ALTERNATIVE FUEL/COGENERATION STUDY

FOR

ST. PETER STATE HOSPITAL

PREPARED FOR

DEPARTMENT OF ADMINISTRATION

AND STATE PLANNING AGENCY

JANUARY 31, 1986

PREPARED BY

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INTRODUCTION

The Minnesota Legislature allocated $ 100,000 to the Department of Human Services to complete several studies examining the feasibility of burning refuse and using cogeneration at State owned institutions. This funding was administered by the State Planning Agency with the assistance of the Department of Administration. As a part of this funding, the Department of Administration contracted with Sam Stewart & Associates to conduct a detailed refuse/cogeneration feasibility study for the St. Peter State Hospital.

This study was begun on December 20, 1985 and a report was presented to the Department of Administration and State Planning Agency on January 31, 1986.

Three major programs were evaluated in this study. The first was the installation of a new boiler at the State Hospital to burn either densified refuse derived fuel or green wood. This program examines the availability and cost of refuse and wood, initial cost of new equipment, annual operating cost savings and payback for refuse and wood fuels.

The second program was the use of cogeneration. Historical energy use data was collected and thermal and electric load profiles were developed. Different cogeneration operating cycles were analyzed as well as the opportunities for selling the excess electricity generated. Three energy sources were considered for cogeneration; refuse, wood, and natural gas. Estimates of initial cost of new equipment, annual operating cost savings, and payback were provided for each energy source option.

In the process of conducting this study, two additional energy cost saving options were identified. These options, unrelated to refuse burning or cogeneration, became the third program in the study. The first option was utility electric demand peak shaving. The second option was to combine the Upper and Lower Campus electric meters into one bill.

1.0 EXECUTIVE SUMMARY

1.1 DEFINITION OF COGENERATION

Cogeneration is defined as the simultaneous production of useful thermal and electric energy. Cogeneration combines on-site generation of electricity with conventional utility delivered electricity. A cogeneration system operates at an overall thermal efficiency as much as 2-1/2 times to 3 times that of conventional utility electrical generation systems. The reason for this is that electricity is generated at the point of use, thereby allowing the normally wasted exhaust heat to be captured and partially used for thermal or electric energy production.

The three most common configurations for cogeneration systems are steam turbines, gas turbines and reciprocating engines. These are discussed in more detail in Section 7.1.

There are three factors which significantly affect the economic feasibility of a cogeneration project. First, the energy user should have significant requirements for process or other heat uses, generally from steam or hot water. The combination of the production of heat with the generation of electricity typically makes a cogeneration project attractive.

Second, the on-site generating plant must be integrated with the utility distribution in order to transfer excess power to the utility or to purchase power from the utility. In addition, there must be a contractual arrangement with the electric utility to purchase excess power from the cogenerator at a reasonable buyback rate.

Third, the institution should have high electric rates compared to natural gas or another primary fuel source such as refuse or wood. This allows the institution to generate high priced electricity with a lower priced primary fuel.

1.2 SCOPE AND OBJECTIVES

This study has two objectives; the first objective is to determine the economic feasibility of using wood or refuse as an alternate energy source; the second objective is to determine the economic feasibility of cogeneration.

The use of on-site cogeneration has been expanded significantly during the last few years because of Federal legislation which requires electric utilities to purchase power from qualified cogeneration plants. The rate paid users for this power is based on the utilities avoided costs of producing the equivalent power. This atmosphere provides a strong incentive for large energy users such as St. Peter State Hospital to carefully investigate cogeneration systems.

The options evaluated in this study are based on the current energy requirements at St. Peter State Hospital. Our analysis includes a detailed hour by hour simulation of thermal and electric loads. This level of detail is necessary to determine whether the Hospitals thermal demand is greater than or less than the cogeneration systems thermal output capacity.

The hour by hour analysis of thermal and electric loads mandates using a computer program. The program we selected was developed by Integrated Energy Systems, Inc. (IES). The IES software package has the following two features which are necessary to perform a comprehensive analysis:

- o Cost savings are calculated for two possible contractural arrangements with the local electric utility company: buy-all, sell-all or offset-load, sell-surplus.

- o If the minimum thermal demand (which is an input to the program) is less than system capability, the system is operated at part-load.

For St. Peter State Hospital, we have selected the Offset-Load, Sell-Surplus as the appropriate contractual arrangement with the electric utility company. In this mode, the cogenerator offsets his load with his system and therefore pays the utility company only for his net consumption. If he generates more than he uses, the utility company buys only that excess at the agreed upon "avoided cost" rates. Standby charges are a part of the rate structure.

The St. Peter State Hospital has a 800 KW continuous duty diesel engine generator set in place. The cogeneration options analyzed in this report assume this unit can be run for short intervals to avoid paying utility standby charges.

Each Offset-Load, Sell-Surplus cogeneration option discussed in this report is analyzed using buy back rates from the City of St. Peter Municipal Electric Utility and from NSP. Selling electric energy to NSP would require the City of St. Peter Municipal Electric Utility to wheel the power. We have assumed a $ 0.001/KWH wheeling charge in our calculations.

1.3 FACILITY DESCRIPTION

The St. Peter State Hospital is located in the southwest corner of St. Peter. It includes thirty-two (32) buildings and is divided into an Upper and Lower Campus. Figure 1 shows Lower Campus buildings. The total heated area is 721,000 square feet. The total cooled area is approximately 230,000 square feet.

High pressure steam (125 PSIG) is generated at the power plant on the Lower Campus. Steam is supplied to all Lower and Upper Campus buildings through tunnels or via direct burial.

The Lower Campus purchases 4,160 volt electric power from the City of St. Peter Municipal Electric Utility. The Upper Campus purchases secondary voltage electric power from the City through a separate electric meter.

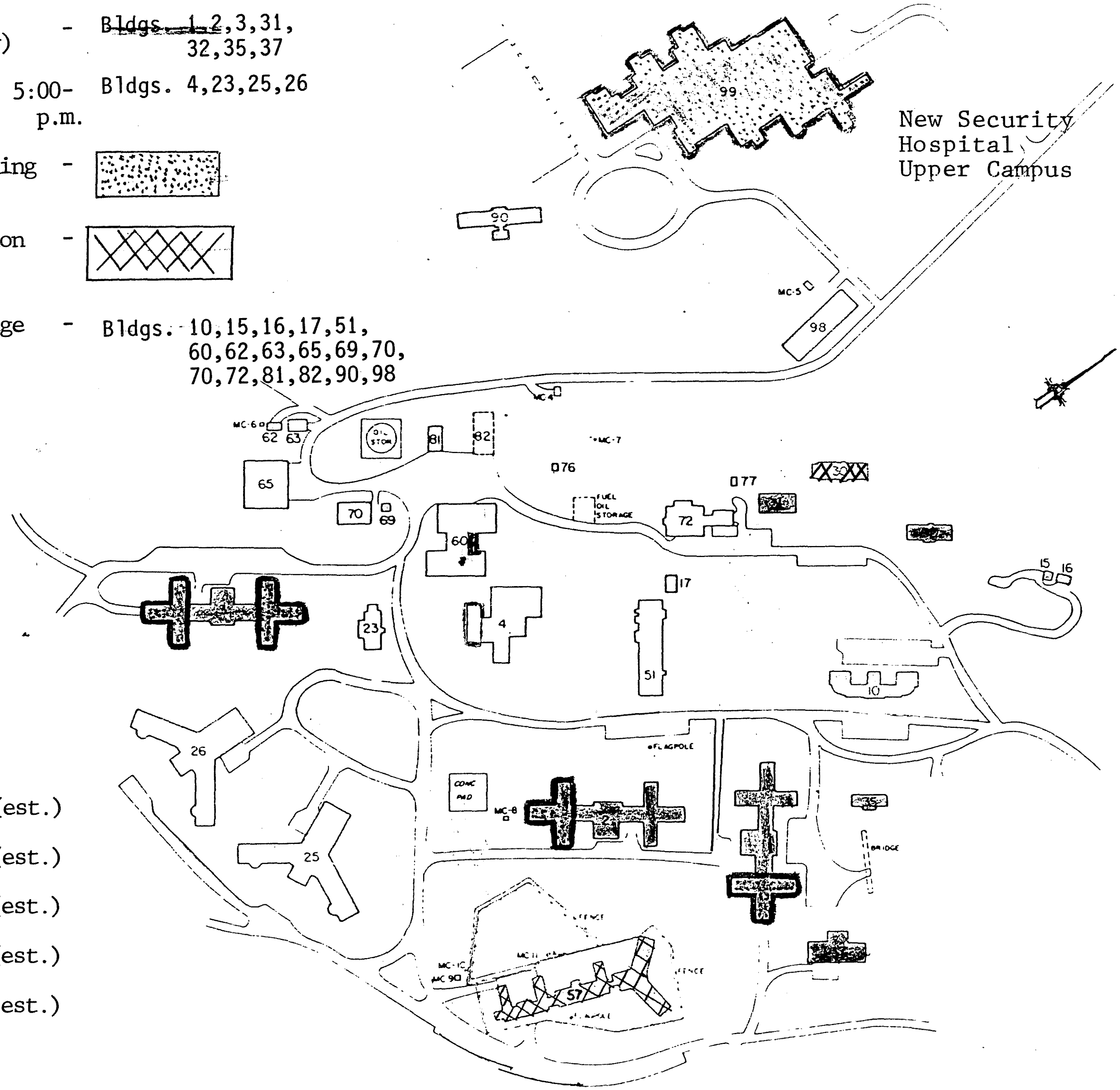
Patient/Resident bldg. (24 hour occupancy) - ~~Bldgs. 1,~~2,3,31, 32,35,37

Academic (Program) - 7:30 a.m. - 5:00-p.m. Bldgs. 4,23,25,26

Areas with central air conditioning -

Buildings scheduled for demolition -

Indicates Admin/Supportive/Storage - Bldgs. 10,15,16,17,51, 60,62,63,65,69,70, 70,72,81,82,90,98



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Air Conditioned Areas

Building #1 - 27,000 sq.ft. (est.)

Building #2 - 29,000 sq.ft. (est.)

Building #3 - 58,000 sq.ft. (est.)

Building #4 - 1,500 sq.ft. (est.)

Building #60 - 720 sq.ft. (est.)

Building #99 - 117,072 sq.ft.

ST. PETER STATE HOSPITAL

1.4 SUMMARY OF ALTERNATIVE FUEL / COGENERATION / OTHER OPTIONS

OPTIONS	SYSTEM DESCRIPTION	EQUIPMENT REQUIRED	Heat Recovery For Steam Production	Heat Recovery For Preheating Water	ADDITIONAL BUILDINGS REQUIRED
Alternative Fuel Options					
OPTION 1 - REFUSE FIRED BOILER	REFUSE TO ENERGY SYSTEM DESIGNED TO BURN DENSIFIED REFUSE DERIVED FUEL (DRDF)	INSTALL A 20,000 LB/HR REFUSE FIRED 125 PSIG STEAM BOILER			CONSTRUCT AN ADDITION TO THE EXISTING POWER PLANT TO HOUSE THE REFUSE BOILER
OPTION 2 - WOOD FIRED BOILER	WOOD TO ENERGY SYSTEM DESIGNED TO BURN GREEN CHIPS AND BARK	INSTALL A 20,000 LB/HR WOOD FIRED 125 PSIG STEAM BOILER			CONSTRUCT AN ADDITION TO THE EXISTING POWER PLANT TO HOUSE THE WOOD BOILER
Cogeneration Options					
OPTION 3 - RECIPROCATING GAS ENGINE COGENERATION	BASELOADED, THERMALLY SIZED, OFF-SET LOAD,SELL SURPLUS	INSTALL ONE 460 KW NATURAL GAS ENGINE GENERATOR SET	RECOVER EXHAUST HEAT FOR THE PRODUCTION OF 125 PSIG STEAM	RECOVER HEAT FROM JACKET WATER FOR PREHEATING BOILER MAKE-UP WATER	CONSTRUCT AN ADDITION TO THE EXISTING POWER PLANT TO HOUSE THE NEW ENGINE GENERATOR SET
OPTION 4 - GAS TURBINE COGENERATION	BASELOADED, THERMALLY SIZED, OFF-SET LOAD,SELL SURPLUS	INSTALL ONE 440 KW NATURAL GAS ENGINE GENERATOR SET	RECOVER EXHAUST HEAT FOR THE PRODUCTION OF 125 PSIG STEAM		CONSTRUCT AN ADDITION TO THE EXISTING POWER PLANT TO HOUSE THE NEW TURBINE GENERATOR SET
OPTION 5 - REFUSE FIRED BOILER WITH STEAM TURBINE COGENERATION	BASELOADED, THERMALLY SIZED, OFF-SET LOAD,SELL SURPLUS	INSTALL A 100 KW BACK PRESSURE STEAM TURBINE GENERATOR SET			NOT APPLICABLE
OPTION 6 - WOOD FIRED BOILER WITH STEAM TURBINE COGENERATION	BASELOADED, THERMALLY SIZED, OFF-SET LOAD,SELL SURPLUS	INSTALL A 100 KW BACK PRESSURE STEAM TURBINE GENERATOR SET			NOT APPLICABLE
Other Energy Cost Saving Options					
OPTION 7 - NEGOTIATED PURCHASE ARRANGEMENT	ELECTRIC DEMAND PEAK SHAVING	INSTALL A 500 KW DIESEL ENGINE GENERATOR SET WHICH WOULD OPERATE LESS THAT 400 HOURS/YEAR			NOT APPLICABLE
OPTION 8 - MODIFY THE ELECTRIC METERS	COMBINE THE UPPER AND LOWER CAMPUS ELECTRIC METERS INTO ONE ELECTRIC BILL FOR THE ENTIRE STATE HOSPITAL	NOT APPLICABLE			NOT APPLICABLE

1.5 ECONOMIC SUMMARY

The options evaluated in this study were based on the current energy requirements at the St. Peter State Hospital. A summary of the economics of each option is shown below.

		Utility Buy-Back	Initial Cost of System	Annual Cost Savings	Payback Period (Years)
ALTERNATE FUEL OPTIONS					
Option #1	Refuse Fired Boiler		$ 1,050,000	$ 28,482	36.86
Option #2	Wood Fired Boiler		1,100,000	87,234	12.61
COGENERATION OPTIONS					
Option #3	Reciprocating Gas Engine Cogeneration	SMMPA	378,768	51,395	7.37
	(without standby charges)	NSP	379,400	54,455	6.96
Option #4	Gas Turbine Cogeneration	SMMPA	916,550	49,688	18.45
		NSP	924,500	51,777	17.86
Option #5	Refuse Fired Boiler with Steam Turbine	SMMPA	1,282,000	56,365 *	22.70
	Cogeneration	NSP	1,282,000	56,365 *	22.70
Option #6	Wood Fired Boiler with Steam Turbine	SMMPA	1,332,000	115,939 *	11.49
	Cogeneration	NSP	1,332,000	115,939 *	11.49
OTHER ENERGY COST SAVING OPTIONS					
Option #7	Negotiated Purchase Arrangement		100,000	36,172	2.76
Option #8	Modify the Electric Meters		0	5,155	immediate

* All electric power is used on site, therefore SMMPA and NSP buy-back rates are not relevent.

1.6 OBSERVATIONS AND RECOMMENDATIONS

OBSERVATIONS

GENERAL

1. The price of natural gas from Minnegasco decreased three times during 1985 as follows:

April 27, 1985	from	$ 4.01 per MCF to $ 3.80 per MCF
October 27, 1985	from	$ 3.80 per MCF to $ 3.70 per MCF
December 27, 1985	from	$ 3.70 per MCF to $ 3.52 per MCF

2. The price of electric power from the City of St. Peter Municipal Electric Company decreased approximately 0.8 cents per KWH during October, 1985. (From approximately 5.8 cents per KWH to approximately 5.0 cents per KWH)

ALTERNATIVE FUELS

3. Because of the difficulties in matching thermal requirements with refuse availability, densified refuse derived fuel (DRDF) would be the preferred fuel if the State Hospital converted to refuse burning. A facility to convert refuse to DRDF would be built by a third party. Fuel from this facility would cost approximately $ 40.00 per ton delivered.

4. At the present time there is adequate refuse available in the area surrounding St. Peter to provide all of the thermal requirements of the St. Peter State Hospital. However, refuse availability could become a problem if NSP constructed a refuse derived fuel (RDF) plant near the Wilmarth Power Plant.

5. NSP is converting their Wilmarth Power Plant in Mankato to burn refuse derived fuel. This plant is expected to be operational by July, 1987. In conjunction with this facility, NSP is considering building a plant near Wilmarth which would produce refuse derived fuel.

6. There is an adequate supply of green waste wood from Minnesota Valley Forest Products in nearby Courtland. This wood is available at $ 18.00 per ton delivered.

COGENERATION

7. In order for cogeneration to be economically attractive, the purchased power rates should be high relative to the fuel source used to operate the cogeneration system.

8. Utility buy-back rates for electric power for qualifying cogeneration systems are less than 60% of the rate for purchased power.

RECOMMENDATIONS

ALTERNATIVE FUELS

1. With the present cost of natural gas and DRDF, the State Hospital would only realize a small fuel cost savings if they installed a refuse fired boiler. Because the payback for the refuse boiler is estimated to be over 35 years, it should not be seriously considered at this time. However, there are other circumstances that could affect a decision to convert the State Hospital to burn refuse:

- First, because the payback for this type of system is very sensitive to fuel costs, a significant rise in natural gas rates or a significant drop in the price of DRDF would shorten the payback.

