	1.2	1.0	0.9	0.7	0.6	0.5	0.4	0.5	0.6	0.5	1.1	1.0	8.8	
27	9.1	8.9	6.5	4.7	5.7	5.9	7.0	6.7	6.5	4.7	4.4	7.1	77.0	
28	5.0	2.7	2.4	1.4	1.0	0.6	0.5	0.8	2.0	2.6	3.2	4.7	26.9	
29	1.7	1.3	1.0	0.6	0.4	0.2	0.2	0.2	0.4	0.5	0.5	1.6	8.5	
30	0.8	0.8	0.5	0.6	0.3	0.2	0.1	0.2	0.2	0.2	0.2	0.4	4.4	
31	0.8	0.6	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.5	2.6	
32	0.2	0.5	0.7	0.5	0.6	4.5	3.4	4.4	0.1	0.0	0.4	0.2	15.4	
33	1.0	1.2	1.7	0.5	0.1	0.0	0.0	0.0	0.0	2.3	1.1	2.0	9.6	
34	10.1	11.3	10.7	9.4	9.8	8.0	8.8	8.0	6.3	7.1	8.7	10.1	108.1	
35	4.1	3.8	2.9	1.8	0.9	0.2	0.0	0.1	0.3	1.1	1.8	3.5	17.1	
36	44.1	68.7	38.9	15.3	14.7	12.3	4.5	4.5	6.5	4.9	9.2	10.7	234.2	
37	6.8	7.3	5.7	7.7	6.8	6.3	4.7	6.2	6.2	6.4	6.7	6.5	75.8	
38	18.0	19.7	9.8	22.8	15.7	19.4	19.9	18.1	14.0	19.7	17.3	18.3	212.6	
39	42.2	41.5	36.7	20.7	14.0	9.0	4.4	4.4	9.5	11.3	19.4	35.3	248.4	
40	17.3	16.5	7.0	6.4	1.8	3.2	3.5	3.9	3.5	7.1	11.8	16.5	98.5	
41	0.42	0.41	0.29	0.19	0.11	0.01	0.01	0.01	0.01	0.08	0.16	0.32	2.0	B-CBD
42	0.21	0.27	0.20	0.09	0.02	0.01	0.01	0.01	0.01	0.04	0.08	0.23	1.2	B-CBD
43	1.04	0.95	0.74	0.43	0.19	0.02	0.03	0.02	0.02	0.19	0.41	0.85	4.9	B-CBD
44	0.34	0.22	0.32	0.12	0.05	0.02	0.02	0.02	0.02	0.06	0.09	0.26	1.5	B-CBD
45	1.48	1.38	1.01	0.50	0.20	0.03	0.03	0.03	0.03	0.21	0.44	1.11	6.5	B-CBD
46	1.68	1.34	1.20	0.79	0.44	0.17	0.17	0.17	0.16	0.56	0.65	1.34	8.7	B-CBD
47	0.51	0.44	0.41	0.21	0.09	0.01	0.01	0.01	0.01	0.20	0.21	0.41	2.5	B-CBD

NOTE: B-CBD = Beloit Central Business District

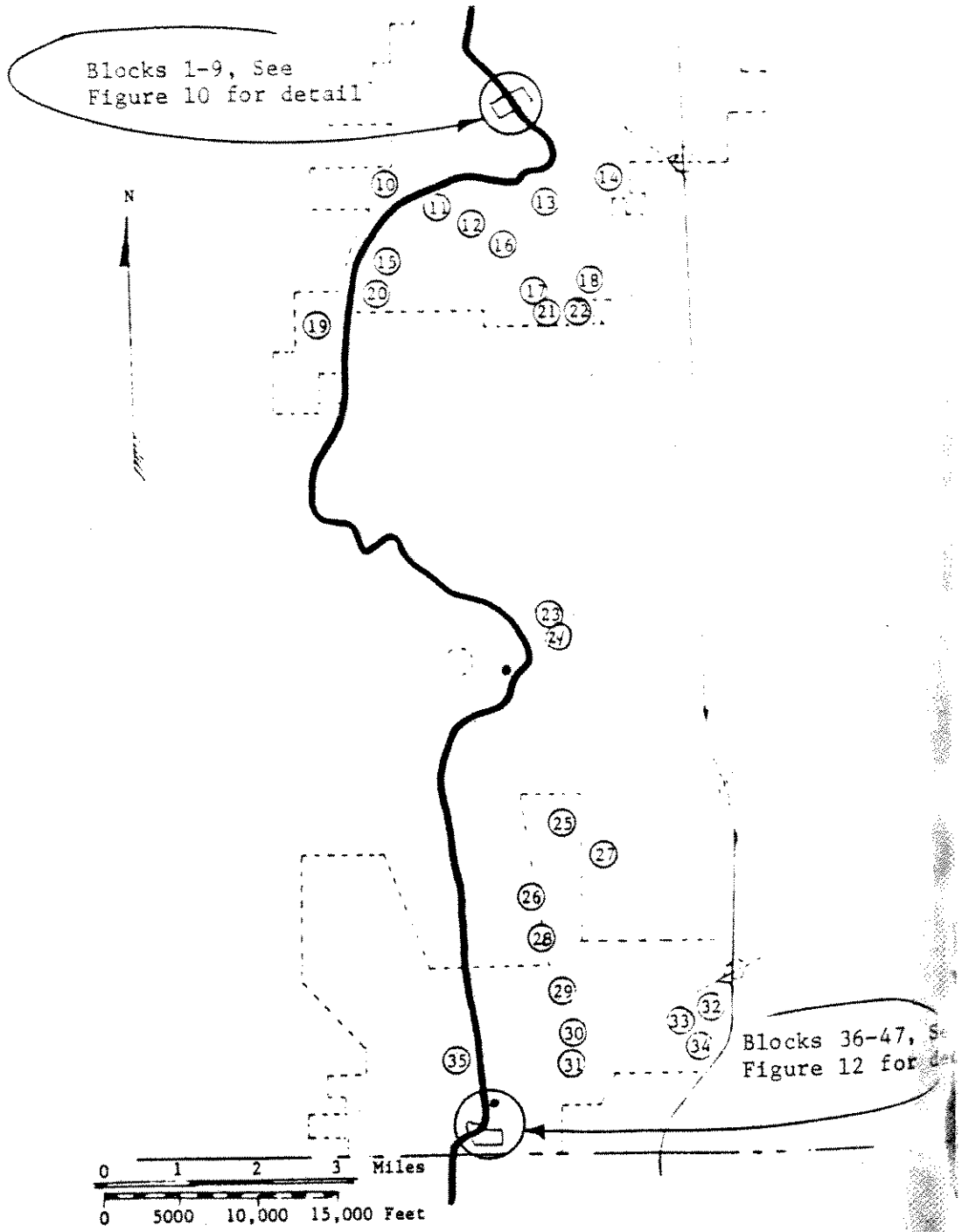


Figure 9. Location of 47 Blocks of Data, Janesville/Beloit

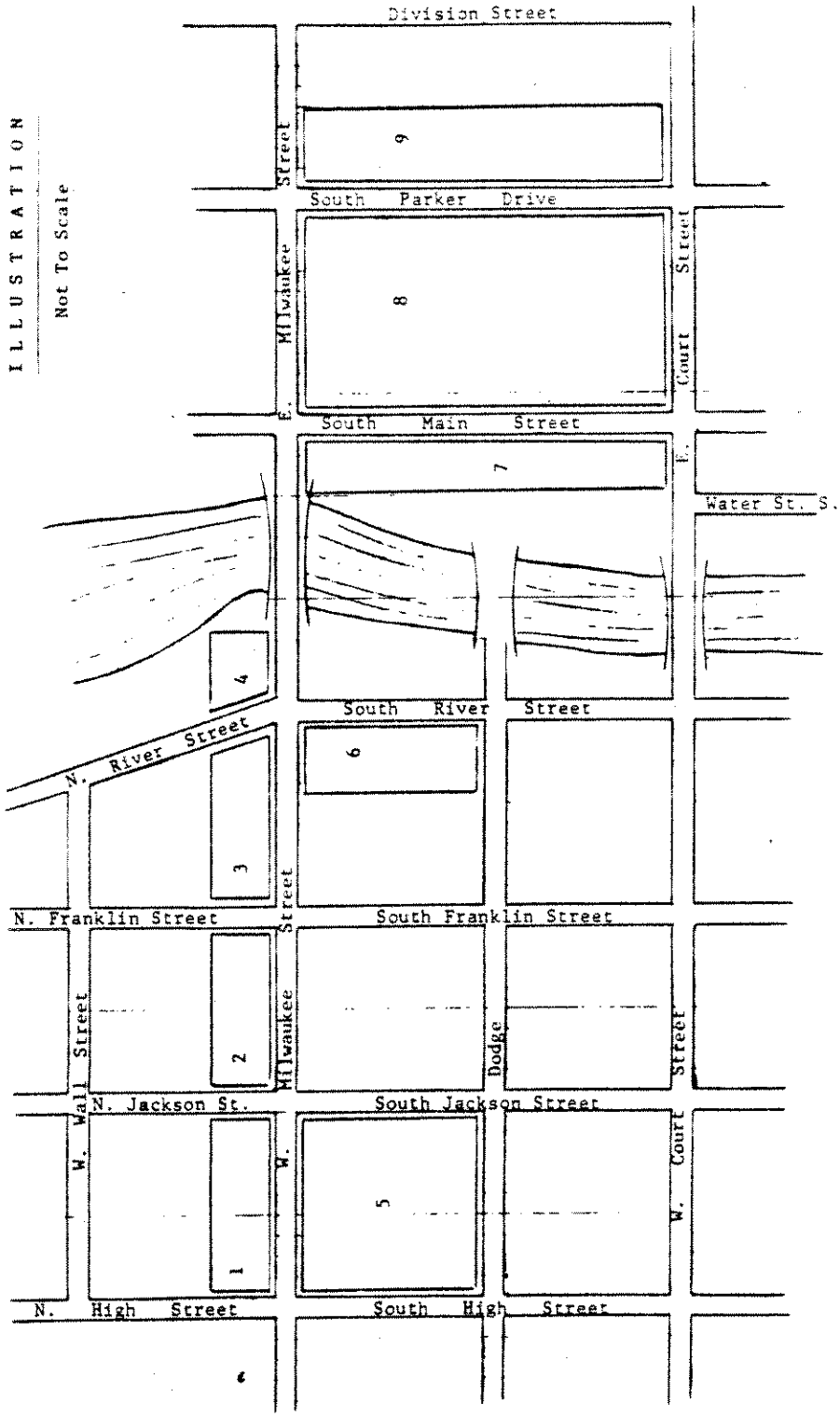


Figure 10. Detail of Janesville Central Business District

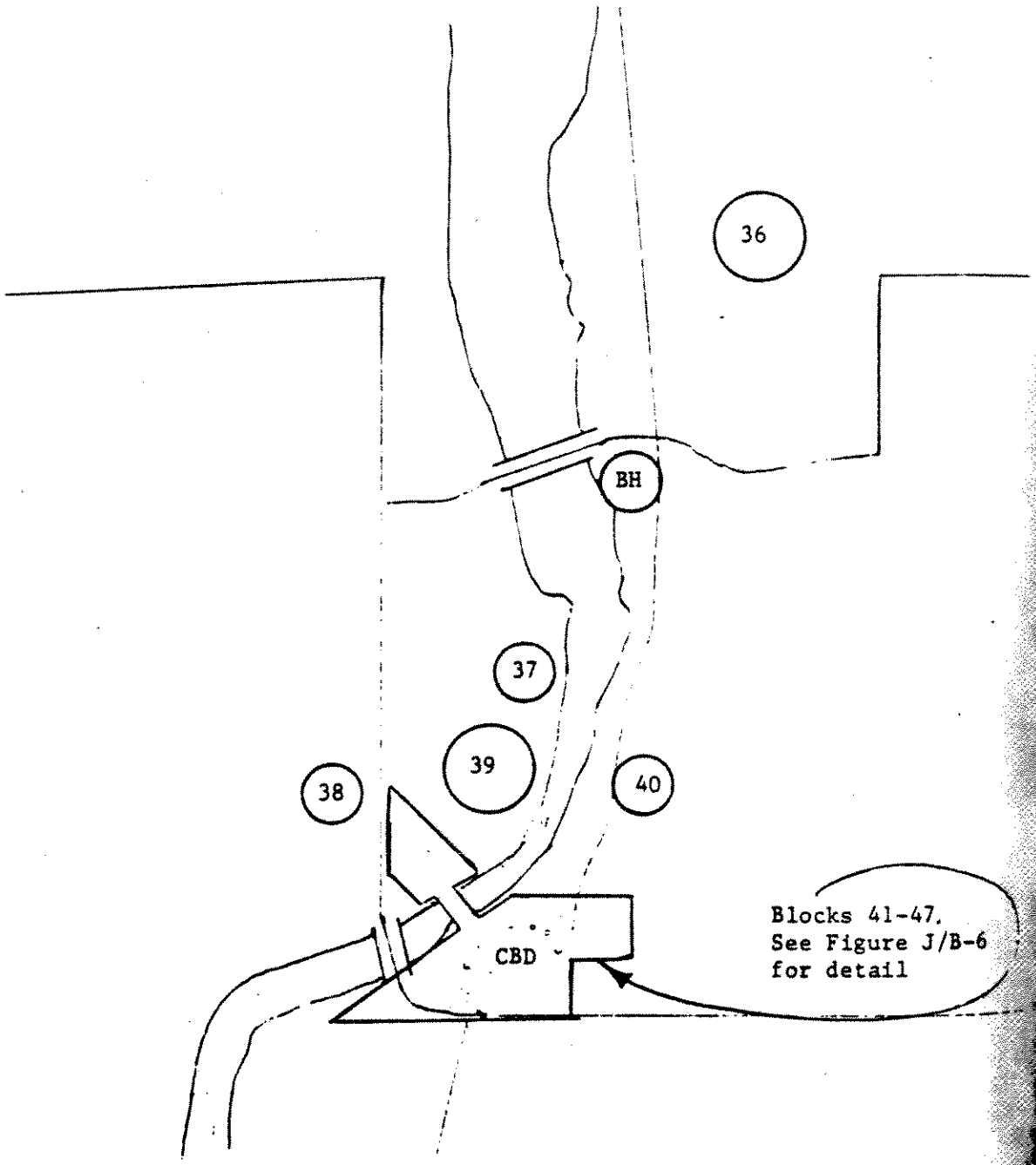


Figure 11. Detail of Downtown Beloit Subarea

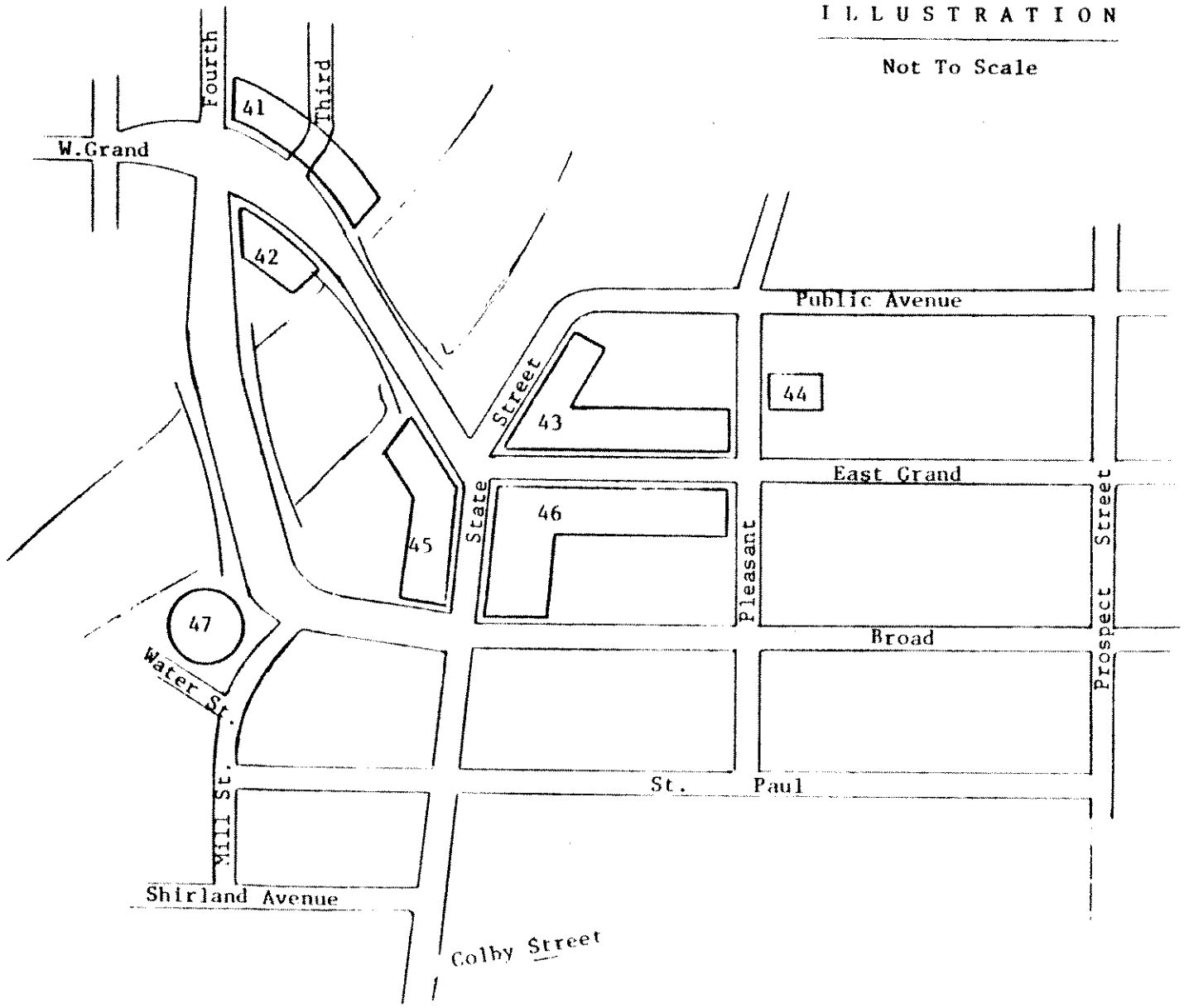


Figure 12. Detail of Beloit Central Business District

Areas Selected for Detailed Analysis

The areas selected for detailed analysis are shown in Figure 8. They include the Janesville CBD and areas to the south of it, the Beloit CBD and areas nearby, and an area of industry east of Beloit.

The thermal market in this selected area can be descriabed as:

- Beloit thermal loads which are very close to the Black Hawk Power Plant. These loads include the Beloit CBD, industry and Beloit college, and are appropriate for consideration of a very compact distribution network.
- Thermal loads south of Janesville, which are applicable to a network off of a pipe from the Rock River Power Plant, with or without a connection to Black Hawk. These loads include the Janesville CBD, industry and schools.
- Additional thermal loads north and east of Beloit. These loads include industry, schools and a hospital (called Beloit "other").

The area north of the Janesville CBD is not included in the detailed analysis because it is mostly residential and scattered commercial of a low thermal density and too far from the power plant for efficient delivery of thermal energy. The residential areas in both cities are of too low a thermal density for consideration. A great deal of open farmland exists in the area between Beloit and Janesville.

Current Thermal Load--The thermal demand for the selected Janesville/Beloit area is delineated in Table IX. This demand is characterized by 47 "blocks" of data, which include CBD blocks, industries, schools and other entities. The location of each "block" is defined by Figure 9 and detail Figures 10, 11 and 12. The thermal demand was derived using natural gas consumption (1977-78) supplied by Wisconsin Power and Light (WP&L) Company. The load data was calculated using an efficiency factor of 75 percent.

Peak Hour Demand--Peak hour demand was estimated by determining the peak day load (from weather data) and calculating the maximum hourly load based on ASHRAE design recommendations. For the selected area, the peak loads occurred in February 1978. The peak days in February were the 2nd and 3rd. The following degree-day data was used:

- Degree days for February (base 65°F) - 1466
- Maximum degree days for 2nd and 3rd - 62
- ASHRAE design temperature - -13°F

Therefore, the maximum daily load was

$$(\text{February load}) \times \left(\frac{62}{1466}\right)$$

and the average hourly load (maximum day) was

$$(\text{February load}) \times \left(\frac{62}{1466}\right) \times \left(\frac{1}{24}\right)$$

and the peak hourly load would be

$$\left(\frac{78}{62}\right) \times \text{average hourly load (max. day)} =$$

$$\left(\frac{78}{62}\right) \times (\text{February load}) \times \left(\frac{62}{1466}\right) \times \left(\frac{1}{24}\right) =$$

$$(0.00222)$$

Table X summarizes the peak hourly load from the selected service areas.

Load Distribution--Because the building types in the Janesville/Beloit service area range from small commercial buildings to large manufacturing facilities,

Table X. Peak Hourly Load Summary

Block	Total Feb. Load (BTU x 10^9)	Peak Hour (BTU x 10^6)	Subtotals BTU x 10^6)
1	0.5	1	
2	0.3	1	
3	0.5	1	
4	0.7	2	
5	1.0	2	
6	0.6	1	
7	0.6	1	
8	0.9	2	
9	0.3	1	
10	0.4	1	
11	3.6	8	
12	0.6	1	
13	91.5	203	
14	3.2	7	
15	1.6	4	
16	1.7	4	
17	3.5	8	
18	15	33	
19	6.5	14	
20	1.0	2	
21	0.7	2	
22	0.2	0	
23	1.9	4	
24	2.0	4	307 (Janesville)
25	1.7	4	
26	1.0	2	
27	8.9	20	
28	2.7	6	
29	1.3	3	
30	0.8	2	
31	0.6	1	
32	0.5	1	
33	1.2	3	
34	11.3	25	75
35	3.8	8	75 (Beloit "Other")
36	68.7	152	
37	7.3	16	
38	19.7	44	
39	41.5	92	
40	16.5	37	
41	0.4	1	
42	0.3	1	
43	1.0	2	
44	0.2	0	
45	1.4	3	
46	1.3	3	
47	0.4	1	352 (Beloit Downtown)

the thermal loads vary greatly and are not uniformly distributed. Thirty-four of the "blocks" represent single point loads (i.e., one manufacturing facility). Even the CBD blocks (13) are characterized by widely varying loads. Table XI illustrates the load distribution; the total yearly load by block, the rank of the block with respect to size of load, the total number of customers per block and, in the case of multiple customers, a distribution by major customers.

Cooling Load--Little emphasis was placed on the potential cooling load unless large loads were discovered. The HVAC analysis indicates very minimal use of absorption chillers and a high perponderance of small electrical window air conditoners. Thus, the cost of retrofit to absorption cooling equipment would probably be prohibitive, and the cooling load is therefore not evaluated.

Future Loads--Neither Janesville or Beloit are expected to experience commercial growth that would significantly influence the thermal demand analysis. However, due to the large amount of available land, some potential does exist for industrial parks between the two cities. One planned industrial park will be located west of Rock River Power Plant (Figure 9). Forecast loads for that park are estimated to be over 10^{12} Btu/year with a peak of 250×10^{6} Btu/hour based on Wisconsin Power & Light discussions with potential tenants. Thus, the potential load would rank first in the service area and represent over 40 percent of the existing load.

Load Summary--Table XII summarizes the loads for the Janesville/Beloit area. The data is presented for:

- Janesville CBD,
- Janesville industry,

Table XI. Janesville/Beloit Load Distribution

Block	Total Load BTU/Yr. x 10^9	Rank	Total Number of Customers	Distribution
1	2.6	38	6	1 = 69%
2	1.6	43	5	1 = 59%
3	3.0	37	12	1 = 43%, 2 = 57%
4	3.7	33	3	1 = 47%
5	6.5	26	5	1 = 90%
6	3.2	36	9	1 = 57%
7	4.0	32	5	1 = 69%
8	5.6	28	16	3 = 57%
9	1.6	44	1	
10	2.0	41	1	
11	23.2	12	1	
12	3.4	32	1	
13	831.0	1	1	(35% of total, i.e. of 2408)
14	19.0	13	1	
15	9.8	20	1	
16	9.2	22	1	
17	17.4	14	1	
18	180	5	1	
19	65.4	10	1	
20	4.6	30	1	
21	3.4	35	1	
22	0.9	47	1	
23	11.7	17	1	
24	10.0	18	1	
25	9.8	19	1	
26	8.8	23	1	
27	77.0	8	1	
28	26.9	11	1	
29	8.5	25	1	
30	4.4	31	1	
31	2.6	39	1	
32	15.4	16	1	
33	9.6	21	1	
34	108.1	6	1	
35	17.1	5	1	
36	234.2	3	1	(-10 of total)
37	75.8	9	1	
38	212.6	4	1	(9% of total)
39	248.4	2	1	(10% of total)
40	98.5	7	1	
41	2.0	42	5	1 = 51%
42	1.2	46	4	1 = 36%
43	4.9	29	18	3 = 53%
44	1.5	45	1	
45	6.5	27	12	1 = 36%, 2 = 57%
46	8.7	24	21	1 = 44%, 2 = 63%
47	2.5	40	1	
Total	2408			

Table XII. Janesville/Beloit Load Summary

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Janesville CBD	6.1	5.3	2.8	2.3	0.8	0.5	0.5	0.5	0.8	1.9	5.1	5.3	31.9
Janesville Industry	143.7	132.9	117.1	106.2	83.4	69.7	58.3	57.7	63.9	100.3	119.0	140.4	1192.6
Beloit CBD	5.7	5.0	4.2	2.5	1.1	0.3	0.3	0.3	0.3	1.3	2.0	4.6	27.6
Beloit Industry	164.3	160.5	127.3	94.2	73.0	70.3	57.4	52.0	56.1	69.2	87.1	120.0	1131.4
Totals	319.8	303.7	251.4	205.2	158.3	140.8	116.5	110.5	121.1	172.7	213.2	270.3	2383.5
Future Ind. Pk.	120	110	100	90	70	60	50	50	50	90	100	120	1010

Peak Hr. Loads

Janesville CBD	12×10^6 BTU/hr
Janesville Ind.	295×10^6 BTU/hr
Beloit CBD	11×10^6 BTU/hr
Beloit Ind.	416×10^6 BTU/hr
Totals	734×10^6 BTU/hr
Future Ind. Pk.	250×10^6 BTU/hr

FUEL USAGE	
Coal	35%
Gas	65%

- Beloit CBD,
- Beloit industry,
- Totals,
- Future loads,
- Peak hour loads.

The fuel usage breakout is also included in the table.

HVAC Inventory--Data characterizing the types of heating, hot water, process heat and air conditioning equipment were collected and analyzed for 21 blocks (approximately 45 percent of total) of the Janesville/Beloit service area. Detailed data is contained in Appendix C.

The vast majority (90 percent of the "blocks" use natural gas-fired boilers as a source of space and process heating. Five percent use natural gas-fired space heaters and 5 percent use coal boilers plus gas space heaters. Oil is the predominant backup fuel for the boilers (50 percent of the blocks), LP gas is used as backup in 14 percent of the cases, coal is used as backup in 5 percent of the cases, and 27 "blocks" have no backup.

Hot water is provided by gas hot water heaters and steam-to-water heat exchangers on a 50/50 ratio.

The majority of the air conditioning equipment consists of small window units. Larger businesses have central electric chillers. Two "blocks" (27 and 40) use central absorption units.

3.4 MADISON

Madison is located in Dane County in central Wisconsin. Prominant in the topography of Madison are Lake Mendota and Lake Monana, between which the city is situated. The 1970 census population of Madison is 173,285.

Potential Service Area

Madison Gas and Electric Company supplies electric power and natural gas to the metropolitan area of Madison. The Blount Street Power Plant is located just off the downtown loop, between the two lakes (Figure 13).

The thermal market in the immediate area of the Blount Street Plant can be described as follows:

- The Central Business District (CBD) contains office, retail store, and hotel/motel buildings. This area is bounded on the northeast by Blount Street and the southwest by Bedford Street. Lake Mendota and Lake Monana provide the boundaries to the northwest and southeast.

  Within the CBD are a number of state/country buildings that are heated and some of which are cooled by a separate, state-operated coal-, gas-and oil-fired steam (125 psig) generating plant (Capitol Heating Plant). The buildings currently heated by this network include the State Capitol Building, State Office Building, City/County Building and General Executive Facility (GEF) No. 1. GEF No. 2 and GEF No. 3, currently under construction, will also be supplied by this network. The buildings that are and will be supplied chilled water from a 2500-ton, steam-turbine-driven central chiller are the three newer General Executive Facility buildings. The location of the Capitol Heating Plant and building served by the plant are identified in Figure 14. (i.e., those blocks with "///" around them.)
- The University of Wisconsin occupies a large area along Lake Mendota and west of the CBD (Figure 13). This area contains about 150 buildings. The university operates two, (coal, oil and

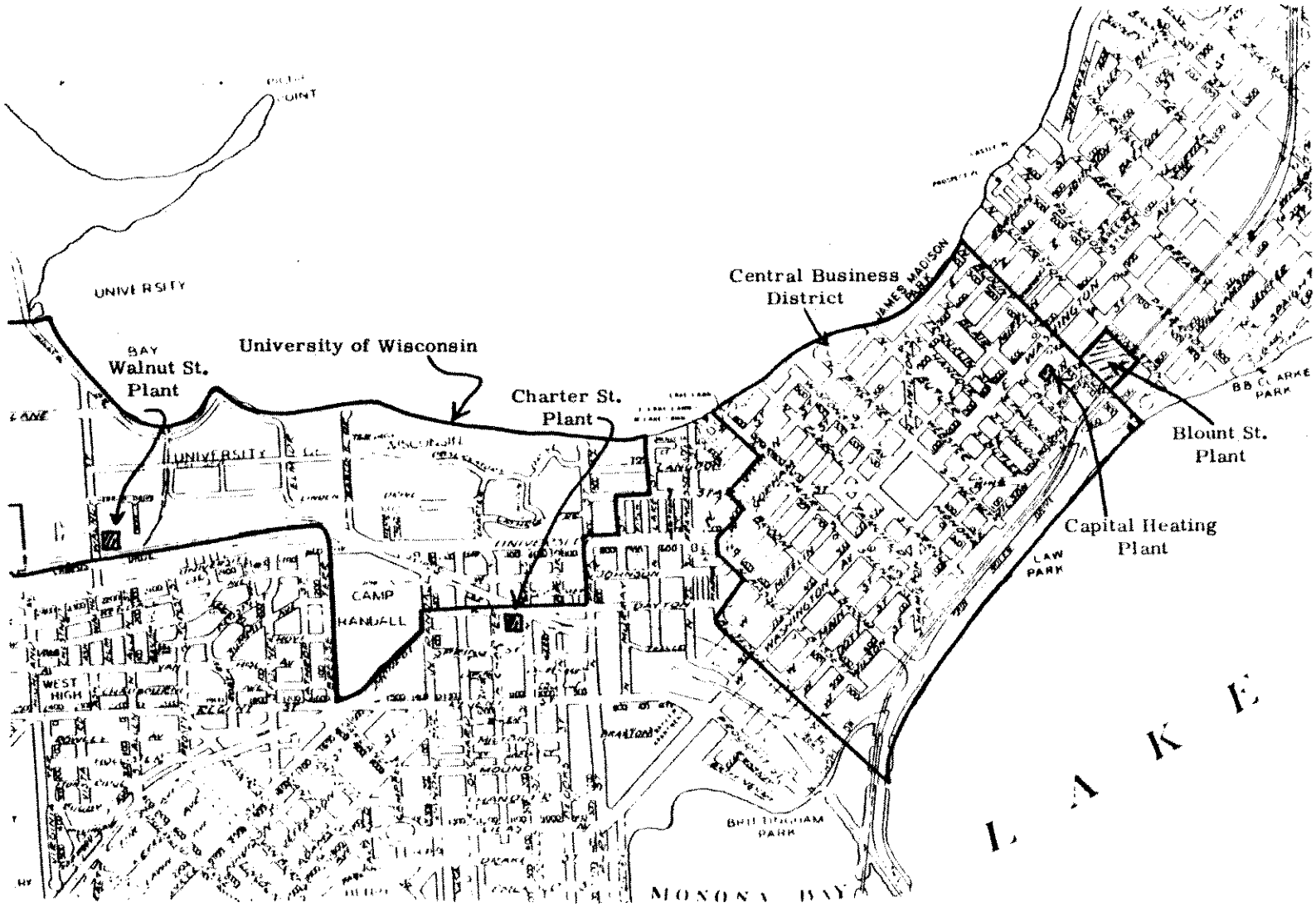


Figure 13. Madis[illegible] ervice Area

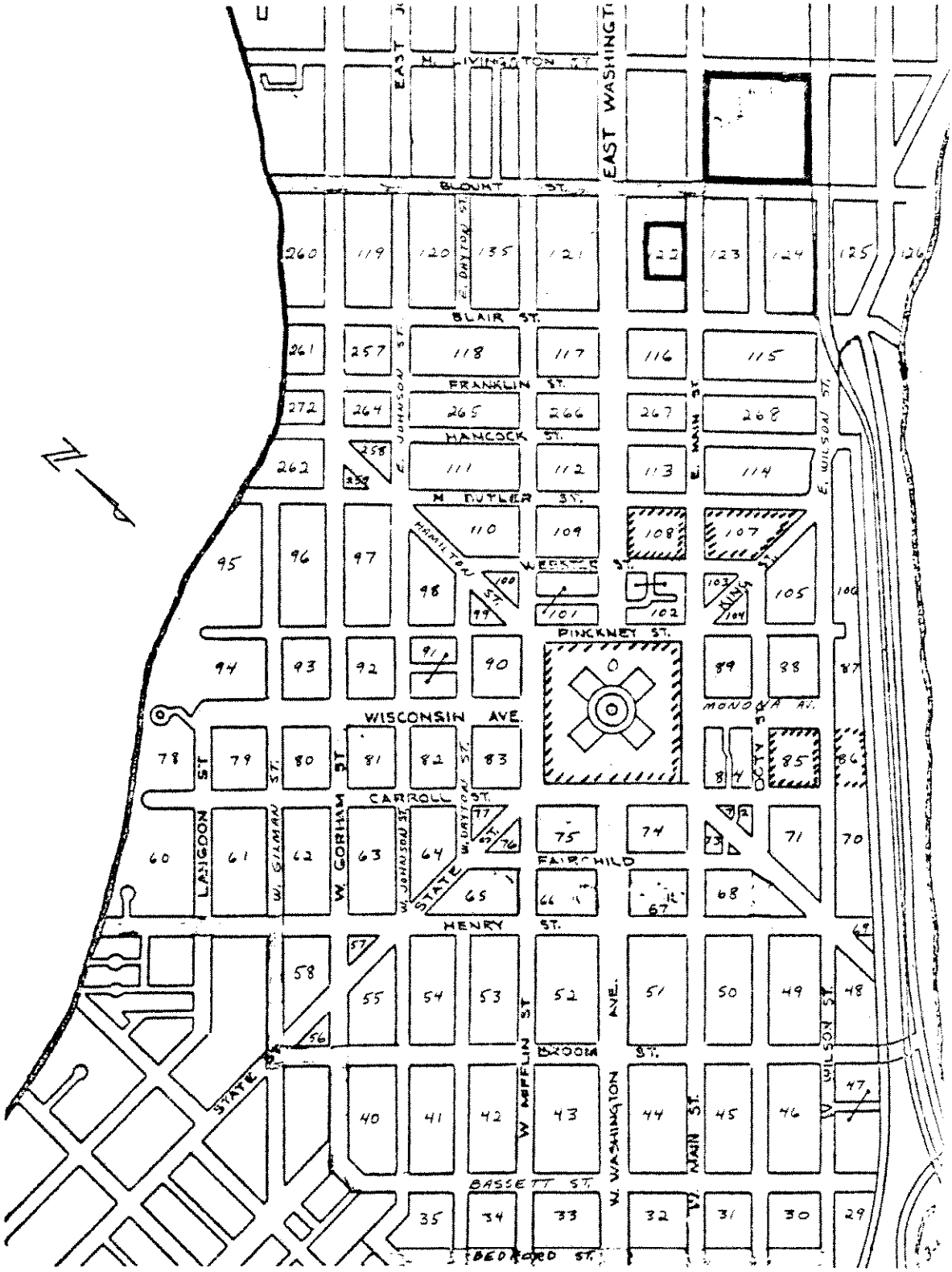


Figure 14. Madison Central Business District

Table XIII. Madison - Current Load Data (Btu x 10^9) 1977-1978

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
00	4.500	3.780	3.150	2.430	2.120	2.300	1.750	1.670	1.710	2.340	3.110	4.460	33.320
29	.096	.105	.098	.081	.047	.082	.160	.058	.045	.062	.079	.098	.867
30	.782	.842	.690	.649	.298	.380	.077	.281	.236	.466	.645	.748	6.093
31	.229	.230	.197	.144	.048	.043	.009	.035	.036	.096	.146	.199	1.411
32	.613	.562	.450	.266	.158	.068	.066	.058	.863	.189	.277	.460	3.252
33	.704	.635	.553	.288	.138	.015	.016	.014	.160	.127	.271	.498	3.274
34													0
35													0
40	.369	.464	.304	.262	.111	.091	.016	.063	.064	.189	.312	.364	2.609
41	1.427	1.268	.868	.638	.497	.177	.173	.157	.184	.399	.735	1.280	7.801
42	.090	.082	.065	.039	.024	.007	.007	.004	.005	.028	.082	.082	0.596
43	.231	.231	.167	.069	.032	.008	.007	.008	.011	.046	.125	.202	1.136
44	1.013	.889	.702	.399	.198	.114	.133	.067	.113	.287	.456	.802	5.191
45	.075	.068	.052	.033	.010	.014	.003	.011	.010	.026	.046	.070	0.417
46	.179	.179	.135	.092	.029	.008	.001	.001	.010	.102	.116	.176	1.025
47	.443	.458	.352	.246	.088	.083	.016	.054	.056	.116	.027	.416	2.642
48	.086	.086	.065	.051	.020	.016	.003	.007	.012	.041	.064	.091	0.541
49													0
50	.652	.609	.507	.414	.171	.288	.062	.214	.184	.340	.474	.619	4.533
51	1.747	1.317	1.077	.735	.254	.024	.024	.023	.050	.370	.678	1.140	7.437
52	3.819	3.442	2.812	1.292	.418	.215	.192	.197	.451	.451	1.867	2.379	17.302
53													0
54	1.267	.900	.672	.440	.258	.176	.145	.129	.182	.351	.665	.977	6.160
55	.244	.238	.181	.126	.057	.097	.020	.080	.065	.106	.150	.206	1.569
56	.552	.509	.347	.205	.065	.078	.018	.069	.048	.164	.314	.484	2.852
57	.147	.134	.104	.071	.029	.024	.001	.001	.005	.039	.091	.135	0.779
58	.313	.302	.229	.157	.145	.022	.005	.013	.021	.103	.204	.292	1.704
60	3.962	3.761	2.948	1.839	1.078	.268	.268	.223	.302	1.240	2.076	3.545	21.510
61	1.529	1.595	1.294	.822	.592	.281	.300	.292	.383	.581	.958	1.379	10.010

Table XIII. Madison - Current Load Data (Btu x 10^9) 1977-1978 (continued)

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
62	.930	.845	.699	.442	.241	.138	.096	.112	.135	.332	.509	.753	5.201
63	.932	.932	.671	.425	.145	.131	.029	.111	.109	.311	.528	.797	5.154
64	.725	.747	.516	.220	.094	.010	.007	.007	.007	.135	.382	.511	3.360
65	.659	.617	.362	.135	.048	.024	.025	.029	.051	.051	.025	.524	2.753
66	2.078	1.900	1.143	.438	.057	.005	.005	.005	.005	.266	.809	1.462	8.174
67	2.173	1.944	1.633	.963	.461	.157	.188	.220	.366	1.026	1.422	2.034	12.585
68	.155	.112	.086	.023	.006	.003	.003	.003	.003	.008	.036	.081	.517
69													0
70	1.039	1.065	.829	.611	.210	.192	.037	.133	.142	.432	.732	1.043	6.464
71	.764	.748	.538	.367	.133	.083	.017	.062	.077	.280	.463	.684	4.195
72	.295	.290	.227	.154	.047	.075	.017	.051	.035	.108	.168	.278	1.746
73	.650	.650	.547	.293	.078	.056	.015	.040	.054	.231	.390	.570	3.573
74	4.841	4.335	2.175	1.267	.886	.773	.704	.670	.746	1.121	1.927	3.641	23.112
75	2.451	2.148	2.119	.796	.271	.061	.051	.045	.053	.534	1.466	2.374	12.369
76	.589	.884	.460	.234	.147	.113	.108	.114	.103	.165	.341	.699	3.957
77	.111	.106	.069	.012	.005	.001	.001	.001	.001	.026	.060	.090	.484
78													0
79	1.103	1.011	.794	.593	.235	.222	.046	.145	.157	.462	.726	1.003	6.497
80	.433	.414	.289	.194	.060	.023	.004	.016	.017	.076	.212	.350	2.088
81	.662	.621	.509	.326	.076	.022	.005	.016	.036	.211	.462	.711	3.656
82	3.800	4.408	3.215	.563	.418	.008	.008	.008	.032	1.148	2.432	2.545	18.583
83	1.386	1.985	1.187	.582	.187	.108	.095	.081	.086	.305	.989	1.417	8.409
84	1.751	1.768	1.360	.745	.159	.132	.026	.094	.109	.373	.894	1.496	8.906
85	4.500	3.780	3.150	2.430	2.120	2.300	1.750	1.670	1.710	2.340	3.110	4.460	33.320
86	4.500	3.780	3.150	2.430	2.120	2.300	1.750	1.670	1.710	2.340	3.110	4.460	33.320
87	1.251	1.293	1.076	.855	.316	.292	.054	.201	.218	.631	.967	1.279	8.430
88	1.079	.884	.672	.395	.087	.016	.017	.017	.017	.019	.383	.927	4.514
89	1.150	1.144	.824	.504	.167	.163	.034	.129	.109	.282	.611	1.083	6.201
90	2.037	1.965	1.477	.572	.161	.010	.007	.007	.011	.354	1.005	2.226	9.831

Table XIII. Madison - Current Load Data (Btu x 10^9) 1977-1978 (continued)

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
91	.883	.936	.654	.384	.173	.057	.048	.046	.051	.311	.518	.803	4.865
92	1.902	1.103	.849	.554	.094	.136	.032	.032	.047	.373	.750	.207	6.077
93	1.2839	1.135	.847	1.098	.326	.118	.116	.126	.134	.420	.781	1.034	7.419
94	3.486	3.476	2.910	1.786	1.271	.567	.405	.468	.512	1.155	2.239	3.403	21.680
95	3.050	2.521	1.804	1.016	.501	.181	.163	.161	.171	.566	1.528	2.296	13.957
96	.319	.282	.211	.119	.077	.134	.031	.029	.032	.095	.178	.245	1.652
97	.360	.309	.246	.158	.096	.051	.043	.036	.036	.117	.210	.291	1.953
98	.390	.371	.292	.172	.082	.026	.026	.023	.026	.010	.242	.454	2.204
99	.200	.205	.148	.084	.041	.011	.024	.024	.026	.040	.084	.121	1.008
100	.308	.306	.268	.171	.115	.070	.075	.053	.053	.123	.224	.297	2.064
101	2.144	1.919	1.511	.934	.699	.148	.219	.248	.299	.748	1.148	1.937	11.954
102	3.000	2.651	1.923	1.347	.396	.089	.019	.076	.087	.516	1.551	2.435	14.093
103	.091	.084	.066	.044	.006	.018	.000	.001	.007	.031	.052	.077	.476
104	.934	.926	.612	.365	.087	.013	.002	.008	.035	.247	.560	.920	4.713
105	.099	.110	.112	.127	.076	.154	.030	.112	.084	.110	1.189	2.100	4.303
106	.775	.756	.512	.269	.067	.040	.008	.030	.039	.174	.397	.699	3.766
107													0
108	6.500	5.460	4.550	3.510	3.070	3.330	2.520	2.420	2.470	3.380	4.500	6.450	48.160
109	.554	.480	.372	.199	.137	.073	.068	.075	.089	.164	.236	.433	2.883
110	.140	.149	.109	.063	.044	.033	.029	.017	.023	.060	.099	.128	.895
111	.266	.269	.206	.103	.059	.032	.034	.029	.033	.083	.152	.231	1.496
112	1.029	.977	.729	.280	.159	.033	.041	.041	.049	.190	.397	.575	4.502
113	.282	.272	.201	.109	.028	.022	.005	.018	.123	.086	.137	.239	1.422
114	.255	.226	.174	.110	.033	.018	.003	.014	.021	.099	.176	.237	1.366
115	.378	.354	.246	.130	.048	.037	.016	.023	.015	.095	.194	.338	1.873
116	.167	.156	.123	.079	.039	.022	.010	.015	.016	.046	.089	.140	.902
117													0
118													0
119	.107	.104	.078	.049	.029	.009	.008	.009	.008	.034	.063	.091	.591

Table XIII. Madison - Current Load Data (Btu x 10^9) 1977-1978 (concluded)

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
120	.085	.087	.066	.041	.031	.024	.009	.007	.009	.028	.047	.073	.508
121	.720	.666	.511	.349	.117	.026	.005	.020	.039	.191	.324	.585	3.553
122	1.023	.915	.641	.337	.080	.039	.007	.028	.041	.196	.521	.905	4.734
123	.497	.424	.292	.139	.055	0	.006	.016	.007	.009	.131	.334	1.913
124	.590	.438	.468	.243	.429	.648	.714	.663	.547	.183	.312	.424	5.659
125	.187	.193	.135	.076	.018	.009	.002	.007	.012	.040	.100	.184	.965
126													0
257													0
258	.085	.081	.062	.040	.024	.027	.020	.025	.027	.039	.052	.072	.555
260													0
264	.722	.616	.514	.340	.105	.001	.002	.000	.022	.050	.374	.592	3.340
265	.185	.183	.135	.067	.032	.016	.013	.011	.015	.040	.084	.145	.927
266	.761	.487	.462	.301	.270	.225	.220	.224	.265	.279	.311	.441	4.047
267	.357	.347	.260	.167	.046	.016	.004	.017	.021	.109	.223	.332	1.899
268	.791	.777	.538	.367	.137	.160	.031	.104	.119	.262	.487	.739	4.512
Total (CBD)	113.574	104.032	71.603	44.084	24.797	18.810	13.433	14.642	16.815	32.525	52.567	89.607	609.071
UW	225	201	171	119	106	103	94	88	89	106	141	194	1637
TOTALS	338.574	305.032	242.603	163.084	130.797	121.810	107.433	102.642	105.815	138.525	193.567	283.314	2246.071

natural gas) steam heating plants (Walnut St. and Charter St. plants) that produce (150-175 psig) steam to heat all of and cool some of these building. Cooling is accomplished by steam-turbine-driven chillers (one 7000-ton unit and four 3500-ton units). The majority of the buildings contain steam distribution systems. Buildings constructed since 1960 have hot water distribution systems.

- The area west of the CBD and south of the university contains scattered commercial buildings, some multifamily (two to three units) and single-family residences.
- The area to the northeast of the CBD contains scattered commercial buildings, multifamily (two to three units) and single-family residences.

Areas Selected for Detailed Analysis

The areas selected for detailed analysis include the Central Business District and those building heated by the Capitol Heating Plant and the University of Wisconsin campus. The CBD encompasses about 100 city blocks of multistory commercial retail and hotel/motel buildings, and includes those buildings (i.e. office) served by the Capitol Heating Plant. The University of Wisconsin occupies an area about the size of the CBD. The campus contains about 150 multistory classroom, office and dormitory buildings.

The remaining areas on either side of the CBD were rejected for the present time because of the low thermal density and extended distribution system that would be required to serve them.

Current Thermal Load--The current thermal load was derived using natural gas consumption and steam supply data (1977-78, reference 4) supplied by Madison Gas and Electric. Load data for natural gas consumption were

converted using an efficiency factor of 75 percnet. Load data computed from steam supply data for the Capitol Heating Plant and the University of Wisconsin (Appendix D) were derived by assuming 1000 pounds steam equals 10^6 Btu.

Table XIII summarizes the load data by block and month. The block numbers used correspond to those in Figure 14 and also to city numbers. For this reason, the block numbers do not run consecutively. The State Capitol was arbitrarily assigned a block number of 0.

Peak Hour Demand--Peak hour demand for the CBD (excluding the buildings served by the Capitol Heating Plant) was estimated by determining the peak day load and then calculating the maximum hourly load based on the minimum temperature. For Madison during January 1978, the following conditions prevailed:

• Degree-days for January (base 65°F)	1688
• Maximum degree-day (9th)	71
• Minimum temperature (30th)	-12°F
• ASHRAE design temperature	-13°F

Therefore, the maximum daily load was

$$(\text{January load}) \times \left(\frac{71}{1688}\right)$$

and the average hourly load (maximum day) was

$$(\text{January load}) \times \left(\frac{71}{1688}\right) \times \left(\frac{1}{24}\right)$$

and the peak hourly load would be (ASHRAE)

$$(\frac{78}{71}) \times \text{average hourly load (maximum day)} =$$

$$(\frac{78}{71}) \times (\text{January load}) \times (\frac{71}{1688}) \times (\frac{1}{24}) =$$

$$(0.00193) \times (\text{January load})$$

The total peak hourly load for the CBD is 219.198 x 10^6 Btu/hour.

Peak hour loads for the buildings occupied by the capitol heating plant and the University of Wisconsin were determined (Appendix D) to be 62 x 10^6 Btu/hour and 580 x 10^6 Btu/hour, respectively.

Future Thermal Loads--Appendix B contains a detailed analysis of additional future loads within the CBD, their magnitude, location and distribution. These have been summarized on a block-by-block, month-by-month basis in Table XIV. The peak hourly load for this future load is estimated to be 8.8 x 10^6 Btu/hour.

Cooling Loads--No cooling load data was collected for Madison. The CBD contains a number of commercial buildings that are cooled during portion of the summer months. As indicated by the sample HVAC data collected, the vast majority of the buildings that do contain air conditioning equipment have electric window units and central chillers. Only one absorption air conditioning unit was identified.

Converting to absorption air conditioning equipment would be expensive, especially in light of the fact that there would be conversion costs for the heating systems. The cooling loads are currently viewed as a potential add-on to a DHCS, once the system becomes operational.

Table XIV. Future Loads, Madison (Btu x 10^9)

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
53	.50	.40	.40	.20	.10	-	-	-	.10	.20	.30	.40	2.60
65	2.01	1.68	1.45	.79	.40	.10	.02	.05	.23	.64	1.22	1.80	10.39
107	1.80	1.40	1.40	1.00	1.00	1.20	1.20	1.20	1.00	1.00	1.20	1.40	14.80
Totals	4.31	3.48	3.25	1.99	1.50	1.30	1.22	1.25	1.33	1.84	2.72	3.60	27.79

Load Summary--Table XV contains a summary of the load data for Madison: monthly and total loads, peak hour demands and types of fuels used for the Madison service area.

HVAC Inventory Analysis--Data characterizing the type and age of heating, hot water and air conditioning equipment were collected and analyzed for 25 buildings (approximately 10 percent of total) in the Central Business District. Detailed data are contained in Appendix C. A summary of types and age distributions is contained in Tables XVI and XVII.

The vast majority of buildings in the Central Business District have natural gas-fired boilers. Of these, about 80 percent have steam distribution systems; the remainder have hot water. This appears to correlate with the general age of the buildings. The majority were built before 1960 when steam was the common distribution media.

Gas-fired hot water heaters are used in the majority of buildings. In buildings having a large hot water requirement (i.e., hotel/motels), steam or hot water heat exchangers are used.

The majority of air conditioning euqipment consists of electric window units or central chillers. One building, a hospital, has a central absorp tion unit.

3.5 FACTORS TO INDUCE POTENTIAL USERS

To determine what factors would induce potential users to subscribe to th DHCS, 13 interviews (representing 23 people) were conducted in the commu of Green Bay, Janesville/Beloit and Madison. Owners, managers, operator and directors representing a cross-section of building types were intervi Applicable comments from each interview are summarized in Appendix E. Th

Table XV. Load Summary, Madison

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Current													
CBD (includes Capital Htg. Plant)	113.574	104.032	71.603	44.084	24.797	18.810	13.433	14.642	16.815	32.525	52.567	89.607	609.071
University	225	201	171	119	106	103	94	88	89	106	141	194	1637
Future													
CBD	4.31	3.48	3.25	1.99	1.50	1.30	1.22	1.25	1.33	1.84	2.72	3.60	27.79
University	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	342.884	308.512	245.853	165.074	132.297	123.110	108.653	103.892	107.145	140.365	196.287	287.207	2273.861

Peak Hr. Demand BTU x 10^6

Current

CBD 281.198
University 580.000

CBD without Capital Plant 219.198 x 10^6
Capital Plant 62.0 x 10^6
Total 281.198 x 10^6 BTU/Hr.

Future

CBD 8.800
University 0

Total 869.998

Fuels Used

CBD - Natural Gas
Capital - Natural Gas 65%
#6 Fuel Oil 7%
Coal 28%

UW Natural Gas 39%
Coal 38%
#5 Fuel Oil 6.5%
#2 Fuel Oil 16.5%

Table XVI. HVAC Inventory Summary

	Number	Percentage
Heat Source		
• Boiler	25	100
Distribution		
• Steam	21	81
• Hot Water	5*	19
Hot Water		
• Steam Exchanger	5*	19
• Hot Water Exchanger	1	4
• Gas Fired	20*	77
Air Conditioning		
• Electric	22	88
• Absorption	1	4
• None	2	8

Table XVII. Age Distribution

Age	Number	Percentage
0-5	1	4
6-10	3	12
11-15	2	8
16-20	1	4
> 20	18	72

remaining paragraphs of this section describe the approach used to determine what factors would induce potential users to subscribe and an evaluation of these factors.

During a monthly working session, the study team identified a number of factors that might induce potential users to subscribe to a DHCS. These were used to develop a lits of topical questions (Figure 15) that would be used to solicit views and comments from prospective users.

Interviews were arranged through the utilities serving each of three communities. Each actual interview was conducted by a Honeywell and a utility representative.

Evaluation of Factors

As determined from the interviews, factors that would induce potential users to subscribe to the DHCS fall into the following categoreis:

- Economics
- Additional Information
- Reliability
- Pollution
- Disruption
- Safety

Economics--Economics are the consideration most often mentioned. During the interviews, it was determined that capital expenditures within a business should be projected to produce a payback ranging from three to five years. Financial expenditures longer than this period would receive less attention.

Q - AS A POTENTIAL CUSTOMER OF A DISTRICT HEATING AND COOLING SYSTEM, WHAT ARE SOME OF YOUR CONCERNS ABOUT BECOMING A SUBSCRIBER AND WHAT ARE SOME INDUCEMENTS THAT YOU WOULD CONSIDER?

TOPICS

- Rates
  - Less than competitive fuels
  - Amount less (5 percent, 10 percent, etc.)
  - Regulated rates (PSC Commission)
- Conversion Costs
  - Discount for early subscribers
  - Tax rebate for initial conversion costs
  - ROI target for conversion
  - Payback time
  - Low Interest Loans
  - Less manpower requirements in building
- Reliability/Service
  - Multiple paths to customer
  - Downtime $\leq$ 1 hour
  - Service organization
- Conversion Time
  - Customer organization
- Disruptive Time
  - Ripped up streets
- Air pollution
  - 50 percent less
- Safety
- Others

Figure 15. Topical Questions

Once this was determined, factors that would help achieve this payback criteria for a DHCS and circumstances where it would be realized were examined.

Achieve Payback Criteria

- Tax Credits--Tax credits were often mentioned by private businesses/corporations as a means to help offset initial retrofit costs. Tax credits would not help some of the people interviewed (e.g., school, YMCA) because of their nonprofit status.
- Low Interest Loads--Low interest loans were the next most often mentioned method to help achieve the financing objective. As opposed to tax credits, this vehicle would also benefit nonprofit organization.
- Government Financial Participation in Construction--The Federal Government should consider financing a portion of the DHCS installation. Private business was quick to point out that the Government funds many social welfare programs, hydro dams and nuclear power plants.

Relaxed Payback Criteria

- Energy Outlook--Because of the bleak outlook for energy, energy-related expenditures appear to be receiving higher priority in business decisions. Because of this factor, most people would be willing to relax payback criteria. Ranges cited include an extension from three to five years.
- Business Climate--The better the business cliamate at the time, the more relaxed the economic payback. This was expressed during interviews by people who were residents of the community. Some people interviewed (e.g., manager of a shopping plaza) suggested that the owners, who were not residents of the community, would not be swayed by this argument. They would examine the investment in light of alternative investments only.

- Community Involvement--Those persons who lived in and also owned/operated businesses in the community appeared more inclined to support the DHCS concept because of possible benefits to the community. This sentiment was also expressed by persons at the State Bureau of Engineering, who suggested that the State of Wisconsin might succumb to community pressure to participate as a building owner within the community.
- Reduced Pollution--Reduced pollution was a welcomed benefit. However, those interviewed seemed unable to place a value on pollution because it was an intangible benefit and difficult to quantify.

The interviews were conducted early in the DHCS program. At the time, little concrete information was available on costs involved, what the system would entail, how it would work and the advantages of the DHCS concept. A frequent comment expressed by numerous people, especially those with no technical background, was the desire to obtain additional (written, verbal) information. When this was available, they would feel more comfortable with the DHCS concept and better able to make decisions on becoming a potential user.

In contrast to those who expressed comments about the lack of information were people who were familiar with steam district heating systems and those who had an engineering background. While these people were in the minority (about 4 out of 23), they seemed to grasp and relate to the DHCS concept more readily. Those who were familiar with steam district heating systems in Milwaukee and St. Louis and who worked in buildings heated by the system knew that the DHCS system is a viable and reliable concept. They would have no qualms about eliminating their own boiler after the DHCS system was checked out and working. This was in contrast to the majority of the

people who expressed that they would keep their present boilers, etc., as backup.

People with technical backgrounds, even though they were not familiar with the DHCS concept, were quick to grasp the concept and relate to it. They could foresee the benefits, such as increased plant efficiency, less pollution and no on-site boilers to maintain, as being beneficial to their business.

Additional information about DHCS systems--how it works, what current users think about it and costs--would greatly add to the general public acceptance of the DHCS concept. Based on the small sample of people interviewed, this would be a significant factor in inducing potential users to subscribe to the DHCS system.

Reliability--Reliability was not deemed a significant factor as perceived by the user. This is not to say that they are not concerned. Rather, they would view a project such as this to be reliable because the system will be designed as such. They also view the thermal energy as coming from the utility, which they generally regard as reliable.

The reliability of the in-building components, such as heat exchangers, controls, etc., was not broached.

The reliability concern was expressed mainly by those that did not understand the DHCS concept. Those familiar with steam DHCSs knew them to be highly reliable over extended periods of operation. This implies that general education of the public would help greatly to eliminate reliability as a factor that might preclude subsricption.

Pollution--Reduced pollution within the area was seen as a desirable benefit of the DHCS. Those that lived in the community would welcome an improved environment.

However, when probed about what they would be willing to pay for improved air quality, the responses ranged from vague generalities to very little. Hence, reduced pollution is seen as a factor that would tend to relax economic considerations rather that being a determing factor on whether or not to subscribe to the DHCS program.

Disruption--Having streets torn up for installation of the DHCS distribution system was determined not to be a significant factor that would deter potential users. Businessmen commented that torn up streets make it inconvenient for customers, thus business tends to suffer.

Industry views this potential problem even less significantly. As long as supplies can be received and products shipped, there is no problem.

Safety--Few comments on the safety of the system were received. Those that did comment viewed the safety of the system as good or better than natural gas systems.

The question of safety may be associated more with the general education (additional information) of the subscribers. Known and unknown safety advantages to the DHCS could be pointed out.

SECTION 4.0 TECHNICAL REVIEW AND ASSESSMENT

The stated objective of the technical review and assessment is to define and evaluate power plant retrofit schemes and distribution networks and determine their effect on the utilities' current and future operation and ability to conserve scarce fuels.

The heat market data that was correlated during Task 3 was refined, tabulated and sent to the three participating utilities. Using an in-house simulation model, yearly fuel, operation and maintenance costs and hours of interruption were calculated. The heating system was considered to be an interruptible load (when maximum power is needed, the heating system would be cut off).

From analysis of the site description and load data developed during Tasks 2 and 3, it was determined that four power plants and seven alternate retrofit schemes would be considered.

The alternate retrofit schemes that were evaluated were those that could supply the quantity of heat necessary without major turbine changes, corresponding downtime and turbine retrofit costs.

ALTERNATE POWER PLANT RETROFIT SCHEMES

Generally power plant steam turbine can be retrofitted in the following ways: (1) multistage uncontrolled extraction in parallel to existing feedwater extraction; (2) convert a straight condensing turbine to a pack-pressure turbine; (3) add automatic extraction valve gear to an existing straight condensing turbine; and (4) add valves and piping in the crossover piping to remove a portion of the medium pressure steam that went to the low pressure turbine.

The turbine retrofit details of the first three choices are discussed in the attached letter from General Electric, dated 2/17/77 (Appendix F). The first, second and fourth schemes are relatively easy.

Also contained in Appendix F are the flow diagram and Mollier diagram of a single case turbine with extractions and the flow diagram and Mollier diagram of a cross-compound turbine.

The seven alternate power plant retrofit schemes that were reviewed are:

- Green Bay Central Business District (CBD) with three paper mills--Pulliam 8 unit with one medium pressure extraction and crossover extraction steam.
- Green Bay CBD with two paper mills--same as above.
- Heavy Beloit heat users--Black Hawk Units 3 or 4 with three extraction points.
- Heavy Beloit and Janesville heat users--Rock River Unit 1 or 2 with two medium pressure extractions and crossover extraction.
- Future Rock River Industrial Park--same as above.
- Madison Heat for University--Blount Street Unit 6 or 7 by using the existing one automatic extraction point on each machine.
- Madison Downtown Heat--Blount Street Unit 6 or 7 by using existing automatic extraction.

ADVANTAGES/DISADVANTAGES OF PLANT RETROFIT SCHEMES

The analysis of each alternative is based on fuel cost, operating and maintenance cost, number of interruptible hours, capital cost, and the losses in the distribution system.

The fuel cost, operating and maintenance cost, and number of interruptible hours were calculated by a utility simulation model based on the tables of "power lost" and loads that were submitted to them (Tables XVIII through XXVII).

The results from the Wisconsin Public Service Corporation's analysis are summarized in Tables XXVIII and XXIX. The 1985 operation (three paper mills) is given in Table XXVIII. The heat losses and pumping losses are summarized in Table XXXV. The heat gained to power lost ratio for the Pulliam 8 Plant is 12.8 MM Btu/hour per MW.

Table XVIII on page 4-4 shows the average reduction of electrical capacity after retrofit for the largest (three paper mills) case and smaller (two paper mills) case. The reduction of electrical capacity for the three-paper-mills case varies from 37.3 to 31.1 MW, and for the two-paper-mills case varies from 17.2 to 11.7 MW. The heat balance, shown on Figure 16 on page 4-17, is based on the average hourly January heat loads and power lost values from Table XVIII (476.9 million Btu/hour: 37.3 MW and 213.9 million Btu/hour: 17.2 MW).

The following tables were sent to the Wisconsin Power and Light Company for their analysis of the three Beloit and Janesville schemes:

Table XXI. Heavy Beloit Heat Users (27, 28, 34-40) (Black Hawk Power Plant)

Table XXII. Heavy Beloit Heat Users and Heavy Janesville Users (11, 13, 14, 17, 18, 19)

Table XXIII. Future Industrial Park West of Rock River

The heat gained to power lost ratio for the first scheme is 15.0 MM Btu/hour per MW. The ratio for the other two schemes is 14.5 MM Btu/hour per MW.

The following tables were sent to the Madison Gas and Electric Company for their analysis of the two Madison schemes:

Table XXIV. Simulated Monthly Blount Street Cogeneration Operation

Table XXV. Capitol Heating Plant Data

Table XXVI. Madison Ten Largest Downtown Blocks

Table XVIII. Simulated Monthly Pulliam Cogeneration Operation

MONTH	* LARGEST HOURLY HEAT LOAD BTU X 10^6	** LARGEST MW POWER LOST USING PULLIAM 8	*** SMALLER HEAT LOAD BTU X 10^6/HR	**** SMALLER MW POWER LOST USING PULLIAM 8
Jan.	476.929	37.3	213.9	17.2
Feb.	478.389	37.3	215.4	17.2
Mar.	460.306	35.7	197.3	15.8
Apr.	444.598	32.5	181.6	14.6
May	423.371	32.3	160.4	12.8
June	412.885	31.5	149.9	12.0
July	409.283	31.1	146.3	11.7
Aug.	409.199	31.1	146.3	11.7
Sept.	412.388	31.4	149.4	12.0
Oct.	421.852	32.3	148.9	12.8
Nov.	437.737	33.7	174.7	14.0
Dec.	459.463	35.6	196.5	15.7

* Including 401 MM Btu/hour for the three paper mills (the word "largest" means the three-paper-mill alternate).

** Power lost using Pulliam 8 is based on $\frac{476.9}{37.269} = 12.80 \frac{\text{MM Btu/hour}}{\text{MW}}$

*** Including 138 MM Btu/hour for two paper mills (the word "smaller" means the two-paper-mill alternate).

**** Power lost using Pulliam 8 is based on $\frac{215.4}{17.254} = 12.48 \frac{\text{MM Btu/hour}}{\text{MW}}$

Table XIX. Commercial Green Bay Heating Load

MONTH	CURRENT MONTHLY LOAD BTU x 10^9	CURRENT HOURLY LOAD BTU x 10^6	ADDITIONAL FORECASTED MONTHLY LOAD BTU x 10^9	ADDITIONAL HOURLY LOAD BTU x 10^6	FUTURE TOTAL HOURLY LOAD BTU x 10^6
Jan.	45.041	60.539	11.450	15.390	75.929
Feb.	41.897	62.347	10.108	15.042	77.389
Mar.	35.318	47.470	8.806	11.836	59.306
Apr.	26.214	36.408	5.177	7.190	43.598
May	13.839	18.601	2.805	3.770	22.371
June	7.522	10.447	1.035	1.438	11.885
July	5.651	7.595	0.512	0.688	8.283
Aug.	5.426	7.293	0.674	0.906	8.199
Sept.	6.608	9.178	1.591	2.210	11.388
Oct.	11.601	15.593	3.913	5.259	20.852
Nov.	19.274	26.769	7.177	9.968	36.737
Dec.	33.257	44.700	10.240	13.763	58.463

Table XX. Green Bay Commercial Space Heating and Domestic Hot Water Monthly Loads

MONTH	FUTURE TOTAL HOURLY LOAD BTU X 10^6	* SPACE HEATING HOURLY LOAD BTJ X 10^6	AVERAGE DEGREE DAYS	AVERAGE TEMP. (F)
JAN.	75.929	67.7	1494	16.9
FEB.	77.389	69.1	1313	18.1
MAR.	59.306	51.0	1141	28.2
APR.	43.598	35.3	654	43.2
MAY	22.371	14.1	335	54.2
JUNE	11.885	3.6	99	61.7
JULY	8.283	- -	28	64.1
AUG.	8.199	- -	50	63.4
SEPT.	11.388	3.1	174	59.2
OCT.	20.852	12.6	484	49.4
NOV.	36.737	28.4	924	34.2
DEC.	58.463	50.2	1333	22.0

* Domestic hot water is assumed to be an average of 8.3 BTU X 10^6/ based on the July and August total heat load.

Based on 1494 degree days for January, the average degree day is $\frac{1494}{31} = 48.2$.

Maximum degree day is based on the minimum temperature of - 14 on January 30 which corresponds to a 79 degree day.

Maximum hourly space heating load is $\frac{79}{48.2}$ (67.6) = 110.8 MM Bt

Maximum hourly space heating and domestic hot water load is 110.8 + 8.3 = 119.1 MM Btu/hr.

Table XXI. Simulated Monthly Cogeneration Opeartion
**Heavy Beloit Heat Users (27, 28, 34-40)
(Blackhawk Power Plant)

Month	Aver. Heat From Boiler Btu X 10^6/hr	Aver. Heat From Turbine Btu X 10^6/hr	MW Power Lost Using Black Hawk *
January	111.4	93.7	6.23
February	165.5	93.7	6.23
March	62.9	93.7	6.23
April	27.0	93.7	6.23
May	0	88.3	5.86
June	0	82.8	5.49
July	0	62.9	4.18
August	0	62.9	4.18
September	0	69.9	4.69
October	0	84.4	5.64
November	19.0	93.7	6.23
December	54.6	93.7	6.23

* Power lost using Black Hawk is $\frac{46.87}{3.124} = \frac{15.0 \text{ MM Btu/hr}}{\text{MW}}$

** Only heat users of 2 MM Btu X 10^3 or larger for the month of January were included.

Table XXII. Simulated Monthly Cogeneration Operation Heavy Beloit Heat Users and Heavy Janesville Heat Users (11, 13*, 14, 17, 18, 19) (Rock River Power Plant)

Month	Aver. Heat From Boiler Btu X 10^6/hr	Aver. Heat From Turbine Btu X 10^6/hr	MW Power Lost Using Rock River **
January	23.5	362.	24.9
February	80.7	362.	24.9
March	0	303.6	20.9
April	0	261.3	18.1
May	0	196.2	13.5
June	0	177.9	12.3
July	0	140.3	9.7
August	0	139.7	9.6
September	0	156.8	10.8
October	0	215.3	14.9
November	0	270.1	18.7
December	0	325.7	22.5

* Only coal fired boilers are replaced in Block 13.

** Power lost using Rock River is $\frac{362}{25.007} = \frac{14.48 \text{ MM Btu/hr}}{\text{MW}}$

Table XXIII. Future Industrial Park West of Rock River Power Plant

Estimated load is over 1 X 10^{12} Btu/yr with a peak of 250 MM Btu/hr.

Assuming 343 days per year operation at 150 MM Btu/hr the yearly load is 343 X 24 X 150 = 1,234,800 MM Btu.

Power lost using Rock River is $\frac{362}{25.007} = \frac{14.48 \text{ MM Btu/hr}}{\text{MW}}$

Average power lost is $\frac{150}{14.48} = 10.36$ MW.

For purposes of the "power lost" replacement fuel cost, O & M cost, and hours of interruption, the assumed power lost is 10.36 MW for every hour of the year.

Table XXIV. Simulated Monthly Blount Street Cogeneration Operation (Madison Downtown Heat Users)

MONTH	* HOURLY HEAT LOAD BTU X 10^6	** MW POWER LOST USING #4	*** MW POWER LOST USING #6 or #7
Jan.	57.9	6.36	4.63
Feb.	61.5	6.76	4.92
Mar.	45.9	5.04	3.67
Apr.	27.0	2.97	2.16
May	15.7	1.73	1.26
June	5.5	0.60	0.44
July	5.8	0.64	0.46
Aug.	4.7	0.52	0.38
Sept.	8.7	0.96	0.70
Oct.	20.3	2.23	1.62
Nov.	31.1	3.42	2.49
Dec.	45.0	4.95	3.60

* Included are the Capitol Heating Plant potential cogeneration steam sale and the 10 largest downtown heat users (74, 94, 8[illegible] 82, 52, 102, 95, 67, 75 and 101).

** Power lost using #4 is based on $\frac{94.94}{10.43} = \frac{9.099 \text{ MM Btu/hr}}{\text{MW}}$

*** Power lost using #6 or #7 is based on $\frac{248.65}{19.90} = \frac{12.49 \text{ MM B[illegible]}}{\text{MW}}$

Table XXV. Capitol Heating Plant Data

MONTH	MEGAWATT-HR	EXHAUST STEAM LB/HR AVER. *	HEATING STEAM LB/HR AVER. **	POTENTIAL SALE COGENERATION STM. LB/HR AVER. ***
Jan.	669	20,448	34,300	13,852
Feb.	446	15,092	31,100	16,008
Mar.	317	9,689	24,700	15,011
Apr.	249	7,864	18,500	10,636
May	228	6,969	14,030	7,061
June	217	6.854	9,000	2,146
July	200	6,113	9,000	2,887
Aug.	242	7,397	9,000	1,603
Sept.	234	7,391	11,930	4,539
Oct.	359	10,973	19,900	8,927
Nov.	528	16,676	23,300	6,624
Dec.	604	18,461	27,800	9,339

* 1977 Data based on a steam rate of 22.74

** 1976 Data May thru Sept. corrected based on some of the Capitol plant boiler generation being used for chiller steam turbine drive at 9.85 lb/ton.

*** Potential is the difference of the heating steam (sum of blocks 000, 85, and 86) and the exhaust steam production. Even though this is the difference of data from 2 different years the answer should be approximately correct.

Table XXVI. Madison Ten Largest Downtown Blocks (Excluding 000, 85 and 86 Served by Capitol System)

BLOCK	JAN	FEB	MAR	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	
74	4.841	4.335	2.175	1.267	.886	.773	.704	.670	.746	1.121	1.927	3.641	
94	3.486	3.476	2.910	1.786	1.271	.567	.405	.468	.512	1.155	2.239	3.403	
60	3.962	3.761	2.948	1.839	1.078	.268	.268	.223	.302	1.240	2.076	3.545	
82	3.800	4.408	3.215	.563	.418	.008	.008	.008	.032	1.148	2.432	2.545	
52	3.819	3.442	2.812	1.292	.418	.215	.192	.197	.451	.451	1.867	2.379	
102	3.000	2.651	1.923	1.347	.396	.089	.019	.076	.087	.516	1.551	2.435	
95	3.050	2.521	1.804	1.016	.501	.181	.163	.161	.171	.566	1.528	2.296	
67	2.173	1.944	1.633	.963	.461	.157	.188	.220	.366	1.026	1.422	2.034	
75	2.451	2.148	2.119	.796	.271	.061	.051	.045	.053	.534	1.466	2.374	
101	2.144	1.919	1.511	.934	.699	.148	.219	.248	.299	.748	1.148	1.937	
TOTAL	32.726	30.605	23.050	11.803	6.399	2.467	2.217	2.316	3.019	8.505	17.656	26.589	Monthly X 10^9 Btu
	44.0	45.5	30.9	16.39	8.60	3.43	2.90	3.10	4.19-11.4		24.52	35.74	Average X 10^6 Btu/hr

Table XXVII. Simulated Monthly Blount Street Cogeneration Operation When Supplying Heat Only to University of Wisconsin Buildings for Space Heat and Domestic Hot Water

MONTH	* HOURLY HEAT LOAD BTU X 10^6	** MW POWER LOST USING #6 or #7
Jan.	252	20.2
Feb.	214	17.1
Mar.	214	17.1
Apr.	201	16.1
May	123	9.8
June	79	6.3
July	26.5	2.1
Aug.	26.5	2.1
Sept.	94.5	7.6
Oct.	154	12.3
Nov.	176	14.1
Dec.	198	15.9

* Not included is the heat to generate high pressure steam for electric generation and steam turbine driven chillers.

** Power lost using #6 or #7 is based on

$$\frac{248.65}{19.90} = \frac{12.49 \text{ MM Btu/hr}}{\text{MW}}$$

Table XXVIII. Green Bay District Heating System (Three Paper Mills) 1985 Operation

MONTH	OPERATING HOURS	FUTURE TOTAL HOURLY BTU X 10^6	MONTHLY BTU X 10^6
Jan.	744	477	354,888
Feb.	593	478	283,454
Mar.	744	460	342,240
Apr.	720	445	320,400
May	744	423	314,712
June	720	413	297,360
July	744	409	304,296
Aug.	137	409	56,033
Sept.	720	412	296,640
Oct.	744	422	313,968
Nov.	720	438	315,360
Dec.	744	459	341,496
			3,540,847

NOTES:

(a) August operating hours are low because 79 of the interruptible hours and the 22 days of holidays and planned shutdowns are assumed to occur then. February hours are low because 79 of the interruptible hours are assumed to occur then.

(b) The difference between the heat supplied (3,540,847) and the thermal loads (page 3-13) is due to the 158 hours that heat supply is interrupted since full power is needed and the 22 days of holidays and planned shutdowns. Capital costs for a 100 million Btu/hour standby oil- or gas-fired water heater to provide enough heat for downtown area during the interruption hours are included. The quantity of heat that would be sold from the standby-fired water heater is not included since this would be replacing oil- or gas-fired building boilers.

Table XXIX. Green Bay District Heating System
(Two Paper Mills)

1985 OPERATION

MONTH	OPERATING HOURS	FUTURE TOTAL HOURLY BTU X 10^6	MONTHLY BTU X 10^6
Jan.	744	213.9	159,142
Feb.	593	215.4	127,732
Mar.	744	197.3	146,791
Apr.	720	181.6	130,752
May	744	160.4	119,338
June	720	149.9	107,928
July	744	146.3	108,847
Aug.	137	146.2	20,029
Sept.	720	149.4	107,568
Oct.	744	158.9	118,222
Nov.	720	174.7	125,784
Dec.	744	196.5	146,196
			1,418,329

NOTES:

(a) August operating hours are low because 79 of the interruptible hours and the 22 days of holidays and planned shutdowns are assumed to occur then. February hours are low because 79 of the interruptible hours are assumed to occur then.

The heat gained to power lost ratio for the cogeneration designs that use Blount Street Unit 4 is 9.099 MM Btu/hour per MW. The ratio when using Unit 6 or 7 is 12.49 MM Btu/hour per MW.