- Second, as landfill regulations become more rigid in the next 5 to 10 years, refuse disposal costs will increase. This could lower the cost of DRDF and shorten the payback for installing a refuse fired boiler.

- Third, as groundwater pollution problems with sanitary landfills increase, the State may decide that burning refuse is a more environmentally sound option.

2. If the State Hospital installed a refuse energy system, they should have a guaranteed supply of refuse. An agreement would have to be negotiated with the County Boards in each of the surrounding counties which required that all of the waste collected in their county be delivered to the DRDF plant.

3. With the present cost of natural gas and waste wood, the payback for converting to a wood energy system would be over 12 years. As with a refuse burning system, the payback for a wood energy system is very sensitive to the costs of natural gas and waste wood. If natural gas rates were to rise or if wood costs were to drop, the payback might be short enough for the State to consider this option.

COGENERATION

4. At current fuel costs, the only option that appears economically feasible is reciprocating natural gas engine cogeneration. The payback for this system is approximately 7 years. This option requires that the State Hospital use their existing diesel engine generator for electric backup when the primary system is down for maintenance or repairs. Otherwise, they would be required to pay utility stand-by charges, lengthening the payback.

5. The buy-all, sell-all * contractual arrangement is not cost-effective for any cogeneration option because of the large difference between purchased power and buyback rates. The thermal savings with cogeneration is not large enough to offset the rate difference. Therefore, the contractual arrangement with the City of St. Peter Municipal Electric Company should be off-set load, sell-surplus. * Under this option, the cogeneration electricity is principally used on site.

   * See page 43 for definitions.

OTHER OPTIONS

6. The State Hospital should discuss with the City of St. Peter Municipal Electric Company a negotiated purchase arrangement to reduce the utility peak electric demand. The resultant savings could be shared by the City and the Hospital.

7. The State Hospital should also discuss with the City the possibility of combining the Upper and Lower Campus electric meter readings into one bill. This would reduce the electric demand charges and save the State Hospital approximately $ 5,000 annually at current electric rates.

2.0 EXISTING THERMAL AND ELECTRIC SYSTEMS

2.1 THERMAL SYSTEMS

The power plant contains five (5) boilers as described below:

	Manufacturer	Type	Year Installed	Hp	Maximum Steam Flow Lbs/Hr	General Condition
#1	Bros	Water Tube	1965	870	30,000	good
#2	Bros	Water Tube	1965	870	30,000	good
#3	Bros	Water Tube	1965	435	15,000	good
#4	Bros	Water Tube	1965	435	15,000	good
#5	C.B.	Fire Tube	1985	250	8,625	new

The above boilers are capable of burning either natural gas or No. 6 oil to provide 125 PSIG steam. Boiler #5 is a combination high/low pressure boiler installed for summer operation.

High pressure steam is supplied to both the lower and upper campus. Steam lines for the lower campus are installed in utility and passage tunnels. The 4 inch steam line to the upper campus is direct buried along with a 2 inch condensate return and a 3 inch hot water line.

The maximum steam demand for 1985 was 29,400 Lbs/Hr and the minimum steam demand was approximately 2,000 Lbs/Hr. The annual steam consumption for 1985 was approximately 82,486 MLbs.

The boiler plant has oil storage capacity of 600,000 gallons.

Early in 1985, a study was conducted to determine the feasibility of using deionized water for boiler feedwater at St. Peter State Hospital. The Hospital has two wells, #149 and #154, which supply water for the entire campus. Well #149 is used primarily for standby. The poor well water quality at St. Peter State Hospital results in:

- sludge in the boiler and scaling of the tubes
- corrosion in the condensate return lines
- blow down of large quantities of water
- the use of high amounts of chemical additives
- reduced boiler efficiency

The study concluded that a new reverse Osmosis/Deionization System would have a payback of 4.25 years.

2.2 ELECTRIC UTILITY SERVICES

The St. Peter State Hospital has the following four electric meter stations:

- Central meter for the lower campus
- Meter for the upper campus (Minnesota Security Hospital)
- Meter for Gluek Building (Recreation Park)
- Meter for street lighting (Highway #333 Upper Campus)

Tables 2 - 5 show the annual electric energy consumption and cost data for two years for each meter station.

The lower and upper campus and the street lighting are served by the City of St. Peter Municipal Electric Utility. The Gluek Building is served by Frost Benco, an REA. Each metering station is billed separately.

The central meter for the lower campus is located on a power pole near the Northeast corner of the State property. Electric power from this metering station is distributed via two 4,160 volt underground feeders to switchgear in Shantz Hall. From Shantz Hall, 4,160 volt power is looped around the campus to accomodate all buildings.

The meter for the upper campus is located in the Security Hospital Building. Electric power is supplied to this site at 13,800 volts.

In 1982, a 940 KW, 1,175 KVA engine generator set was installed in the boiler house to meet the emergency power needs of the lower campus. The set consists of a Caterpillar 1,800 RPM diesel engine driving a Kato generator. The generator has a 800 KW continuous duty rating. This standby generator is large enough to handle the entire lower campus electrical load during power outages. It is connected to the 4,160 volt campus loop and is designed to start up automatically if the Municipal Power Company service fails.

A 275 KW diesel engine generator set was installed to meet the emergency power needs of the upper campus.

2.3 THERMAL AND ELECTRIC HISTORICAL CONSUMPTION AND COST DATA

See the following five (5) pages.

Table 1

ANNUAL FUEL CONSUMPTION AND COST

Facility ST. PETER REGIONAL TREATMENT CENTER Building Name HEATING PLANT Date

Address

	1984						1985					
MONTH	DATE From/To	FUEL TYPE INT. GAS UNITS MCF	$ COST	FUEL TYPE #6 OIL UNITS GAL.	$ COST	TOTAL FUEL COST $	DATE From/To	FUEL TYPE INT. GAS UNITS MCF	$ COST	FUEL TYPE #6 OIL UNITS GAL.	$ COST	TOTAL FUEL COST
Jan.	12/26/83 to 1/26/84	15,730	64,752	3,955	2,689	67,441	12/27/84 1/26/85	15,618	62,718	8,573	5,830	68,548
Feb.	1/27/84 to 2/26/84	13,495	55,558	-	-	55,558	1/28/85 to 2/27	15,628	62,759	-	-	62,759
March	2/27/84 to 3/26/84	12,510	51,506	-	-	51,506	2/17/85 to 3/26	10,317	41,446	-	-	41,446
April	3/27/84 to 4/26/84	9,560	39,361	-	-	39,361	4/1/85 to 5/1	8,208	32,983	-	-	32,983
May	4/26/84 to 5/26/84	6,158	25,370	-	-	25,370	4/27/85 to 5/26	4,132	15,894	-	-	15,894
June	5/27/84 to 6/26/84	3,337	13,769	-	-	13,769	5/27/85 to 6/26	3,294	12,557	-	-	12,557
July	6/26/84 to 7/26/84	2,984	12,317	-	-	12,317	6/26/85 to 7/26	2,755	10,510	-	-	10,510
Aug.	7/26/84 to 8/26/84	2,963	12,231	-	-	12,231	7/26/85 to 8/26	3,037	11,581	-	-	11,581
Sept.	8/26/84 to 9/26/84	4,010	16,537	-	-	16,537	8/26/85 to 9/26	3,808	14,510	-	-	14,510
Oct.	9/27/84 to 10/26/84	10,933	45,008	-	-	45,008	9/26/85 to 10/26	7,851	29,867	-	-	29,867
Nov.	10/27/84 to 11/26/84	11,449	47,130	-	-	47,130	10/26/85 to 11/26	11,627	43,110	-	-	43,110
Dec.	11/27/84 to 12/26/84	14,015	57,683	4,726	3,214	60,897	11/26/85 to 12/26	16,251	60,237	-	-	60,237
	TOTAL	107,144	441,222		3,214	447,125		102,526	398,172		5,830	404,002

UNITS OF MEASURE: Gas - CF = cubic feet CCF = Therms/hundreds of feet
MCF = thousands of cf 1000 CF = 10 CCF = 1 MCF

Steam - Lbs. - pounds MLB - thousands of lbs.
Chilled water - THR - Ton hours
Propane and oil - gallons

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Table 2

ANNUAL ELECTRICAL ENERGY CONSUMPTION & COST

BUILDING: LOWER CAMPUS

NAME OF PERSON COMPLETING FORM:

METER NUMBER: ONE 4,160 volt (Primary)

AREA(S) SERVED: LOWER CAMPUS

UTILITY NAME: CITY OF ST. PETER

PHONE:

1984

DATES FROM / TO (1)	DEMAND KW BILLED / ACTUAL (2)	P.F. (3)	KWH (4)	COSTS: DEMAND CHARGE (5)	COSTS: KWH CHARGE (6)	COSTS: TOTAL COST (7)
1/3 – 2/1	720	85.6	324,000	5,099		12,847
2/1 – 2/29	728	84.9	308,000	5,153		12,503
2/29 – 4/2	704	84.9	348,800	4,992		13,358
4/2 – 5/1	672	84.4	289,600	4,777		11,692
5/1 – 6/1	704	84.5	307,200	4,992		12,330
6/1 – 7/2	848	85.0	357,600	5,957		14,491
7/2 – 8/1	904	85.4	392,800	6,632		15,717
8/1 – 9/4	928	85.5	451,200	6,493		17,313
9/4 – 10/1	680	85.1	268,000	4,831		11,209
10/1 – 11/1	704	85.2	319,200	4,492		12,626
11/1 – 12/3	712	85.6	344,000	5,045		13,290
12/3 – 12/31	736	86.4	320,000	5,206		12,850
			4,030,400			160,226

1985

DATES FROM / TO (1)	DEMAND KW BILLED / ACTUAL (2)	P.F. (3)	KWH (4)	COSTS: DEMAND CHARGE (5)	COSTS: KWH CHARGE (6)	COSTS: TOTAL COST (7)
12/31 – 1/31	736	86.6	360,800	7,134		21,098
1/31 – 3/1	712	86.3	327,200	6,914		19,210
3/1 – 4/1	680	85.4	314,400	6,620		18,329
4/1 – 5/1	664	85.9	309,600	6,473		17,873
5/31 – 6/1	680	85.9	313,600			17,786
6/1 – 7/1	880	86.1	334,400	8,456		19,470
7/1 – 8/1	912	86.6	391,200			21,193
8/1 – 9/3	864	85.9	363,200			19,949
9/3 – 10/1	824	86.2	314,400			18,339
10/1 – 11/1	712	86.1	324,000			16,852
11/1 – 12/2	728	85.5	336,800	6,862	8,592	15,454
12/2 – 1/2	736	85.6	354,400			16,146
			4,044,000			221,699

Table 3

ANNUAL ELECTRICAL ENERGY CONSUMPTION & COST

BUILDING: ____________________

NAME OF PERSON COMPLETING FORM: ____________________

METER NUMBER: TWO 480 Volt

AREA(S) SERVED: MINNESOTA SECURITY HOSPITAL

UTILITY NAME: ____________________

PHONE: ____________________

1984							1985						
DATES FROM TO (1)	DEMAND KW BILLED ACTUAL (2)	P.F. (3)	KWH (4)	COSTS: DEMAND CHARGE (5)	COSTS: KWH CHARGE (6)	COSTS: TOTAL COST (7)	DATES FROM TO (1)	DEMAND KW BILLED ACTUAL (2)	P.F. (3)	KWH (4)	COSTS: DEMAND CHARGE (5)	COSTS: KWH CHARGE (6)	COSTS: TOTAL COST (7)
Jan			170,500			6,708	Jan			180,000			10,662
Feb			188,500			7,410	Feb			163,000			9,482
Mar			170,000			6,689	Mar			157,000			9,079
Apr			154,000			6,065	Apr			139,000			7,985
May			160,500			6,318	May			178,000			9,976
June			171,000			6,728	June			243,500			12,987
July			258,500			10,140	July			196,500			10,232
Aug			248,000			9,731	Aug			251,000			13,118
Sep			218,000			8,561	Sep			236,000			12,622
Oct			173,000			6,806	Oct			131,000			6,685
Nov			170,500			6,708	Nov	400		229,500			9,932
Dec			213,500			8,385	Dec	400		145,000	3,877		7,846
			2,296,000			90,249				2,249,500			120,606

Table 4

ANNUAL ELECTRICAL ENERGY CONSUMPTION & COST

BUILDING: ____________________

NAME OF PERSON COMPLETING FORM: ____________________

METER NUMBER: THREE

AREA(S) SERVED: GLUEK BUILDING

UTILITY NAME: FROST-BENCO

PHONE: ____________________

1984							1985						
DATES FROM TO (1)	DEMAND KW BILLED ACTUAL (2)	P.F. (3)	KWH (4)	COSTS DEMAND CHARGE (5)	COSTS KWH CHARGE (6)	COSTS TOTAL COST (7)	DATES FROM TO (1)	DEMAND KW BILLED ACTUAL (2)	P.F. (3)	KWH (4)	COSTS DEMAND CHARGE (5)	COSTS KWH CHARGE (6)	COSTS TOTAL COST (7)
Jan			7,691		.08	623.20	Jan			3,341		.06	259.06
Feb			6,300		.08	529.42	Feb			8,462		.07	629.11
Mar			5,065		.08	414.44	Mar			5,307		.08	420.03
Apr			4,000		.08	324.35	Apr			3,407		.08	267.78
May			4,419		.08	354.93	May			2,160		.07	161.81
June			1,338		.08	107.90	June			957		.08	76.53
July			333		.09	30.97	July			426		.09	38.06
Aug			434		.09	39.72	Aug			761		.08	61.25
Sep			543		.09	48.74	Sep			421		.09	38.59
Oct			700		.09	61.26	Oct			586		.09	51.80
Nov			1,611		.08	122.66	Nov			*			
Dec			4,246		.07	315.83	Dec			*			
			36,680			2,973.42							

* not available

Table 5

ANNUAL ELECTRICAL ENERGY CONSUMPTION & COST

BUILDING: STATE HIGHWAY #333
STREET LIGHTING

NAME OF PERSON COMPLETING FORM:

METER NUMBER: FOUR

AREA(S) SERVED:

UTILITY NAME:

PHONE:

1984							1985						
DATES FROM TO (1)	DEMAND KW BILLED ACTUAL (2)	P.F. (3)	KWH (4)	COSTS: DEMAND CHARGE (5)	COSTS: KWH CHARGE (6)	COSTS: TOTAL COST (7)	DATES FROM TO (1)	DEMAND KW BILLED ACTUAL (2)	P.F. (3)	KWH (4)	COSTS: DEMAND CHARGE (5)	COSTS: KWH CHARGE (6)	COSTS: TOTAL COST (7)
Jan			1,020		.08	80.52	Jan			920		.12	105.80
Feb			1,060		.08	82.56	Feb			1,160		.11	125.42
Mar			880		.08	70.38	Mar			870		.11	99.03
Apr			730		.08	58.98	Apr			720		.11	82.46
May			760		.08	61.26	May			820		.11	92.20
June			740		.08	59.74	June			830		.11	91.12
July			420		.08	35.42	July			450		.11	51.00
Aug			720		,08	58.22	Aug			500		.11	56.27
Sep			760		.08	61.26	Sep			1,050		.11	112.45
Oct			780		.08	62.78	Oct			960		.11	102.15
Nov			820		.08	65.82	Nov			*			
Dec			1,290		.07	94.29	Dec			*			
			9,980			791.23							

* not available

3.0 BASELINE YEAR

3.1 THERMAL AND ELECTRIC LOAD PROFILES

Four average 24 hour profiles were created for each month (thermal weekday, thermal weekend, electric weekday and electric weekend). The primary difference between weekday and weekend days is that the laundry operates from approximately 7:00 am to 4:30 pm on weekdays.

The values for each hour for each profile are the average of all the hours within a specific timeframe. For example, for a 20 weekday month, the value for 2:00 pm is the average of the 20 hours from 1:00 pm to 2:00 pm.

The thermal 24 hour profiles were developed by selecting a weekday and weekend day for each month that closely approximated the normal year average temperature. For example - for January, the normal average temperature is 11.2°F as shown on Table 6. We reviewed all January 1985 weekdays to find the one which had an average temperature closest to the normal temperature. January 28 was selected for our weekday thermal profile because it had an average temperature of 12.0°F.

The electric 24 hour profiles were determined using the thermal profile days. This assures that the thermal and electric profiles are synchronized for each month and minimizes the chance for error.

Table 7 shows normal year (baseline year) thermal (steam) consumption and electrical consumption. Average 24 hour profile values multiplied by the number of weekdays and weekend days equals the total steam and electric consumption for each month. Note that the normal year thermal consumption is 0.6 % higher than the actual (Table 1) for the previous twelve months primarily because of the difference in heating degree days. Also note that the normal year electric consumption is only 1.73% higher than the actual for the previous twelve months. The fact that the normal totals are close to the actual totals indicates that the average profile concept used on this project is valid.

Table 6

Average Montly Temperatures

	Normal Year Average Temperature	Actual Temperature National Weather Service	St. Peter Hospital Temperature
January	11.2	10.1 (1985)	14.0 (1985)
February	17.5	16.5 (1985)	17.4 (1985)
March	29.1	35.6 (1985)	37.8 (1985)
April	46.0	52.1 (1985)	52.2 (1985)
May	58.5	62.2 (1985)	64.8 (1985)
June	68.1	63.9 (1985)	64.5 (1985)
July	73.1	73.9 (1985)	65.7 (1985)
August	70.6	67.6 (1985)	66.4 (1985)
September	60.6	59.9 (1985)	61.2 (1985)
October	49.5	50.7 (1984)	48.2 (1985)
November	33.2	33.3 (1984)	(not available)
December	19.2	17.9 (1984)	20.23 (1984)

3.2 THERMAL AND ELECTRIC CONSUMPTION AND COST DATA

Table 7

ST. PETER HOSPITAL

Monthly Energy Consumption (Baseline Year)

Month	Thermal Consumption MMBtu/Mo	Fuel Cost $/Mo	Electrical Consumption KWH/Mo	Electrical Cost $/Mo
1	13,040	$ 52,487	366,760	$ 17,241
2	11,101	$ 45,282	331,344	$ 16,027
3	9,872	$ 42,060	337,648	$ 15,913
4	6,694	$ 30,926	304,608	$ 14,839
5	3,436	$ 19,337	319,792	$ 15,412
6	2,831	$ 16,278	319,680	$ 17,229
7	2,057	$ 12,249	398,744	$ 19,741
8	2,871	$ 16,572	345,104	$ 17,797
9	2,893	$ 16,587	322,760	$ 16,805
10	6,110	$ 29,262	331,344	$ 16,027
11	9,463	$ 40,374	340,240	$ 16,423
12	12,119	$ 49,556	362,464	$ 17,120
TOTAL	82,486	$ 370,970	4,080,488	$ 200,577

Baseyear Fuel Cost: 104,499 MMBtu at $ 370,970
(MMBtu's of fuel used include effects of boiler efficiency and partial load efficiency)
Baseyear Electrical Cost: 4,080,488 KWH at $ 200,577
Baseyear Total Energy Cost: $ 571,546

3.3 CUMULATIVE HOUR BINS

See Section 7.2 for detailed description

```
Total Hrs    MMBtu Thermal Load (H)
---------    ----------------------
    0          48:
    0          44:
    0          40:
    0          36:
    0          32:
    0          28:
    0          24:
  106          20:X
 1437          16:XXXXXXXXX:XXXX
 3463          12:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXX
 4566           8:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXX
 6176           4:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XX
 8760           0:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXX
                  0---------I---------I---------I---------I---------I---------I---------I---------I---------I
                  0         1         2         3         4         5         6         7         8         9

                      Annual Hours at Thermal Load H or Greater
```

```
Total Hrs    KW Electrical Load (P)
---------    ----------------------
    0        1000:
    0         900:
    0         800:
  148         700:X
 1305         600:XXXXXXXXX:XXX
 2659         500:XXXXXXXXX:XXXXXXXXX:XXXXXXX
 5574         400:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXX
 8760         300:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXX
 8760         200:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXX
 8760         100:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXX
 8760           0:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXXX:XXXXXXXX
                  0---------I---------I---------I---------I---------I---------I---------I---------I---------I
                  0         1         2         3         4         5         6         7         8         9

                      Annual Hours at Load P (KW) or greater
```

4.0 ALTERNATIVE FUEL SOURCES

4.1 REFUSE FUEL

4.11 Overview of the Waste Disposal Issue

Until the 1970's burning garbage in open dumps was the standard practice in Minnesota, as well as the rest of the United States. In 1967, the Legislature created the Minnesota Pollution Control Agency (MPCA), and granted them broad powers to control air, water , and land pollution. The MPCA had to address the problems of open dumps which included: smoke, rodents, flies, blowing paper, and ground and water pollution.

As a result, the MPCA developed rules for the siting of sanitary landfills. At the time it was believed that these landfills were the best solution to disposing of ever increasing quantities of solid waste. It wasn't until the mid-1970' that water monitoring results began to indicate the presence of leachate at sanitary landfills.

As further testing revealed additional hazardous waste problems, the MPCA began work on alternatives to landfills. The three most common alternatives include recycling, composting and energy recovery.

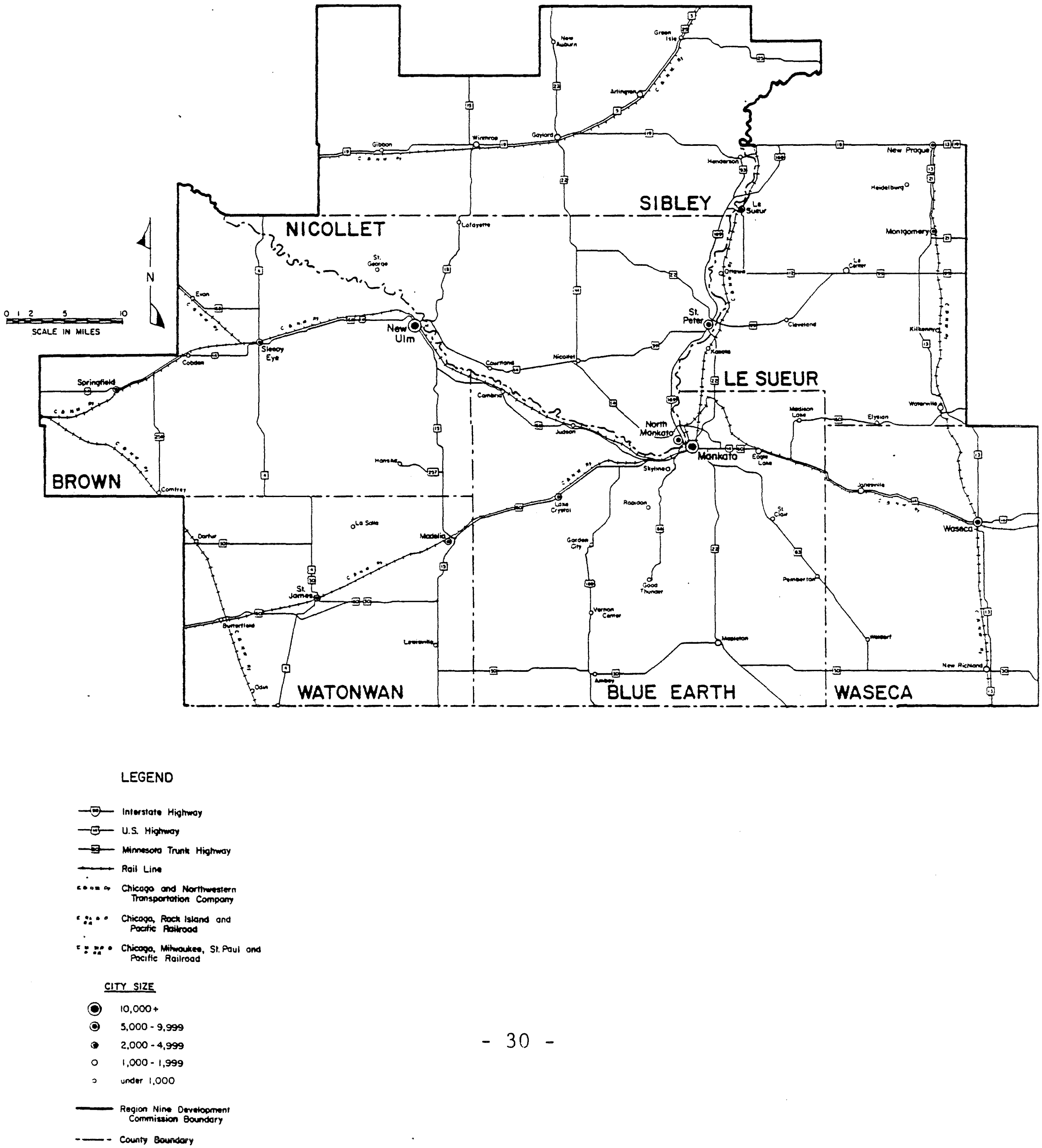
This search for alternatives led to the reemergence of the concept of burning refuse as an environmental and economic alternative to conventional landfills. Conversion of municipal solid waste is not a new concept, it has been used in Europe for over 80 years.

4.12 Refuse in the St. Peter Area

As a part of their effort to help develop alternatives to sanitary landfills, the MPCA has required all Minnesota Counties to develop comprehensive solid waste management plans. In order to meet this requirement, seven counties including Blue Earth, Brown, Le Sueur, Nicollet, Rice, Sibley and Waseca have joined together to form the South Central Solid Waste Planning Board. This Board has recently advertised for assistance in developing the comprehensive solid waste plans required by the MPCA. These plans, when completed, will include detailed information on all relevant solid waste issues, including the potential for siting a energy resource recovery system in the area.

Because detailed data on the amount and characteristics of waste collected would not be available until the comprehensive solid waste plans were completed, personal interviews and national estimates were used. Interviews were completed with county solid waste officials and one landfill owner. A brief discussion of the data collected by county is shown below. Table 8 summarizes the data for all seven counties and Figure 2 is a map of the area surrounding St. Peter.

FIGURE 2


SIBLEY
NICOLLET
LE SUEUR
BROWN
WATONWAN
BLUE EARTH
WASECA
N
0 1 2 5 10
SCALE IN MILES
New Ulm
St. Peter
Mankato
North Mankato
Le Sueur
Sleepy Eye
Springfield
Madelia
St. James
Waseca
Montgomery
New Prague
Gaylord
Winthrop
Gibbon
Henderson
Lake Crystal
Janesville
LEGEND
Interstate Highway
U.S. Highway
Minnesota Trunk Highway
Rail Line
Chicago and Northwestern Transportation Company
Chicago, Rock Island and Pacific Railroad
Chicago, Milwaukee, St. Paul and Pacific Railroad
CITY SIZE
10,000+
5,000 - 9,999
2,000 - 4,999
1,000 - 1,999
under 1,000
Region Nine Development Commission Boundary
County Boundary

Blue Earth County

There are three landfills operating in Blue Earth County. However, two of these are demolition landfills and accept primarily building materials that are not practical to burn. The third landfill is privately owned and is called the Ponderossa landfill. It is located approximately 7 miles south west of downtown Mankato. This landfill accepts approximately 37,000 tons of refuse annually. The tipping fee, set by the County Board, is currently $2.25 per compacted yard or approximately $7.00/ton. This rate will rise to $2.50/yard or $7.70/ton on March 1, 1986. Almost all of the waste brought to this landfill is from within the county expect for a small portion from North Mankato which is in Nicollet County.

Brown County

Brown County has one privately owned landfill which is located south of Sleepy Eye. It receives approximately 12,500 tons/year of refuse. Most of this refuse is from Brown County with a small portion originating in Nicollet County. The current tipping fee is $4.25/compacted yard

Le Sueur County

There are two landfills in Le Sueur County, Telejohn landfill and Reak landfill. The Telejohn landfill was opened in 1972 and is privately owned. It receives an estimated 57 tons/day or approximately 15,000 tons/year. The Reak landfill was opened in 1972 and is also privately owned. It receives approximately 1,500 tons/year. Most of the waste shipped to these two landfills originates in LeSueur County, although a small portion comes from Nicollet, Blue Earth and Sibley County. The current tipping fee at both landfills is $2.00 yard or approximately $6.15/Ton. This rate is set by the landfill owners and is expected to rise soon.

Nicollet County

There are no sanitary landfills in Nicollet County, the county that the St. Peter State Hospital is located in. Currently, waste is hauled to the Telejohn landfill in Le Sueur County and the Ponderossa landfill in Blue Earth County.

Rice County

The one landfill operating in Rice County is owned by the county. The tipping fee is $9.00/ton. A total of approximately 38,000 tons of waste is deposited here annually.

Sibley County

Currently, there are no landfills operating in Sibley County. The waste generated from Sibley County is shipped to the Ponderossa landfill in Blue Earth County and the Telejohn landfill in LeSueur County.

Waseca County

There is only one landfill in Waseca County. It is located 6 miles south of Waseca and is owned by the county. The tipping fee is currently $2.25/compacted yard but is expected to rise to near $3.50/compacted yard in the near future. Most of the 11,000 tons of refuse brought here annually is from Waseca County.

TABLE 8

REFUSE AVAILABILITY AND COSTS

County	Annual Tonnage	Tipping Fees
Nicollet	0	NA
LeSueur	16,500	$6.15/ton
Sibley	0	NA
Blue Earth	37,000	$9.00/ton
Brown	12,500	$13.00/ton
Rice	38,000	$9.00/ton
Waseca	11,000	$7.00/ton
TOTAL	115,000 tons/year	

* The tipping fees are either based on tons or compacted yard. A density of 650 lbs/per compacted yard was assumed.

These county waste estimates were cross-checked by using per capita waste factors based on national estimates. For rural communities, it is estimated that 2.2 pounds of waste is generated daily.

The 1985 population estimate for these seven counties as obtained from the Minnesota State Demographers Office is 221,000. Therefore an estimated 243 Tons/day of waste is generated in this area. This translates to approximately 88,700 tons annually. This figure is reasonably close to the estimate in Table 8. Therefore we estimate the annual waste resource in this seven county area at between 89,000 and 115,000 tons.

4.13 Densified Refuse Derived Fuel (DRDF)

There are two common technologies for using waste as an energy resource. The first is known as mass burn incineration. With mass burn, solid waste is dumped on a tipping floor or pit for storage and then placed in a hopper or feeder and batch fed into an incinerator as heat requirements dictate. The main advantages to this technology are inexpensive fuel costs and the fact that this is a proven technology. The main disadvantage is the problem of matching the energy demands with the available resources. Unfortunately, the time when the energy demand for the State Hospital is the greatest, the winter, is also the time when there is the least waste. The waste quantity peaks in the summer months when the requirements for energy at the State Hospital are at their lowest.

The second common technology is to produce densified fuel pellets from the waste and burn the pellets using technology similar to burning wood chips. The main advantage to this option is the ability to produce fuel pellets when waste is available. These pellets are easily transported and stored until the time they are needed. The primary disadvantage is the higher fuel costs. Because of ability to store fuel pellets, this study focused on a facility which could burn DRDF.

A typical sized DRDF plant can process approximately 80 tons of waste daily. Approximately 55% of the raw waste fed into the plant is converted to fuel pellets. A plant operating 8 hours per day, 250 days per year could produce 11,000 tons of fuel pellets annually. A DRDF facility produces fuel pellets that have a BTU content of approximately 8,000 per pound or 16.0 MMBTU/Ton with a moisture content of 12% or less.

A plant of this size would cost approximately $1.8 million to construct. The cost of the fuel pellets is determined primarily by the tipping fee charged. The reason is the tipping fees represents a major source of revenue to the plant. Assuming a tipping fee of $25.00/Ton, the fuel pellets would cost approximately $36-40 per ton delivered to the State Hospital. If the tipping fee were lower, the fuel costs would be higher. Conversely, if the tipping fee were higher, the fuel costs would be lower.

This type of facility would have to be built by an independent company. Discussions with Preferable Fuels and Systems, Inc. of Eden Prairie revealed that they would be interested in financing and constructing such a facility if they were able to sign a contract for fuel pellets with the State Hospital. Preferable Fuels has built a similar facility in Thief River Falls and is also planning two DRDF plants to be located in Willmar and Chanhassen.

With an estimated 80 to 115 million tons of waste available annually, a DRDF plant located near St. Peter could produce 44,000 to 63,000 tons of fuel pellets annually. The Btu's available from this waste is shown below:

GROSS = 44,000 tons/year X 16.0 MMBtu/tons = 704,000 MMbtu/year
63,000 tons/year X 16.0 MMBtu/ton = 1,008,000 MMBtu/year

NET = 704,000 MMBtu/year X .68 = 479,000 MMBtu/year
1,008,000 MMBtu/year X .68 = 685,000 MMbtu/year

Since the net annual energy required for the St. Peter State Hospital is 80,000 MMBtu it appears that there is adequate waste in the seven county area.

4.14 Environmental Issues of Burning Refuse

There are many unanswered questions regarding the potential air pollution problems from burning refuse. Although refuse burning facilities have been in operation for many years, very little emission monitoring has been completed.

This is causing serious concern from many groups including the Minnesota Pollution Control Agency (MPCA), public officials, environmentalists and the general public. These groups are being asked to support refuse burning with its potential air pollution problems over landfills with their known ground water pollution problems.

The MPCA is responsible for approving large-scale refuse burning operations. Their primary concern for facilities the size of the one that would have to be built at the St. Peter State Hospital is the possible production and release of dioxins. To limit the production of dioxins, the MPCA is recommending that the boilers be preheated to 1600-1800 degrees F with a fossil fuel before introducing refuse fuel. Even if this is done, the MPCA is still concerned about the potential for dioxin production when heat is extracted from the exhaust gases. Unfortunately, there is very little empirical data to guide the MPCA in establishing their guidelines.

If the State Hospital were to install a refuse burner, they would have to apply for and receive a permit from the MPCA. The refuse burning facility would either have to meet Ms s 116.07 subd 4 - Standards of Performance for Incinerators or Standards of Performance for Indirect Heating Fossil Fuel-Burning Equipment in order to receive a permit. An official of the MPCA said that the two primary requirements the facility would have to meet would be to monitor temperatures to assure that combustion temperatures are at least 1600 degrees F and include an electrostatic precipitator to control particulate emissions.

4.15 NSP Wilmarth Plant

NSP has begun converting the Wilmarth Plant in Mankato to burn Refuse Derived Fuel (RDF). The plant which currently burns coal, is expected to be ready to burn RDF by July of 1987. This plant is scheduled to act as a back-up to the NSP Red Wing Plant.