MODES OF OPERATION FOR TURBINE RETROFIT SCHEME

The Green Bay scheme for three and two paper mills is illustrated in Figure 16. Medium pressure steam flow to DHS heater 2 is flow controlled to eliminate any turbine upsets due to any district heating system upset. Because of the large heat capacity of the water in the district heating system, the possibility of a district heating system upset is slight. During a peaking operation, control valve FIC-1 CV will automatically close.

The minimum steam flow to the low pressure turbine is indirectly controlled by control valve FIV-2CV, which controls the flow of steam to DHS heater 1. The pressure of the steam to DHS heater 1 is controlled by PIC-1CV. During a peaking operation, FIC-2CV closes and PIC-1CV opens.

The basic operation continues the original design throttle and reheat steam flows and pressures.

At intermediate heat loads, FIC-2 and FIC-1 are reset to adjust the steam flows to DHS heaters 1 and 2. Determination of the priority of steam to either DHS heater 1 or 2 will be made during Phase 2 of this project.

The operation of the Black Hawk (Figure 17), Rock River (Figure 18), and Blount Street (Figure 19) cogeneration schemes is similar to that described above for Pulliam 8.

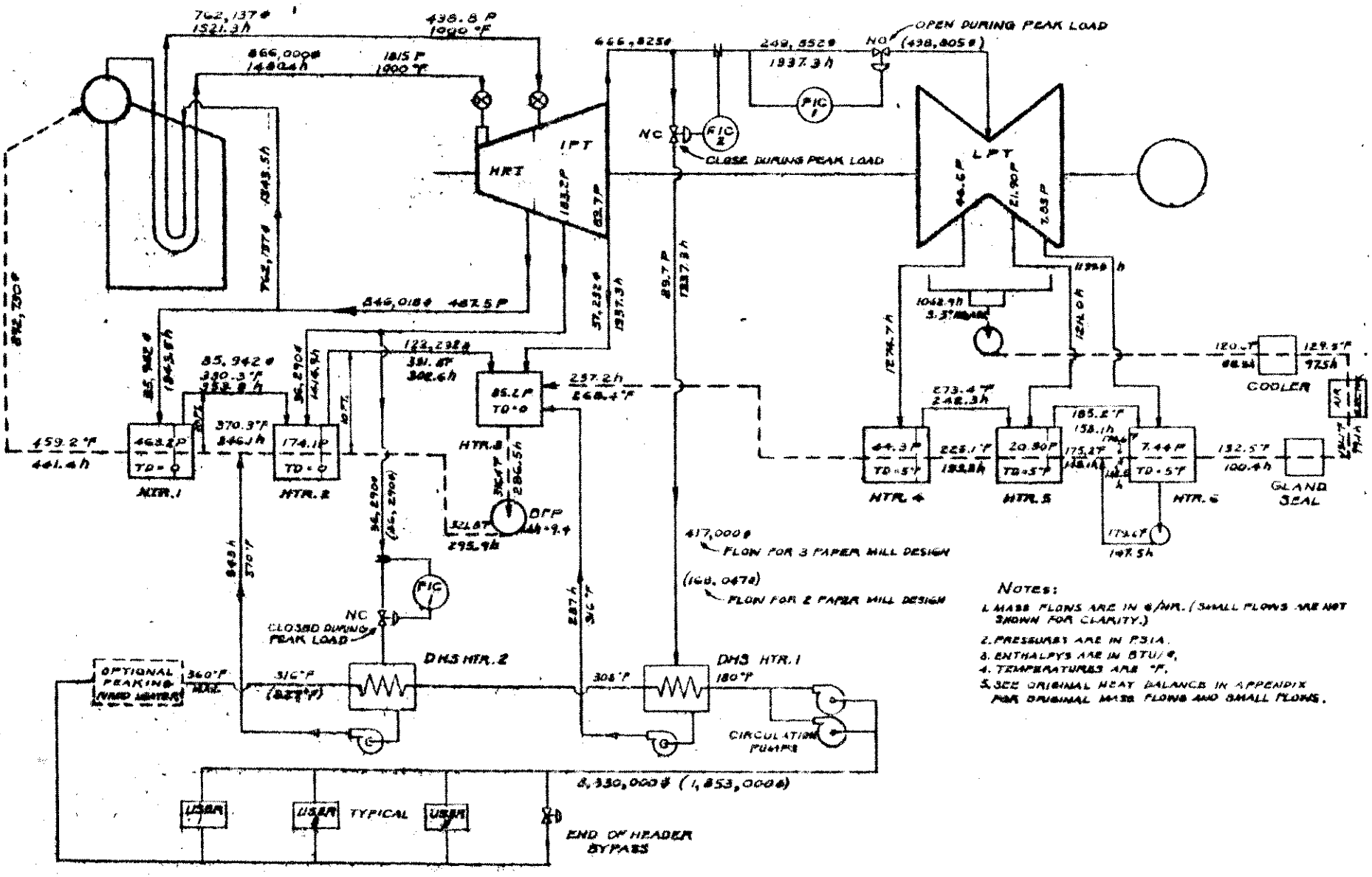
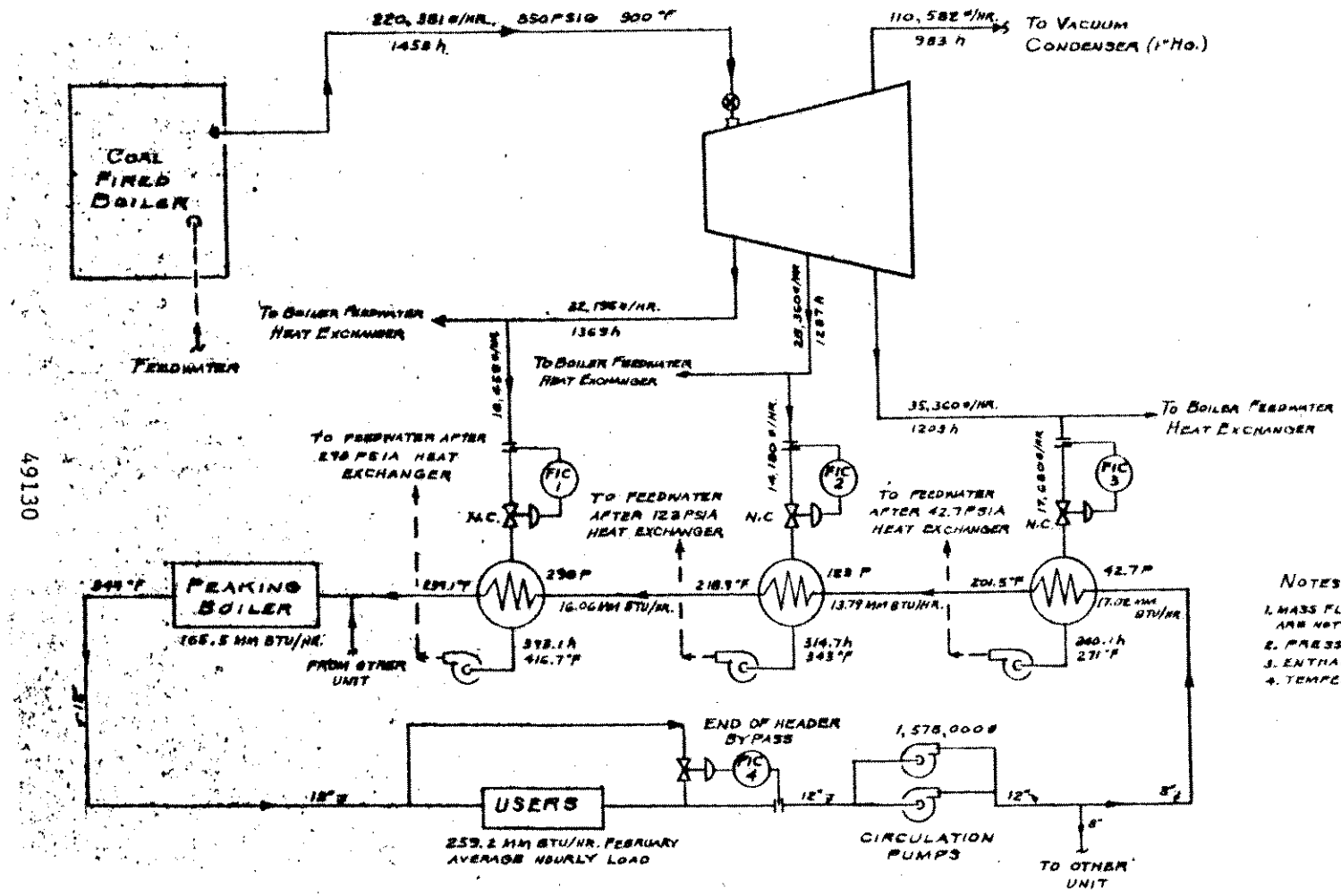


Figure 16. Pulliam 8 Heat Balance Diagram with District Heating System Retrofit for Three- and Two-Mill Heat Loads and Downtown Green Bay Loads



Notes:

1. Mass flows are in #/HR. (Small flows are not shown for clarity)
2. Pressures are in P.S.I.A.
3. Enthalpys are in BTU/#
4. Temperatures are °F

Figure 17. Black Hawk 3 and 4 Heat Balance Diagram with District Heating System Retrofit for Ten Largest Beloit Users

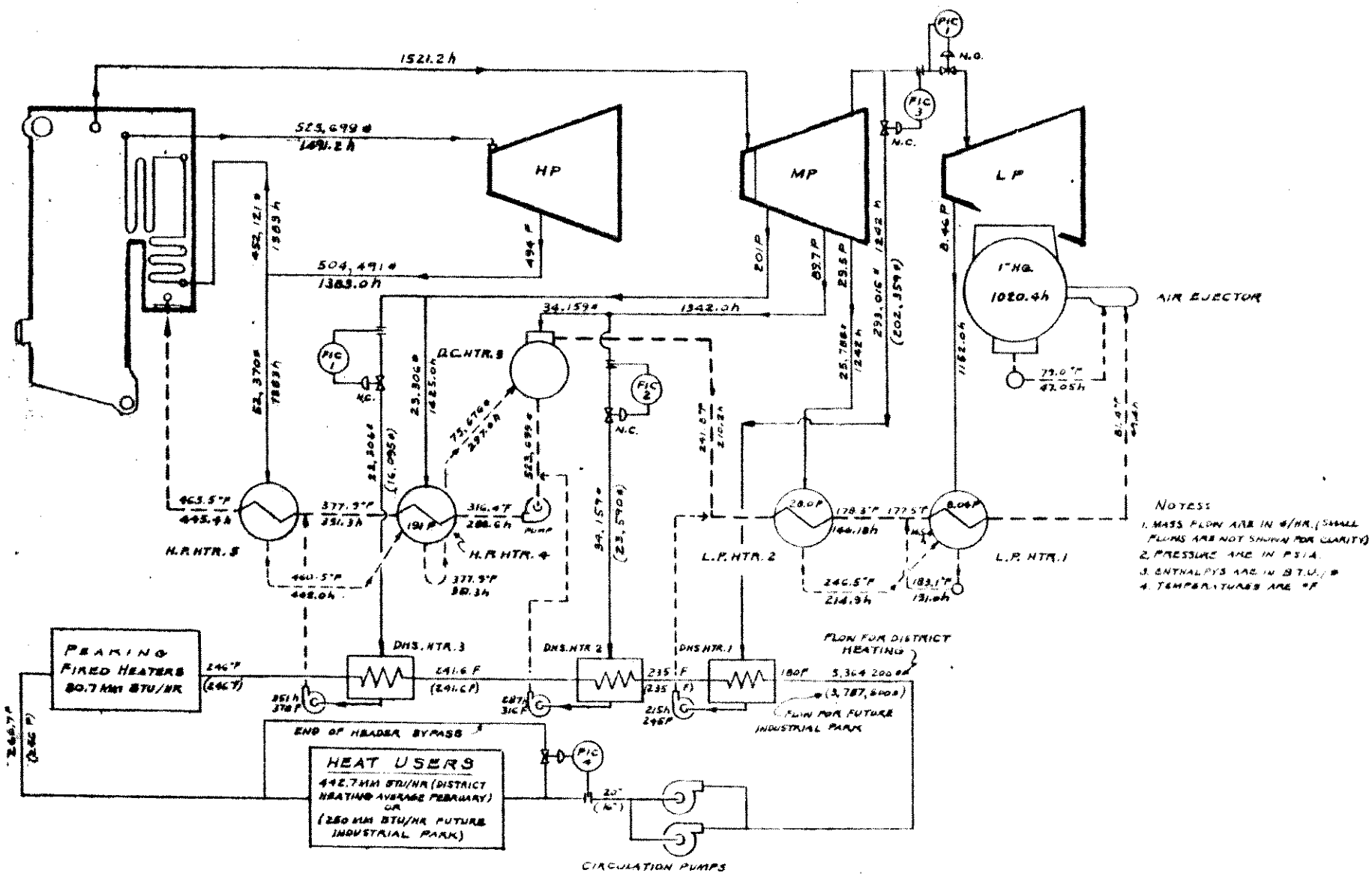


Figure 18. Rock River 1 or 2 Heat Balance Diagram with Turbine Retrofit for District Heating System or Future Industrial Park

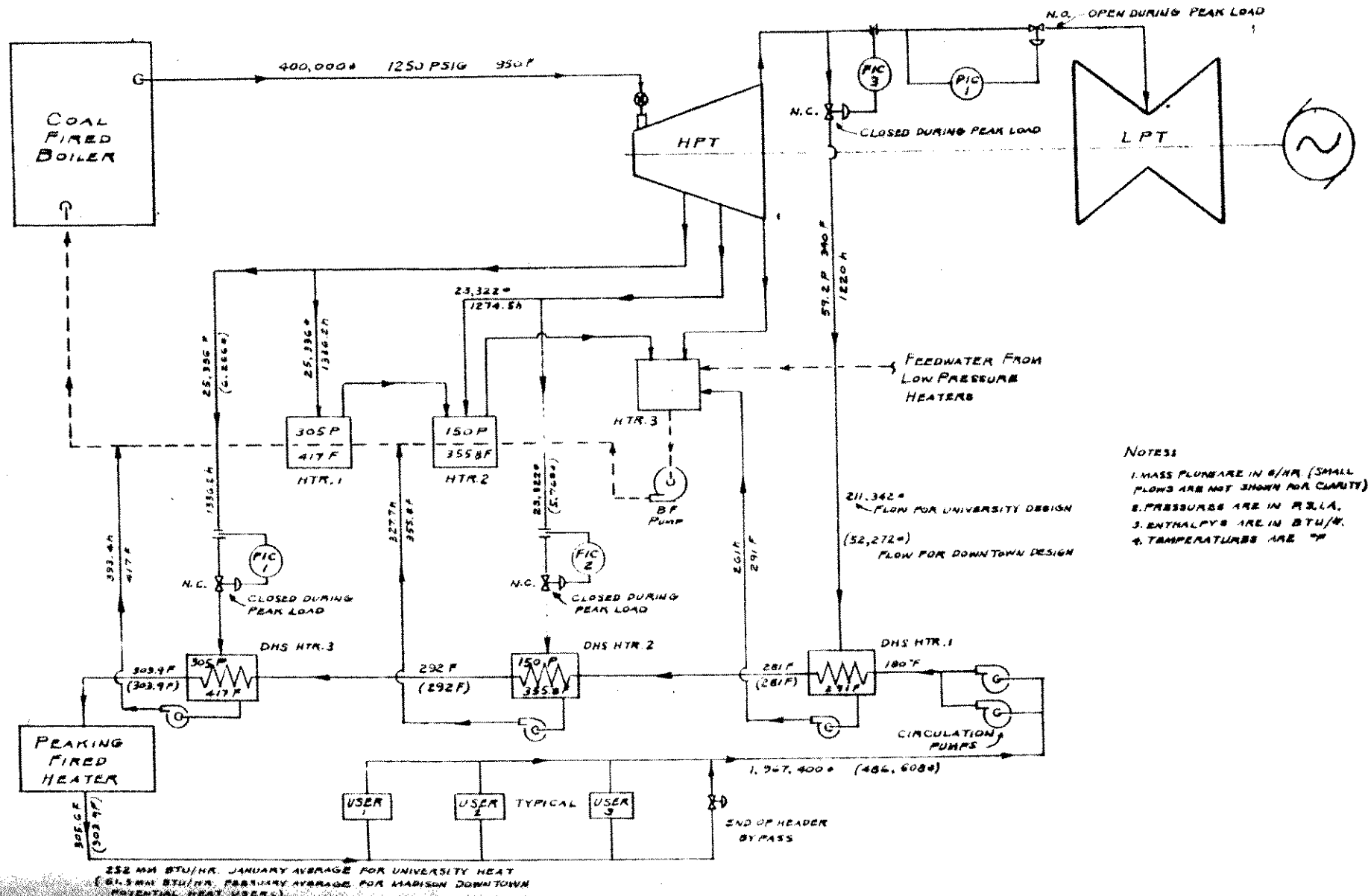


Figure 19. Blount Street 6 or 7 Heat Balance Diagram with District Heat for University and Downtown

EFFECTS OF UTILITY PLANT LOAD VARIATION

The effects of variation of heat demand on the total cogeneration operation will be considered for the following expected range of operation:

- Average winter operation,
- Peak winter operation,
- Spring and fall operation,
- Summer operation.

For all of the designs considered, the cogeneration turbine was a "must run" turbine, and the electrical output from that unit was fully dependent on the amount of heat that was taken off to the district heating system.

The throttle steam flow and pressure would normally be at design conditions. The extraction steam and crossover steam flows would be controlled to meet the heating system loads, but not in excess of the requirements for the safe operation of the turbine.

If the heat demand is greater than that available from the turbine, either a peaking boiler must be used, some heat loads must be interrupted, or excess high pressure steam from other power plant boilers must be used.

During peak winter operation, thermal storage of the water in the distribution piping will average out the turbine heat drain during peak hourly loads.

During summer, spring, or fall operation the district heating system can operate with lower temperatures if the heat is used only for space heating and domestic hot water.

EFFECT ON UTILITY'S GENERATION CAPACITY

During cogeneration, the power output from the retrofitted turbine is reduced. The lost power must be made up by generating additional power from other units in the utility's complete system.

If the cogeneration operation is considered an "interruptible" operation, during times of peak power demand in either the winter or summer seasons the cogeneration heat from the turbine could be shut off. For this operation there would be no effect on the total reserve capacity of the utility. As an example, the Green Bay operation would have a range of "interruption" hours per year from 42 (year 1980) to 329 (year 1990).

Wisconsin Public Service Corporation's analysis of the Green Bay operation considered the district heating system in their dispatching order in a position just after the combustion turbines, but before their other interruptible loads (large electric interruptible loads and electric domestic hot water heaters).

AVAILABLE THERMAL ENERGY FROM POWER PLANT

The peak theoretical thermal energy and the corresponding highest temperature level of the energy when it is transmitted by high temperature water is:

- Pulliam 8 - 674 MM Btu/hour at 313°F;
- Pulliam 7 - 364 MM Btu/hour at 330°F;
- Black Hawk 3 - 46.9 MM Btu/hour at 407°F;
- Rock River - 362 MM Btu/hour at 246°F;
- Blount Street 4 - 118 MM Btu/hour at 386°F;
- Blount Street 5 - 116 MM Btu/hour at 386°F;
- Blount Street 6, 7 - 249 MM Btu/hour at 304°F.

The actual thermal energy that was considered to be available is shown on Tables XVIII, XXI, XXII, XXIII, XXIV, and XXVII.

SYSTEM CHARACTERISTICS

General

The most common media used for generating and distributing heat for space heating and industrial heating are steam and hot water. In indirect or secondary heating systems, heat from the combustion of fuel or from electric energy is transferred to a liquid or a gas and distributed through pipes or ducts to the area or process where a second heat transfer takes place. This method makes it possible to obtain close control of temperatures, to supply heat to a number of processes or areas from one primary heating unit, and to locate that unit in the most convenient place. The most common example of indirect heating is that used for building heat where water, steam, or air is used as the heat-transfer medium. Among the heat-transfer fluids used in industry, aside from steam, water, and air, are the special petroleum-based heat-transfer oils, various chemical fluids, and inorganic salt mixtures.

Steam Systems

A steam heating system uses the vapor phase of water to supply heat to a conditioned space or a process. In the steam heating system, the heat transfer medium moves through successive changes of state. Basically, the cycle is as follows: heat from a suitable source is supplied to water (in a steam boiler), causing it to boil and continuously vaporize. The vapor is transported to terminal equipment through a system of piping. In the terminal equipment, the flow of heat is transferred, and condensation takes place (again changes state). The cycle is completed by the return of condensate to the boiler, where heat is reapplied to reconvert it into steam.

In some installations, the cycle is only partially completed. The vapor is transported to the terminal equipment where its energy is transferred; the condensate is subcooled as far as practicable, and then released to the sewer

instead of being returned to be recycled. Such disposal of condensate usually occurs in large district heating systems or process work where it may be contaminated or may be considered more economical to discard it than to provide piping for its return; this waste of water increases the feedwater makeup and chemical treatment requirements, and increases the possibility of corrosion.

Steam heating systems may be classified according to their operating pressure ranges as follows:

- Low-pressure system when the operating pressures vary from 0 to 15 psig;
- Medium-pressure system when the operating pressures vary from 15 to 155 psig;
- High-pressure system when the operating pressures are above 155 psig.

Low-pressure systems range from small residences to large commercial or industrial buildings where the main load consists of comfort heating and domestic hot water requirements.

Medium-pressure systems are most commonly used in industrial plants, institutional buildings, for process applications, and to supply steam to widespread loads.

High-pressure systems are used in those industrial plants where higher process temperatures are required and for large area distribution, as well as for district heating where the heat energy is to be transported over long distances. In all large systems where steam is generated and transmitted at high pressures, the high pressures are reduced to medium pressures and subsequently to low pressures to suit local requirements for process heating and space heating. Pressure reducing valves are installed at convenient locations in each building or area where the reduced pressure are required.

The return of condensate to the boiler is a guiding factor in successful steam system design. In gravity return systems, the condensate returns to the boiler solely by gravity, but the steam flows by the effect of the steam to pressure. Gravity systems are usually limited to small loads or package processing equipment, in which operation at various pressures is not required. When conditions are such that the condensate cannot be returned to the boiler by the action of gravity, either traps or pumps (or both) must be employed, and these systems are known as mechanical return systems. Such return systems are employed in large installations and multibuilding complexes where many changes in elevation of steam mains occur and where long condensate return mains make it impractical to use a gravity return system.

An important consideration in the design of a steam system is to provide for proper drainage of the condensate that separates out in the steam piping. The steam mains must be uniformly graded and free from places where condensate can collect, except those provided for its collection and drainage. The distribution of steam should be rapid, uniform and without noise. The condensate which collects in steam piping must be drained to prevent interference with the ready flow of steam. This dictates that the steam piping should always pitch downward in the direction of flow. Also, the system should be designed and installed so that the steam piping can drain completely by gravity whenever the steam is shut off. If condensate runs against the steam flow (counter flow of condensate and steam), the steam piping must be oversized to reduce the steam velocity and prevent picking up of the condensate by the steam, which would cause turbulence, noise, water hammer and severe shocks to the piping system.

Hot Water Systems

A water heating system is one in which hot water is used to convey heat to or from a conditioned space or process through piping connecting a boiler or water heater, with suitable terminal heat transfer units located at the space

or process. Hot water systems handle only a liquid, not a liquid and its vapor as do steam systems.

Hot water systems are usually classified according to their operating temperature ranges, as follows:

- Low-temperature water system (LTW) - A hot water heating system operating at a temperature below 250°F, with a maximum working pressure of 30 psig;
- Medium-temperature water system (MTW) - A hot water heating system operating at a design supply temperature between 250° and 350°F, with a working pressure not exceeding 150 psig;
- High-temperature water system (HWT) - A hot water heating system operating at temperatures over 350°F and a usual pressure rating of 300 psig for the system.

Low-temperature water systems have replaced steam systems for residential heating applications. Many commercial, institutional and residential buildings have been successfully and economically designed using low-temperature water. Where loads consist primarily of space and domestic water heating and do not exceed 5 to 10 million Btu per hour total, low-temperature water is generally used.

Medium-temperature water systems are most commonly used in industrial process applications and in heating systems in large commercial and institutional buildings. Medium-temperature water is generally used for industrial applications with process loads and for space heating or district heating applications having total loads of from 5 to 20 million Btu per hour.

High-temperature water systems are generally used in large district heating installations, such as: military bases, campuses, shopping center, airports, and in applications having process heating requirements in excess of 325°F.

High-temperature water is generally used for space heating applications where loads are in excess of 20 million Btu per hour.

High-Temperature Water Systems--High-temperature water systems are basically similar to the conventional forced circulation hot water heating system. Basic components are: HTW generator or boiler, expansion vessel, boiler circulating pump, system circulating pump, distribution piping, and heat utilization equipment. In operation, the HTW generator receives low-temperature return water from the system and adds required heat to bring the water up to the system circulating pump, which circulates the water through the distribution piplines to the points of application in the various buildings. The system water return to the generator at a lower temperature to complete the cycle. For this study, the HTW generator will be a heat exchanger with HTW on one side and turbine extraction steam on the other side.

At certain times, the simultaneous closing of many control valves in the system will reduce the quantity of HTW returning to the generator. Should the flow of the system return water to the generator become less than the minimum design flow requirements, high-temperature water from the generator discharge will flow through the bypass connection to combine with the system return water and maintain minimum flow to the HTW generator.

System circulating pumps are used to overcome the frictional resistance to fluid flow within the distribution pipes. HTW permits the transportation of thermal energy over long distances with a very slight drop in temperature. For example, in a properly insulated 6-inch diameter pipe, the loss in temperature is generally less than $3^{o}F$ per mile of conduit.

Vents are installed at the high points and drains at the low points of the system. The system is vented at these points mainly when starting. The drains are used when additions or repairs to the system require the draining

and subsequent filling of the sections.

Heat is extracted throughout the system by user equipment. As the system is completely closed, no water is consumed in satisfying the heating requirements. All unused heat remaining in the water is returned to the source. Changes in volume in the system water due to temperature fluctuations in the system are taken up in the expansion vessel, which at the same time is used for pressurizing the system.

HTW Flexibility--High-temperature water is suitable for both space and process heating in a wide range of applications. Where high temperatures are required, HTW can be applied directly to space or process heating coils. For normal baseboard or radiator heating, domestic hot water, and lower temperature process jobs, closed-circuit heat exchangers are employed at desired locations. Medium and low pressure process steam can be generated, where needed, by HTW-to-steam heat exchangers.

In summary, high-temperature water is capable of producing any or all of the following:

- Direct heating with high-temperature water;
- Indirect heating by use of high to low-temperature water heat exchangers for localized space heating with low-temperature water
- Domestic hot water for local use;
- Low-pressure steam for space heating;
- Steam used for process or for power;
- Medium-temperature water or low-pressure steam for absorption air conditioning systems.

Flow Generation--In terms of flow generation, hot water heating systems are of two types; (1) the gravity system, in which circulation of the water is due to the difference in weight between the supply and return water col

of any circuit or system, and (2) the forced system in which a pump, usually driven by an electric motor, maintains the necessary flow.

Gravity systems are no longer used in the United States. In the past they were used for single dwellings and small to moderate size commercial installations. The forced circulation system gives better control, quicker response, positive circulation, and lower first cost due to the much smaller pipe sizes and smaller terminal heating units.

Pressurization--In a hot water heating system, an expansion tank must be provided to take care of changes in water volume resulting from changes in water temperature. Expansion tanks may be open or closed. The open tank is vented to the atmosphere and must be located above the highest point in the system. Open tanks are limited to small installations having operating temperatures of 180°F or less, and thus have very limited use.

By far, the largest number of installations are furnished with closed expansion tanks, which provide a means of pressurization over a wide range of operating conditions. In addition to accommodating changes in water volume, the closed expansion tank controls the pressure of the system above the saturation temperature of the water to prevent boiling of the water, which can lead to serious operational difficulties.

There are two methods of pressurization in common use: (1) inert gas pressurization and (2) steam pressurization. In a gas pressurized system, the expansion space in the expansion vessel is filled with an inert gas, usually nitrogen, which varies in pressure as the water level rises and falls. In a steam pressurized system, the expansion vessel is located above the boilers and connected in the supply water line from the boilers. Water in the expansion vessel flashes into steam and maintains system pressure above the saturation point of the cooler water in the balance of the system.

Distributive Systems

The central heating plant will comprise one or more heat exchangers and their related pumps, receivers and auxiliary equipment. The heat exchangers will receive extraction steam from the steam-driven turbine generators and generate high temperature water for distribution to surrounding buildings for heating purposes and industrial uses.

It is usually preferable that groups of buildings be supplied with heat from a central plant rather than from individual plants to permit design for better combustion efficiency with less expensive fuel and reduction of labor per unit of output. The central plant justifies use of more competent personnel and often decreases the investment required.

There are other advantages such as confining noises, odors, and debris to a single location where it is more convenient for handling.

The term district heating refers to the supplying of heat from a central plant to a group of buildings in a city, institution, housing development, or industrial or commercial area. District heating systems may serve a wide variety of heating and cooling loads in a large area. Loads commonly encountered are comfort heating and cooling, and steam generation for process or power use. The proportion and duration of these loads can be a major factor in determining the type of district heating system which is best for a given area.

Distribution Piping--Distribution piping in district heating systems may be run through buildings, through the air on poles or other structures, or underground in conduits or tunnels. Local conditions and investment will be governing factors in establishing the route of the pipes. Important points in laying out distribution piping are:

- Piping within buildings or basements is normally least expensive to install and to maintain.
- Underground installations involve excavation, which represents a substantial portion of the total cost. The depth of such excavations should be kept to a minimum after due consideration has been given to the possible damaging effect of the operating-line heat on lawns and shrubbery and the possible damage to the underground structure due to heavy traffic, etc.
- Walking tunnels usually are not provided for distribution mains in the district heating industry because of their relatively high first cost as compared with smaller conduits, unless they are required to accomodate miscellaneous other services or to provide underground passage between buildings.
- Overhead piping on poles or structures is generally less expensive than underground lines, especially in some institutional and industrial areas, and may be a means of eliminating buried conduit in areas where underground installations would be expensive or undesirable. Thin corrugated aluminum sheets are available for covering the insulation on lines exposed to the weather. Such lines may introduce freeze-up problems, higher heat losses and, in many locations, would be considered unsightly. For purposes of this study, overhead piping was not considered.
- Piping routed in loops, with suitable valves to provide alternate feeds for major loads, allows service to be maintained despite trouble in any one feeder.
- It is desirable to estimate as far as possible the probable growth and change in load centers. Since the character of the district served is almost certain to change with time, the distribution system must be planned to accommodate changes. It is helpful to provide a master distribution plan, that can be revised from time to time to suit conditions as the system grows.

Distribution System Characteristics--

Steam Systems--

Steam distribution pressure: The pressure at which the steam is distributed depends upon the requirements of the building served by the system, the size of the load, and the length of the distribution piping. Large steam distribution systems usually operate at send-out pressures between 125 and 250 psig. Steam pressure higher than 250 psig are usually not justified because the increased cost for heavier system components, such as piping, valves, and pressure-reducing stations, exceed the benefits derived from operating at higher pressure.

Depending on its use, steam can be used either at line pressure or by passing it through a pressure-reducing valve. Steam at line pressure is used in industrial process applications; for steam supply to laundries; and for other high-pressure equipment such as steam-driven turbines for water chillers in air conditioning systems. The upper limit of 250 psig, which is equivalent to 405°F, restricts the usefulness of a steam system for general industrial applications since many industries require higher temperatures.

For comfort heating applications, the high pressure district steam is reduced in pressure by passing the steam through one or two pressure-reducing valves. Most building heating systems, such as apartment houses, office and commercial systems, such as apartment houses, office and commercial buildings, operate at pressures from 2 to 15 psig. The reasons for operating at the low pressure are mainly: (1) less danger to the building occupants should there be a break in the piping or failure in a piece of equipment; (2) more comfortable environment when terminal heating equipment such as radiators, convectors and baseboard heaters operate at lower surface temperatures; and (3) lower cost of terminal heating equipment when designed for low pressures.

Two-Pipe System: A two-pipe steam distribution system consists of one large-diameter pipe for steam distribution and a relatively small-diameter pipe for condensate return. Steam piping in distribution systems is normally subject to very little corrosion, and carbon steel pipe is used with satisfactory results. Condensate return on the other hand is subject to rapid, and in some cases severe, corrosion. For condensate return lines, wrought iron pipe is often used because of its slower rate of corrosion; however its cost is greater than that of steel pipe. Brass or copper, which have much longer life than steel or wrought iron, are seldom used today because of their high cost.

One-Pipe System: Some large steam distribution systems eliminate condensate return piping because of high initial cost for a corrosion resistant system, or because of high replacement costs if steel pipe material is used. However, if the condensate is wasted instead of being returned to the plant, there is a total loss of the heat energy available in the condensate. This loss of heat energy alone can reduce the overall thermal efficiency by 10 to 15 percent, not to mention the additional installation cost for equipment and operating costs of a water treatment system to handle 100 percent makeup water for boiler feed. In addition, this type of system wastes a valuable natural resource. For these reasons a one-pipe system was not considered for this study.

Pitch: Steam piping should be pitched downward in the direction of flow. If conditions make it necessary to pitch pipe in the opposite (counterflow) direction, the pipe size must be increased to reduce turbulence. Gravity-condensate piping must be pitched to the collection point; pumped-condensate piping is pitched only for drainage purposes. The direction and amount of pitch for all underground piping are governed by ground profile and/or the location of interferences.

Drip Points: All steam piping must be dripped at the low points through a suitable steam trap. The trap discharge can be connected to the gravity-condensate return main, if available, or to the pumped-condensate return main. The least desirable method is to discharge the trap to waste.

Condensate Return: As much condensate as possible should be returned to the steam generating plant to save heat and the cost of treating water for boiler feed. It may be returned by gravity or pumping. If site contour and boiler plant location with respect to the buildings are favorable, the gravity system can be used; otherwise, a condensate return pump is necessary in each building. It is sometimes possible to group several favorably located buildings so that one pump can be used for the group.

A regular schedule of inspection and maintenace must be set up for the outlying receiving tanks and pumps. Tanks must be kept clear of sludge and corrosion accumulations. Air vents must be kept clear, but must be arranged so that the mixture of free air with the water in the tank is retarded.

Float-switch mechanisms must be kept free and in proper operating condition to maintain a proper level in the tanks. Condensate pumps and motors must be lubricated according to a schedule, and packing must be adjusted and/or renewed periodically to prevent excessive leakage or shaft damage from too tight or hardened packing. Strainer must be kept in proper repair and cleaned periodically.

Insulation and Waterproofing: All piping must be insulated to conserve heat, and underground piping must be waterproofed to protect ferrous materials against corrosion.

Pipe Expansion: Under operating conditions, pipe is increased in length by the difference between its installed and final temperatures. Expansion is controlled by using loops or bends; various types of corrugated

packless-type expansion joints; flexible ball-type joints; or slip, packed-type joints.

Two-Pipe High-Temperature Water Systems--

Design Considerations--The choice of a hot water system should be based on a careful analysis of a number of factors; the nature of the loads involved; the characteristics and layout of the buildings; the comfort and control requirements; and analysis of the economics of the complete system.

The principal economic consideration in any water system design is the balance of first cost and operating cost. First cost includes generating and terminal equipment and distribution system. Generally speaking, the cost of the generators and terminals will be determined by the load requirements and temperature range selected, and the cost of the distribution system at design conditions, the more economical the distribution system will be.

As a general rule, for a specific system both first cost and operating costs will be reduced with reductions in water quantity circulated. First-cost reductions result from the smaller and less expensive piping system, reduced requirement for secondary building space, smaller pumps, etc. Reduced operating costs result from lower pump horsepowers. Much depends upon the techniques employed to make smaller flow rates possible.

Water Temperature and Flow Rate--The design water temperature and flow rates are interrelated, as are the system piping layout and pump selections. Also, the type and control of the heat exchangers employed in the system affect the flow rate and pump selection, and the pump selection and distribution system affect the controllability. These are examples of the major interrelationships which exist.

In small residential buildings or small commercial structures, flow rates to all heat transfer elements are based on an assumed single overall system temperature difference. For example, a 20-degree temperature drop is commonly selected for such applications. This has led to certain rules of thumb that simplify design procedure and afford sound economy with satisfactory performance.

However, for large systems, determination of the minimum system flow rate is recommended as it usually results in the least overall cost and best performing system. The minimum system flow rate is determined by summation of the flow rates to individual users. The most satisfactory method of determining the minimum system flow rate is to assume that the leaving water temperature (primary system) at each heat exchanger is higher than the final temperature of the heated medium (secondary system) by a constant value. Thus, the lower the final temperature of the heated medium, the larger the temperature drop through the exchanger. For example, with a 20-degree difference, the following temperatures result:

	Final Secondary Temperature	Leaving Primary Temperature
Air-Handling Coil	120°F	140°F
Domestic Water Heater	140°F	160°F
Steam Generator at 7 psig	235°F	255°F

This method is particularly useful in the design of large systems having a wide variety of comfort and process loads.

The system design temperature depends on the requirements of the buildings served by the system, the size of the load, and the length of the distribution piping. Temperatures vary between 350°F for medium size systems to 420°F for large systems. The usual practical limit of temperature is above

450°F due to the rapid rate of pressure higher pressure-rated components required.

In large systems, then, a large temperature drop can be taken; at a generated temperature of 420°F, the normal drop can be about 160°F, but may be as high as 200°F. In small systems a drop of 60°F is sufficient.

Heat Exchangers--The most widely used method for converting the heat in high-temperature water to a medium adaptable for use in buildings is to pass it through a heat exchanger in which either lower temperature hot water or steam is generated. The converted heat can be used for space heating and process work, with one heat exchanger required for each service. Process heat exchangers can also be used to heat or cool some other process fluid.

Heat in the form of low-pressure steam or medium-temperature water can be used as the operating force of an absorption refrigeration machine to produce chilled water for air conditioning. The absorption refrigeration machine is a water chilling package that uses heat directly without the use of a prime mover, thus utilizing the central heating facilities on a full-time, year-round basis.

Piping--The selection of piping materials for a high-temperature water system is greatly simplified since the supply and return pipes are of the same material; and with proper water treatment, very little corrosion takes place in the system. Schedule 40 steel pipe, with welded steel fittings and steel valves, is applicable to most HTW systems.

Pitch--Piping for high-temperature water can be laid to follow ground contours. Piping need not be dripped at each low point, but should have provisions for emptying sections of piping for shutdown. The elevation of hot water pipes in buildings may be changed as often as required to suit the installation.

Insulation and Waterproofing--The provisions for insulating and waterproofing of high-temperature water piping are generally similar to those for steam piping.

Expansion of high-temperature water piping is similar to that described for steam systems.

Storage--High-temperature water systems may be operated to even out the peak loads and low loads within 24-hour cycles by using storage. Storage is usually accomplished by bypassing water from the flow to the return mains and thereby storing heat in the return main for future use or storing heat in accumulators. Systems that experience normal peaks may obtain as much as 15 percent added capacity through such heat storage.

Two-Pipe Medium and Low Temperature Water Systems--The design and characteristics of two-pipe medium and low temperature water systems are similar to high temperature water systems.

Piping Systems--Various pipe and insulation methods are used for underground distribution of high temperature hot water. Some typical systems are described below.

Insulated Pipe in Steel Conduit (Figure 20)--This system consists of an inner, fluid-carrying pipe with four inches of rigid calcium silicate insulation. The outer covering is a 10-gage steel casing coated with waterproofing material. Using specially designed spacers, the inner pipe and insulation is supported in a manner that provides a 1-inch air space between the insulation and outer steel covering. The system is prefabricated in 40-foot lengths.

Temperature range of the insulation is up to 1200°F. All fittings, such as tees, angles and reducing plates, required for a complete system are available. Installation is direct burial with anchors supporting the conduit assembly every 400 feet. Costs are summarized in Table XXX.

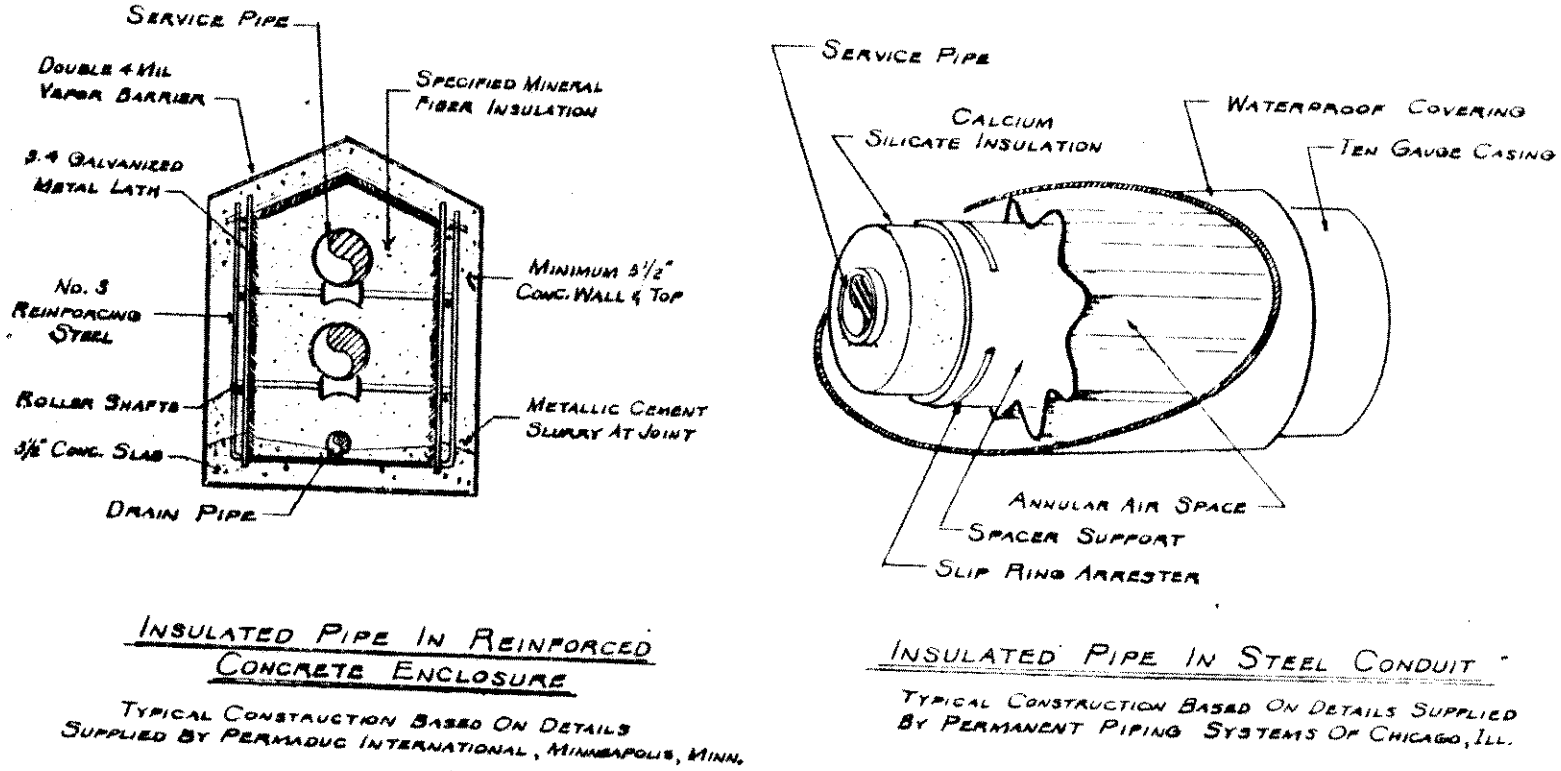


Figure 20. Insulated Pipe in Steel Conduit and Reinforced Concrete

Table XXX. Capital Costs of Primary Piping Systems per Foot of Piping (1979 Dollars)

AREA	PIPE DIAMETER	POURED CONCRETE (Notes 1 & 4)	STEEL CONDUIT (Note 2)	REINFORCED CONCRETE (Note 3)	REFERENC (Note 5)
URBAN	12"	$ 629	$ 638	$ 588	$ 582
	16"		800	707	
	20"	945	1,033	826	892
	24"	1,048	1,236	868	
	30"	1,285	1,460	1,089	1,248
	36"		2,071	1,258	
SUBURBAN	12"	256	511	550	
	16"		640	668	
	20"	385	827	786	
	24"	427	989	830	443
	30"	524	1,168	1,053	515
	36"		1,657	1,228	612
RURAL	12"	233	425	520	
	16"		533	635	
	20"	350	689	750	
	24"	388	824	794	405
	30"	476	973	1,005	474
	36"		1,381	1,183	572

Note 1. Costs estimated using "Means Mechanical & Electric Cost Data 1979" - Published by Means.

Note 2. Costs based on manufacturers data (Permanent Pipin Systems) including estimate of escalation for subu and urban areas.

Note 3. Costs are based on data from "Permaduc".

Note 4. Rural costs were calculated. Suburban costs were obtained by multiplying by 1.1 and urban costs by multiplying by 2.7. These escalation factors were derived from the Oliker and Philipp report refere in Note 5.

Note 5. Reference report is "Technical and Economic Aspec of District Heating Systems Supplied From Cogener of Power Plants" by Oliker and Philipp for poured concrete fill design. Reference costs in 1977 do were increased by 16% to obtain 1979 dollars.

Insulated Pipe in Reinforced Concrete Enclosures (Figure 20)--This is a patented system with the trade name "Permaduc" consisting of steel piping with mineral fiber insulation contained in an enclosure constructed of reinforced monolithic concrete covered with a waterproof barrier. The insulation is four to six inches thick and is rated up to 600°F. The system is assembled in the field and is suitable for direct burial. Because of its strength it need not be buried below the frost line. Costs are shown in Table XXX.

Insulated Pipe in Plastic Conduit (Figure 21)--This system consists of a steel pipe with polyurethane foam and a polyethylene protecting sleeve. The pipe is prefabricated at the factory and shipped in 20- or 40-foot lengths. Standard units are suitable for service temperatures up to 120°C (248°F), with special units available up to 170°C (338°F). The system is designed for direct burial, and fittings are available for bends, branch takeoffs, adapters and couplings required for a complete system. Cost data is not available at this time.

Insulated Pipe in Poured Concrete (Figure 20)--This system consists of steel pipe with four inches of thermobestos insulation (or equipvalent) encased in a poured concrete bank. Insulation for service rating up to 1200°F is available. The entire system is field fabricated and suitable for direct burial. Cost data is shown in Table XXX.

An alternate type of poured concrete construction uses an insulating cement in place of insulation around the pipe. To allow pipe expansion, an air gap is created around the pipe with a parting medium such as asphaltic-lined corrugated cardboard. Service temperature of this system is 800°F.

River Crossings--An important design consideration in distribution systems is the method used to cross rivers. We will describe two possible methods.

Figure 22 illustrates a typical design whereby a separate bridge is constru ted to cross the Fox River in Green Bay. The design shows a 20-inch supply return pipe with 4 inches of insulation which is encased in a steel conduit. The cost for this application is approximately $1,000,000 and is the recomm method for crossing the Fox River.

Figure 23 illustrates a typical design whereby the piping is installed under the roadway and inside openings in the transverse floor girders. This desig can only be considered if the piping details are known when the bridge is being designed. For the Green Bay application, it is probably too late to add the piping since the bridge is under construction.

Typical Distribution Piping Network Configurations--Figures 24 and 25 show two different distribution configurations for the Green Bay application.

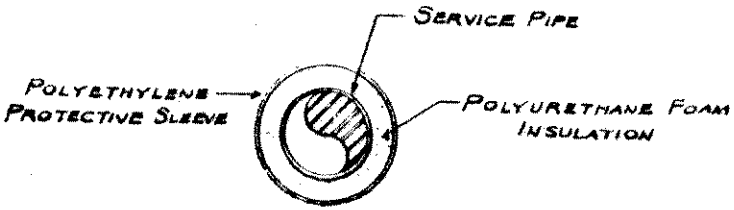
The first network crosses the river near the power plant and follows the routing of the roads east of the paper mills. For the three-mill design, there is approximately 9700 feet of 20-inch pipe, 2600 feet of 14-inch pipe, 2100 feet of 10-inch pipe, and 1900 feet of 3-inch pipe.

The second network crosses the narrowest part of river near the paper mills and runs along the shore west of the power plants. For the three-mill desi there is approximately 9900 feet of 20-inch pipe, 2700 feet of 14-inch pipe 660 feet of 10-inch pipe, and 640 feet of 3-inch pipe.

ADVANTAGES OF HIGH-TEMPERATURE WATER VERSUS STEAM

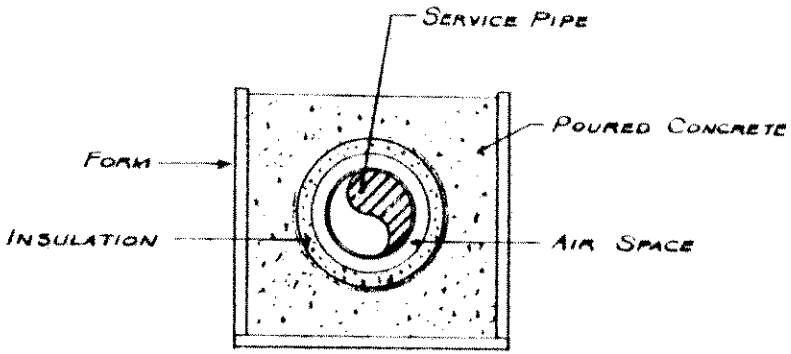
The following are among the outstanding advantages of HTW systems as compar to steam distribution systems or low-temperature water systems:

- The HTW system is completely closed circuit, with supply and ret mains maintained under pressure. There are no losses due to fla ing, and very little makeup water is required. Corrosion within



INSULATED PIPE
IN PLASTIC CONDUIT

TYPICAL CONSTRUCTION BASED ON DETAILS SUPPLIED BY M. L. SHELDON PLASTICS CO.



INSULATED PIPE
IN POURED CONCRETE
(SEE NOTE 1)

NOTE 1

AN ALTERNATE CONFIGURATION WOULD REPLACE THE INSULATION AND AIR SPACE WITH A PARTING MEDIUM SUCH AS ASPHALTIC LINED CORRUGATED CARDBOARD AND THE CONCRETE WOULD BE AN INSULATING TYPE SUCH AS "Z-CRETE."

Figure 21. Insulated Pipe in Plastic Conduit and Poured Concrete

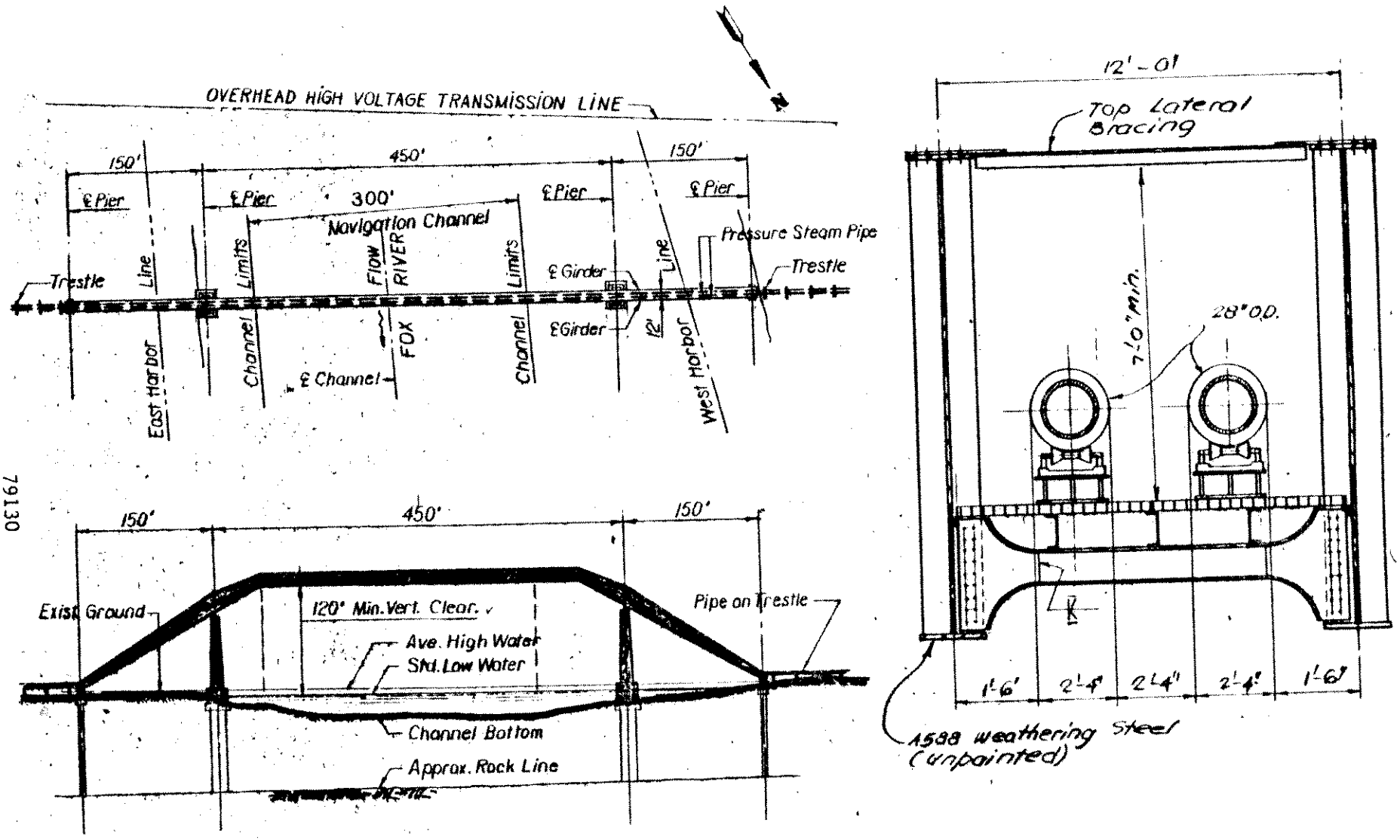
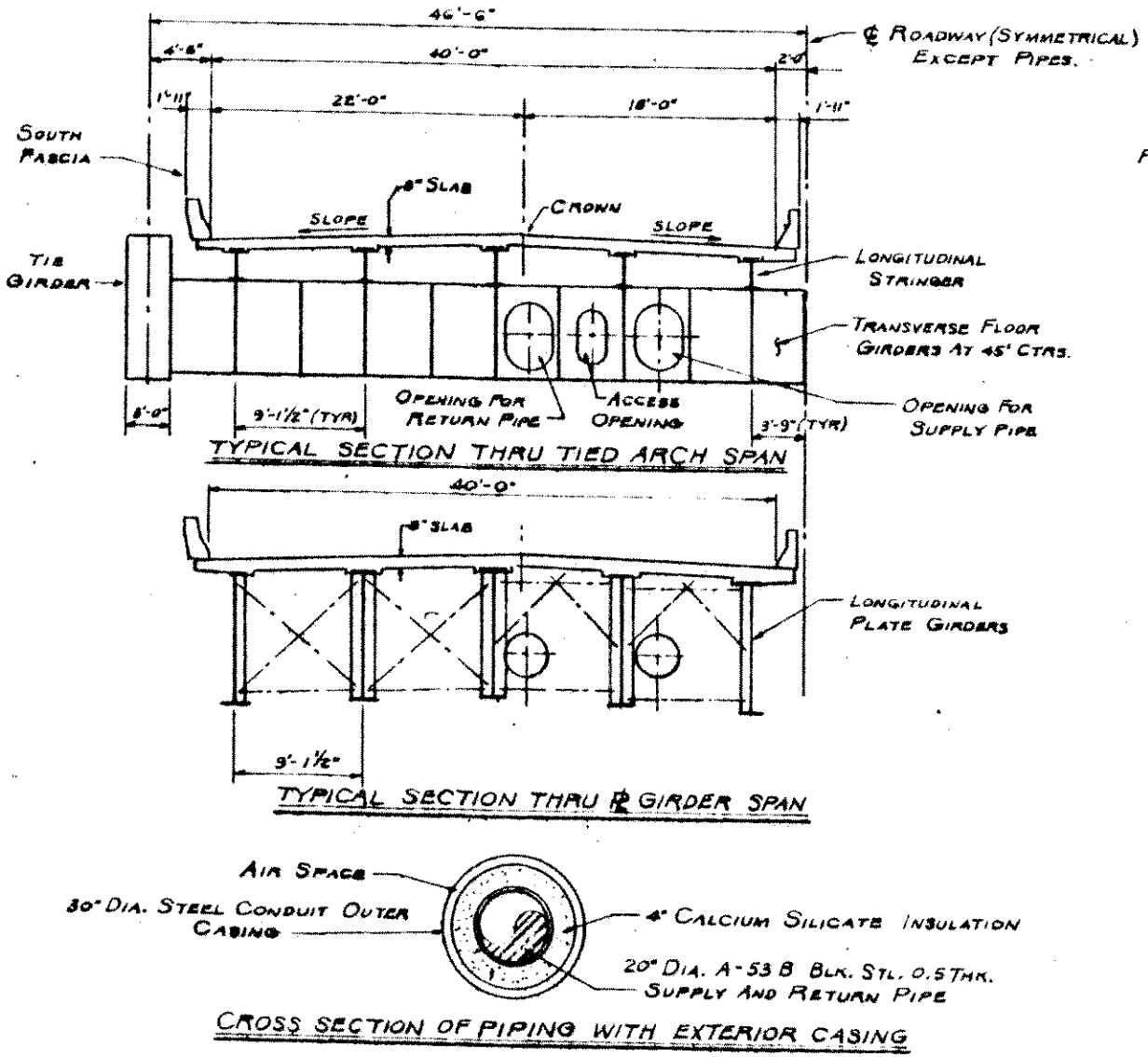
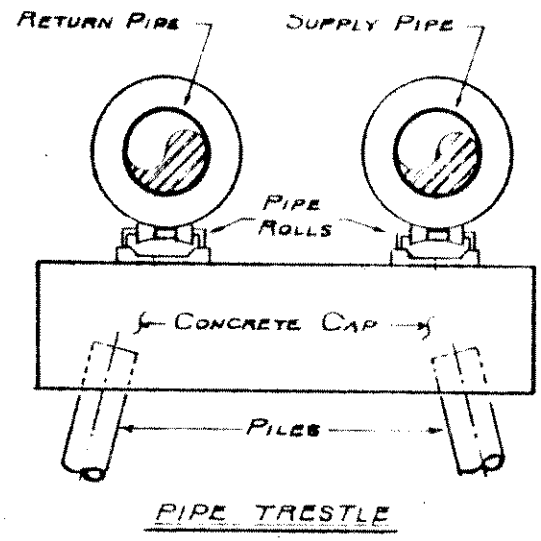


Figure 22. Green Bay, Separate Pipe Bridge





Notes:
Typical design (not for construction)
This figure is revised by American Hydrotherm from plate 3 of Consoer Townsend & Associates Report "Proposed Steam Distribution System Wisconsin Public Service Corp."

Figure 23. Green Bay, Cross-Section and Details of Proposed Tower Drive Bridge

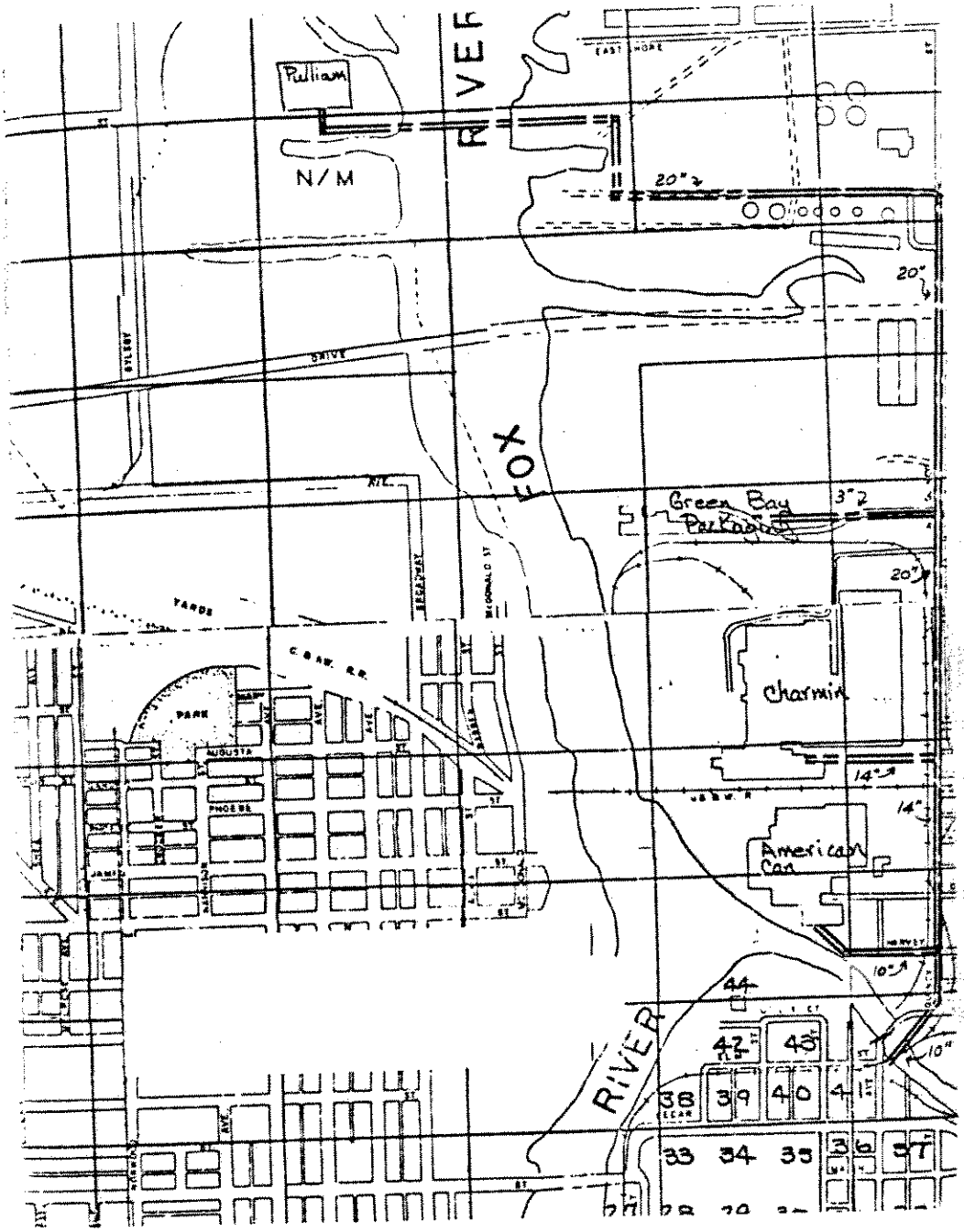


Figure 24. Green Bay Distribution System with Northern River Crossing

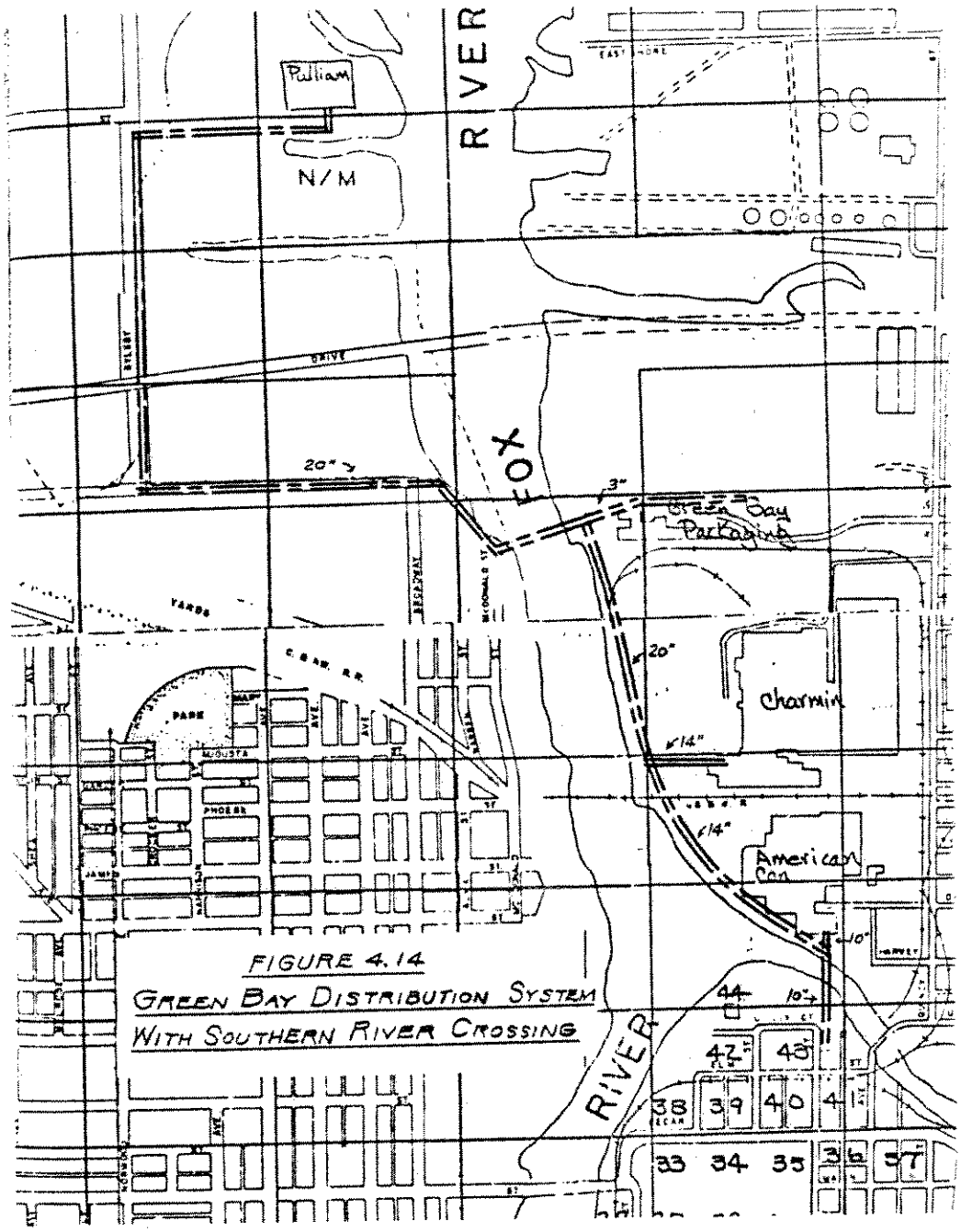


Figure 25. Green Bay Distribution System with Southern River Crossing

the system is minimized. Because the HTW system is closed circuit, the heat not utilized in the terminal heat transfer equipment is returned to the high-temperature water boilers.

- There is ability in a HTW system to design for large temperature drops; thus smaller pipe sizes and less pumping capacity can be employed.
- Operation and temperature control are easily maintained. Uniform temperature is easily maintained, not only for normal operation, but also during peak loads, abnormal operating schedules, and for long periods of banked loads such as overnight or weekends.
- Piping may slope up or down to suit the terrain, reducing the amount of excavation required and eliminating all drip points and return pump locations, as compared to steam.
- There are lower distribution piping costs since pipe sizes are generally smaller than in a steam system or low-temperature water system of the same capacity. Fewer specialties are required, with elimination of steam traps, pressure-reducing valves, separators, flash tanks, condensate receivers and return pumps, as compared to steam.
- Lower operating costs result from better utilization of heat and reduced maintenance.
- There is a tremendous "flywheel" effect in the heat storage in the HTW system, which acts to even out fluctuations in the load.

Of all the factors favoring the HTW heating system, the "flywheel" effect in heat storage is the most important. The available heat storage of a water system operating at 400°F compared to 400°F steam is many times as great for the water system, assuming equal volume for the two systems.

Thermal storage is a function of the heat capacity per unit volume (Btu/cubic foot). In one cubic foot of 400°F water we have the following energy:

- Water Density x Enthalpy (Btu/lb) = Total Heat Content.
- 53.65 x 375 Btu/lb = 20,119 Btu in 1 cubic foot of water at 400°F.
- Steam Density x Enthalpy of Steam = Total Heat Content.
- 0.537 x 1201 = 645 Btu in one cubic feet of steam at 400°F.

Thus, the stored energy in a HTW system is about 30 times greater than that in a comparable steam system.

Safety Considerations

A question often arises regarding the safety features of high-temperature water compared with steam systems operating at the same temperatures and pressures. Events in which a sudden rupture or large leak may have developed in a HTW line are very rare, and little is known about the damages which result. However, from practical tests of the flow of HTW from an open pipe into the atmosphere, and also from reports of the few accidents that have occurred, some knowledge has been obtained regarding the behavior of the sudden discharge of HTW into the atmosphere. Two characteristic features accompany the sudden expansion of high-temperature water upon a release of pressure to atmosphere:

- A very high rate of increase in volume;
- A very low rate of energy release during expansion.

Flashing into steam and expansion will absorb the potential energy stored in the fluid. The expanding high-temperature water will transform into a very wet fog. The expansion will reduce the temperature of the fluid to 212°F. A further reduction below 212°F is caused by the turbulent mising of the fluid with the room air. The exact reduction below 212°F depends on many factors; the temperature of the system; the discharge area; the distance from the point of discharge; and the room temperature. Under ordinary conditions, the temperature in the discharge falls to about 125° to 140°F

within a short distance as compared to the temperature of the discharge of a low-temperature water system, which remains essentially the same as the temperature of the working fluid. Thus, the temperature in the discharge of an LTW system will normally be higher than the temperature developed in the discharge of an HTW system.

It is well known that accidental breaks in high pressure steam lines have caused serious damages to persons and property since:

- The heat transmitted to a closed space by escaping steam is very high in a short interval of time.
- The steam exit velocity and kinetic energy are about five times that of escaping water.
- Escaping steam will rapidly displace the air in a closed space causing suffocation to persons trapped in the space.
- High pressure steam striking the skin will cause severe burns.

High-temperature water can be considered a safer heat transfer agent than high-pressure steam.

In view of the distinct advantages of distributing high temperature water over distances associated with a project of this complexity, steam systems will not be given further consideration.

Capital Costs

Capital costs have been established for the primary hot water distribution system on a linear foot basis. They were based on 12-inch through 36-inch pipe to give a range of costs. A summary of primary distribution costs is shown in Table XXX. Detailed costs (i.e., excavation, pipe bedding, back-fill, etc.) are tabulated in Appendix F.

TECHNIQUES FOR INTERFACING WITH END USER

Where an existing process or plant is using HTW for process or space heating, the direct interface of distribution fluid to user equipment is simple and inexpensive. If, however, an attempt were made to convert an existing steam system to HTW, the changes are complex and expensive, and each system would have to be evaluated on its own merits for its cost effectiveness. In addition, a break or problem in the end user's equipment could severely affect the distribution system and the central plant. In view of this, and since each system conversion from steam to HTW is unique, no attempt was made to establish costs for direct interface.

Indirect interface of user's equipment with the district HTW using heat exchangers is an effective way of adapting existing facilities to an HTW distribution system. Heat exchangers can be sized to generate domestic hot water (DHW), process steam, or space heating hot water. The basic design of a converter system would be similar for all buildings. Basically, equipment sizes and quantities would vary. Two typical conversion schemes are illustrated in Figures 26 and 27.

Costs have been developed for heat exchangers, interior and exterior plumbing, excavation and controls. Costs have not been included for the customer's internal distribution. These costs are tabulated in detail in Appendix F and summarized in Tables XXXI and XXXII.

Table XXXIII shows total annual cost for a building assuming piping distances and thermal loads as indicated. In addition, we have assumed operating, maintenance and insurance costs of 2.75 percent of the capital costs.

Table XXXIV shows total capital cost for an absorption chilled water system using HTW as the heat source.

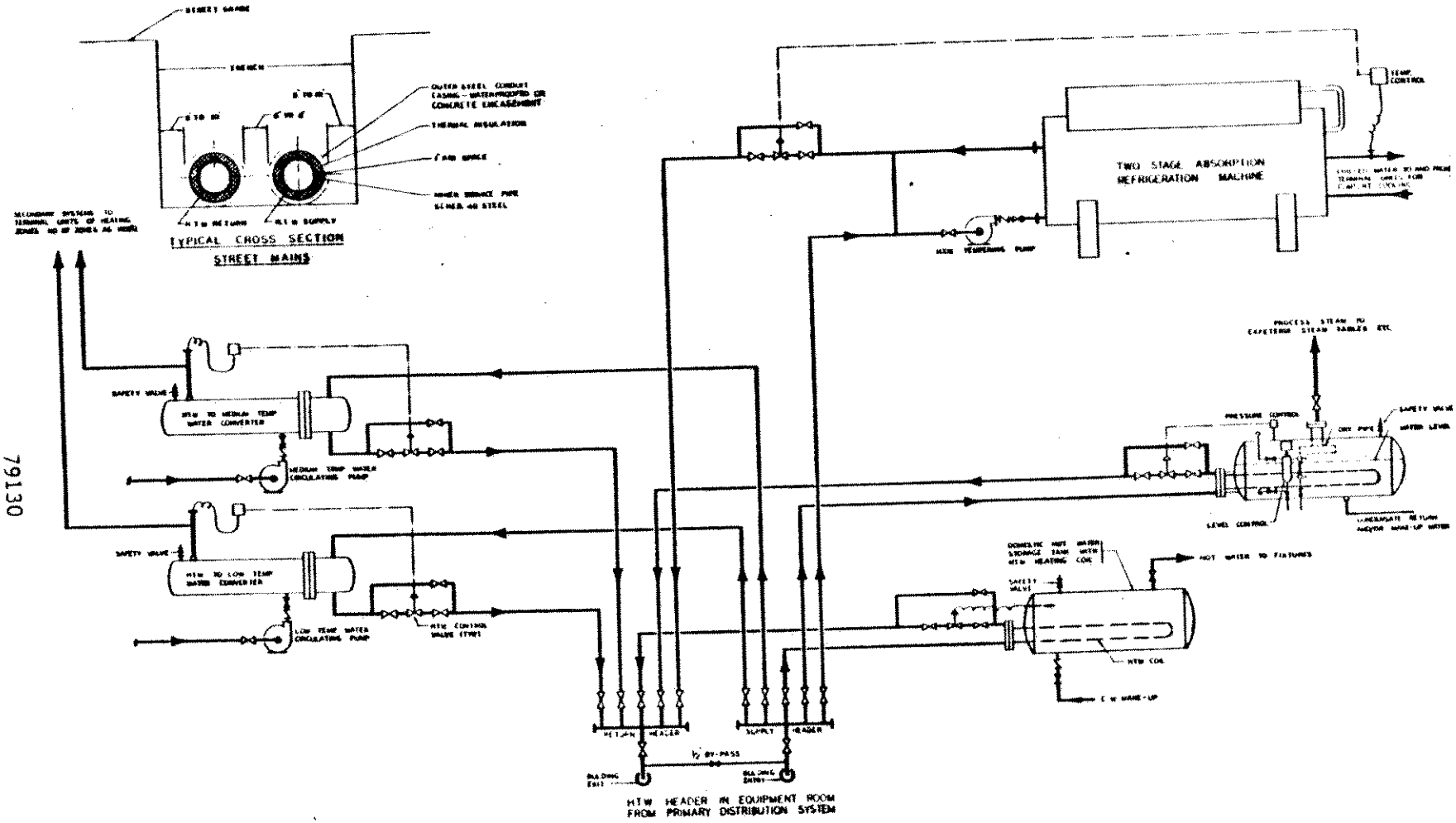


Figure 26. Typical Converter Room for Multiservice Use of High Temperature Water

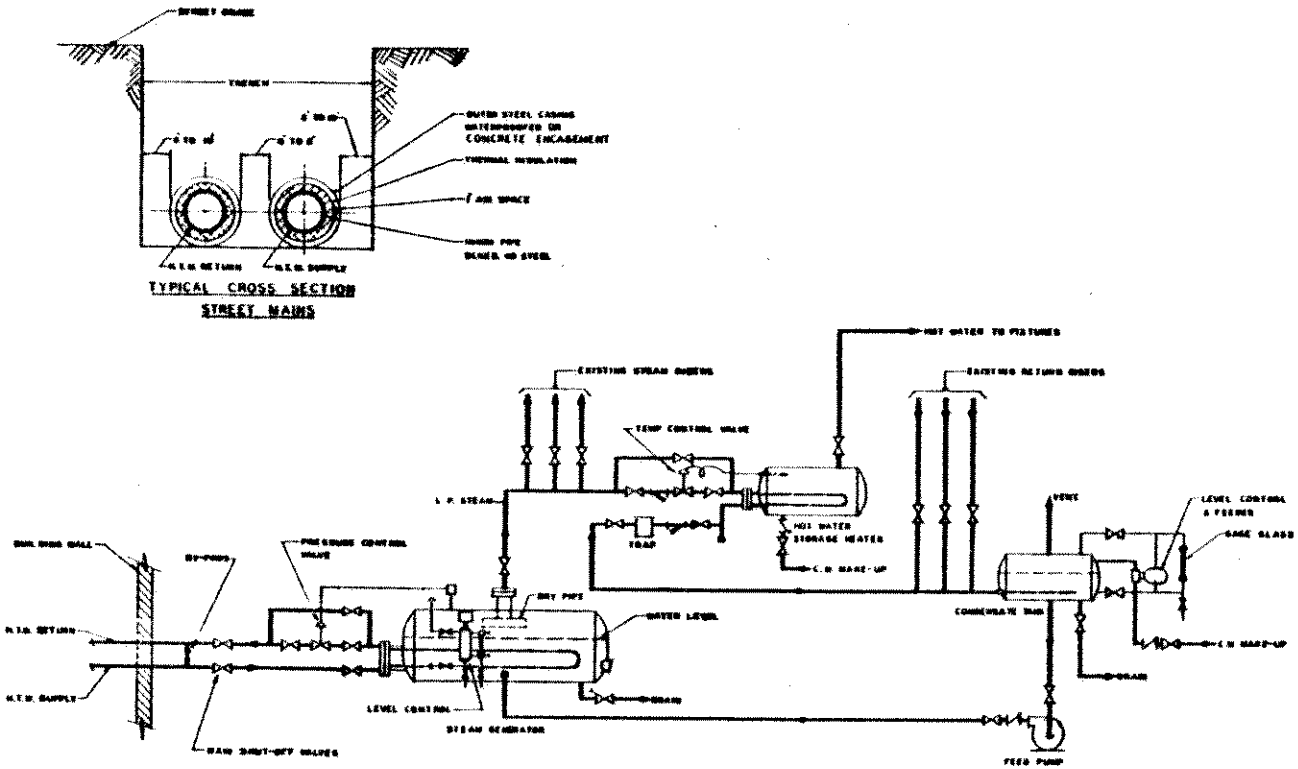


Figure 27. Typical Arrangement of High Temperature Water Converter Room

Table XXXI. Heat Exchanger Costs, Customer System Retrofit (1979 Dollars)

LOAD MMBH	SERVICE	HEAT EXCHANGER AREA - ft^2	COST INCLUDING INSTALLATION
2	HOT WATER TO LOW PRESSURE STEAM	22.1	1216
4		41	1882
6	"	68	2678
8	"	98	3532
10	"	143	5896
12	"	143	5896
14	"	195	7402
16	"	195	7402
18	"	195	7402
20	"	251	9322
2	HOT WATER TO HOT WATER	58	2236
4	"	110	3450
6	"	138	3960
8	"	200	5438
10	"	258	7778

Table XXXII. Customer Retrofit Costs (1979 Dollars)

INTERIOR PLUMBING		EXTERIOR PLUMBING		EXTERIOR EXCAVATION	CONTROL SYSTEMS	
SPACE HEATING & DHW	PROCESS HEAT	SPACE HEATING & DHW	PROCESS HEAT		SPACE HEATING & DHW	PROCESS HEAT
$34.28 LF	$50.43 LF	$37.65 LF	$47.46 LF	$154.29 LF	$8,896	$10,627

LF = Linear Foot

Table XXXIII. Typical Building Costs (Note 1)
Customer System Retrofit (1979 Dollars)

	DHW	PROCESS OR SPACE HEATING	TOTAL
Interior Plumbing	$3,428	$ 5,043	$ 8,471
Exterior Plumbing	3,765	4,747	8,512
Excavation	---	15,428	15,428
Heat Exchanger	3,960	3,532	7,492
Controls	8,896	10,627	19,523
TOTAL	$20,049	$39,377	$59,426

(NOTE 1) ASSUMPTIONS: 100' Interior and exterior runs

6 MMBH for DHW

8 MMBH for Low Pressure Steam - Process or Space Heating

A 200-unit high-rise apartment building would require approximately the above heat for domestic hot water and space heating.