As a part of this project, NSP is considering the construction of a RDF plant near the Wilmarth Plant. This plant, if constructed, would probably burn waste from the seven county area around Mankato. NSP is considering a plant that could process about 250 to 400 tons of waste per day. Approximately 70% of this waste would be converted to RDF with a Btu content of 5500 Btu/lb. or 11.0 MMBtu/Ton.

If NSP were to construct an RDF facility near the Wilmarth plant and consume refuse from the area, it would require nearly all of the burnable waste in the seven county area. The result would be that there may not be enough waste left to make the construction of a DRDF plant near St. Peter economically feasible.

4.2 WOOD FUEL

4.21 Wood Energy System Overview

Over the past five years there have been considerable developments in the wood energy system market. Not only have the design, operation and availability of wood energy equipment improved, but the entire infrastructure required to support the industry has rapidly improved.

The hardware components for wood energy systems are manufactured by many different suppliers. Currently, design engineers and fabricators combine hardware components into field erected packages which meet the needs of each user. Each wood energy conversion package is unique, in that it must operate within wood source, boiler, space, budget and code constraints.

Because of this, the design of commercial/industrial wood energy systems is more an art than a science. Standard engineering manuals are not available, therefore, designers must rely on their knowledge and experience when designing wood energy systems. In spite of this drawback, system designs are improving. In addition, the standardization of equipment has eliminated many of the equipment problems of years ago.

It is important to mention that wood energy systems have not been without problems. Quality and dependability of fuel can been a problem. This can cause equipment failures. There are often start-up problems. In addition, more maintenance is required to operate a wood system than a natural gas boiler.

4.22 Wood Availability in St. Peter

One of the most important factors that determines the success of a wood energy system is a close, dependable supply of high quality fuel. Although there are no large producers of waste wood in St. Peter, there is one in nearby Courtland, 20 miles west of St. Peter on Highway 99. Minnesota Valley Forest Products, located in Courtland, produces a variety of wood products from hardwoods, including grade lumber for housing and furniture and wood pallets. They have been in business over ten years and employ 53 people in their year round operation.

Minnesota Valley has chips, mulch and sawdust available, all of which are very clean. They have established some markets for chips and sawdust. The total amount of waste wood that Minnesota Valley produces annually is shown in Table 9 below. These figures are based on discussions with Mr. Frank Kilibarda, President and owner of Minnesota Valley Forest Products.

TABLE 9

WASTE WOOD PRODUCED BY MINNESOTA VALLEY FOREST PRODUCTS

Wood Type	Daily Production	Annual Production
Wood Chips	37 Tons	8,400 Tons
Mulch	25 Tons	5,600 Ton
Sawdust	15 Tons	3,300 Tons
Totals	77 Tons/Day	17,300 Tons/Year

* The average mix of this waste wood is estimated to have 9.0 MMBtu/Ton.

In addition to the current production of waste wood, Minnesota Valley Forest Products has a stockpile of wood waste estimated at 9,000 tons. This pile is several years old and consists of chips, mulch and sawdust. The quality of this wood is uncertain.

Minnesota Valley Forest Products would be willing to sell this waste wood to the St. Peter State Hospital at a first year cost of $18-20 per ton delivered to the site. It would be delivered with a self-unloading trailer. They are also interested in a long term contract for this wood supply at a price to be determined through negotiation with the State Hospital.

The waste wood produced by Minnesota Valley is green wood and has a moisture content of approximately 50%. The BTU content of this waste wood is estimated at 9.0 MMBTU/Ton. The total annual BTU's available from this waste wood, assuming a 68% efficient boiler, is estimated at 102.8 MMBTU as shown below.

GROSS = 17,300 Tons/Year X 9.0 MMBtu/Ton = 155.7 MMBtu/Year

NET = 155.7 MMBtu/Year X .68% = 102.8 MMBtu/Year

The total thermal energy required for the State Hospital is approximately 80,000 MMBTU. This represents 13,000 Tons of green wood annually at a boiler efficiency of 68%. With a trailer capacity of 25 tons, there would be almost 550 deliveries annually; from a high of 85 per month in January to a low of 13 per month in July.

Minnesota Valley Forest Products represents an ideal source of waste wood for this project. They appear to be a very stable company which operates year round. They are located reasonably close to the State Hospital. They have an adequate production level of waste wood to supply all of the needs of the St. Hospital. They are willing to enter into a long-term contract for supplying waste wood. They are willing to deliver the product and they have their own self-unloading trailer.

4.23 Environmental Issues of Wood Burning

Although there is limited data available, it appears that the environmental problems associated with small commercial/industrial wood burning systems may be less serious than for refuse burning systems. The Minnesota New Source Performance Standards, enforced by the Minnesota Pollution Control Agency, are the governing rules for air emissions sources.

The particulate matter rules for wood energy systems in Minnesota are relatively easy to meet with properly designed available control technologies. Compliance for particulate matter would probably require an electrostatic precipitator or baghouse. Nitrogen oxides could be controlled by wood fuel selection and boiler operation procedures, without the addition of specific nitrogen oxide control equipment.

Another concern of some officials is disposal of wood ash. There is very little literature on the environmental problems associated with the disposal of ash from wood burning facilities. The literature that is available seems to indicate that wood ash is not considered hazardous.

5.0 UTILITY INCENTIVES FOR COGENERATION

5.1 BACKGROUND

The St. Peter State Hospital presently receives electric service from the City of St. Peter Municipal Electric Utility under the City's Large General Service - Industrial Rate. The incremental cost of demand under this rate is \$ 9.10 per KW per month, and the incremental cost of energy is \$ .0281 per KWH. The hospital presently receives service at two points of delivery, one at 4,160 volt primary voltage (called the St. Peter State Hospital - Lower Campus) and the other at secondary voltage (called the St. Peter Security Hospital - Upper Campus). The Lower Campus service demand is nearly twice the Upper Campus service demand (912 KW versus 500 KW).

In April, 1985 the City issued their rules and regulations regarding cogeneration within the City's system. These rules reflect that the City is a "whole-requirements" wholesale customer of the Southern Minnesota Municipal Power Agency (SMMPA). Based on the City's rules, the rules of Northern States Power Company, and provisions of PURPA, the St. Peter State Hospital has two basic options for utilizing the electric output from a cogeneration unit.

5.2 ELECTRIC UTILITY INTERFACE OPTIONS

A. Buy-All, Sell-All

Under this option the State Hospital remains a full-requirements customer of the City and pays its two electric bills as in the past. The cogeneration unit is considered completely separate from the two electric services and the entire output is sold either to the City of St. Peter or to Northern States Power Company under their avoided cost purchase tariffs. Primary concerns under the buy-all, sell-all arrangement are:

1. How have the two utilities determined their avoided capacity costs, and what are the capacity payments ? What is the required availability of the cogeneration unit to receive these payments ?

2. What are the prices paid for purchased energy and how do the time-of-day periods relate to operation of the cogeneration unit ?

3. What contract period is required ?

B. Offset-Load, Sell-Surplus

Under this option, the cogenerated electricity is principally used on-site to reduce the Hospital's electric bill. During periods when the cogenerated electricity is insufficient to supply the entire needs of the Hospital, supplemental electricity must be purchased from the City at a standard tariff rate. During periods when the potential cogenerated electric output exceeds the needs of the Hospital, the surplus can be sold to the City at the surplus sale rate (if it makes economic sense to do so). There are four primary concerns with the arrangement:

1. Does the smaller amount of electricity purchased disqualify the Hospital for the Large Industrial Rate and force the Hospital onto a more expensive rate for the supplemental electricity purchased ?

2. What are the backup power costs and the other standby arrangements necessary with the City to provide a "full-requirements" purchase when the cogeneration unit is out of service ?

3. How do the costs of electric production compare to the incremental sales revenues for selling the surplus ? This in turn relates to how the needs for steam relate to the electric needs, i.e., the overall energy cost of producing steam and electricity simultaneously is less than the energy cost of producing electricity without steam.

6.0 ANALYSIS OF ALTERNATIVE FUEL OPTIONS

6.1 OPTION #1 - REFUSE FIRED BOILER

Description of Equipment

One (1) 20,000 Lb/Hr Densified RDF fired 125 PSIG boiler with all accessories including I. D. fan, pollution control devices, soot blower, ash auger, control panel, conveyor/hopper, storage bin and metal building.

Description of System

The refuse fired boiler has the capability of producing 20,000 Lbs/Hr of steam. Peak winter steam demands exceeding 20,000 Lbs/Hr can be picked up by the 8,600 Lb/Hr boiler installed during late 1985. The new small boiler will operate about 500 hours per year. Based on a 60% average load, the MCF of gas used by the small boiler will be:

$$\frac{8{,}600 \text{ Lbs/Hr} \times .60 \times 500 \text{ Hrs} \times 1{,}000 \text{ BTU/Lb}}{.80 \text{ Eff.} \times 10^{6} \text{ BTU/MCF}} = 3{,}225 \text{ MCF/Year}$$

The following pages summarize the economics of converting to a refuse fired energy system.

Table 10 on page 49 shows the payback period for different refuse fuel costs and natural gas costs.

COST COMPARISON MODEL FOR CONVERTING TO A REFUSE ENERGY SYSTEM

STEP A DETERMINE THE NET ANNUAL ENERGY REQUIRED

Gross natural gas consumption =	104,499 (site specific)		line 1
Refuse fuel substitution = (104,499Mcf - 3225Mcf)	101,274 (site specific)	Mcf	line 2
Annual fuel combustion efficiency = (expressed as a decimal)	.789 (site specific)		line 3

Net annual energy required =

gas consumption X combustion eff. X 10^6 Btu/Mcf =

line 2 X line 3 X 10 Btu/Mcf =	79,905	MMBtu	line 4

STEP B DETERMINE THE TONS OF REFUSE REQUIRED ANNUALLY

Type of refuse fuel to be used =	Densified RDF (DRDF) (site specific)		line 5
Moisture content of DRDF =	12%		line 6
Btu content of DRDF per ton =	16.0	MMbtu	line 7
Combustion efficiency of refuse system = (expressed as a decimal)	0.68		line 8

Tons of DRDF required annually =

net annual energy requirement
Btu content of DRDF X combustion eff. =

line 4 (line 6 X line 8) =	7,344	Tons	line 9

STEP C DETERMINE THE SIZE AND COST OF THE PROPOSED REFUSE ENERGY SYSTEM

Size of refuse energy system	20,000	Lbs/Hr	line 10
Cost of refuse energy system	$1,050,000		line 11

STEP D DETERMINE THE ADDITIONAL ANNUAL OPERATING COSTS FOR A REFUSE ENERGY SYSTEM

Additional maintenance costs =	7,000	$/Year	line 12
Additional electricity consumption =	80,000	kwh	line 13
Electricity rate =	0.05	$/kwh	line 14
Additional electricity costs			
additional elec. consumption X electricity rate =			
line 13 X line 14 =	4,000	$/Year	line 15
Hours per day system is operated =	24	Hrs	line 16
Days per year system is operated =	365	Days	line 17
Hours per year system is operated			
hours per year X days per year =			
line 16 X line 17 =	8,760	Hrs/Year	line 18
Hours of labor required for maintenance per hour of operation =	0.25	Hrs	line 19
Labor rate	12.00 (site specific)	$/Hr	line 20
Additional labor costs			
hours operated X add'l labor X labor rate =			
line 18 X line 19 X line 20 =	26,280	$/Year	line 21
TOTAL ADDITIONAL ANNUAL OPERATING COSTS			
maintenance + electricity + labor =			
line 12 + line 15 + line 21 =	37,280	$/Year	line 22

STEP E DETERMINE THE NET ANNUAL OPERATING SAVINGS FOR A REFUSE ENERGY SYSTEM

Cost of present fuel = 3.55 (site specific) \$/Mcf line 23

Total annual cost of present fuel

annual fuel consumption X fuel cost =

line 1 X line 23 = 370,970 \$/Year line 24

Cost of DRDF = 40.00 \$/Ton line 25

Total annual cost of DRDF + natural gas =

(annual DRDF consumption X cost of DRDF) +
(annual natural gas consumption X cost of gas) =

(line 9 X line 25) + (line 1 - line 2) X line 23 = 305,208 \$/Year line 26

NET ANNUAL OPERATING SAVINGS FOR NON-TAX PAYING INSTITUTIONS

Annual operating savings =

annual cost of present fuel -
(cost of refuse fuel + add'l operating costs) =

line 24 - (line 26 + line 22) = 28,482 \$/Year line 27

STEP E DETERMINE THE PAYBACK PERIOD FOR NON-TAX PAYING INSTITUTIONS

$$\frac{\text{Installed cost of refuse energy system}}{\text{Annual operating savings}} =$$

$$\frac{\text{line 11}}{\text{line 27}} =$$ 36.86 Years line 28

Table 10 below shows the payback in years for a refuse energy system at the St. Peter State Hospital at various fuel costs. This table shows natural gas costs ranging from $3.25/MCF to $5.00/MCF and refuse fuel costs from $32.00/Ton to $56.00/Ton. At current fuel costs, $3.55/MCF for natural gas and $40.00 for DRDF, the payback would be 36.7 years.

The payback for this refuse energy system is very sensitive to fuel costs. For example, if natural gas costs were at the December 1984 level of $4.00/MCF and DRDF could be purchased for $32.00/Ton, the payback would drop to 7.8 years.

TABLE 10

PAYBACK PERIOD FOR A REFUSE ENERGY SYSTEM AT ST. PETER STATE HOSPITAL

REFUSE FUEL COSTS ($/TON)	NATURAL GAS RATES ($/MCF)							
	$3.25	$3.55	$3.75	$4.00	$4.25	$4.50	$4.75	$5.00
$56.00	-	-	-	-	-	102.4	28.9	16.8
$52.00	-	-	-	-	77.8	26.5	15.9	11.4
$48.00	-	-	-	62.7	24.5	15.2	10.9	8.7
$44.00	-	-	52.5	22.8	14.5	10.7	8.4	7.1
$40.00	-	36.7	21.3	13.9	10.3	8.2	6.8	5.8
$36.00	39.6	18.2	13.3	10.1	8.1	6.7	5.7	5.1
$32.00	18.8	12.1	9.7	7.8	6.6	5.6	4.9	4.4

* All Paybacks are shown in number of years.

6.2 OPTION #2 - WOOD FIRED BOILER

Description of Equipment

One (1) 20,000 Lb/Hr wood fired 125 PSIG boiler with all accessories including I. D. fan, pollution control devices, soot blower, ash auger, control panel, conveyor/hopper, unloader, storage bin, bucket elevator and metal building.

Description of System

The wood fired boiler has the capability of producing 20,000 Lbs/Hr of steam. Peak winter steam demands exceeding 20,000 Lbs/Hr can be picked up by a new 8,600 Lb/Hr boiler installed during late 1985. The new small boiler would not operate over 500 hours per year. Based on a 60% average load, the MCF of gas used by the small boiler would be:

$$\frac{8{,}600 \text{ Lbs/Hr} \times .60 \times 500 \text{ Hrs} \times 1{,}000 \text{ BTU/Lb}}{.80 \text{ Eff.} \times 10^{6} \text{ BTU/MCF}} = 3{,}225 \text{ MCF/Year}$$

The following pages summarize the economics of converting to a wood fired energy system.

Table 11 on page 54 shows the payback period for different wood fuel costs and natural gas costs.

COST COMPARISON MODEL FOR CONVERTING TO A WOOD ENERGY SYSTEM

STEP A DETERMINE THE NET ANNUAL ENERGY REQUIRED

Gross natural gas consumption = 104,499 (site specific) line 1

Wood fuel substitution = 101,274 Mcf (site specific) line 2
(104,499Mcf - 3225Mcf)

Annual fuel combustion efficiency = .789 (site specific) line 3
(expressed as a decimal)

Net annual energy required =

gas consumption X combustion eff. X 10^6 Btu/Mcf =

line 2 X line 3 X 10 Btu/Mcf = 79,905 MMBtu line 4

STEP B DETERMINE THE TONS OF WOOD REQUIRED ANNUALLY

Type of wood fuel to be used = Green Chips + Bark (site specific) line 5

Moisture content of wood fuel = 50% line 6

Btu content of wood fuel per ton = 9.0 MMbtu line 7

Combustion efficiency of wood system = 0.68 line 8
(expressed as a decimal)

Tons of wood required annually =

net annual energy requirement
Btu content of wood X combustion eff. =

line 4 (line 6 X line 8) = 13,056 Tons line 9

STEP C DETERMINE THE SIZE AND COST OF THE PROPOSED WOOD SYSTEM

Size of wood energy system = 20,000 Lbs/Hr line 10

Cost of wood energy system installation = $1,100,000 line 11

STEP D DETERMINE THE ADDITIONAL ANNUAL OPERATING COSTS FOR A WOOD ENERGY SYSTEM

Additional maintenance costs =	7,000	$/Year	line 12
Additional electricity consumption =	80,000	kwh	line 13
Electricity rate =	0.05	$/kwh	line 14
Additional electricity costs			
additional elec. consumption X electricity rate =			
line 13 X line 14 =	4,000	$/Year	line 15
Hours per day system is operated =	24	Hrs	line 16
Days per year system is operated =	365	Days	line 17
Hours per year system is operated			
hours per year X days per year =			
line 16 X line 17 =	8,760	Hrs/Year	line 18
Hours of labor required for maintenance per hour of operation =	0.25	Hrs	line 19
Labor rate	12.00 (site specific)	$/Hr	line 20
Additional labor costs			
hours operated X add'l labor X labor rate =			
line 18 X line 19 X line 20 =	26,280	$/Year	line 21
TOTAL ADDITIONAL ANNUAL OPERATING COSTS			
maintenance + electricity + labor =			
line 12 + line 15 + line line 21 =	37,280	$/Year	line 22

STEP E DETERMINE THE NET ANNUAL OPERATING SAVINGS FOR A WOOD ENERGY SYSTEM

Cost of present fuel = 3.55 (site specific) $/Mcf line 23

Total annual cost of present fuel

annual fuel consumption X fuel cost =

line 2 X line 23 = 370,970 $/Year line 24

Cost of wood fuel = 18.00 $/Ton line 25

Total annual cost of wood fuel =

annual fuel consumption x cost of wood fuel) +
(annual natural gas consumption X cost of gas) =

(line 9 X line 25) + (line 1 - line 2) X line 23 = 246,456 $/Year line 26

NET ANNUAL OPERATING SAVINGS FOR NON-TAX PAYING INSTITUTIONS

Annual operating savings =

annual cost of present fuel -
(cost of wood fuel + add'l operating costs) =

line 24 - (line 26 + line 22) = 87,234 $/Year line 27

STEP E DETERMINE THE PAYBACK PERIOD FOR NON-TAX PAYING INSTITUTIONS

$$\frac{\text{Installed cost of wood energy system}}{\text{Annual operating savings}} =$$

$$\frac{\text{line 11}}{\text{line 27}} =$$ 12.61 Years line 28

Table 11 below shows the payback in years for a wood energy system at the St. Peter State Hospital at various fuel costs. This table shows natural gas costs ranging from $3.25/MCF to $5.00/MCF and wood fuel costs from $10.00/Ton to $20.00/Ton. At current fuel costs, $3.55/MCF for natural gas and $18.00 for wood fuel, the payback would be 12.7 years.