Table XXXIV. Typical Costs for Absorption Cooling*

TONS OF REFRIGERATION	ABSORPTION UNIT #/TON	INSTALLATION $/TON	PUMPS & MOTORS $/TON	COOLING TOWER $/TON	PLUMBING $/TON	WIRING $/TON	TOTAL $/TON
60	180	25	100	214	55	55	629
90	180	20	100	186	55	55	596
125	160	18	100	173	55	55	561
150	160	18	100	172	55	55	560
300	160	17	100	163	55	55	550
400	160	15	100	156	55	55	541
1000	140	14	100	149	55	55	293

* Does not include cost of distribution within the building

SCARCE FUEL CONSERVATION POTENTIAL

Scarce fuel is understood to mean fuel gas or fuel oil. The scarce fuel conservation potential depends on the following factors:

- Turbine retrofit effectiveness, which could be expressed as the ratio of heat gained to power lost.
- The fuel that the utility fires to replace the power lost due to cogeneration.
- The heat losses in the distribution system (normally less than one percent of heat sold, so this is ignored).
- Distribution pumping charges (the equivalent fuel to be fired to generate the electricity to drive the pumps was shown as a cost item, not as a subtraction from the potentional scarce fuel that would be saved).
- The type of fuel fired as an alternate by the heat user if he did not use heat from the cogeneration system and the efficiency of his boiler.

For the Green Bay applications, the approximate scarce fuel saved per year is 1,418,000 MMBtu. The three-mill and two-mill designs are the same since the heat that would be sold to the larger paper mill is now generated by firing coal. The downtown Green Bay business district is now using gas to supply its heat. The two smaller paper mills are also using 100 percent scarce fuel now. The fuel that the utility fires to replace the power lost due to cogeneration is approximately 75 percent coal and 25 percent oil.

For the Beloit (Black Hawk Plant) application, the approximate scarce fuel saved per year is 840,252 MMBtu. It is assumed that all of the heat users are using either gas or oil and have a 75 percent boiler efficiency. The fuel that the utility fires to replace the power lost due to cogeneration is approximately 94 percent coal and 6 percent oil.

For the Janesville and Beloit (Rock River Plant) application, the approximate scarce fuel saved per year is 2,314,000 MMBtu. It is assumed that all heat users are firing scarce fuel at 75 percent efficiency. The fuel that the utility fires to replace the power lost due to cogeneration is 90 percent coal and 10 percent oil.

For the future industrial park (Rock River Plant) application, the approximate scarce fuel saved per year is 1,482,000 MMBtu. It is assumed again that the industrial park might be firing 100 percent scarce fuel at 75 percent efficiency. The replacement fuel that the utility fired is 90 percent coal and 10 percent oil.

Data was not fully available on the Madison applications so the operation was assumed to be similar to the Rock River applications. On this basis the downtown Madison design would save approximately 258,000 MMBtu of scarce fuel, and the University design would save approximately 1,176,000 MMBtu.

CONCLUSIONS

There are no technical problems with any of the seven retrofit schemes that were assessed in detail and summarized in Table XXXV.

The most promising project would be one in which a major amount of the heat would be removed from the turbine from relatively high pressure crossover piping, the power plant is near to the heat consumers to reduce the distribution piping and pumping cost, the heat load throughout the year is relatively constant due to the sale of heat to low temperature level industrial consumers, and a high proportion of scarce fuel will be saved.

The Green Bay site appears to fit well into the above criteria. The crossover piping is at 89.7 psia, the Pulliam Plant is approximately two miles from the

paper mills and three miles from downtown Green Bay (about 25 percent of the downtown area is being renovated), and approximately 1,400,000 MMBtu of scarce fuel will be saved.

The capital cost of the Green Bay three-mill design is approximately $11,000,0 and of the two-mill design is approximately $8,700,000. A major factor in the capital costs is the distribution system portions, which are $8,000,000 and $6,500,000, respectively.

It is finally concluded that the Green Bay site is technically promising, and that work should be continued in Phase 2 of this project.

Table XXXV. Summary of Capital Costs and Technical Data, Green Bay, Pulliam Plant

	THREE MILLS	TWO MILLS
Distribution System	$8,000,000	$6,500,000
Power Plant	3,000,000	2,200,000
Aver. Pumping KWH/MM Btu	1.6	1.6
Yearly Heat Sold (MM Btu)	3,540,847	1,418,329
Yearly KWH for Pumping	5,665,355	2,269,326
Heat Losses (MM Btu/hr)	2.86	2.07
Scarce Fuel Saved (MM Btu)	1,418,329	1,418,329

JANESVILLE/BELOIT (BLACK HAWK AND ROCK RIVER PLANTS)

	Black Hawk & Beloit	Rock River & Both	Rock River & Park
Distribution System	$14,300,000	$67,200,000	$5,200,000
Power Plant	1,500,000	2,500,000	1,500,000
Aver. Pumping KWH/MM Btu	.339	2.05	1.57
Yearly Heat Sold (MM Btu)	670,414	1,928,614	1,234,800
Yearly KWH for Pumping	227,270	3,953,659	1,938,636
Heat Losses (MM Btu/hr)	3.2	17.4	1.2
Scarce Fuel Saved (MM Btu)	840,252	2,314,337	1,481,760

MADISON (BLOUNT ST. PLANT)

	Downtown	University
Distribution System	$3,500,000	$14,200,000
Power Plant	1,000,000	2,400,000
Aver. Pumping KWH/MM Btu	.34	.25
Yearly Heat Sold (MM Btu)	215,101	1,176,048
Yearly KWH for Pumping	73,135	293,937
Scarce Fuel Saved (MM Btu)	258,121	1,411,258

SECTION 5.0
INSTITUTIONAL ASSESSMENT

This section analyzes the institutional problems of establishing a District Heating and Cooling System (DHCS) in Wisconsin. Before elaborating on the findings, both the Public Service Commission of Wisconsin (PSCW) commitment and the Federal Government commitment to the concept of cogeneration should be outlined.

5.1 STATE COMMITMENT

Every two years, the major Wisconsin utilities are required by Wisconsin Statute (196,491) to submit Advance Plans--reports of their long-range power facility need projections and their plans to meet those needs. The PSCW, in turn, is required to assess the utilities' projections and plans. The first such assessment was issued in December 1976 and discussed the issue of cogeneration as an alternative to building larger utility plants:

> Power plants operate most efficiently when they approach maximum output. When the power generating system has smaller plants, the plants are more likely to be operating at maximum output more of the time. This leads to more efficient operation of the plants, and less use of fuel. The resulting fuel cost savings offsets still more of the additional cost of smaller units.
>
> Smaller plants can be used as dual-purpose plants more easily than larger plants. A dual-purpose plant provides steam or hot water in addition to electricity. Because generation of electricity is inherently inefficient--typically at least two-thirds of the energy content of the fuel is lost as waste heat--dual purpose use of the plant can recover some of the energy that would be lost as waste heat. The steam or hot water can be sold to replace natural gas and oil.

> For dual-purpose operation to succeed, the power plant has to be located fairly close to the steam and hot water customers. This type of siting would be more feasible with smaller plants. Very large plants are almost always located away from population and load centers. Such siting makes it much more difficult to sell steam and hot water economically.
>
> The use of dual-purpose plants is presently the subject of much study. It is not yet clear how the costs and benefits of this dual approach balance, but it does appear that, given the dwindling supplies of oil and gas, dual-purpose plants are very promising. (Pg. 23)

In the order analyzing the submittal of these reports (05-EP-1), the Commission stipulated that, "The utilities shall develop incentive rate structures for the sale of electrical energy to, and the purchase of electrical energy from, industrial or commercial firms which cogenerate" (PSC 05-EP-1, 8/78). Furthermore, the Commission repeatedly emphasized its desire for increased efforts in the areas of conservation, efficient energy use and the utilization of alternative energy sources:

> In this advanced plan, the Commission directed the utilities to consider several prospective changes. Specifically, the Commission directed quantifications of the effects on future load growth of 1) conservation, 2) conversion from natural gas, 3) load management, 4) rate structure reform, and 5) improvements in end-use efficiency (Pg. 11).
>
> Cogeneration has potential for increasing the efficiency of energy use in Wisconsin. The industrial cogeneration of electric energy appears to provide more potential for improving energy efficiency than utility cogeneration of steam. Process steam appears to be economical if sold on an interruptible basis. Economic usage of utility cogeneration seems to depend on the simultaneous availability of a high load factor plant and a nearby high load factor, high volume user of low-temperature energy. The utilization of waste heat is another provision of option (Pg. 23)
>
> Programs designed to explore utilization of alternative energy sources and fuels, utilization of waste products and waste heat, and methods of controlling load are also appropriate and should be pursued. The Commission recommends that funds planned to be used on breeder research be diverted to these and similar ends. (Pg. 24)

> The Commission finds that alternative sources of energy are potentially valuable and that it is in the public interest for the utilities to become more involved in the development and implementation of such sources. (Pg. 27)
>
> All utilities filing plans for the next planning period shall also include an analysis of the projected effect, year by year, of their proposed and alternative generation plans. (Pg. 30)
>
> The utilities shall investigate and adopt reasonable alternative generating strategies. (Pg. 31)

In addition, the Commission has authorized cogeneration rates in the most recent Madison Gas & Electric rate case (4220-UR-4/5, January 22, 1979). This order clearly states the Commission's commitment to encouraging the cogeneration of electricity. "MG&E is encouraged to pursue cogeneration contracts with other customers." MG&E is ordered to increase its credit to the cogenerator from an off-peak rate for energy to a full-time differentiated rate. It is further ordered to give a generation capacity credit for displaced KW's.

5.2 FEDERAL COMMITMENT

On November 9, 1978, President Carter signed into law the Public Utility Regulatory Policies Act (PURPA). The purposes of the act are to encourage conservation of electrical energy, optimum efficiency of use of facilities and resources by electric utilities, and equitable rates for electric customers.

Among the provisions of the act is a discussion of Federal requirements for the sale or purchase of electrical energy to cogeneration or small power production facilities (section 210).

TITLE II--CERTAIN FEDERAL ENERGY
REGULATORY COMMISSION AND
DEPARTMENT OF ENERGY AUTHORITIES

Sec. 201. DEFINITIONS

Section 3 of the Federal Power Act is amended by inserting the following before the period at the end thereof:

"(17)(A) 'small power production facility' means a facility which--

"(i) produces electric energy solely by the use, as a primary energy source, or biomass, waste, renewable resources, or any combination thereof; and

"(ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts:

"(B) 'primary energy source' means the fuel or fuels used for the generation of electric energy, except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy--

"(i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and

"(ii) the minimum amounts of fuel required to alleviate or prevent--

"(I) unanticipated equipment outages, and

"(II) emergencies, directly affecting the public health, safety, or welfare, which would result from electrical power outages;

"(C) 'qualifying small power production facility' means a small power production facility--

"(i) which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe: and

"(ii) which is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

"(D) 'qualifying small power producer' means the owner or operator of a qualifying small power production facility;

"(1S)(A) 'cogeneration facility' means a facility which produces--

"(i) electric energy, and

"(ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes;

"(B) 'qualifying cogeneration facility' means a cogeneration facility which--

"(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency as the Commission may, by rule, prescribe; and

"(ii) is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

"(C) 'qualifying cogenerator' means the owner or operator of a qualifying cogeneration facility.

Although the rules for cogeneration and small power production are still being developed, section 210 of PURPA provides that such rules be prescribed that encourage the sale and purchase of electric energy to cogenerators or small power production facilities.

One of the outstanding features of section 210 is the provision exempting cogenerators from the regulations typically associated with electric energy sales or purchases. Some of these exemptions include the Federal Power Act, the Public Utility Holding Company Act, and state laws and regulations respecting rates. Any small power production facility that has a power production capacity, combined with any other facilities at the same site, of less than 30 MW qualifies for these exemptions.

One of the more attractive regulatory exemptions is the laxed rate-making procedure. Unlike an electric utility, a private cogeneration facility is not authorized a rate of return on its operation. To compensate for the greater risk associated with establishing a cogeneration facility, Congress has deemed it reasonable to exempt cogenerators and small power production facilities from the type of examination that is traditionally given to electric utility rate applications (section 210, subsection B). Relieving cogenerators of the burdensome examination typically associated with electric rate-making will be a major incentive for the development of more cogeneration facilities.

The Act is specifically aimed at nonutility-owned systems of cogenerating facilities over utility-owned cogenerating systems. For reasons important to the Wisconsin project, this is an issue of interest. We have basically limited our research to a utility-owned system. However, some of the utility companies are wary about the risks associated with a cogeneration system and feel financing may be difficult to get without affecting bond ratings and their other utility operations. A viable alterantive is for an independent agent to own the cogenerator and possibly lease or buy equipment (generation capacity) and space from the utility.

5.3 OBJECTIVE

The objective of this task is to provide an analysis of the impacts of all statutes, codes, ordinances, regulations and other extenral factors which may impact the establishment of a DHCS in Wisconsin. In short, the task was to identify the legal, finanical and regulatory problems that might abe met by the District Heating and Cooling Demonstration Project.

5.4 APPROACH

The approach consisted of examining the subtasks outlined in the contract and expanding on them when necessary. To do a thorough analysis, it was necessary for us to contant other State agencies and recruit the assistance of the utilities involved. The Stage agencies contacted were: the Department of Natural Resources (DNR), Department of Transportation (DOT), and Department of Revenue (DOR), and the Secretary of State's Office.

Extent and Effects of State and/or Local Utility Commission Regulation

Wisconsin Statute 196.01 defines a Public Utility as the following:

> Public Utility means and embraces every corporation, company, individual, association, their lessees, trustees, or receivers appointed by any court, and every sanitary district, town, village or city that may own, operate, manage or control any toll bridge or any plant or equipment or any part of a plant or equipment, within the state, for the conveyance of telephone messages of for the production, transmission, delivery of furnishing of heat, light, water or power either directly or indirectly to or for the public.

Thus, a District Heating and Cooling System would necessarily have to conform to the regulations of the PSCW that guide all utilities; however, none of these seem to impede the feasibility of a DHCS in Wisconsin.

The principal areas of regulation are:

- Construction,
- Rate of Return,
- Rate Level and Structure,
- Safety.

Construction--Regulations involving construction, installation, or operation of any new plant, equipment, property or facility or the improvement or addition to existing equipment, property, apparatus, or facilities, state that no work shall occur until the utility complies with any applicable general or special order of the Commission. The specifics that must be included in the application are in PSC 112.06 of the Administrative Code. Simply put, the applicant must show the need for the work and show that the work does not impair the efficiency of the service or add to the cost of service without proportionately adding to the value or available quantity thereof.

Rate of Return--After reviewing a utility's accounting books and records, the PSCW determines the rate of return it feels will enable the utility to attract sufficient capital from investors to continue providing adequate service. In the case of the proposed DHCS, the PSCW will have to determine a rate of return that will attract investors to a new utility service. The utility companies have indicated that a DHCS is a greater risk than their other services and will require, perhaps a rate of return slightly higher than is established for their other services. However, this state has encouraged conservation and efficient energy use--Department of Industry, Labor and Human Relations codes, PSC conservation program, Office of State Planning and Energy efforts. Since the PSC sets different rates of return for different services, one may expect that a just and appropriate rate would be set for DHCS services.

An additional option to help reduce the risk of a DHCS is for the State to guarantee utility bonds. Something like this has been provided for in Ontario. If similar arrangement can be made in Wisconsin, an additional organizational and financial option may be an independently owned cogeneration system that sells the by-product, electric energy, to utilities and other power-producing industries at a reasonable and just rate or that leases generation capacity from an electric utility.

Rate Level and Structure--It is within the power of the PSCW to assure that utility rates be just, reasonable, sufficient and nondiscriminatory. If it appears to the Commission that these provisions are not met, the Commission can require the utility to establish new tariffs, or it can determine, and by order fix, reasonable rates to be imposed in lieu of those found to be unlawful or unreasonable.

The PSCW believes in the appropriateness of marginal cost pricing for energy. It is therefore appropriate to expect the DHCS system, when regulated

by the PSCW, would have to present rate schedules based on marginal cost analysis. If the electrical generation capacity is owned by the electric utility, the capacity costs charged to the DHCS would be on a diurnal and seasonal time differentiated basis. Most, if not all, generating capacity costs may be avoided if the DHCS can operate under an interruptible rate from the electric utility. This will depend on the length of interruption that can be tolerated in relation to the maximum number of hours of interruption that the electric utility requires during the heating season. Since the improved natural gas supply concomitant with the DHCS would serve to reduce projected winter electric heating loads, it is reasonable to expect that most Wisconsin electric utilities would remain summer peaking with relatively few interruptions needed in the winter. At the national level, the effects of the incremental cost pass-through clause for natural gas pricing to large industrial customers will make any DHCS that is competitive with No. 2 oil also competitive with natural gas.

Safety--Wisconsin Statute 196.745 reads: "Every public utility which owns, operates, manages or controls facilities for the production, transmission or distribution of gas shall construct, operate and maintain such facilities in a reasonably adequate and safe manner." After holding hearings, the Commission is to issue orders or rules requiring that the construction or operation of the facility in question be safe.

Arrangements Under Which Electric Utilities Would Modify and Operate Power Plants as Part of a District Heating and Cooling System

The basic assumption used for determining a feasible site for a DHCS in Wisconsin is that an existing power plant be retrofit. The specific engineering and technical modifications necessary were covered under the previous task.

An issue that cannot be overlooked is the near certainty of increasing the hours of operation of the Blount Street (Madison) and Black Hawk/Rock River (Janesville/Beloit) plants. To provide the amount of steam needed to operate a DHCS, the plants will have to increase their hours of operation. The Pulliam (Green Bay) plant is unlike these in that it already operates much like a base-load plant and will not have to increase its operating hours.

Extent and Effects of Legal Requirements to Obtain Easements, Franchises to occupy the Public Right-of-Way, Land Acquisition and to Obtain Certificates of Convenience and Necessity

Wisconsin Statute 32.02 outlines the rights of eminent domain. In subsection 5, the right of condemnation is extended to any Wisconsin corporation furnishing heat, power or electric light for the public, and for additions or extensions to its part and for the purpose of conducting tests or valid studies to determine the suitability of a site for the placement of a facility. Once a utility receives a certificate of approval from the PSCW, it has the power of condemnation of all land excluding that owned by another utility, railroad, river crossing, or highway department. To obtain right-of-way in a wetlands area, the utility will have to comply with section 404 of the Federal Water Pollution Control Act of 1972 requiring permits from the Army Corps of Engineers. In addition to this Federal regulation, the utility will have to comply with Chapter 10 of the River and Harbor Act of 1899 and Chapter 30 of the State DNR statutes. If the utility does not need to lay the pipes in a riverbed or cross a navigable river, Wisconsin Statute 182.017 states that it is exempt from the normal permit procedure.

The utility is required by Wisconsin Statute 196.58 to obtain municipal approval for the furnishing of service in the municipalities in which it operates. This approval should be obtained prior to applying to the PSCW for authorization.

Applications for authorization from the PSCW must follow the guidelines in Chapter 112.06 of the PSC Administration Code. The utility is required to furnish information describing the project, the proposed method of financing the project, the purpose and need of the project, the effect on the cost of operation and quality and reliability of service, a description and cost of alternatives that were considered, Environmental Impact Statement (EIS) screening information, and the designation of public utilities, municipalities and others principally affected by the project.

For a DHCS in Green Bay, the distribution system will have to cross the Fox River to reach the customers. There are three proposed alternatives for the river crossing:

- Via a utility-owned and -built bridge,
- Via an existing interstate highway bridge,
- Via the riverbed.

The first requires permits from the Department of Natural Resources (DNR), Brown County and, depending on the design, the Army Corps of Engineers. Section 10 of the Harbor Act of 1899 and Section 404 of the 1972 Federal Water Pollution Control Act are the regulations that will determine if the Corps enters the picture. Simply put, if the proposed bridge alters the navigability or quality of the river at all, the Army Corps of Engineers will probably require permits.

The second proposal is to hang the distribution pipes under the interstate highway bridge. This poses even more obstacles in the form of permits. The Federal Highway Administration has regulations that guide interference with any of its structures. In addition to this, the State Department of Transportation (DOT) has established strict standards with which utilities must comply when crossing public highway rights-of-way. Design approval

must be obtained from the DOT as well as compliance with section 3.301 of the policy statement, Provisions For Bridge Attachments (as stated below). Our discussions with the DOT have led us to believe they will contest our placing pipes at the proposed site.

3.301 Provisions for Bridge Attachments

> Generally, acceptable utility installations are those which will occupy a position beneath the structure's floor, inside the outer girders or beams or within a cell, and at an elevation above low superstructure steel or masonry.
>
> Communication and electric power line attachments shall be suitably insulated, grounded, and preferably carried in protective conduit or pipe from the point of exit from the ground to re-entry. Carrier pipe shall be suitably insulated from electric power line attachments.
>
> Pipelines to be attached to a highway structure shall not exceed a maximum internal pressure of 150 P.S.I.G.
>
> A utility proposing to occupy a highway structure with its lines must have an acceptable method of suspending the facility, allowing for expansion and contraction and going through or around the bridge abutments.

Alternative three is to lay the pipes in the riverbed. This will require the same approval from the Corps of Engineers as stated above and compliance with Chapter 30 of the DNR codes. This alternative appears to necessitate the most burdensome channels of approval.

Effect of State and Local Tax Laws

In Wisconsin the local tax is replaced by the State Ad Valorem property tax. The formula used to determine the tax dollars to be collected is as follows:

Original cost (cost to put in service)

\- depreciation cost

net book value

x full value average tax rate $\frac{\text{(amt. of property taxes collected)}}{\text{(value of property taxed)}}$

gross tax dollars

x .10 (investment credit appropriated from the general fund)

net tax

The implementation of a district heating and cooling system will increase the net book value since the company will have to invest in retrofitting an existing plant and establishing a distribution system (piping). Although the PSC may decide to adjust the depreciation rates--an old plant is being materially improved rather than a new plant being added--the cost of putting in the DHCS will change the net book value.

The resulting change in net book value will correspondingly change the amount of net tax dollars. All else remaining constant, the utility can expect to have its AD VALOREM taxes increase if its net book value increases.

Effects of a Statutory Mandate to Serve All

Wisconsin Statute 196.37 provides that customers within a utility's service area have a right to receive service, i.e., upon reasonable request the utility has a duty to servce all customers in its established service territory. This provision should have no significant impact on the proposed DHCS. Each utility already has an established service territory within the state.

Within the territory the utility offers different services to different customers. Once a utility decides to whom it wants to make the service available and has the PSCW authorization, it is obligated to serve all who request it; however, not everyone is required to take the service that is offered. It should be pointed out that in the 1940s Northern States Power Company faced the unusual situation of having a customer who wished to connect to its steam heating system at a location that previously did not have service. The company claimed it would cost a great deal of money to hook up this customer. The court ordered the utility to serve that customer, dispite the financial burden it placed on the utility, because the utility had an obligation to serve.

Extent and Effects of Environmental Regulations

The DHCS projects that are described in this report involve the retrofitting of existing turbine facilities. Due to the fact that no new boilers would be constructed, no air quality permits would have to be issued for such a project to be built. In fact, one of the advantages of a DHCS that is often cited is that such a system may lead to an improvement in air quality. Therefore, regulations covering air quality standards do not seem to be a barrier to these systems.

There are two facets of any DHCS project that would fall under the environmental review procedures of the Public Service Commission. These would be the retrofitting of the power plant steam turbine equipment and the construction of the steam transmission and distribution facilities.

Under Section PSC 2.90 of the Wisconsin Administrative Code, construction of steam production facilities is an action that requires an individual screening to determine whether an environmental impact statement (EIS) is required. It is unclear whether the retrofitting of turbine equipment would fall into this

category. Construction of utility facilities not otherwise specified in PSC 2.90 are classified as Type 3 actions: no EIS is required. Consequently, a classificatory determination would have to be made by the Commission before the need for an EIS could be determined with certainty. The approval for the construction of steam transmission and distribution facilities is also classified as a Type 3 action. It should be noted that the Commission can consider any action brought to its attention and determine that an EIS is required.

The Green Bay DHCS project would require environmental review from other state and federal agencies. The particular agencies involved would depend upon the river crossing option chosen for the final design. The available alternatives are: (1) a bridge constructed specifically for that purpose; (2) the I-43 highway bridge now under construction; and (3) a submarine crossing on the riverbed.

The State of Wisconsin Department of Natural Resources would have the general state jurisdiction for the river crossing. To make a determination as to whether an EIS would have to be filed before DNR permits were granted, detailed engineering plans would have to be submitted. Field personnel would also visit the site of the crossing and from this information a decision would be made concerning the need for a more formalized environmental review. In a telephone conversation, a DNR employee in the Bureau of Environmental Impact gave an informal opinion that no EIS would be required for such a project.

The United States Coast Guard would have to issue a permit for any overhead crossing. This would involve options 1 and 2. If the distribution pipes are attached to the highway bridge but are above the low point of steel, no permit would be required from the Coast Guard. However, a permit would still be required from the State of Wisconsin Department of Transportation. If the pipes were tucked up under the steel substructure of the bridge so there would

be no visual impact, it is most probable that the Department of Transportat would not require that an EIS be filed before granting a permit.

The Coast Guard would definitely require a permit if a separate bridge is constructed. Whoever files the permit application would be required to fil general environmental analysis for the bridge. The Coast Guard would revie the impact of the bridge on wetlands, wildlife habitat and the human envi- ronment, including the effects on commercial and industrial activity. Fro this information, they would make a determination as to whether or not an EIS would be required. However, due to the predominantly industrial charac of the Fox River in the project area, it is doubtful that the Coast Guard would require a more detailed environmental review.

For a submarine crossing, the U. S. Army Corps of Engineers would have to issue a permit. The Corps would consider the chemical makeup of the botto sediments and might require that any contaminated sediments be removed fro the site as a condition of the permit. They would also need to evaluate final engineering plans before a permit could be issued, and thus would al need these plans to determine the need for an EIS. Once again, a telephon conversation with an employee in the Permit Section of the Corps' Chicago o fice gave the impression that no EIS would be required by the Corps for a crossing permit to be issued.

It is difficult to state categorically whether or not detailed environmenta review of DHCS projects would be needed without at least preliminary engin ing plans. However, it can be stated that environmental restrictions are probably not great barriers to project construction.

Extent and Effects of Power Siting Laws and Local Zoning Laws on Ability to Retrofit an Existing Power Plant and Build a District Heating and Cooling System

The power plant siting law, Wisconsin Statute 196.491, places no direct obstacles in the way of retrofitting a power plant for cogeneration. PSC 111.12, Administrative Code, states that the inefficient use of energy should be discouraged; a DHCS improves the efficiency of energy use.

Local zoning laws do not create obstacles. Because no new plants are being constructed, there is no problem with the zoning ordinances. The location of each plant is already in a properly zoned area, and a change in the oepration will not pose any problems.

Review of the Corporate Charters of Each Participating Utility Company and All Applicable Statutes, Codes and Ordinances, to Confirm the Legal Capacity to Construct, Own and Operate the District Heating and Cooling Demonstration Projects

The corporate charters of the three eligible utilities clearly allow each to own, operate and maintain steam heating utilities. However, there are two requiremeents that will have to be met before the demonstration project can proceed. The utility must apply to the local government council for franchise rights to establish a heating system within the municipality. Once this is approved, the utility must apply to the Commission for authority to implement the project. When these two provisions are met, the utility may proceed with constructing a DHCS.

Detailed Schedules of Approvals, Both Internal and External, That Have to be Obtained in Order to Reach a Decision on the Construction of the Project

The following will be required:

- Apply to municipality to operate a steam heating utility;
- Apply to PSC for construction approval;
- Obtain licensing approval from
  - DNR,
  - DOT,
  - Army Corps of Engineers;
- Obtain financial guarantees;
- Obtain engineering approvals;
- Obtain customer contracts.

5.5 CONCLUSIONS

The reform-minded utility regulatory climate in Wisconsin ensures that a DHCS system will be supported. Institutional impediments can be expected, however, when a multitude of agencies are to give approvals before the DHCS can proceed. An example is intervention of the Federal Highway Administration, which is expected to oppose a river briding in Green Bay using the existing bridge.

The State regulations often override local regulations, as in the case of siting and taxes due to the existing State laws and the support of the utility customers.

It appears that institutional problems would be minimized if the DHCS were owned/operated by an existing utility. However, eventual rules of PURPA may favor setting up an independent DHCS which purchases heat from the electric utility.

State-backed utility bonds are an option that opens the financial way for an independtly owned DHCS system should this alternative prove preferable.

The PSCW believes the main test of DHCS viability is economic, not institutional. If energy can be delivered at a cost that is competitive with that of No. 6 fuel oil, success appears likely. If it cannot be competitive with No. 6 oil but only with No. 2 oil, the risks are greater but reduced by the effects of marginal cost-based pricing for natural gas.

SECTION 6.0 PRELIMINARY ECONOMIC ANALYSIS

This section examines the economic viability of the district heating system alternatives for Green Bay, Janesville/Beloit and Madison. An approach is outlined and basic assumptions delineated. Summary results for each alternative are illustrated. Detailed results, including fuel escalation sensitivity analysis, income statements, balance sheets and specific examples illustrating how the economic results were determined, are contained in Appendix G.

APPROACH

From the rate structure charged to the customer, an annual or gross income (I_n) would be realized. In providing heat, yearly operational, maintenance and fuel expenses (OM_N) would be incurred. Expenses would also be incurred from yearly revenue requirements (R_N) that are necessary to recover capital investments and taxes. The difference between income and expenses is the annual savings (AS_N); that is,

$$AS_N = I_N - OM_N - R_N$$

For each of the three sites and for each district heating system alternative analyzed, these cost components were determined, annual savings calculated and results discounted to present (1979) dollars. Since the economic results are particularly sensitive to future fuel costs, a number of alternatives were generated to examine the sensitivity of real fuel escalation rates. Finally, a single fuel escalation scenario was selected and the resultant calculations examined to determine the sensitivity of other cost parameters.

ASSUMPTIONS

Major assumptions used for the economic analysis include:

- Period of Analysis--A 25-year period was selected.
- Inflation Rate--A constant rate of seven percent per year was used over the analysis period. This rate was applied to all fuel, operation and maintenance expenses.
- Annual Investments for Capital Equipment--All expenditures for plant retrofit and the distribution network were assumed to occur in the first year, except where system costs were high. These are specifically noted.
- Income from the Sale of Thermal Energy--The determination of income from the sale of thermal energy depends on the amount charged and the fuel escalation rate over the analysis period. For purposes of this analysis, it was assumed that the customer would need an economic incentive to switch to the district heating system that would defray costs associated with conversion of his building. Therefore, as a starting point, a thermal energy base rate of 90 percent of the cost of the least expensive fuel used by building owners in the area was selected. This cost then was escalated over a range of different rates (2 to 10 percent) for that fuel to test the sensitivity of the economics. The other major assumption applied to income from the sale of thermal energy was to assume that all potential customers are connected to the system immediately rather than having a gradual customer buildup over a period of time.
- Capacity Charges--Capacity charges to reflect the loss of electrical generation capability at the power plant were not considered since customers were treated as interruptible loads.
- Lost Revenue from Sale of Gas--Loss revenue from the sale of natural gas and its economic impact on the utility was not considered in this analysis.

Operation and Maintenance Costs/Distribution and Transportation System

Operation and maintenance costs for each system alternative analyzed are detailed in Appendix G. An example for Green Bay is illustrated in Table XXXVI and includes:

- Maintenance on Distribution/Transportation System--This cost was assumed to be one percent of the annual distribution system cost, an amount experienced by Swedish District Heating Systems.
- Insurance Cost on Distribution/Transportation System--A figure of 0.2 percent of the total cost per year was used.
- Operational Costs for Distribution/Transportation System--Pumping costs were based on the size required to pump the necessary amount of water through the system. The total yearly KWH required (e.g., 5,500,000) were multiplied by the industrial electric rate (e.g., $.022/KWH) for that area.

Operation and Maintenance Costs--Plant Retrofit Components

Operation and maintenance costs for utility plant retrofit were determined using a simulation model that considers the district heat required and the characteristics of the unit(s) selected to provide the heat. The model determines fuel and operation/maintenance costs for energy extracted from that unit (e.g., electricity foregone) and fuel and O&M costs of other units that have to be fired to make up that lost electrical generation. The two costs combined are the total O&M costs for plant retrofit (Table XXXVI). Costs per year vary because the projected hours of interruption and projected generation requirements vary over the years.

Year	Distribution			Plant		Total O&M Costs
	Maintenance 1% of Cost ($8x10^6$)	Insurance .2% of Cost ($8x10^6$)	Pump Power $5.5x10^6$ kWh/yr @ 022/kWh	District Heating Portion	Cost of Shifting to less Efficient Boilers	
1980	80	16	122	260	117	595
1981	86	17	131	295	140	669
1982	92	18	140	315	239	804
1983	98	20	149	337	223	827
1984	105	21	160	359	199	844
1985	112	22	171	384	276	966
1986	120	24	183	408	330	1066
1987	128	26	196	432	427	1209
1988	137	27	210	464	443	1282
1989	147	29	224	495	316	1212
1990	157	31	240	472	329	1230
1991	168	34	257	456	286	1233
1992	180	36	275	488	306	1320
1993	193	39	294	522	328	1412
1994	206	41	315	559	351	1511
1995	221	44	337	598	375	1617
1996	236	47	360	640	401	1730
1997	253	51	385	684	430	1851
1998	270	54	412	732	460	1981
1999	289	58	441	783	492	2120
2000	310	62	472	838	526	2268
2001	331	66	505	897	563	2426
2002	354	71	541	960	603	2596
2003	379	76	578	1027	645	2778
2004	406	81	619	1099	690	2972

Table XXXVI. O & M Costs (x 1000), Green Bay, Three Mill and CBD Alternative

Results and Fuel Escalation Rates

A parametric analysis was performed for the following range of fuel escalation rates:

Fuel	Real Rate	Rate with Inflation
Coal	0 to 7 percent	7 to 14 percent
Oil	3 to 10 percent	10 to 17 percent
Natural Gas	2 to 10 percent	9 to 17 percent

The results consisted of a number of curves representing life-cycle savings versus real fuel escalation rates for natural gas, as shown in Figure 28.

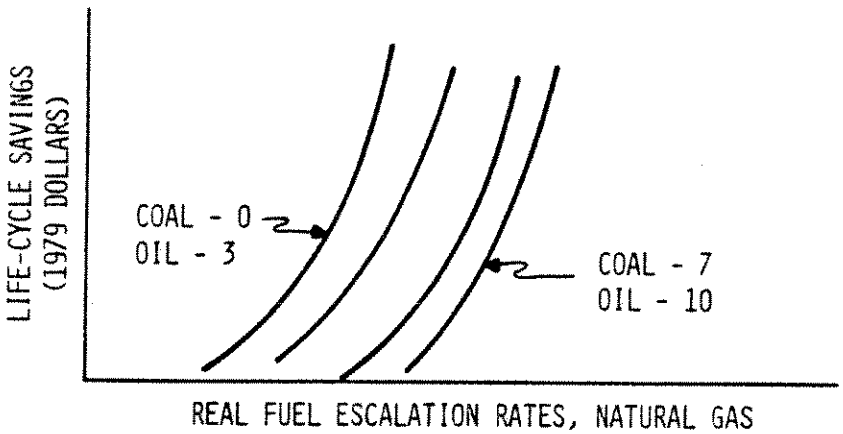


Figure 28. Sample Results, Life-Cycle Savings

Natural gas is the dominant fuel used in Green Bay, Janesville/Beloit and Madison. Therefore, income from the sale of thermal energy to the consumer was tied to the current price of natural gas and the expected escalation rates.

The results depicted represent life-cycle savings that could be achieved using a base rate and range of escalation rates. Using these results, the economic viability of the district heating system can be determined as a function of:

- Costs and escalation rates for fuel burned (coal and oil) at the utility,
- Income escalation at different rates.

To examine the year-by-year flow of funds into the district heating system, the accumulated net present value for each year was determined (Figure 29).

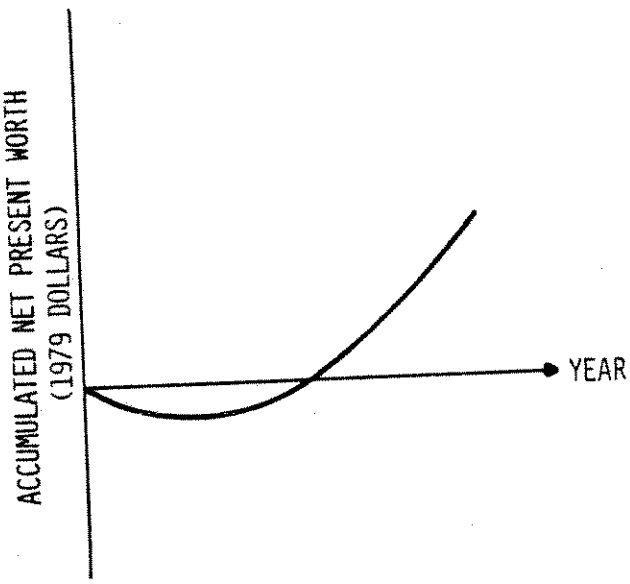


Figure 29. Sample Results, Accumulated Net Present Worth

The cost of determining the accumulated net present worth of the district heating system for all fuel escalation rates would be prohibitive. Therefore a single escalation rate was selected for each fuel. Real fuel escalation

rates selected (i.e. those in excess of inflation) include:

- Natural Gas 7.0 percent
- Distillate Fuel Oil 4.1 percent
- Coal 4.0 percent

These real escalation rates were extracted from, "Historic and Forecasted Energy Prices by DOE Region and Fuel Type for Three Macroeconomic Scenarios and One Imported Oil Price Scenario," Office of Energy Use Analysis, November 1978. The rates are based on the Trendlong scenario, which depicts a situation of relatively stable long-term economic growth.

The results illustrated depict the accumulated net present worth of the district heating system assuming:

- Coal and oil used by the utility is escalating at 4.0 percent and 4.1 percent, respectively.
- Income from the sale of thermal energy on a base rate for that area and escalating at 7 percent.

Financing Options

Three financing options were considered for each alternative investigated. These include:

- Utility Financing--The entire cost of the project (i.e., plant retrofit equipment and distribution system) is financed by the utility using its capitalization structure. The entire system is operated and maintained by the utility.
- Utility/Municipal--The cost of the plant retrofit equipment is financed by the utility, whereas the cost of the distribution system is financed by a municipal utility. The cost of operating and

maintaining the plant portion of the system is borne by the utility. The municipal utility operates and maintains the distribution system.

- Municipal--The entire cost of the project (including operation and maintenance) is financed by a municipal utility.

Capitalization Inputs

The preliminary economic analysis performed for each of the three sites was based on the capitalization structure of each utility. For the municipal financing option, a return rate of 8 percent was used for all three sites. Inputs are summarized in Table XXXVII.

District Heating Alternatives Analyzed

The district heating alternatives analyzed were described in detail in Section 3.0. A brief summary of these alternatives follows.

Green Bay--

- Three Mills and CBD--Includes three paper mills (located across the Fox River from the power plant) and the Central Business District (CBD), which is located immediately south of the paper mills. The distance from the Green Bay Pullium Plant to the southern boundary of the CBD is approximately two miles. Distribution costs include $1,000,000 for a pipe bridge across the Fox River.
  - Heat Supplies 3540.85×10^9 Btu/year
  - System Costs
    - Plant Retrofit $3,000,000
    - Distribution System $8,000,000

Table XXXVII. Economic Analysis Input Summary

	Green Bay Wisconsin Public Service Corporation	Janesville/Beloit Wisconsin Power & Light	Madison Madison Gas & Electric
Capitalization	Bonds 47% @ 9% Preferred 12% @ 9% Common 41% @ 13%	Bonds 48% @ 9.75% Preferred 12% @ 9.5% Common 40% @ 14.5%	Bonds 51% @ 8.0% Preferred 14% @ 9.0% Common 35% @ 12.0%
Income Tax Rate (State/Fed)	49.95%	50%	49.95%
Advalorem Tax Rate	$30 per $1000 Assessed Valuation	$25 per 1000 Assessed Valuation	$30 per 1000 Assessed Valuation
Investment Tax Credit Rate	10%	10%	10%
Utility Discount Rate Employed	17%	11.62%	9.54%
Book Life	27 years	31 years	27 years
Depreciation Method	Double Declining - 1st two years Sum of Digits - Remaining years	Double Declining - 1st two years Sum of Digits - Remaining years	Double Declining + 1st two years Sum of Digits - Remaining years
Municipal Financing Rate	Bonds 100% @ 8%	Bonds 100% @ 8%	Bonds 100% @ 8%
Municipal Discount Rate Employed	8%	8%	8%

- Two Mills and CBD--Includes the two smaller paper mills and the CBD. The largest paper mill was omitted. Distribution costs include $1,000,000 for a pipe bridge across the Fox River.
  - Heat Supplied 1418.33×10^9 Btu/year
  - System Costs
    - Plant Retrofit $2,200,000
    - Distribution System $6,500,000

Janesville/Beloit--

- Rock River to Industrial Park--Includes a proposed (i.e., no current tenants) industrial park located near the Rock River Power Plant.
  - Heat Supplied (Estimate) 1234.80×10^9 Btu/year
  - System Costs
    - Plant Retrofit $1,500,000
    - Distribution System $5,200,000
- Blackhawk to Beloit--Includes large industrial users in and near Beloit, Wisconsin.
  - Heat Supplied 670.41×10^9 Btu/year
  - System Costs
    - Plant Retrofit $ 1,500,000
    - Distribution System $14,300,000
- Rock River to Janesville and Beloit--Includes heavy users near Janesville and Beloit, with all energy extracted from the Rock River Power Plant.
  - Heat Supplied 1928.61×10^9 Btu/year
  - System Costs
    - Plant Retrofit $ 2,500,000
    - Distribution System $67,200,000

Madison--

- CBD and Capitol Heating Complex--Includes portions of the Central Business District and the buildings heated by the Capitol Heating Plant.
  - ▲ Heat Supplied — 215.10×10^9 Btu/year
  - ▲ System Costs
    - Plant Retrofit — $1,000,000
    - Distribution — $3,500,000
- University of Wisconsin--Includes complex of buildings (approximately 150) at the University of Wisconsin.
  - ▲ Heat Supplied — 1176.05×10^9 Btu/year
  - ▲ System Costs
    - Plant Retrofit — $2,400,000
    - Distribution — $14,200,000

CONCLUSIONS

Detailed results of the economic analysis are contained in Appendix G.

A summary of the results for each of the three sites and each of the alternatives analyzed is illustrated in Figures 30 through 36. The summary results depict the accumulated net present worth or annual savings as a function of the year of operation for each financing alternative considered.

For each of the three sites and each of the alternatives analyzed, yearly fixed revenue requirements necessary to retire the cost of the capital investment were determined. Yearly fuel costs at the power plant, based on coal escalating at a real rate of 4 percent and oil at 4.1 percent, were calculated. These were added to yearly operations and maintenance costs of the system (based on a yearly average inflation rate of 7 percent) to determine total revenue requirements.

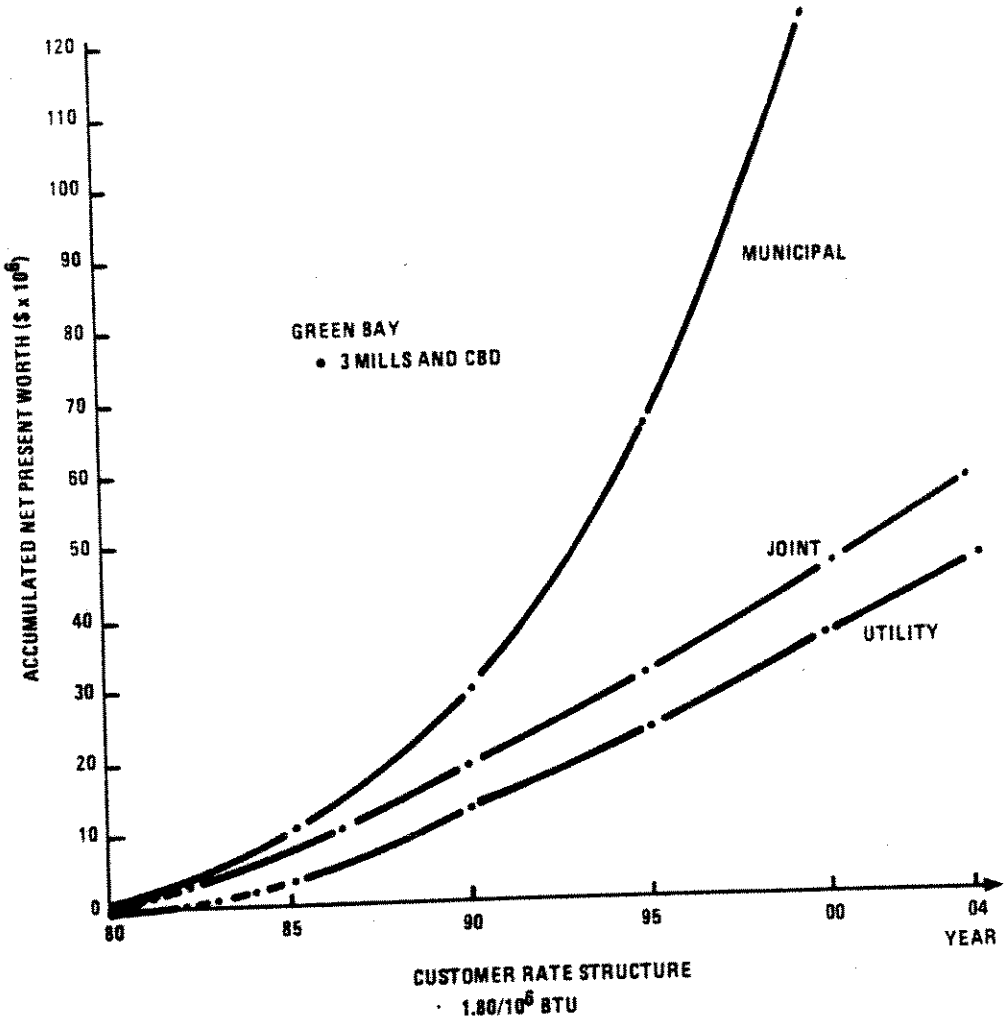


Figure 30. Accumulated Net Worth versus Year, Green Bay, Three Mills and CBD

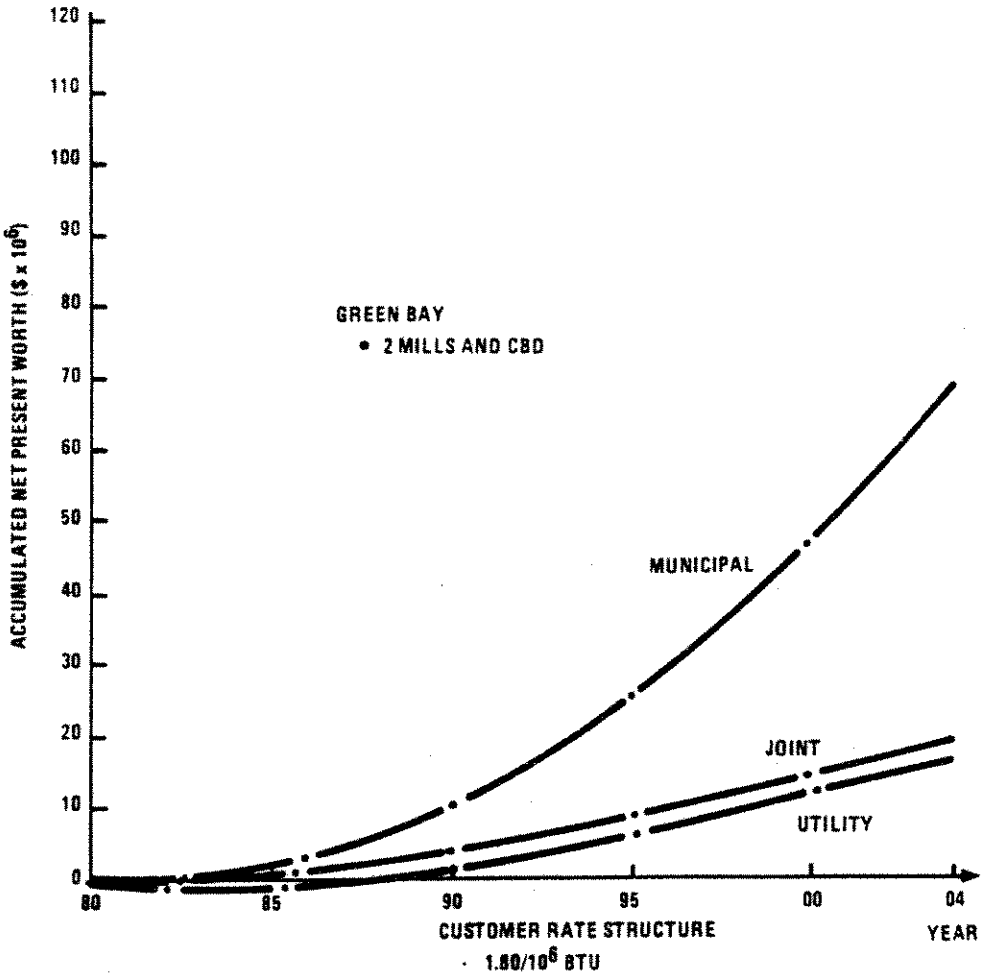


Figure 31. Accumulated Net Worth versus Year
Green Bay, Two Mills and CBD

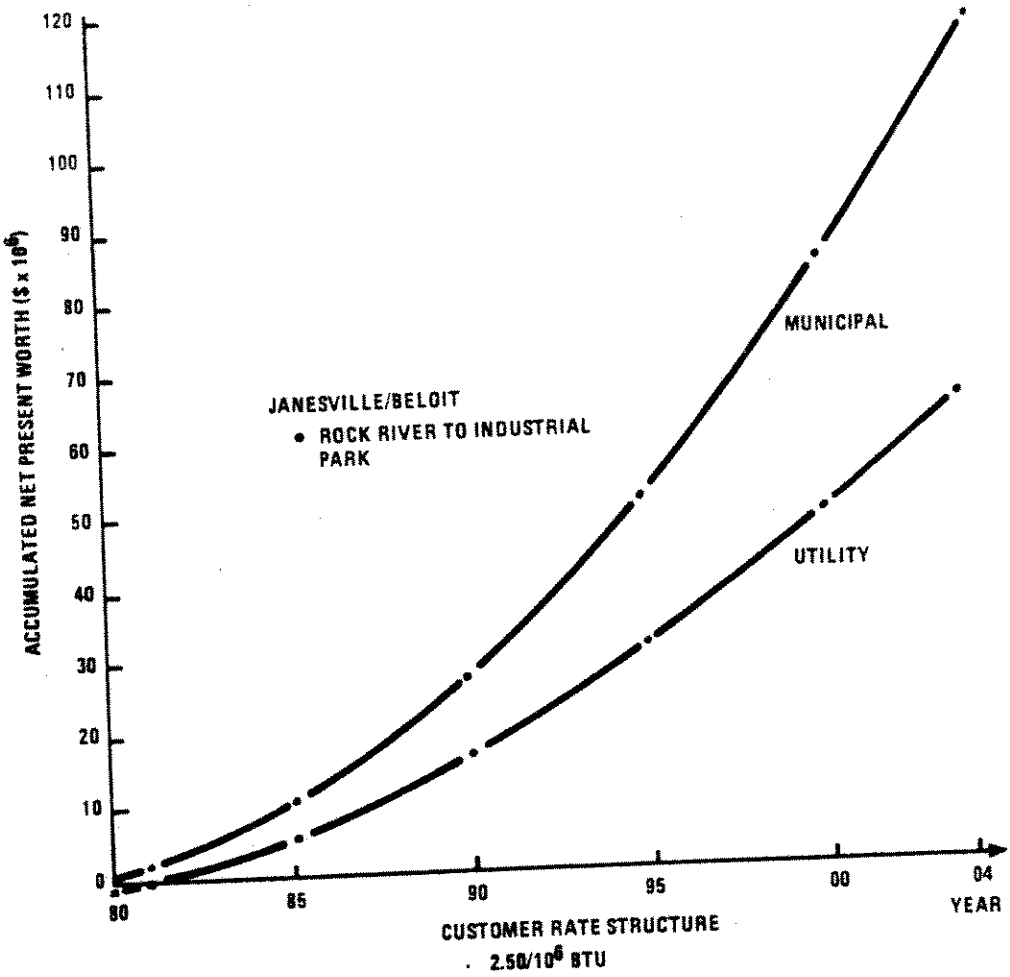


Figure 32. Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Industrial Park

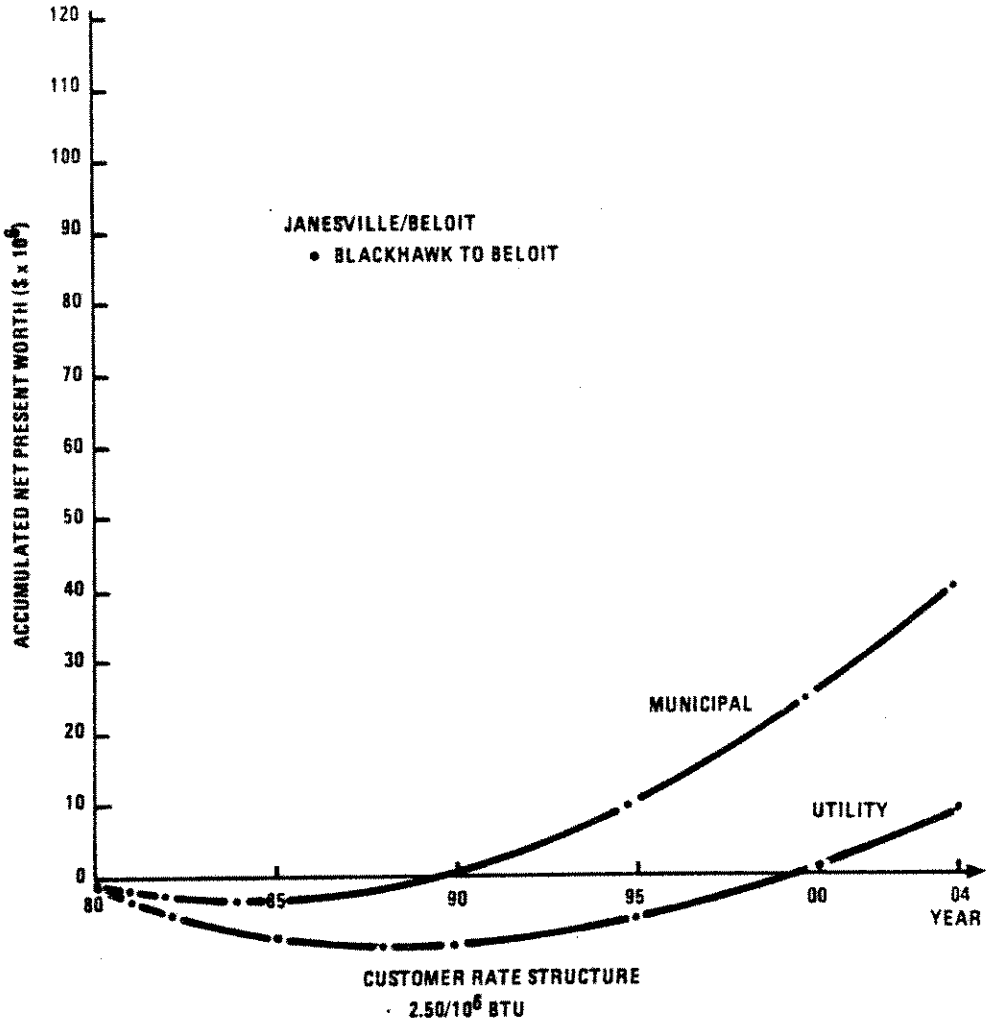


Figure 33. Accumulated Net Present Worth versus Year, Janesville/Beloit, Blackhawk to Beloit

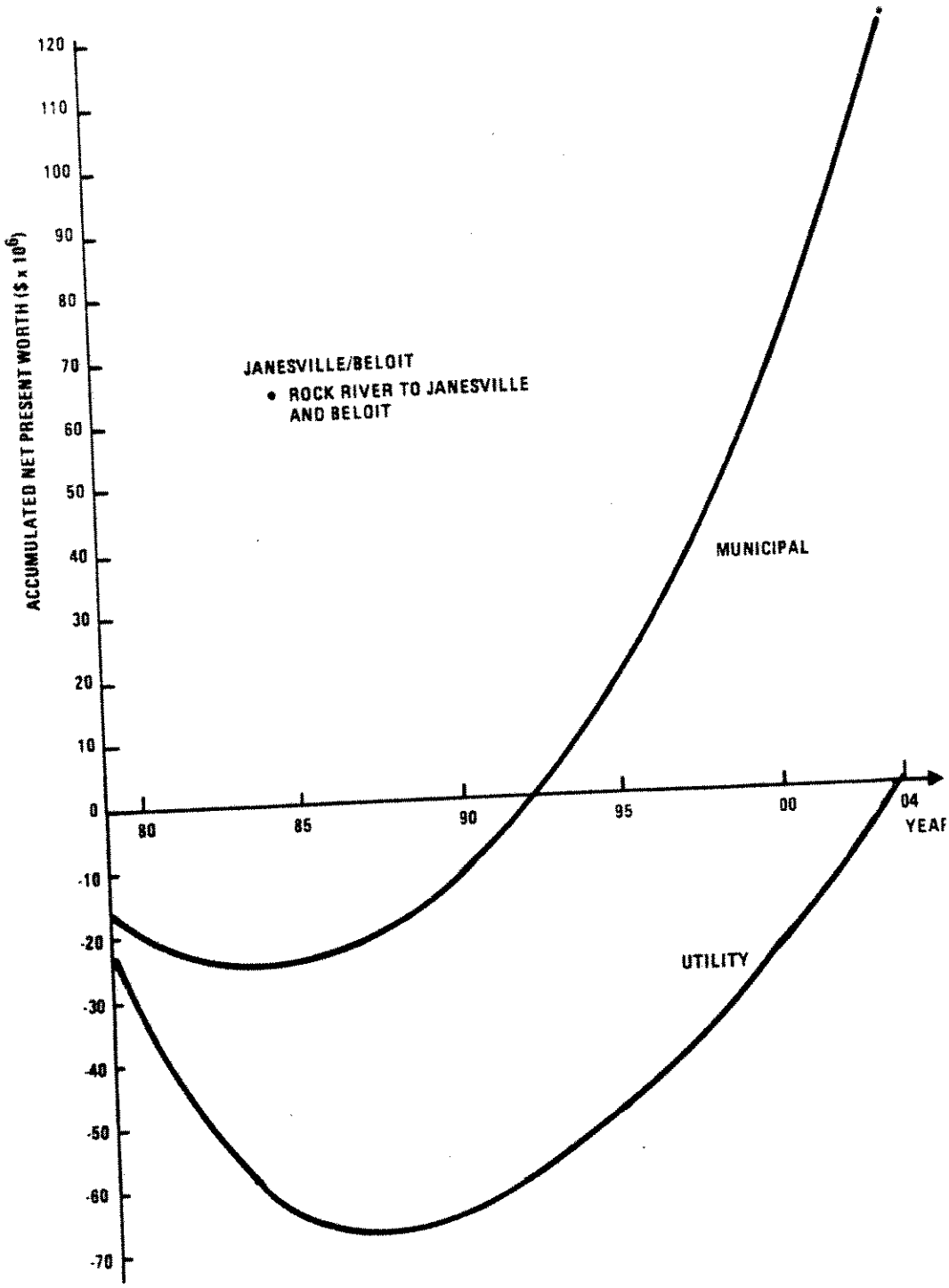


Figure 34. Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Janesville and Beloit

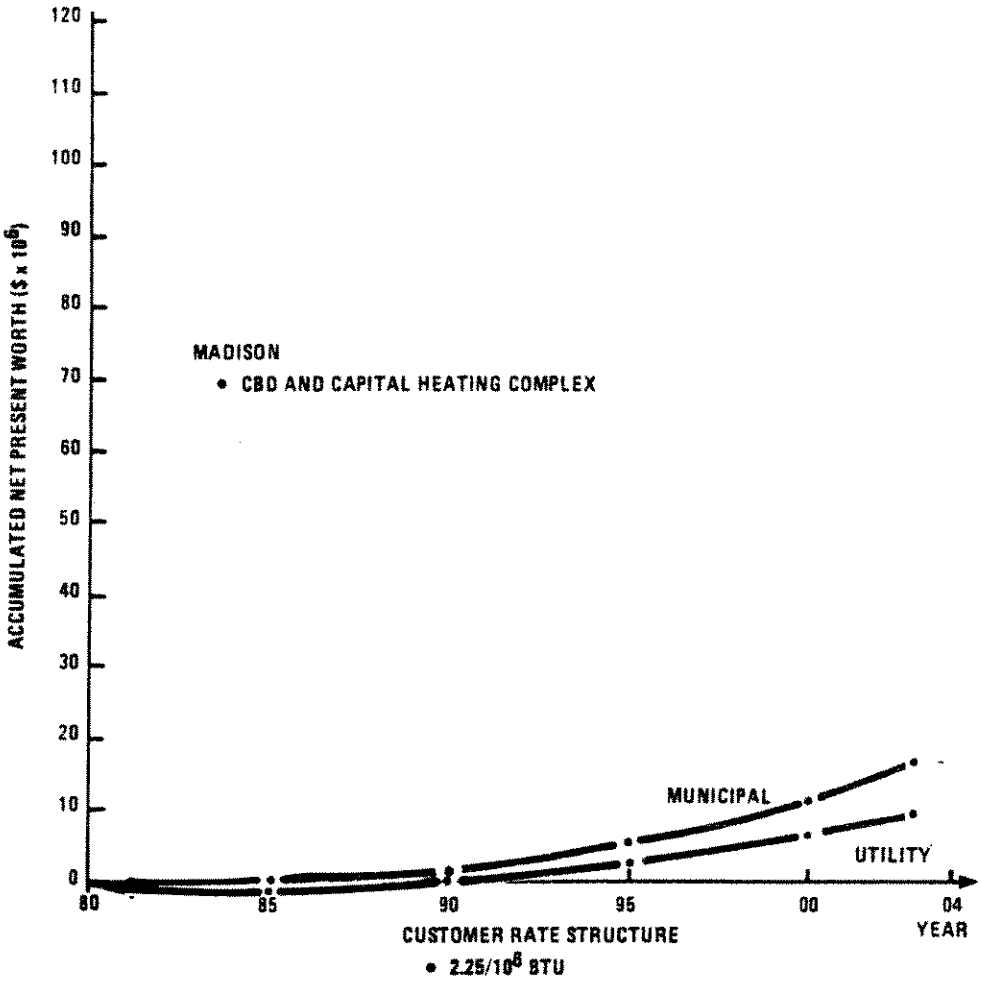


Figure 35. Accumulated Net Present Worth versus Year, Madison, CBD and Capitol Heating Complex

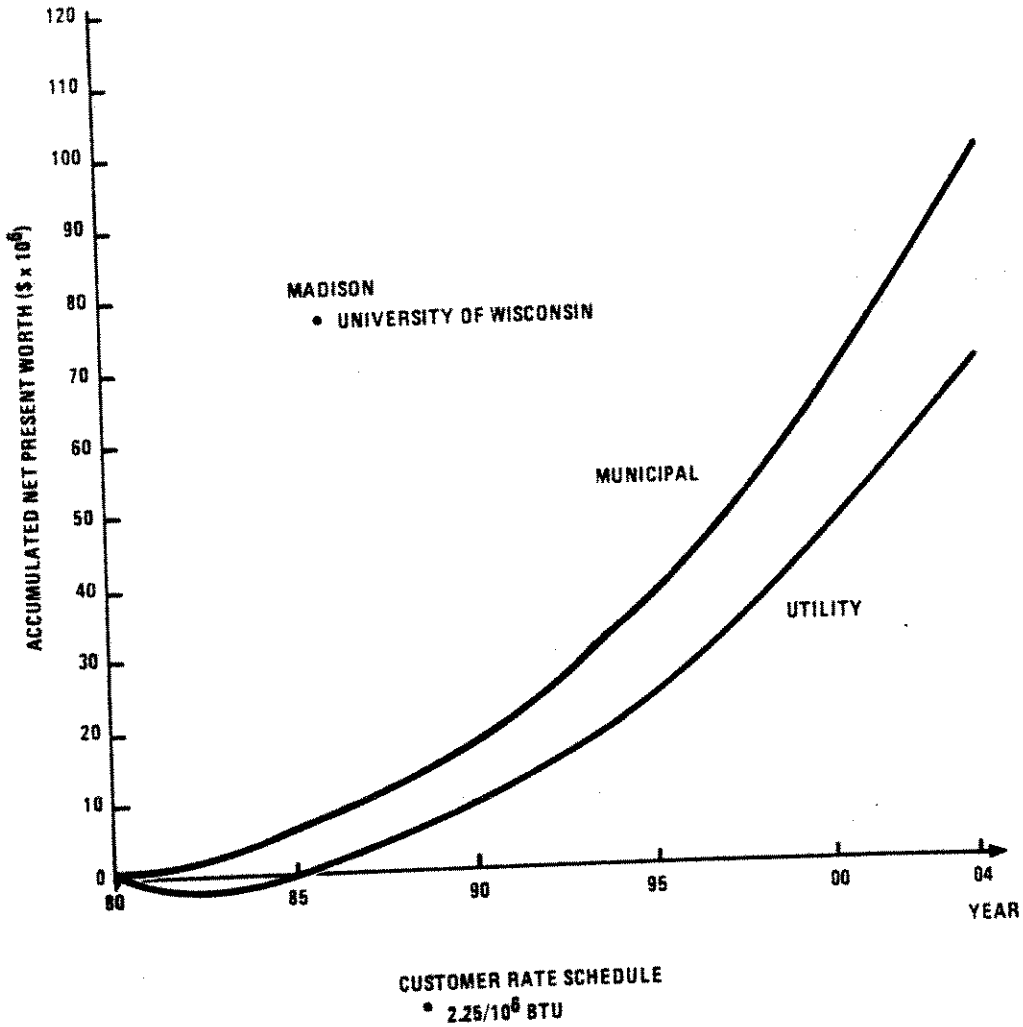


Figure 36. Accumulated Net Present Worth versus Year, Madison, University of Wisconsin

Gross income for each of the three sites was determined by selecting a customer rate structure and escalating it at a rate equal to that expected for the fuel that would be displaced. In each of the three sites, the fuel that would be displaced is natural gas. The customer rate was selected by taking 90 percent of the current charge for natural gas at each site. This would become the rate charged for thermal energy from the DHCS. A 10 percent reduction was selected as a means of providing an incentive for customers to convert their building to the DHCS. The customer rate was escalated at a rate expected for natural gas (7 percent) and the gross yearly income was determined.

Annual savings were then determined by subtracting total yearly return requirements. Accumulated annual savings (in 1979 dollars) were then plotted on a yearly basis. Thus the results illustrated depict the economic viability of the DHCS for each alternative while considering:

- Capitalization structure of the utility or municipality,
- Cost of the DHCS,
- Thermal load supplied,
- Fuel, operations and maintenance costs,
- Income based on a competitive energy charge rate, and
- Income based on a charge rate that provides incentive for building owners/operators to convert their buildings.

A comparative summary of the sites and alternatives considered is given in Table XXXVIII. For each alternative, total fixed revenue requirements (in 1979 dollars) are tabulated. Also tabulated and illustrated in Figures 30 through 36 are the number of years required until accumulated net present worth of savings equals fixed revenue requirements.

Table XXXVIII. Comparative Summary of DHCS Alternatives

DISTRICT HEATING SYSTEM ALTERNATIVE	TOTAL FIXED REVENUE REQUIREMENTS FOR DHCS SYSTEM ($1979 x 1000)		YEARS UNTIL TOTAL ANNUAL SAVINGS EQUAL REVENUE REQ.	
	UTILITY	MUNICIPAL	UTILITY	MUNICIPAL
GREEN BAY				
3 MILLS & CBD	11,137	10,881	10	6
2 MILLS & CBD	8,808	8,606	18	10
JANESVILLE/BELOIT				
ROCK RIVER TO INDUSTRIAL PARK	9,720	6,511	7	3
BLACKHAWK TO BELOIT	22,920	15,353	>25	17
ROCK RIVER TO JANESVILLE/ BELOIT	117,744	77,683	>25	21
MADISON				
CBD & CAPITOL HEATING COMPLEX	6,065	4,451	19	14
UNIVERSITY OF WISCONSIN	22,373	16,420	14	9

The most promising site is Green Bay, where a large industrial process load as well as a commercial building heating and hot water load are located close to the Pulliam Power Plant. The industrial process load from the three paper mills represents about 90 percent of the total load in the defined service area. If these loads come on line immediately, as assumed in the economic analysis, positive net annual savings can be realized within two years. This would provide a large study source of income for the DHCS while the downtown business area is brought on line over a time-phased period.

For the other alternative considered for Green Bay, consisting of the two smallest paper mills and the Central Business District, the total load is 40 percent of the three-mill alternative while the costs are 80 percent. These proportionate loads and costs combine to make the economics slightly less desirable,with positive net annual saving realized in seven years. The large industrial base load would provide the same benefit as with the three-mill alternative, providing a steady income while the CBD is gradually brought on line.

The most economically attractive alternative analyzed is the industrial park to be located near the Rock River Power Plant in the Janesville/Beloit area. The concentration of estimated loads and the short distribution system could make this site economically attractive at a future date. At present, no industries have been identified as park occupants.

The next most promising site analyzed was Madison. The two alternatives included (1) a portion of the CBD and buildings heated by the Capitol Heating Complex and (2) the University of Wisconsin complex of buildings. Both analyses assumed that all customers would come on line during the first year of system operation. This would be an optimistic assumption for the CBD; in reality, the buildings would come on line over a time-phase period. Hence, the economics would tend to be less desirable than portrayed.

The University of Wisconsin currently has two central boiler plants and a steam distribution system. Because of the distance from the Blount Street Power Plant, a substantial investment ($16,600,000) would be required to transport hot water to the central plants for distribution to the buildings. Costs for converting each building would also be substantial. These costs were not included in the economic analysis performed. Combined with a time-phased building conversion plan, these costs would represent a less desirable economic outlook.

The two remaining alternatives analyzed for Janesville/Beloit have scattered concentrations of loads requiring extensive and costly distribution systems. The results of the economic analysis illustrate this situation, depicting long periods where the system would have negative accumulated savings.

A sensitivity analysis was performed that related fuel escalation rates to life-cycle savings (Appendix G, Volume III). The analysis illustrates how life-cycle savings over a 25-year period vary as a function of fuel escalation rates for fuels (coal and oil) consumed by the power plant and district heating fuel costs to the consumer. The latter is represented by escalation rates for natural gas, for which the cost of district heating energy was assumed to follow. This analysis was conducted for utility, municipal and joint financing.

The results of the analysis indicate that the economic viability of the project is very sensitive to fuel escalation rates. Given the uncertainty of future fuel escalation rates, this would indicate that district heating systems with lengthy payback periods should be carefully analyzed. Those with shorter payback periods or those that do not operate at a large deficit for a long period of time can be viewed more favorably. The Green Bay, Wisconsin, site appears to fall into the latter category.

COO-4981-1

DISTRICT HEATING AND COOLING SYSTEMS FOR COMMUNITIES THROUGH POWER PLANT RETROFIT AND DISTRIBUTION NETWORKS

PHASE 1 - IDENTIFICATION AND ASSESSMENT

FINAL REPORT

VOLUME III - APPENDICES

SEPTEMBER 1979

WISCONSIN STATE ENERGY OFFICE

PREPARED FOR:

U.S. DEPARTMENT OF ENERGY
CHICAGO OPERATIONS OFFICE
UNDER CONTRACT EM-78-C-02-4981

79130

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APPENDIX A
UTILITY PLANT CHARACTERISTICS

This appendix contains information (Tables A-I through A-VIII) describing the characteristics of seven utility plants that were considered during the final site selection process.

Table A-I. Valley Electric Generating Plant

LOCATION: DOWNTOWN MILWAUKEE, ABOUT EIGHT BLOCKS SOUTH OF THE MILWAUKEE RIVER AND APPROXIMATELY ONE MILE WEST OF LAKE MICHIGAN.

OWNERSHIP: WISCONSIN ELECTRIC POWER COMPANY

NUMBER OF UNITS: 2

RATED CAPACITY: 136 MW/UNIT WITH NO STEAM EXTRACTION: 70-136 MW/UNIT WITH VARIOUS RATES OF STEAM EXTRACTION

DATES OF INSTALLATION: UNIT 1-1968; UNIT 2-1969

TYPE OF FUEL: ILLINOIS COAL

AVERAGE HEAT RATE (1977): 12,636 BTU/KWH

Table A-II. Manitowoc Electric Generating Plant

LOCATION: DOWNTOWN MANITOWOC, ON LAKE MICHIGAN, ABOUT EIGHT BLOCKS SOUTH OF THE MANITOWOC RIVER.

OWNERSHIP: MANITOWOC PUBLIC UTILITIES (MUNICIPAL)

NUMBER OF UNITS: 5 (NUMBERED 2 THROUGH 6)

RATED CAPACITY:
- UNIT 2 - 5MW WITH NO STEAM EXTRACTION (UP TO 50,000 POUNDS PER HOUR STEAM EXTRACTION CAPABILITY)
- UNIT 3 - 10 MW
- UNIT 4 - 10 MW WITH NO STEAM EXTRACTION (UP TO 100,000 POUNDS PER HOUR STEAM EXTRACTION CAPABILITY)
- UNIT 5 - 22 MW
- UNIT 6 - 22 MW

DATES OF INSTALLATION: UNIT 2 - 1935; UNIT 3 - 1941; UNIT 4 - 1950; UNIT 5 - 1956; UNIT 6 - 1964

TYPE OF FUEL: COAL

AVERAGE HEAT RATE (1977): 15,533 BTU/KWH

Table A-III. Blount Street Electric Generating Plant

LOCATION: DOWNTOWN MADISON, ABOUT SIX BLOCKS EAST OF THE CAPITOL BUILDING.

OWNERSHIP: MADISON GAS AND ELECTRIC COMPANY

NUMBER OF UNITS: 7

RATED CAPACITY:
UNIT 1 - 10 MW
UNIT 2 - 5 MW
UNIT 3 - 37.5 MW
UNIT 4 - 25 MW
UNIT 5 - 27.5 MW
UNIT 6 - 50 MW
UNIT 7 - 50 MW

DATES OF PLANNED RETIREMENT: UNIT 1 - 1984; UNIT 2 - 1984; UNIT 3 - 1994; UNIT 4 - 1989; UNIT 5 - 1989; UNIT 6 - 2004; UNIT 7 - 2004

TYPE OF FUEL: COAL

AVERAGE HEAT RATE (1977): 12,095 BTU/KWH

Table A-IV. Pulliam Electric Generating Plant

LOCATION: DOWNTOWN GREEN BAY, AT THE WEST SIDE OF THE MOUTH OF THE FOX RIVER.

OWNERSHIP: WISCONSIN PUBLIC SERVICE CORPORATION

NUMBER OF UNITS: 6 (NUMBERED 3 THROUGH 8)

RATED CAPACITY:
UNIT 3 - 30 MW
UNIT 4 - 30 MW
UNIT 5 - 50 MW
UNIT 6 - 62.5 MW
UNIT 7 - 75 MW
UNIT 8 - 125 MW

DATES OF INSTALLATION: UNIT 3 - 1943; UNIT 4 - 1947; UNIT 5 - 1949; UNIT 6 - 1951 UNIT 7 - 1958; UNIT 8 - 1964

TYPE OF FUEL: COAL

AVERAGE HEAT RATE (1977): 11,218 BTU/KWH

Table A-V. Edgewater Electric Generating Plant

LOCATION: DOWNTOWN SHEBOYGAN, ON LAKE MICHIGAN, ABOUT 1-3/4 MILES SOUTH OF THE SHEBOYGAN RIVER.

OWNERSHIP: UNITS 1, 2 and 3 - WISCONSIN POWER AND LIGHT COMPANY
UNIT 4 - WISCONSIN POWER AND LIGHT COMPANY (68.2%)
WISCONSIN PUBLIC SERVICE CORPORATION (31.8%)

NUMBER OF UNITS - 3 (NUMBERED 2 THROUGH 4)

RATED CAPACITY: UNIT 2 - 31 MW
UNIT 3 - 74 MW
UNIT 4 - 325 MW

DATES OF INSTALLATION: UNIT 2 - 1942; UNIT 3 - 1951;
UNIT 4 - 1969

TYPE OF FUEL: COAL

AVERAGE HEAT RATE (1977): 10,204 BTU/KWH

Table A-VI. Rock River Electric Generating Plant

LOCATION: ON THE ROCK RIVER, ABOUT TWO TO FOUR MILES NORTH OF BELOIT AND FOUR TO SIX MILES SOUTH OF JANESVILLE.

OWNERSHIP: WISCONSIN POWER AND LIGHT COMPANY

NUMBER OF UNITS: 2

RATED CAPACITY: UNIT 1 - 78 MW
UNIT 2 - 78 MW

DATES OF INSTALLATION: UNIT 1 - 1954; UNIT 2 - 1955

TYPE OF FUEL: COAL

AVERAGE HEAT RATE (1977): 11,097 BTU/KWH

Table A-VII. Black Hawk Electric Generating Plant

LOCATION: DOWNTOWN BELOIT, ON THE ROCK RIVER, ABOUT NINE BLOCKS NORTH OF THE WISCONSIN/ILLINOIS BORDER.

OWNERSHIP: WISCONSIN POWER AND LIGHT COMPANY

NUMBER OF UNITS: 2 (NUMBERED 3 AND 4)

RATED CAPACITY: UNIT 3 - 24 MW
UNIT 4 - 24 MW

DATES OF INSTALLATION: UNIT 3 - 1946; UNIT 4 - 1948

TYPE OF FUEL: COAL

AVERAGE HEAT RATE (1977): 12,845 BTU/KWH

APPENDIX B
FUTURE LOADS

This appendix contains a detailed description of future thermal loads for each of the three sites--Green Bay, Janesville/Beloit and Madison. Assumptions on their calculations and distribution within the service areas selected are described.

GREEN BAY, WISCONSIN

Future loads are forecasted for the downtown business district and an industrial park near the utility power plant.

Green Bay Central Business District

Development Plan--The city of Green Bay has developed a plan, Project Plan for Tax Incremental District Number One, to renovate areas in the Central Business District. The area covered by this plan includes the CBD area selected for detailed analysis in this feasibility study and a smaller area on the west side of the Fox River (Figure B-1).

The plan has been designed to:

- Promote necessary development to advance opportunities for intensifying the business activities within the area.
- Upgrade the physical qualities and use of the area by eliminating deteriorated, obsolete, blighted and structurally substandard buildings.
- Assemble an adequate number of readily saleable and developable sites for appropriate commercial, office and multifamily buildings through acquisition.

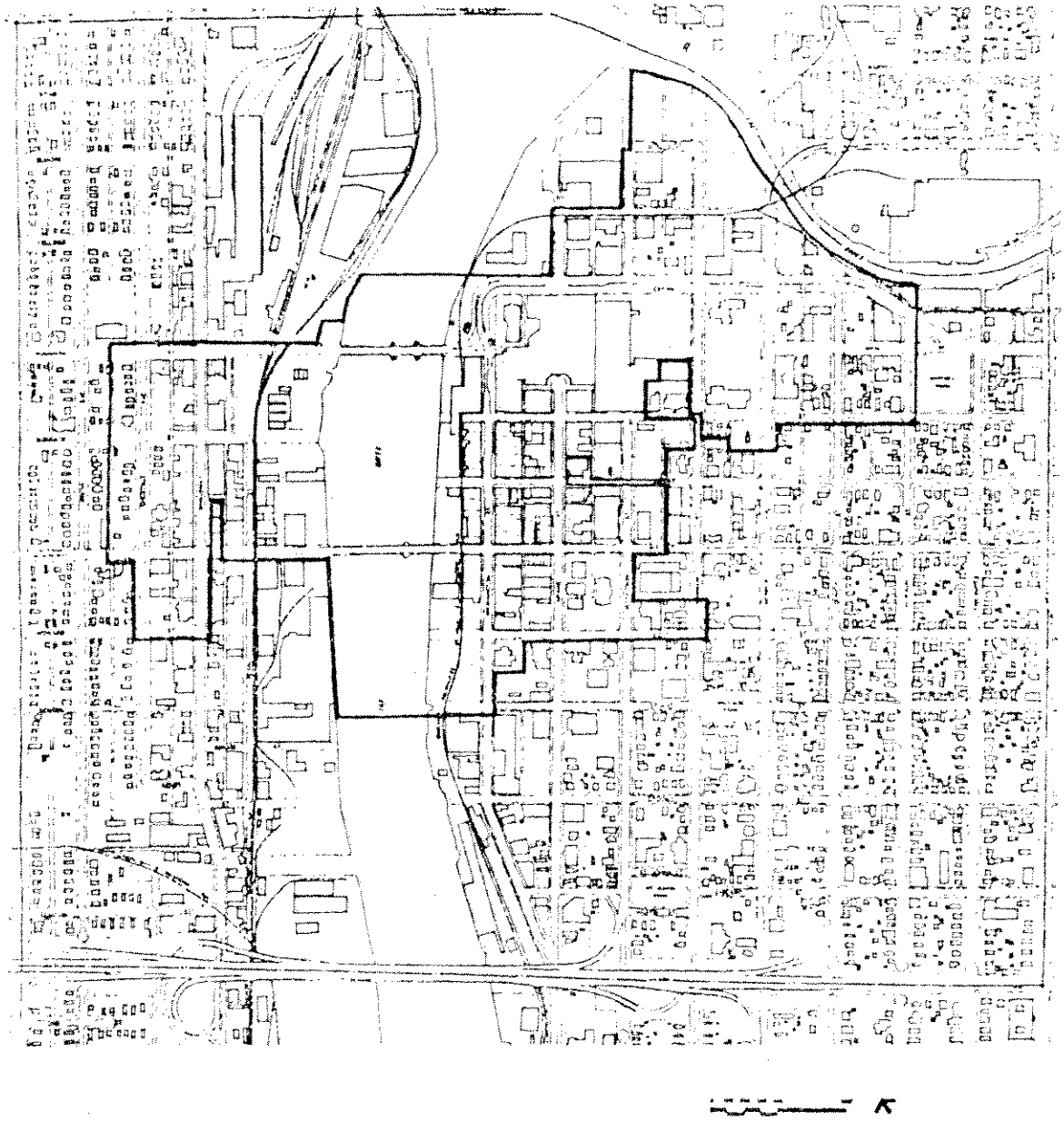

Figure B-1. Tax Incremental District Number One
Green Bay, Wisconsin

The plan, although recently enacted, has started to show fruition: A large (four square blocks) shopping plaza, parking ramp and multistory building for elderly housing have been built. Other areas are being razed for future buildings.

Future Load Potential--The potential increase for additional thermal energy can be estimated from the projected increase in building square footage for various building types (Table B-I). Since the available data indicates additional units for hotel/motel and multifamily, it was assumed that the corresponding square footage for this type of space would be 250 and 750 square feet, respectively.

Table B-I. Current/Planned Building Space

LOAD USE	EXISTING SPACE $FT^2 \times 10^3$	ADDITIONAL SPACE (1985) $FT^2 \times 10^3$
RETAIL	1,633.5	505.4
DEPARTMENT STORES	445.0	191.6
SERVICES	169.9	42.5
OFFICES	576.0	219.4
HOTEL/MOTEL	(764) UNITS	(212) UNITS*
MULTIFAMILY	NOT AVAILABLE	(507) UNITS**

*EACH UNIT EQUAL TO 250 SQUARE FEE

**EACH APARTMENT EQUAL TO 750 SQUARE FEET

To convert square footage to total monthly, yearly and peak hour energy consumption for space heating and hot water, the following empirical relationships were used:

- Residential buildings

  Space Heat = $14.6 \frac{\text{Btu}}{\text{ft}^2} \times$ heat degree-days

  Hot water = $22 \frac{\text{Btu}}{\text{ft}^2\ \text{day}}$

- High-density residential

  Space Heat = 0.72 x (residential building)

  Hot water = $15 \frac{\text{Btu}}{\text{ft}^2\ \text{day}}$

- Commercial

  Space heat = 0.5 x (residential)

  Hot water = $9 \frac{\text{Btu}}{\text{ft}^2\ \text{day}}$

The diverse building types identified in Table B-I were grouped into two classifications--commercial (retail, department, services, offices) and high-density residential (hotel/ motel, multifamily). This resulted in total additional planned square footage as follows:

- High-density residential 433,300
- Commercial 958,900

Based on monthly degree-day and design-day information for Green Bay (Table B-II), monthly space heating and hot water energy requirements were derived.

Table B-II. Monthly Degree-Day/Design Temperatures, Green Bay

MONTH	DEGREE-DAY	PERCENT OF DEGREE-DAYS PER MONTH
JANUARY	1494	18.6
FEBRUARY	1313	16.4
MARCH	1141	14.2
APRIL	654	8.1
MAY	335	4.2
JUNE	99	1.2
JULY	28	0.3
AUGUST	50	0.6
SEPTEMBER	174	2.2
OCTOBER	484	6.0
NOVEMBER	924	11.5
DECEMBER	1333	16.6
TOTAL	8029	

DESIGN TEMPERATURE (99%) -13°F

These are given in Table B-III (high-density residential) and Table B-IV (commercial).

Total Future Loads/Green Bay CBD--The future load was distributed in the area being analyzed using planning data supplied by the city of Green Bay. Based on this data, the following estimates were made (Table B-V):

- All future hotel/motel space will be in the area analyzed and is planned for blocks 39 and 40. It was assumed that the additional load will be equally split between the two blocks.
- Eighty percent of the increase in office space will be in the analyzed area. Of the total projected increase, 10 percent will be in blocks 24 and 25 and 15 percent will be in blocks 10, 31, 35 and 43.
- Sixty-five percent of the increase in retail, department and service store space will be in the area analyzed. Of the total projected increase, five percent will be in blocks 9, 10, 15, 16, 17, 21, 22, 23, 27, 28, 32, 37 and 41.
- Sixty percent of the increase in multifamily units will be in the area analyzed. Of the total increase, 30 percent will be in blocks 7 and 44.

Table B-III. Future High-Density Residential Heating/Hot Water Loads, Green Bay (1985)

MONTH	DAYS	DEGREE DAYS (DD)	HEATING BTU/FT^2 MONTH	HOT WATER BTU/FT^2 MONTH	TOTAL HEATING, HOT WATER BTU/FT^2 MONTH	TOTAL BTU/MONTH X 10
JANUARY	31	1494	15,705	465	16,170	7.007
FEBRUARY	28	1313	13,802	420	14,222	6.161
MARCH	31	1141	11,994	465	12,459	5.399
APRIL	30	654	6,875	450	7,325	3.174
MAY	31	335	3,522	465	3,987	1.728
JUNE	30	99	1,041	450	1,491	.646
JULY	31	28	294	465	759	.329
AUGUST	31	50	526	465	991	.429
SEPTEMBER	30	174	1,829	450	2,279	.987
OCTOBER	31	484	5,088	465	5,553	2.406
NOVEMBER	30	924	9,713	450	10,163	4.404
DECEMBER	31	1333	14,013	465	14,478	6.273
					TOTAL	39.944

Table B-IV. Future Commercial Heating/Hot Water Loads, Green Bay (1985)

MONTH	DAYS	DEGREE DAYS (DD)	HEATING BTU/FT^2 MONTH	HOT WATER BTU/FT^2 MONTH	TOTAL/HEATING HOT WATER BTU/FT^2 MONTH	TOTAL BTU/MONTH X 10^9
JANUARY	31	1494	10,906	279	11,185	10.730
FEBRUARY	28	1313	9,585	252	9,837	9.433
MARCH	31	1141	8,329	279	8,608	8.254
APRIL	30	654	4,774	270	5,044	4.837
MAY	31	335	2,446	279	2,725	2.613
JUNE	30	99	723	270	993	.952
JULY	31	28	204	279	483	.463
AUGUST	31	50	365	279	644	.618
SEPTEMBER	30	174	1,270	270	1,540	1.477
OCTOBER	31	484	3,503	279	3,812	3.655
NOVEMBER	30	924	6,745	270	7,015	6.727
DECEMBER	31	1333	9,730	279	10,009	9.598

Table B-V. Future Load Data (Btu x 10^9)

BLOCK	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	TOTAL
1	NONE												0
2	NONE												0
3	NONE												0
4	NONE												0
5	NONE												0
6	NONE												0
7	1.621	1.417	1.249	0.734	0.400	0.149	0.076	0.099	0.228	0.557	1.019	1.451	9.242
8	NONE												0
9	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
10	0.783	0.688	0.602	0.354	0.191	0.070	0.034	0.045	0.108	0.267	0.490	0.700	4.326
11	NONE												0
12	NONE												0
13	NONE												0
14	NONE												0
15	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
16	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
17	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
18	NONE												0
19	NONE												0
20	NONE												0
21	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
22	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
23	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
24	0.246	0.246	0.189	0.111	0.050	0.022	0.011	0.014	0.034	0.084	0.154	0.220	1.358
25	0.246	0.246	0.189	0.111	0.050	0.022	0.011	0.014	0.034	0.084	0.154	0.220	1.358
26	NONE												0
27	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
28	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
29	NONE												0
30	NONE												0
31	0.369	0.324	0.284	0.176	0.090	0.033	0.016	0.021	0.051	0.126	0.231	0.330	2.037
32	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
33	NONE												0
34	NONE												0
35	0.369	0.324	0.284	0.167	0.090	0.033	0.016	0.021	0.051	0.126	0.231	0.330	2.037
36	NONE												0
37	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
38	NONE												0
39	0.429	0.377	0.330	0.194	0.106	0.040	0.020	0.026	0.061	0.147	0.270	0.384	2.443
40	0.429	0.377	0.330	0.194	0.106	0.040	0.020	0.026	0.061	0.147	0.270	0.384	2.443
41	0.414	0.364	0.318	0.187	0.101	0.037	0.018	0.024	0.057	0.141	0.259	0.370	2.289
42	NONE												0
43	0.369	0.324	0.284	0.167	0.090	0.033	0.016	0.021	0.051	0.126	0.231	0.330	2.037
44	1.621	1.417	1.249	0.734	0.400	0.149	0.076	0.099	0.228	0.557	1.019	1.451	9.242
TOTALS	11.450	10.108	8.606	5.177	2.805	1.035	0.512	0.674	1.591	3.913	7.177	10.240	63.991

Peak Hour--An estimate of the peak hour space heat and hot water requirements were generated using the ASHRAE 99 percent design temperature. For Green Bay this design temperature is - 13 F. This resulted in peak hour loads of:

- Space heating

  - Commercial

    $(0.5)\ (14.6\ \text{Btu/ft}^2 \times \text{HDD}) \times (65 - (-13/24\ \text{HDD/hour}$

    $= 23.725\ \text{Btu/ft}^2\text{- hour}$

  - High-density residential

    $(0.72)\ (14.6\ \text{Btu/ft}^2 \times \text{HDD}) \times (65 - (-13))/24\ \text{HDD/hour}$

    $= 34.164\ \text{Btu/ft}^2 - \text{hr}$

- Hot water

  - Commercial $\quad 9\ \frac{\text{Btu}}{\text{ft}^2\ \text{day}} \times$ 24-hour day

    $= 0.375\ \frac{\text{Btu}}{\text{ft}^2\ \text{hour}}$

  - High-density residential $\quad 15\ \frac{\text{Btu}}{\text{ft}^2\ \text{day}} \cdot$ 24-hour day

    $= 0.625\ \frac{\text{Btu}}{\text{ft}^2\ \text{hour}}$

The peak load is then

- Commercial

  $(23.725 + 0.375)\ \frac{\text{Btu}}{\text{ft}^2\ \text{hour}} \cdot 958.9 \times 10^3\ \text{ft}^2$

  $= 0.023 \times 10^9\ \frac{\text{Btu}}{\text{hour}}$

- High-density residential

  $(34.164 + 0.625)\ \frac{\text{Btu}}{\text{ft}^2\ \text{hour}}\ /433.3 \times 10^3\text{ft}^2$

$= 0.015 \times 10^9 \frac{Btu}{hour}$

The total peak hour load is: 0.038×10^9 Btu/hour

Green Bay Paper Mills

No increase in thermal load is forecast for the near future.

Future Industrial Park

An area adjacent to the power plant and along Lake Michigan has been set aside to attract future industry. Currently, there are no industrial plants in the area and no construction is in progress.

Although, this area offers a large potential for thermal energy, it would be difficult to speculate on the magnitude and timing of this future requirement.

JANESVILLE/BELOIT

Neither Janesville or Beloit can be expected to experience commercial growth that would significantly influence this thermal demand analysis. However, due to the large amount of available land, some potential for industrial parks between the two cities does exist. One planned industrial park is located just west of the Rock River Power Plant. Forecast loads for that park are estimated to be over 1×10^6 MMBtu/year with a peak of 250 MMBtu/hour based on WP&L discussions with potential tenants. Thus, this potential load would rank second in the selected area and represents over 32 percent of the existing land.

MADISON, WISCONSIN

Buildings that are being constructed and will be constructed in the CBD in the near time frame (1985) include the following:

- General Executive Facility No. 2 (under construction in block 107)
- General Executive Facility No. 3 (planned for block 107)
- Civic Center (planned for block 65)
- Federal Building (planned for block 53)

These buildings are being and will be built on vacant property. Thus, the loads represent additional thermal requirements for the DHCS.

The monthly, yearly (Table B-VI) and peak hour (Table B-VII) loads for these buildings were derived from a study conducted for MG&E (reference 4) in 19[illegible]. At that time, these loads were estimates based on conversations with designers and contractors.

Table B-VI. Future Loads, Madison (Btu x 10^6)

BLOCK	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	TOTAL
53	0.50	0.40	0.40	0.20	0.10	--	--	--	0.10	0.20	0.30	0.40	2.60
65	2.01	1.68	1.45	0.79	0.40	0.10	0.02	0.05	0.23	0.64	1.22	1.80	10.39
107	1.80	1.40	1.40	1.00	1.00	1.20	1.20	1.20	1.00	1.00	1.20	1.40	14.80
TOTALS	4.31	3.48	3.25	1.99	1.50	1.30	1.22	1.25	1.33	1.84	2.72	3.60	27.79

Table B-VII. Peak Hour Demands - Future Loads, Madison

	Btu x 10^6/Hour
GENERAL EXECUTIVE FACILITY NO. 2	2.00
GENERAL EXECUTIVE FACILITY NO. 3	2.00
CIVIC CENTER	3.70
FEDERAL BUILDING	1.10
	8.80

APPENDIX C
HVAC INVENTORY

This appendix contains detailed data gathered on the type of heating, hot water and air conditioning equipment commonly found in the cities of Green Bay, Madison, Janesville and Beloit.

The data were gathered using three approaches--personnel interviews, utility data and discussions with utility personnel.

- Interviews - A number of interviews were conducted in each community to identify factors that would induce potential users to subscribe to the DHCS (Appendix E). As part of this interview the types and conditions of HVAC equipment were also surveyed.
- Utility Data - The utilities, routinely, have compiled data on the types of HVAC equipment on major energy users.
- Discussions with Utility Personnel - Additional information and clarification of HVAC data was obtained from personnel within the Consumers Affairs/Applications Departments. These people regularly visit customers and have a general, and in some cases specific, knowledge of user HVAC equipment.

HVAC INVENTORY PROBLEMS ENCOUNTERED

Problems encountered during the HVAC inventory included:

- The age of HVAC equipment often had to be estimated. The current owner/occupants of the building were not necessarily the original owners/occupants.

- Some buildings have two or more types of HVAC systems. This was the result of renovation, splitting up of buildings and add-ons over the years. All types within a building are mentioned.

Table C-I contains detailed data for Green Bay. Data for Madison and Janesville Beloit are contained in Tables C-II and C-III, respectively.

Table C-I. HVAC Inventory Data - Green Bay

Building Type	Heat Source	Distribution Type	Heat System Age (Yr)	Notes	Hot Water System	Air Condition
1) Office/Retail	Boiler	Steam	35		Gas	Electric
2) Office/Retail	Boiler	Steam	30		Steam Exchanger	Electric
3) Office	Boiler	Steam	20		Steam Exchanger	Electric
4) Office	Boiler	Hot Water	4		Gas	Electric
5) Office/Retail	Boiler	Hot Water	20		Gas	Electric
6) Retail	Boiler	Steam	50		Gas	Electric
7) Retail Stores	Boiler Electric Units	Hot Water	3		Hot Water Exchanger	Electric
8) Retail	Boiler Electric Units	Hot Water	2		Hot Water Exchanger	Electric
9) Retail	Boiler Gas Forced Air	Steam Air	25 5		Gas	Electric
10) Motel	Boiler	Hot Water	10		Hot Water Exchanger	Electric
11) Multi-Family	Boiler	Hot Water	5		Hot Water Exchanger	Electric
12) School	Boiler	Steam	30		Gas	None
13) Church	Boiler	Steam	35		Gas	None
14) Office	Boiler	Hot Water	22	Replacing absorption unit	Hot Water Exchanger	Absorption
15) Office	Boiler	Steam	30		Steam Exchanger	Electric
16) Office	Gas	Air	12		Gas	Electric

Table C-I. HVAC Inventory Data - Green Bay (Concluded)

Building Type	Heat Source	Distribution Type	Heat System Age (Yr)	Notes	Hot Water System	Air Condition
17) Office	Boiler	Steam	30		Gas	Electric
18) Museum	Boiler	Steam	20		Gas	None
19) Motel	Boiler	Steam	30	Converting to H.W.	Steam Exchanger	Electric
20) Motel	Electric	Air	5	Electric unit each Room	Hot Water Exchanger	Electric
21) Office/Garage	Gas	Air	10		Gas	Electric
22) Department Store	Gas	Air	15		Gas	None
23) Department Store	Boiler	Hot Water	20		Hot Water Exchanger	Electric
24) Motel	Boiler	Hot Water	6		Hot Water Exchanger	Electric
25) Apartments	Boiler	Steam	40		Gas	Electric
26) Office	Gas	Air	1		Gas	Electric
	Boiler	Hot Water	10			
27) Manufacturing	Boiler	Steam	25		Steam Exchanger	Electric
28) Office	Boiler	Steam	20		Gas	Electric

Table C-II. HVAC Inventory Data - Janesville/Beloit

Building Type	Heat Source	Distribution Type	Age	Hot Water System	Air Condition
1. School	Boilers (2)	Hot Water		Gas	Elec.
2. Apartments	Boilers (3)	Steam	>7 yr	HX	Elec.
3. School	Boilers (3)	Steam	>7 yr	HX	Elec/Abs.
4. Mfg.	Boilers (2)	Steam	<7 yr	HX	Elec.
5. Mfg.	Boilers (3)	Steam	<7 yr	HX	
6. Mfg.	Boilers (5)	Steam	>7 yr	Gas	Elec.
7. Mfg.	Boiler	Steam	>7 yr	Gas	
8. Mfg.	Boilers (2)	Steam	>7 yr	Gas	
9. Mfg.	Boilers (3)	Steam	>7 yr	HX	Elec.
10. Mfg.	Boilers (2)	Steam	>7 yr	HX	
11. Hospital	Boilers (3)	Steam	<7 yr	HX	Abs.
12. Mfg.	Boilers (2)	Steam	<7 yr	HX	Elec.
13. Mfg.	Boilers (4)			Gas	
14. Mfg.	Boilers (3)				
15. Mfg.	Boilers (5)	Steam	>7 yr		
16. Mfg.	Gas Heaters	Air	<7 yr		
17. Mfg.	Boiler		>7 yr	Gas	
18. School	Boiler		>7 yr	Gas	
19. Mfg.	Boiler		>7 yr	Gas	
20. Mfg.	Boiler			Gas	
21. Mfg.	Boiler	Steam	>7 yr	HX	

Table C-III. HVAC Inventory Data - Madison

Building Type	Heat Source	Distribution Type	Age (yrs)	Notes	Hot Water System	Air Conditioning
1. Bank/Office	Boiler	Hot Water	10		Gas	Elec. Central
2. Bank/Office	Boiler	Steam	>20		Gas	Elec. Central
3. Retail/Office	Boiler	Steam	>20		Gas	Elec. Window
4. Bank/Office	Boiler	Steam	5	Gas W.H. in summer only	HX/Gas	Elec. Chiller
5. Retail/Apts.	Boiler	Steam	>20		Gas	Elec. Window
6. Retail/Theater	Boiler	Steam	>20		Gas	Elec. Central
7. Retail	Boiler	Steam/Hot Water	>20		Steam Exchanger	Elec. Window
8. Retail/Office	Boiler	Hot Water	>20		Gas	Elec. Window
9. Office	Boiler	Hot Water	>20		Gas	
10. Hotel	Boiler	Hot Water	17		Hot Water Exchanger	Elec. Window
11. Office	Boiler	Steam	>20		Gas	Elec. Window
12. School	Boiler	Steam	>20		Steam	None
13. Office	Boiler	Steam	15		Gas	Elec. Window
14. Library	Boiler	Steam	12		Gas	Elec. Central
15. Bank/Office	Boiler	Hot Water	8		Gas	Elec. Chiller

Table C-III. HVAC Inventory Data - Madison (Concluded)

Building Type	Heat Source	Distribution Type	Age (yrs)	Notes	Hot Water System	Air Conditioning
16. Office	Boiler	Steam	>20		Gas	Elec. Chiller
17. Hotel	Boiler	Steam	>20		Steam Exchanger	None
18. Office	Boiler	Steam	>20		Gas	Elec. Window
19. Office	Boiler	Steam	8		Gas	Elec. Central
20. Lodge Hall	Boiler	Hot Water	>20		Gas	Elec.
21. Office	Boiler	Steam	>20		Gas	Elec. Central
22. Office	Boiler	Steam	>20		Gas	Elec. Central
23. Office	Boiler	Steam	>20		Gas	Elec. Central
24. Retail/Office	Boiler	Hot Water	>20		Gas	Elec. Window
25. Hospital	Boiler	Steam	>20		Steam Exchanger	Absorption

APPENDIX D
LOAD CALCULATIONS

This appendix contains detailed information on load calculations for the Capitol Heating Plant and University of Wisconsin Plant located in Madison.

CAPITOL HEATING PLANT

The Capitol Heating Plant currently services four buidings: State Capitol Building, General Executive Facility No. 1, City County Building and State Office Building. One, the General Executive Facility No. 1, is both heated and cooled.

Load Data

Total steam production and loads for each of the buildings are contained in Table D-I. The total amount of steam distributed, on a monthly basis, was obtained during conversations with state personnel. This is itemized in Table D-I with respect to steam used for heating and hot water and steam consumed at the plant to produce chilled water.

To obtain heating and hot water loads for the individual buildings, the following distribution of steam was used, based on conversations with state personnel:

- Line losses/electric generation — 20 percent
- State Capitol Building — 18 percent
- General Executive Faility No. 1 — 26 percent
- City County Building — 18 percent
- State Office Building — 18 percent

Table D-I. Capitol Heating Plant/Building Data (1978)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Steam Distributed X 10^6 lbs	25.0	21.0	17.5	13.5	11.8	12.8	9.7	9.3	9.5	13.0	17.3	24.8	185.2
Heating/Hot Water	-	-	-	-	.7	.4	2.3	2.7	1.5	-	-	-	7.6
Air Conditioning													
Building Load BTU x 10^9													
State Capital	4.50	3.78	3.15	2.43	2.12	2.30	1.75	1.67	1.71	2.34	3.11	4.46	33.32
GEF No. 1	6.50	5.46	4.55	3.51	3.07	3.33	2.52	2.42	2.47	3.38	4.50	6.45	48.16
City/County	4.50	3.78	3.15	2.43	2.12	2.30	1.75	1.67	1.71	2.34	3.11	4.46	33.32
State Office	4.50	3.78	3.15	2.43	2.12	2.30	1.75	1.67	1.71	2.34	3.11	4.46	33.32
Total Loads	20.00	16.80	14.00	10.80	9.43	10.23	7.77	7.43	7.60	10.40	7.61	19.83	148.12

The load calculated for each building is included in the section on Madison. The load for the Capitol building is specified in block 0.

Fuel Consumed

The Capitol Heating Plant burns natural gas, No. 6 fuel oil and coal. Based on 1977 records (1977 was a respresentative year for types of fuels consumed), the following percentages of different fuels were used:

- Natural Gas 65 percent
- Coal 28 percent
- No. 6 Fuel Oil 7 percent

UNIVERSITY OF WISCONSIN PLANTS

The University of Wisconsin operates two steam generating power plants, Charter Street and Walnut Street, to heat all of and cool some of the approximately 150 buildings on the campus. Steam production (1978) for each plant is itemized on a monthly basis in Table D-II.

Load Data

Some of the steam produced is used by mechanically driven chillers at the plants. Exact data could not be obtained on the amount of steam consumed by the chillers. Therefore, the amount was estimated using the following assumptions:

- There are four 3500-ton and one 7000-ton (21,000-ton total) chillers at the University.
- Ten pounds of steam are required per ton-hour of cooling.

Table D-II. University of Wisconsin Data (1978)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Steam Produced lbs x 10^6													
Charter St.	233	206	170	114	119	113	119	116	102	104	135	191	1722
Walnut	48	45	44	35	38	48	40	38	34	29	41	51	491
Totals	281	251	214	149	157	161	159	154	136	133	176	242	2213
Steam Distribution lbs x 10^6													
Heating/Hot Water	281	251	214	149	132	129	117	110	111	133	176	242	2045
Air Conditioning	-	-	-	-	25	32	42	44	25	-	-	-	168
Load BTU x 10^9													
Heat/Hot Water	225	201	171	119	106	103	94	88	89	106	141	194	1637

79130

- Total amount of steam required for cooling was estimated to be:

$$21{,}000 \text{ tons} \times 800 \frac{\text{full load hours}}{\text{year}} \times \frac{10 \text{ pounds}}{\text{ton-hour}}$$

$$= 168 \times 10^6 \text{ pounds/year for chillers}$$

- The cooling season is 800 hours over the following months:

May	120 hours	15 percent
June	150 hours	19 percent
July	200 hours	25 percent
August	210 hours	26 percent
September	120 hours	15 percent

Once the amount of steam consumed by the chillers was determined, the remainder was reduced by 20 percent and converted to Btu (1000 Btu/pound). The 20 percent reduction was a reasonable estimate for distribution losses and in-plant electrical generation. The load data calculated is included in the Madison Service Area load data.

Peak Hour Demand

The peak hour demand was 580,000 pounds/hour, or 580×10^6 Btu/hour, based on conversations with plant operational personnel.

Fuel Used

Based on 1978 records, the following fuels were used:

- Natural Gas 39.0 percent
- No. 2 Fuel Oil 16.5 percent
- No. 5 Fuel Oil 6.5 percent
- Coal 38.0 percent

APPENDIX E
FACTORS TO INDUCE POTENTIAL USERS

INTRODUCTION

Interviews were conducted with building owners and managers and facility directors in an effort to explore concerns that people would have with respect to subscribing to a District Heating and Cooling System. This appendix contains a tabulation of concerns and viewpoints expressed. For each interview, the position of the person (i.e., manager, owner) and building type are described. Views expressed are personal and do not necessarily reflect the views of the owners.

INTERVIEW RESULTS

President, Banker and Architect - Hotel

The president is the owner of the building. He also owns other commercial buildings in the community. The banker and architect are close business associates and participated in the interview.

Applicable comments from the interview included:

- The primary concern is one of economics; are the rates and conversion costs such that the project is a viable investment?
- There is a building in Duluth, Minnesota, where a small community steam system exists. Their rates would be about 30 percent higher if they used their own equipment.
- Tax rebates and low interest loans for retrofit costs would be a further inducement to subscribe to a DHCS.

- Side benefits, such as a reduced pollution and being a resident of the community, would enter into the decision-making process.
- The present boilers would be kept as backup. This would also be a hedge against unreasonable future rate increases.
- A commitment or letter of intent would, for now, be based purely on economics. More information about the project would be required.
- The government should consider funding some of the actual construction. I don't think the Federal Government would finance a project that would create funds for a public corporation. They may finance a project that was owned by a municipality. This would take care of other institutional problems since the municipality owns the streets. This financial splitting would relieve the utilities of a large expenditure that they probably don't want.
- The concept of a central heating source should be an added enticement to get new business to locate in the community.

President - Realty Company

The president of the realty company is the owner of the building.

Applicable comments from the interview included:

- The primary concern is one of costs. The present heating system would be used unless there were some inertia to change.
- The DHCS system would have to be more economical to run and operate. The conversion costs would have to be amortized.
- All the costs involved would be examined. The remaining life of my present boiler system would also be examined. I do not measure investments only in terms of payback times or return on investment rates.

- Tax rebates, low interest loans or any financial considerations that would improve the economics of participation in a DHCS would be most welcome.
- Improvements in the air quality would be welcome. However, the economics would still be the prime consideration.
- If business were generally good, I would be more favorable, in terms of committing capital for conversion equipment, to connecting to the DHCS system.
- The reliability of the system would not be of great concern. I would assume that the system would be designed properly. I do not foresee that it will be any less reliable than a gas pipe.
- I would be reluctant to throw out my current boiler, unless it were in the way.
- When streets are ripped up they are an inconvenience to the local business people. They have always been torn up for improvements, except for the last year.
- To sign a letter of intent or commitment, I would have to have a better picture of the costs.
- I would have to get more information on the systems, its costs and merits before I could support the concept. I have the feeling that the government is trying to "foist something" on me.

Director - YMCA

Applicable comments from the interview included:

- The number one concern would be the economics of the district heating and cooling system.
- The board of directors (local businessmen) would help review and evaluate the investment of connecting and subscribing to a DHCS.
- I am familiar with a steam district heating system in St. Louis. It was very reliable. There never was a failure during the time

that I was there. I would gladly get rid of my boiler when the DHCS was checked out. This would also eliminate the insurance premium on the boiler.

- The YMCA is a nonprofit organization. All improvements are paid in cash. Tax rebates and low interest loans would be of no interest to us.
- A letter of commitment or intent would have to be approved by the board of directors. A letter probably could be obtained, based on specified economic and reliability constraints.
- Any improvement in air pollution would be welcome as long as the benefits are not excessively costly.
- I would be interested in hearing more about the DHCS at a later date when more concrete data is available.

Manager, Plant Engineer - Shopping Plaza

The shopping plaza is owned by a series of corporations located from coast to coast.

Applicable comments from the interview included:

- The first concern would be the capital costs, where the savings would come from and the point at which a net gain would be realized.
- The owners (corporations) look at all investments from a cash flow basis. A connection to a district heating and cooling system would be veiwed in that light.
- The owners probably would not consider side benefits, such as decreased air pollution and energy savings, to weight in the decision-making process.

- Tax rebates, low interest loans, etc., that would improve the cash flow from an investment point of view would be considered.
- Reliability is of utmost importance because the lease requires me to maintain a certain space temperature in the stores. When the temperature is not maintained, the tenants do not have to pay rent.
- If the store were on the DHCS, the present system could serve as a backup.
- A reliability agreement with the utilities that could be passed on to the tenants would be considered.
- To obtain a commitment, a formal presentation would have to be made to the corporations.
- A letter of intent probably could be obtained based on specified economic conditions. This could take a long period of time (6 to 8 months) since a number of corporations are involved.

President, Vice President - Screen Printing Company

The company is a subsidiary of another company. The parent company is also the building owner.

Applicable comments from the interview included:

- Rates should be less than competitive fuels because of the cost of retrofit must be amortized.
- The retrofit system should have a payback of three to five years.
- Our current heating system was revamped in the last year. I would not be particularly interested in redoing the system again without good justification.

- Because the cost of borrowed money is so expensive, tax rebates, low interest loans, etc., that would help reduce the potential payback would be most welcome.
- The reliability would not be a great concern, since I would believe that the people that would put in the DHCS would know what they are doing.
- The present boilers and rooftop unit would be kept as a backup and as a hedge against the rates going up too high.
- I am familiar with the steam district heating system in Milwaukee. Other than turning the system off too early in the spring and on too late in the fall, I do not remember any failures or downtime during the heating season. Our own equipment has not maintained this track record.
- The improvement gained in air pollution would be a welcome benefit and I would rate it high in the decision process; but my first responsibility is to stay in business.
- Because this appears to be such a large program and the success appears to be strongly linked to the number of people that would have to be connected, I would be concerned if I were forced to join.
- My requirements for a commitment to sign up would be to get data on initial retrofit costs, energy costs and some guarantee on future energy costs such that they do not escalate unnecessarily.
- I would like to have the right to disconnect if I wanted.
- Ripped up streets would not be a prime concern.
- The government should consider putting money into the construction phase of this project. They put money in hydropower plants.

Plant Manager, Engineer - Vegetable Canning Company

Applicable comments from the interview included:

- The price of the energy would have to be, at the least, as low as gas (the least expensive fuel in this area). This would be an equitable price, especially if it would help the supply of gas for other uses.
- The price of the heat would have to take into account the cost of capitalization of the retrofit system.
- The payback of the retrofit costs would have to be less than five years and preferably two to three years. In the interest of conservation, the payback times may be relaxed.
- Connection costs would be favorable for new construction.
- Two much emphasis may be placed on costs; we are very much conservation oriented. especially with respect to gas.
- Pollution would not be a concern to our particular company or operation and would have little bearing on the decision whether to participate as a user.
- Reliability of the supply is very important. Heat is used to keep the product from freezing in the warehouse. We would have to be convinced of the reliability of the system--its supply, peaks and valleys, temperatures, etc.
- The present system would be kept. It could serve as a backup. It would probably cost more to tear it out than we could get by selling the system.
- Some hot water from the DHCS could possibly be used to produce low pressure steam for in-plant use.
- If rates were regulated, the PSC would look for the industrial customers to absorb high rates and subsidize the system.

- To provide a commitment for use, we would have to calculate in-house use of energy and connection costs. We would then talk to the utility about rates.
- A letter of intent, based on costs and benefits, would be a possibility.
- Disruptions to the plant and streets would not be a determinant. They seem to be the norm lately.
- The DHCS concept sounds like a very good idea. One should never turn our back on a proposition such as this because it is in the public interest.

Plant Engineering Manager - Paper Industry

Applicable comments from the interview included:

- At this plant, there is a large requirement for boiler makeup water and hot process water.
- Since the company is a profit-making organization that uses a substantial amount of energy, the company is very concerned about the current and future costs of energy.
- The company would be interested if the energy costs were priced attractively. We would be even more interested if the power company would provide hot treated water that could be used directly.
- Because energy related costs are given priority on capital investments, the return on investment would be relaxed from greater than 20 per cent to less than 20 per cent.

President - Commercial Building Owner/Manager

The president owns and manages a number of builsings that are used as office space, retail sales and hotel/motel.

Applicable comments from the interview included:

- The financial aspects of a DHCS would be the first concern. The finances would have to be such that a payback could be realized in less than five years.
- Tax rebates, low interest loands, etc., that would improve the economics would be acceptable and possibly necessary to get the idea going in a community.
- Energy-related expenditures are high on my priority list. I would consider relaxing my payback requirements, given that business conditions were generally good.
- The government should help finance the DHCS. They finance every other social program.
- A DHCS program would benefit the community and enhance the business environment.
- I would be willing to sign a letter of intent based on favorable economic conditons.

Property Manager, Engineering Service Manager - Bank

Applicable comments from the interview included:

- To get people interested in the DHCS concept, the energy must be sold at lower price than other fuels.
- Our bank and officers of the bank are very energy conscious. Even though the building is rather new, a considerable amount of money has been spent on rezoning the heating system and using condensing water for the reheat system.
- An absorption air conditioning system would be an expensive retrofit--more so than the heating conversion costs.
- A payback of less than five years is desirable; up to eight years is acceptable.

- Energy-related investments are different from other investment alternatives in that you know that you will never get it cheaper.
- DHCS seems to have a lot of potential. One of our banks in Milwaukee is heated by a steam district heating system. They do not seem to have any problems.
- Reliability of supply is important to us because we rent office space in the building. Our office space is some of the highest priced in town, and our tenants are under contract to be serviced.
- A letter of commitment or intent would not be appropriate at the present time. We would have to learn more about the project and the true costs.
- Tax credits and low interest loans to help finance retrofit costs would be an inducement to subscribe to the DHCS system.

Bureau of Engineering - State of Wisconsin

The Capitol Heating Plant is owned and operated by the State of Wisconsin. The plant currently supplies steam to the State Capitol Building, State Office Building, the City/County building and the General Executive Facility (GEF) No. 1 (i.e., office building). It will serve two other State buildings, General Executive Facilities No. 1 and No. 2, which are currently under construction. The plant also contains a central chiller that supplies chilled water to GEF No. 1 and will to GEF No. 2 and No. 3.

Applicable comments from the interview included:

- The State got into the energy business because it was cheaper and because of the limited capacity of the utility plant at the time.

- Economics would be the prime consideration that would be investigated in switching to a DHCS. The economic evaluation would include looking at building retrofit costs.
- If the DHCS concept were good for the community and had widespread support in the community, it would receive better State support.
- State financing procedures (financing vehicle and rates) differ from private companies. The present plant was paid for with tax dollars. Any borrowed money (bonds) is retired at a modest (5 to 7 percent) interest rate.
- Legislative action would be required for the State to participate in a DHCS.
- A letter of commitment or intent, based on favorable economics, might be obtained.
- The plant complies with State EPA regulations on emmissions. We burn a mixture of natural gas, oil and coal, in order to achieve specified levels.

Plant Manger - Large Manufacturing Facility

The company is locally owned and has three sites. The manager lives in the community.

Applicable comments from the interview included:

- The existing boilers are old and it is expected that they will have to be replaced about 1980. The new units will be expensive because they will have to meet strict pollution standards.
- For capital investment, paybacks must be three to five years. Large projects could show payoffs out to 15 years.
- The DHCS energy price that would be paid is related to the size of the investment. A discounted rate would be preferred.

- A contract with the utility would be required.
- Discounts and tax rebates should be related to the investment and amount of energy use. The preferred inducement would be investment tax credits.
- I would expect the utility (not a private corporation) to sell the energy. We have a good relationship with the utility.
- Our plant typically operates 24 hours a day (sometimes 16 to 20) and the energy service must be reliable. The length of the down time is more important than the number of times. It could be down for 10 minutes frequently, but never for over an hour. I would expect the reliability to be consistent with other utility services.
- Conversion time and disruption are not problems. Disruption is no problem as long as materials can be shipped and received.
- Air pollution is a problem only when considering the cost of new boilers.
- If the plant were converted to the DHCS, the boilers would be kept for a couple of years as backup. They would then tear them out to use the space.
- Boiler maintenance could be eliminated, about one-quarter. Pressurized surge tanks would be required and would need some maintenance.
- I would be concerned about corrosion and problems with the condensate return pipes. This is typically a problem due to chemical action of condensate.
- A 15 percent ROI would be acceptable.
- A letter of committment could be submitted based on favorable economics.

Plant Manger - Manufacturing Facility

The plant manager lives in the community. The company is locally owned. Most of the thermal energy is used in processes.

Applicable comments from the interview included:

- Primary concerns are: availability of gas, price of gas, price of oil.
- Those concerns and the rate structure would influence the decision to hook up. We are happy with the utility as a supplier.
- Payback time is the key--anywhere from one to ten years.
- A tax rebate would be the best way to reduce conversion costs.
- Reliability is not a concern. The present boilers would be kept as backup.
- Conversion time and disruption time are not foreseen as problems.
- Air pollution would be a problem if coal were used as fuel.
- No boiler replacement is foreseen. The existing boilers will work for decades. Availability of fuel and/or cost of fuel would change this consideration.
- A letter of interest or commitment, based on the final results of the economic analysis, could be generated.

Vice-President - Business Operations College

The vice-president lives in the community. The school is a small private liberal arts college.

Applicable comments from the interview included:

- No new construction on campus is foreseen. There are now ten dorms in operation; two are being refurbished, so heating loads could increase slightly when they are occupied.
- The rate structure of the DHCS should allow us to achieve a future cost saving. Energy costs are a significant part of their operating expenses, and we are willing to invest in future savings.
- The entity that sells the steam does not seem important.
- A tax rebate is of no consequence to the school. Low interest loans are more appropriate.
- Paybacks of two to fifty years would be considered. The investment could be financed with 30-year bonds.
- The school is operating with minimum manpower; removing the boilers would not reduce manpower. It might reduce insurance costs.
- Conversion would be no problem in the summer. Disruption would not be a problem in their location.
- There currently is no pollution problem.

APPENDIX F
TURBINE RETROFIT/DISTRIBUTION SYSTEM DATA

This appendix contains background data used in the technical review and assessment task, including:

- General Electric Company discussion of three turbine retrofit schemes;
- Flow diagram (Figure F-1) and Mollier diagram (Figure F-2) of a single case turbine with extractions;
- Flow diagram (Figure F-3) and Mollier diagram (Figure F-4) of a cross-compound turbine;
- Installation data for distribution piping (Tables F-I through F-IV);
- Customer retrofit costs (Tables F-V and F-VI);
- Thermal losses in distribution piping (Tables F-VII and F-VIII).

GENERAL ELECTRIC

INDUSTRIAL SALES DIVISION

GENERAL ELECTRIC COMPANY, 641 LEXINGTON AVENUE, NEW YORK, NEW YORK 10022
Phone (212) 750-2000

MODIFICATION OF EXISTING UTILITY
POWER PLANTS FOR DISTRICT HEATING

February 17, 1977

Mr. William Diskant
Executive Vice President
American Hydrotherm Corporation
470 Park Avenue South
New York, N.Y., 10016

Dear Mr. Diskant:

It was a pleasure talking with you over the phone earlier last week. We understand that you have been asked by ERDA to discuss the possibility of modifying existing utility power plants to provide additional steam flows for district heating. As we have discussed, modifications to the steam turbine would be possible in several ways.

1. As you are aware, the typical utility steam turbine is a condensing machine with uncontrolled extraction points at various pressures. These extraction points consist simply of openings in the casing, sized for the required feedwater heating load. To provide an additional district heating steam flow, these openings could quite simply be enlarged to permit an increased flow for this second usage. Generally speaking, all steam path parts i.e., turbine wheels and diaphragms and inlet valve gear would need to be checked to assure that any new operating condition did not exceed those set as a maximum for safe operation. Although each case would, of course, have to be reviewed on an individual basis, we would not expect a modification of this sort to propose any great problems.

2. The conversion of a straight condensing steam turbine to operation with noncondensing exhaust is also in general a quite feasible modification. Such a modification would involve the removal through machining of both turbine wheels and diaphragms in the condensing end of the machine. A blanking diaphragm to prevent flow past the required exhaust pressure would be installed

GENERAL ELECTRIC

2. Continued

and openings machined into the casing to allow for the exhaust flow. Modifications could be also required to the shaft sealing system. This type of modification is one which our factory has performed on numerous occasions.

3. The addition of an extraction valve gear to an existing straight condensing steam turbine to allow for the controlled provision of steam for district heating would be a much more complicated and expensive modification than No. 2 discussed above. Such a modification would require the removal of one or more stages at some point on the rotor, to create sufficient space for the insertion of an extraction diaphragm. An extraction valve gear would be mounted on top of the casing. This is a modification which we have never performed before and would be very expensive. We would not, however, rule out the possibility of successfully completing such a modification and believe that a final conclusion would only be reached regarding a specific steam turbine.

In all three of the above cases, our comments apply to units rated less than 100 MW. The cost for any of the above modifications could vary in the extreme depending upon the basic configuration of the unit under consideration as well as the perceived modification. Modifications described in No. 1 and No. 2 above could often be performed at a total cost of less than $100,000. An estimate of the cost of modification No. 3 above is much more difficult to make. If attempted successfully, the cost of such a modification could extend up close to a million dollars.

The above comments are necessarily very general in nature. More specific comments could be made on any unit chosen for consideration which has been manufactured by the General Electric Company. Please call if we can be of further assistance.

Yours truly,

Eric F. Grina

Eric F. Grina, Industrial Turbine Sales, Ext. 2371

leh

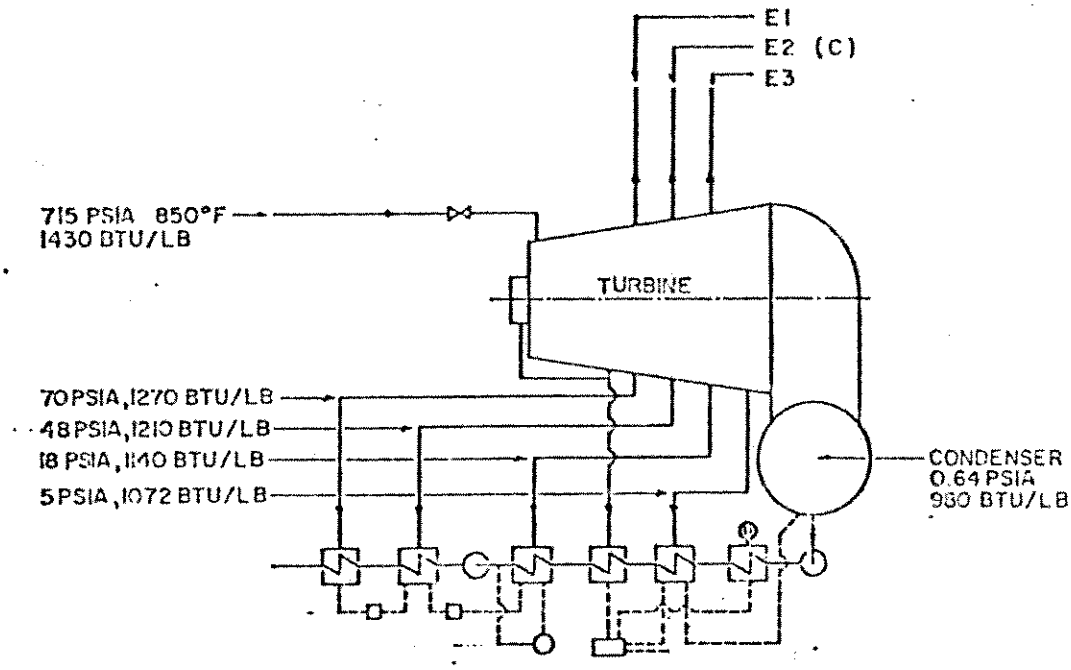

Figure F-1. Generic 30 MW Single Case Steam Turbine with Extractions

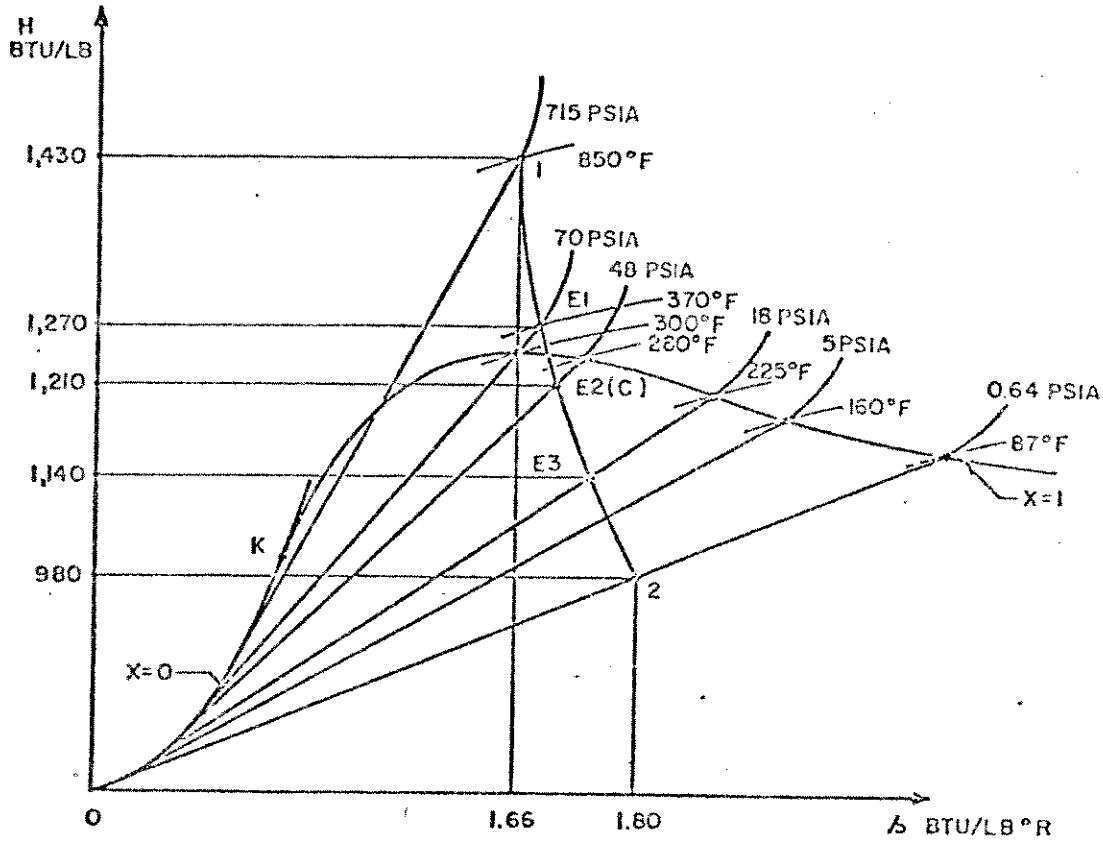

Figure F-2. Mollier Diagram of Cycle for Generic 30 MW Steam Turbine

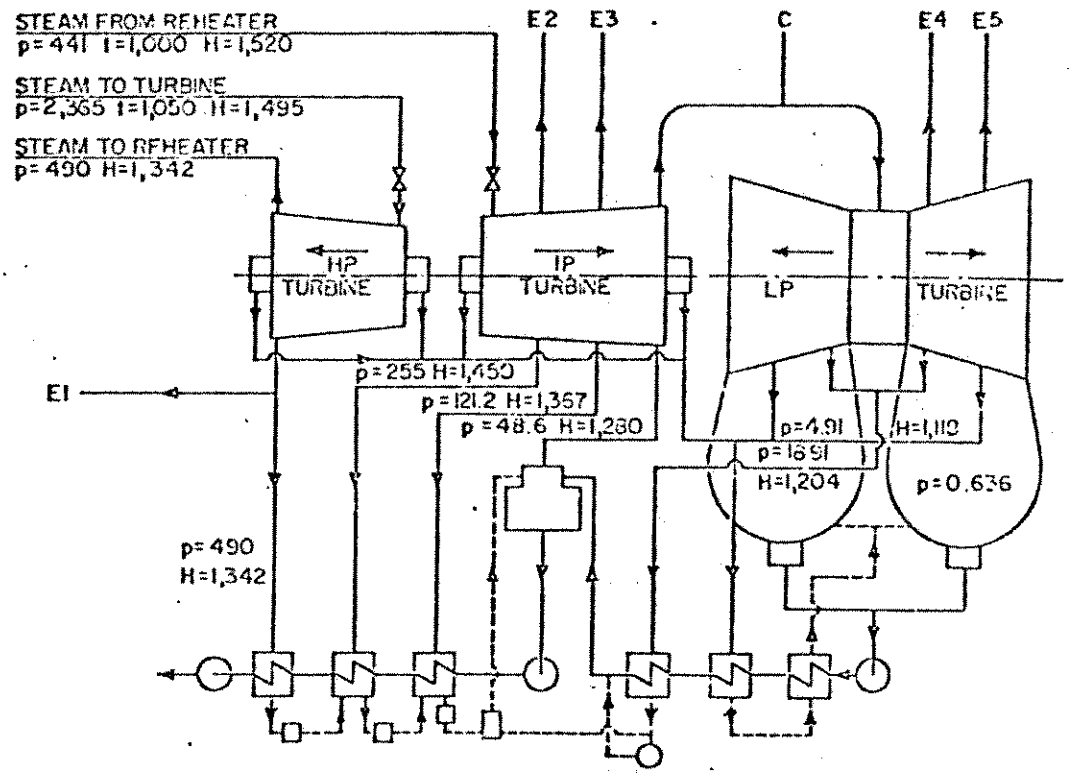

Figure F-3. Generic 200 MW Cross-Compound Steam Turbine

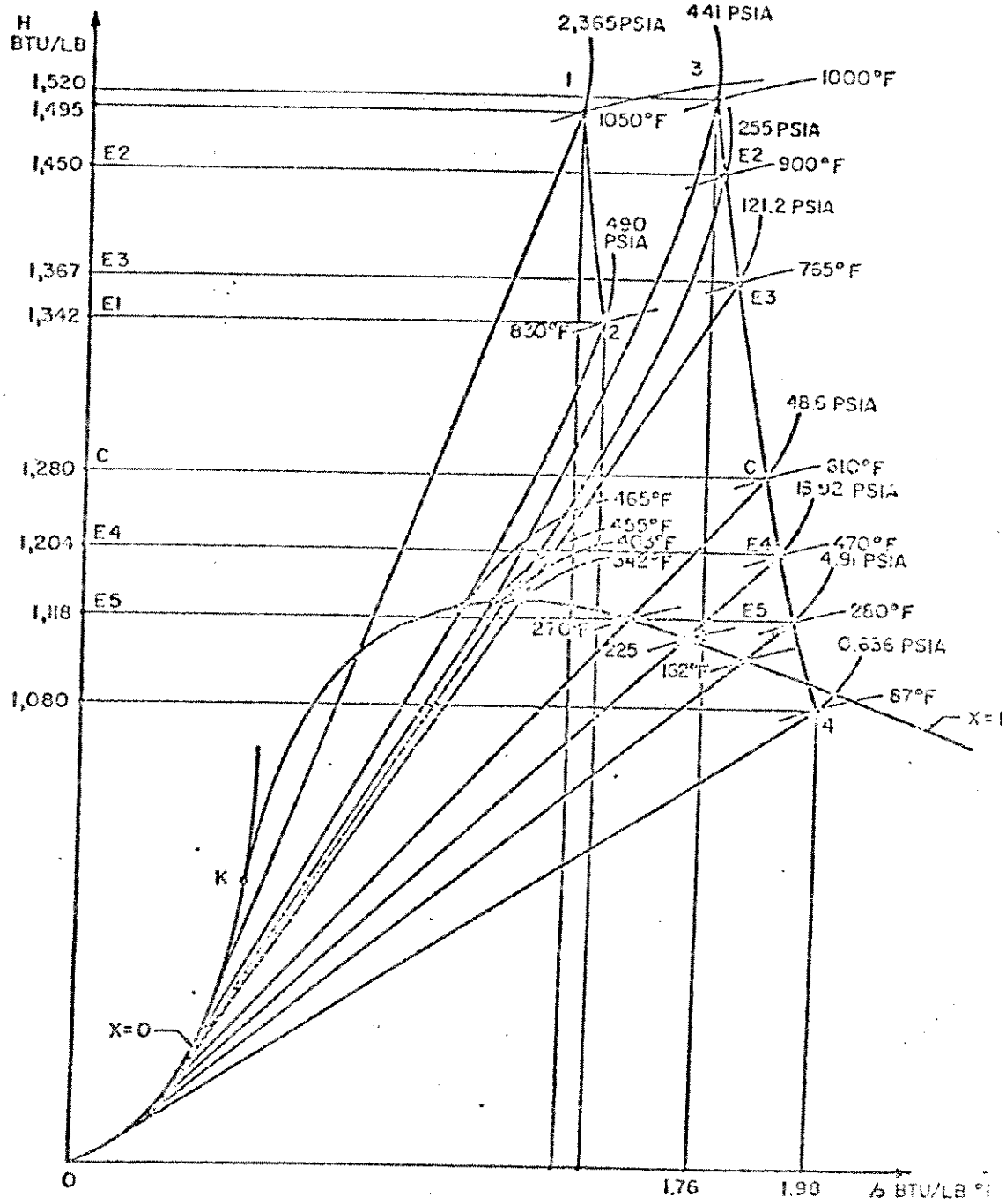

Figure F-4. Mollier Diagram of Cycle for Generic 200 MW Steam Turbine

Table F-I. Primary Distribution Cost Data, Poured Concrete, 30-Inch Pipe

EXCAVATION--	
TRENCH 8 FEET DEEP, 10 INCH BOTTOM WIDTH, 1-FOOT X 1-FOOT SIDE SLOPE	$ 9.90/LF
CONCRETE REMOVAL TO 6 INCHES THICK, WIRE MESH, 26 FEET WIDE	14.22/LF
PIPE BEDDING	15.26/LF
PIPE--30-INCH-DIAMETER INSTALLED IN TRENCH, TWO PIPES	131.20/LF
PIPE INSULATION--TWO PIPES, 4 INCHES THICK	94.43/LF
BACKFILL	0.84/LF
CRANE AND CREW (25 DAYS/MILE)	5.71/LF
UTILITY VAULT (3/MILE)	1.88/LF
CONCRETE ENCASEMENT OF PIPES	
FORMWORK	25.93/LF
CONCRETE	56.64/LF
LABOR	7.00/LF
VALVES--TWO/VAULT	15.63/LF
REPAVING	27.92/LF
SUBTOTAL	$406.56/LF
CONTINGENCY, CLEANUP , FEES, PERMITS (17 PERCENT OF TOTAL)	69.11/LF
TOTAL	$475.68/LF

Table F-II. Primary Distribution Cost Data, Poured Concrete, 24-Inch Pipe

EXCAVATION	
TRENCH, 8 FEET DEEP, 8 FOOT BOTTOM WIDTH, 1 FOOT X 1 FOOT SIDE SLOPE	$ 8.80/LF
*CONCRETE REMOVAL TO 6 INCHES THICK, WIRE MESH, 24 FEET WIDE	13.13/LF
PIPE BEDDING	10.30/LF
PIPE--24 INCH DIAMETER, INSTALLED IN TRENCH, TWO PIPES	100.80/LF
PIPE INSULATION--TWO PIPES, 4 INCHES THICK	80.00/LF
BACKFILL	0.84/LF
CRANE AND CREW (20 DAYS/MILE)	4.37/LF
UTILITY VAULT--8 FEET X 14 FOOT X 7 FEET, 3/MILE)	1.88/LF
CONCRETE ENCASEMENT OF PIPES	
FORMWORK	20.74/LF
CONCRETE	46.09/LF
LABOR	6.25/LF
VALVES--TWO/VAULT	12.48/LF
REPAVING	25.77/LF
SUBTOTAL	$ 331.71/LF
CLEANUP, CONTINGENCY, ENGINEERING FEES, PERMITS--17 PERCENT OF TOTAL	$ 56.39/LF
TOTAL	** $ 388.10/LF

NOTE: THE ABOVE AND SUCCEEDING COST DATA ARE BASED PRIMARILY ON "MECHANICAL AND ELECTRICAL COST DATA, 1979," BY MEANS.

* INCLUDES HAULING TO DUMP

** FOR RURAL AREAS, USE AS IS. FOR SUBURBAN AREAS, MULTIPLY BY 1.1, AND FOR URBAN AREAS, BY 2.7.

Table F-III. Primary Distribution Cost Data, Poured Concrete, 20-Inch Pipe

EXCAVATION--SAME AS FOR 24-INCH PIPE	$ 21.93/LF
PIPE BEDDING	9.27/LF
PIPE--20-INCH-DIAMETER INSTALLED, TWO PIPES	84.00/LF
PIPE INSULATION--TWO PIPES, 4 INCHES THICK	75.50/LF
BACKFILL	0.84/LF
CRANE AND CREW (20 DAYS/MILE)	4.57/LF
UTILITY VAULT (THREE/MILE)	1.88/LF
CONCRETE ENCASEMENT--	
FORMS	20.74/LF
CONCRETE	39.37/LF
LABOR	5.75/LF
VALVES--TWO/VAULT	9.39/LF
REPAVING	25.77/LF
SUBTOTAL	$ 299.01/LF
CLEANUP, CONTINGENCY, FEES, PERMITS--17 PERCENT OF TOTAL	50.83/LF
TOTAL	$ 349.84/LF

NOTE: THE ABOVE AND SUCCEEDING COST DATA ARE BASED PRIMARILY ON "MECHANICAL AND ELECTRICAL COST DATA, 1979," BY MEANS.

Table F-IV. Primary Distribution Cost Data, Poured Concrete, 12-Inch Pipe

EXCAVATION--	
TRENCH, 8 FEET DEEP, 6-FOOT BOTTOM, 1-FOOT X 1-FOOT SIDE SLOPE	$ 7.70/LF
CONCRETE REMOVAL TO 6 INCHES THICK, WIRE MESH, 2 FEET WIDE	6.11/LF
PIPE BEDDING	4.91/LF
PIPE--12-INCH-DIAMETER, TWO PIPES	50.40/LF
PIPE INSULATION--TWO PIPES, 4 INCHES THICK	49.00/LF
BACKFILL	1.80/LF
CRANE AND CREW (15 DAYS/MILE)	3.43/LF
UTILITY VAULT (THREE/MILE)	1.88/LF
CONCRETE ENCASEMENT OF PIPES	
FORMS	12.10/LF
CONCRETE	27.52/LF
LABOR	4.75/LF
VALVES--TWO/VAULT	6.24/LF
REPAVING	23.50/LF
SUBTOTAL	$199.34/LF
CLEANUP, CONTINGENCY, FEES, PERMITS--17 PERCENT OF TOTAL	33.89/LF
TOTAL	$233.23/LF

NOTE: THE ABOVE AND SUCCEEDING COST DATA ARE BASED PRIMARILY ON "MECHANICAL AND ELECTRICAL COST DATA, 1979", BY MEANS.

Table F-V. Customer Retrofit Costs

HEAT EXCHANGERS--HTW TO HOT WATER			HEAT EXCHANGERS-HTW TO STEAM		
LOAD MMBH	SURFACE AREA (FT^2)	COST * ($)	LOAD MMBH	SURFACE AREA (FT^2)	COST * ($)
1	36.2	1554	1	22.1	1216
2	58	2236	2	22.1	1216
3	75	2610	4	41	1802
4	110	3450	6	68	2678
5	124	3706	8	98	3532
6	138	3960	10	143	5896
7	180	5056	12	143	5896
8	200	5438	14	195	7402
9	200	5438	16	195	7402
10	258	7778	18	195	7402
			20	251	9322

* INCLUDES FEES AND REMOVAL OF EXISTING BOILERS

INTERIOR PLUMBING:	
SPACE HEATING AND DOMESTIC HOT WATER--TYPICAL COSTS	
PIPE--2-1/2-INCH DIAMETER, INSTALLED, TWO PIPES	$ 19.00/LF
INSULATION--2 INCHES	10.30/LF
SUBTOTAL	$ 29.30/LF
FEES, CONTINGENCY, ETC.	4.98/LF
TOTAL	$ 34.28/LF
PROCESS HEAT	
PIPE--4-INCH DIAMETER INSTALLED, TWO PIPES	$ 30.30
INSULATION--2-INCHES, TWO PIPES	12.80
SUBTOTAL	$ 43.10
FEES, CONTINGENCY, ETC.	7.33
TOTAL	$ 50.43

Table F-V. Customer Retrofit Costs (continued)

CONTROL SYSTEMS	
SPACE HEATING AND DOMESTIC HOT WATER	
INSTRUMENTS, PANELS, VALVES	$7,603
CONTINGENCY AND FEES	1,293
TOTAL	$8,896
PROCESS HEATING	
INSTRUMENTS, PANELS, VALVES	$ 9,083
CONTINGENCY AND FEES	1,544
TOTAL	$10,627
EXTERIOR PLUMBING	
SPACE HEATING AND DHW PIPING	
PIPE--2-1/2-INCH DIAMETER, INSTALLED IN TRENCH, TWO PIPES	$ 9.00/LF
INSULATION--4 INCHES THICK, TWO PIPES	23.18/LF
SUBTOTAL	32.18/LF
CONTINGENCY AND FEES	5.47/LF
TOTAL	$ 37.65/LF
PROCESS HEATING	
PIPE--4-INCH DIAMETER, INSTALLED IN TRENCH, TWO PIPES	$ 12.10/LF
INSULATION--4 INCHES THICK, TWO PIPES	28.46/LF
SUBTOTAL	$ 40.56/LF
CONTINGENCY AND FEES	6.90/LF
TOTAL	$ 47.46/LF
EXCAVATION--	
TRENCH, 8 FEET DEEP, 4-FOOT BOTTOM, 1-FOOT X 1-FOOT SIDE SLOPE	$ 5.93/LF
CONCRETE REMOVAL, 20 FEET WIDE	10.94/LF
BEDDING	4.91/LF
BACKFILL	1.80/LF
CRANE AND CREW, 1/2 DAY	10.00/LF
ENCASE CONDUIT IN CONCRETE	
FORMS	2.75/LF
CONCRETE	22.22/LF
LABOR	1.68/LF
VALVES (2)	50.00/LF
REPAVING	21.44/LF
SUBTOTAL	$131.87/LF
CONTINGENCY, FEES	22.42/LF
TOTAL	$154.29/LF

Table F-V. Customer Retrofit Costs (concluded)

COSTS FOR TYPICAL BUILDING ASSUMING:

100-FOOT INTERIOR AND EXTERIOR RUNS

6 MBH FOR DHW

8 MBH LOW PRESSURE STEAM FOR PROCESS OR SPACE HEATING

	DHW ($)	PROCESS OR SPACE HEAT ($)
INTERIOR PLUMBING	3,428	5,043
EXTERIOR PLUMBING	3,765	4,747
CONTROLS	8,896	10,627
HEAT EXCHANGER	3,960	3,532
EXCAVATION	--	15,428
TOTAL EACH SYSTEM	20,049	39,377
GRAND TOTAL	$59,426	

COMPARISON TO PUBLISHED DATA:

REPORT BY OLIKER AND PHILIPP--TECHNICAL AND ECONOMIC ASPECTS OF DISTRICT HEATING SYSTEMS SUPPLIED FROM COGENERATION OF POWER PLANTS.

COST FOR RETROFITTING APARTMENT BUILDING, HOT WATER HEAT, WINDOW AIR CONDITIONING, INSTALLED CAPACITY 16.5 MMBH--$63,600 IN 1977 DOLLARS.

ESCALATED TO 1979 COST IS $73,776 (16 PERCENT ESCALATION)
OUR COST FOR TYPICAL BUILDING INCREASED BY $11,305 TO SUPPLY TOTAL OF 16.45 MMBH
$61,662

Table F-VI. Absorption Cooling Cost Data

FROM ASHRAE 1979 EQUIPMENT VOLUME(PAGE 14.3) A TYPICAL COEFFICIENT OF PERFORMANCE (COP) FOR ABSORPTION SYSTEMS IS 0.6.

THEREFORE FOR EACH TON OF COOLING THE THERMAL INPUT IS:

$$\frac{12000}{.6} \text{ BTUH/TON} = 20{,}000 \text{ BTUH/TON}$$

HIGH TEMP WATER RATE REQUIRED IS:

$$Q = \frac{20000}{\Delta T} \text{ BTUH} \times \frac{1}{60} \frac{\text{MIN}}{\text{HR}} \times \frac{1}{\rho_T} = \text{GPM}$$

WHERE:

ΔT = TEMP (°F) AT INLET - TEMP (°F) AT OUTLET

ρ_T = DENSITY (#/GAL) AT INLET WATER TEMP

ASSUME: INLET TEMP = 290° F

ΔT = 50° F

ρ_T = 7.7#/GAL

$$Q = \frac{20000}{50} \times \frac{1}{60} \times \frac{1}{7.7} = .865 \text{ gpm/TON}$$

TONS OF REFRIGERATION	GPM OF HOT WATER	MMBTUH SUPPLIED BY CENTRAL PLANT
60	69	1.2
90	104	1.8
125	145	2.5
150	173	3.0
300	347	6.0
400	462	8.0
1000	1156	20.0

Table F-VI. Absorption Cooling Cost Data (concluded)

TYPICAL COSTS FOR ABSORPTION COOLING *

TONS OF REFRIGERATION	ABSORPTION UNIT ($/TON)	INSTALLATION ($/TON)	PUMPS AND MOTORS ($/TON)	COOLING TOWER ($/TON)	PLUMBING ($/TON)	WIRING ($/TON)	TOTAL ($/TON)
60	180	25	100	214	55	55	629
90	180	20	100	186	55	55	596
125	160	18	100	173	55	55	561
150	160	18	100	172	55	55	560
300	160	17	100	163	55	55	550
400	160	15	100	156	55	55	541
1000	140	14	100	149	55	55	293

* DOES NOT INCLUDE COST OF DISTRIBUTION WITHIN THE BUILDING

Table F-VII. Thermal Losses, Pipe in Steel Conduit

THERMAL LOSSES IN PIPE WITH AN AVERAGE OF ΔT OF 220°F AND 4 INCHES OF INSULATION--OBTAINED FROM JOHNS MANSVILLE THERMOBESTOS SPECIFICATION DATA:

$$k = 0.37 \text{ Btu } \frac{\text{inch}}{\text{ft}^2 \text{°F hour}}$$

12 INCH PIPE--81.2 Btu/hour/LF

20 INCH PIPE--122 Btu/hour/LF

24 INCH PIPE--146 Btu/hour/LF

THEREFORE A ONE-MILE-LONG DISTRIBUTION SYSTEM WITH 20-INCH MAINS WOULD HAVE A THERMAL LOSS OF:

$$2 \times 5{,}280 \times 122 = 1.288 \text{ MMBH}$$

Table F-VIII. Primary Distribution Cost Data, Pipe in Steel Conduit *

12-INCH PIPE, 4 INCHES INSULATION IN STEEL CONDUIT **	
PIPE AND FITTINGS (TWO PIPES)	$ 208.66/LF
INSTALLATION (INCLUDES REPAVING, CLEANUP, ETC.)	208.66/LF
UTILITY VAULTS--THREE/MILE	1.88/LF
VALVES (TWO/VAULT)	6.24/LF
TOTAL	$ 425.44/LF
RURAL AREA	$ 425.44/LF
SUBURBAN AREA	$ 510.53/LF
URBAN AREA	$ 638.16/LF
16-INCH PIPE, 4 INCHES INSULATION IN STEEL CONDUIT	
PIPE AND FITTINGS (TWO PIPES)	$ 261.79/LF
INSTALLATION	261.79/LF
UTILITY VAULTS--THREE/MILE	1.88/LF
VALVES (TWO/VAULT)	7.82/LF
TOTAL	$ 533.28/LF
RURAL AREA	$ 533.28/LF
SUBURBAN AREA	$ 639.94/LF
URBAN AREA	$ 799.92/LF
20-INCH PIPE, 4 INCHES INSULATION IN STEEL CONDUIT	
PIPE AND FITTINGS (TWO PIPES)	$ 338.80/LF
INSTALLATION	338.80/LF
UTILITY VAULT (THREE/MILE)	1.88/LF
VALVES (TWO/VAULT)	9.39/LF
TOTAL	$ 688.87/LF
RURAL AREA	$ 688.87/LF
SUBURBAN AREA	$ 826.64/LF
URBAN AREA	$1033.31/LF

* PIPE, FITTING AND INSTALLATION COSTS AND SCALING FACTORS FOR URBAN AREA WERE SUPPLIED BY A MANUFACTURER OF DISTRICT HEATING PIPING SYSTEMS.