The payback for this wood energy system is very sensitive to fuel costs. For example, if natural gas costs were at the December 1984 level of $4.00/MCF and wood could be purchased for $14.00/Ton, the payback would drop to 5.9 years.

TABLE 11

PAYBACK PERIOD FOR A WOOD ENERGY SYSTEM AT ST. PETER STATE HOSPITAL

WOOD FUEL COSTS ($/TON)	NATURAL GAS RATES ($/MCF) $3.25	$3.55	$3.75	$4.00	$4.25	$4.50	$4.75	$5.00
$20.00	36.9	17.9	13.4	10.2	8.2	6.9	5.9	5.2
$18.00	19.7	12.7	10.2	8.2	6.9	5.9	5.2	4.6
$16.00	13.4	9.7	8.2	6.9	5.9	5.2	4.6	4.2
$14.00	10.2	7.9	6.9	5.9	5.2	4.6	4.2	3.8
$12.00	8.2	6.6	5.9	5.2	4.6	4.2	3.8	3.5
$10.00	6.9	5.7	5.2	4.6	4.2	3.8	3.5	3.2

* All figures are shown in number of years

7.0 ANALYSIS OF COGENERATION OPTIONS

7.1 DEFINITION OF COGENERATION

Cogeneration is defined as the simultaneous production of useful thermal and electrical energy.

A cogeneration system operates at an overall thermal efficiency as much as 2-1/2 times to 3 times that of conventional utility electrical generating systems. The normally wasted exhaust heat is captured and partially used for thermal or electric energy production. This thermal and electric energy can be recovered and used in cogeneration system operations in a "topping" or "bottoming" mode. In a topping system, thermal energy exhausted in the production of electrical or mechanical energy is used in industrial processes or for heating or cooling.

Bottom cycle cogeneration reverses this process. Fuel is consumed to produce the high-temperature heat needed in an industrial process such as paper production or aluminum remelting. Heat is extracted from the hot exhaust waste stream and, through a heat exchanger (usually a waste heat recovery boiler), used to drive a turbine and produce electrical or mechanical energy.

Any heat engine can be combined with a waste heat recovery boiler to create a cogeneration system. The most important, and by far the most costly component of a cogeneration system is the prime mover, the equipment or heat engine that converts the energy content of fuel to mechanical shaft energy. The mechanical energy is then used either to drive a generator and produce electricity, or directly as mechanical shaft horsepower. Other components of a cogeneration system include the thermal distribution system; electrical switchgear and paralleling equipment; supplementary boilers (if needed); fuel storage or pipeline interconnection; controls and performance monitoring equipment.

The prime mover, the heart of a cogeneration system, is also classified as either topping or bottoming. Topping cycle prime movers include extraction turbines, backpressure turbines, gas turbines, diesel or gas-fired reciprocating engines, and externally fired Brayton cycles. Bottoming cycle prime movers include low-pressure steam turbines and organic Rankine engines. Bottoming cycle prime movers use the hot exhaust waste stream of the industrial process as energy input (via a waste heat boiler) for electric production.

Most existing and planned cogeneration systems operate on topping cycles using steam turbines, gas turbines or reciprocating engines.

Steam

Steam turbine topping cycles represent the most widely used method for electric utility power generation, accounting for about 80 percent of the electric power generated in the United States. In a cogeneration system, steam is taken from the turbine at a pressure and temperature appropriate for the process energy needs (generally much higher than the energy conventionally rejected from a power plant). This is achieved by extracting the steam exhausted from the turbine at a high pressure. The result is a decrease in the amount of electricity produced per unit of steam and an increase in the availability of thermal energy.

Gas Turbine

Gas turbines are like stationary jet engines. Large volumes of air are compressed through several stages of rotary compressor blades. Fuel is combusted in a separate chamber and heats the air causing it to expand. Expansion takes place in the turbine section. As the hot air expands it drives blades in the turbine causing the turbine to turn one or more shafts. The hot expanded exhaust is expelled through a duct. The shafts drive the compressor and a generator. Electric utilities frequently use gas turbines for power generation at their peak loads.

In cogeneration, the high temperature (800 - 1,000 degrees F) exhaust heat from a gas turbine can be used as a heat source for process use or input to a waste heat boiler to generate steam. For a given quality of steam requirements, gas turbines can produce more electricity than steam turbines.

Reciprocating Engines

Diesel engines have a higher electrical conversion efficiency than gas turbines, but also require petroleum-based fuels. Diesel engines require on-site fuel storage facilities which add appreciably to the capital cost of an installation. A typical diesel engine used for power generation has an electrical conversion efficiency of 30 to 40 percent and the exhaust gases and the water jackets contain considerable heat that can be recovered. Diesel engines are more efficient than either small gas turbines or small steam turbines at full and partial load, and offer approximately twice the electricity per unit of steam as the gas turbine and ten times that of the back pressure steam turbine.

Gas engines are well developed and commercially available. They are especially attractive for small cogeneration applications because natural gas is a relatively clean-burning fuel. While the diesel engine operates on a compression ignition system, the gas engine operates on spark ignition using natural gas or gasoline. The gas engine was introduced in many topping cycle "total energy" systems during the early 1960's. In addition to natural gas, these engines can burn propane, butane or methane.

7.2 DESCRIPTION OF CALCULATION PROCEDURES

Cogeneration options are analyzed using the Integrated Energy Systems, Inc. (IES) computer software package.

The program begins each hour's sequence by determining whether the facility thermal demand is greater than or less than the cogen thermal output capacity. If demand is greater than or equal to the system thermal capacity, the full-load performance parameters (thermal and electrical efficiencies, net fuel, rate, etc.) are used. If the facility thermal demand is less than system capacity, then the system runs at the partial load corresponding to thermal demand for that hour.

The program compares the electricity generated against the facility demand for that hour and calculates the excess generated, if any. The program then decides, based on the utility rate structure, whether the hour is:

1. On-peak month, on-peak hour, or
2. On-peak month, off-peak hour, or
3. Off-peak month, on-peak hour, or
4. Off-peak month, off-peak hour.

Once the appropriate bin is selected, the following values are calculated for that bin:

1. Amount of KWH to be added to the bin
2. The number of hours to be added to the bin
   (weekday = 24 x number of weekdays in month; same for weekend)

3. The excess KWH to be added to the bin, if any

4. The fuel increment to be added to the bin (BTU's)

5. For Buy-All, Sell-All, the cost of the electricity being purchased minus the revenues for the electricity being sold to the utility

6. For Offset-Load, Sell-Surplus, if excess electricity is being generated, how much revenue is generated

7. For Offset-Load, Sell-Surplus, if excess is not being generated, how much the purchased electricity costs; the running total net cost is incremented accordingly

When all thermal profile hours have been analyzed and each bin has all values accumulated accordingly, net revenues, costs, and savings can be calculated.

This functional area adds all the hourly bin data for both "Buy-All, Sell-All (BASA)" and "Offset-Load, Sell-Surplus (OLSS)" operation modes. Monthly charges are calculated, fuel savings (in fuel switch cases) are accounted for, and net costs, savings, and revenues are summarized on a monthly and annual basis.

The output of this section includes monthly and annual summaries of electricity generated (KWH), fuel increment charged (BTU's), total fuel required (BTU's), and net operational costs from each operational mode. Also, a complete bin breakdown summary of all costs and revenues is presented. Finally, investment costs are estimated and all first year revenues, savings, and costs are presented for economic analysis.

The bin values calculated in the system performance area of the program are totalled to obtain:

1. Monthly and annual KWH generated
2. Monthly and annual excess electricity generated, if any
3. Monthly and annual fuel increment required (BTU's)

These values are transferred to the Net Savings, Costs, and Revenues area of the program to calculate:

1. Monthly and annual energy costs for purchased electricity (both BASA and OLSS)

2. Net monthly and annual cost to the facility for electrical energy (not including monthly charges, fuel savings due to fuel switch, or fuel increment)

Based on the utility rate structure being analyzed, the program then calculates all monthly charges such as:

1. Customer charge (if applicable)
2. Fuel increment
3. Billing demand

7.3 OPTION #3 - RECIPROCATING GAS ENGINE COGENERATION

Description of Equipment

- One (1) 460 KW gas engine generator set and controls or similar equipment
- A heat recovery system to recover heat from the exhaust gas, jacket cooling water and oil cooling water
- A switchgear system to connect the engine generator to the load(s) and to operate in parallel with the City of St. Peter Municipal Electric Utility
- A system of meters and recorders to establish the electrical and thermal energy delivered to the Hospital
- The building to house the above equipment, and all necessary piping and electrical interface connections

Description of System

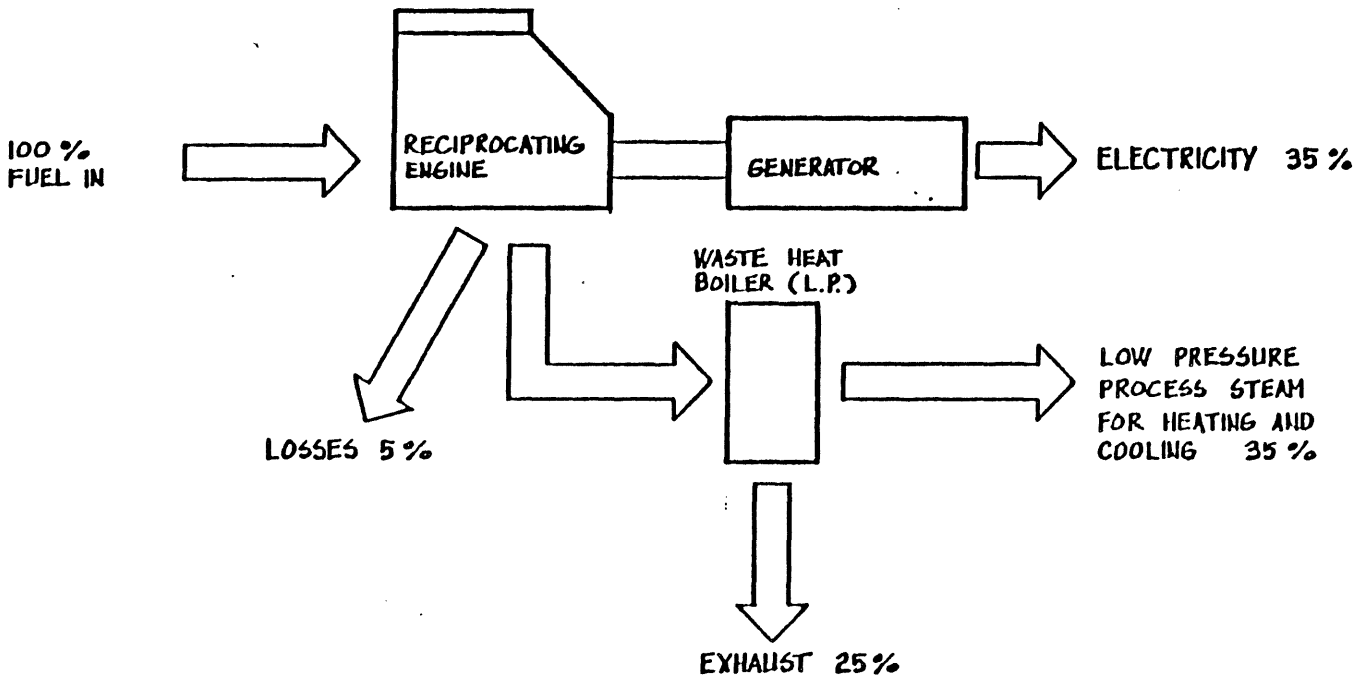
Figure 3 shows how a gas engine cogeneration system is usually configured.

The gas engine generator has the capability of generating approximately 460 KW of electric energy. The engine will operate on a continuous basis on interruptible natural gas. If the Gas Company interrupts gas service, which is expected to be minimal, the natural gas engine generator set will be shut down and the Hospital will operate the existing 800 KW diesel standby generator set or if necessary will purchase all electric power from the City of St. Peter Municipal Electric Utility. It is our opinion that the few hours of natural gas curtailment during winter months will not justify the installation of a $ 20,000 propane standby system.

An economic analysis of a gas engine cogeneration system is shown on pages 64 to 73 .

Figure 3

RECIPROCATING ENGINE COGENERATION



I SMMPA BUY-BACK

Summary of Input/Output Parameters

Facility: ST. PETER HOSPITAL

Input Parameters

Boiler fuel cost ($/MMBtu)	3.55
Cogen fuel cost ($/MMBtu)	3.55
System Thermal Efficiency (%)	52.0
System Electrical Efficiency (%)	27.0
System T/E Ratio	1.93
System Net Fuel Rate (Btu's/kwh)	12637.04
Fuel Cost to Generate($/kwh)	$0.045

Utility Rate Structures

Energy Credits:

Summer On-Peak ($/kwh)	$0.030
Summer Off-Peak ($/kwh)	$0.016
Winter On-Peak ($/kwh)	$0.029
Winter Off-Peak ($/kwh)	$0.020

Capacity Credits:

On-Peak Summer ($/kwh)	$0.000
On-Peak Non-Summer ($/kwh)	$0.000

Rate for Large General Service ($/kwh) : $0.050

Rate structure has been specified as fixed.

SMMPA Buy-Back Continued

Total Electricity Generated in On-Peak/Off-Peak Periods

Facility: ST. PETER HOSPITAL

Tsize: 3.022 MMBtu/Hr (Thermal output)

Period	Hrs	Excess kwh	Total kwh	Bin No.	
On-Peak Mo., On-Peak Hr	1092	8,888	491,631	1	Summer Month 9AM to 9PM
Off-Peak Mo, On-Peak Hr	2197	16,772	1,010,359	3	Winter Month 9AM to 9PM
On-Peak Mo., Off-Peak Hr	1836	88,626	718,371	2	Summer Month 9PM to 9AM
Off-Peak Mo, Off-Peak Hr	3635	221,909	1,671,669	4	Winter Month 9PM to 9AM

System Performance

Month	EGEN MKWH	'EXCESS' MKWH	Add. Fuel MMBtus
1	342	19	4,324
2	309	19	3,905
3	342	29	4,324
4	331	46	4,184
5	342	44	4,324
6	331	34	4,184
7	206	0	2,598
8	342	30	4,324
9	331	34	4,184
10	342	39	4,324
11	331	23	4,184
12	342	20	4,324
Total	3,892	336	49,184

Note: 'Add. Fuel' is the extra fuel consumed to generate electricity beyond fuel required to meet the thermal load.

SMMPA Buy-Back Continued

Monthly Operating Costs for Buy-All, Sell-All (BASA) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	6648	9275	7850	7010	0	0	0	$	30,783
-Rev	1	$	0	0	0	0	0	3587	3629	3946	3587	0	0	0	$	14,749
BASA	1	$	0	0	0	0	0	3061	5646	3904	3423	0	0	0	$	16,034
Ecost	2	$	0	0	0	0	0	9336	10662	9406	9128	0	0	0	$	38,532
-Rev	2	$	0	0	0	0	0	3385	1354	3370	3385	0	0	0	$	11,494
BASA	2	$	0	0	0	0	0	5951	9308	6036	5743	0	0	0	$	27,038
Ecost	3	$	8338	7311	7056	6854	7427	0	0	0	0	7958	7360	7896	$	60,201
-Rev	3	$	3814	3294	3641	3641	3814	0	0	0	0	3988	3468	3641	$	29,300
BASA	3	$	4524	4017	3415	3214	3613	0	0	0	0	3970	3892	4255	$	30,900
Ecost	4	$	10000	9256	9826	8376	8562	0	0	0	0	8609	9652	10227	$	74,509
-Rev	4	$	4213	3909	4332	4111	4213	0	0	0	0	4093	4231	4332	$	33,433
BASA	4	$	5787	5347	5494	4265	4350	0	0	0	0	4516	5421	5895	$	41,076
Elect Subtot		$	10311	9364	8909	7478	7963	9012	14954	9939	9166	8487	9314	10150	$	115,048
Facility Chg		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 3)		$	15349	13864	15349	14854	15349	14854	9224	15349	14854	15349	14854	15349	$	174,602
Fuel(Note 4)		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 5)		$	49114	41280	34698	20563	5407	2982	3212	2832	3264	17573	33166	44926	$	259,017
System O & M		$	3422	3090	3422	3311	3422	3311	2056	3422	3311	3422	3311	3422	$	38,920
Total Cost		$	78197	67598	62379	46207	32141	30159	29446	31542	30596	44831	60645	73847	$	587,588

Notes.