** ALL PIPES ARE 0.500-INCH WALL.

Table F-VIII. Primary Distribution Cost Data, Pipe in Steel Conduit (concluded)

24-INCH PIPE, 4 INCHES INSULATION IN STEEL CONDUIT	
PIPE AND FITTINGS (TWO PIPES)	$ 404.73/LF
INSTALLATION	404.73/LF
UTILITY VAULT (THREE/MILE)	1.88/LF
VALVES (TWO/VAULT)	12.48/LF
TOTAL	$ 823.82/LF
RURAL AREA	$ 823.82/LF
SUBURBAN AREA	$ 988.58/LF
URBAN AREA	$1235.73/LF
30-INCH PIPE, 4 INCHES INSULATION IN STEEL CONDUIT	
PIPE AND FITTINGS (TWO PIPES)	$ 477.82/LF
INSTALLATION	477.82/LF
UTILITY VAULT (THREE/MILE)	1.88/LF
VALVES (TWO/VAULT)	15.63/LF
TOTAL	$ 973.15/LF
RURAL AREA	$ 973.15/LF
SUBURBAN AREA	$1167.78/LF
URBAN AREA	$1459.73/LF
36-INCH PIPE, 4 INCHES INSULATION IN STEEL CONDUIT	
PIPE AND FITTINGS (TWO PIPES)	$ 679.97/LF
INSTALLATION	679.97/LF
UTILITY VAULT (THREE/MILE)	1.88/LF
VALVES (TWO/VAULT)	18.75/LF
TOTAL	$1380.56/LF
RURAL AREA	$1380.56/LF
SUBURBAN AREA	$1656.67/LF
URBAN AREA	$2070.84/LF

APPENDIX G

DETAILED ECONOMIC ANALYSIS RESULTS/DATA

This appendix contains detailed results and supporting data used in the economic analysis of district heating system alternatives for Green Bay, Janesville/Beloit and Madison.

District heating alternatives analyzed are briefly described with total yearly heat supplied and system costs. A detailed example is provided for one alternative in Green Bay. Summary tables and results are provided for the other sites. Income statements and balance sheets are provided for Green Bay, the most promising site.

DISTRICT HEATING ALTERNATIVES ANALYZED

The district heating alternatives analyzed were described in detail in Section 6.0. A brief summary of these alternatives includes:

Green Bay

- Three Mills and CBD - Includes three paper mills (located across the Fox River from the power plant) and the Central Business District (CBD), which is located immediately south of the paper mills. The distance from the Green Bay Pullium Plant to the southern boundry of the CBD is approximately two miles. The distribution costs include the costs (1,000,000) for a pipe bridge across the Fox River.

▲ Heat Supplied	3540.85×10^9 Btu per year
▲ System Costs	
Plant Retrofit	$3,000,000
Distribution System	$8,000,000

- Two Mills and CBD - Includes the two smaller paper mills and the CBD. The largest paper mill was omitted. The distribution costs include the cost (1,000,000) for a pipe bridge across the Fox River.

▲ Heat Supplied	1418.33×10^9 Btu per year
▲ System Costs	
Plant Retrofit	$1,500,000
Distribution System	$5,200,000

Janesville/Beloit

- Rock River to Industrial Park - Includes a proposed (i.e., no current tenants) industrial park located near the Rock River Power Plant.

Heat Supplied (Estimate)	1234.80×10^9 Btu per year
System Costs	
Plant Retrofit	$1,500,000
Distribution System	$5,200,000

- Blackhawk to Beloit - Includes large industrial users in and near Beloit, Wisconsin.

▲ Heat Supplied	670.41×10^9 Btu per year
▲ System Costs	
Plant Retrofit	$ 1,500,000
Distribution System	$14,300,000

- Rock River to Janesville and Beloit - Includes heavy users near Janesville and Beloit, with all energy extracted from the Rock River Power Plant.

▲ Heat Supplied	1928.61×10^9 Btu per year
▲ System Costs	
Plant Retrofit	$ 2,500,000
Distribution System	$67,200,000

Madison

- CBD and Capitol Heating Complex - Includes portions of the Central Business District and the buildings heated by the Capitol Heating Plant.

▲ Heat Supplied	215.10×10^9 Btu per year
▲ System Costs	
Plant Retrofit	$1,000,000
Distribution	$3,500,000

- University of Wisconsin - Includes a complex of buildings (approximately 150) at the University of Wisconsin.

▲ Heat Supplied	1176.05×10^9 Btu per year
▲ System Costs	
Plant Retrofit	$ 2,400,000
Distribution	$14,200,000

ECONOMIC INPUTS

The economic viability of each alternative was determined using the capitalization structure of the utility for that site. These inputs, by site, are summarized in Table G-1. A single-return requirement of eight percent for municipal financing was used at each site.

Table G-1. Economic Analysis Input Summary

	Green Bay Wisconsin Public Service Corporation	Janesville/Beloit Wisconsin Power & Light	Madison Madison Gas & Electric
Capitalization	Bonds 47% @ 9% Preferred 12% @ 9% Common 41% @ 13%	Bonds 48% @ 9.75% Preferred 12% @ 9.5% Common 40% @ 14.5%	Bonds 51% @ 8.0% Preferred 14% @ 9.0% Common 35% @ 12.0%
Income Tax Rate (State/Fed)	49.95%	50%	49.95%
Advalorem Tax Rate	$30 per $1000 Assessed Valuation	$25 per 1000 Assessed Valuation	$30 per 1000 Assessed Valuation
Investment Tax Credit Rate	10%	10%	10%
Utility Discount Rate Employed	17%	11.62%	9.54%
Book Life	27 years	31 years	27 years
Depreciation Method	Double Declining - 1st two years Sum of Digits - Remaining years	Double Declining - 1st two years Sum of Digits - Remaining years	Double Declining + 1st two years Sum of Digits - Remaining years
Municipal Financing Rate	Bonds 100% @ 8%	Bonds 100% @ 8%	Bonds 100% @ 8%
Municipal Discount Rate Employed	8%	8%	8%

DETAILED EXAMPLES

The following is a detailed example of the economic analysis used for Green Bay--three mills and CBD alternative. Each of the three financing alternatives is illustrated

Utility Financing

Fixed-return requirements were calculated using the capitalization structure of the utilities and included:

- Book depreciation,
- Ad valorem tax,
- Income tax,
- Return for equity and debt.

An example of these fixed-return requirements for an $11,000,000 district heating investment in Green Bay is illustrated in Table G-2, Depreciation, Table G-3, Return on Debt and Equity, Table G-4, Taxes. Total fixed return requirements are summarized in Table G-5. All amounts are expressed in terms of thousands of dollars. Once determined, fixed-return requirements were discounted to present value (1979 dollars) using the utility discount rate. For the Green Bay example illustrated, this is 17 percent.

Table G-2. Depreciation (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option

YEAR	NET PLANT	BOOK DEPR
1980	11000	346
1981	10654	670
1982	9984	639
1983	9345	618
1984	8727	597
1985	8130	576
1986	7554	556
1987	6998	535
1988	6463	514
1989	5949	493
1990	5456	473
1991	4983	452
1992	4531	431
1993	4100	411
1994	3689	391
1995	3298	369
1996	2929	349
1997	2580	328
1998	2252	307
1999	1945	287
2000	1658	266
2001	1392	245
2002	1147	224
2003	923	204
2004	719	204

Table G-3. Return Requirement (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option

YEAR	BOND INTEREST	PREFERRED DIVIDENDS	COMMON STOCK	TOTAL RETURN
1980	465	117	586	1170
1981	451	115	568	1134
1982	422	108	532	1062
1983	395	101	498	994
1984	367	94	465	926
1985	344	88	433	865
1986	319	82	403	804
1987	296	76	373	745
1988	273	70	344	687
1989	252	64	317	633
1990	231	59	291	581
1991	211	54	266	531
1992	192	49	241	482
1993	173	44	218	435
1994	156	40	197	393
1995	139	36	176	351
1996	124	32	156	312
1997	109	28	137	274
1998	95	24	120	239
1999	82	21	104	207
2000	70	18	88	176
2001	59	15	74	148
2002	48	12	61	121
2003	37	10	49	96
2004	30	8	38	76

Table G-4. Taxes (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option

YEAR	TAX SAVE	ITC RESTORED	REV. TAX	GROSS TAX	INCOME TAX
1980	142	21	21	704	520
1981	263	41	41	681	436
1982	232	41	41	659	325
1983	211	41	41	598	395
1984	190	41	41	558	286
1985	169	41	41	520	260
1986	149	41	41	483	252
1987	128	41	41	448	238
1988	107	41	41	413	224
1989	86	41	41	381	213
1990	66	41	41	347	201
1991	45	41	41	319	192
1992	24	41	41	290	184
1993	4	41	41	262	176
1994	16	41	41	236	170
1995	38	41	41	211	167
1996	-58	41	41	187	163
1997	-79	41	41	165	162
1998	-100	41	41	144	162
1999	-120	41	41	124	162
2000	-141	41	41	106	165
2001	-162	41	41	89	169
2002	-183	41	41	73	174
2003	-203	41	41	59	180
2004	-203	41	41	46	167

Table G-5. Summary, Fixed Charges (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option

	TOTAL FIXED CHARGES						
YEAR	BOOK DEPR	INCOME TAX	ADVALUREM TAX	TOTAL RETURN	TOTAL FIXCHRG	PV	ACC PV
1980	346	520	330	1170	2366	2022	2022
1981	670	336	320	1134	2460	1797	3819
1982	639	325	300	1062	2326	1451	5270
1983	618	305	280	994	2197	1171	6441
1984	597	286	262	928	2073	944	7385
1985	576	269	244	865	1954	760	8145
1986	556	257	227	804	1839	612	8757
1987	535	238	210	745	1728	491	9248
1988	514	224	194	687	1619	393	9641
1989	493	213	178	633	1517	315	9956
1990	473	201	164	581	1419	251	10207
1991	452	192	149	531	1324	200	10407
1992	431	184	136	482	1233	160	10567
1993	411	176	123	435	1145	127	10694
1994	391	170	111	393	1065	101	10795
1995	369	167	99	351	986	80	10875
1996	349	163	88	312	912	63	10938
1997	328	162	77	274	841	50	10988
1998	307	162	68	239	776	39	11027
1999	287	162	58	207	714	31	11058
2000	266	165	50	176	657	24	11082
2001	245	169	42	148	604	19	11101
2002	224	174	34	121	553	15	11116
2003	204	180	28	98	510	12	11128
2004	204	167	22	76	469	9	11137

Variable return requirements (operation, maintenance, fuel costs) were determined for a range of fuel escalation rates. Table G-6 itemizes operations and maintenance costs. Table G-7 illustrates fuel and O&M costs for the range of fuel escalation rates used and the single rate selected.

Gross income from the sale of thermal energy was determined by selecting a base charge per 10^6 Btu and escalating that charge at a number of different rates. These are illustrated in Table G-8. In the example for Green Bay (Table G-8) the base charge rate is $1.80/10^6$ Btu (90 percent of the current rate for natural gas in Green Bay). Yearly income is based on a total consumer thermal energy requirement of 3540.85×10^9 Btu per year. The base charge rate is escalating at 7 percent (14 percent with inflation).

Results are illustrated by two graphs:

- Life-Cycle Savings versus Real Fuel Escalation Rates (Figure G-1) for four fuel escalation ranges. A "+" indicates the results for the fuel escalation rate case selected as most representative of Wisconsin (real annual rates of coal--4 percent, oil--4 percent, natural gas--7 percent.
- Accumulated Net Present Worth versus Year of Operation (Figure G-2) for two rate structures and the single escalation rate assumed for each fuel type.

Table G-6. Green Bay, Operations and Maintenance Costs, Three Mills and CBD Alternative

Year	Distribution			Plant		Total O&M Costs
	Maintenance 1% of Cost ($8x10^6$)	Insurance .2% of Cost ($8x10^6$)	Pump Power $5.5x10^6$ kWh/yr @ 022/kWh	District Heating Portion	Cost of Shifting to less Efficient Boilers	
1980	80	16	122	260	117	595
1981	86	17	131	295	140	669
1982	92	18	140	315	239	804
1983	98	20	149	337	223	827
1984	105	21	160	359	199	844
1985	112	22	171	384	276	966
1986	120	24	183	408	330	1066
1987	128	26	196	432	427	1209
1988	137	27	210	464	443	1282
1989	147	29	224	495	316	1212
1990	157	31	240	472	329	1230
1991	168	34	257	456	286	1233
1992	180	36	275	488	306	1320
1993	193	39	294	522	328	1412
1994	206	41	315	559	351	1511
1995	221	44	337	598	375	1617
1996	236	47	360	640	401	1730
1997	253	51	385	684	430	1851
1998	270	54	412	732	460	1981
1999	289	58	441	783	492	2120
2000	310	62	472	838	526	2268
2001	331	66	505	897	563	2426
2002	354	71	541	960	603	2596
2003	379	76	578	1027	645	2778
2004	406	81	619	1099	690	2972

Table G-7. Fuel/O & M Data (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option

COAL COS	$1.4/10^6$ Btu
OIL COST	$2.9/10^6$ Btu
COAL ESC RATE	7%
OIL ESC RATE	10%
DISCOUNT RATES	17%

Year	Coal Cost	Oil Cost	Total Fuel	Total O&M	Total Fuel/O&M	PV	Acc. PV
1980	3402.	695.	4097.	595.	4692.	4011.	4011.
1981	3457.	1576.	5033.	669.	5702.	4165.	8176.
1982	3713.	1374.	5087.	804.	5891.	3678.	11854.
1983	4105.	1002.	5107.	827.	5934.	3167.	15021.
1984	4367.	1565.	5932.	844.	6776.	3090.	18111.
1985	4408.	2317.	6725.	966.	7691.	2998.	21110.
1986	4606.	3317.	7924.	1066.	8990.	2995.	24105.
1987	4604.	4066.	8670.	1209.	9879.	2813.	26918.
1988	5078.	3303.	8381.	1282.	9663.	2352.	29270.
1989	5621.	3182.	8803.	1212.	10015.	2083.	31354.
1990	5838.	3210.	9048.	1229.	10277.	1827.	33181.
1991	6246.	3531.	9778.	1233.	11011.	1673.	34854.
1992	6683.	3884.	10568.	1320.	11888.	1544.	36398.
1993	7151.	4273.	11424.	1412.	12836.	1425.	37824.
1994	7652.	4700.	12352.	1511.	13863.	1315.	39139.
1995	8188.	5170.	13358.	1617.	14975.	1214.	40353.
1996	8761.	5687.	14448.	1730.	16178.	1121.	41475.
1997	9374.	6256.	15630.	1851.	17481.	1036.	42511.
1998	10030.	6882.	16912.	1981.	18893.	957.	43467.
1999	10732.	7570.	18302.	2119.	20421.	884.	44351.
2000	11483.	8327.	19810.	2268.	22078.	817.	45168.
2001	12287.	9159.	21447.	2426.	23873.	755.	45922.
2002	13147.	10075.	23223.	2596.	25819.	698.	46620.
2003	14068.	11083.	25151.	2778.	27929.	645.	47265.
2004	15052.	12191.	27244.	2972.	30216.	596.	47862.

Table G-7. Fuel/O & M Data (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option (continued)

COAL COST	$1.40/10^6$ Btu
OIL COST	$2.90/10^6$ Btu
COAL ESC RATE	7%
OIL ESC RATE	17%
DISCOUNT RATES	17%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3402.	740.	4142.	595.	4737.	4048.	4048.
1981	3457.	1782.	5240.	669.	5909.	4316.	8365.
1982	3713.	1654.	5367.	804.	6171.	3853.	12218.
1983	4105.	1282.	5388.	827.	6215.	3316.	15534.
1984	4367.	2130.	6497.	844.	7341.	3348.	18882.
1985	4408.	3355.	7763.	966.	8729.	3403.	22285.
1986	4606.	5109.	9715.	1066.	10781.	3592.	25878.
1987	4604.	6660.	11264.	1209.	12473.	3552.	29430.
1988	5078.	5755.	10833.	1282.	12115.	2949.	32378.
1989	5621.	5897.	11517.	1212.	12729.	2648.	35027.
1990	5838.	6328.	12166.	1229.	13395.	2382.	37408.
1991	6246.	7404.	13650.	1233.	14883.	2262.	39670.
1992	6693.	8653.	15346.	1320.	16666.	2165.	41835.
1993	7151.	10135.	17286.	1412.	18698.	2076.	43911.
1994	7652.	11858.	19510.	1511.	21021.	1995.	45905.
1995	8188.	13874.	22062.	1617.	23679.	1920.	47826.
1996	8761.	16233.	24993.	1730.	26723.	1852.	49678.
1997	9374.	18992.	28366.	1851.	30217.	1790.	51468.
1998	10030.	22221.	32251.	1981.	34232.	1733.	53202.
1999	10732.	25998.	36731.	2119.	38850.	1681.	54883.
2000	11483.	30418.	41902.	2268.	44170.	1634.	56517.
2001	12287.	35589.	47877.	2426.	50303.	1590.	58107.
2002	13147.	41639.	54787.	2596.	57383.	1551.	59658.
2003	14068.	48718.	62786.	2778.	65564.	1514.	61172.
2004	15052.	57000.	72053.	2972.	75025.	1481.	62653.

Table G-7. Fuel/O & M Data (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option (continued)

COAL COST	$1.4/10^6$ Btu
OIL COST	$2.9/10^6$ Btu
COAL ESC RATE	14%
OIL ESC RATE	10%
DISCOUNT RATES	17%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3625.	695.	4320.	595.	4915.	4201.	4201.
1981	3925.	1576.	5500.	669.	6169.	4507.	8707.
1982	4491.	1374.	5865.	804.	6669.	4164.	12871.
1983	5289.	1002.	6292.	827.	7119.	3799.	16670.
1984	5995.	1565.	7560.	844.	8404.	3833.	20503.
1985	6447.	2317.	8764.	966.	9730.	3793.	24296.
1986	7178.	3317.	10495.	1066.	11561.	3852.	28148.
1987	7644.	4066.	11709.	1209.	12918.	3679.	31827.
1988	8983.	3303.	12285.	1282.	13567.	3302.	35129.
1989	10593.	3182.	13775.	1212.	14987.	3118.	38247.
1990	11721.	3210.	14931.	1229.	16160.	2873.	41121.
1991	13362.	3531.	16893.	1233.	18126.	2755.	43875.
1992	15233.	3884.	19117.	1320.	20437.	2655.	46530.
1993	17365.	4273.	21638.	1412.	23050.	2559.	49089.
1994	19796.	4700.	24497.	1511.	26008.	2468.	51557.
1995	22568.	5170.	27738.	1617.	29355.	2381.	53938.
1996	25727.	5687.	31415.	1730.	33145.	2297.	56235.
1997	29329.	6256.	35585.	1851.	37436.	2218.	58453.
1998	33435.	6882.	40317.	1981.	42298.	2142.	60595.
1999	38116.	7570.	45686.	2119.	47805.	2069.	62664.
2000	43452.	8327.	51779.	2268.	54047.	1999.	64663.
2001	49536.	9159.	58695.	2426.	61121.	1932.	66596.
2002	56471.	10075.	66546.	2596.	69142.	1868.	68464.
2003	64377.	11083.	75460.	2778.	78239.	1807.	70271.
2004	73389.	12191.	85521.	2972.	88553.	1748.	72019.

Table G-7. Fuel/O & M Data (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option (continued)

COAL COST	$1.4/10^6$ Btu
OIL COST	$2.9/10^6$ Btu
COAL ESC RATE	14%
OIL ESC RATE	17%
DISCOUNT RATES	17%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3625.	740.	4364.	595.	4959.	4239.	4239.
1981	3925.	1782.	5707.	669.	6376.	4658.	8896.
1982	4491.	1654.	6144.	804.	6948.	4338.	13235.
1983	5289.	1282.	6572.	827.	7399.	3948.	17183.
1984	5995.	2130.	8125.	844.	8969.	4091.	21274.
1985	6447.	3355.	9802.	966.	10768.	4198.	25472.
1986	7178.	5109.	12287.	1066.	13353.	4449.	29921.
1987	7644.	6660.	14304.	1209.	15513.	4418.	34339.
1988	8983.	5755.	14737.	1282.	16019.	3899.	38238.
1989	10593.	5897.	16490.	1212.	17702.	3683.	41920.
1990	11721.	6328.	18049.	1229.	19278.	3428.	45348.
1991	13362.	7404.	20766.	1233.	21999.	3343.	48691.
1992	15233.	8663.	23895.	1320.	25215.	3275.	51967.
1993	17365.	10135.	27500.	1412.	28912.	3210.	55176.
1994	19796.	11858.	31655.	1511.	33166.	3147.	58323.
1995	22568.	13874.	36442.	1617.	38059.	3087.	61410.
1996	25727.	16233.	41960.	1730.	43690.	3028.	64439.
1997	29329.	18992.	48321.	1851.	50172.	2972.	67411.
1998	33435.	22221.	55656.	1981.	57637.	2919.	70330.
1999	38116.	25998.	64115.	2119.	66234.	2867.	73196.
2000	43452.	30418.	73871.	2268.	76139.	2816.	76013.
2001	49536.	35589.	85125.	2426.	87551.	2768.	78781.
2002	56471.	41639.	98110.	2596.	100706.	2721.	81503.
2003	64377.	48718.	113095.	2778.	115873.	2676.	84178.
2004	73389.	57000.	130390.	2972.	133362.	2633.	86811.

Table G-7. Fuel/O & M Data (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option (concluded)

COAL COST	1.40/10^6 Btu
OIL COST	2.90/10^6 Btu
COAL ESC RATE	11%
OIL ESC RATE	11.1%
DISCOUNT RATES	17%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3529.	702.	4232.	595.	4827.	4125.	4125.
1981	3721.	1607.	5328.	669.	5997.	4381.	8506.
1982	4145.	1416.	5561.	804.	6365.	3974.	12480.
1983	4754.	1043.	5797.	827.	6624.	3535.	16015.
1984	5247.	1644.	6891.	844.	7735.	3528.	19543.
1985	5494.	2460.	7953.	966.	8919.	3477.	23020.
1986	5956.	3557.	9512.	1066.	10578.	3525.	26545.
1987	6175.	4402.	10578.	1209.	11787.	3357.	29901.
1988	7066.	3612.	10678.	1282.	11960.	2911.	32813.
1989	8113.	3515.	11628.	1212.	12840.	2671.	35484.
1990	8741.	3582.	12323.	1229.	13552.	2410.	37893.
1991	9703.	3979.	13682.	1233.	14915.	2267.	40160.
1992	10770.	4421.	15191.	1320.	16511.	2145.	42305.
1993	11955.	4912.	16866.	1412.	18278.	2029.	44334.
1994	13270.	5457.	18726.	1511.	20237.	1920.	46254.
1995	14729.	6063.	20792.	1617.	22409.	1817.	48072.
1996	16349.	6735.	23085.	1730.	24815.	1720.	49792.
1997	18148.	7483.	25631.	1851.	27482.	1628.	51420.
1998	20144.	8314.	28458.	1981.	30439.	1541.	52961.
1999	22360.	9237.	31597.	2119.	33716.	1459.	54420.
2000	24820.	10262.	35081.	2268.	37349.	1382.	55802.
2001	27550.	11401.	38951.	2426.	41377.	1308.	57110.
2002	30580.	12666.	43247.	2596.	45843.	1239.	58349.
2003	33944.	14072.	48016.	2778.	50794.	1173.	59522.
2004	37678.	15634.	53312.	2972.	56284.	1111.	60633.

Table G-8. Gross Income Data (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option

DISCOUNT RATE 17%
FUEL QUANTITY 3540.85×10^9 Btu/yr
FUEL COST $1.80/10^6$ Btu
ESCALATION RATE 9%

Year	Income	PV	Acc. PV
1980	6947.	5938.	5938.
1981	7572.	5532.	11469.
1982	8254.	5153.	16623.
1983	8997.	4801.	21424.
1984	9806.	4473.	25897.
1985	10659.	4167.	30064.
1986	11651.	3882.	33946.
1987	12700.	3617.	37562.
1988	13843.	3369.	40932.
1989	15088.	3139.	44071.
1990	16446.	2924.	46995.
1991	17927.	2724.	49720.
1992	19540.	2538.	52258.
1993	21299.	2365.	54622.
1994	23215.	2203.	56825.
1995	25305.	2052.	58877.
1996	27582.	1912.	60789.
1997	30065.	1781.	62571.
1998	32771.	1659.	64230.
1999	35720.	1546.	65776.
2000	38935.	1440.	67216.
2001	42429.	1342.	68558.
2002	46232.	1250.	69808.
2003	50422.	1165.	70972.
2004	54954.	1085.	72057.

DISCOUNT RATE 17%
FUEL QUANTITY 3540.85×10^9 Btu/yr
FUEL COST $1.80/10^6$ Btu
ESCALATION RATE 11%

Year	Income	PV	Acc. PV
1980	7075.	6047.	6047.
1981	7853.	5737.	11783.
1982	8717.	5442.	17226.
1983	9675.	5163.	22389.
1984	10740.	4899.	27288.
1985	11921.	4647.	31935.
1986	13232.	4409.	36344.
1987	14688.	4183.	40527.
1988	16304.	3968.	44495.
1989	18097.	3765.	48260.
1990	20088.	3572.	51832.
1991	22297.	3389.	55220.
1992	24750.	3215.	58435.
1993	27473.	3050.	61485.
1994	30495.	2894.	64379.
1995	33849.	2745.	67124.
1996	37573.	2604.	69729.
1997	41706.	2471.	72199.
1998	46293.	2344.	74544.
1999	51385.	2224.	76767.
2000	57038.	2110.	78877.
2001	63312.	2002.	80879.
2002	70276.	1899.	82778.
2003	78007.	1802.	84580.
2004	86587.	1709.	86289.

Table G-8. Gross Income Data (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option (continued)

DISCOUNT RATE 17%
FUEL QUANTITY 3540.85×10^9 Btu/yr
FUEL COST $1.80/10^6$ Btu
ESCALATION RATE 13%

Year	Income	PV	Acc. PV
1980	7202.	6156.	6156.
1981	8138.	5945.	12101.
1982	9196.	5742.	17842.
1983	10292.	5546.	23388.
1984	11743.	5356.	28744.
1985	13269.	5173.	33917.
1986	14994.	4996.	38913.
1987	16944.	4825.	43739.
1988	19146.	4660.	48399.
1989	21635.	4501.	52900.
1990	24448.	4347.	57247.
1991	27626.	4198.	61445.
1992	31218.	4055.	65500.
1993	35276.	3916.	69417.
1994	39862.	3782.	73199.
1995	45044.	3653.	76852.
1996	50900.	3528.	80380.
1997	57516.	3408.	83788.
1998	64994.	3291.	87079.
1999	73443.	3179.	90258.
2000	82990.	3070.	93328.
2001	93779.	2965.	96292.
2002	105970.	2864.	99156.
2003	119746.	2766.	101922.
2004	135313.	2671.	104593.

DISCOUNT RATE 17%
FUEL QUANTITY 3540.85×10^9 Btu/yr
FUEL COST $1.80/10^6$ Btu
ESCALATION RATE 15%

Year	Income	PV	Acc. PV
1980	7330.	6265.	6265.
1981	8429.	6157.	12422.
1982	9693.	6052.	18474.
1983	11147.	5949.	24423.
1984	12819.	5847.	30270.
1985	14742.	5747.	36017.
1986	16954.	5649.	41666.
1987	19497.	5552.	47219.
1988	22421.	5457.	52676.
1989	25784.	5364.	58040.
1990	29652.	5272.	63313.
1991	34100.	5182.	68495.
1992	39215.	5094.	73589.
1993	45097.	5007.	78595.
1994	51862.	4921.	83516.
1995	59641.	4837.	88353.
1996	68587.	4754.	93108.
1997	78875.	4673.	97781.
1998	90707.	4593.	102374.
1999	104313.	4515.	106889.
2000	119960.	4437.	111326.
2001	137953.	4362.	115687.
2002	158646.	4287.	119974.
2003	182443.	4214.	124188.
2004	209910.	4142.	128330.

Table G-8. Gross Income Data (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option (concluded)

DISCOUNT RATE	17%
FUEL QUANTITY	3540.85×10^9 Btu/yr
FUEL COST	$1.80/10^6$ Btu
ESCALATION RATE	17%

Year	Income	PV	Acc. PV
1980	6459.	5520.	5520.
1981	7363.	5379.	10899.
1982	8393.	5241.	16139.
1983	9569.	5106.	21246.
1984	10908.	4975.	26221.
1985	12435.	4848.	31069.
1986	14176.	4723.	35792.
1987	16161.	4602.	40394.
1988	18423.	4484.	44879.
1989	21003.	4369.	49248.
1990	23943.	4257.	53505.
1991	27295.	4148.	57654.
1992	31116.	4042.	61695.
1993	35473.	3938.	65634.
1994	40439.	3837.	69471.
1995	46100.	3739.	73210.
1996	52555.	3643.	76852.
1997	59912.	3550.	80402.
1998	68300.	3459.	83861.
1999	77862.	3370.	87230.
2000	88762.	3283.	90514.
2001	101139.	3199.	93713.
2002	115356.	3117.	96830.
2003	131506.	3037.	99867.
2004	149916.	2959.	102827.

DISCOUNT RATE	17%
FUEL QUANTITY	3540.85×10^9 Btu/yr
FUEL COST	$1.80/10^6$ Btu
ESCALATION RATE	14%

Year	Income	PV	Acc. PV
1980	7266.	6210.	6210.
1981	8283.	6051.	12261.
1982	9443.	5896.	18157.
1983	10765.	5745.	23901.
1984	12272.	5597.	29499.
1985	13990.	5454.	34952.
1986	15949.	5314.	40266.
1987	18181.	5178.	45444.
1988	20726.	5045.	50489.
1989	23628.	4916.	55404.
1990	26936.	4789.	60194.
1991	30707.	4667.	64860.
1992	35006.	4547.	69407.
1993	39907.	4430.	73838.
1994	45494.	4317.	78155.
1995	51863.	4206.	82361.
1996	59124.	4098.	86459.
1997	67401.	3993.	90452.
1998	76837.	3891.	94343.
1999	87595.	3791.	98134.
2000	99858.	3694.	101828.
2001	113838.	3599.	105427.
2002	129775.	3507.	108934.
2003	147944.	3417.	112351.
2004	168656.	3329.	115680.

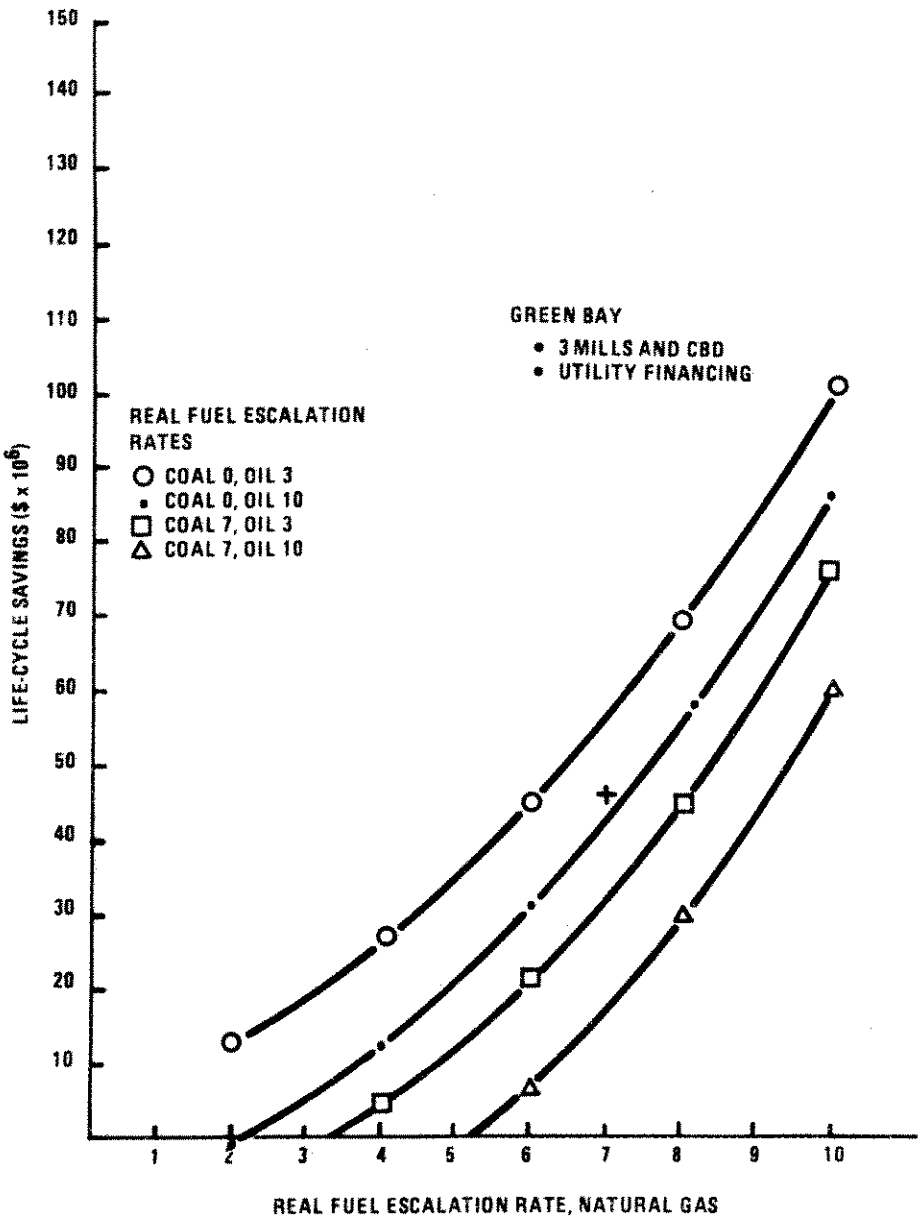

Figure G-1. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

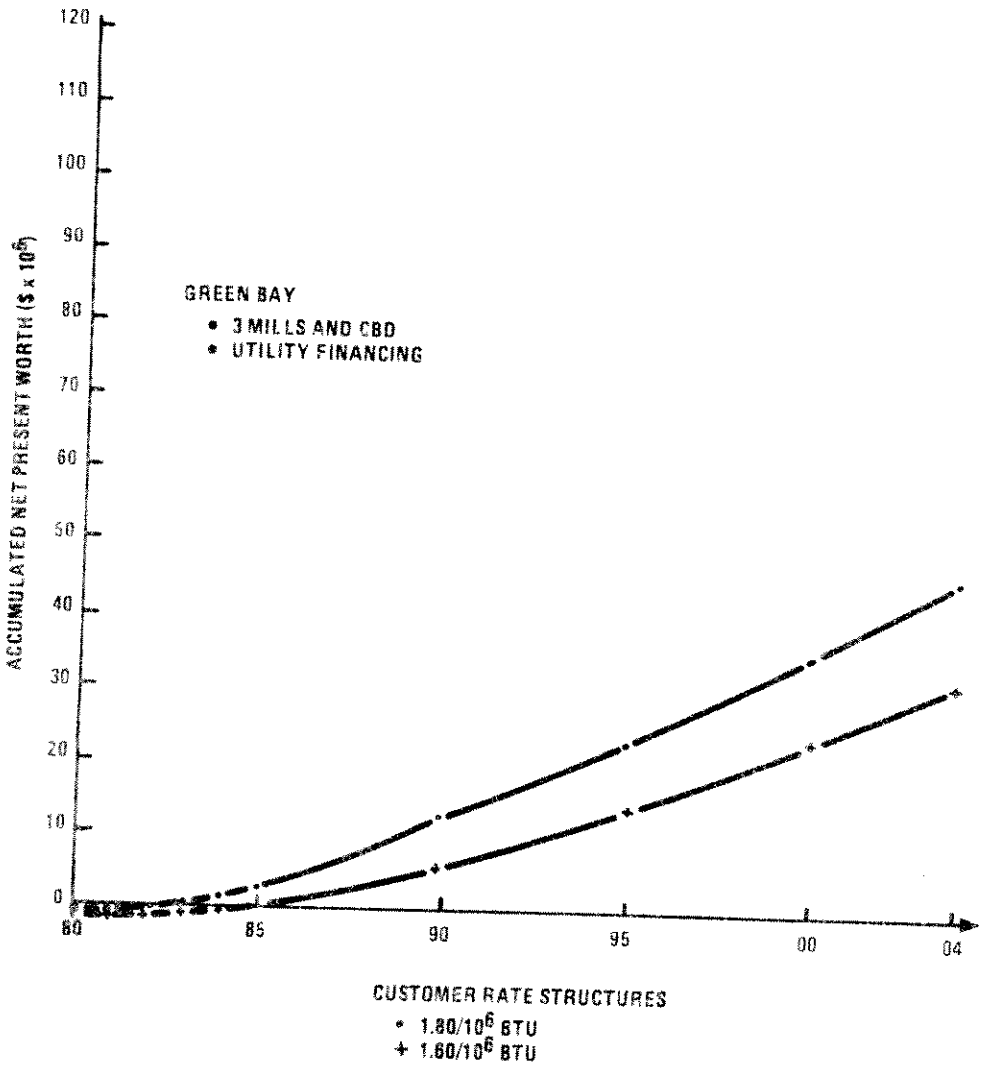

Figure G-2. Accumulated Net Present Worth versus Year of Operation

Municipal Financing

Return requirements were based on a return rate of eight percent and discounted at eight percent to determine the present value. A book life equal to that used by the utility was used. Depreciation was calculated using the straight line method.

An example of the fixed return requirements for a municipality are illustrated in Table G-9. All numbers are expressed in terms of thousands of dollars. The example represents a 11,000,000 district heating system investment, a book life of 27 years, a return requirement of eight percent of the net investment and a total return discounted at eight percent.

Annual savings for this case were determined by calculating the gross income, subtracting the fixed revenue requirements and variable operations, maintenance and fuel expenses, and discounting the results at eight percent. Resultant calculations were expressed similarly to those described for utility financing (Tables G-9 through G-13). Figure G-3 and G-4 are examples for Green Bay, three mills and CBD alternative.

Table G-9. Return Requirements (x 100), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option

Book Life 27 years
Capital Cost 11,000,000

Depreciation Method St. Line
Return Rate 8%
Discount Rate 8%

Year	Book Dep	Net Book Dep	Net Inv	Ret Req	Total Ret	PV	Acc. PV
1980	407.	0.	11000.	880.	1287.	1192.	1192.
1981	407.	407.	10593.	847.	1255.	1076.	2268.
1982	407.	815.	10185.	815.	1222.	970.	3238.
1983	407.	1222.	9778.	782.	1190.	874.	4112.
1984	407.	1630.	9370.	750.	1157.	787.	4900.
1985	407.	2037.	8963.	717.	1124.	709.	5609.
1986	407.	2444.	8556.	684.	1092.	637.	6246.
1987	407.	2852.	8148.	652.	1059.	572.	6818.
1988	407.	3259.	7741.	619.	1027.	514.	7332.
1989	407.	3667.	7333.	587.	994.	460.	7792.
1990	407.	4074.	6926.	554.	961.	412.	8204.
1991	407.	4481.	6519.	521.	929.	369.	8573.
1992	407.	4889.	6111.	489.	896.	330.	8903.
1993	407.	5296.	5704.	456.	864.	294.	9197.
1994	407.	5704.	5296.	424.	831.	262.	9459.
1995	407.	6111.	4889.	391.	799.	233.	9692.
1996	407.	6519.	4481.	359.	766.	207.	9899.
1997	407.	6926.	4074.	326.	733.	184.	10082.
1998	407.	7333.	3667.	293.	701.	162.	10245.
1999	407.	7741.	3259.	261.	668.	143.	10388.
2000	407.	8148.	2852.	228.	636.	126.	10514.
2001	407.	8556.	2444.	196.	603.	111.	10625.
2002	407.	8963.	2037.	163.	570.	97.	10722.
2003	407.	9370.	1630.	130.	538.	85.	10807.
2004	407.	9778.	1222.	98.	505.	74.	10881.

Table G-10. Gross Income Data (x 1000), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option

DISCOUNT RATE 8%
FUEL QUANTITY $3540.85/10^9$ Btu/yr
FUEL COST $\$1.80/10^6$ Btu
ESCALATION RATE 9%

Year	Income	PV	Acc. PV
1980	6947.	6433.	6433.
1981	7572.	6492.	12925.
1982	8254.	6552.	19477.
1983	8997.	6613.	26090.
1984	9806.	6674.	32764.
1985	10689.	6736.	39500.
1986	11651.	6798.	46298.
1987	12700.	6861.	53159.
1988	13843.	6925.	60084.
1989	15088.	6989.	67073.
1990	16446.	7054.	74127.
1991	17927.	7119.	81245.
1992	19540.	7185.	88430.
1993	21299.	7251.	95682.
1994	23215.	7318.	103000.
1995	25305.	7386.	110386.
1996	27582.	7455.	117841.
1997	30065.	7524.	125365.
1998	32771.	7593.	132958.
1999	35720.	7664.	140622.
2000	38935.	7735.	148356.
2001	42439.	7806.	156162.
2002	46258.	7878.	164041.
2003	50422.	7951.	171992.
2004	54959.	8025.	180017.

DISCOUNT RATE 8%
FUEL QUANTITY 3540.85×10^9 Btu/yr
FUEL COST $\$1.80/10^6$ Btu
ESCALATION RATE 11%

Year	Income	PV	Acc. PV
1980	7075.	6551.	6551.
1981	7853.	6733.	13283.
1982	8717.	6920.	20203.
1983	9675.	7112.	27314.
1984	10740.	7309.	34624.
1985	11921.	7512.	42136.
1986	13232.	7721.	49857.
1987	14688.	7935.	57793.
1988	16304.	8156.	65948.
1989	18097.	8382.	74331.
1990	20088.	8615.	82946.
1991	22297.	8855.	91801.
1992	24750.	9101.	100902.
1993	27473.	9353.	110255.
1994	30495.	9613.	119868.
1995	33849.	9880.	129748.
1996	37573.	10155.	139903.
1997	41706.	10437.	150340.
1998	46293.	10727.	161067.
1999	51385.	11025.	172091.
2000	57038.	11331.	183422.
2001	63312.	11646.	195068.
2002	70276.	11969.	207037.
2003	78007.	12302.	219338.
2004	86587.	12643.	231982.

Table G-10. Gross Income Data (x 1000), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option (continued)

DISCOUNT RATE 8%
FUEL QUANTITY 3540.85×10^9 Btu/yr
FUEL COST $\$1.80/10^6$ Btu
ESCALATION RATE 13%

Year	Income	PV	Acc. PV
1980	7202.	6669.	6669.
1981	8138.	6977.	13646.
1982	9196.	7300.	20946.
1983	10392.	7638.	28585.
1984	11743.	7992.	36577.
1985	13269.	8362.	44939.
1986	14994.	8749.	53688.
1987	16944.	9154.	62842.
1988	19146.	9578.	72420.
1989	21635.	10021.	82441.
1990	24448.	10485.	92926.
1991	27626.	10971.	103897.
1992	31218.	11479.	115376.
1993	35276.	12010.	127386.
1994	39862.	12566.	139952.
1995	45044.	13148.	153100.
1996	50900.	13757.	166856.
1997	57516.	14393.	181250.
1998	64994.	15060.	196310.
1999	73443.	15757.	212067.
2000	82990.	16486.	228553.
2001	93779.	17250.	245803.
2002	105970.	18048.	263851.
2003	119746.	18884.	282735.
2004	135313.	19758.	302493.

DISCOUNT RATE 8%
FUEL QUANTITY 3540.85×10^9 Btu/yr
FUEL COST $\$1.80/10^6$ Btu
ESCALATION RATE 15%

Year	Income	PV	Acc. PV
1980	7330.	6787.	6787.
1981	8429.	7227.	14013.
1982	9693.	7695.	21708.
1983	11147.	8194.	29902.
1984	12819.	8725.	38626.
1985	14742.	9290.	47917.
1986	16954.	9892.	57809.
1987	19497.	10534.	68342.
1988	22421.	11216.	79559.
1989	25784.	11943.	91502.
1990	29652.	12717.	104219.
1991	34100.	13542.	117761.
1992	39215.	14419.	132180.
1993	45097.	15354.	147534.
1994	51862.	16349.	163883.
1995	59641.	17409.	181291.
1996	68587.	18537.	199828.
1997	78875.	19738.	219567.
1998	90707.	21018.	240585.
1999	104313.	22380.	262965.
2000	119960.	23831.	286796.
2001	137953.	25375.	312171.
2002	158646.	27020.	339191.
2003	182443.	28771.	367962.
2004	209810.	30636.	398598.

Table G-10. Gross Income Data (x 1000), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option (concluded)

DISCOUNT RATE 8%
FUEL QUANTITY 3540.85 x 10^9 Btu
FUEL COST $1.80/$10^6$ Btu
ESCALATION RATE 17%

Year	Income	PV	Acc. PV
1980	6459.	5980.	5980.
1981	7363.	6312.	12292.
1982	8395.	6663.	18955.
1983	9569.	7033.	25989.
1984	10908.	7424.	33413.
1985	12435.	7836.	41249.
1986	14176.	8272.	49521.
1987	16161.	8731.	58252.
1988	18423.	9216.	67468.
1989	21002.	9728.	77197.
1990	23943.	10269.	87465.
1991	27295.	10839.	98305.
1992	31116.	11441.	109746.
1993	35473.	12077.	121823.
1994	40439.	12748.	134571.
1995	46100.	13456.	148028.
1996	52555.	14204.	162231.
1997	59912.	14993.	177224.
1998	68300.	15826.	193050.
1999	77862.	16705.	209755.
2000	88762.	17633.	227388.
2001	101189.	18613.	246001.
2002	115356.	19647.	265648.
2003	131566.	20738.	286386.
2004	149916.	21890.	308277.

DISCOUNT RATE 8%
FUEL QUANTITY 3540.85 x 10^9 Btu
FUEL COST $1.80/$10^6$ Btu
ESCALATION RATE 14%

Year	Income	PV	Acc. PV
1980	7266.	6728.	6728.
1981	8283.	7101.	13829.
1982	9443.	7496.	21325.
1983	10765.	7912.	29237.
1984	12272.	8352.	37589.
1985	13990.	8816.	46405.
1986	15948.	9306.	55711.
1987	18181.	9823.	65533.
1988	20726.	10368.	75902.
1989	23628.	10944.	86846.
1990	26936.	11552.	98398.
1991	30707.	12194.	110593.
1992	35006.	12872.	123464.
1993	39907.	13587.	137051.
1994	45494.	14342.	151393.
1995	51863.	15138.	166531.
1996	59124.	15979.	182510.
1997	67401.	16867.	199377.
1998	76837.	17804.	217181.
1999	87595.	18793.	235975.
2000	99858.	19837.	255812.
2001	113838.	20939.	276751.
2002	129775.	22103.	298854.
2003	147944.	23331.	322185.
2004	168656.	24627.	346812.

Table G-11. Fuel/O & M Cost Data (x 1000), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option (continued)

COAL COST	$1.40/10^6$ Btu
OIL COST	$2.90/10^6$ Btu
COAL ESC RATE	7%
OIL ESC RATE	10%
DISCOUNT RATES	8%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3402.	695.	4097.	595.	4692.	4345.	4345.
1981	3457.	1576.	5033.	669.	5702.	4888.	9233.
1982	3713.	1374.	5087.	804.	5891.	4677.	13910.
1983	4105.	1002.	5107.	827.	5934.	4362.	18272.
1984	4367.	1565.	5932.	844.	6776.	4611.	22883.
1985	4408.	2317.	6725.	966.	7691.	4847.	27730.
1986	4606.	3317.	7924.	1066.	8990.	5245.	32975.
1987	4604.	4066.	8670.	1209.	9879.	5337.	38312.
1988	5078.	3303.	8381.	1282.	9663.	4834.	43146.
1989	5621.	3182.	8803.	1212.	10015.	4639.	47785.
1990	5838.	3210.	9048.	1229.	10277.	4408.	52192.
1991	6246.	3531.	9778.	1233.	11011.	4372.	56565.
1992	6683.	3884.	10568.	1320.	11888.	4371.	60936.
1993	7151.	4273.	11424.	1412.	12836.	4370.	65306.
1994	7652.	4700.	12352.	1511.	13863.	4370.	69676.
1995	8188.	5170.	13358.	1617.	14975.	4371.	74047.
1996	8761.	5687.	14448.	1730.	16178.	4372.	78420.
1997	9374.	6256.	15630.	1851.	17481.	4375.	82794.
1998	10030.	6882.	16912.	1981.	18893.	4378.	87172.
1999	10732.	7570.	18302.	2119.	20421.	4381.	91553.
2000	11483.	8327.	19810.	2268.	22078.	4386.	95939.
2001	12287.	9159.	21447.	2426.	23873.	4391.	100331.
2002	13147.	10075.	23223.	2596.	25819.	4397.	104728.
2003	14068.	11083.	25151.	2778.	27929.	4404.	109132.
2004	15052.	12191.	27244.	2972.	30216.	4412.	113544.

Table G-11. Fuel/O & M Cost Data (x 1000), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option (continued)

COAL COST	$\$1.40/10^6$ Btu
OIL COST	$\$2.90/10^6$ Btu
COAL ESC RATE	7%
OIL ESC RATE	17%
DISCOUNT RATES	8%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3402.	740.	4142.	595.	4737.	4386.	4386.
1981	3457.	1782.	5240.	669.	5909.	5066.	9452.
1982	3713.	1654.	5367.	804.	6171.	4898.	14350.
1983	4105.	1282.	5388.	827.	6215.	4568.	18918.
1984	4367.	2130.	6497.	844.	7341.	4996.	23914.
1985	4408.	3355.	7763.	966.	8729.	5501.	29415.
1986	4606.	5109.	9715.	1066.	10781.	6291.	35706.
1987	4604.	6660.	11264.	1209.	12473.	6739.	42444.
1988	5078.	5755.	10833.	1282.	12115.	6060.	48505.
1989	5621.	5897.	11517.	1212.	12729.	5896.	54401.
1990	5838.	6328.	12166.	1229.	13395.	5745.	60146.
1991	6246.	7404.	13650.	1233.	14883.	5910.	66056.
1992	6683.	8663.	15346.	1320.	16666.	6128.	72184.
1993	7151.	10135.	17286.	1412.	18698.	6366.	78550.
1994	7652.	11858.	19510.	1511.	21021.	6627.	85177.
1995	8188.	13874.	22062.	1617.	23679.	6912.	92088.
1996	8761.	16233.	24993.	1730.	26723.	7222.	99311.
1997	9374.	18992.	28366.	1851.	30217.	7562.	106873.
1998	10030.	22221.	32251.	1981.	34232.	7932.	114805.
1999	10732.	25998.	36731.	2119.	38850.	8335.	123140.
2000	11483.	30418.	41902.	2268.	44170.	8775.	131914.
2001	12287.	35589.	47877.	2426.	50303.	9253.	141167.
2002	13147.	41639.	54787.	2596.	57383.	9773.	150940.
2003	14068.	48718.	62786.	2778.	65564.	10339.	161280.
2004	15052.	57000.	72053.	2972.	75025.	10955.	172235.

Table G-11. Fuel/O & M Cost Data (x 1000), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option (continued)

COAL COST	$1.40/10^6$ Btu
OIL COST	$2.90/10^6$ Btu
COAL ESC RATE	14%
OIL ESC RATE	10%
DISCOUNT RATES	8%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3625.	695.	4320.	595.	4915.	4551.	4551.
1981	3925.	1576.	5500.	669.	6169.	5289.	9840.
1982	4491.	1374.	5865.	804.	6669.	5294.	15134.
1983	5289.	1002.	6292.	827.	7119.	5232.	20366.
1984	5995.	1565.	7560.	844.	8404.	5719.	26085.
1985	6447.	2317.	8764.	966.	9730.	6132.	32217.
1986	7178.	3317.	10495.	1066.	11561.	6746.	38963.
1987	7644.	4066.	11709.	1209.	12918.	6979.	45942.
1988	8983.	3303.	12285.	1282.	13567.	6787.	52729.
1989	10593.	3182.	13775.	1212.	14987.	6942.	59671.
1990	11721.	3210.	14931.	1229.	16160.	6931.	66602.
1991	13362.	3531.	16893.	1233.	18126.	7198.	73800.
1992	15233.	3884.	19117.	1320.	20437.	7515.	81315.
1993	17365.	4273.	21638.	1412.	23050.	7848.	89163.
1994	19796.	4700.	24497.	1511.	26008.	8199.	97361.
1995	22568.	5170.	27738.	1617.	29355.	8568.	105930.
1996	25727.	5687.	31415.	1730.	33145.	8958.	114888.
1997	29329.	6256.	35585.	1851.	37436.	9368.	124256.
1998	33435.	6882.	40317.	1981.	42298.	9801.	134057.
1999	38116.	7570.	45686.	2119.	47805.	10256.	144313.
2000	43452.	8327.	51779.	2268.	54047.	10737.	155050.
2001	49536.	9159.	58695.	2426.	61121.	11243.	166293.
2002	56471.	10075.	66546.	2596.	69142.	11776.	178069.
2003	64377.	11083.	75460.	2778.	78238.	12338.	190407.
2004	73389.	12191.	85581.	2972.	88553.	12930.	203337.

Table G-11. Fuel/O & M Cost Data (x 1000), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option

COAL COST	$1.40/10^6$ Btu
OIL COST	$2.90/10^6$ Btu
COAL ESC RATE	14%
OIL ESC RATE	17%
DISCOUNT RATES	8%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3625.	740.	4364.	595.	4959.	4592.	4592.
1981	3925.	1782.	5707.	669.	6376.	5466.	10058.
1982	4491.	1654.	6144.	804.	6948.	5516.	15574.
1983	5289.	1282.	6572.	827.	7399.	5438.	21012.
1984	5995.	2130.	8125.	844.	8969.	6104.	27116.
1985	6447.	3355.	9802.	966.	10768.	6786.	33902.
1986	7178.	5109.	12287.	1066.	13353.	7791.	41693.
1987	7644.	6660.	14304.	1209.	15513.	8381.	50074.
1988	8983.	5755.	14737.	1282.	16019.	8014.	58088.
1989	10593.	5897.	16490.	1212.	17702.	8199.	66287.
1990	11721.	6328.	18049.	1229.	19278.	8268.	74555.
1991	13362.	7404.	20766.	1233.	21999.	8736.	83291.
1992	15233.	8663.	23895.	1320.	25215.	9272.	92563.
1993	17365.	10135.	27500.	1412.	28912.	9844.	102406.
1994	19796.	11858.	31655.	1511.	33166.	10455.	112862.
1995	22568.	13874.	36442.	1617.	38059.	11109.	123971.
1996	25727.	16233.	41960.	1730.	43690.	11808.	135779.
1997	29329.	18992.	48321.	1851.	50172.	12556.	148334.
1998	33435.	22221.	55656.	1981.	57637.	13355.	161690.
1999	38116.	25998.	64115.	2119.	66234.	14210.	175900.
2000	43452.	30418.	73871.	2268.	76139.	15125.	191025.
2001	49536.	35589.	85125.	2426.	87551.	16104.	207129.
2002	56471.	41639.	98110.	2596.	100706.	17152.	224281.
2003	64377.	[illegible]718.	113095.	2778.	115873.	18273.	242554.
2004	73399.	57899.	[illegible]	2972.	133362.	19473.	262027.

Table G-11. Fuel/O & M Cost Data (x 1000), Green Bay, Three Mills and CBD Alternative, Municipal Financing Option (concluded)

COAL COST	$\$1.40/10^6$ Btu
OIL COST	$\$2.90/10^6$ Btu
COAL ESC RATE	11%
OIL ESC RATE	11.1%
DISCOUNT RATES	8%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3529.	702.	4232.	595.	4827.	4469.	4469.
1981	3721.	1607.	5328.	669.	5997.	5141.	9610.
1982	4145.	1416.	5561.	804.	6365.	5053.	14663.
1983	4754.	1043.	5797.	827.	6624.	4869.	19532.
1984	5247.	1644.	6891.	844.	7735.	5264.	24796.
1985	5494.	2460.	7953.	966.	8919.	5621.	30417.
1986	5956.	3557.	9512.	1066.	10578.	6172.	36589.
1987	6175.	4402.	10578.	1209.	11787.	6368.	42957.
1988	7066.	3612.	10678.	1282.	11960.	5983.	48940.
1989	8113.	3515.	11628.	1212.	12840.	5947.	54888.
1990	8741.	3582.	12323.	1229.	13552.	5812.	60700.
1991	9703.	3979.	13682.	1233.	14915.	5923.	66623.
1992	10770.	4421.	15191.	1320.	16511.	6071.	72694.
1993	11955.	4912.	16866.	1412.	18278.	6223.	78917.
1994	13279.	5457.	18726.	1511.	20237.	6380.	85296.
1995	14729.	6063.	20792.	1617.	22409.	6541.	91837.
1996	16349.	6735.	23085.	1730.	24815.	6707.	98544.
1997	18148.	7483.	25631.	1851.	27482.	6877.	105421.
1998	20144.	8314.	28458.	1981.	30439.	7053.	112474.
1999	22360.	9237.	31597.	2119.	33716.	7234.	119708.
2000	24820.	10262.	35081.	2268.	37349.	7420.	127128.
2001	27550.	11401.	38951.	2426.	41377.	7611.	134739.
2002	30580.	12666.	43247.	2596.	45843.	7808.	142546.
2003	33944.	14072.	48016.	2778.	50794.	8010.	150556.
2004	37678.	15634.	53312.	2972.	56284.	8219.	158775.

Table G-12. Income Statement (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
REVENUE													
GROSS INCOME	7266	8283	9443	10765	12272	13990	15948	18181	20726	23628	26946	30707	35006
EXPENSES													
OPERATION/MAINTENANCE	595	669	804	827	844	966	1066	1209	1282	1212	1230	1233	1320
FUEL	4243	5323	5561	5797	6891	7953	9512	10578	10678	11628	12323	13682	15191
TAXES	520	336	325	305	286	269	252	238	224	213	201	192	184
ADVALOREM TAX	330	320	300	280	262	244	227	210	194	178	164	149	136
DEPRECIATION	346	670	639	618	597	576	556	535	514	493	473	452	431
INTEREST	1170	1134	1062	994	928	865	804	745	687	633	581	531	482
TOTAL EXPENSES	7193	8457	8691	8821	9808	10873	12418	13515	13579	14357	14972	16239	17744
INCOME (BEFORE TAXES)	73	-174	752	1944	2464	3117	3530	4666	7147	9271	11964	14468	17262
INCOME ($ 1979)	62	-127	469	1036	1121	1213	1172	1325	1737	1919	2118	2185	2227

Table G-12. Income Statement (x 1000), Green Bay, Three Mills and CBD Alternative, Utility Financing Option (concluded)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
REVENUE												
GROSS INCOME	39907	45494	51863	59124	67401	76837	87595	99858	113838	129775	147944	168656
EXPENSES												
OPERATING EXPENSES	1412	1511	1617	1730	1851	1981	2120	2268	2426	2596	2778	2972
FUEL	16866	18726	20792	23085	25631	28458	31597	35081	38951	43247	48016	53312
TAXES	176	170	167	163	162	162	162	165	169	174	180	167
ADVALOREM TAX	173	111	99	88	77	68	58	50	42	34	28	22
DEPRECIATION	411	391	369	349	328	307	287	266	245	224	204	204
INTEREST	435	393	351	312	274	239	207	176	148	121	98	76
TOTAL EXPENSES	19423	21302	23395	25727	28323	31215	34431	38006	41981	46396	51304	56753
INCOME (BEFORE TAXES)	20484	24192	28468	33397	39078	45622	53164	61852	71857	83379	96690	111903
INCOME ($ 1979)	2274	2284	2297	2301	2302	2296	2286	2273	2256	2237	2216	2192

Table G-13. Balance Sheet ($ x 1000) as of December 31, 1980, District Heating System, Green Bay, CBD and Three-Mill Alternative, Utility Financing Option

Assets			Liabilities and Stockholders' Equity		
Fixed Assets:			Long-Term Liabilities:		
Property			Long-Term Debt		
Plant Retrofit	$3000		Bonds	$5170	
Distribution Network	7000		Total Liabilities		$5170
Pipe Bridge	1000				
Total Property		$11,000	*Stockholders' Equity:		
			Preferred Stock - x par value	1320	
			Authorized - x shares Issued - x shares		
			Common Stock - x par value	4510	
			Authorized - x shares Issued - x shares		
			Total Stockholder Equity		$5830
Total Assets		$11,000	Total Liabilities and Stockholders' Equity		$11,000

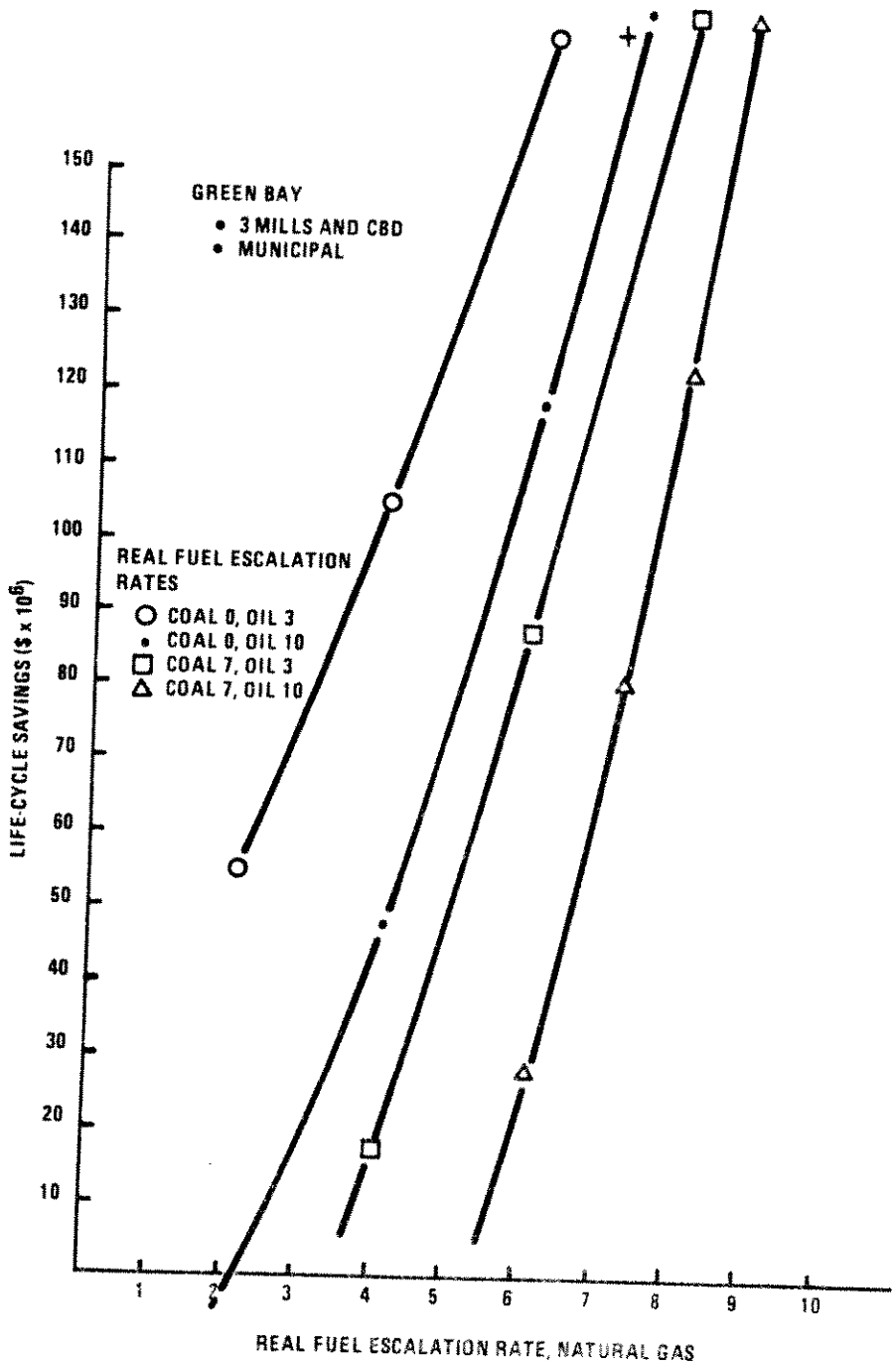

Figure G-3. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

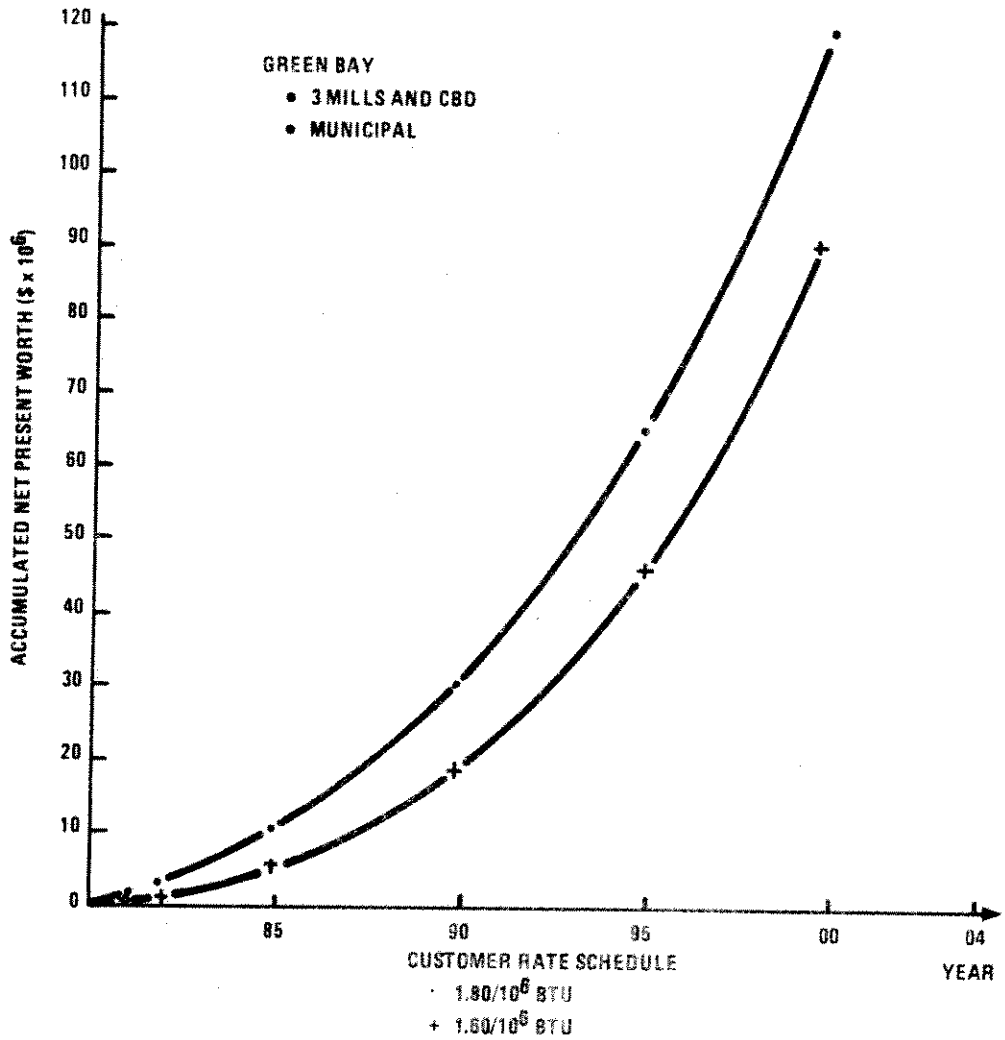

Figure G-4. Accumulated Net Present Worth versus Year

Joint Utility/Municipal Financing

The effect of joint financing of the district heating system was determined by:

- Determining the total return requirements associated with that portion financed, operated and maintained by the utility (Table G-14). These included return requirements for plant retrofit equipment, operations and maintenance expenses for the plant and fuel (Table G-15). Once these were determined, the net result was discounted to present value using the discount rate of the utility.
- Determing the total return requirements associated with that portion financed, operated and maintained by the municipality (Table G-16). This included return requirements for the distribution system and operation and maintenance expenses (Table G-17). These yearly costs were then discounted to present value using the discount rate of the municipality.
- Determining the gross income, distributing the gross income on a percentage basis (Table G-18) with respect to the return required by each owner, and discounting each portion accordingly (Tables G-19 and G-20). An income statement is given as Table G-21, and a balance sheet is given as Table G-22.

The result (Figure G-5) illustrates the Accumulated Net Percent Worth versus Year. Life-Cycle Savings curves were not generated due to the prohibitive number of runs required.

Table G-14. Summary, Fixed Charges (x 1000), Green Bay, Three Mills and CBD Alternative, Joint Financing Option Utility Portion ($3 x 10^6)

YEAR	TOTAL FIXED CHARGES: BOOK DEPR	INCOME TAX	ADVALOREM TAX	TOTAL RETURN	TOTAL FIXCHRG	PV	ACC PV
1980	94	142	90	319	645	551	551
1981	183	92	87	309	671	490	1041
1982	174	89	82	289	634	395	1436
1983	166	84	76	272	600	320	1756
1984	163	78	71	254	566	258	2014
1985	157	74	67	236	534	208	2222
1986	151	70	62	219	502	167	2389
1987	146	67	57	204	472	134	2523
1988	140	62	53	188	443	108	2631
1989	134	59	49	174	416	86	2717
1990	129	55	45	158	387	69	2786
1991	123	53	41	145	362	55	2841
1992	117	51	37	131	336	43	2884
1993	112	49	34	119	314	35	2919
1994	107	46	30	108	291	27	2946
1995	101	46	27	96	270	22	2968
1996	95	45	24	86	250	17	2985
1997	90	44	21	76	231	14	2999
1998	84	44	18	66	212	11	3010
1999	78	45	16	56	195	8	3018
2000	73	45	14	48	180	7	3025
2001	67	46	11	40	164	5	3030
2002	61	48	9	33	151	4	3034
2003	56	49	8	27	140	3	3037
2004	52	45	6	20	128	3	3040

Table G-15. Fuel/O & M Cost Data (x 1000), Green Bay, Three Mills and CBD Alternative, Joint Financing Option, Utility Portion

COAL COST	$1.40/10^6$ Btu
OIL COST	$2.90/10^6$ Btu
COAL ESC RATE	11%
OIL ESC RATE	11.1%
DISCOUNT RATES	17%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	3529.	702.	4232.	377.	4609.	3939.	3939.
1981	3721.	1607.	5328.	436.	5764.	4211.	8150.
1982	4145.	1416.	5561.	554.	6115.	3818.	11968.
1983	4754.	1043.	5797.	560.	6357.	3392.	15360.
1984	5247.	1644.	6891.	558.	7449.	3398.	18758.
1985	5494.	2460.	7953.	660.	8613.	3358.	22115.
1986	5956.	3557.	9512.	739.	10251.	3416.	25531.
1987	6175.	4402.	10578.	859.	11437.	3257.	28788.
1988	7066.	3612.	10678.	907.	11585.	2820.	31608.
1989	8113.	3515.	11628.	811.	12439.	2588.	34196.
1990	8741.	3582.	12323.	800.	13123.	2333.	36529.
1991	9703.	3979.	13682.	774.	14456.	2197.	38726.
1992	10770.	4421.	15191.	829.	16020.	2081.	40807.
1993	11955.	4912.	16866.	887.	17753.	1971.	42778.
1994	13270.	5457.	18726.	947.	19673.	1867.	44644.
1995	14729.	6063.	20792.	1015.	21807.	1769.	46413.
1996	16349.	6735.	23085.	1086.	24171.	1675.	48088.
1997	18148.	7483.	25631.	1162.	26793.	1587.	49676.
1998	20144.	8314.	28458.	1244.	29702.	1504.	51180.
1999	22360.	9237.	31597.	1331.	32928.	1425.	52605.
2000	24820.	10262.	35081.	1424.	36505.	1350.	53955.
2001	27550.	11401.	38951.	1523.	40474.	1280.	55235.
2002	30580.	12666.	43247.	1630.	44877.	1213.	56448.
2003	33944.	14072.	48016.	1745.	49761.	1149.	57597.
2004	37678.	15634.	53312.	1866.	55178.	1089.	58686.

Table G-16. Return Requirements (x 1000), Green Bay, Three Mills and CBD Alternative, Joint Financing Option, Municipal Portion

Book Life 27 years
Capital Costs $8,000,000

Depreciation Method - St. Line
Return Rate 8%
Discount Rate 8%

Year	Book Dep	Net Book Dep	Net Inv	Ret Req	Tot Ret	PV	Acc PV
1980	296.	0.	8000.	640.	936.	867.	867.
1981	296.	296.	7704.	616.	913.	782.	1649.
1982	296.	593.	7407.	593.	889.	706.	2355.
1983	296.	889.	7111.	569.	865.	636.	2991.
1984	296.	1185.	6815.	545.	841.	573.	3564.
1985	296.	1481.	6519.	521.	818.	515.	4079.
1986	296.	1778.	6222.	498.	794.	463.	4542.
1987	296.	2074.	5926.	474.	770.	416.	4958.
1988	296.	2370.	5630.	450.	747.	374.	5332.
1989	296.	2667.	5333.	427.	723.	335.	5667.
1990	296.	2963.	5037.	403.	699.	300.	5967.
1991	296.	3259.	4741.	379.	676.	268.	6235.
1992	296.	3556.	4444.	356.	652.	240.	6475.
1993	296.	3852.	4148.	332.	628.	214.	6689.
1994	296.	4148.	3852.	308.	604.	191.	6879.
1995	296.	4444.	3556.	284.	581.	170.	7049.
1996	296.	4741.	3259.	261.	557.	151.	7199.
1997	296.	5037.	2963.	237.	533.	133.	7333.
1998	296.	5333.	2667.	213.	510.	118.	7451.
1999	296.	5630.	2370.	190.	486.	104.	7555.
2000	296.	5926.	2074.	166.	462.	92.	7647.
2001	296.	6222.	1778.	142.	439.	81.	7727.
2002	296.	6519.	1481.	119.	415.	71.	7798.
2003	296.	6815.	1185.	95.	391.	62.	7860.
2004	296.	7111.	889.	71.	367.	54.	7913.

Table G-17. Fuel/O & M Cost Data (x 1000), Green Bay, Three Mills and CBD Alternative, Joint Financing Option, Municipal Portion

COAL COST	$1.40/10^6$ Btu
OIL COST	$2.90/10^6$ Btu
COAL ESC RATE	11%
OIL ESC RATE	11.1%
DISCOUNT RATES	8%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	0.	0.	0.	218.	218.	202.	202.
1981	0.	0.	0.	233.	233.	200.	402.
1982	0.	0.	0.	250.	250.	198.	600.
1983	0.	0.	0.	267.	267.	196.	796.
1984	0.	0.	0.	286.	286.	195.	991.
1985	0.	0.	0.	306.	306.	193.	1184.
1986	0.	0.	0.	327.	327.	191.	1375.
1987	0.	0.	0.	350.	350.	189.	1564.
1988	0.	0.	0.	375.	375.	188.	1751.
1989	0.	0.	0.	401.	401.	186.	1937.
1990	0.	0.	0.	429.	429.	184.	2121.
1991	0.	0.	0.	459.	459.	182.	2303.
1992	0.	0.	0.	491.	491.	181.	2484.
1993	0.	0.	0.	525.	525.	179.	2663.
1994	0.	0.	0.	562.	562.	177.	2840.
1995	0.	0.	0.	601.	601.	175.	3015.
1996	0.	0.	0.	644.	644.	174.	3189.
1997	0.	0.	0.	689.	689.	172.	3362.
1998	0.	0.	0.	737.	737.	171.	3532.
1999	0.	0.	0.	788.	788.	169.	3701.
2000	0.	0.	0.	844.	844.	168.	3869.
2001	0.	0.	0.	903.	903.	166.	4035.
2002	0.	0.	0.	966.	966.	165.	4200.
2003	0.	0.	0.	1033.	1033.	163.	4363.
2004	0.	0.	0.	1106.	1106.	161.	4524.

Table G-18. Cost/Fuel Distribution, Green Bay Joint Financing Option

Utility				Municipal							
Fuel Cost	Plant O&M	Fixed Ret Utility	Total Utility	Dist O&M	Dist Return	Total Municipal	Total Utility & Municipal	% Municipal	% Utility	Municipal Fuel Input	Utility Fuel Input
3 Mill Scenario Data											
503,115	24,724	9,094	536,933	13,790	16,296	30,086	567,019	5.31	94.69	188.02	3352.83
2 Mill Scenario Data											
181,071	18,017	6,658	205,746	8,094	13,241	21,335	227,081	9.40	90.60	76.25	1342.08

Table G-19. Gross Income Data (x 1000), Green Bay, Three Mills and CBD Alternative, Joint Financing Option, Municipal Portion

DISCOUNT RATE 8%
FUEL QUANTITY 188.02×10^9 Btu/yr
FUEL COST $\$1.80/10^6$ Btu
ESCALATION RATE 14%

Year	Income	PV	Acc. PV
1980	386.	357.	357.
1981	440.	377.	734.
1982	501.	398.	1132.
1983	572.	420.	1553.
1984	652.	443.	1996.
1985	743.	468.	2464.
1986	847.	494.	2958.
1987	965.	522.	3480.
1988	1101.	551.	4030.
1989	1255.	581.	4612.
1990	1430.	613.	5225.
1991	1631.	648.	5872.
1992	1859.	683.	6556.
1993	2119.	721.	7277.
1994	2416.	762.	8039.
1995	2754.	804.	8843.
1996	3139.	849.	9691.
1997	3579.	896.	10587.
1998	4080.	945.	11532.
1999	4651.	998.	12530.
2000	5302.	1053.	13584.
2001	6045.	1112.	14696.
2002	6891.	1174.	15869.
2003	7856.	1239.	17108.
2004	8956.	1308.	18416.

DISCOUNT RATE 8%
FUEL QUANTITY 188.02×10^9 Btu/yr
FUEL COST $\$1.80/10^6$ Btu
ESCALATION RATE 14%

Year	Income	PV	Acc. PV
1980	343.	318.	318.
1981	391.	335.	653.
1982	446.	354.	1007.
1983	508.	373.	1380.
1984	579.	394.	1774.
1985	660.	416.	2190.
1986	753.	439.	2630.
1987	858.	464.	3093.
1988	978.	489.	3583.
1989	1115.	517.	4099.
1990	1271.	545.	4644.
1991	1449.	576.	5220.
1992	1652.	608.	5828.
1993	1884.	641.	6469.
1994	2147.	677.	7146.
1995	2448.	715.	7860.
1996	2791.	754.	8615.
1997	3181.	796.	9411.
1998	3627.	840.	10251.
1999	4134.	887.	11138.
2000	4713.	936.	12074.
2001	5373.	988.	13063.
2002	6125.	1043.	14106.
2003	6983.	1101.	15207.
2004	7961.	1162.	16370.

Table G-20. Gross Income Data (x 1000), Green Bay, Three Mills and CBD Alternative, Joint Financing Option, Utility Portion

DISCOUNT RATE 17%
FUEL QUANTITY 3352.83 x 10^9 Btu/yr
FUEL COST = $1.80/$10^6$ Btu
ESCALATION RATE 14%

Year	Income	PV	Acc. PV
1980	6880.	5880.	5880.
1981	7843.	5730.	11610.
1982	8941.	5583.	17193.
1983	10193.	5440.	22632.
1984	11620.	5300.	27932.
1985	13247.	5164.	33096.
1986	15101.	5032.	38128.
1987	17216.	4903.	43031.
1988	19626.	4777.	47808.
1989	22373.	4655.	52462.
1990	25506.	4535.	56997.
1991	29077.	4419.	61416.
1992	33147.	4306.	65722.
1993	37788.	4195.	69917.
1994	43078.	4088.	74005.
1995	49109.	3983.	77987.
1996	55984.	3881.	81868.
1997	63822.	3781.	85649.
1998	72757.	3684.	89333.
1999	82943.	3590.	92923.
2000	94555.	3498.	96421.
2001	107793.	3408.	99829.
2002	122884.	3321.	103150.
2003	140088.	3235.	106385.
2004	159700.	3153.	109538.

DISCOUNT RATE 17%
FUEL QUANTITY 3352.83 x 10^9 Btu/yr
FUEL COST $1.60/$10^6$ Btu
ESCALATION RATE 14%

Year	Income	PV	Acc. PV
1980	6116.	5227.	5227.
1981	6972.	5093.	10320.
1982	7948.	4962.	15282.
1983	9060.	4835.	20117.
1984	10329.	4711.	24829.
1985	11775.	4590.	29419.
1986	13423.	4473.	33892.
1987	15303.	4358.	38250.
1988	17445.	4246.	42496.
1989	19887.	4137.	46633.
1990	22672.	4031.	50664.
1991	25846.	3928.	54592.
1992	29464.	3827.	58419.
1993	33584.	3729.	62148.
1994	38292.	3633.	65782.
1995	43653.	3540.	69322.
1996	49764.	3449.	72772.
1997	56731.	3361.	76133.
1998	64673.	3275.	79408.
1999	73727.	3191.	82598.
2000	84043.	3109.	85707.
2001	95816.	3029.	88737.
2002	109230.	2952.	91688.
2003	124523.	2876.	94564.
2004	141956.	2802.	97367.

Table G-21. Income Statement (x 1000), Green Bay, Three-Mill and CBD Alternative, Municipal Financing Option

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
REVENUE													
GROSS INCOME	7266	8283	9443	10765	12272	13990	15948	18181	20726	23628	26936	30707	35006
EXPENSES													
OPERATION/MAINTENANCE	595	669	804	827	844	966	1066	1209	1282	1212	1230	1233	1320
FUEL	4232	5328	5561	5797	6891	7953	9512	10578	10678	11628	12323	13682	15191
DEPRECIATION	407	407	407	407	407	407	407	407	407	407	407	407	407
INTEREST	880	847	815	782	750	717	684	652	619	587	554	521	489
TOTAL EXPENSES	6114	7251	7587	7813	8892	10043	11669	12846	12986	13834	14514	15843	17407
INCOME	1152	1032	1856	2952	3380	3947	4279	5335	7740	9794	12422	14864	17599
INCOME ($ 1979)	1067	885	1473	2170	2300	2487	2497	2882	3872	4537	5328	5903	6471

Table G-21. Income Statement (x 1000), Green Bay, Three-Mill and CBD Alternative, Municipal Financing Option (concluded)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
REVENUE												
GROSS INCOME	39907	45494	51863	59124	67401	76837	87595	99858	113838	129775	147944	168656
EXPENSES												
OPERATION/MAINTENANCE	1412	1511	1617	1730	1851	1981	2120	2268	2426	2596	2778	2972
FUEL	16866	18726	20792	23085	25631	28458	31597	35081	38951	43247	48016	53312
DEPRECIATION	407	407	407	407	407	407	407	407	407	407	407	407
INTEREST	456	424	391	359	326	293	261	228	196	163	130	98
TOTAL EXPENSES	19141	21068	23207	25581	28215	31139	34385	37984	41980	46413	51331	56789
INCOME	20766	24426	28656	33543	39186	45698	53210	61874	71858	83362	96613	111867
INCOME ($ 1979)	7070	7700	8364	9066	9806	10589	11416	12292	13218	14198	15236	16335

Table G-22. Balance Sheet ($ x 1000) as of December 31, 1980, District Heating System, Green Bay, CBD and Three-Mill Alternative, Municipal Financing Option

Assets			Liabilities and Stockholders' Equity		
Fixed Assets:			Long-Term Liabilities:		
Property			Long-Term Debt		
Plant Retrofit	$3000		Bonds	$11,000	
Distribution Network	7000		Total Liabilities		$11,000
Pipe Bridge	1000				
Total Property		$11,000			
Total Assets		$11,000	Total Liabilities		$11,000

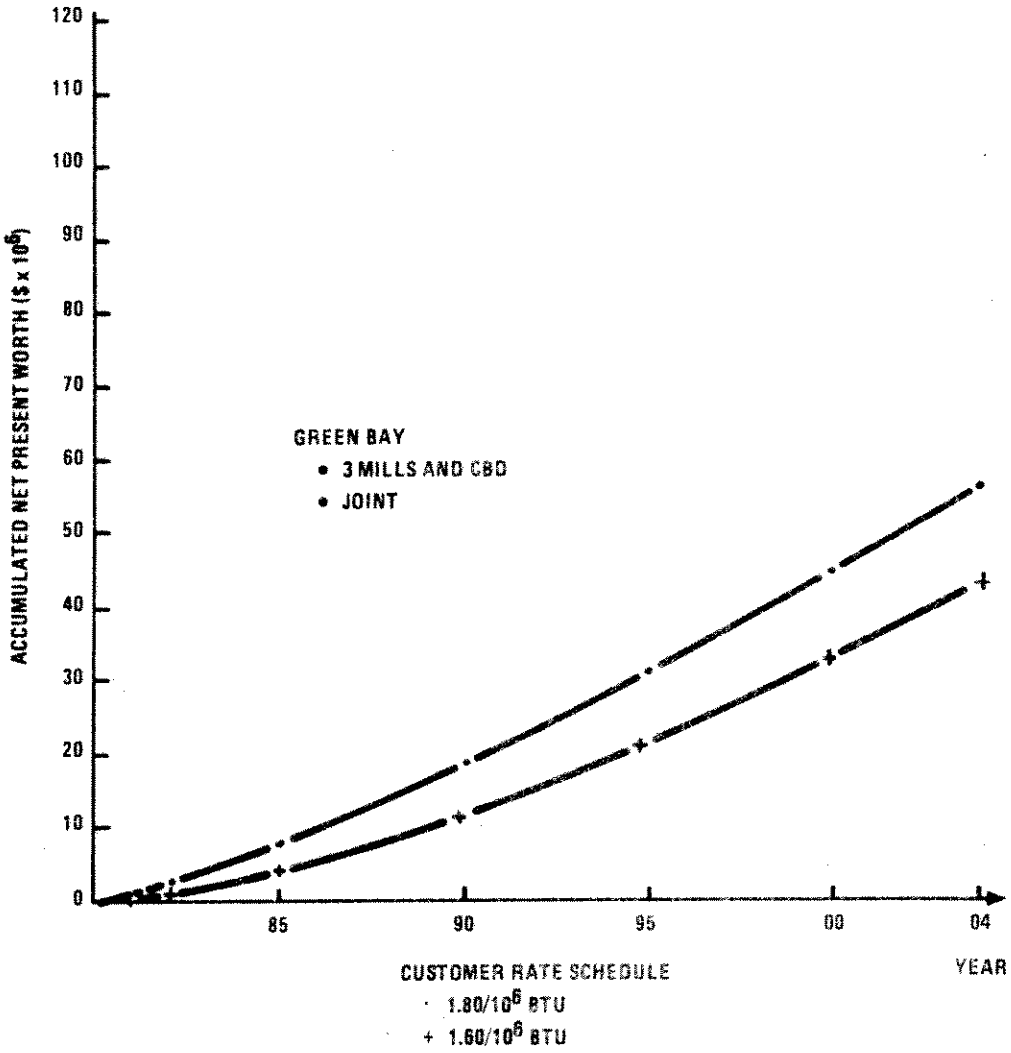

Figure G-5. Accumulated Net Present Worth versus Year

COMPARATIVE RESULTS

Results illustrating the three financial alternatives are summarized in Figure G-6. One rate structure (i.e., 90 percent of the current cost of fuel) is illustrated.

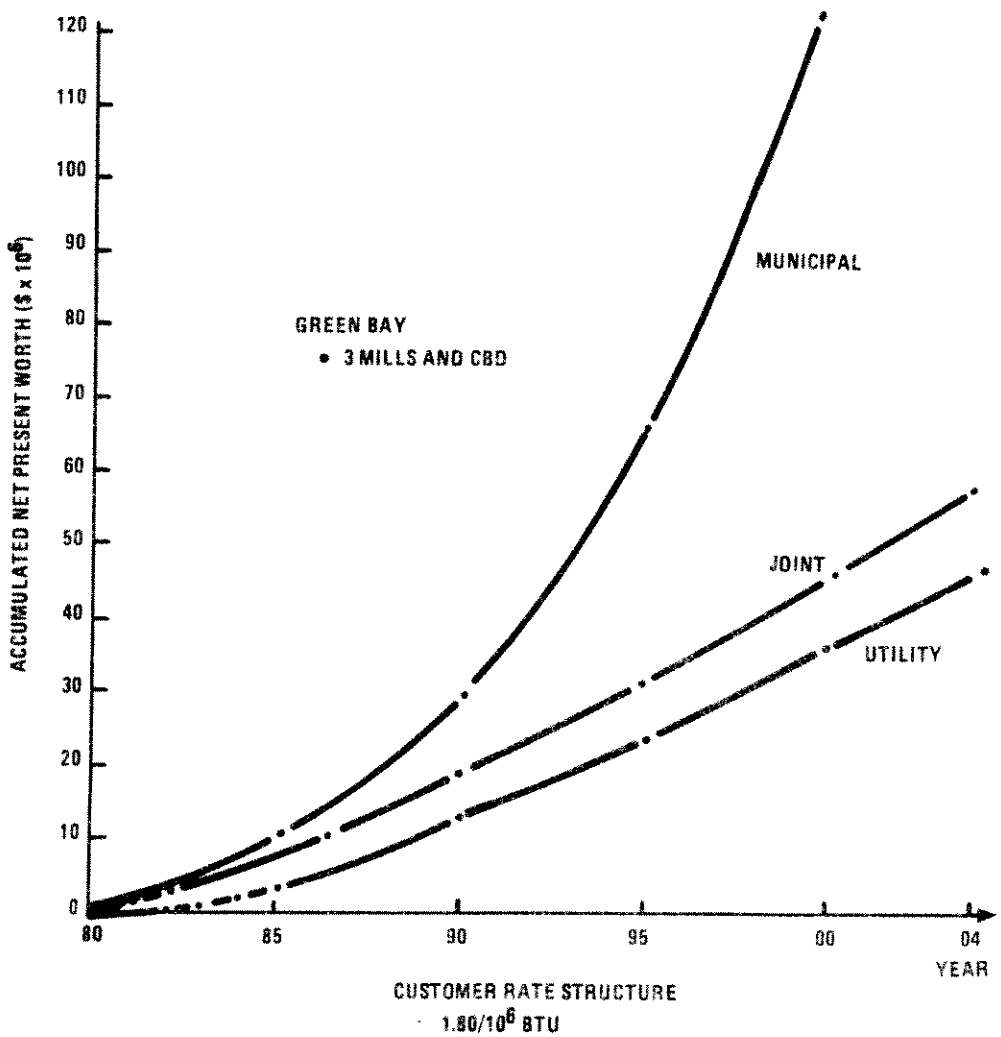

Figure G-6. Accumulated Net Present Worth versus Year

REMAINING ALTERNATIVES

For the remaining alternatives analyzed, only summary tables and results are illustrated. These include:

- Life-Cycle Savings versus Real Fuel Escalation Rates for each financing option;
- Accumulated Net Present Worth versus Year of Operation for each financing option;
- Combined Life-Cycle Savings for financing options considered;
- Tables of operations and maintenance costs;
- Tables of fixed-return requirements for each financing option;
- Tables of fuel, operations and maintenance costs for each financing option for real fuel escalation rates of Coal--4 percent, Oil--4.1 percent, and Natural Gas--7 percent;
- Tables of Gross Income for each financing option for a real fuel escalation rate of 7 percent;
- Tables of annual-savings for range of fuel escalation rates for each financing option.

GREEN BAY, TWO MILLS AND CBD ALTERNATIVE

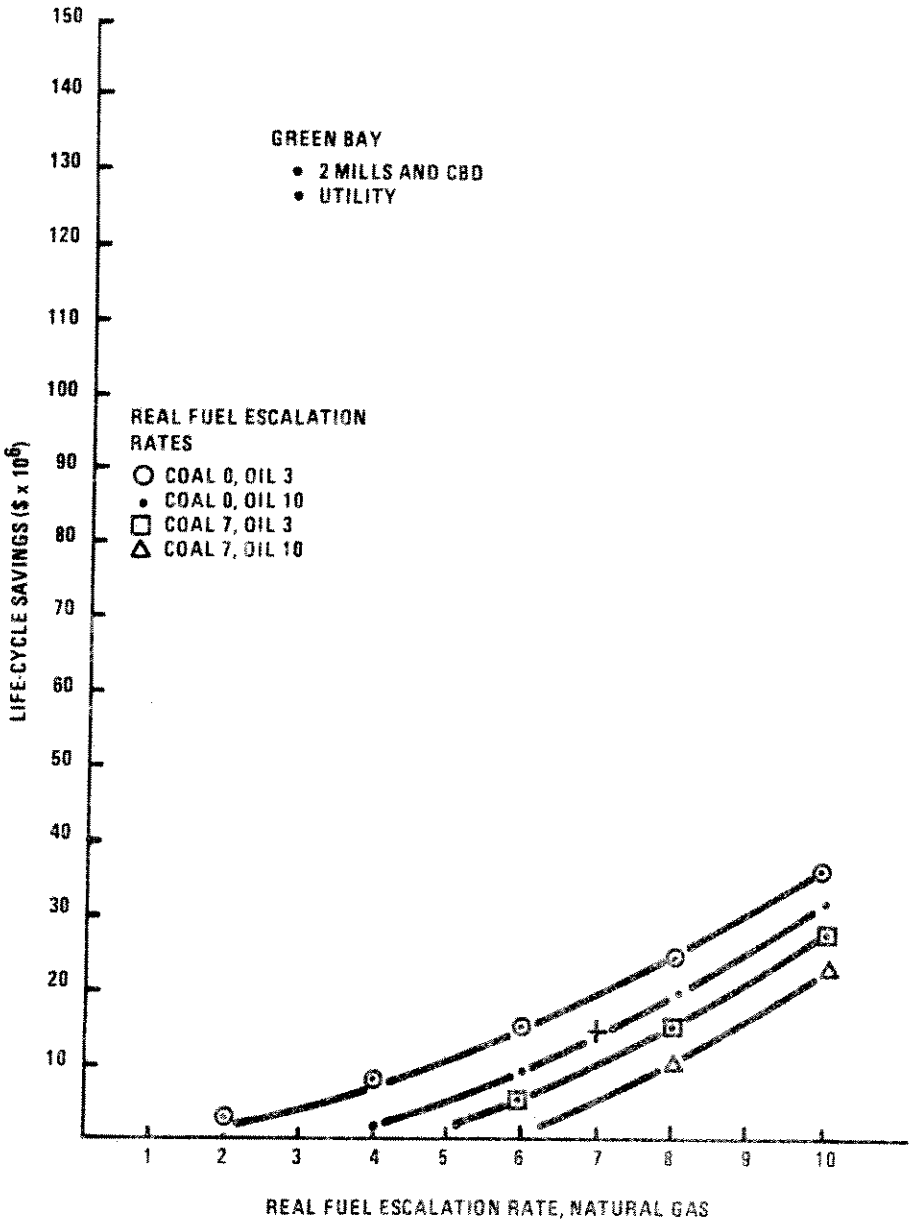

Figure G-7. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

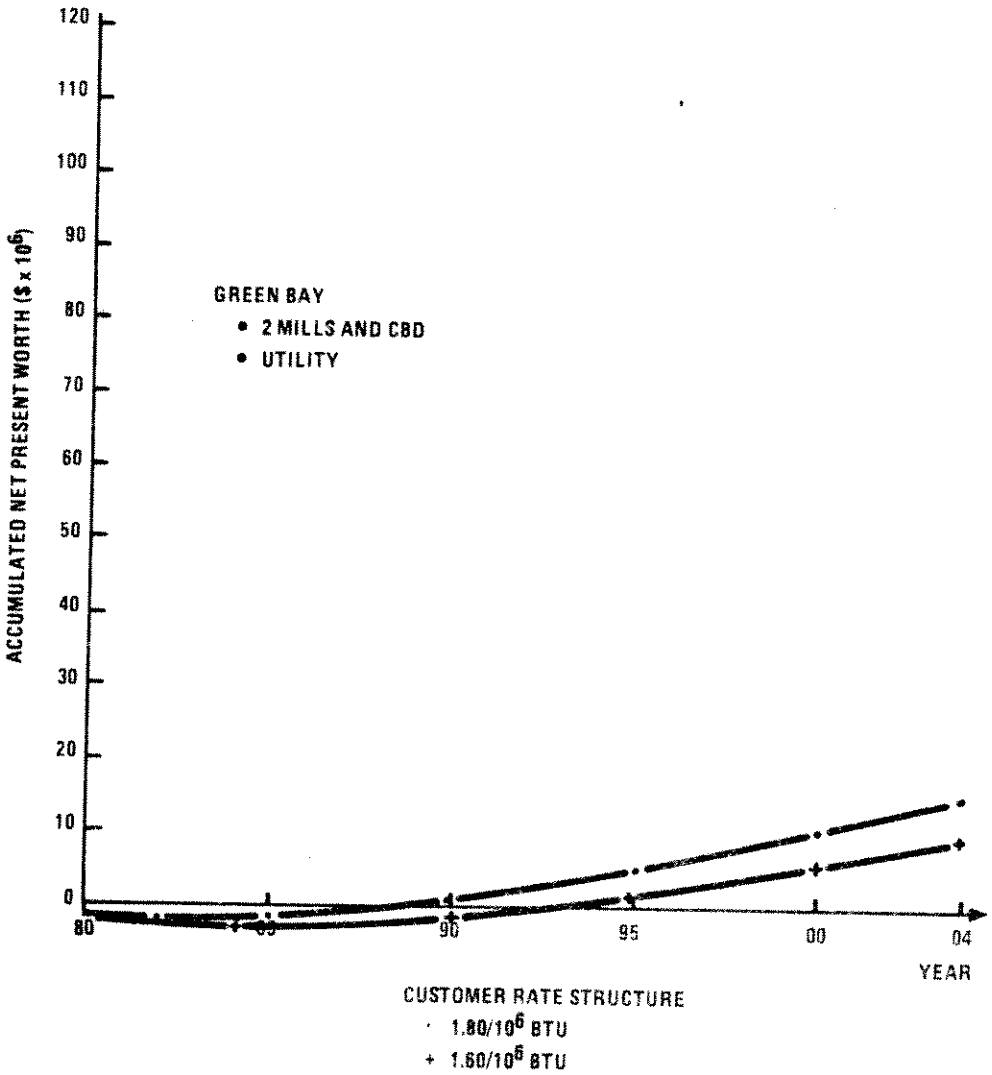

Figure G-8. Accumulated Net Present Worth versus Year

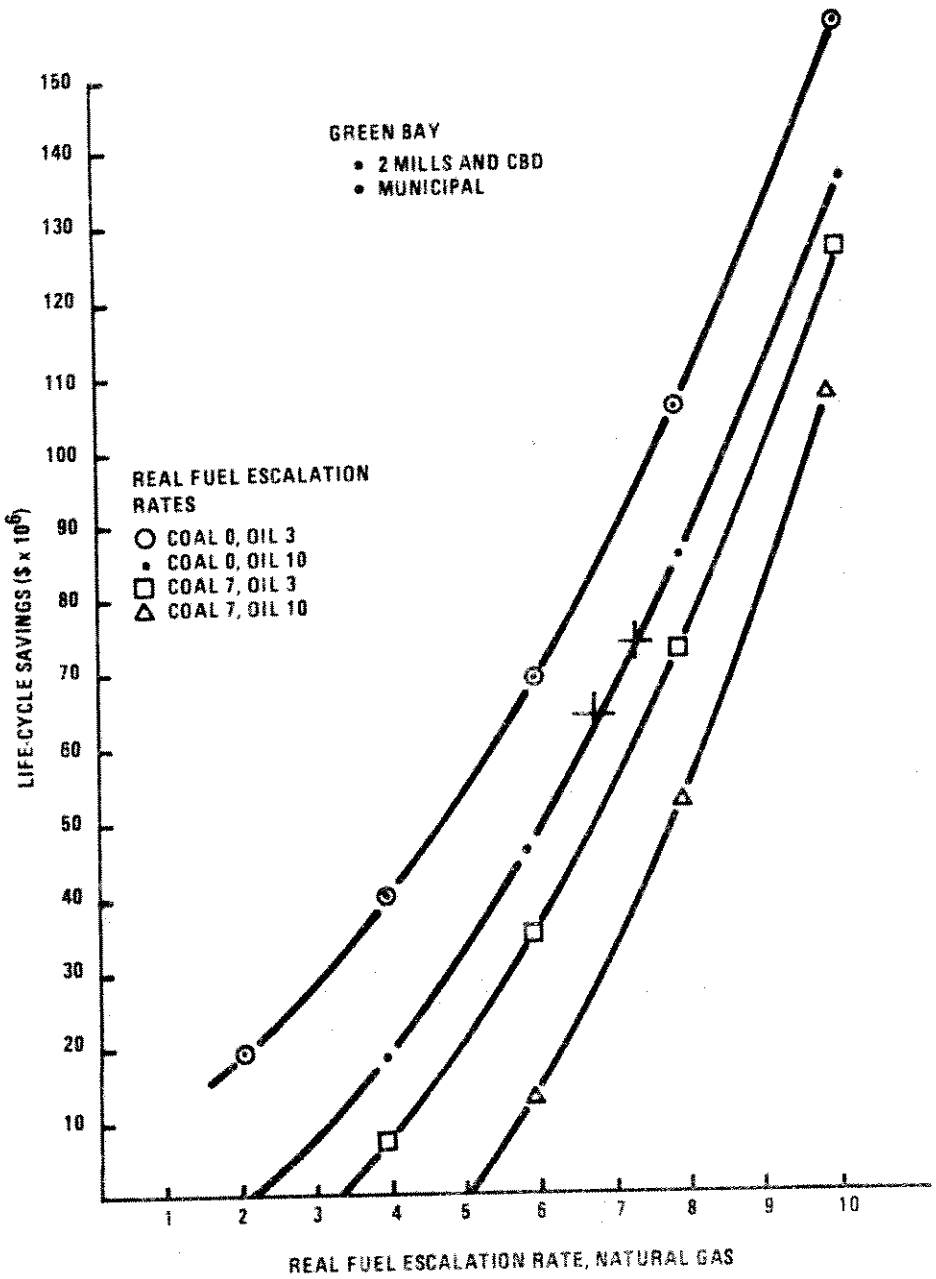

Figure G-9. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

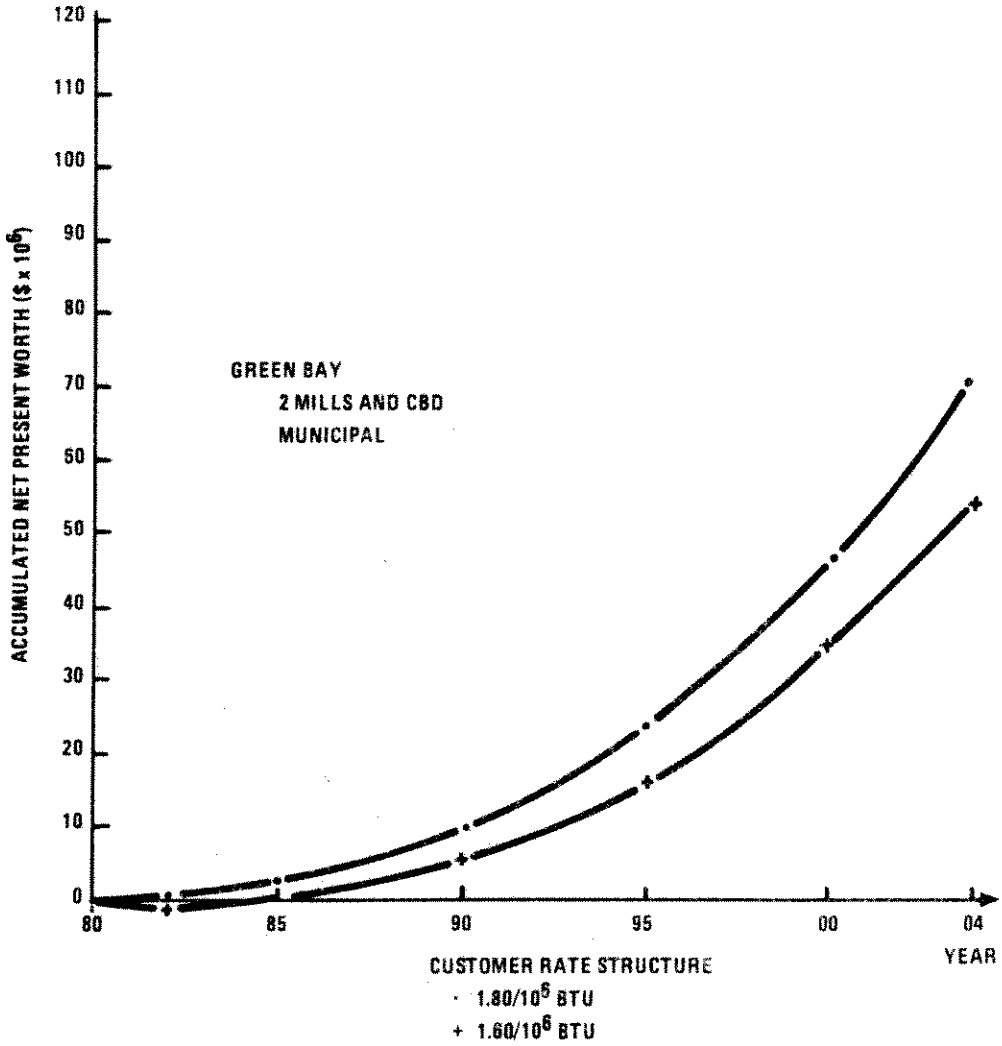

Figure G-10. Accumulated Net Present Worth versus Year

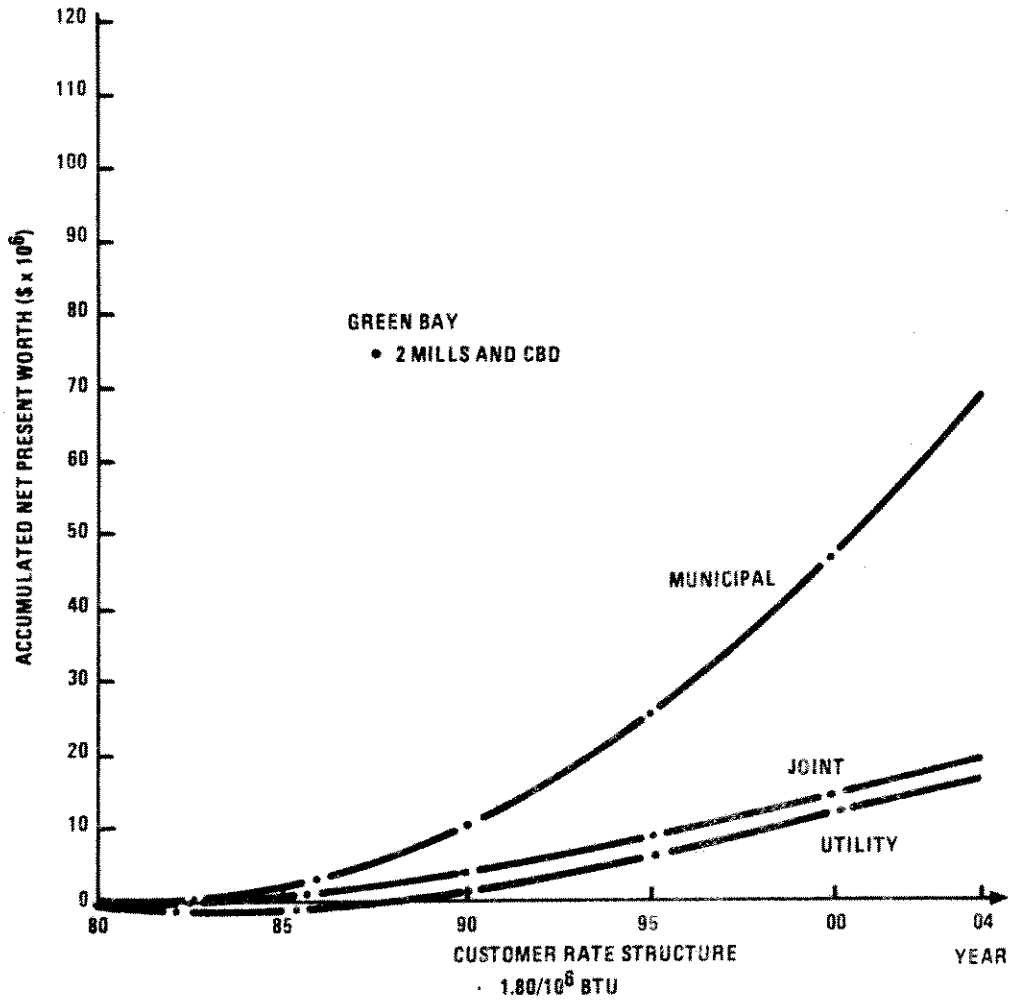

Figure G-11. Accumulated Net Present Worth versus Year

Table G-23. Operations and Maintenance Costs, Green Bay, Two Mills and CBD Alternative

	Distribution			Plant		
Year	Maintenance 1% of Cost (6.5×10^6)	Insurance .2% of Cost ($\$2.2 \times 10^6$)	Pump Power 2.27×10^6 kWh/yr @ .022/kWh	District Heating Portion	Cost of Shifting to less Efficient Boilers	Total O&M Costs
1980	65	13	50	94	42	264
1981	70	14	54	106	50	293
1982	74	15	57	113	86	392
1983	80	16	61	121	81	359
1984	85	17	66	130	72	370
1985	91	18	70	139	100	418
1986	98	20	75	147	119	458
1987	104	21	80	156	154	800
1988	112	22	86	167	160	851
1989	120	24	92	178	114	853
1990	128	26	98	169	118	887
1991	137	27	105	177	103	922
1992	146	29	113	189	110	986
1993	157	31	120	203	118	1056
1994	168	34	129	217	126	1129
1995	179	36	138	232	135	1208
1996	192	38	148	248	144	1293
1997	205	41	158	266	155	1384
1998	220	44	169	284	165	1480
1999	235	47	181	304	177	1584
2000	252	50	193	325	189	1695
2001	269	54	207	348	203	1814
2002	288	58	222	373	217	1941
2003	308	62	237	399	232	2076
2004	330	66	254	427	248	2222

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Table G-24. Summary, Fixed Charges (x 1000), Green Bay, Two Mills and CBD Alternative, Utility Financing Option

Year	Total Fixed Charge	PV	Acc PV
1980	1872	1599	1599
1981	1946	1420	3019
1982	1842	1148	4167
1983	1738	927	5094
1984	1641	747	5841
1985	1547	602	6443
1986	1455	484	6927
1987	1366	388	7315
1988	1281	311	7626
1989	1201	249	7875
1990	1122	199	8074
1991	1047	158	8232
1992	974	126	8358
1993	908	101	8459
1994	843	80	8539
1995	780	63	8602
1996	723	49	8651
1997	666	39	8690
1998	614	31	8721
1999	565	25	8746
2000	519	19	8765
2001	478	15	8780
2002	440	12	8792
2003	403	9	8801
2004	371	7	8808

Table G-25. Return Requirements (x 1000), Green Bay, Two Mills and CBD Alternative, Municipal Financing Option

Book Life	27 years	Depreciation Method -	St. Line
Capital Costs	8,700,000	Return Rate	8%
		Discount Rate	8%

Year	Book Depr	Net Book Depr	Net Inv	Ret Req	Total Return	PV	Acc PV
1980	322.	0.	8700.	696.	1018.	943.	943.
1981	322.	322.	8378.	670.	992.	851.	1794.
1982	322.	644.	8056.	644.	967.	767.	2561.
1983	322.	967.	7733.	619.	941.	692.	3253.
1984	322.	1289.	7411.	593.	915.	623.	3875.
1985	322.	1611.	7089.	567.	889.	560.	4436.
1986	322.	1933.	6767.	541.	864.	504.	4940.
1987	322.	2256.	6444.	516.	838.	453.	5392.
1988	322.	2578.	6122.	490.	812.	406.	5799.
1989	322.	2900.	5800.	464.	786.	364.	6163.
1990	322.	3222.	5478.	438.	760.	326.	6489.
1991	322.	3544.	5156.	412.	735.	292.	6781.
1992	322.	3867.	4833.	387.	709.	261.	7041.
1993	322.	4189.	4511.	361.	683.	233.	7274.
1994	322.	4511.	4189.	335.	657.	207.	7481.
1995	322.	4833.	3867.	309.	632.	184.	7665.
1996	322.	5156.	3544.	284.	606.	164.	7829.
1997	322.	5478.	3222.	258.	580.	145.	7974.
1998	322.	5800.	2900.	232.	554.	128.	8103.
1999	322.	6122.	2578.	206.	528.	113.	8216.
2000	322.	6444.	2256.	180.	503.	100.	8316.
2001	322.	6767.	1933.	155.	477.	88.	8404.
2002	322.	7089.	1611.	129.	451.	77.	8480.
2003	322.	7411.	1289.	103.	425.	67.	8548.
2004	322.	7733.	967.	77.	400.	58.	8606.

Table G-26. Return Requirements (x 1000), [illegible] Bay Mills and CBD Alternative, Joint Finan[illegible]ng [illegible]on

Book Life	27 years	[illegible]ecia[illegible]n Method -	St. Line
Capital Cost	$6,500,000	[illegible]urn [illegible]	8%
		Discoun[illegible]te	8%

Year	Book Depr	Net Book Dep	Net Inv	Ret Req	Total Ret	PV	Acc PV
1980	241.	0.	6500.	520.	761.	704.	704.
1981	241.	241.	6259.	501.	741.	636.	1340.
1982	241.	481.	6019.	481.	722.	573.	1913.
1983	241.	722.	5778.	462.	703.	517.	2430.
1984	241.	963.	5537.	443.	684.	465.	2895.
1985	241.	1204.	5296.	424.	664.	419.	3314.
1986	241.	1444.	5056.	404.	645.	376.	3691.
1987	241.	1685.	4815.	385.	626.	338.	4029.
1988	241.	1926.	4574.	366.	607.	303.	4332.
1989	241.	2167.	4333.	347.	587.	272.	4604.
1990	241.	2407.	4093.	327.	568.	244.	4848.
1991	241.	2648.	3852.	308.	549.	218.	5066.
1992	241.	2889.	3611.	289.	530.	195.	5261.
1993	241.	3130.	3370.	270.	510.	174.	5434.
1994	241.	3370.	3130.	250.	491.	155.	5589.
1995	241.	3611.	2889.	231.	472.	138.	5727.
1996	241.	3852.	2648.	212.	453.	122.	5849.
1997	241.	4093.	2407.	193.	433.	108.	5958.
1998	241.	4333.	2167.	173.	414.	96.	6054.
1999	241.	4574.	1926.	154.	395.	85.	6138.
2000	241.	4815.	1685.	135.	376.	75.	6213.
2001	241.	5056.	1444.	116.	356.	66.	6279.
2002	241.	5296.	1204.	96.	337.	57.	6336.
2003	241.	5537.	963.	77.	318.	50.	6386.
2004	241.	5778.	722.	58.	299.	44.	6430.

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Table G-27. Summary, Return Requirements (x 1000), Green Bay, Two Mills and CBD Alternative, Joint Financing Option, Utility Portion

Year	Total Fixed	PV	Acc PV
1980	473	404	404
1981	492	359	763
1982	466	290	1053
1983	440	234	1287
1984	415	189	1476
1985	391	152	1628
1986	368	122	1750
1987	345	98	1848
1988	324	79	1927
1989	304	63	1990
1990	284	50	2040
1991	265	40	2080
1992	246	32	2112
1993	229	26	2138
1994	213	20	2158
1995	197	16	2174
1996	183	12	2186
1997	168	10	2196
1998	155	8	2204
1999	143	6	2210
2000	131	5	2215
2001	121	4	2219
2002	111	3	2222
2003	102	2	2224
2004	94	2	2226

Table G-28. Fuel/O&M Cost Data (x 1000), Green Bay, Two Mills and CBD Alternative, Utility Financing Option

COAL COST = $1.40/10^6$ Btu
OIL COST = $2.90/10^6$ Btu
COAL ESC RATE = 11%
OIL ESC RATE = 11.1%
DISCOUNT RATES = 17%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	1270.	253.	1523.	264.	1787.	1527.	1527.
1981	1339.	578.	1918.	293.	2211.	1615.	3142.
1982	1492.	510.	2001.	392.	2393.	1494.	4636.
1983	1711.	375.	2086.	359.	2445.	1305.	5941.
1984	1888.	592.	2480.	370.	2850.	1300.	7241.
1985	1977.	885.	2862.	418.	3280.	1279.	8520.
1986	2143.	1280.	3423.	458.	3881.	1293.	9814.
1987	2222.	1584.	3807.	800.	4607.	1312.	11125.
1988	2543.	1300.	3843.	851.	4694.	1143.	12268.
1989	2920.	1265.	4185.	853.	5038.	1048.	13316.
1990	3146.	1289.	4435.	887.	5322.	946.	14262.
1991	3492.	1432.	4924.	922.	5846.	888.	15151.
1992	3876.	1591.	5467.	986.	6453.	838.	15989.
1993	4302.	1768.	6070.	1056.	7126.	791.	16780.
1994	4776.	1964.	6740.	1129.	7869.	747.	17527.
1995	5301.	2182.	7483.	1208.	8691.	705.	18232.
1996	5884.	2424.	8308.	1293.	9601.	666.	18897.
1997	6531.	2693.	9225.	1384.	10609.	629.	19526.
1998	7250.	2992.	10242.	1480.	11722.	594.	20119.
1999	8047.	3324.	11372.	1584.	12956.	561.	20680.
2000	8933.	3693.	12626.	1695.	14321.	530.	21210.
2001	9915.	4103.	14018.	1814.	15832.	501.	21710.
2002	11006.	4559.	15564.	1941.	17505.	473.	22183.
2003	12216.	5065.	17281.	2076.	19357.	447.	22630.
2004	13560.	5627.	19187.	2222.	21409.	423.	23053.

Table G-29. Fuel/O&M Cost Data (x 1000), Green Bay, Two Mills and CBD Alternative, Municipal Financing Option

COAL COST = $1.4/10^6$ Btu
OIL COST = $2.9/10^6$ Btu
COAL ESC RATE = 11%
OIL ESC RATE = 11.1%
DISCOUNT RATES = 8%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/L&M	PV	Acc. PV
1980	1270.	253.	1523.	264.	1787.	1655.	1655.
1981	1339.	578.	1918.	293.	2211.	1895.	3550.
1982	1492.	510.	2001.	392.	2393.	1900.	5450.
1983	1711.	375.	2086.	359.	2445.	1797.	7247.
1984	1888.	592.	2480.	370.	2850.	1940.	9187.
1985	1977.	885.	2862.	418.	3280.	2067.	11254.
1986	2143.	1280.	3423.	458.	3881.	2265.	13519.
1987	2222.	1584.	3807.	800.	4607.	2499.	16008.
1988	2543.	1300.	3843.	851.	4694.	2348.	18356.
1989	2920.	1265.	4185.	853.	5038.	2334.	20689.
1990	3146.	1289.	4435.	887.	5322.	2282.	22972.
1991	3492.	1432.	4924.	922.	5846.	2322.	25294.
1992	3876.	1591.	5467.	986.	6453.	2373.	27666.
1993	4302.	1768.	6070.	1056.	7126.	2426.	30093.
1994	4776.	1964.	6740.	1129.	7869.	2481.	32573.
1995	5301.	2182.	7483.	1208.	8691.	2537.	35110.
1996	5884.	2424.	8308.	1293.	9601.	2595.	37705.
1997	6531.	2693.	9225.	1384.	10609.	2655.	40360.
1998	7250.	2992.	10242.	1480.	11722.	2716.	43076.
1999	8047.	3324.	11372.	1584.	12956.	2780.	45855.
2000	8933.	3693.	12626.	1695.	14321.	2845.	48700.
2001	9915.	4103.	14018.	1814.	15832.	2912.	51612.
2002	11006.	4559.	15564.	1941.	17505.	2981.	54594.
2003	12216.	5065.	17281.	2076.	19357.	3053.	57646.
2004	13560.	5627.	19187.	2222.	21409.	3126.	60773.

Table G-30. Fuel/O&M Cost Data (x 1000), Green Bay, Two Mills and CBD Alternative, Joint Financing Option, Utility Portion

COAL COST = $1.4/10^6$ Btu
OIL COST = $2.9/10^6$ Btu
COAL ESC RATE = 11%
OIL ESC RATE = 11.1%
DISCOUNT RATES = 17%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	1270.	253.	1523.	136.	1659.	1418.	1418.
1981	1339.	578.	1918.	127.	2045.	1494.	2911.
1982	1492.	510.	2001.	146.	2147.	1341.	4252.
1983	1711.	375.	2086.	235.	2321.	1239.	5491.
1984	1888.	592.	2480.	191.	2671.	1218.	6709.
1985	1977.	885.	2862.	190.	3052.	1190.	7899.
1986	2143.	1280.	3423.	226.	3649.	1216.	9115.
1987	2222.	1584.	3807.	252.	4059.	1156.	10271.
1988	2543.	1300.	3843.	580.	4423.	1077.	11348.
1989	2920.	1265.	4185.	616.	4801.	999.	12346.
1990	3146.	1289.	4435.	601.	5036.	895.	13242.
1991	3492.	1432.	4924.	655.	5579.	848.	14090.
1992	3876.	1591.	5467.	698.	6165.	801.	14891.
1993	4302.	1768.	6070.	747.	6817.	757.	15647.
1994	4776.	1964.	6740.	799.	7539.	715.	16363.
1995	5301.	2182.	7483.	855.	8338.	676.	17039.
1996	5884.	2424.	8308.	915.	9223.	639.	17678.
1997	6531.	2693.	9225.	980.	10205.	605.	18283.
1998	7250.	2992.	10242.	1047.	11289.	572.	18855.
1999	8047.	3324.	11372.	1121.	12493.	541.	19395.
2000	8933.	3693.	12626.	1200.	13826.	511.	19907.
2001	9915.	4103.	14018.	1284.	15302.	484.	20390.
2002	11006.	4559.	15564.	1374.	16938.	458.	20848.
2003	12216.	5065.	17281.	1469.	18750.	433.	21281.
2004	13560.	5627.	19187.	1573.	20760.	410.	21691.

Table G-31. Fuel/O&M Cost Data (x 1000), Green Bay, Two Mills and CBD Alternative, Joint Financing Option, Municipal Portion

COAL COST = $1.40/10^6$ Btu
OIL COST = $2.90/10^6$ Btu
COAL ESC RATE = 11%
OIL ESC RATE = 11.1%
DISCOUNT RATES = 8%

Year	Coal	Oil	Total Fuel	O&M	Total Fuel/O&M	PV	Acc. PV
1980	0.	0.	0.	128.	128.	119.	119.
1981	0.	0.	0.	137.	137.	117.	236.
1982	0.	0.	0.	147.	147.	117.	353.
1983	0.	0.	0.	156.	156.	115.	467.
1984	0.	0.	0.	168.	168.	114.	582.
1985	0.	0.	0.	180.	180.	113.	695.
1986	0.	0.	0.	192.	192.	112.	807.
1987	0.	0.	0.	206.	206.	111.	918.
1988	0.	0.	0.	220.	220.	110.	1028.
1989	0.	0.	0.	235.	235.	109.	1137.
1990	0.	0.	0.	252.	252.	108.	1245.
1991	0.	0.	0.	269.	269.	107.	1352.
1992	0.	0.	0.	288.	288.	106.	1458.
1993	0.	0.	0.	308.	308.	105.	1563.
1994	0.	0.	0.	330.	330.	104.	1667.
1995	0.	0.	0.	353.	353.	103.	1770.
1996	0.	0.	0.	378.	378.	102.	1872.
1997	0.	0.	0.	404.	404.	101.	1973.
1998	0.	0.	0.	432.	432.	100.	2073.
1999	0.	0.	0.	463.	463.	99.	2173.
2000	0.	0.	0.	495.	495.	98.	2271.
2001	0.	0.	0.	530.	530.	97.	2369.
2002	0.	0.	0.	567.	567.	97.	2465.
2003	0.	0.	0.	607.	607.	96.	2561.
2004	0.	0.	0.	649.	649.	95.	2656.

Table G-32 Gross Income Data (x 1000), Green Bay, Two Mills and CBD Alternative, Utility Financing Option

DISCOUNT RATE = 17%
FUEL QUANTITY = 1418.33 x 10^9 Btu/yr
FUEL COST = $1.80/$10^6$ Btu/yr
ESCALATION RATE = 17%

Year	Income	PV	Acc. PV
1980	2597.	2211.	2211.
1981	2949.	2154.	4366.
1982	3362.	2099.	6465.
1983	3833.	2045.	8510.
1984	4369.	1993.	10503.
1985	4981.	1942.	12445.
1986	5678.	1892.	14337.
1987	6473.	1844.	16180.
1988	7380.	1796.	17977.
1989	8413.	1750.	19727.
1990	9591.	1705.	21432.
1991	10933.	1662.	23094.
1992	12464.	1619.	24713.
1993	14209.	1577.	26290.
1994	16198.	1537.	27827.
1995	18466.	1498.	29325.
1996	21051.	1459.	30784.
1997	23999.	1422.	32206.
1998	27358.	1385.	33591.
1999	31188.	1350.	34941.
2000	35555.	1315.	36256.
2001	40533.	1281.	37538.
2002	46207.	1249.	38786.
2003	52676.	1217.	40003.
2004	60051.	1185.	41189.

DISCOUNT RATE = 17%
FUEL QUANTITY = 1418.33 x 10^9 Btu/yr
FUEL COST = $1.80/$10^6$ Btu/yr
ESCALATION RATE = 14%

Year	Income	PV	Acc. PV
1980	2910.	2488.	2488.
1981	3318.	2424.	4911.
1982	3782.	2362.	7273.
1983	4312.	2301.	9574.
1984	4916.	2242.	11816.
1985	5604.	2185.	14001.
1986	6388.	2129.	16129.
1987	7283.	2074.	18203.
1988	8302.	2021.	20224.
1989	9465.	1969.	22193.
1990	10790.	1918.	24111.
1991	12300.	1869.	25981.
1992	14022.	1821.	27802.
1993	15965.	1775.	29577.
1994	18223.	1729.	31306.
1995	20774.	1685.	32991.
1996	23683.	1642.	34632.
1997	26998.	1600.	36232.
1998	30778.	1559.	37790.
1999	35087.	1519.	39309.
2000	39999.	1480.	40788.
2001	45599.	1442.	42230.
2002	51983.	1405.	43635.
2003	59261.	1369.	45003.
2004	67557.	1334.	46337.

Table G-33. Gross Income Data (x 1000), Green Bay, Two Mills and CBD Alternative, Municipal Financing Option

DISCOUNT RATE = 8%
FUEL QUANTITY = 1418.33×10^9 Btu/yr
FUEL COST = $\$1.80/10^6$ Btu
ESCALATION RATE = 17%

Year	Income	PV	Acc. PV
1980	2587.	2395.	2395.
1981	2949.	2528.	4924.
1982	3362.	2669.	7593.
1983	3833.	2817.	10410.
1984	4369.	2974.	13384.
1985	4981.	3139.	16523.
1986	5678.	3313.	19836.
1987	6473.	3497.	23333.
1988	7380.	3692.	27025.
1989	8413.	3897.	30922.
1990	9591.	4113.	35035.
1991	10933.	4342.	38377.
1992	12464.	4583.	43960.
1993	14209.	4838.	48798.
1994	16198.	5106.	53904.
1995	18466.	5390.	59294.
1996	21051.	5690.	64984.
1997	23999.	6006.	70989.
1998	27358.	6339.	77329.
1999	31188.	6691.	84020.
2000	35555.	7063.	91082.
2001	40533.	7456.	98539.
2002	46207.	7870.	106409.
2003	52676.	8307.	114716.
2004	60051.	8768.	123484.

DISCOUNT RATE = 8%
FUEL QUANTITY = 1418.33×10^9 Btu/yr
FUEL COST = $\$1.80/10^6$ Btu
ESCALATION RATE = 14%

Year	Income	PV	Acc. PV
1980	2910.	2695.	2695.
1981	3318.	2845.	5539.
1982	3782.	3003.	8542.
1983	4312.	3169.	11711.
1984	4916.	3345.	15057.
1985	5604.	3531.	18588.
1986	6388.	3727.	22316.
1987	7283.	3935.	26250.
1988	8302.	4153.	30403.
1989	9465.	4384.	34787.
1990	10790.	4627.	39415.
1991	12300.	4885.	44299.
1992	14022.	5156.	49455.
1993	15985.	5442.	54897.
1994	18223.	5745.	60642.
1995	20774.	6064.	66706.
1996	23683.	6401.	73107.
1997	26998.	6756.	79863.
1998	30778.	7132.	86995.
1999	35087.	7528.	94523.
2000	39999.	7946.	102469.
2001	45599.	8388.	110856.
2002	51983.	8854.	119710.
2003	59261.	9345.	129055.
2004	67557.	9865.	138920.

Table G-34. Gross Income Data (x 1000), Green Bay, Two Mills and CBD Alternative, Joint Financing Option, Utility Portion

DISCOUNT RATE = 17%
FUEL QUANTITY = 1342.08×10^9 Btu/yr
FUEL COST = $\$1.80/10^6$ Btu
ESCALATION RATE = 14%

Year	Income	PV	Acc. PV
1980	2754.	2354.	2354.
1981	3140.	2293.	4647.
1982	3579.	2235.	6882.
1983	4080.	2177.	9059.
1984	4651.	2122.	11181.
1985	5302.	2067.	13248.
1986	6045.	2014.	15262.
1987	6891.	1962.	17224.
1988	7856.	1912.	19137.
1989	8956.	1863.	21000.
1990	10209.	1815.	22815.
1991	11639.	1769.	24584.
1992	13268.	1723.	26307.
1993	15126.	1679.	27987.
1994	17243.	1636.	29623.
1995	19658.	1594.	31217.
1996	22410.	1553.	32770.
1997	25547.	1514.	34284.
1998	29123.	1475.	35759.
1999	33201.	1437.	37196.
2000	37849.	1400.	38596.
2001	43148.	1364.	39960.
2002	49188.	1329.	41289.
2003	56075.	1295.	42584.
2004	63925.	1262.	43846.

DISCOUNT RATE = 17%
FUEL QUANTITY = 1342.08×10^9 Btu/yr
FUEL COST = $\$1.60/10^6$ Btu
ESCALATION RATE = 14%

Year	Income	PV	Acc. PV
1980	2448.	2092.	2092.
1981	2791.	2039.	4131.
1982	3181.	1986.	6117.
1983	3627.	1935.	8053.
1984	4134.	1886.	9938.
1985	4713.	1837.	11776.
1986	5373.	1790.	13566.
1987	6125.	1744.	15311.
1988	6983.	1700.	17010.
1989	7961.	1656.	18666.
1990	9075.	1614.	20280.
1991	10346.	1572.	21852.
1992	11794.	1532.	23384.
1993	13445.	1493.	24877.
1994	15327.	1454.	26331.
1995	17473.	1417.	27748.
1996	19920.	1381.	29129.
1997	22708.	1345.	30475.
1998	25888.	1311.	31785.
1999	29512.	1277.	33063.
2000	33643.	1245.	34307.
2001	38354.	1213.	35520.
2002	43723.	1182.	36701.
2003	49844.	1151.	37853.
2004	56822.	1122.	38974.

Table G-35. Gross Income Data (x 1000), Green Bay, Two Mills and CBD Alternative, Joint Financing Option, Municipal Portion

DISCOUNT RATE = 8%
FUEL QUANTITY = 76.25×10^9 Btu/yr
FUEL COST = $\$1.80/10^6$ Btu
ESCALATION RATE = 14%

Year	Income	PV	Acc. PV
1980	156.	145.	145.
1981	178.	153.	298.
1982	203.	161.	459.
1983	232.	170.	630.
1984	264.	180.	809.
1985	301.	190.	999.
1986	343.	200.	1200.
1987	392.	212.	1411.
1988	446.	223.	1634.
1989	509.	236.	1870.
1990	580.	249.	2119.
1991	661.	263.	2382.
1992	754.	277.	2659.
1993	859.	293.	2951.
1994	980.	309.	3260.
1995	1117.	326.	3586.
1996	1273.	344.	3930.
1997	1451.	363.	4293.
1998	1655.	383.	4677.
1999	1886.	405.	5082.
2000	2150.	427.	5509.
2001	2451.	451.	5960.
2002	2795.	476.	6436.
2003	3186.	502.	6938.
2004	3632.	530.	7468.

DISCOUNT RATE = 8%
FUEL QUANTITY = 76.25×10^9 Btu/yr
FUEL COST = $\$1.60/10^6$ Btu
ESCALATION RATE = 14%

Year	Income	PV	Acc. PV
1980	139.	129.	129.
1981	159.	136.	265.
1982	181.	143.	408.
1983	206.	151.	560.
1984	235.	160.	720.
1985	268.	169.	888.
1986	305.	178.	1066.
1987	348.	188.	1254.
1988	397.	198.	1453.
1989	452.	209.	1662.
1990	516.	221.	1884.
1991	588.	233.	2117.
1992	670.	246.	2363.
1993	764.	260.	2623.
1994	871.	275.	2898.
1995	993.	290.	3188.
1996	1132.	306.	3494.
1997	1290.	323.	3816.
1998	1471.	341.	4157.
1999	1677.	360.	4517.
2000	1911.	380.	4897.
2001	2179.	401.	5297.
2002	2484.	423.	5721.
2003	2832.	447.	6167.
2004	3228.	471.	6639.

Table G-36. Annual Savings (x 1000), Green Bay, Two Mills and CBD Alternative, Utility Financing Option

GROSS INCOME	REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
28863 AT 2%	8810	14857	1596	CASE COAL 0 OIL 3
34564 AT 4%			7297	
41896 AT 6%			14629	
51404 AT 8%			24137	
63825 AT 10%			36558	
28863		23780	-3727	COAL 0 OIL 10
34504			1974	
41896			9306	
51404			18814	
63825			31235	
28863		27151	-7098	COAL 7 OIL 3
34564			-1397	
41896			5935	
51404			15443	
63825			27864	
28863		32474	-12421	COAL 7 OIL 10
34564			-6720	
41896			612	
51404			10120	
63825			22541	
46337 AT 1.80%		23053	14474	COAL 4 OIL 4.1
41189 AT 1.60%			9326	NATURAL GAS 7

Table G-37. Annual Savings (x 1000), Green Bay, Two Mills and CBD Alternative, Municipal Financing Option

GROSS INCOME	REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
72108 AT 9%	14083	44494	13531	COAL 0 OIL 3
92923 AT 11%			34346	
121167 AT 13%			62590	
159663 AT 15%			101086	
212308 AT 17%			153731	
72108 AT 9%		65617	-7592	COAL 0 OIL 10
92923 AT 11%			13223	
121167 AT 13%			41467	
159663 AT 15%			79963	
212308 AT 17%			132608	
72108 AT 9%		76811	-18786	COAL 7 OIL 3
92923 AT 11%			2029	
121167 AT 13%			30273	
159663 AT 15%			68769	
212308 AT 17%			121414	
72108 AT 9%		97933	-39908	COAL 7 OIL 10
92923 AT 11%			-19093	
121167 AT 13%			9151	
159663 AT 15%			47647	
212308 AT 17%			100292	
138920 AT 1.80%		60773	64064	COAL 9 OIL 4.1
123484 AT 1.60			48628	NATURAL GAS 7

Table G-38. Income Statement (x 1000), Green Bay, CBD and Two-Mill Alternative, Utility Financing Option

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
REVENUE													
GROSS INCOME	2910	3318	3782	4312	4916	5604	6388	7283	8302	9465	10790	12300	14022
EXPENSES													
OPERATION/MAINTENANCE	264	293	392	359	370	418	458	800	851	853	887	922	986
FUEL	1523	1918	2001	2086	2480	2862	3423	3807	3843	4185	4435	4924	5467
TAXES	411	266	257	241	226	213	199	188	177	168	159	152	146
ADVALOREM TAX	261	253	237	221	207	193	180	166	153	141	130	118	108
DEPRECIATION	274	530	505	489	472	456	440	423	407	390	374	357	341
INTEREST	925	897	840	786	734	684	636	589	543	501	460	420	381
TOTAL EXPENSES	3658	4157	4232	4182	4489	4826	5336	5973	5974	6238	6445	6893	7429
INCOME (BEFORE TAXES)	-748	-839	-450	130	427	778	1052	1310	2328	3227	4345	5407	6593
INCOME ($ 1979)	-639	-612	-281	69	194	303	350	372	565	669	770	819	853

Table G-38. Income Statement (x 1000), Green Bay, CBD and Two-Mill Alternative, Utility Financing Option (concluded)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
REVENUE												
GROSS INCOME	15985	18223	20774	23683	26998	30778	35087	39999	45599	51983	59261	67557
EXPENSES												
OPERATION/MAINTENANCE	1056	1129	1208	1293	1384	1480	1584	1695	1814	1941	2076	2222
FUEL	6070	6740	7483	8308	9225	10242	11372	12626	14018	15564	17281	19187
TAXES	139	134	132	129	128	128	128	131	134	138	142	132
ADVALOREM TAX	97	88	78	70	61	54	46	40	33	27	22	17
DEPRECIATION	325	309	292	276	259	243	227	210	194	177	161	161
INTEREST	344	311	278	247	217	189	164	139	117	96	78	60
TOTAL EXPENSES	8031	8711	9471	10323	11274	12336	13521	14841	16310	17943	19760	21779
INCOME (BEFORE TAXES)	7954	9512	11303	13360	15724	18442	21566	25158	29289	34040	39501	45778
INCOME ($ 1979)	879	898	912	921	926	928	927	924	920	913	905	897

Table G-39. Balance Sheet ($ x 1000) as of December 31, 1980, District Heating System, Green Bay, CBD and Two-Mill Alternative, Utility Financing Option

Assets			Liabilities and Stockholders' Equity		
Fixed Assets:			Long-Term Liabilities:		
Property			Long-Term Debt		
Plant Retrofit	$2200		Bonds	$4089	
Distribution Network	5500				
Pipe Bridge	1000		Total Liabilities		$4089
Total Property		$8700	Stockholders' Equity		
			Preferred Stock - x par value	1044	
			Authorized - x shares Issued - x shares		
			Common Stock - x par value	3567	
			Authorized - x shares Issued - x shares		
			Total Stockholder Equity		$4611
Total Assets		$8700	Total Liabilities and Stockholders Equity		$8700

Table G-40. Income Statement (x 1000), Green Bay, CBD and Two-Mill Alternative, Municipal Financing Option

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
REVENUE													
GROSS INCOME	2910	3318	3782	4312	4916	5604	6388	7283	8302	9465	10790	12300	14022
EXPENSES													
OPERATION/MAINTENANCE	264	293	392	359	370	418	458	800	851	853	887	922	986
FUEL	1523	1918	2001	2086	2480	2862	3423	3807	3843	4185	4435	4924	5467
DEPRECIATION	322	322	322	322	322	322	322	322	322	322	322	322	322
INTEREST	696	670	644	619	593	567	541	516	490	464	438	412	387
TOTAL EXPENSES	2805	3203	3359	3386	3765	4169	4744	5445	5506	5824	6082	6580	7162
INCOME	105	115	423	926	1151	1435	1644	1838	2796	3641	4708	5720	6860
INCOME ($ 1979)	97	99	336	681	783	904	959	993	1399	1686	2019	2271	2522

Table G-40. Income Statement (x 1000), Green Bay, CBD and Two-Mill Alternative, Municipal Financing Option (concluded)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
REVENUE												
GROSS INCOME	15985	18223	20774	23683	26998	30778	35087	39999	45599	51983	59261	67557
EXPENSES												
OPERATION/MAINTENANCE	1056	1129	1208	1293	1384	1480	1584	1695	1814	1941	2076	2222
FUEL	6070	6740	7483	8308	9225	10242	11372	12626	14018	15564	17281	19187
DEPRECIATION	322	322	322	322	322	322	322	322	322	322	322	322
INTEREST	361	335	309	284	258	232	206	180	155	129	103	77
TOTAL EXPENSES	7809	8526	9322	10207	11189	12276	13484	14823	16309	17956	19782	21808
INCOME	8176	9697	11452	13476	15809	18502	21603	25176	29290	34027	39479	45749
INCOME ($ 1979)	2784	3057	3343	3642	3956	4287	4635	5001	5388	5795	6226	6680

Table G-41. Balance Sheet ($ x 1000) as of December 31, 1980, District Heating System, Green Bay, CBD and Two-Mill Alternative, Municipal Financing Option

Assets			*Liabilities and Stockholders' Equity		
Fixed Assets:			Long-Term Liabilities		
Property			Long-Term Debt		
Plant Retrofit	$2200		Bonds	$8700	
Distribution Network	5500		Total Liabilities		$8700
Pipe Bridge	1000				
Total Property		$8700			
Total Assets		$8700	Total Liabilities		$8700

* Dollars expressed in $1000

JANESVILLE/BELOIT, ROCK RIVER TO INDUSTRIAL PARK

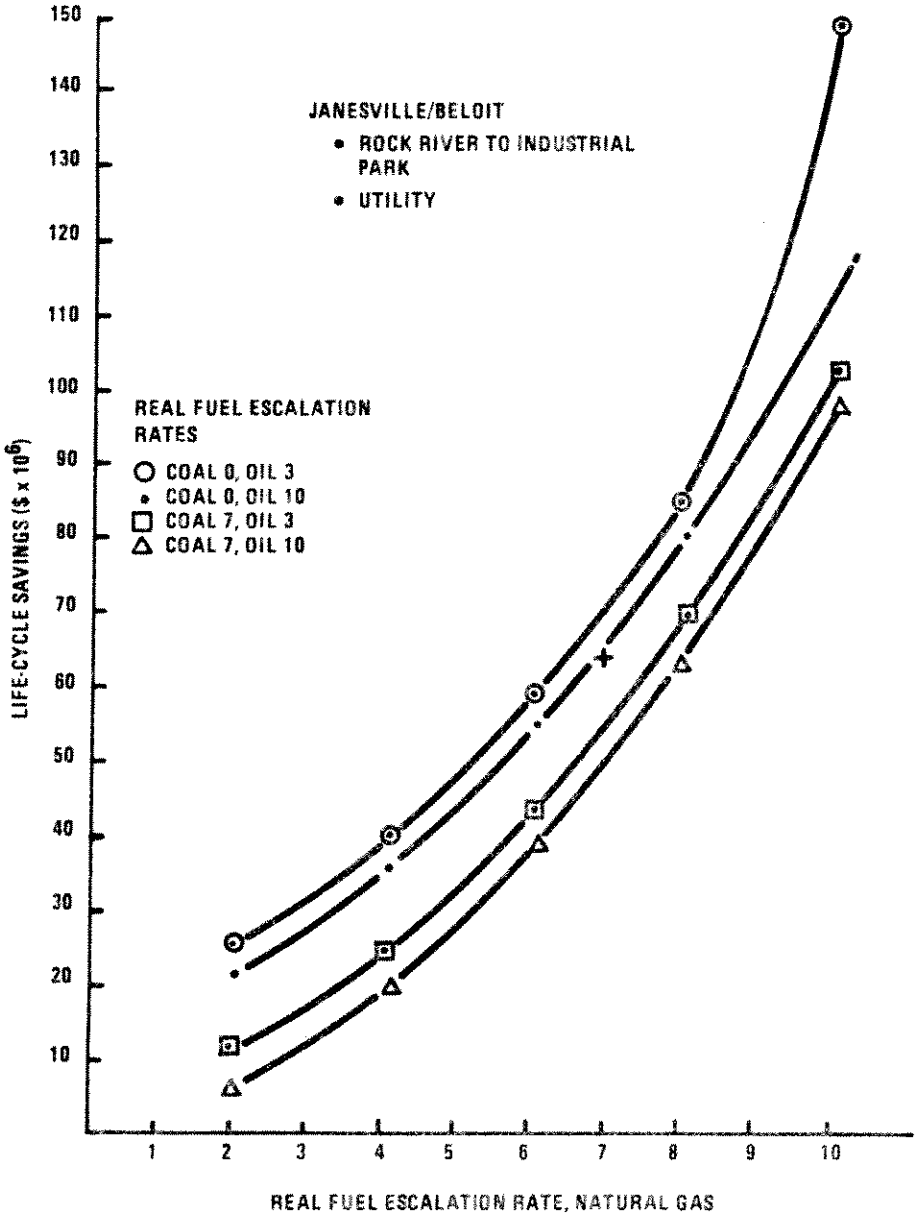

Figure G-12. Life-Cycle Savings versus Real Fuel Escalation Rates

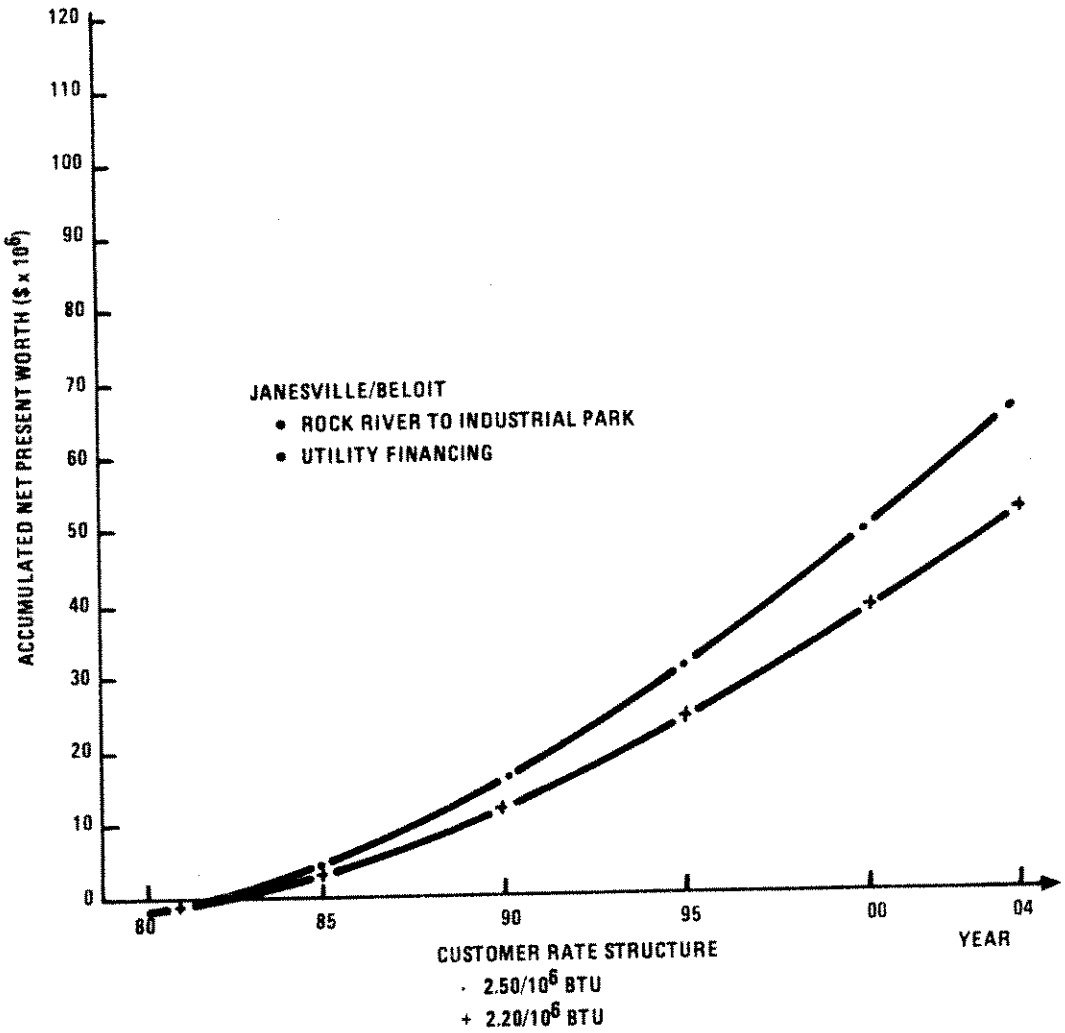

Figure G-13. Accumulated Net Present Worth versus Year

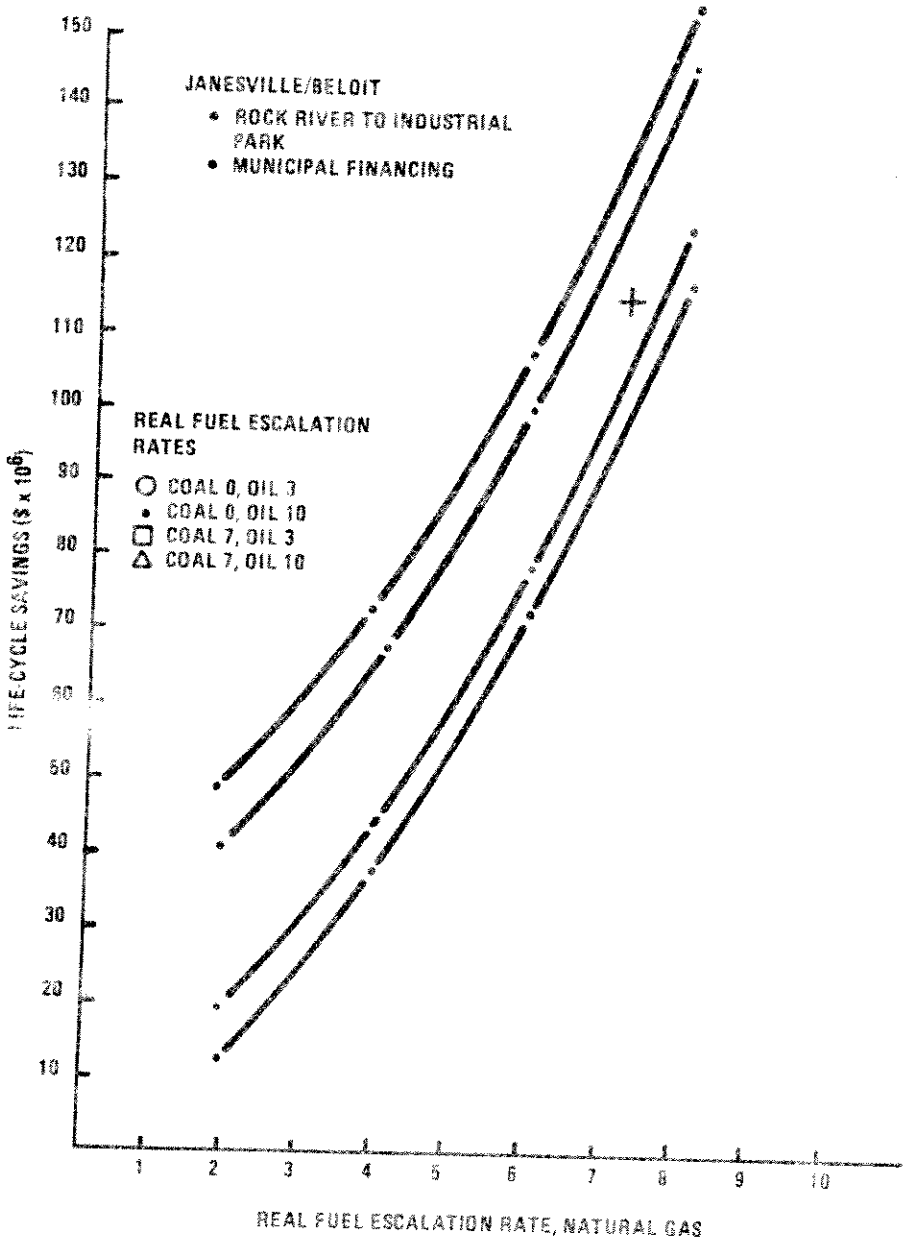

Figure G-14. Life-Cycle Savings versus Fuel and Escalation Rate, Natural Gas

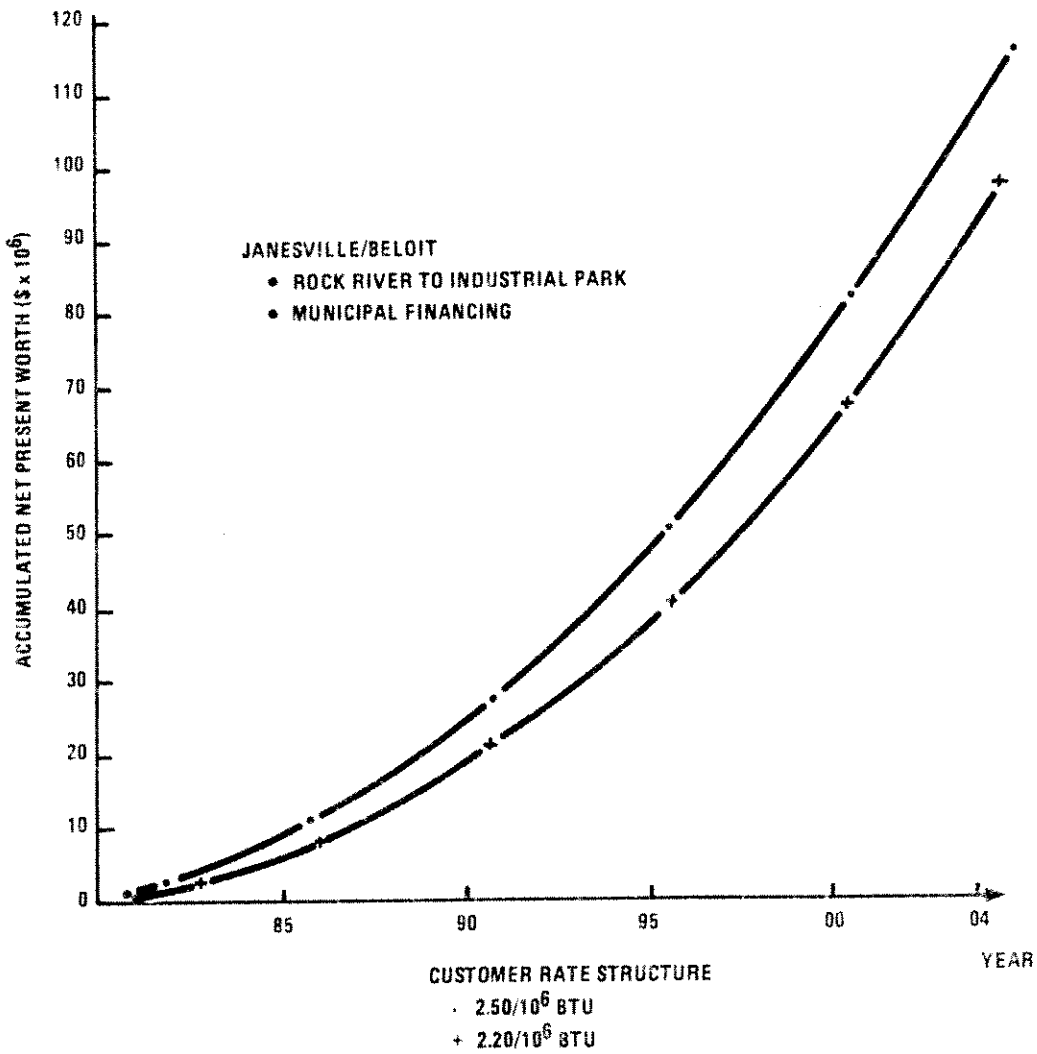

Figure G-15. Accumulated Net Present Worth versus Year

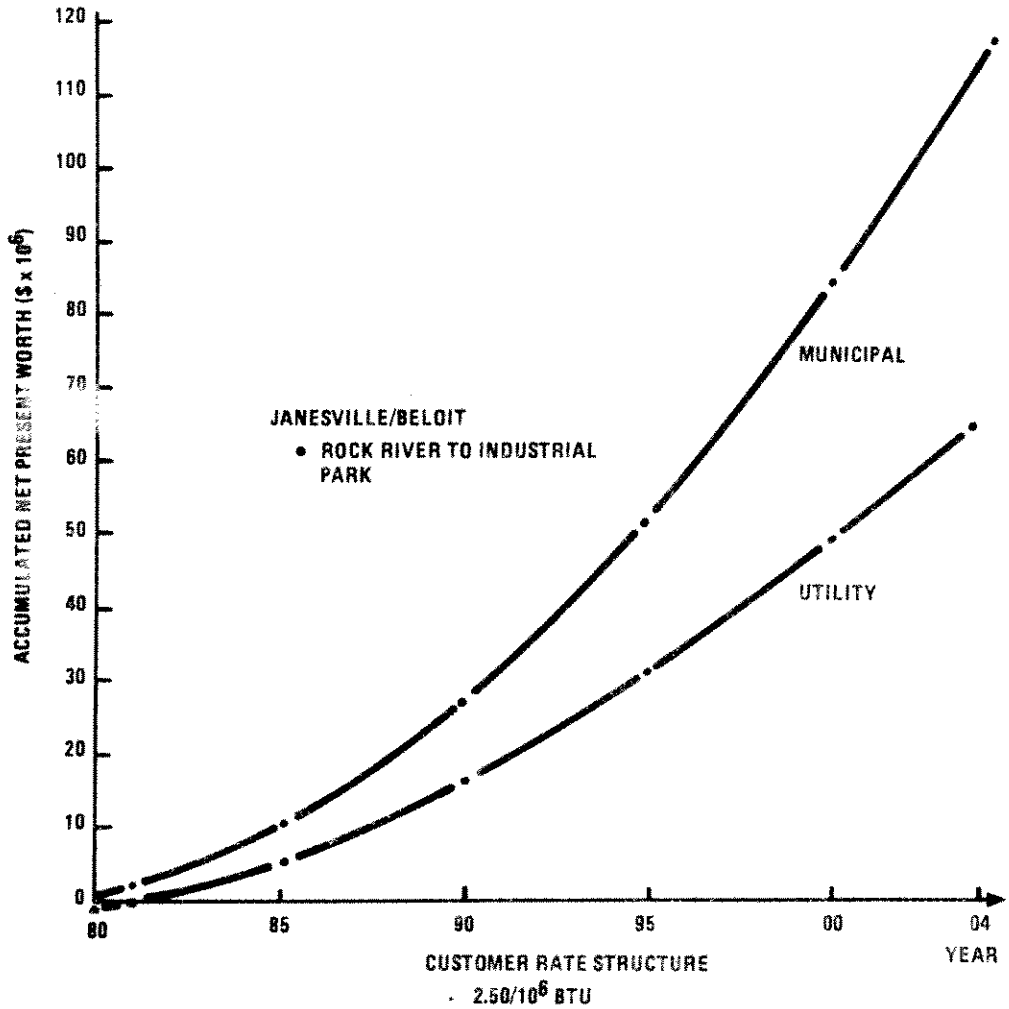

Figure G-16. Accumulated Net Present Worth versus Year

Table G-42. Operations and Maintenance Data (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative

Year	Maintenance 1% of Cost (1% of 5,200)	Insurance .2% of Costs (.2% of 5,200)	Operation 1.235×10^6 kWh/yr at .03 kWh	Total O&M for Distribution	Plant O&M Costs	Total O&M
1980	52	10	37	99	193	292
1981	56	11	40	97	186	283
1982	60	11	42	113	213	226
1983	64	12	45	121	314	435
1984	68	13	49	130	385	515
1985	73	14	52	139	396	535
1986	78	15	56	149	426	575
1987	84	16	59	159	434	593
1988	89	17	64	170	460	630
1989	96	18	68	182	501	783
1990	102	20	73	195	526	721
1991	109	21	78	208	564	772
1992	117	23	83	223	603	826
1993	125	24	89	238	645	883
1994	134	26	95	255	690	945
1995	143	28	102	273	738	1011
1996	154	30	109	293	790	1083
1997	164	32	117	313	845	1158
1998	176	34	125	335	905	1240
1999	188	36	134	358	967	1325
2000	201	39	143	383	1035	1418
2001	215	41	153	409	1107	1516
2002	230	44	164	438	1185	1623
2003	247	47	175	469	1268	1737
2004	264	51	188	503	1357	1860

79130

Table G-43. Return Requirements (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Utility Financing Option

YEAR	CAPITAL COST COMPONENTS: EQUITY RETURN: COMMON	EQUITY RETURN: PREFERRED	DEBT RETURN	INCOME TAX	REVENUE REQUIREMENTS
1978	0.0	0.0	0.0	0.0	0.0
1979	213.5	34.4	141.4	-559.1	615.6
1980	408.6	65.5	268.9	326.2	1571.1
1981	386.9	61.7	253.4	314.9	1495.3
1982	365.9	58.1	238.5	299.4	1422.9
1983	345.4	54.6	224.0	284.7	1352.1
1984	325.5	51.1	210.0	270.5	1283.1
1985	306.1	47.8	196.3	257.0	1216.1
1986	287.2	44.6	183.1	244.1	1151.0
1987	268.9	41.5	170.4	231.9	1087.9
1988	251.1	38.5	158.0	220.3	1026.7
1989	233.8	35.6	146.1	209.4	967.5
1990	217.1	32.8	134.7	199.1	910.2
1991	200.9	30.1	123.6	189.4	854.8
1992	185.3	27.5	113.0	180.4	801.4
1993	170.1	25.0	102.8	172.0	749.9
1994	155.5	22.7	93.1	164.2	700.4
1995	141.5	20.4	83.8	157.1	652.8
1996	128.0	18.2	74.9	150.6	607.1
1997	115.0	16.2	66.4	144.8	563.4
1998	102.5	14.2	58.4	139.6	521.6
1999	90.6	12.4	50.8	135.0	481.8
2000	79.2	10.6	43.7	131.1	443.9
2001	68.4	9.0	36.9	127.6	407.9
2002	58.0	7.5	30.6	125.2	373.9
2003	48.2	6.0	24.7	120.3	341.5
2004	38.7	4.6	19.1	115.8	310.5

Table G-43. Return Requirements (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Utility Financing Option (Concluded)

ACCUMULATED	VALUE 12TH MONTH 1979	ACCUMULATED	YEAR
0.0	0.0	0.0	1978
615.6	615.6	615.6	1979
2186.7	1407.6	2023.1	1980
3662.5	1200.6	3723.7	1981
5105.4	1023.2	4246.9	1982
6457.5	871.0	5117.9	1983
7740.6	740.6	5858.5	1984
8956.7	628.8	6467.3	1985
10107.8	533.2	7020.5	1986
11195.7	451.5	7472.0	1987
12222.4	381.7	7853.8	1988
13189.9	322.3	8176.0	1989
14100.1	271.6	8447.6	1990
14954.9	228.5	8676.2	1991
15756.3	192.0	8868.1	1992
16506.2	160.9	9029.1	1993
17206.6	134.6	9163.7	1994
17859.3	112.4	9276.1	1995
18466.4	93.7	9369.8	1996
19029.8	77.9	9447.7	1997
19551.4	64.6	9512.3	1998
20033.2	53.5	9565.8	1999
20477.1	44.1	9609.9	2000
20885.0	36.3	9646.2	2001
21258.8	29.8	9676.1	2002
21600.4	24.4	9700.5	2003
21910.9	19.9	9720.4	2004

Table G-44. Return Requirement (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Municipal Financing Option

Capital Costs $6,700,000

Book Life 31 years

Depreciation Method: Straight Line

Bond Rate: 8%

Discount Rate: 8%

Year	Book Dep	Net Book Dep	Invest	Ret Req	Total Ret	PU	Acc PU
1980	216.	0.	6700.	536.	752.	696.	696.
1981	216.	216.	6484.	519.	735.	630.	1326.
1982	216.	432.	6268.	501.	718.	570.	1896.
1983	216.	648.	6052.	484.	700.	515.	2411.
1984	216.	865.	5835.	467.	683.	465.	2876.
1985	216.	1081.	5619.	450.	666.	419.	3295.
1986	216.	1297.	5403.	432.	648.	378.	3673.
1987	216.	1513.	5187.	415.	631.	341.	4014.
1988	216.	1729.	4971.	398.	614.	307.	4321.
1989	216.	1945.	4755.	380.	597.	276.	4598.
1990	216.	2161.	4539.	363.	579.	248.	4846.
1991	216.	2377.	4323.	346.	562.	223.	5069.
1992	216.	2594.	4106.	329.	545.	200.	5270.
1993	216.	2810.	3890.	311.	527.	180.	5449.
1994	216.	3026.	3674.	294.	510.	161.	5610.
1995	216.	3242.	3458.	277.	493.	144.	5754.
1996	216.	3458.	3242.	259.	475.	129.	5882.
1997	216.	3674.	3026.	242.	458.	115.	5997.
1998	216.	3890.	2810.	225.	441.	102.	6099.
1999	216.	4106.	2594.	207.	424.	91.	6190.
2000	216.	4323.	2377.	190.	406.	81.	6271.
2001	216.	4539.	2161.	173.	389.	72.	6342.
2002	216.	4755.	1945.	156.	372.	63.	6406.
2003	216.	4971.	1729.	138.	354.	56.	6461.
2004	216.	5187.	1513.	121.	337.	49.	6511.