1. Bin Numbers are assigned to on/off peak hours/months on the previous page.
2. 'Facility Chg' includes monthly facility or customer charges from the electric company.
3. Fuel cost attributable to COGEN electrical output.
4. Fuel cost attributable to COGEN thermal output.
5. Fuel cost attributable to non-COGEN thermal output.

SMMPA Buy-Back Continued

Monthly Operating Costs for Offset-Load, Sell-Surplus (OLSS) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	873	3227	1383	1163	0	0	0	$	6,646
-Rev	1	$	0	0	0	0	0	122	0	66	79	0	0	0	$	267
OLSS	1	$	0	0	0	0	0	751	3227	1317	1084	0	0	0	$	6,379
Ecost	2	$	0	0	0	0	0	235	6429	248	132	0	0	0	$	7,044
-Rev	2	$	0	0	0	0	0	472	0	440	506	0	0	0	$	1,418
OLSS	2	$	0	0	0	0	0	-238	6429	-191	-374	0	0	0	$	5,626
Ecost	3	$	1792	1632	937	921	1018	0	0	0	0	1160	1409	1652	$	10,521
-Rev	3	$	18	0	92	199	97	0	0	0	0	45	16	19	$	486
OLSS	3	$	1775	1632	845	721	921	0	0	0	0	1115	1393	1633	$	10,035
Ecost	4	$	407	422	266	46	75	0	0	0	0	230	199	377	$	2,021
-Rev	4	$	375	375	508	779	818	0	0	0	0	741	450	392	$	4,438
OLSS	4	$	32	46	-242	-733	-743	0	0	0	0	-511	-251	-15	$	-2,417
Elect Subtot		$	1806	1678	603	-12	178	513	9656	1126	710	604	1142	1617	$	19,623
Facility Chg		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 3)		$	15349	13864	15349	14854	15349	14854	9224	15349	14854	15349	14854	15349	$	174,602
Fuel(Note 4)		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 5)		$	49114	41280	34698	20563	5407	2982	3212	2832	3264	17573	33166	44926	$	259,017 *
System O & M			3422	3090	3422	3311	3422	3311	2056	3422	3311	3422	3311	3422	$	38,920
Total Cost		$	69692	59912	54073	38717	24356	21661	24149	22729	22140	36948	52474	65315	$	492,163

Notes.
1. Bin Numbers are assigned to on/off peak hours/months on the previous page.
2. 'Facility Chg' includes monthly facility or customer charges from the electric company.
3. Fuel cost attributable to COGEN electrical output.
4. Fuel cost attributable to COGEN thermal output.
5. Fuel cost attributable to non-COGEN thermal output.

* The $ 259,017 fuel cost is based on 100% utilization of recoverable heat. A portion of the recovered heat from the engine jacket water and lube oil cooling system can not be used during night and weekend hours when the domestic hot water and laundry hot water loads are minimal. Fuel cost increases by $ 27,988 - a 25% reduction in savings - to account for nonusable recoverable heat. Fuel cost (Note 5) increases from $ 259,017 to $ 287,005.

SMMPA Buy-Back Continued

Analysis of First Year Operation

* Tsize: 3.022 MMBtu/Hr Esize: 459 KW *

Base Year Annual Energy Cost:	$	571,546	Thermal & Electrical Total Costs

Summary of COGEN Capital/Cost/Revenue Line Items:

Investments:

Steam Plant Cost:	$	10,000
Engine /Generator Cost:	$	301,400
Engineering & Design:	$	28,026
Contingency Allowance:	$	9,342
Other costs, Not specified:	$	30,000
Subtotal for Investments	$	378,768

Revenues and Savings:

Electricity Revenues (BASA Mode):	$	88,977

Expenses:

Electricity Costs (BASA Mode):	$	204,024
Monthly Electric Company Charges (BASA):	$	0
Electricity Costs (OLSS Mode):	$	26,233
Monthly Electric Company Charges (OLSS):	$	0
Total Fuel Costs (Either Mode):	$	433,620
Annual Operating & Maint Costs:	$	38,920
(O & M Cost Factor [$/kwh]: 0.0100)		

Net First Year Results--BASA Mode

Total Capital Investment:	$	378,768
Net First Year Cost (Expense - Rev.):	$	587,588
First Year Savings (COGEN vs Baseyear):	$	-16,041
Payback	Never	

Net First Year Results--OLSS Mode

Total Capital Investment:	$	378,768	378,768
First Year Cost:	$	492,163	520,151
First Year Savings (COGEN vs Baseyear):	$	79,383	51,395
Payback		4.77 years	7.37 years
		100% use of Recoverable Heat	75% use of Recoverable Heat

II N S P BUY-BACK

Summary of Input/Output Parameters

Facility: ST. PETER HOSPITAL

Input Parameters

Boiler fuel cost ($/MMBtu)	:	3.55
Cogen fuel cost ($/MMBtu)	:	3.55
System Thermal Efficiency (%)	:	52.0
System Electrical Efficiency (%)	:	27.0
System T/E Ratio	:	1.93
System Net Fuel Rate (Btu's/kwh)	:	12637.04
Fuel Cost to Generate($/kwh)	:	$0.045

Utility Rate Structures

Energy Credits:

Summer On-Peak ($/kwh)	:	$0.024
Summer Off-Peak ($/kwh)	:	$0.014
Winter On-Peak ($/kwh)	:	$0.024
Winter Off-Peak ($/kwh)	:	$0.014

Capacity Credits: *

On-Peak Summer ($/kwh)	:	$0.014
On-Peak Non-Summer ($/kwh)	:	$0.014

Rate for Large General Service ($/kwh)
: $0.050

Rate structure has been specified as fixed.

* Applies to all hours On-Peak and Off-Peak

$$\frac{\$\ 10.04/\text{KW}}{720\ \text{Hrs/Mo}} = \$\ 0.014$$

NSP Buy-Back Continued

Total Electricity Generated in On-Peak/Off-Peak Periods

Facility: ST. PETER HOSPITAL

Tsize: 3.022 MMBtu/Hr (Thermal output)

Period	Hrs	Excess kwh	Total kwh	Bin No.	
On-Peak Mo., On-Peak Hr	1092	8,888	491,631	1	Summer Month 9AM to 9PM
Off-Peak Mo, On-Peak Hr	2197	16,772	1,010,359	3	Winter Month 9AM to 9PM
On-Peak Mo., Off-Peak Hr	1836	88,626	718,371	2	Summer Month 9PM to 9AM
Off-Peak Mo, Off-Peak Hr	3635	221,909	1,671,669	4	Winter Month 9PM to 9AM

System Performance

Month	EGEN MKWH	'EXCESS' MKWH	Add. Fuel MMBtus
1	342	19	4,324
2	309	19	3,905
3	342	29	4,324
4	331	46	4,184
5	342	44	4,324
6	331	34	4,184
7	206	0	2,598
8	342	30	4,324
9	331	34	4,184
10	342	39	4,324
11	331	23	4,184
12	342	20	4,324
Total	3,892	336	49,184

Note: 'Add. Fuel' is the extra fuel consumed to generate electricity beyond fuel required to meet the thermal load.

NSP Buy-Back Continued

Monthly Operating Costs for Buy-All, Sell-All (BASA) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	6648	9275	7850	7010	0	0	0	$	30,783
-Rev	1	$	0	0	0	0	0	4544	4597	4998	4544	0	0	0	$	18,682
BASA	1	$	0	0	0	0	0	2104	4678	2852	2466	0	0	0	$	12,101
Ecost	2	$	0	0	0	0	0	9336	10662	9406	9128	0	0	0	$	38,532
-Rev	2	$	0	0	0	0	0	5923	2370	5898	5923	0	0	0	$	20,114
BASA	2	$	0	0	0	0	0	3413	8292	3508	3205	0	0	0	$	18,417
Ecost	3	$	8338	7311	7056	6854	7427	0	0	0	0	7958	7360	7896	$	60,201
-Rev	3	$	4998	4316	4771	4771	4998	0	0	0	0	5225	4544	4771	$	38,394
BASA	3	$	3340	2995	2285	2084	2429	0	0	0	0	2733	2816	3125	$	21,807
Ecost	4	$	10000	9256	9826	8376	8562	0	0	0	0	8609	9652	10227	$	74,509
-Rev	4	$	5898	5473	6065	5756	5898	0	0	0	0	5730	5923	6065	$	46,807
BASA	4	$	4102	3783	3761	2620	2665	0	0	0	0	2879	3729	4162	$	27,702
Elect Subtot		$	7442	6778	6047	4704	5094	5517	12970	6360	5671	5612	6545	7287	$	80,028
Facility Chg		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 3)		$	15349	13864	15349	14854	15349	14854	9224	15349	14854	15349	14854	15349	$	174,602
Fuel(Note 4)		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 5)		$	49114	41280	34698	20563	5407	2982	3212	2832	3264	17573	33166	44926	$	259,017
System O & M		$	3422	3090	3422	3311	3422	3311	2056	3422	3311	3422	3311	3422	$	38,920
Total Cost		$	75328	65012	59516	43432	29272	26664	27463	27963	27101	41956	57876	70985	$	552,568

Notes.
1. Bin Numbers are assigned to on/off peak hours/months on the previous page.
2. 'Facility Chg' includes monthly facility or customer charges from the electric company.
3. Fuel cost attributable to COGEN electrical output.
4. Fuel cost attributable to COGEN thermal output.
5. Fuel cost attributable to non-COGEN thermal output.

NSP Buy-Back Continued

Monthly Operating Costs for Offset-Load, Sell-Surplus (OLSS) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	873	3227	1383	1163	0	0	0	$	6,646
-Rev	1	$	0	0	0	0	0	155	0	83	100	0	0	0	$	338
OLSS	1	$	0	0	0	0	0	718	3227	1300	1063	0	0	0	$	6,308
Ecost	2	$	0	0	0	0	0	235	6429	248	132	0	0	0	$	7,044
-Rev	2	$	0	0	0	0	0	827	0	769	886	0	0	0	$	2,482
OLSS	2	$	0	0	0	0	0	-592	6429	-521	-753	0	0	0	$	4,563
Ecost	3	$	1792	1632	937	921	1018	0	0	0	0	1160	1409	1652	$	10,521
-Rev	3	$	23	0	121	261	127	0	0	0	0	59	21	25	$	637
OLSS	3	$	1769	1632	817	659	891	0	0	0	0	1101	1388	1627	$	9,884
Ecost	4	$	407	422	266	46	75	0	0	0	0	230	199	377	$	2,021
-Rev	4	$	525	525	711	1091	1145	0	0	0	0	1038	629	549	$	6,213
OLSS	4	$	-118	-104	-445	-1045	-1070	0	0	0	0	-808	-431	-172	$	-4,192
Elect Subtot		$	1651	1528	372	-385	-179	126	9656	778	310	294	957	1455	$	16,563
Facility Chg		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 3)		$	15349	13864	15349	14854	15349	14854	9224	15349	14854	15349	14854	15349	$	174,602
Fuel(Note 4)		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 5)		$	49114	41280	34698	20563	5407	2982	3212	2832	3264	17573	33166	44926	$	259,017
System O & M			3422	3090	3422	3311	3422	3311	2056	3422	3311	3422	3311	3422	$	38,920
Total Cost		$	69536	59762	53841	38343	23999	21274	24149	22381	21739	36638	52289	65152	$	489,102

Notes.

1. Bin Numbers are assigned to on/off peak hours/months on the previous page.
2. 'Facility Chg' includes monthly facility or customer charges from the electric company.
3. Fuel cost attributable to COGEN electrical output.
4. Fuel cost attributable to COGEN thermal output.
5. Fuel cost attributable to non-COGEN thermal output.

NSP Buy-Back Continued

Analysis of First Year Operation

* Tsize: 3.022 MMBtu/Hr Esize: 459 KW *

Base Year Annual Energy Cost:	$	571,546	Thermal & Electrical Total Costs

Summary of COGEN Capital/Cost/Revenue Line Items:

Investments:		
Steam Plant Cost:	$	10,000
Engine /Generator Cost:	$	301,400
Engineering & Design:	$	28,000
Contingency Allowance:	$	10,000
Other costs, Not specified:	$	30,000
Subtotal for Investments	$	379,400
Revenues and Savings:		
Electricity Revenues (BASA Mode):	$	123,997
Expenses:		
Electricity Costs (BASA Mode):	$	204,024
Monthly Electric Company Charges (BASA):	$	0
Electricity Costs (OLSS Mode):	$	26,233
Monthly Electric Company Charges (OLSS):	$	0
Total Fuel Costs (Either Mode):	$	433,620
Annual Operating & Maint Costs:	$	38,920
(O & M Cost Factor [$/kwh]: 0.0100)		
Net First Year Results--BASA Mode		
Total Capital Investment:	$	379,400
Net First Year Cost (Expense - Rev.):	$	552,568
First Year Savings (COGEN vs Baseyear):	$	18,979
Payback		19.99 years

Net First Year Results--OLSS Mode			
Total Capital Investment:	$	379,400	379,400
First Year Cost:	$	489,103	517,091
First Year Savings (COGEN vs Baseyear):	$	82,444	54,455
Payback		4.60 years	6.96 years
		100% use of Recoverable Heat	75% use of Recoverable Heat

7.4 OPTION #4 - GAS TURBINE COGENERATION

Description of Equipment

- One (1) 440 KW gas turbine generator set and controls or similar equipment
- A heat recovery boiler to recover heat from the exhaust gas (3,698 Lbs/Hr)
- A switchgear system to connect the turbine generator to the load(s) and to operate in parallel with the City of St. Peter Municipal Electric Utility
- A system of meters and recorders to establish the electrical and thermal energy delivered to the Hospital
- The building to house the above equipment, and all necessary piping and electrical interface connections

Description of System

Figure 4 shows how a gas engine cogeneration system is usually configured.

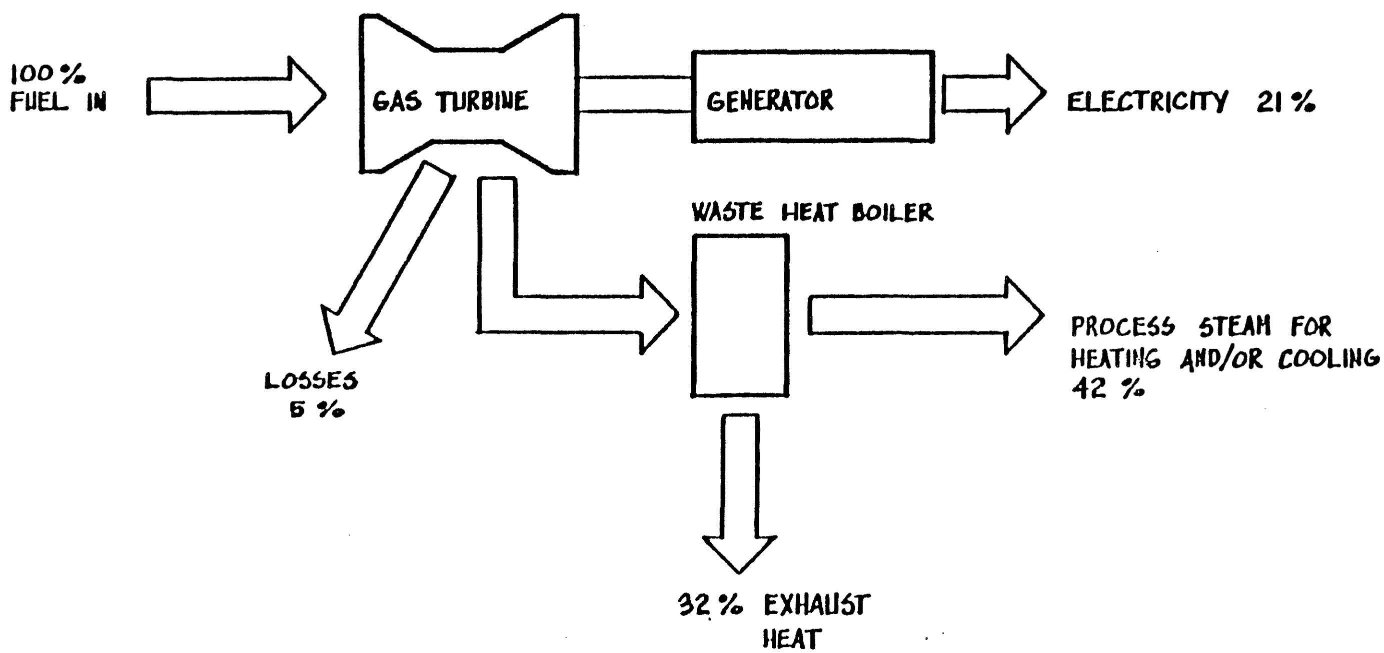
The gas turbine generator has the capability of generating approximately 440 KW of electric energy. The turbine will operate on a continuous basis on interruptible natural gas. If the Gas Company interrupts gas service, which is expected to be minimal, the turbine generator set will be shut down and the Hospital will operate the existing 800 KW diesel standby generator set or if necessary will purchase all electric power from the City of St. Peter Municipal Electric Utility. It is our opinion that the few hours of natural gas curtailment during winter months will not justify the installation of a propane standby system.

An economic analysis of a gas turbine cogeneration system is shown on pages 76 to 85 .

Figure 4

COGENERATION FEASIBILITY STUDY

GAS TURBINE COGENERATION



I SMMPA BUY-BACK

Summary of Input/Output Parameters

Facility: ST. PETER HOSPITAL

Input Parameters

Boiler fuel cost ($/MMBtu)	: 3.55
Gas fuel cost ($/MMBtu)	: 3.55
System Thermal Efficiency (%)	: 44.0
System Electrical Efficiency (%)	: 19.0
System T/E Ratio	: 2.32
System Net Fuel Rate (Btu's/kwh)	:17957.90
Fuel Cost to Generate($/kwh)	: $0.064

Utility Rate Structures

Energy Credits:

Summer On-Peak ($/kwh)	: $0.030
Summer Off-Peak ($/kwh)	: $0.016
Winter On-Peak ($/kwh)	: $0.029
Winter Off-Peak ($/kwh)	: $0.020

Capacity Credits:

On-Peak Summer ($/kwh)	: $0.000
On-Peak Non-Summer ($/kwh)	: $0.000

Rate for Large General Service ($/kwh)
: $0.050

Rate structure has been specified as fixed.

SMMPA Buy-Back Continued

Total Electricity Generated in On-Peak/Off-Peak Periods

Facility: ST. PETER HOSPITAL

Tsize: 3.476 MMBtu/Hr (Thermal output)

Period	Hrs	Excess kwh	Total kwh	Bin No.	
On-Peak Mo., On-Peak Hr	1092	3,585	461,992	1	Summer Month 9AM to 9PM
Off-Peak Mo, On-Peak Hr	2197	7,606	966,500	3	Winter Month 9AM to 9PM
On-Peak Mo., Off-Peak Hr	1836	55,441	730,336	2	Summer Month 9PM to 9AM
Off-Peak Mo, Off-Peak Hr	3635	165,814	1,598,901	4	Winter Month 9PM to 9AM

System Performance

Month	EGEN MKWH	'EXCESS' MKWH	Add. Fuel MMBtus
1	327	13	5,878
2	296	13	5,309
3	327	19	5,878
4	317	35	5,688
5	327	34	5,874
6	314	22	5,633
7	245	0	4,393
8	322	17	5,774
9	313	20	5,612
10	327	29	5,878
11	317	16	5,688
12	327	14	5,878
Total	3,758	232	67,481

Note: 'Add. Fuel' is the extra fuel consumed to generate electricity beyond fuel required to meet the thermal load.

SMMPA Buy-Back Continued

Monthly Operating Costs for Buy-All, Sell-All (BASA) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	6648	9275	7850	7010	0	0	0	$	30,783
-Rev	1	$	0	0	0	0	0	3431	3223	3774	3431	0	0	0	$	13,860
BASA	1	$	0	0	0	0	0	3217	6053	4075	3579	0	0	0	$	16,923
Ecost	2	$	0	0	0	0	0	9336	10662	9406	9128	0	0	0	$	38,532
-Rev	2	$	0	0	0	0	0	3188	2195	3132	3170	0	0	0	$	11,685
BASA	2	$	0	0	0	0	0	6148	8467	6274	5958	0	0	0	$	26,846
Ecost	3	$	8338	7311	7056	6854	7427	0	0	0	0	7958	7360	7896	$	60,201
-Rev	3	$	3649	3151	3483	3483	3649	0	0	0	0	3815	3317	3483	$	28,028
BASA	3	$	4689	4160	3573	3372	3779	0	0	0	0	4143	4043	4413	$	32,172
Ecost	4	$	10000	9256	9826	8376	8562	0	0	0	0	8609	9652	10227	$	74,509
-Rev	4	$	4030	3739	4144	3933	4026	0	0	0	0	3915	4047	4144	$	31,978
BASA	4	$	5970	5517	5682	4443	4537	0	0	0	0	4694	5605	6083	$	42,531
Elect Subtot		$	10660	9677	9256	7815	8315	9364	14520	10349	9536	8837	9648	10496	$	118,473
Facility Chg		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 3)		$	20865	18846	20865	20192	20853	19996	15594	20499	19923	20865	20192	20865	$	239,557
Fuel(Note 4)		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 5)		$	47577	39891	33161	19075	3877	1605	565	1501	1928	16036	31678	43389	$	240,284
System O & M		$	1636	1478	1636	1584	1635	1568	1223	1608	1563	1636	1584	1636	$	18,789
Total Cost		$	80739	69892	64918	48666	34680	32533	31901	33957	32950	47375	63102	76387	$	617,103

Notes.
1. Bin Numbers are assigned to on/off peak hours/months on the previous page.
2. 'Facility Chg' includes monthly facility or customer charges from the electric company.
3. Fuel cost attributable to COGEN electrical output.
4. Fuel cost attributable to COGEN thermal output.
5. Fuel cost attributable to non-COGEN thermal output.

SMMPA Buy-Back Continued

Monthly Operating Costs for Offset-Load, Sell-Surplus (OLSS) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	1033	3904	1603	1323	0	0	0	$	7,862
-Rev	1	$	0	0	0	0	0	62	0	26	19	0	0	0	$	108
OLSS	1	$	0	0	0	0	0	971	3904	1576	1304	0	0	0	$	7,755
Ecost	2	$	0	0	0	0	0	368	3803	404	212	0	0	0	$	4,787
-Rev	2	$	0	0	0	0	0	319	0	251	317	0	0	0	$	887
OLSS	2	$	0	0	0	0	0	49	3803	153	-105	0	0	0	$	3,900
Ecost	3	$	2056	1878	1093	1084	1215	0	0	0	0	1381	1649	1899	$	12,256
-Rev	3	$	5	0	24	136	46	0	0	0	0	0	5	5	$	221
OLSS	3	$	2051	1878	1069	948	1169	0	0	0	0	1381	1644	1895	$	12,036
Ecost	4	$	559	566	399	78	106	0	0	0	0	276	313	558	$	2,855
-Rev	4	$	253	263	373	614	643	0	0	0	0	582	311	277	$	3,316
OLSS	4	$	306	303	26	-536	-537	0	0	0	0	-306	1	282	$	-461
Elect Subtot		$	2356	2181	1095	413	632	1020	7707	1729	1199	1075	1645	2177	$	23,229
Facility Chg		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 3)		$	20865	18846	20865	20192	20853	19996	15594	20499	19923	20865	20192	20865	$	239,557
Fuel(Note 4)		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 5)		$	47577	39891	33161	19075	3877	1605	565	1501	1928	16036	31678	43389	$	240,284
System O & M			1636	1478	1636	1584	1635	1568	1223	1608	1563	1636	1584	1636	$	18,789
Total Cost		$	72436	62396	56757	41264	26997	24189	25089	25337	24613	39613	55100	68068	$	521,859

Notes.
1. Bin Numbers are assigned to on/off peak hours/months on the previous page.
2. 'Facility Chg' includes monthly facility or customer charges from the electric company.
3. Fuel cost attributable to COGEN electrical output.
4. Fuel cost attributable to COGEN thermal output.
5. Fuel cost attributable to non-COGEN thermal output.

SMMPA Buy-Back Continued

Analysis of First Year Operation

* Tsize: 3.476 MMBtu/Hr   Esize: 439 KW *

Base Year Annual Energy Cost:	$	571,546	Thermal & Electrical Total Costs

Summary of COGEN Capital/Cost/Revenue Line Items:

Investments:		
Steam Plant Cost:	$	10,000
Turbine/Generator Cost:	$	785,000
Engineering & Design:	$	63,600
Contingency Allowance:	$	7,950
Other costs, Not specified:	$	50,000
Subtotal for Investments	$	916,550
Revenues and Savings:		
Electricity Revenues (BASA Mode):	$	85,552
Expenses:		
Electricity Costs (BASA Mode):	$	204,024
Monthly Electric Company Charges (BASA):	$	0
Electricity Costs (OLSS Mode):	$	27,760
Monthly Electric Company Charges (OLSS):	$	0
Total Fuel Costs (Either Mode):	$	479,841
Annual Operating & Maint Costs:	$	18,789
(O & M Cost Factor [$/kwh]: 0.0050)		
Net First Year Results--BASA Mode		
Total Capital Investment:	$	916,550
Net First Year Cost (Expense - Rev.):	$	617,103
First Year Savings (COGEN vs Baseyear):	$	-45,556
Payback	Never	
Net First Year Results--OLSS Mode		
Total Capital Investment:	$	916,550
First Year Cost:	$	521,859
First Year Savings (COGEN vs Baseyear):	$	49,688
Payback		18.45 years

II N S P BUY-BACK

Summary of Input/Output Parameters

Facility: ST. PETER HOSPITAL

Input Parameters

Boiler fuel cost ($/MMBtu)	:	3.55
Gas fuel cost ($/MMBtu)	:	3.55
System Thermal Efficiency (%)	:	44.0
System Electrical Efficiency (%)	:	19.0
System T/E Ratio	:	2.32
System Net Fuel Rate (Btu's/kwh)	:	17957.90
Fuel Cost to Generate($/kwh)	:	$0.064

Utility Rate Structures

Energy Credits:

Summer On-Peak ($/kwh)	:	$0.024
Summer Off-Peak ($/kwh)	:	$0.014
Winter On-Peak ($/kwh)	:	$0.024
Winter Off-Peak ($/kwh)	:	$0.014

Capacity Credits:

On-Peak Summer ($/kwh)	:	$0.014
On-Peak Non-Summer ($/kwh)	:	$0.014

Rate for Large General Service ($/kwh)
: $0.050

Rate structure has been specified as fixed.

NSP Buy-Back Continued

Total Electricity Generated in On-Peak/Off-Peak Periods

Facility: ST. PETER HOSPITAL

Tsize: 3.476 MMBtu/Hr (Thermal output)

Period	Hrs	Excess kwh	Total kwh	Bin No.	
On-Peak Mo., On-Peak Hr	1092	3,585	461,992	1	Summer Month 9AM to 9PM
Off-Peak Mo, On-Peak Hr	2197	7,606	966,500	3	Winter Month 9AM to 9PM
On-Peak Mo., Off-Peak Hr	1836	55,441	730,336	2	Summer Month 9PM to 9AM
Off-Peak Mo, Off-Peak Hr	3635	165,814	1,598,901	4	Winter Month 9PM to 9AM

System Performance

Month	EGEN MKWH	'EXCESS' MKWH	Add. Fuel MMBtus
1	327	13	5,878
2	296	13	5,309
3	327	19	5,878
4	317	35	5,688
5	327	34	5,874
6	314	22	5,633
7	245	0	4,393
8	322	17	5,774
9	313	20	5,612
10	327	29	5,878
11	317	16	5,688
12	327	14	5,878
Total	3,758	232	67,481

Note: 'Add. Fuel' is the extra fuel consumed to generate electricity beyond fuel required to meet the thermal load.

NSP Buy-Back Continued

Monthly Operating Costs for Buy-All, Sell-All (BASA) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	6648	9275	7850	7010	0	0	0	$	30,783
-Rev	1	$	0	0	0	0	0	4346	4082	4781	4346	0	0	0	$	17,556
BASA	1	$	0	0	0	0	0	2302	5193	3069	2664	0	0	0	$	13,227
Ecost	2	$	0	0	0	0	0	9336	10662	9406	9128	0	0	0	$	38,532
-Rev	2	$	0	0	0	0	0	5580	3841	5481	5548	0	0	0	$	20,449
BASA	2	$	0	0	0	0	0	3756	6821	3925	3580	0	0	0	$	18,082
Ecost	3	$	8338	7311	7056	6854	7427	0	0	0	0	7958	7360	7896	$	60,201
-Rev	3	$	4781	4129	4564	4564	4781	0	0	0	0	4998	4346	4564	$	36,727
BASA	3	$	3557	3182	2492	2291	2646	0	0	0	0	2960	3014	3332	$	23,474
Ecost	4	$	10000	9256	9826	8376	8562	0	0	0	0	8609	9652	10227	$	74,509
-Rev	4	$	5642	5235	5802	5506	5636	0	0	0	0	5481	5666	5802	$	44,769
BASA	4	$	4358	4021	4025	2870	2927	0	0	0	0	3128	3986	4426	$	29,740
Elect Subtot		$	7915	7203	6517	5161	5573	6058	12014	6994	6244	6087	6999	7758	$	84,523
Facility Chg		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 3)		$	20865	18846	20865	20192	20853	19996	15594	20499	19923	20865	20192	20865	$	239,557
Fuel(Note 4)		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 5)		$	47577	39891	33161	19075	3877	1605	565	1501	1928	16036	31678	43389	$	240,284
System O & M		$	1636	1478	1636	1584	1635	1568	1223	1608	1563	1636	1584	1636	$	18,789
Total Cost		$	77995	67419	62180	46012	31938	29227	29396	30602	29658	44625	60454	73649	$	583,153

Notes.
1. Bin Numbers are assigned to on/off peak hours/months on the previous page.
2. 'Facility Chg' includes monthly facility or customer charges from the electric company.
3. Fuel cost attributable to COGEN electrical output.
4. Fuel cost attributable to COGEN thermal output.
5. Fuel cost attributable to non-COGEN thermal output.

NSP Buy-Back Continued

Monthly Operating Costs for Offset-Load, Sell-Surplus (OLSS) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	1033	3904	1603	1323	0	0	0	$	7,862
-Rev	1	$	0	0	0	0	0	79	0	33	24	0	0	0	$	136
OLSS	1	$	0	0	0	0	0	954	3904	1569	1299	0	0	0	$	7,726
Ecost	2	$	0	0	0	0	0	368	3803	404	212	0	0	0	$	4,787
-Rev	2	$	0	0	0	0	0	558	0	440	555	0	0	0	$	1,552
OLSS	2	$	0	0	0	0	0	-190	3803	-36	-343	0	0	0	$	3,234
Ecost	3	$	2056	1878	1093	1084	1215	0	0	0	0	1381	1649	1899	$	12,256
-Rev	3	$	7	0	32	178	60	0	0	0	0	0	6	6	$	289
OLSS	3	$	2049	1878	1061	906	1155	0	0	0	0	1381	1643	1893	$	11,967
Ecost	4	$	559	566	399	78	106	0	0	0	0	276	313	558	$	2,855
-Rev	4	$	354	369	522	859	900	0	0	0	0	815	436	387	$	4,643
OLSS	4	$	204	197	-123	-781	-794	0	0	0	0	-539	-124	171	$	-1,788
Elect Subtot		$	2254	2076	938	125	361	764	7707	1534	956	843	1519	2064	$	21,140
Facility Chg		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 3)		$	20865	18846	20865	20192	20853	19996	15594	20499	19923	20865	20192	20865	$	239,557
Fuel(Note 4)		$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
Fuel(Note 5)		$	47577	39891	33161	19075	3877	1605	565	1501	1928	16036	31678	43389	$	240,284
System O & M			1636	1478	1636	1584	1635	1568	1223	1608	1563	1636	1584	1636	$	18,789
Total Cost		$	72333	62291	56601	40976	26726	23933	25089	25142	24370	39380	54974	67955	$	519,770

Notes.
1. Bin Numbers are assigned to on/off peak hours/months on the previous page.
2. 'Facility Chg' includes monthly facility or customer charges from the electric company.
3. Fuel cost attributable to COGEN electrical output.
4. Fuel cost attributable to COGEN thermal output.
5. Fuel cost attributable to non-COGEN thermal output.