Table G-45. Fuel/O & M Data (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Municipal Financing Option

COAL COST = 1.58/10-6 BTU
OIL COST = 2.67/10-6 BTU
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 8.00%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	1312.	27.	1339.	292.	1631.	1510.	1510.
1981	1184.	69.	1253.	283.	1536.	1317.	2826.
1982	1301.	81.	1381.	226.	1607.	1276.	4102.
1983	1326.	102.	1428.	435.	1863.	1369.	5472.
1984	1448.	113.	1561.	515.	2076.	1413.	6885.
1985	1421.	191.	1612.	535.	2147.	1353.	8238.
1986	1427.	340.	1767.	575.	2342.	1367.	9605.
1987	1981.	415.	2396.	593.	2989.	1615.	11220.
1988	2243.	599.	2842.	630.	3472.	1737.	12957.
1989	2400.	537.	2937.	783.	3780.	1751.	14707.
1990	2878.	442.	3320.	721.	4041.	1733.	16441.
1991	3135.	451.	3586.	772.	4358.	1770.	18211.
1992	3546.	546.	4092.	826.	4918.	1808.	20019.
1993	3936.	606.	4543.	883.	5426.	1847.	21866.
1994	4369.	673.	5043.	945.	5988.	1888.	23754.
1995	4850.	748.	5598.	1011.	6609.	1929.	25683.
1996	5384.	831.	6215.	1083.	7298.	1972.	27656.
1997	5976.	923.	6899.	1158.	8057.	2016.	29672.
1998	6633.	1026.	7659.	1240.	8899.	2062.	31734.
1999	7363.	1140.	8503.	1325.	9828.	2108.	33842.
2000	8173.	1266.	9439.	1418.	10857.	2157.	35999.
2001	9072.	1407.	10479.	1516.	11995.	2206.	38205.
2002	10070.	1563.	11633.	1623.	13256.	2256.	40463.
2003	11177.	1736.	12914.	1737.	14651.	2310.	42773.
2004	12407.	1929.	14336.	1860.	16196.	2365.	45138.

Table G-46. Fuel/O & M Data (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Utility Financing Option

COAL COST = 1.58/10-6 BTU
OIL COST = 2.67/10-6 BTU
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 11.62%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	1312.	27.	1339.	292.	1631.	1461.	1461.
1981	1184.	69.	1253.	283.	1536.	1233.	2693.
1982	1301.	81.	1381.	226.	1607.	1156.	3849.
1983	1326.	102.	1428.	435.	1863.	1200.	5050.
1984	1448.	113.	1561.	515.	2076.	1198.	6248.
1985	1421.	191.	1612.	535.	2147.	1110.	7358.
1986	1427.	340.	1767.	575.	2342.	1085.	8443.
1987	1981.	415.	2396.	593.	2989.	1240.	9684.
1988	2243.	599.	2842.	630.	3472.	1291.	10975.
1989	2400.	597.	2997.	783.	3780.	1259.	12234.
1990	2878.	442.	3320.	721.	4041.	1206.	13440.
1991	3195.	491.	3686.	772.	4458.	1192.	14632.
1992	3546.	546.	4092.	826.	4918.	1178.	15810.
1993	3936.	606.	4543.	883.	5426.	1164.	16974.
1994	4369.	673.	5043.	945.	5988.	1151.	18125.
1995	4850.	748.	5598.	1011.	6609.	1138.	19263.
1996	5384.	831.	6215.	1083.	7298.	1126.	20390.
1997	5976.	923.	6899.	1158.	8057.	1114.	21503.
1998	6633.	1026.	7659.	1240.	8899.	1102.	22606.
1999	7363.	1140.	8503.	1325.	9828.	1090.	23696.
2000	8173.	1266.	9439.	1418.	10857.	1079.	24775.
2001	9072.	1407.	10479.	1516.	11995.	1068.	25843.
2002	10070.	1563.	11633.	1623.	13256.	1058.	26901.
2003	11177.	1736.	12914.	1737.	14651.	1047.	27948.
2004	12407.	1929.	14336.	1860.	16196.	1037.	28985.

Table G-47. Gross Income Data (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Utility Financing Option

DISCOUNT RATE = 11.62%
FUEL QUANTITY = 1234.80/10-9 BTU/YR
FUEL COST = 2.20/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV
1980	3097.	2774.	2774.
1981	3530.	2834.	5608.
1982	4025.	2894.	8502.
1983	4588.	2956.	11458.
1984	5231.	3019.	14477.
1985	5963.	3083.	17560.
1986	6798.	3149.	20709.
1987	7749.	3216.	23925.
1988	8834.	3285.	27209.
1989	10071.	3355.	30564.
1990	11481.	3426.	33990.
1991	13088.	3499.	37490.
1992	14920.	3574.	41063.
1993	17009.	3650.	44713.
1994	19391.	3728.	48441.
1995	22105.	3807.	52249.
1996	25200.	3889.	56137.
1997	28728.	3971.	60109.
1998	32750.	4056.	64165.
1999	37335.	4143.	68307.
2000	42562.	4231.	72538.
2001	48521.	4321.	76860.
2002	55313.	4413.	81273.
2003	[illegible]	4507.	85780.
2004	71885.	4604.	90384.

DISCOUNT RATE = 11.62%
FUEL QUANTITY = 1234.80/10-9 BTU/YR
FUEL COST = 2.50/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV
1980	3519.	3153.	3153.
1981	4012.	3220.	6373.
1982	4574.	3289.	9662.
1983	5214.	3359.	13020.
1984	5944.	3430.	16451.
1985	6776.	3504.	19954.
1986	7725.	3578.	23533.
1987	8806.	3655.	27187.
1988	10039.	3733.	30920.
1989	11444.	3812.	34732.
1990	13046.	3893.	38625.
1991	14873.	3976.	42602.
1992	16955.	4061.	46663.
1993	19329.	4148.	50811.
1994	22035.	4236.	55047.
1995	25120.	4327.	59374.
1996	28636.	4419.	63792.
1997	32646.	4513.	68305.
1998	37216.	4609.	72915.
1999	42426.	4708.	77622.
2000	48366.	4808.	82430.
2001	55137.	4910.	87340.
2002	62856.	5015.	92356.
2003	71656.	5122.	97478.
2004	81688.	5231.	102709.

Table G-48. Gross Income Data (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Municipal Financing Option

DISCOUNT RATE = 8.00%
FUEL QUANTITY = 1234.80/10-9 BTU/YR
FUEL COST = 2.50/10-6 $TU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV	YEAR	INCOME	PV	ACC PV
1980	3519.	3259.	3259.	1980	3097.	2867.	2867.
1981	4012.	3440.	6698.	1981	3530.	3027.	5894.
1982	4574.	3631.	10329.	1982	4025.	3195.	9089.
1983	5214.	3832.	14161.	1983	4588.	3372.	12462.
1984	5944.	4045.	18206.	1984	5231.	3560.	16021.
1985	6776.	4270.	22476.	1985	5963.	3758.	19779.
1986	7725.	4507.	26983.	1986	6798.	3966.	23745.
1987	8806.	4758.	31741.	1987	7749.	4187.	27932.
1988	10039.	5022.	36763.	1988	8834.	4419.	32351.
1989	11444.	5301.	42064.	1989	10071.	4665.	37016.
1990	13046.	5595.	47659.	1990	11481.	4924.	41940.
1991	14873.	5906.	53565.	1991	13088.	5197.	47137.
1992	16955.	6234.	59800.	1992	14920.	5486.	52624.
1993	19329.	6581.	66380.	1993	17009.	5791.	58415.
1994	22035.	6946.	73327.	1994	19391.	6113.	64527.
1995	25120.	7332.	80659.	1995	22105.	6452.	70980.
1996	28636.	7740.	88398.	1996	25200.	6811.	77791.
1997	32646.	8170.	96568.	1997	28728.	7189.	84980.
1998	37216.	8623.	105191.	1998	32750.	7589.	92568.
1999	42426.	9102.	114294.	1999	37335.	8010.	100578.
2000	48366.	9608.	123902.	2000	42562.	8455.	109034.
2001	55137.	10142.	134044.	2001	48521.	8925.	117958.
2002	62856.	10705.	144749.	2002	55313.	9421.	127379.
2003	71656.	11300.	156049.	2003	63057.	9944.	137323.
2004	81684.	11928.	167977.	2004	71885.	10497.	147820.

Table G-49. Annual Savings (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Municipal Financing Option

GROSS INCOME	MUNICIPAL REV. REQ.	FUEL/O & M	TOTAL RETURN	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
87191 AT 9% 112360 AT 11% 146512 AT 13% 193060 AT 15% 256716 AT 17%	6511	31644	38155	49036 74205 108357 154905 218561	C - 0 O - 3
87191 AT 9% 112360 AT 11% 146512 AT 13% 193060 AT 15% 256716 AT 17%		38838	45349	41842 67011 101163 147711 210878	C - 0 O - 10
87191 AT 9% 112360 AT 11% 146512 AT 13% 193060 AT 15% 256716 AT 17%		60764	67275	19916 45085 79237 125785 189441	C - 7 O - 3
87191 AT 9% 112360 AT 11% 146512 AT 13% 193060 AT 15% 256716 AT 17%		67958	74469	12722 37891 72043 118591 182247	C - 7 O - 10
167977 147820		45138	51649	116328 96171	C - 4 O - 4.1 NG - 7

Table G-50. Annual Savings (x 1000), Janesville/Beloit, Rock River to Industrial Park Alternative, Utility Financing Option

GROSS INCOME	UTILITY REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
57503 AT 9% 71842 AT 11% 90898 AT 13% 116387 AT 15% 150656 AT 17%	9720	21262	26521 40860 59916 85405 150656	C - 0 O - 3
57503 AT 9% 71842 AT 11% 90898 AT 13% 116387 AT 15% 150656 AT 17%		25207	22576 36915 55971 81460 115729	C - 0 O - 10
57503 AT 9% 71842 AT 11% 90898 AT 13% 116387 AT 15% 150656 AT 17%		37619	10164 24503 43559 69048 103317	C - 7 O - 3
57503 AT 9% 71842 AT 11% 90898 AT 13% 116387 AT 15% 150656 AT 17%		41563	6220 20559 39615 65104 99373	C - 7 O - 10
102709 90384 78059		28985	64004 51679 39354	C - 4 O - 4 NG - 7

JANESVILLE/BELOIT, BLACK HAWK TO BELOIT

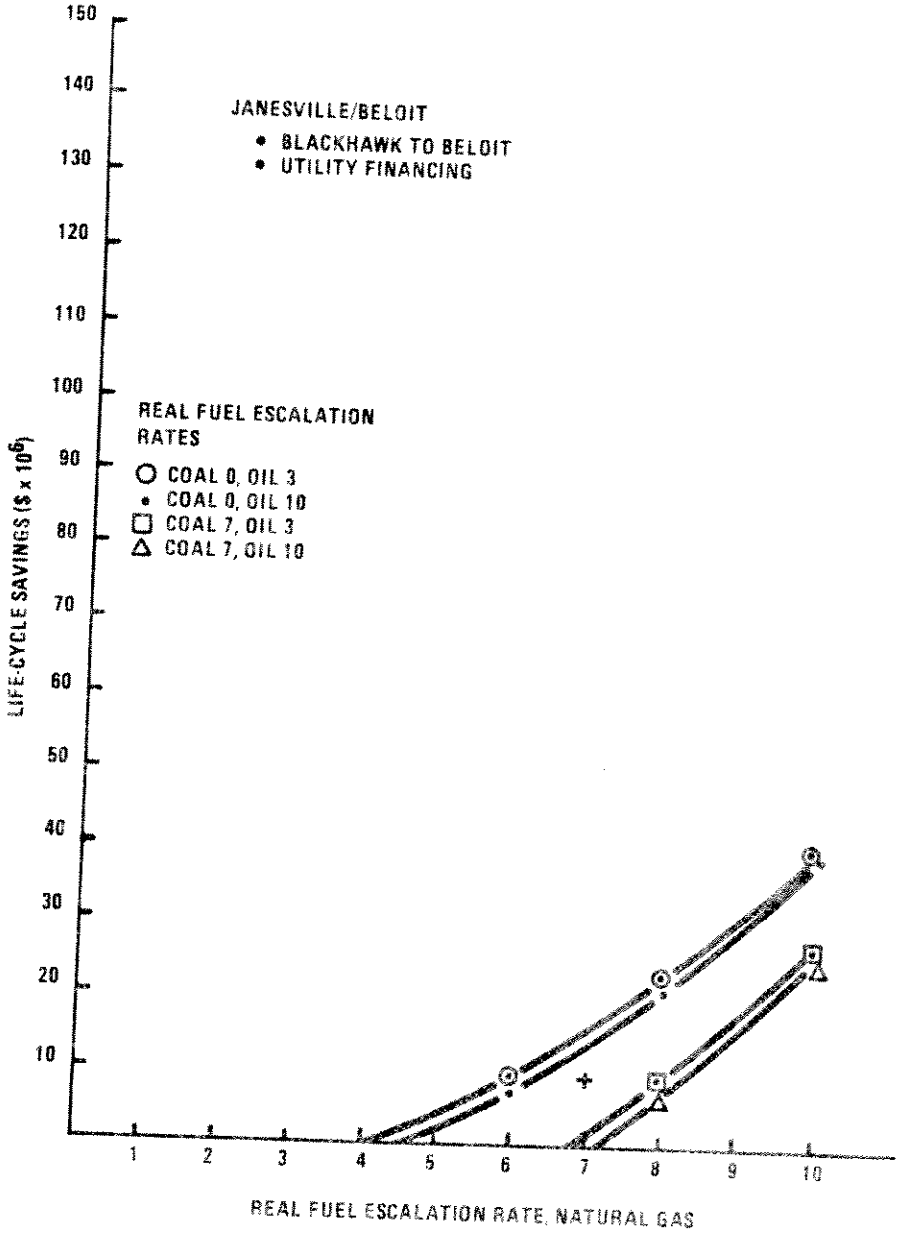

Figure G-17. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

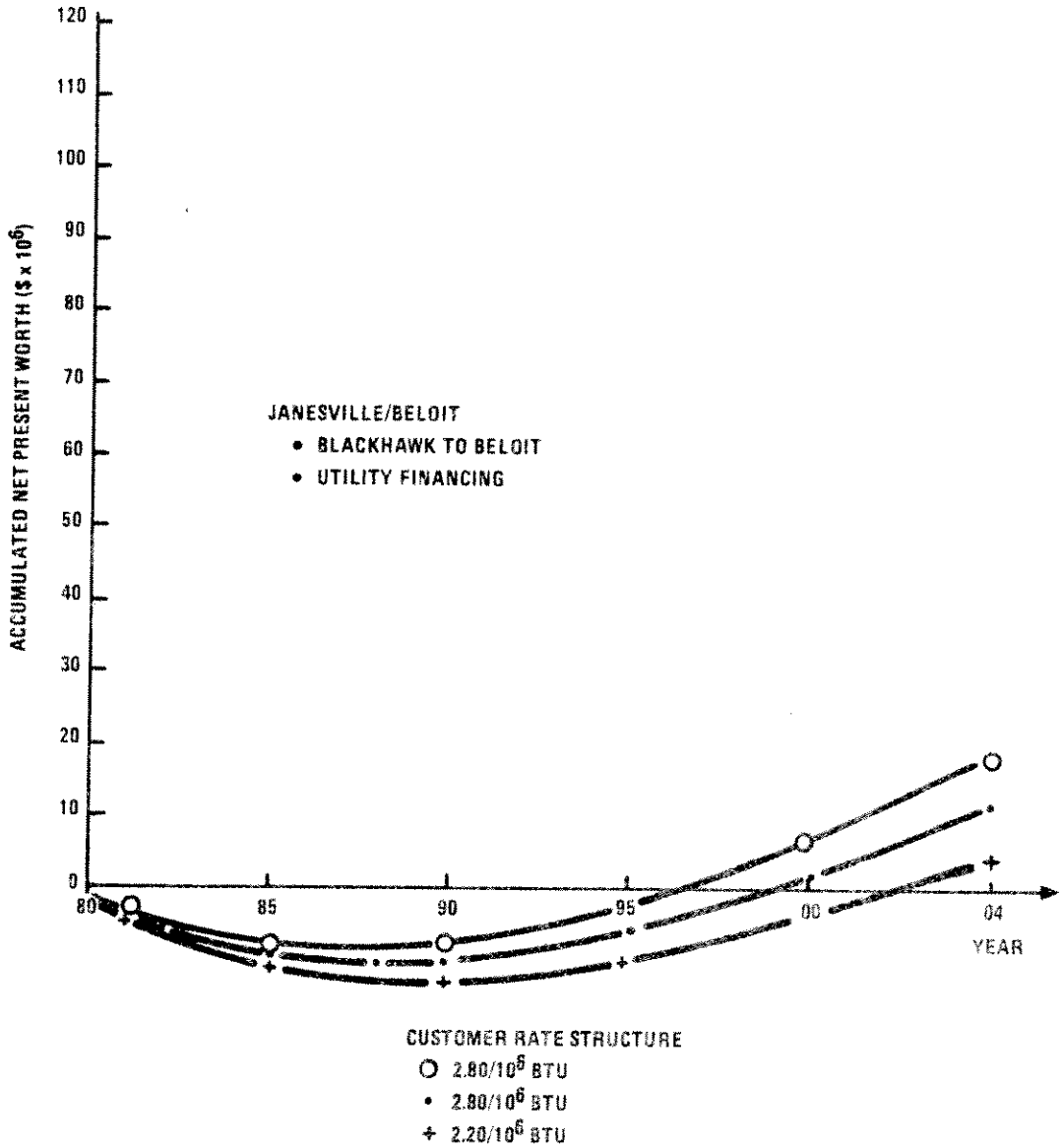

Figure G-18. Accumulated Net Present Worth versus Year

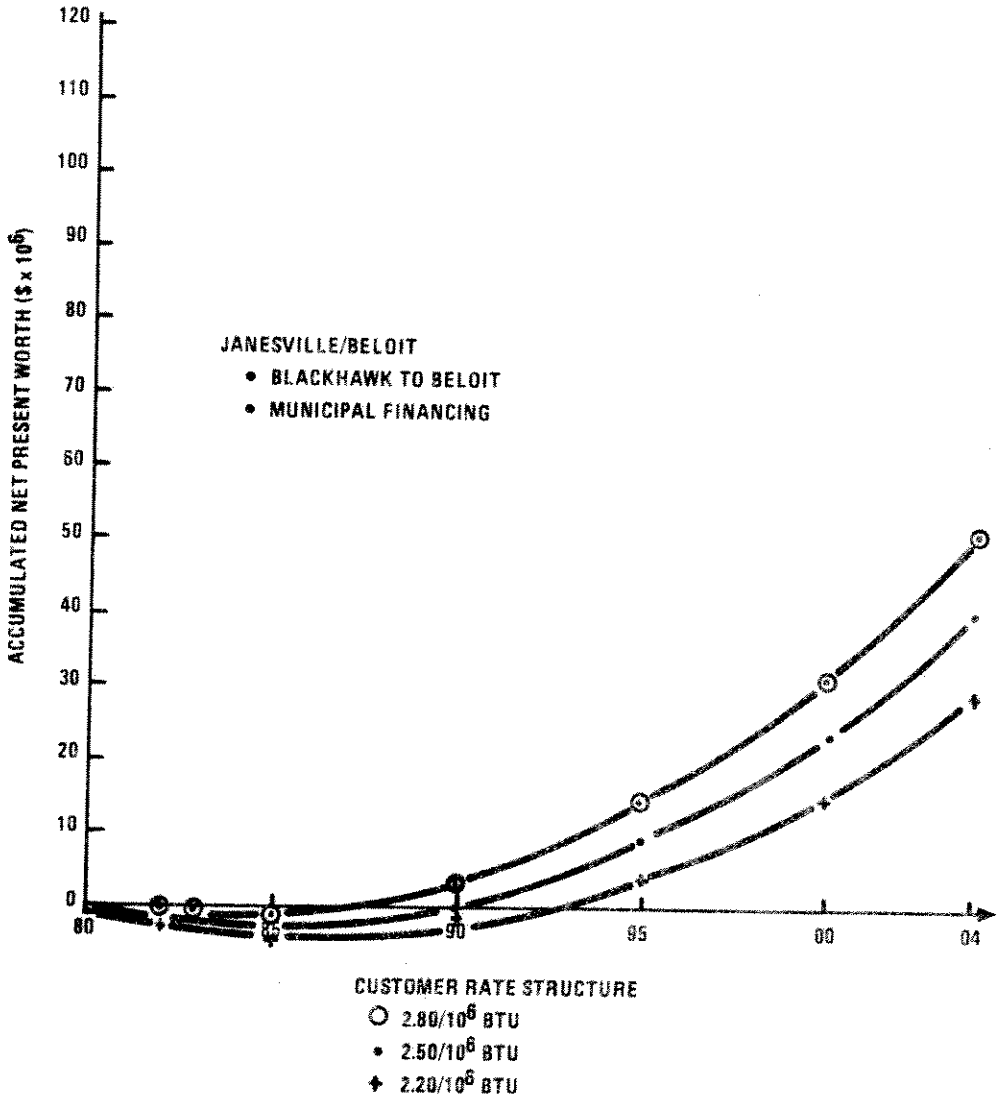

Figure G-19. Accumulated Net Present Worth versus Year

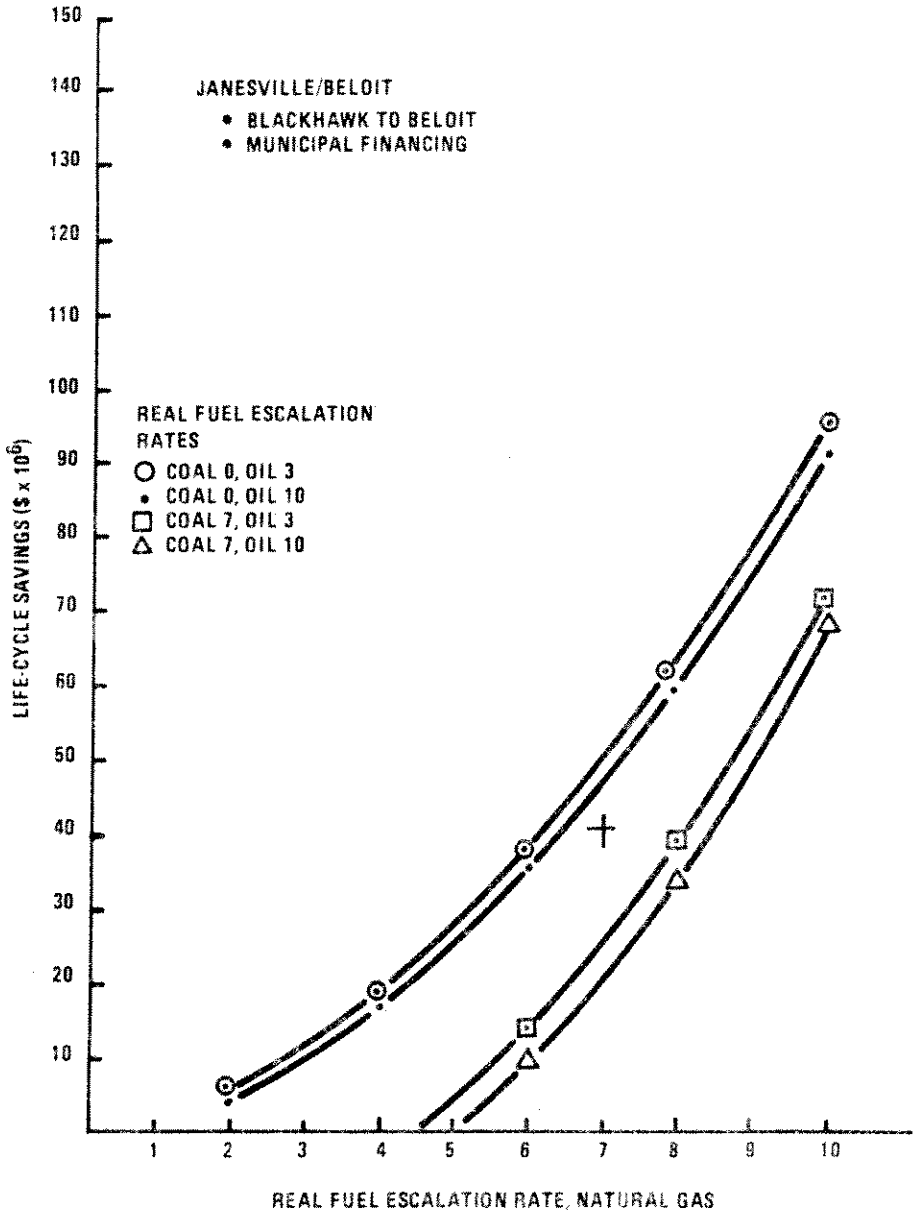

Figure G-20. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

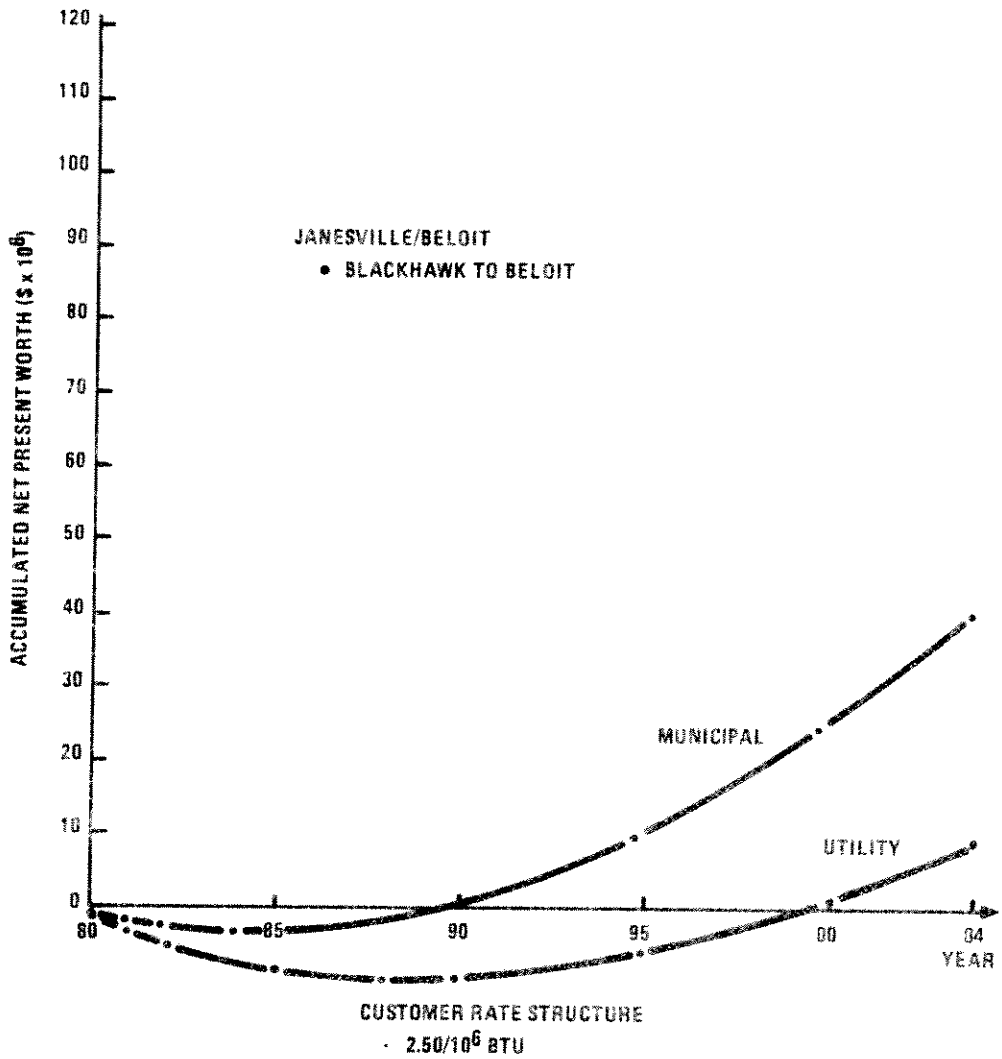

Figure G-21. Accumulated Net Present Worth versus Year

Table G-51. Operations and Maintenance Data (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative

Year	Maintenance 1% of Cost (1% of 14,300)	Insurance .2% of Costs (.2% of 14,300)	Operation $.227 \times 10^6$ kWh/yr at .03 kWh	Total O&M for Distribution	Plant O&M Costs	Total O&M
1980	143	23	7	173	123	296
1981	153	25	7	185	109	294
1982	164	26	8	198	117	315
1983	175	28	9	212	131	343
1984	187	30	9	226	151	377
1985	201	32	10	243	149	392
1986	215	35	11	261	170	431
1987	230	37	11	285	177	462
1988	246	40	12	298	195	493
1989	263	42	13	318	201	519
1990	281	45	14	340	202	542
1991	301	48	14	363	216	579
1992	322	52	16	390	231	621
1993	345	55	17	417	248	665
1994	369	59	18	446	264	710
1995	395	63	19	477	283	760
1996	422	68	21	511	303	814
1997	452	73	22	547	325	872
1998	483	78	24	585	347	932
1999	517	83	25	625	371	996
2000	553	89	27	669	397	1066
2001	592	95	29	716	425	1141
2002	634	102	31	767	455	1222
2003	678	109	33	820	487	1307
2004	725	117	36	878	521	1399

Table G-52. Return Requirements (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative, Municipal Financing Option

Capital Cost $15,800,000

Book Life 31 years

Depreciation Method: Straight Line

Bond Rate 8%

Discount Rate 8%

Year	Book Dep	Net Dep	Invest	Ret Req	Total Return	PV	Acc PV
1980	510.	0.	15800.	1264.	1774.	1642.	1642.
1981	510.	510.	15290.	1223.	1733.	1486.	3128.
1982	510.	1019.	14781.	1182.	1692.	1343.	4471.
1983	510.	1529.	14271.	1142.	1651.	1214.	5685.
1984	510.	2039.	13761.	1101.	1611.	1096.	6781.
1985	510.	2548.	13252.	1060.	1570.	989.	7770.
1986	510.	3058.	12742.	1019.	1529.	892.	8663.
1987	510.	3566.	12232.	979.	1488.	804.	9467.
1988	510.	4077.	11723.	938.	1447.	724.	10191.
1989	510.	4587.	11213.	897.	1407.	652.	10842.
1990	510.	5097.	10703.	856.	1366.	586.	11428.
1991	510.	5606.	10194.	815.	1325.	526.	11954.
1992	510.	6116.	9684.	775.	1284.	472.	12427.
1993	510.	6626.	9174.	734.	1244.	423.	12850.
1994	510.	7135.	8665.	693.	1203.	379.	13229.
1995	510.	7645.	8155.	652.	1162.	339.	13568.
1996	510.	8155.	7645.	612.	1121.	303.	13872.
1997	510.	8665.	7135.	571.	1081.	270.	14142.
1998	510.	9174.	6626.	530.	1040.	241.	14383.
1999	510.	9684.	6116.	489.	999.	214.	14597.
2000	510.	10194.	5606.	449.	958.	190.	14787.
2001	510.	10703.	5097.	408.	917.	169.	14956.
2002	510.	11213.	4587.	367.	877.	149.	15106.
2003	510.	11723.	4077.	326.	836.	132.	15237.
2004	510.	12232.	3568.	285.	795.	116.	15353.

Table G-53. Return Requirements (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative, Utility Financing Option

YEAR	CAPITAL COST COMPONENTS: EQUITY RETURN: COMMON	EQUITY RETURN: PREFERRED	DEBT RETURN	INCOME TAX	REVENUE REQUIREMENTS
1978	228.2	36.7	150.6	-450.2	680.3
1979	731.6	117.9	487.9	-329.7	2310.6
1980	964.5	154.6	634.9	789.9	3714.7
1981	914.0	145.0	598.9	762.0	3539.6
1982	865.1	137.4	564.2	725.0	3370.0
1983	817.3	129.2	530.5	689.5	3204.9
1984	770.8	121.2	497.7	655.3	3043.8
1985	725.4	113.5	465.8	622.6	2887.2
1986	681.2	106.0	435.0	591.2	2734.8
1987	638.2	98.7	405.0	561.3	2586.7
1988	596.3	91.6	376.0	532.8	2442.9
1989	555.7	84.8	348.0	505.7	2303.5
1990	516.2	78.2	320.9	480.0	2168.3
1991	477.6	71.8	294.8	455.9	2037.4
1992	440.8	65.7	269.7	432.9	1910.8
1993	404.9	59.8	245.5	411.5	1788.5
1994	370.1	54.1	222.2	391.5	1670.4
1995	336.6	48.7	199.9	372.9	1556.7
1996	304.2	43.5	178.6	355.7	1447.3
1997	272.9	38.5	158.2	339.9	1342.2
1998	243.0	33.8	138.7	325.6	1241.2
1999	214.2	29.3	120.3	312.6	1144.9
2000	186.5	25.0	102.7	301.1	1052.6
2001	160.1	21.0	86.2	291.0	964.6
2002	134.3	17.2	70.5	282.3	880.9
2003	110.6	13.6	55.8	272.1	801.3
2004	87.5	10.2	41.9	263.1	725.4

Table G-53. Return Requirements (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative, Utility Financing (concluded)

ACCUMULATED	VALUE 12TH MONTH 1979	ACCUMULATED	YEAR
680.3	759.3	759.3	1978
2990.9	2310.6	3069.9	1979
6705.6	3328.0	6397.9	1980
10245.2	2841.0	9238.9	1981
13615.2	2423.3	11662.2	1982
16820.0	2064.6	13726.8	1983
19863.8	1756.7	15483.5	1984
22751.0	1492.9	16976.4	1985
25485.8	1266.9	18243.3	1986
28072.5	1073.5	19316.8	1987
30515.4	908.3	20225.1	1988
32818.9	767.3	20992.4	1989
34987.2	647.1	21639.5	1990
37024.5	544.7	22184.2	1991
38935.3	457.7	22641.9	1992
40723.8	383.8	23025.6	1993
42394.2	321.1	23346.8	1994
43951.0	268.1	23614.9	1995
45398.3	223.3	23838.2	1996
46740.4	185.5	24023.8	1997
47981.8	153.7	24177.5	1998
49126.6	127.0	24304.6	1999
50179.1	104.6	24409.2	2000
51143.7	85.9	24495.1	2001
52024.7	70.3	24565.4	2002
52826.0	57.3	24622.7	2003
53551.4	46.5	24669.1	2004

Table G-54. Fuel/O & M Data (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative, Utility Financing Option

COAL COST = 1.58/10-6 BTU
OIL COST = 2.67/10-6 BTU
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 11.62%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	1152.	24.	1176.	296.	1472.	1319.	1319.
1981	1078.	46.	1125.	294.	1419.	1139.	2457.
1982	1098.	59.	1156.	315.	1471.	1058.	3515.
1983	1341.	77.	1418.	343.	1761.	1135.	4650.
1984	1392.	108.	1501.	377.	1878.	1084.	5734.
1985	1362.	166.	1528.	392.	1920.	993.	6726.
1986	1361.	324.	1685.	431.	2116.	980.	7707.
1987	1799.	260.	2059.	462.	2521.	1046.	8753.
1988	2025.	331.	2355.	493.	2848.	1059.	9812.
1989	2086.	367.	2453.	519.	2972.	990.	10802.
1990	2465.	127.	2592.	542.	3134.	935.	11737.
1991	2736.	142.	2878.	579.	3457.	924.	12662.
1992	3037.	157.	3194.	621.	3815.	914.	13576.
1993	3371.	175.	3546.	665.	4211.	904.	14479.
1994	3742.	194.	3936.	710.	4646.	893.	15372.
1995	4154.	216.	4369.	760.	5129.	883.	16256.
1996	4611.	240.	4850.	814.	5664.	874.	17130.
1997	5118.	266.	5384.	872.	6256.	865.	17995.
1998	5681.	296.	5977.	932.	6909.	856.	18851.
1999	6306.	329.	6634.	996.	7630.	847.	19697.
2000	6999.	365.	7364.	1066.	8430.	838.	20535.
2001	7769.	406.	8175.	1141.	9316.	830.	21365.
2002	8624.	451.	9074.	1222.	10296.	822.	22186.
2003	9572.	501.	10073.	1307.	11380.	813.	23000.
2004	10625.	556.	11182.	1399.	12581.	806.	23806.

Table G-55. Fuel/O & M Data (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative, Municipal Financing Option

COAL COST = 1.58/10-6 BTU
OIL COST = 2.67/10-6 BTU
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 8.00%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	1152.	24.	1176.	296.	1472.	1363.	1363.
1981	1078.	46.	1125.	294.	1419.	1216.	2579.
1982	1098.	59.	1156.	315.	1471.	1168.	3747.
1983	1341.	77.	1418.	343.	1761.	1294.	5042.
1984	1392.	108.	1501.	377.	1878.	1278.	6320.
1985	1362.	166.	1528.	392.	1920.	1210.	7530.
1986	1361.	324.	1685.	431.	2116.	1235.	8764.
1987	1799.	260.	2059.	462.	2521.	1362.	10126.
1988	2025.	331.	2355.	493.	2848.	1425.	11551.
1989	2086.	367.	2453.	519.	2972.	1377.	12928.
1990	2465.	127.	2592.	542.	3134.	1344.	14272.
1991	2736.	142.	2878.	579.	3457.	1373.	15645.
1992	3037.	157.	3194.	621.	3815.	1403.	17048.
1993	3371.	175.	3546.	665.	4211.	1434.	18482.
1994	3742.	194.	3936.	710.	4646.	1465.	19946.
1995	4154.	216.	4369.	760.	5129.	1497.	21444.
1996	4611.	240.	4850.	814.	5664.	1531.	22974.
1997	5118.	266.	5384.	872.	6256.	1566.	24540.
1998	5681.	296.	5977.	932.	6909.	1601.	26141.
1999	6306.	329.	6634.	996.	7630.	1637.	27778.
2000	6999.	365.	7364.	1066.	8430.	1675.	29453.
2001	7769.	406.	8175.	1141.	9316.	1714.	31166.
2002	8624.	451.	9074.	1222.	10296.	1754.	32920.
2003	9572.	501.	10073.	1307.	11380.	1795.	34714.
2004	10625.	556.	11182.	1399.	12581.	1837.	36551.

Table G-56. Gross Income Data (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative, Utility Financing Option

DISCOUNT RATE = 11.62%
FUEL QUANTITY = 670.41/10-9 BTU/YR
FUEL COST = 2.50/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV	YEAR	INCOME	PV	ACC PV
1980	1911.	1712.	1712.	1980	1681.	1506.	1506.
1981	2178.	1748.	3460.	1981	1917.	1538.	3045.
1982	2483.	1786.	5246.	1982	2185.	1571.	4616.
1983	2831.	1824.	7069.	1983	2491.	1605.	6221.
1984	3227.	1862.	8932.	1984	2840.	1639.	7860.
1985	3679.	1902.	10834.	1985	3237.	1674.	9534.
1986	4194.	1943.	12777.	1986	3691.	1710.	11243.
1987	4781.	1984.	14761.	1987	4207.	1746.	12990.
1988	5450.	2026.	16787.	1988	4796.	1783.	14773.
1989	6213.	2070.	18857.	1989	5468.	1821.	16594.
1990	7083.	2114.	20971.	1990	6233.	1860.	18454.
1991	8075.	2159.	23130.	1991	7106.	1900.	20354.
1992	9205.	2205.	25335.	1992	8101.	1940.	22295.
1993	10494.	2252.	27587.	1993	9235.	1982.	24276.
1994	11963.	2300.	29887.	1994	10528.	2024.	26300.
1995	13638.	2349.	32236.	1995	12000.	2067.	28367.
1996	15548.	2399.	34635.	1996	13682.	2111.	30479.
1997	17724.	2450.	37085.	1997	15597.	2156.	32635.
1998	20206.	2503.	39588.	1998	17781.	2202.	34837.
1999	23034.	2556.	42143.	1999	20270.	2249.	37086.
2000	26259.	2610.	44754.	2000	23108.	2297.	39383.
2001	29936.	2666.	47420.	2001	26343.	2346.	41729.
2002	34127.	2723.	50143.	2002	30031.	2396.	44126.
2003	38904.	2781.	52924.	2003	34236.	2447.	46573.
2004.	44351.	2840.	55764.	2004	39029.	2499.	49072.

Table G-57. Gross Income Data (x 1000), Janesville/Beloit, Blackhawk to Beloit, Municipal Financing Option

DISCOUNT RATE = 8.00%
FUEL QUANTITY = 670.41/10-9 BTU/YR
FUEL COST = 2.50/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV	YEAR	INCOME	PV	ACC PV
1980	1911.	1769.	1769.	1980	1681.	1557.	1557.
1981	2178.	1867.	3637.	1981	1917.	1643.	3200.
1982	2483.	1971.	5608.	1982	2185.	1735.	4935.
1983	2831.	2081.	7688.	1983	2491.	1831.	6766.
1984	3227.	2196.	9885.	1984	2840.	1933.	8699.
1985	3679.	2318.	12203.	1985	3237.	2040.	10739.
1986	4194.	2447.	14650.	1986	3691.	2153.	12892.
1987	4781.	2583.	17233.	1987	4207.	2273.	15165.
1988	5450.	2727.	19960.	1988	4796.	2399.	17564.
1989	6213.	2878.	22838.	1989	5468.	2533.	20097.
1990	7083.	3038.	25876.	1990	6233.	2673.	22770.
1991	8075.	3207.	29082.	1991	7106.	2822.	25592.
1992	9205.	3385.	32467.	1992	8101.	2979.	28571.
1993	10494.	3573.	36040.	1993	9235.	3144.	31715.
1994	11963.	3771.	39811.	1994	10528.	3319.	35034.
1995	13638.	3981.	43792.	1995	12002.	3503.	38537.
1996	15548.	4202.	47994.	1996	13682.	3698.	42235.
1997	17724.	4435.	52430.	1997	15597.	3903.	46138.
1998	20206.	4682.	57111.	1998	17781.	4120.	50258.
1999	23034.	4942.	62053.	1999	20270.	4349.	54607.
2000	26259.	5217.	67270.	2000	23108.	4591.	59198.
2001	29936.	5506.	72776.	2001	26343.	4846.	64043.
2002	34127.	5812.	78589.	2002	30031.	5115.	69158.
2003	38904.	6135.	84724.	2003	34236.	5399.	74557.
2004	44351.	6476.	91200.	2004	39029.	5699.	80256.

Table G-58. Annual Savings (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative, Utility Financing Option

GROSS INCOME	UTILITY RET. REQ.	FUEL/O & M	TOTAL RETURN	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
31223 AT 9% 39006 AT 11% 49351 AT 13% 63190 AT 15% 81795 AT 17%	22920	17290	40210	-8987 -1205 9141 22980 41585	C - 0 O - 3
31223 AT 9% 39005 AT 11% 49351 AT 13% 63190 AT 15% 81795 AT 17%		18661	41581	-10358 -2576 7770 21609 40214	C - 0 O - 10
31223 AT 9% 39005 AT 11% 49351 AT 13% 63190 AT 15% 81795 AT 17%		31469	54389	-23166 -15384 -5038 8801 27406	C - 7 O - 3
31223 AT 9% 39005 AT 11% 49351 AT 13% 63190 AT 15% 81795 AT 17%		32839	55759	-24536 -16754 -6408 7431 26036	C - 7 O - 10
55764 49072 43280		23806	46726	9038 2346 -4346	C - 4 O - 4.1 NG - 7

Table G-59. Annual Savings (x 1000), Janesville/Beloit, Blackhawk to Beloit Alternative, Municipal Financing Option

GROSS INCOME	MUNICIPAL REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATE
47339 AT 9% 61003 AT 11% 79546 AT 13% 104818 AT 15% 139379 AT 17%	15353	25233	6753 20417 38960 64232 98793	C - 0 O - 3
47339 AT 9% 61003 AT 11% 79546 AT 13% 104818 AT 15% 139379 AT 17%		27609	4377 18041 36584 61856 96417	C - 0 O - 10
47339 AT 9% 61003 AT 11% 79546 AT 13% 104818 AT 15% 139379 AT 17%		50381	-18395 -4731 13812 39084 73645	C - 7 O - 3
47339 AT 9% 61003 AT 11% 79546 AT 13% 104818 AT 15% 139379 AT 17%		52757	-20771 -4731 11436 36708 71269	C - 7 O - 10
102144 91200 82056		36551	50240 39296 28352	C - 4 O - 4 NG - 7

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JANESVILLE/BELOIT, ROCK RIVER TO JANESVILLE AND BELOIT

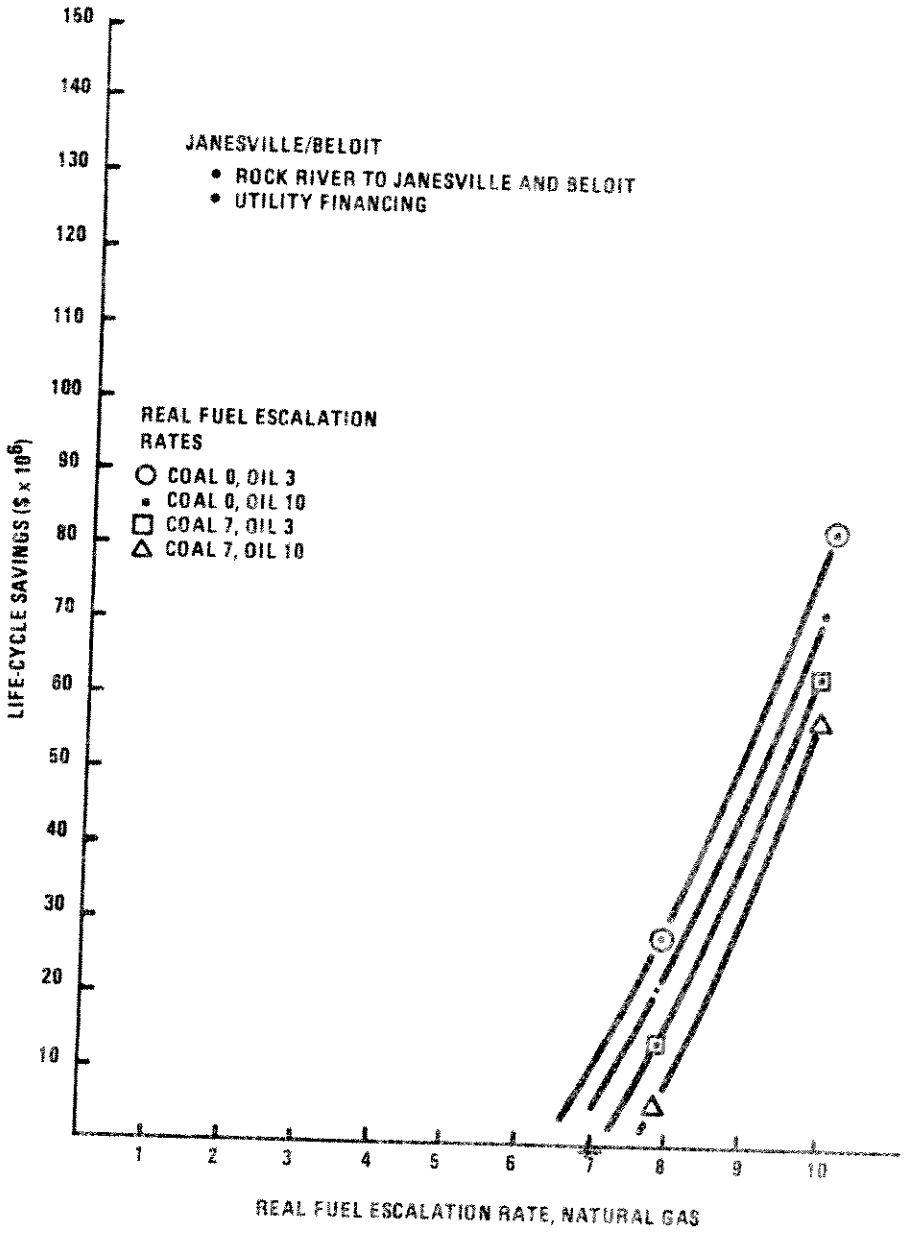

Figure G-22. Life-Cycle Savings versus Real Fuel Escalation Rates, Natural Gas

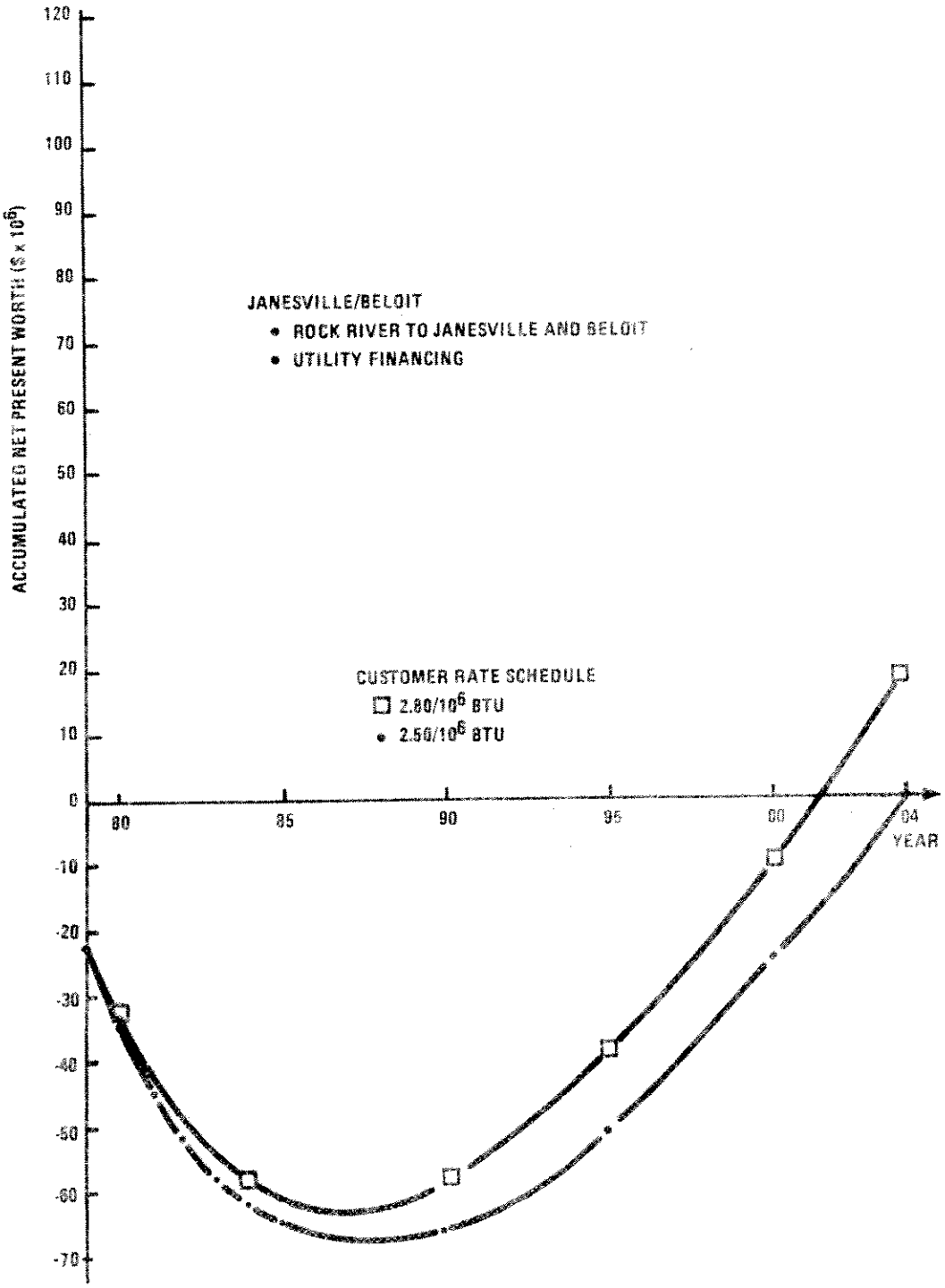

Figure G-23. Accumulated Net Present Worth versus Year

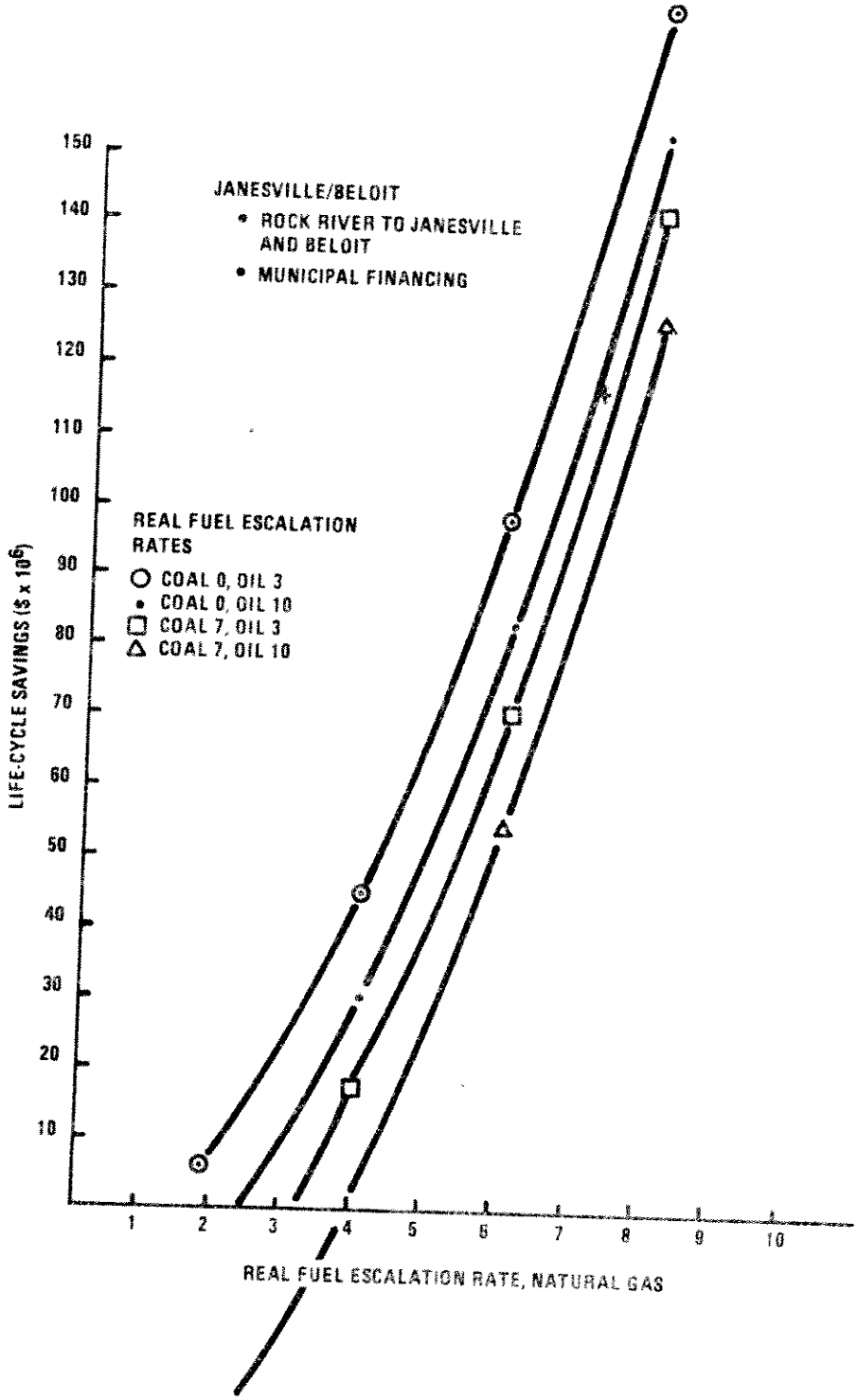

Figure G-24. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

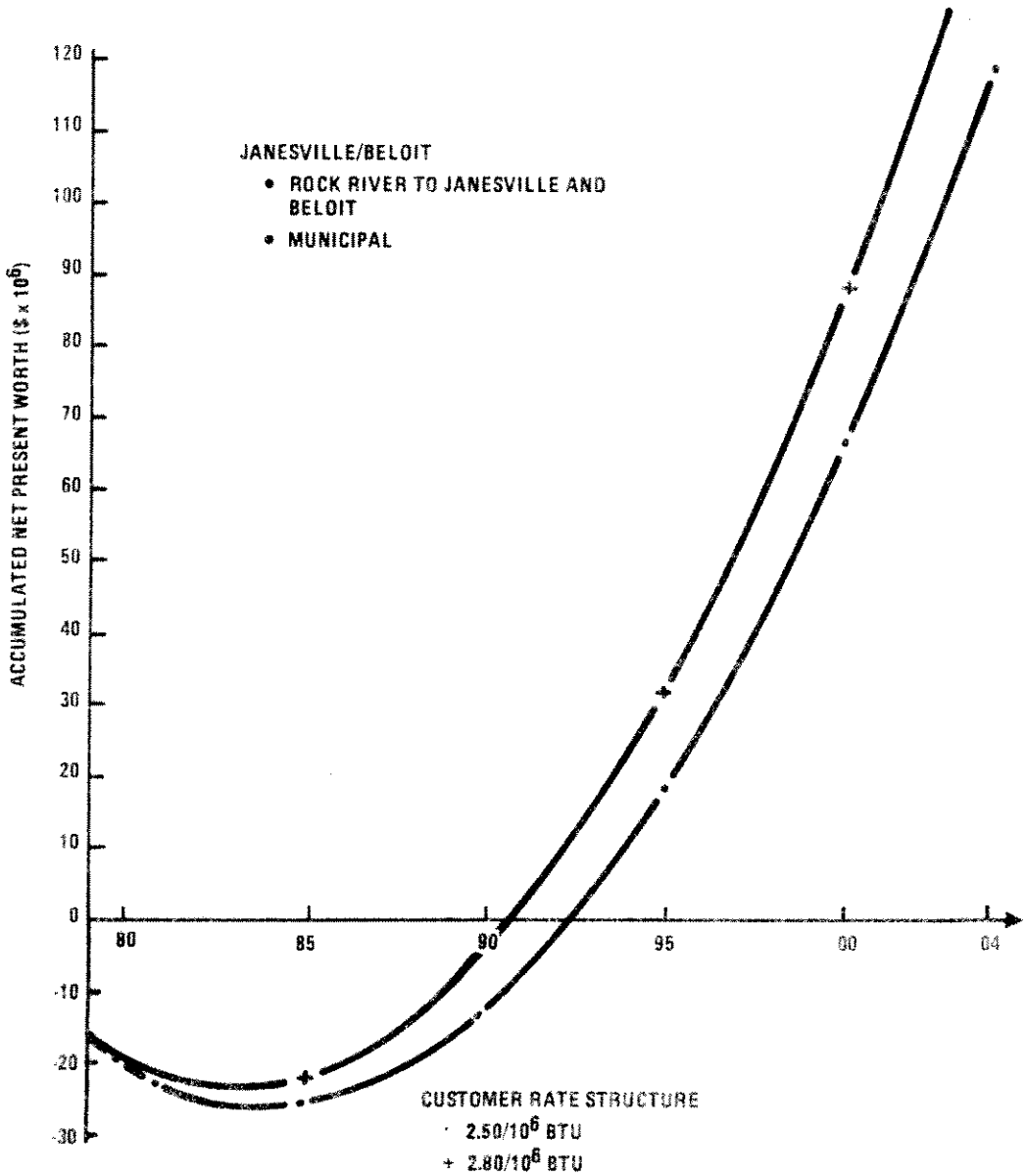

Figure G-25. Accumulated Net Present Worth versus Year

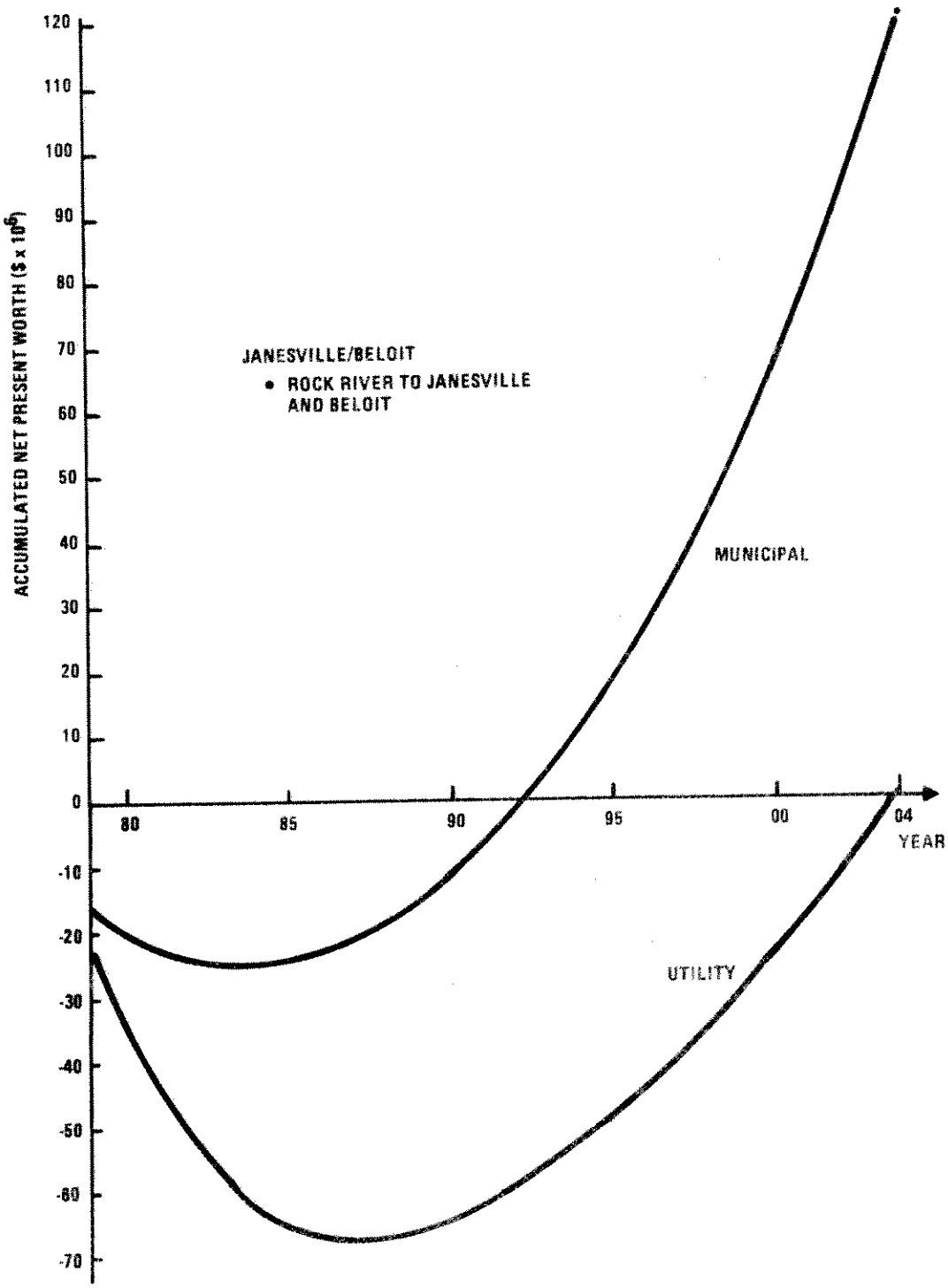

Figure G-26. Accumulated Net Present Worth versus Year

Table G-60. Operations and Maintenance Data (x 1000), Janesville/Beloit, Rock River to Janesville and Beloit Alternative

Year	Maintenance 1% of Cost (1% of 67,200)	Insurance .2% of Costs (.2% of 67,200)	Operation 3.954×10^6 kWh/yr at .03 kWh	Total O&M for Distribution	Plant O&M Costs	Total O&M
1980	672	134	119	925	193	1118
1981	719	143	127	989	186	1175
1982	769	153	136	1058	213	1271
1983	823	164	146	1133	314	1447
1984	881	176	156	1213	385	1598
1985	943	188	167	1298	396	1694
1986	1008	201	179	1388	426	1814
1987	1079	215	191	1485	434	1919
1988	1155	230	204	1589	460	2049
1989	1235	246	219	1700	501	2201
1990	1322	264	234	1820	526	2346
1991	1414	282	250	1946	564	2510
1992	1513	302	268	2083	603	2686
1993	1619	323	287	2229	645	2874
1994	1733	346	307	2386	690	3076
1995	1854	370	328	2552	738	3290
1996	1984	396	351	2731	790	3521
1997	2123	423	376	2922	845	3767
1998	2271	453	402	3126	905	4031
1999	2430	485	430	3345	967	4312
2000	2600	519	460	3579	1035	4614
2001	2782	555	492	3829	1107	4936
2002	2977	594	527	4098	1185	5283
2003	3186	635	564	4385	1268	5653
2004	3409	680	603	4692	1357	6049

Table G-61. Return Requirements (x 1000), Janesville/Beloit, Rock River to Janesville/Beloit Alternative, Utility Financing Option

YEAR	CAPITAL COST COMPONENTS: EQUITY RETURN: COMMON	EQUITY RETURN: PREFERRED	DEBT RETURN	INCOME TAX	REVENUE REQUIREMENTS
1977	714.8	114.9	471.7	-1410.3	2131.1
1978	2144.4	344.7	1415.2	249.1	6953.4
1979	3650.4	588.0	2414.0	390.5	11786.1
1980	4296.4	692.5	2802.0	3526.2	16426.6
1981	4035.7	644.2	2644.7	3401.1	15639.2
1982	3821.7	607.2	2492.6	3236.6	14896.7
1983	3611.1	571.1	2344.6	3078.2	14170.6
1984	3406.0	536.1	2200.6	2925.9	13463.3
1985	3207.1	502.0	2060.8	2779.6	12775.5
1986	3012.7	469.0	1925.0	2639.4	12105.5
1987	2823.4	438.8	1793.3	2505.2	11453.9
1988	2639.1	409.7	1665.7	2377.1	10820.6
1989	2459.9	382.7	1542.1	2255.0	10205.8
1990	2286.7	356.6	1422.7	2139.0	9609.3
1991	2116.6	331.5	1307.3	2029.1	9031.2
1992	1950.7	307.3	1196.0	1925.2	8471.4
1993	1793.6	285.2	1088.3	1827.3	7930.1
1994	1636.7	263.1	985.7	1735.5	7407.1
1995	1490.8	242.9	886.7	1649.8	6902.5
1996	1347.0	216.0	791.7	1570.1	6416.2
1997	1209.3	192.6	700.9	1496.5	5948.3
1998	1074.6	170.7	614.1	1428.9	5493.9
1999	946.0	149.6	531.4	1367.4	5067.7
2000	822.4	129.4	452.3	1312.0	4655.0
2001	703.9	110.3	378.3	1262.6	4260.6
2002	590.[illegible]	92.1	307.8	1219.2	3884.7
2003	482.0	75.0	241.3	1177.1	3526.6
2004	378.[illegible]	58.8	178.7	1140.6	3185.9

Table G-61. Return Requirements (x 1000), Janesville/Beloit, Rock River to Janesville/Beloit Alternative, Utility Financing Option (concluded)

ACCUMULATED	VALUE 12TH MONTH 1979	ACCUMULATED	YEAR
2131.1	2655.2	2655.2	1977
9084.5	7761.4	10416.6	1978
20870.6	11786.1	22202.6	1979
37277.2	14698.6	36901.2	1980
52916.3	12552.5	49453.7	1981
67812.0	10711.1	60164.8	1982
81982.5	9128.9	69293.7	1983
95446.4	7770.7	77064.4	1984
108221.8	6605.8	83670.2	1985
120327.3	5607.7	89277.9	1986
131781.1	4753.5	94031.4	1987
142631.8	4023.2	98054.6	1988
152807.5	3399.6	101454.2	1989
162416.8	2867.7	104321.9	1990
171447.9	2414.6	106736.4	1991
179919.3	2029.1	108765.6	1992
187849.4	1701.7	110467.3	1993
195256.5	1424.0	111891.3	1994
202158.9	1188.9	113080.2	1995
208575.1	990.1	114070.2	1996
214523.5	822.3	114892.5	1997
220022.3	681.0	115573.6	1998
225090.1	562.3	116135.9	1999
229745.1	462.7	116598.6	2000
234005.7	379.4	116978.1	2001
237890.4	309.9	117288.0	2002
241417.0	252.1	117540.1	2003
244603.0	204.0	117744.1	2004

Table G-62. Return Requirements (x 1000), Janesville/Beloit, Rock River to Janesville/Beloit Alternative, Municipal Financing Option

YEAR	BOOK DEP.	NET BOOK DEPRECIATION	NET INV.	RETURN REQUIREMENT	TOTAL RETURN	PV	ACC. PV
1977	723	0	22400	1792	2515	2934	2934
1978	1446	2169	42631	3410	4856	5244	8178
1980	2249	4418	65282	5223	7472	7472	15650
1981	2249	6667	63033	5043	7292	6752	22902
1982	2249	11165	58535	4683	6932	5503	34002
1983	2249	13414	56286	4503	6752	4473	43438
1984	2249	15663	54037	4323	6572	4473	43438
1985	2249	17912	51788	4143	6392	4028	47466
1985	2249	20161	49539	3963	6212	3625	51091
1986	2249	20161	49539	3963	6212	3625	51091
1987	2249	22410	47290	3783	6032	3259	54350
1988	2249	24659	45041	3603	5852	2927	57277
1989	2249	26908	42792	3423	5672	2627	59904
1990	2249	29157	40543	3243	5492	2355	62259
1991	2249	31406	38294	3063	5312	2109	64968
1992	2249	33655	35045	2883	5132	1887	66255
1993	2249	35904	33796	2703	4952	1686	67941
1994	2249	38153	31547	2523	4772	1405	59445
1995	2249	40402	29298	2343	4592	1340	70785
1996	2249	42651	27049	2163	4412	1192	71977
1997	2249	44900	24800	1983	4232	1059	73036
1998	2249	47149	22551	1803	4052	939	73975
1999	2249	49398	20302	1623	3872	831	74806
2000	2249	51647	18053	1443	3692	733	75539
2001	2249	53896	15804	1263	3512	646	76752
2003	2249	58394	11306	903	3152	497	77249
2004	2249	50543	9057	723	2972	434	77683

Table G-63. Fuel/O & M Data (x 1000), Janesville/Beloit, Rock River to Janesville and Beloit Alternative, Utility Financing Option

COAL COST = 1.58×10-6 $/B
OIL COST = 2.67×10-6 $/B
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 11.62%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL+O&M	PV	ACC PV
1980	1568.	53.	1621.	1118.	2739.	2454.	2454.
1981	1213.	122.	1335.	1175.	2510.	2014.	4469.
1982	1333.	143.	1476.	1271.	2747.	1975.	6444.
1983	1367.	171.	1538.	1447.	2985.	1923.	8367.
1984	1467.	221.	1688.	1598.	3286.	1897.	10264.
1985	1416.	346.	1762.	1694.	3456.	1787.	12051.
1986	1417.	586.	2003.	1814.	3817.	1768.	13819.
1987	1955.	638.	2594.	1919.	4513.	1873.	15692.
1988	2162.	923.	3085.	2049.	5134.	1909.	17600.
1989	2252.	1033.	3285.	2201.	5486.	1827.	19428.
1990	2709.	952.	3661.	2346.	6007.	1793.	21220.
1991	3007.	1058.	4065.	2510.	6575.	1758.	22978.
1992	3338.	1175.	4513.	2686.	7199.	1724.	24702.
1993	3705.	1305.	5010.	2874.	7884.	1692.	26394.
1994	4112.	1450.	5563.	3076.	8639.	1661.	28055.
1995	4565.	1611.	6176.	3290.	9466.	1630.	29686.
1996	5067.	1790.	6857.	3521.	10378.	1601.	31287.
1997	5624.	1989.	7613.	3767.	11380.	1573.	32860.
1998	6243.	2210.	8453.	4031.	12484.	1546.	34406.
1999	6930.	2455.	9384.	4312.	13696.	1520.	35926.
2000	7692.	2727.	10419.	4614.	15033.	1494.	37420.
2001	8538.	3030.	11568.	4936.	16504.	1470.	38890.
2002	9477.	3366.	12844.	5283.	18127.	1446.	40336.
2003	10520.	3740.	14260.	5653.	19913.	1423.	41760.
2004	11677.	4155.	15832.	6049.	21881.	1401.	43161.
			146604.	75234.			

Table G-64. Fuel/O & M Data (x 1000), Janesville/Beloit, Rock River to Janesville/Beloit Alternative, Municipal Financing Option

COAL COST = 1.58/10-6 BTU
OIL COST = 2.67/10-6 BTU
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 8.00%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	1568.	53.	1621.	1118.	2739.	2536.	2536.
1981	1213.	122.	1335.	1175.	2510.	2152.	4688.
1982	1333.	143.	1476.	1271.	2747.	2181.	6869.
1983	1367.	171.	1538.	1447.	2985.	2194.	9063.
1984	1467.	221.	1688.	1598.	3286.	2237.	11300.
1985	1416.	346.	1762.	1694.	3456.	2178.	13477.
1986	1417.	586.	2003.	1814.	3817.	2227.	15705.
1987	1955.	638.	2594.	1919.	4513.	2438.	18143.
1988	2162.	923.	3085.	2049.	5134.	2568.	20711.
1989	2252.	1033.	3285.	2201.	5486.	2541.	23252.
1990	2709.	952.	3661.	2346.	6007.	2576.	25828.
1991	3007.	1058.	4065.	2510.	6575.	2611.	28439.
1992	3338.	1175.	4513.	2686.	7199.	2647.	31086.
1993	3705.	1305.	5010.	2874.	7884.	2684.	33770.
1994	4112.	1450.	5563.	3076.	8639.	2723.	36493.
1995	4565.	1611.	6176.	3290.	9466.	2763.	39256.
1996	5067.	1790.	6857.	3521.	10378.	2805.	42061.
1997	5624.	1989.	7613.	3767.	11380.	2848.	44909.
1998	6243.	2210.	8453.	4031.	12484.	2893.	47802.
1999	6930.	2455.	9384.	4312.	13696.	2939.	50740.
2000	7692.	2727.	10419.	4614.	15033.	2986.	53727.
2001	8538.	3030.	11568.	4936.	16504.	3036.	56763.
2002	9477.	3366.	12844.	5283.	18127.	3087.	59850.
2003	10520.	3740.	14260.	5653.	19913.	3140.	62990.
2004	11677.	4155.	15832.	6049.	21881.	3195.	66185.
			146604.	75234.			

Table G-65 Gross Income Data (x 1000), Janesville/Beloit, Rock River to Janesville/Beloit Alternative, Utility Financing Option

DISCOUNT RATE = 11.62%
FUEL QUANTITY = 1928.81/10-9 BTU/YR
FUEL COST = 2.80/10-6 $/U
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV
1980	6156.	5515.	5515.
1981	7018.	5633.	11148.
1982	8000.	5753.	16901.
1983	9121.	5876.	22777.
1984	10397.	6001.	28778.
1985	11853.	6129.	34906.
1986	13513.	6260.	41166.
1987	15404.	6393.	47559.
1988	17561.	6529.	54088.
1989	20019.	6669.	60757.
1990	22822.	6811.	67568.
1991	26017.	6956.	74524.
1992	29668.	7104.	81628.
1993	33812.	7256.	88884.
1994	38546.	7410.	96294.
1995	43942.	7568.	103862.
1996	50094.	7730.	111592.
1997	57107.	7895.	119487.
1998	65102.	8063.	127550.
1999	74216.	8235.	135785.
2000	84607.	8411.	144195.
2001	96452.	8590.	152785.
2002	109955.	8773.	161558.
2003	125348.	8960.	170518.
2004	142897.	9151.	179669.

DISCOUNT RATE = 11.62%
FUEL QUANTITY = 1928.81/10-9 BTU/YR
FUEL COST = 2.50/10-6 $/U
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV
1980	5497.	4924.	4924.
1981	6266.	5029.	9954.
1982	7143.	5137.	15090.
1983	8143.	5246.	20336.
1984	9283.	5358.	25694.
1985	10583.	5472.	31166.
1986	12065.	5589.	36755.
1987	13754.	5708.	42463.
1988	15679.	5830.	48293.
1989	17874.	5954.	54247.
1990	20377.	6081.	60328.
1991	23230.	6211.	66539.
1992	26482.	6343.	72882.
1993	30189.	6478.	79360.
1994	34416.	6616.	85977.
1995	39234.	6756.	92734.
1996	44727.	6902.	99636.
1997	50988.	7049.	106685.
1998	58127.	7199.	113884.
1999	66285.	7353.	121236.
2000	75542.	7509.	128746.
2001	86117.	7669.	136415.
2002	98174.	7833.	144248.
2003	111918.	8000.	152248.
2004	127587.	8171.	160419.

Table G-66. Gross Income Data (x 1000), Janesville/Beloit, Rock River to Janesville/Beloit Alternative, Municipal Financing Option

DISCOUNT RATE = 8.00%
FUEL QUANTITY = 1928.61/10-9 BTU/YR
FUEL COST = 2.50/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV
1980	5497.	5089.	5089.
1981	6266.	5372.	10462.
1982	7143.	5671.	16132.
1983	8143.	5986.	22118.
1984	9283.	6318.	28436.
1985	10583.	6669.	35105.
1986	12065.	7040.	42145.
1987	13754.	7431.	49575.
1988	15679.	7844.	57419.
1989	17874.	8279.	65698.
1990	20377.	8739.	74438.
1991	23230.	9225.	83662.
1992	26482.	9737.	93400.
1993	30189.	10278.	103678.
1994	34416.	10849.	114527.
1995	39234.	11452.	125979.
1996	44727.	12088.	138068.
1997	50988.	12760.	150827.
1998	58127.	13469.	164296.
1999	66265.	14217.	178513.
2000	75542.	15007.	193520.
2001	86117.	15840.	209360.
2002	98174.	16721.	226081.
2003	111918.	17649.	243730.
2004	127587.	[illegible]	[illegible]

DISCOUNT RATE = 8.00%
FUEL QUANTITY = 1928.61/10-9 BTU/YR
FUEL COST = 2.80/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV
1980	6156.	5700.	5700.
1981	7018.	6017.	11717.
1982	8000.	6351.	18068.
1983	9121.	6704.	24772.
1984	10397.	7076.	31848.
1985	11853.	7469.	39318.
1986	13513.	7884.	47202.
1987	15404.	8322.	55525.
1988	17561.	8785.	64309.
1989	20019.	9273.	73582.
1990	22822.	9788.	83370.
1991	26017.	10332.	93702.
1992	29660.	10906.	104608.
1993	33812.	11512.	116119.
1994	38548.	12151.	128271.
1995	43942.	12826.	141097.
1996	50094.	13539.	154636.
1997	57107.	14291.	168927.
1998	65102.	15085.	184012.
1999	74216.	15923.	199935.
2000	84607.	16808.	216742.
2001	96452.	17741.	234484.
2002	109955.	18727.	253210.
2003	125348.	19767.	272978.
2004	142897.	[illegible]	[illegible]

Table G-67. Annual Savings (x 1000), Janesville/Beloit, Park River to Janesville/Beloit Alternative, Municipal Financing Option

GROSS INCOME	MUNICIPAL REV. REG.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
136182 AT 9%	77683	52615	5884	C - 0
175492 AT 11%			45194	O - 3
228834 AT 13%			98536	
301536 AT 15%			171238	
400960 AT 17%			270662	
136182 AT 9%		67729	-9230	C - 0
175492 AT 11%			30080	O - 10
228834 AT 13%			83422	
301536 AT 15%			56124	
400960 AT 17%			255548	
136182 AT 9%		80185	-21686	C - 7
175492 AT 11%			17624	O - 3
228834 AT 13%			70966	
301536 AT 15%			143668	
400960 AT 17%			243092	
136182 AT 9%		95300	-36801	C - 7
175492 AT 11%			2509	O - 10
228834 AT 13%			55851	
301536 AT 15%			128553	
400960 AT 17%			227977	
293843		66185	149975	C - 4
262360			118492	O - 7
				NG - 7

Table G-68. Annual Savings (x 1000), Janesville/Beloit, Rock River to Janesville/Beloit Alternative, Utility Financing Option

GROSS INCOME	UTILITY REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
89820 112209 141972 181783 235306	117744	35385	-63309 -40920 -11157 28654 82177	C - 0 O - 3
89820 112209 141972 181783 235306		43591	-71515 -49126 -19363 20448 73971	C - 0 O - 10
89820 112209 141972 181783 235306		50918	-78842 -56453 -26690 13121 66644	C - 7 O - 3
89820 112209 141972 181783 235306		59124	-87048 -64659 -34896 4915 58438	C - 7 O - 10
179669 160419 141169		43161	18764 -486 -19736	C - 4 O - 4.1 NG - 7

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MADISON, CBD AND CAPITOL HEATING COMPLEX

79130

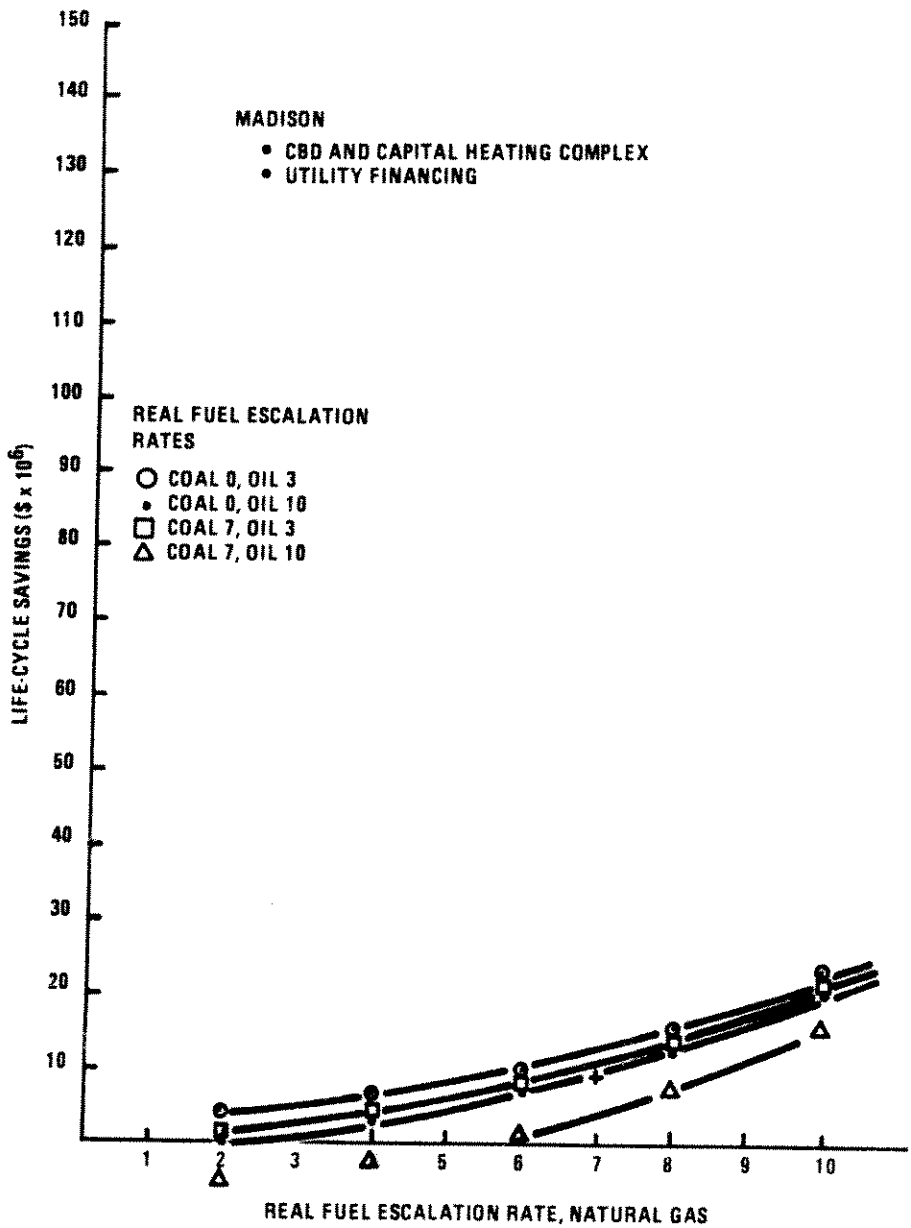

Figure G-27. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

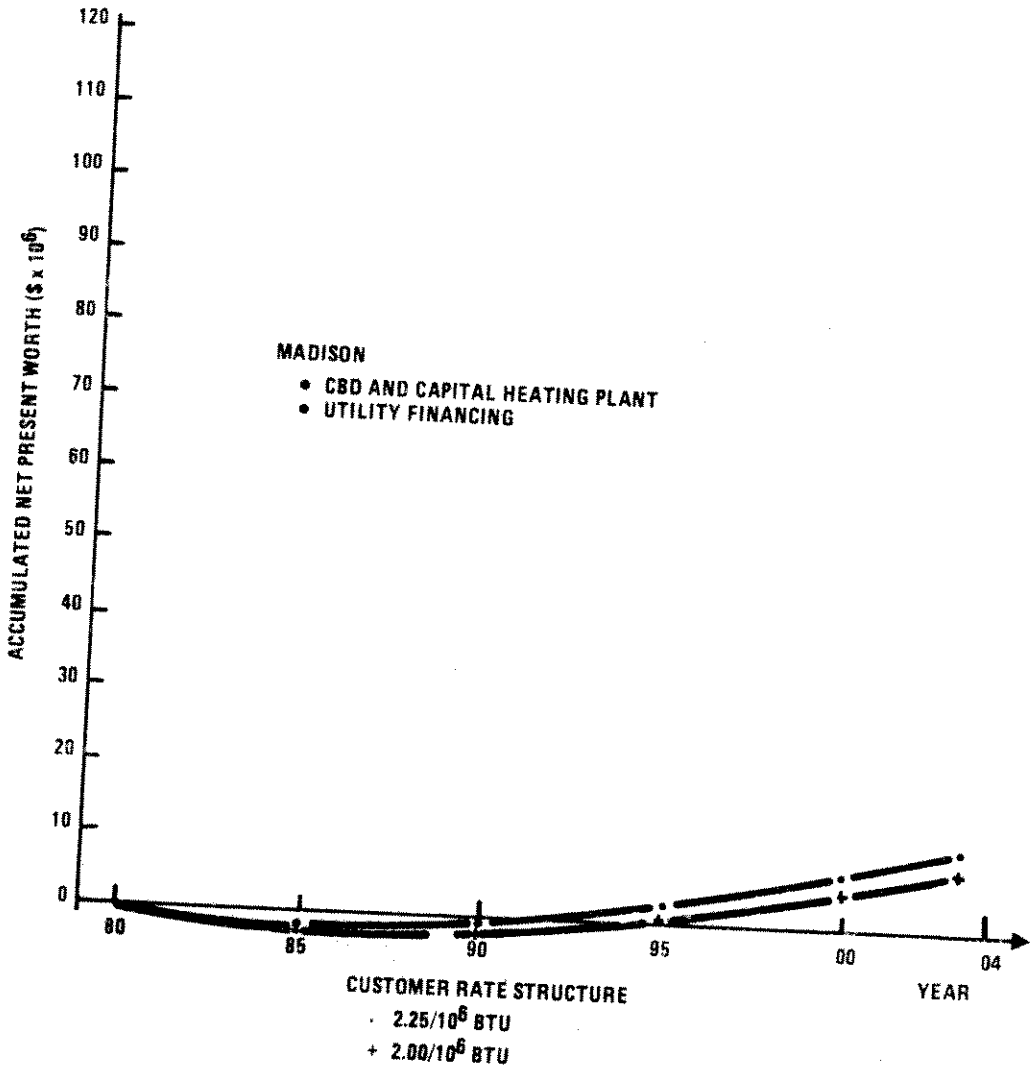

Figure G-28. Accumulated Net Present Worth versus Year

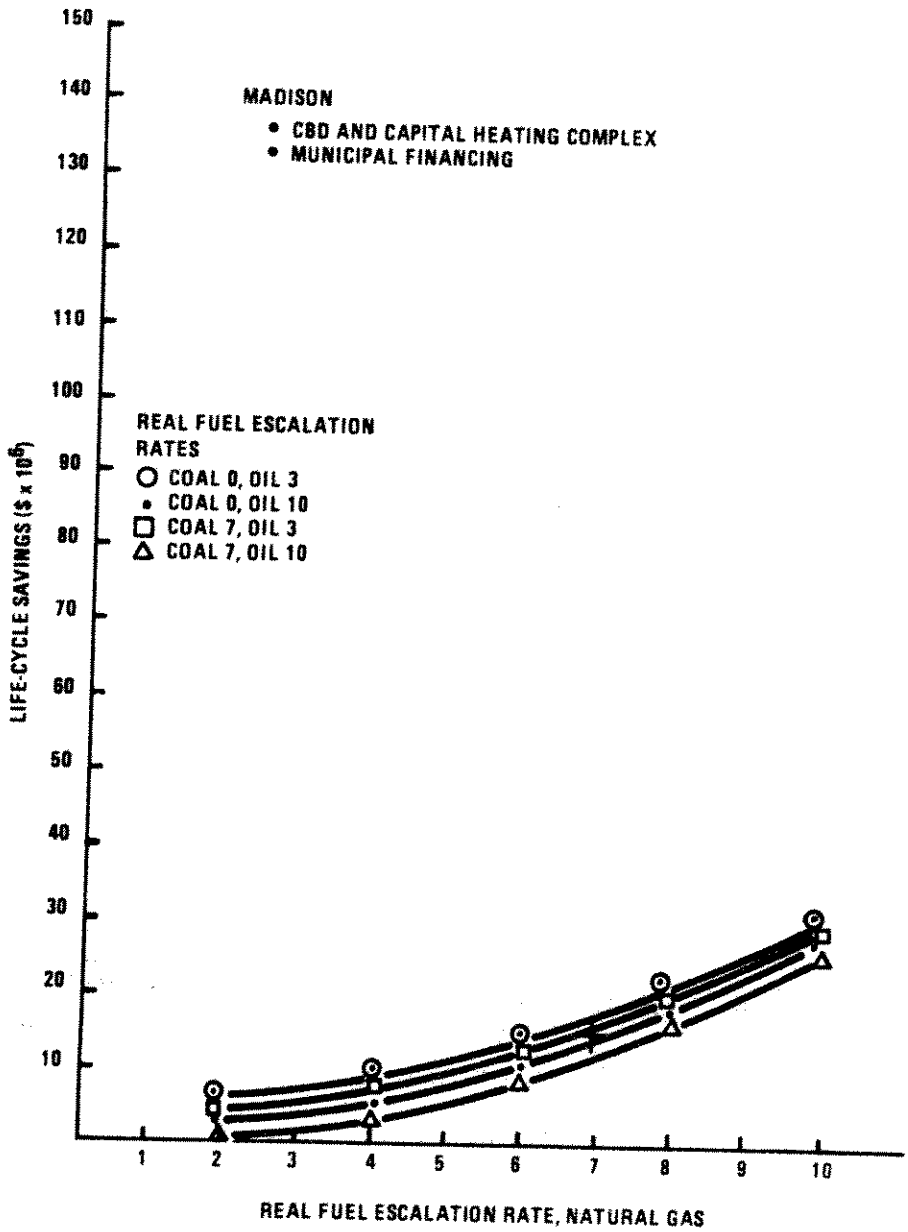

Figure G-29. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

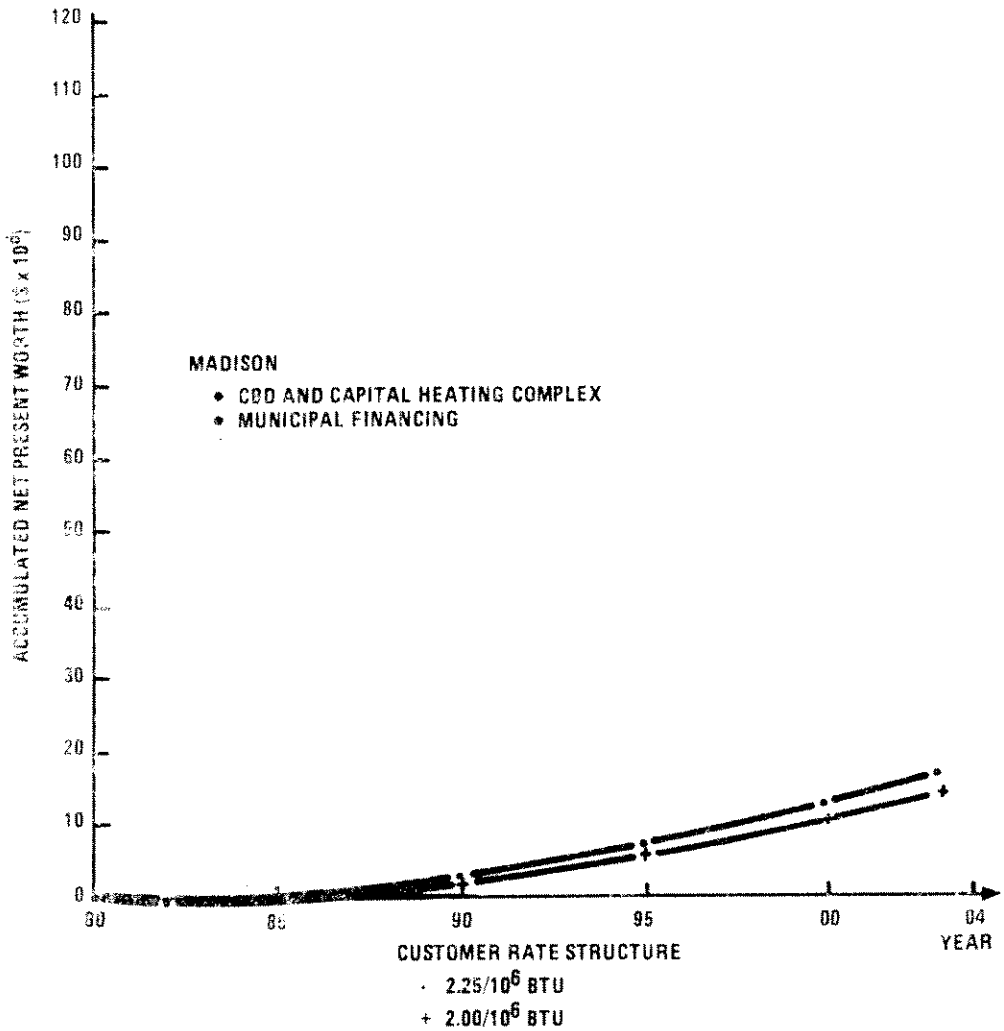

Figure G-30. Accumulated Net Present Worth versus Year

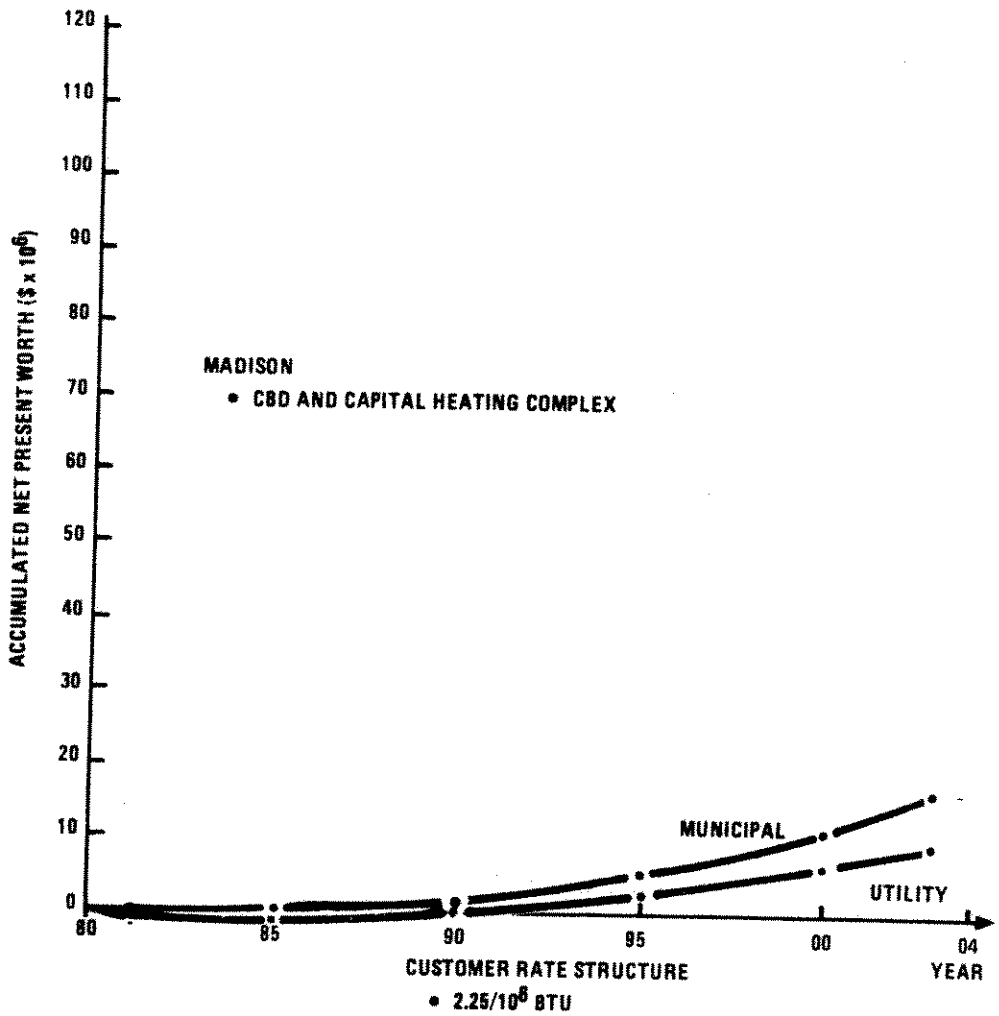

Figure G-31. Accumulated Net Present Worth versus Year

Table G-69. Operations and Maintenance Data (x 1000), Madison CBD and Capitol Heating Complex Alternative

YEAR	MAINTENANCE 1% OF COST	INSURANCE 0.2% OF COST	OPERATION 73,100 KWH/YR AT 0.03/KWH	TOTAL O & M DISTRIBTUION	PLANT RETROFIT O & M	TOTAL O & M
1980	35	7	2	44	13	57
1981	37	7	2	46	13	59
1982	40	8	2	50	15	65
1983	43	9	2	54	22	76
1984	46	9	3	58	27	85
1985	49	10	3	62	28	90
1986	53	11	3	67	32	99
1987	56	11	3	70	32	102
1988	60	12	3	75	35	110
1989	64	13	4	81	39	120
1990	69	14	4	87	42	129
1991	74	15	4	93	45	138
1992	79	16	5	100	48	148
1993	84	17	5	106	51	157
1994	90	18	5	113	55	168
1995	97	19	6	122	59	181
1996	103	21	6	130	63	193
1997	111	22	6	139	67	206
1998	118	24	7	149	72	221
1999	127	25	7	159	77	236
2000	135	27	8	170	83	253
2001	144	29	8	181	88	269
2002	155	31	9	195	95	180
2003	166	33	9	208	101	309
2004	178	35	10	223	108	331

Table G-70. Revenue Requirements (x 1000), Madison, CBD and Capitol Complex Alternative, Municipal Financing Option

Capital Costs $4,500,000

Book Life 27 years

Depreciation Method: Straight Line

Bond Rate 8%

Discount Rate 8%

Year	Book Dep	Net Dep	Invest	Ret	Total Ret	PU	Acc PU
1980	167.	0.	4500.	360.	527.	488.	488.
1981	167.	167.	4333.	347.	513.	440.	928.
1982	167.	333.	4167.	333.	500.	397.	1325.
1983	167.	500.	4000.	320.	487.	358.	1682.
1984	167.	667.	3833.	307.	473.	322.	2005.
1985	167.	833.	3667.	293.	460.	290.	2294.
1986	167.	1000.	3500.	280.	447.	261.	2555.
1987	167.	1167.	3333.	267.	433.	234.	2789.
1988	167.	1333.	3167.	253.	420.	210.	2999.
1989	167.	1500.	3000.	240.	407.	188.	3188.
1990	167.	1667.	2833.	227.	393.	169.	3356.
1991	167.	1833.	2667.	213.	380.	151.	3507.
1992	167.	2000.	2500.	200.	367.	135.	3642.
1993	167.	2167.	2333.	187.	353.	120.	3762.
1994	167.	2333.	2167.	173.	340.	107.	3870.
1995	167.	2500.	2000.	160.	327.	95.	3965.
1996	167.	2667.	1833.	147.	313.	85.	4050.
1997	167.	2833.	1667.	133.	300.	75.	4125.
1998	167.	3000.	1500.	120.	287.	66.	4191.
1999	167.	3167.	1333.	107.	273.	59.	4250.
2000	167.	3333.	1167.	93.	260.	52.	4301.
2001	167.	3500.	1000.	80.	247.	45.	4347.
2002	167.	3667.	833.	67.	233.	40.	4386.
2003	167.	3833.	667.	53.	220.	35.	4421.
2004	167.	4000.	500.	40.	[illegible]	[illegible]	[illegible]

Table G-71. Return Requirements (x 1000), Madison, CBD and Capitol Heating Complex Alternative, Utility Financing Option

YEAR	RETURN PV	ACC. PV
1980	798	798
1981	763	1561
1982	660	2221
1983	570	2791
1984	491	3282
1985	423	3705
1986	364	4069
1987	312	4381
1988	267	4648
1989	229	4877
1990	195	5072
1991	167	5239
1992	142	5381
1993	122	5503
1994	103	5606
1995	87	5693
1996	74	5767
1997	62	5829
1998	53	5882
1999	44	5926
2000	38	5964
2001	32	5996
2002	27	6023
2003	27	6046
2004	19	6065

Table G-72. Fuel/O & M Data (x 1000), Madison, CBD and Capitol Complex Alternative, Utility Financing Option

COAL COST = 1.58/10-6 BTU
OIL COST = 2.67/10-6 BTU
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 9.54%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	165.	9.	174.	57.	231.	211.	211.
1981	103.	16.	120.	59.	179.	149.	360.
1982	115.	22.	136.	65.	201.	153.	513.
1983	120.	24.	144.	76.	220.	153.	666.
1984	122.	36.	159.	85.	244.	154.	820.
1985	115.	50.	165.	90.	255.	148.	968.
1986	115.	84.	198.	99.	297.	157.	1125.
1987	157.	87.	243.	102.	345.	167.	1292.
1988	166.	124.	290.	110.	400.	176.	1468.
1989	166.	145.	311.	120.	431.	173.	1641.
1990	199.	153.	352.	129.	481.	177.	1818.
1991	221.	170.	391.	138.	529.	177.	1995.
1992	245.	189.	434.	148.	582.	178.	2173.
1993	272.	210.	482.	157.	639.	178.	2352.
1994	302.	233.	535.	168.	703.	179.	2531.
1995	336.	259.	595.	181.	776.	180.	2712.
1996	373.	288.	660.	193.	853.	181.	2893.
1997	414.	320.	733.	206.	939.	182.	3075.
1998	459.	355.	814.	221.	1035.	183.	3258.
1999	510.	395.	904.	236.	1140.	184.	3443.
2000	566.	438.	1004.	253.	1257.	185.	3628.
2001	628.	487.	1115.	269.	1384.	186.	3815.
2002	697.	541.	1238.	180.	1418.	174.	3989.
2003	774.	601.	1375.	309.	1684.	189.	4178.
2004	859.	668.	1526.	331.	1857.	190.	4368.

Table G-73. Fuel/O & M Data (x 1000), Madison, CBD and Capitol Complex Alternative, Municipal Financing Option

COAL COST = 1.58/10-6 BTU
OIL COST = 2.67/10-6 BTU
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 8.00%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	165.	9.	174.	57.	231.	214.	214.
1981	103.	16.	120.	59.	179.	153.	367.
1982	115.	22.	136.	65.	201.	160.	527.
1983	120.	24.	144.	76.	220.	162.	689.
1984	122.	36.	159.	85.	244.	166.	855.
1985	115.	50.	165.	90.	255.	161.	1016.
1986	115.	84.	198.	99.	297.	174.	1189.
1987	157.	87.	243.	102.	345.	187.	1376.
1988	166.	124.	290.	110.	400.	200.	1576.
1989	166.	145.	311.	120.	431.	200.	1775.
1990	199.	153.	352.	129.	481.	206.	1982.
1991	221.	170.	391.	138.	529.	210.	2192.
1992	245.	189.	434.	148.	582.	214.	2406.
1993	272.	210.	482.	157.	639.	218.	2624.
1994	302.	233.	535.	168.	703.	222.	2845.
1995	336.	259.	595.	181.	776.	226.	3072.
1996	373.	288.	660.	193.	853.	231.	3302.
1997	414.	320.	733.	206.	939.	235.	3537.
1998	459.	355.	814.	221.	1035.	240.	3777.
1999	510.	395.	904.	236.	1140.	245.	4022.
2000	566.	438.	1004.	253.	1257.	250.	4272.
2001	628.	487.	1115.	269.	1384.	255.	4526.
2002	697.	541.	1238.	180.	1418.	241.	4768.
2003	774.	601.	1375.	309.	1684.	265.	5033.
2004	859.	668.	1526.	331.	1857.	271.	5304.

Table G-74. Gross Income Data (x 1000), Madison, CBD and Capitol Complex Alternative, Utility Financing Option

DISCOUNT RATE = 9.54%
FUEL QUANTITY = 215.10/10-9 BTU/YR
FUEL COST = 2.00/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV	YEAR	INCOME	PV	ACC PV
1980	490.	448.	448.	1980	552.	504.	504.
1981	559.	466.	914.	1981	629.	524.	1028.
1982	637.	485.	1399.	1982	717.	546.	1573.
1983	727.	505.	1903.	1983	817.	568.	2141.
1984	828.	525.	2428.	1984	932.	591.	2732.
1985	944.	547.	2975.	1985	1062.	615.	3347.
1986	1076.	569.	3544.	1986	1211.	640.	3987.
1987	1227.	592.	4136.	1987	1381.	666.	4653.
1988	1399.	616.	4752.	1988	1574.	693.	5346.
1989	1595.	641.	5393.	1989	1794.	721.	6067.
1990	1818.	667.	6061.	1990	2045.	751.	6818.
1991	2073.	694.	6755.	1991	2332.	781.	7599.
1992	2363.	723.	7478.	1992	2658.	813.	8412.
1993	2694.	752.	8230.	1993	3030.	846.	9259.
1994	3071.	783.	9013.	1994	3455.	881.	10139.
1995	3501.	815.	9827.	1995	3938.	917.	11056.
1996	3991.	848.	10675.	1996	4490.	954.	12010.
1997	4549.	882.	11558.	1997	5118.	993.	13002.
1998	5186.	918.	12476.	1998	5835.	1033.	14035.
1999	5912.	956.	13432.	1999	6652.	1075.	15111.
2000	6740.	995.	14426.	2000	7583.	1119.	16229.
2001	7684.	1035.	15461.	2001	8644.	1164.	17394.
2002	8760.	1077.	16538.	2002	9854.	1212.	18606.
2003	9986.	1121.	17660.	2003	11234.	1261.	19867.
2004	11384.	1167.	18826.	2004	12807.	1313.	21180.

Table G-75. Gross Income Data (x 1000), Madison, CBD and Capitol Heating Complex Alternative, Municipal Financing Option

DISCOUNT RATE = 8.00%
FUEL QUANTITY = 215.10/10-9 BTU/YR
FUEL COST = 2.00/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV	YEAR	INCOME	PV	ACC PV
1980	490.	454.	454.	1980	552.	511.	511.
1981	559.	479.	933.	1981	629.	539.	1050.
1982	637.	506.	1439.	1982	717.	569.	1619.
1983	727.	534.	1973.	1983	817.	601.	2220.
1984	828.	564.	2537.	1984	932.	634.	2854.
1985	944.	595.	3132.	1985	1062.	669.	3524.
1986	1076.	628.	3760.	1986	1211.	707.	4230.
1987	1227.	663.	4423.	1987	1381.	746.	4976.
1988	1399.	700.	5123.	1988	1574.	787.	5764.
1989	1595.	739.	5862.	1989	1794.	831.	6595.
1990	1818.	780.	6642.	1990	2045.	877.	7472.
1991	2073.	823.	7465.	1991	2332.	926.	8398.
1992	2363.	869.	8334.	1992	2658.	977.	9375.
1993	2694.	917.	9251.	1993	3030.	1032.	10407.
1994	3071.	968.	10219.	1994	3455.	1089.	11496.
1995	3501.	1022.	11240.	1995	3938.	1150.	12646.
1996	3991.	1079.	12319.	1996	4490.	1213.	13859.
1997	4549.	1138.	13458.	1997	5118.	1281.	15140.
1998	5186.	1202.	14659.	1998	5835.	1352.	16492.
1999	5912.	1269.	15928.	1999	6652.	1427.	17919.
2000	6740.	1339.	17267.	2000	7583.	1506.	19425.
2001	7684.	1413.	18680.	2001	8644.	1590.	21015.
2002	8760.	1492.	20172.	2002	9854.	1678.	22694.
2003	9986.	1575.	21747.	2003	11234.	1772.	24465.
2004	11384.	1662.	23409.	2004	12807.	1870.	26335.

Table G-76. Annual Savings (x 1000), Madison, CBD and Capitol Complex Alternative, Utility Financing Option

GROSS INCOME	UTILITY REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
11354 AT 9%	6065	3481	1808	C - 0
14438 AT 11%			4892	O - 3
18587 AT 13%			9041	
24198 AT 15%			14652	
31819 AT 17%			22273	
11354 AT 9%		5320	-31	C - 0
14438 AT 11%			3053	O - 10
18587 AT 13%			7202	
24198 AT 15%			12813	
31819 AT 17%			20434	
11354 AT 9%		5081	208	C - 7
14438 AT 11%			3292	O - 10
18587 AT 13%			7441	
24198 AT 15%			13052	
31819 AT 17%			20673	
11354 AT 9%		6919	-5111	C - 7
14438 AT 11%			-2027	O - 10
18587 AT 13%			2122	
24198 AT 15%			7733	
31819 AT 17%			15354	
23533		4368	13100	C - 4
21180			10747	O - 4.1
18826			8393	NG - 7

Table G-77. Annual Savings (x 1000), Madison, CBD and Capitol Heating Complex Alternative, Municipal Financing Option

GROSS INCOME	MUNICIPAL REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
13670 AT 9% 17616 AT 11% 22970 AT 13% 30268 AT 15% 40248 AT 17%	4451	4172	5047 8993 14347 21645 31625	C - 0 O - 3
13670 AT 9% 17616 AT 11% 22970 AT 13% 30268 AT 15% 40248 AT 17%		6575	2644 6590 11944 19242 29222	C - 0 O - 10
13670 AT 9% 17616 AT 11% 22970 AT 13% 30268 AT 15% 40248 AT 17%		6224	2995 6941 12295 19593 29573	C - 7 O - 3
13670 AT 9% 17616 AT 11% 22970 AT 13% 30268 AT 15% 40248 AT 17%		8627	592 4538 9892 17190 27170	C - 7 O - 10
26335 23409		5304	16580 13654	C - 4 O - 4.1 NG - 7

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MADISON, UNIVERSITY OF WISCONSIN

79130

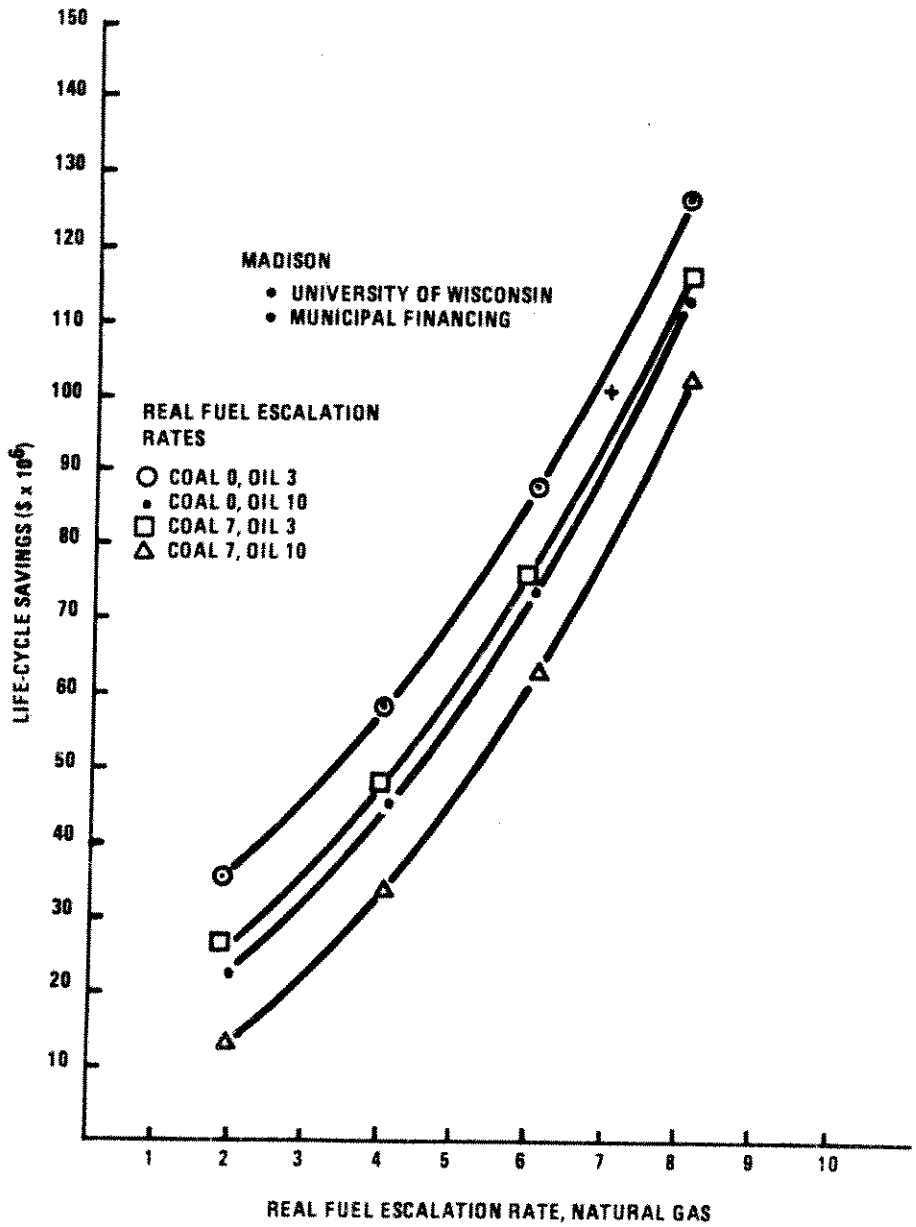

Figure G-32. Life-Cycle Savings versus Real Fuel Escalation Rate, Natural Gas

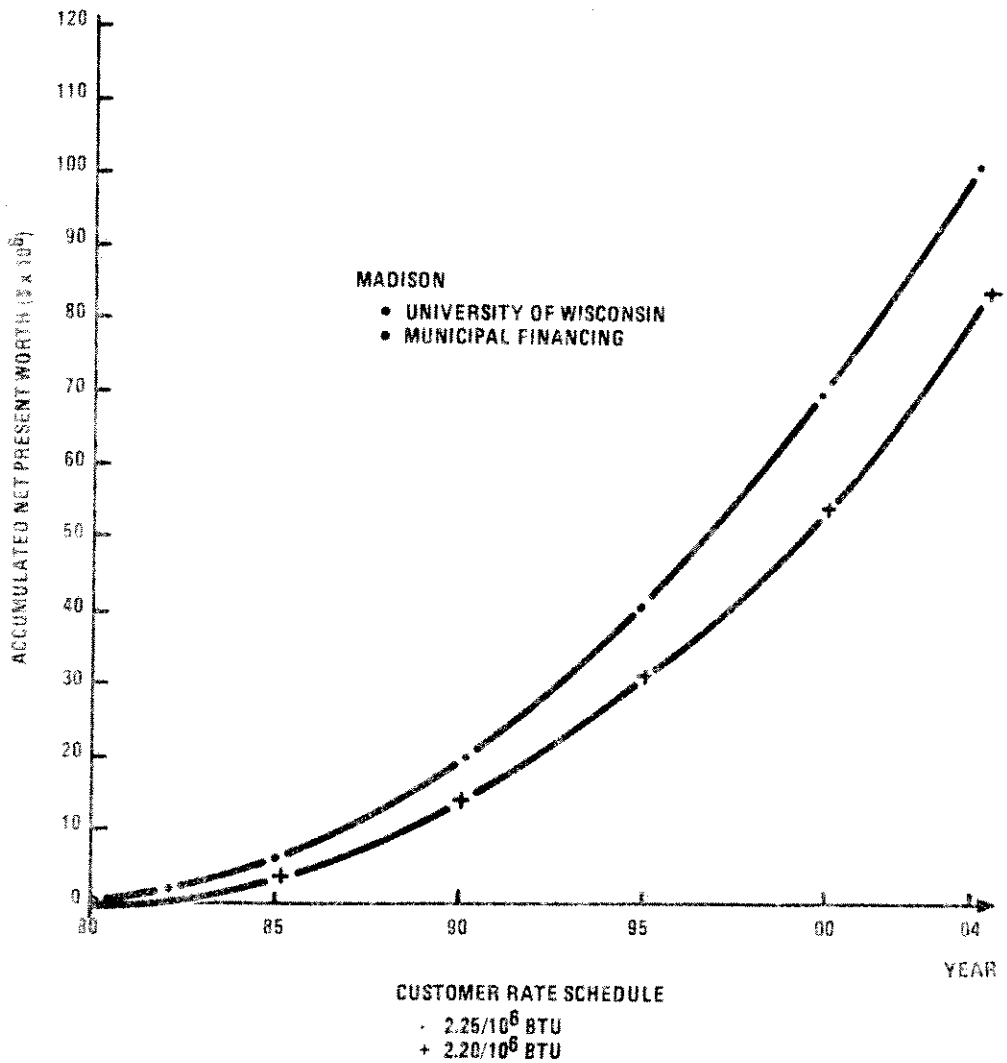

Figure G-33. Accumulated Net Present Worth versus Year

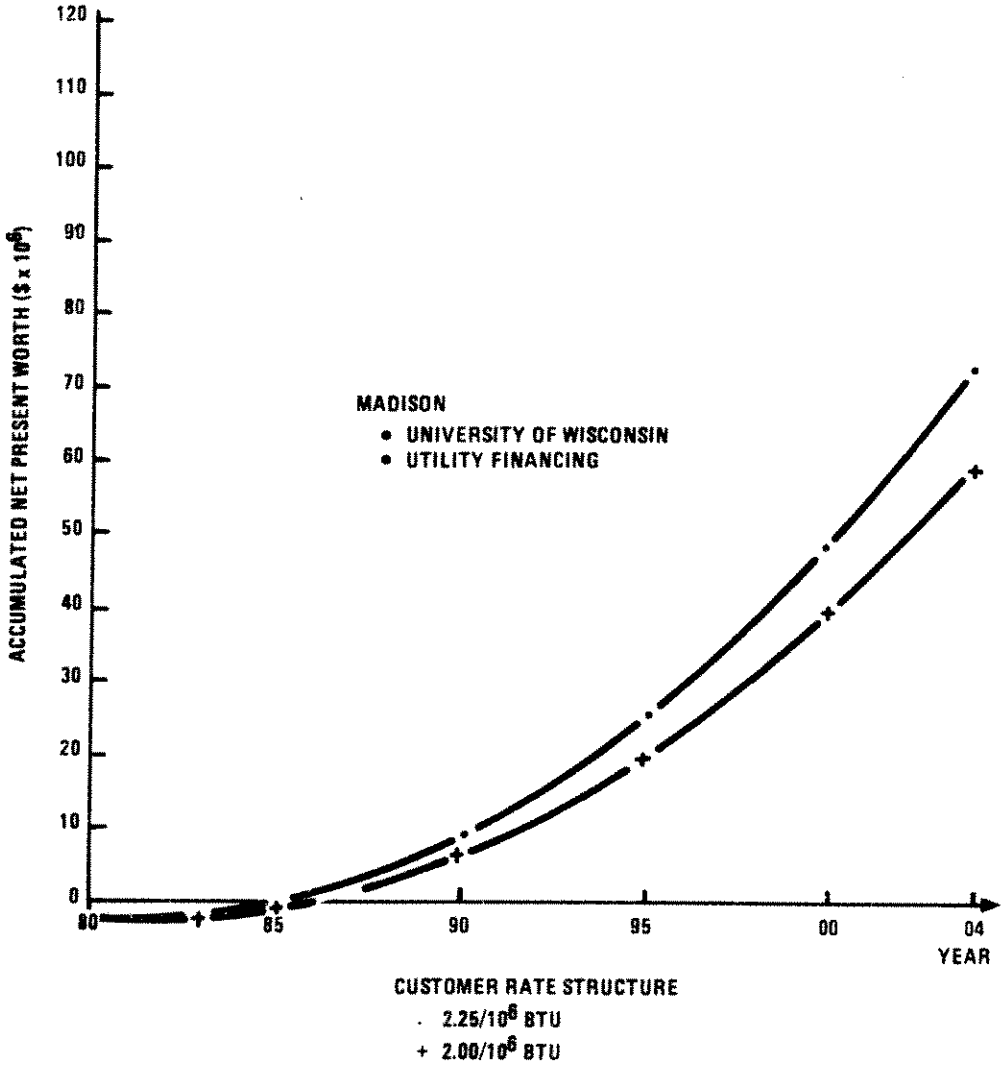

Figure G-34. Accumulated Net Present Worth versus Year

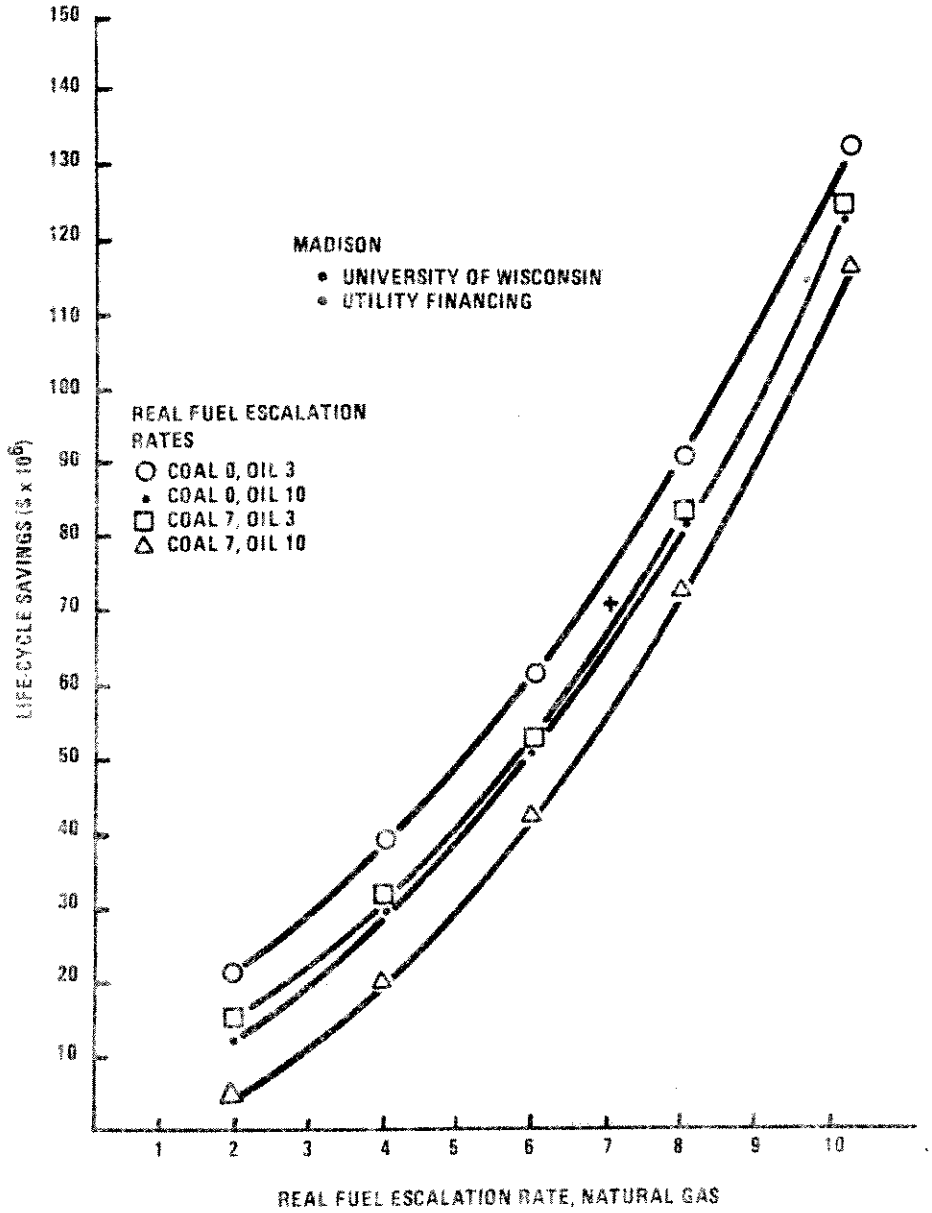

Figure G-35. Life-Cycle Costs versus Real Fuel Escalation Rate, Natural Gas

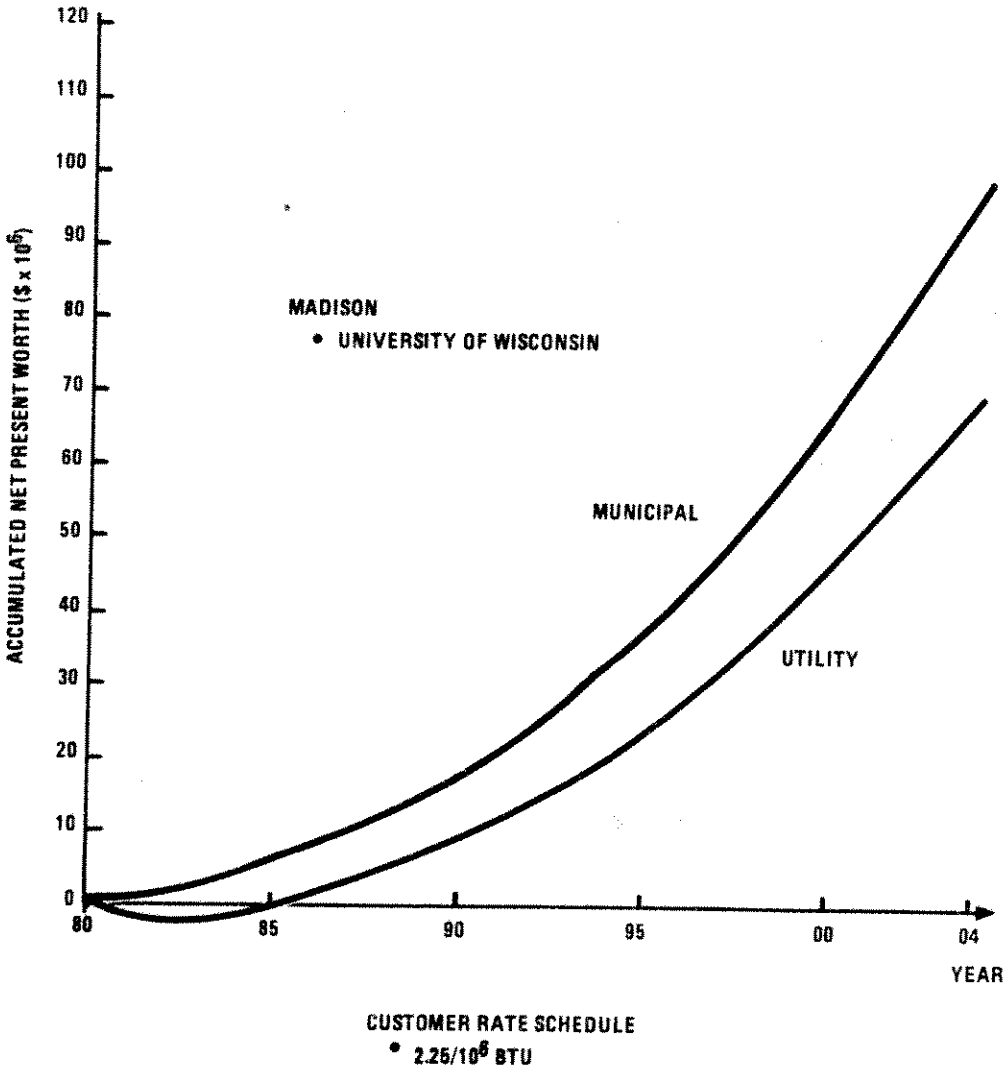

Figure G-36. Accumulated Net Present Worth versus Year

Table G-78. Operations and Maintenance Data (x 1000), Madison University of Wisconsin Alternative

YEAR	MAINTENANCE 1% OF COST (14.2×10^6)	INSURANCE 0.2% OF COST (2.4×10^6)	OPERATION 293,900 KHW/YR AT 0.03/KWH	TOTAL O & M DISTRIBUTION	PLANT RETROFIT O & M	TOTAL O & M
1980	142	28	9	179	74	253
1981	152	30	10	192	69	261
1982	163	32	10	205	82	287
1983	174	34	11	219	120	339
1984	186	37	12	235	145	380
1985	199	39	13	251	153	404
1986	213	42	14	269	173	442
1987	228	45	14	287	176	463
1988	244	48	15	307	193	500
1989	261	51	17	329	212	541
1990	279	55	18	352	228	580
1991	299	59	19	377	244	621
1992	320	63	20	403	261	664
1993	342	67	22	431	279	710
1994	366	72	23	461	299	760
1995	392	77	25	494	320	814
1996	419	83	27	529	342	853
1997	448	88	28	564	866	930
1998	480	95	30	605	392	997
1999	513	101	33	647	419	1066
2000	550	108	35	693	449	1142
2001	588	116	37	741	480	1221
2002	629	124	40	793	514	1307
2003	673	133	43	849	549	1398
2004	720	142	46	908	588	1496

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Table G-79. Return Requirements (x 1000), Madison, University of Wisconsin Alternative, Utility Financing Option

YEAR	RETURN PV	ACC. PV
1980	2945	2945
1981	2815	5760
1982	2434	8194
1983	2102	10296
1984	1813	12109
1985	1560	13669
1986	1341	15010
1987	1152	16162
1988	986	17148
1989	843	17991
1990	720	18711
1991	618	19329
1992	525	19854
1993	448	20302
1994	378	20680
1995	322	21002
1996	272	21274
1997	299	21503
1998	196	21699
1999	163	21862
2000	139	22001
2001	116	22117
2002	100	22217
2003	83	22300
2004	70	22373

Table G-80. Revenue Requirements (x 1000), Madison, University of Wisconsin Alternative, Municipal Financing Option

CAPITAL COSTS $16,600,000

BOOK LIFE 27 years

DEPRECIATION METHOD: STRAIGHT LINE

BOND RATE 8%

DISCOUNT RATE 8%

Year	Book Dep	Net Dep	Invest	Ret	Total Ret	PU	Acc PU
1980	615.	0.	16600.	1328.	1943.	1799.	1799.
1981	615.	615.	15985.	1279.	1894.	1623.	3422.
1982	615.	1230.	15370.	1230.	1844.	1464.	4887.
1983	615.	1844.	14756.	1180.	1795.	1320.	6206.
1984	615.	2459.	14141.	1131.	1746.	1188.	7394.
1985	615.	3074.	13526.	1082.	1697.	1069.	8464.
1986	615.	3689.	12911.	1033.	1648.	961.	9425.
1987	615.	4304.	12296.	984.	1599.	864.	10289.
1988	615.	4919.	11681.	935.	1549.	775.	11064.
1989	615.	5533.	11067.	885.	1500.	695.	11759.
1990	615.	6148.	10452.	836.	1451.	622.	12381.
1991	615.	6763.	9837.	787.	1402.	557.	12938.
1992	615.	7378.	9222.	738.	1353.	497.	13435.
1993	615.	7993.	8607.	689.	1303.	444.	13879.
1994	615.	8607.	7993.	639.	1254.	395.	14274.
1995	615.	9222.	7378.	590.	1205.	352.	14626.
1996	615.	9837.	6763.	541.	1156.	312.	14938.
1997	615.	10452.	6148.	492.	1107.	277.	15215.
1998	615.	11067.	5533.	443.	1057.	245.	15460.
1999	615.	11681.	4919.	393.	1008.	216.	15677.
2000	615.	12296.	4304.	344.	959.	191.	15867.
2001	615.	12911.	3689.	295.	910.	167.	16035.
2002	615.	13526.	3074.	246.	861.	147.	16181.
2003	615.	14141.	2459.	197.	812.	128.	16309.
2004	615.	14756.	1844.	148.	762.	111.	16420.

Table G-81. Fuel/O & M Data (x 1000), Madison, University of Wisconsin, Alternative, Utility Financing Option

COAL COST = 1.58/10-6 BTU
OIL COST = 2.67/10-6 BTU
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 9.54%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	905.	44.	949.	253.	1202.	1098.	1098.
1981	568.	96.	664.	261.	925.	771.	1869.
1982	627.	114.	740.	287.	1027.	781.	2650.
1983	648.	130.	778.	339.	1117.	776.	3426.
1984	674.	185.	859.	380.	1239.	786.	4211.
1985	635.	266.	901.	404.	1305.	756.	4967.
1986	630.	452.	1082.	442.	1524.	805.	5772.
1987	863.	459.	1322.	463.	1785.	861.	6633.
1988	909.	675.	1584.	500.	2084.	918.	7551.
1989	902.	803.	1705.	541.	2246.	903.	8454.
1990	1086.	824.	1910.	580.	2490.	914.	9368.
1991	1205.	916.	2121.	621.	2742.	919.	10287.
1992	1338.	1018.	2355.	664.	3019.	923.	11210.
1993	1485.	1131.	2615.	710.	3325.	929.	12139.
1994	1648.	1256.	2904.	760.	3664.	934.	13073.
1995	1829.	1395.	3225.	814.	4039.	940.	14013.
1996	2031.	1550.	3581.	853.	4434.	942.	14954.
1997	2254.	1722.	3976.	930.	4906.	952.	15906.
1998	2502.	1914.	4415.	997.	5412.	958.	16864.
1999	2777.	2126.	4903.	1066.	5969.	965.	17829.
2000	3082.	2362.	5444.	1142.	6586.	972.	18801.
2001	3422.	2624.	6046.	1221.	7267.	979.	19780.
2002	3798.	2915.	6713.	1307.	8020.	986.	20766.
2003	4216.	3239.	7455.	1398.	8853.	994.	21760.
2004	4679.	3599.	8278.	1496.	9774.	1002.	22762.

Table G-82. Fuel/O & M Data (x 1000), Madison, University of Wisconsin
Alternative, Municipal Financing Option

COAL COST = 1.58×10-6 $/B
OIL COST = 2.67×10-6 $/B
COAL ESC RATE = 11.0%
OIL ESC RATE = 11.1%
DISCOUNT RATE = 8.00%

YEAR	COAL	OIL	TOTAL FUEL	O&M	TOTAL FUEL/O&M	PV	ACC PV
1980	905.	44.	949.	253.	1202.	1113.	1113.
1981	568.	96.	664.	261.	925.	793.	1906.
1982	627.	114.	740.	287.	1027.	815.	2722.
1983	648.	130.	778.	339.	1117.	821.	3543.
1984	674.	155.	829.	380.	1209.	843.	4386.
1985	635.	266.	901.	404.	1305.	825.	5209.
1986	630.	452.	1082.	442.	1524.	889.	6098.
1987	863.	459.	1322.	463.	1785.	964.	7062.
1988	909.	675.	1584.	500.	2084.	1042.	8104.
1989	902.	803.	1705.	541.	2246.	1040.	9145.
1990	1086.	824.	1910.	580.	2490.	1068.	10213.
1991	1205.	916.	2121.	621.	2742.	1088.	11301.
1992	1388.	1018.	2455.	664.	3019.	1110.	12412.
1993	1405.	1131.	2615.	710.	3325.	1132.	13544.
1994	1648.	1256.	2904.	760.	3664.	1155.	14699.
1995	1829.	1395.	3225.	814.	4039.	1179.	15878.
1996	2081.	1550.	3581.	853.	4434.	1198.	17076.
1997	2254.	1722.	3976.	930.	4906.	1228.	18304.
1998	2500.	1914.	4415.	997.	5412.	1254.	19558.
1999	2777.	2126.	4903.	1066.	5969.	1281.	20838.
2000	3082.	2362.	5444.	1142.	6586.	1308.	22147.
2001	3422.	2624.	6046.	1221.	7267.	1337.	23484.
2002	3798.	2915.	6713.	1307.	8020.	1366.	24850.
2003	4216.	3239.	7455.	1398.	8853.	1396.	26246.
2004	4679.	3599.	8278.	1496.	9774.	1427.	27673.

Table G-83. Gross Income Data (x 1000), Madison, University of Wisconsin Alternative, Utility Financing Option

DISCOUNT RATE = 8.00%
FUEL QUANTITY = 215.10/10-9 BTU/YR
FUEL COST = 2.25/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV	YEAR	INCOME	PV	ACC PV
1980	2881.	2448.	2448.	1980	3017.	2754.	2754.
1981	3057.	2548.	4995.	1981	3439.	2866.	5620.
1982	3485.	2651.	7647.	1982	3920.	2983.	8602.
1983	3973.	2759.	10406.	1983	4469.	3104.	11707.
1984	4529.	2872.	13277.	1984	5095.	3230.	14937.
1985	5163.	2988.	16266.	1985	5808.	3362.	18299.
1986	5886.	3110.	19376.	1986	6621.	3499.	21798.
1987	6710.	3237.	22613.	1987	7548.	3641.	25439.
1988	7649.	3369.	25981.	1988	8605.	3790.	29229.
1989	8720.	3506.	29487.	1989	9810.	3944.	33173.
1990	9941.	3648.	33136.	1990	11188.	4105.	37277.
1991	11332.	3797.	36933.	1991	12749.	4272.	41549.
1992	12919.	3952.	40884.	1992	14534.	4446.	45995.
1993	14727.	4112.	44997.	1993	16568.	4627.	50621.
1994	16789.	4280.	49277.	1994	18888.	4815.	55436.
1995	19140.	4454.	53731.	1995	21532.	5011.	60447.
1996	21819.	4636.	58366.	1996	24547.	5215.	65662.
1997	24874.	4824.	63191.	1997	27983.	5427.	71089.
1998	28356.	5021.	68211.	1998	31901.	5648.	76738.
1999	32326.	5225.	73436.	1999	36367.	5878.	82616.
2000	36852.	5438.	78874.	2000	41458.	6118.	88734.
2001	42011.	5659.	84534.	2001	47262.	6367.	95100.
2002	47892.	5890.	90423.	2002	53879.	6626.	101726.
2003	54597.	6130.	96553.	2003	61422.	6896.	108622.
2004	62241.	6379.	102932.	2004	70021.	7176.	115798.

Table G-84. Gross Income Data (x 1000), Madison, University of Wisconsin
Alternative, Municipal Financing Option

DISCOUNT RATE = 8.00%
FUEL QUANTITY = 1176.05/10-9 BTU/YR
FUEL COST = 2.00/10-6 BTU
ESCALATION RATE = 14.0%

YEAR	INCOME	PV	ACC PV	YEAR	INCOME	PV	ACC PV
1980	2681.	2483.	2483.	1980	3017.	2793.	2793.
1981	3057.	2621.	5103.	1981	3439.	2948.	5741.
1982	3485.	2766.	7870.	1982	3920.	3112.	8853.
1983	3973.	2920.	10790.	1983	4469.	3285.	12138.
1984	4529.	3082.	13872.	1984	5095.	3467.	15606.
1985	5163.	3253.	17125.	1985	5808.	3660.	19266.
1986	5886.	3434.	20560.	1986	6621.	3863.	23130.
1987	6710.	3625.	24185.	1987	7548.	4078.	27208.
1988	7649.	3826.	28011.	1988	8605.	4305.	31512.
1989	8720.	4039.	32050.	1989	9810.	4544.	36056.
1990	9941.	4263.	36313.	1990	11183.	4796.	40852.
1991	11332.	4500.	40813.	1991	12749.	5063.	45915.
1992	12919.	4750.	45564.	1992	14534.	5344.	51259.
1993	14727.	5014.	50578.	1993	16568.	5641.	56900.
1994	16789.	5293.	55870.	1994	18888.	5954.	62854.
1995	19140.	5587.	61457.	1995	21532.	6285.	69139.
1996	21819.	5897.	67354.	1996	24547.	6634.	75773.
1997	24874.	6225.	73579.	1997	27983.	7003.	82776.
1998	28356.	6570.	80149.	1998	31901.	7392.	90168.
1999	32326.	6935.	87085.	1999	36367.	7802.	97970.
2000	36852.	7321.	94405.	2000	41458.	8236.	106206.
2001	42011.	7728.	102133.	2001	47262.	8693.	114900.
2002	47892.	8157.	110290.	2002	53879.	9176.	124076.
2003	54597.	8610.	118900.	2003	61422.	9686.	133762.
2004	62241.	9088.	127988.	2004	70001.	10224.	143987.

Table G-85. Annual Savings (x 1000), Madison, University of Wisconsin Alternative, Utility Financing Option

GROSS INCOME	UTILITY REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
62076 AT 9% 78937 AT 11% 101622 AT 13% 132303 AT 15% 173968 AT 17%	22373	17932	21771 38632 61317 91998 133663	C - 0 O - 3
62076 AT 9% 78937 AT 11% 101622 AT 13% 132303 AT 15% 173968 AT 17%		27843	11860 28721 51406 82087 123752	C - 0 O - 10
62076 AT 9% 78937 AT 11% 101622 AT 13% 132303 AT 15% 173968 AT 17%		26657	13046 29907 52592 83273 124938	C - 7 O - 3
62076 AT 9% 78937 AT 11% 101622 AT 13% 132303 AT 15% 173968 AT 17%		36568	3134 19995 42680 73361 115026	C - 7 O - 10
115798 102932		22762	70663 57797	C - 4 O - 4.1 NG - 7

Table G-86. Annual Savings (x 1000), Madison, University of Wisconsin Alternative, Municipal Financing Option

GROSS INCOME	MUNICIPAL REV. REQ.	FUEL/O & M	ANNUAL SAVINGS	REAL FUEL ESCALATION RATES
74738 AT 9%	16420	21514	36804	C - 0
96312 AT 11%			58378	O - 3
125587 AT 13%			87653	
165487 AT 15%			127553	
220052 AT 17%			182118	
74738 AT 9%		34466	23852	C - 0
96312 AT 11%			45426	O - 10
125587 AT 13%			74701	
165487 AT 15%			114601	
220052 AT 17%			169166	
74738 AT 9%		32702	25616	C - 7
96312 AT 11%			47190	O - 3
125587 AT 13%			76465	
165487 AT 15%			116365	
220052 AT 17%			170930	
74738 AT 9%		45654	12664	C - 7
96312 AT 11%			34238	O - 10
125587 AT 13%			63513	
165487 AT 15%			103413	
220052 AT 17%			157978	
143987		27673	99894	C - 4
127988			83895	O - 4
				NG - 7