NSP Buy-Back Continued

Analysis of First Year Operation

* Tsize: 3.476 MMBtu/Hr   Esize: 439 KW   *

Base Year Annual Energy Cost:	$	571,546	Thermal & Electrical Total Costs

Summary of COGEN Capital/Cost/Revenue Line Items:

Investments:		
Steam Plant Cost:	$	10,000
Turbine/Generator Cost:	$	785,000
Engineering & Design:	$	63,600
Contingency Allowance:	$	15,900
Other costs, Not specified:	$	50,000
Subtotal for Investments	$	924,500
Revenues and Savings:		
Electricity Revenues (BASA Mode):	$	119,501
Expenses:		
Electricity Costs (BASA Mode):	$	204,024
Monthly Electric Company Charges (BASA):	$	0
Electricity Costs (OLSS Mode):	$	27,760
Monthly Electric Company Charges (OLSS):	$	0
Total Fuel Costs (Either Mode):	$	479,841
Annual Operating & Maint Costs:	$	18,789
(O & M Cost Factor [$/kwh]: 0.0050)		
Net First Year Results--BASA Mode		
Total Capital Investment:	$	924,500
Net First Year Cost (Expense - Rev.):	$	583,153
First Year Savings (COGEN vs Baseyear):	$	-11,607
Payback	Never	
Net First Year Results--OLSS Mode		
Total Capital Investment:	$	924,500
First Year Cost:	$	519,770
First Year Savings (COGEN vs Baseyear):	$	51,777
Payback		17.86 years

7.5 OPTION #5 - REFUSE FIRED BOILER WITH STEAM TURBINE COGENERATION

Description of Equipment

- One (1) 100 KW back pressure steam turbine generator set and controls or similar equipment
- A switchgear system to connect the steam turbine generator to the load(s) and to operate in parallel with the City of St. Peter Municipal Electric Utility
- A system of meters and recorders to measure the electrical energy delivered to the Hospital

Description of System

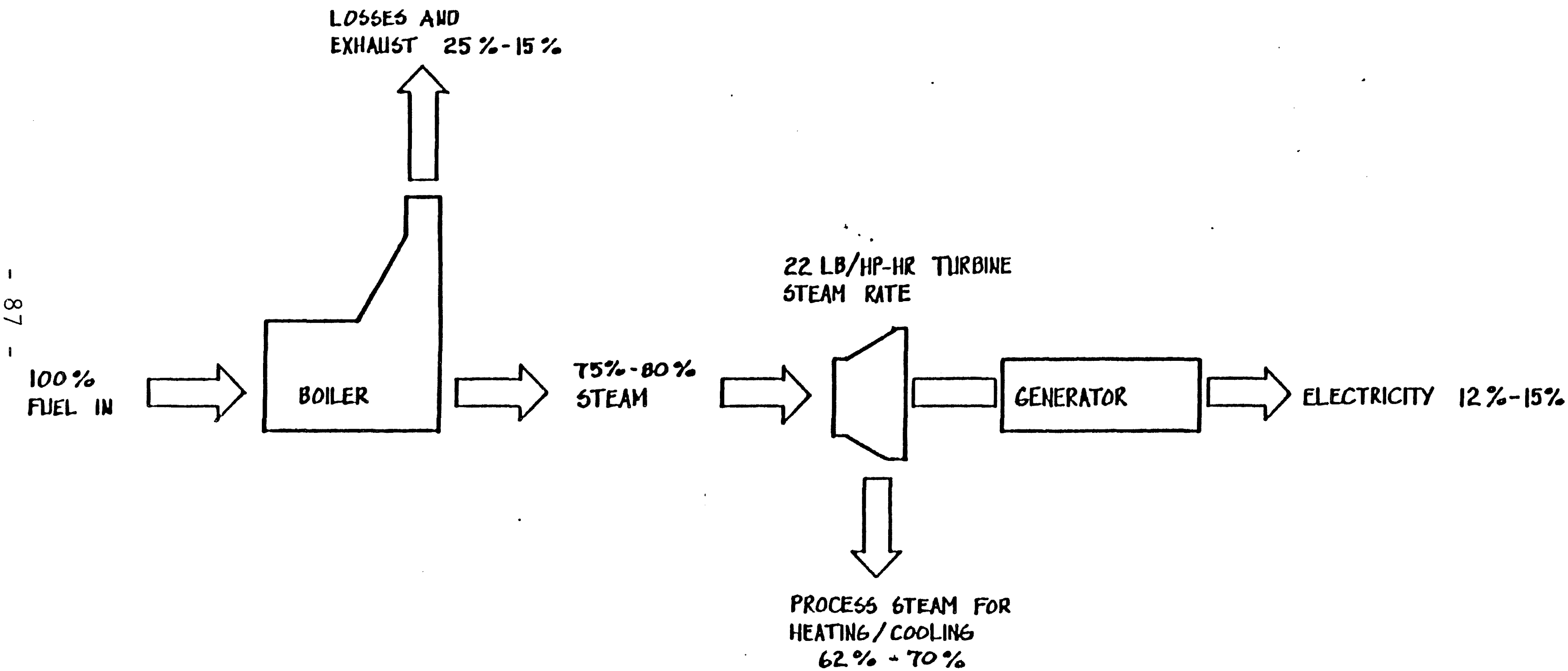
The steam turbine generator has the capability of generating approximately 100 KW of electric energy. The turbine will operate on a continuous basis on 600 PSIG steam supplied by the new refuse fired boiler (Option #1) discussed in Section 6.1. The only change from Option #1 is that the boiler would be designed to operate at 600 PSIG instead of 125 PSIG.

The incremental cost for a 600 PSIG steam boiler is included under this Option.

Figure 5

COGENERATION FEASIBILITY STUDY

BOILER/STEAM TURBINE COGENERATION



```
Function # 2:  Properties of saturated vapor as a function of pressure

    Pressure =  615 psia

Enthalpy =  1203.897 Btu/lbm
Entropy =  1.443517 Btu/lbm-R
Spec. vol. =    0.750363 cu ft/lbm
Internal energy =  1118.501 Btu/lbm
Saturation temperature =  488.8625 deg F
```

```
Function # 7:  Enthalpy of wet steam as a function of pressure
               and entropy

    Pressure =  140 psia
    Entropy =  1.443517 Btu/lbm-R

Enthalpy =  1086.099 Btu/lbm
Quality =  0.88
```

I SMMPA BUY-BACK

Summary of Input/Output Parameters

Facility: ST. PETER HOSPITAL

Input Parameters

Turbine Inlet Pressure (psig)	: 600	
Turbine Outlet Pressure (psig)	: 125	
Turbine Inlet Enthalpy (BTU/lb)	: 1,204	
Turbine Inlet Entropy (BTU/lb/f)	: 1.44	
Turbine Thermal Efficiency (%)	: 49	
Turbine Mech--Elec Efficiency (%)	: 85	(Assumed)
Existing Boiler Efficiency (%)	: 80	
COGEN Boiler Efficiency (%)	: 68	
Fuel cost ($/MMBtu)	: 2.92	

Calculated COGEN Parameters (@ Full Load)

Steam Unit Input Energy (Btu/Lb)	: 1476.32
System Thermal Efficiency (%)	: 64.1
System Electrical Efficiency (%)	: 3.3
System T/E Ratio	: 19.27
System Net Fuel Rate (Btu's/kwh)	:20404.97
System Steam Rate (lbs/kwh)	: 69.49
Fuel Cost to Generate($/kwh)	: $0.060

Utility Rate Structures

Energy Credits:

Summer On-Peak ($/kwh)	: $0.030
Summer Off-Peak ($/kwh)	: $0.016
Winter On-Peak ($/kwh)	: $0.029
Winter Off-Peak ($/kwh)	: $0.020

Capacity Credits:

On-Peak Summer ($/kwh)	: $0.000
On-Peak Non-Summer ($/kwh)	: $0.000

Rate for Large General Service ($/kwh)
: $0.050

Rate structure has been specified as fixed.

SMMPA Buy-Back Continued

Total Electricity Generated in On-Peak/Off-Peak Periods

Facility: ST. PETER HOSPITAL

Tsize: 6.58 MMBtu/Hr (Thermal output)

Period	Hrs	Excess kwh	Total kwh	Bin No.	
On-Peak Mo., On-Peak Hr	1092	0	64,484	1	Summer Month 9AM to 9PM
Off-Peak Mo, On-Peak Hr	2197	0	214,870	3	Winter Month 9AM to 9PM
On-Peak Mo., Off-Peak Hr	1836	0	80,529	2	Summer Month 9PM to 9AM
Off-Peak Mo, Off-Peak Hr	3635	0	342,674	4	Winter Month 9PM to 9AM

System Performance

Month	EGEN MKWH	'EXCESS' MKWH	Add. Fuel MMBtus
1	74	0	1,519
2	67	0	1,372
3	74	0	1,519
4	72	0	1,470
5	48	0	1,049
6	39	0	874
7	26	0	632
8	40	0	886
9	40	0	893
10	74	0	1,519
11	72	0	1,470
12	74	0	1,519
Total	703	0	14,726

Note: 'Add. Fuel' is the extra fuel consumed to generate electricity beyond fuel required to meet the thermal load.

SMMPA Buy-Back Continued

Monthly Operating Costs for Buy-All, Sell-All (BASA) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	6648	9275	7850	7010	0	0	0	$	30,783
-Rev	1	$	0	0	0	0	0	489	372	530	543	0	0	0	$	1,935
BASA	1	$	0	0	0	0	0	6159	8903	7319	6467	0	0	0	$	28,848
Ecost	2	$	0	0	0	0	0	9336	10662	9406	9128	0	0	0	$	38,532
-Rev	2	$	0	0	0	0	0	365	219	351	353	0	0	0	$	1,288
BASA	2	$	0	0	0	0	0	8971	10443	9055	8775	0	0	0	$	37,243
Ecost	3	$	8338	7311	7056	6854	7427	0	0	0	0	7958	7360	7896	$	60,201
-Rev	3	$	830	717	792	792	684	0	0	0	0	868	755	792	$	6,231
BASA	3	$	7508	6594	6264	6062	6743	0	0	0	0	7090	6605	7104	$	53,970
Ecost	4	$	10000	9256	9826	8376	8562	0	0	0	0	8609	9652	10227	$	74,509
-Rev	4	$	917	851	943	895	494	0	0	0	0	891	921	943	$	6,853
BASA	4	$	9083	8405	8884	7481	8069	0	0	0	0	7718	8731	9284	$	67,656
Elect Subtot		$	16591	15000	15147	13543	14811	15129	19346	16374	15242	14809	15337	16388	$	187,717

SMMPA Buy-Back Continued

Monthly Operating Costs for Offset-Load, Sell-Surplus (OLSS) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	5833	8655	6966	6105	0	0	0	$	27,559
-Rev	1	$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
OLSS	1	$	0	0	0	0	0	5833	8655	6966	6105	0	0	0	$	27,559
Ecost	2	$	0	0	0	0	0	8194	9977	8309	8025	0	0	0	$	34,505
-Rev	2	$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
OLSS	2	$	0	0	0	0	0	8194	9977	8309	8025	0	0	0	$	34,505
Ecost	3	$	6907	6075	5690	5488	6247	0	0	0	0	6462	6059	6530	$	49,457
-Rev	3	$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
OLSS	3	$	6907	6075	5690	5488	6247	0	0	0	0	6462	6059	6530	$	49,457
Ecost	4	$	7708	7129	7469	6139	7328	0	0	0	0	6382	7350	7870	$	57,375
-Rev	4	$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
OLSS	4	$	7708	7129	7469	6139	7328	0	0	0	0	6382	7350	7870	$	57,375
Elect Subtot		$	14615	13204	13159	11627	13575	14027	18632	15275	14130	12844	13409	14400	$	168,897

A. COGENERATION ONLY

BASE YEAR ANNUAL ENERGY COST

$ 200,577 + $ 305,208 = $ 505,785

Electric + Fuel

Summary of Cogeneration Capital/Cost/Revenue Line Items:

Investments:	$ 232,000	
Expenses:		
Electricity costs (OLSS mode)	$ 168,897	
Fuel costs	305,208	(1)
Incremental cost of generating 600 PSIG steam versus 125 PSIG steam	3,094	(2)
Maintenance Costs	703	

Net First Year Results - OLSS Mode

Total Capital Investment	$ 232,000
First Year Cost	477,902
First Year Savings (Cogeneration versus Base Year)	27,883
Payback	8.32 Years

(1) From Option #1

(2) $\frac{1,204}{1,193}$ x $ 305,486 = $ 308,302 - $ 305,208 = $ 3,094

B. COGENERATION AND REFUSE BOILER

Total Capital Investment	$ 1,282,000
First Year Savings	56,365
Payback	22.70 Years

II N S P BUY-BACK

Total Electricity Generated in On-Peak/Off-Peak Periods

Facility: ST. PETER HOSPITAL

Tsize: 6.58 MMBtu/Hr (Thermal output)

Period	Hrs	Excess kwh	Total kwh	Bin No.	
On-Peak Mo., On-Peak Hr	1092	0	64,484	1	Summer Month 9AM to 9PM
Off-Peak Mo, On-Peak Hr	2197	0	214,870	3	Winter Month 9AM to 9PM
On-Peak Mo., Off-Peak Hr	1836	0	80,529	2	Summer Month 9PM to 9AM
Off-Peak Mo, Off-Peak Hr	3635	0	342,674	4	Winter Month 9PM to 9AM

System Performance

Month	EGEN MKWH	'EXCESS' MKWH	Add. Fuel MMBtus
1	74	0	1,519
2	67	0	1,372
3	74	0	1,519
4	72	0	1,470
5	48	0	1,049
6	39	0	874
7	26	0	632
8	40	0	886
9	40	0	893
10	74	0	1,519
11	72	0	1,470
12	74	0	1,519
Total	703	0	14,726

Note: 'Add. Fuel' is the extra fuel consumed to generate electricity beyond fuel required to meet the thermal load.

Monthly Operating Costs for Buy-All, Sell-All (BASA) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12	Total Yr
Ecost	1	$	0	0	0	0	0	6648	9275	7850	7010	0	0	0	$ 30,783
-Rev	1	$	0	0	0	0	0	718	545	778	797	0	0	0	$ 2,837
BASA	1	$	0	0	0	0	0	5930	8730	7072	6213	0	0	0	$ 27,946
Ecost	2	$	0	0	0	0	0	9336	10662	9406	9128	0	0	0	$ 38,532
-Rev	2	$	0	0	0	0	0	868	521	834	838	0	0	0	$ 3,060
BASA	2	$	0	0	0	0	0	8468	10141	8572	8290	0	0	0	$ 35,472
Ecost	3	$	8338	7311	7056	6854	7427	0	0	0	0	7958	7360	7896	$ 60,201
-Rev	3	$	802	692	765	765	661	0	0	0	0	838	729	765	$ 6,016
BASA	3	$	7536	6619	6291	6089	6766	0	0	0	0	7120	6631	7131	$ 54,184
Ecost	4	$	10000	9256	9826	8376	8562	0	0	0	0	8609	9652	10227	$ 74,509
-Rev	4	$	1742	1616	1791	1700	938	0	0	0	0	1693	1750	1791	$ 13,022
BASA	4	$	8258	7640	8035	6676	7624	0	0	0	0	6917	7902	8436	$ 61,488
Elect Subtot		$	15795	14259	14326	12765	14390	14399	18871	15644	14503	14037	14534	15567	$ 179,089

Monthly Operating Costs for Offset-Load, Sell-Surplus (OLSS) Mode

Item	Bin #		M 1	M 2	M 3	M 4	M 5	M 6	M 7	M 8	M 9	M10	M11	M12		Total Yr
Ecost	1	$	0	0	0	0	0	5833	8655	6966	6105	0	0	0	$	27,559
-Rev	1	$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
OLSS	1	$	0	0	0	0	0	5833	8655	6966	6105	0	0	0	$	27,559
Ecost	2	$	0	0	0	0	0	8194	9977	8309	8025	0	0	0	$	34,505
-Rev	2	$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
OLSS	2	$	0	0	0	0	0	8194	9977	8309	8025	0	0	0	$	34,505
Ecost	3	$	6907	6075	5690	5488	6247	0	0	0	0	6462	6059	6530	$	49,457
-Rev	3	$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
OLSS	3	$	6907	6075	5690	5488	6247	0	0	0	0	6462	6059	6530	$	49,457
Ecost	4	$	7708	7129	7469	6139	7328	0	0	0	0	6382	7350	7870	$	57,375
-Rev	4	$	0	0	0	0	0	0	0	0	0	0	0	0	$	0
OLSS	4	$	7708	7129	7469	6139	7328	0	0	0	0	6382	7350	7870	$	57,375
Elect Subtot		$	14615	13204	13159	11627	13575	14027	18632	15275	14130	12844	13409	14400	$	168,897

7.6 OPTION #6 - WOOD FIRED BOILER WITH STEAM TURBINE COGENERATION

This option is identical to Option #5 in terms of description of equipment, description of system, and electricity costs (OLSS Mode). Changes are reflected in the following Base Year Energy Cost Summary.

COGENERATION ONLY

Base Year Annual Energy Cost $ 200,577 + $ 246,456 = $ 447,033

electric + fuel

Summary of Cogeneration Capital/Cost/Revenue Line Items:

Investments	$ 232,000	
Expenses:		
Electricity Costs (OLSS Mode)	168,897	
Fuel Costs	246,456	(1)
Incremental Cost of Generating 600 PSIG Steam versus 125 PSIG Steam	2,272	(2)
Maintenance Costs	703	

Net First Year Results - OLSS Mode

Total Capital Investment	$ 232,000
First Year Cost	418,328
First Year Savings (Cogeneration versus Base Year)	28,705
Payback	8.08 Years

(1) From Option #2

(2) $\frac{1,204}{1,193} \times \$\ 246,456 = \$\ 248,728 - \$\ 246,456 = \$\ 2,272$

COGENERATION AND WOOD BOILER

Total Capital Investment	$ 1,332,000
First Year Savings	115,939
Payback	11.49 Years

8.0 ANALYSIS OF OTHER OPTIONS

8.1 OPTION #7 - NEGOTIATED PURCHASE ARRANGEMENT

The City of St. Peter Municipal Electric Utility buys power from the Southern Minnesota Municipal Power Agency (SMMPA) on a Contract Demand Basis. This option assumes the City of St. Peter and the State Hospital can negotiate an arrangement whereby the hospital operates a standby generator for those few hours each year when the Municipal Electric Company demand exceeds their contract demand. A negotiated purchase arrangement as described above could function as follows:

Assumptions

1. The City of St. Peter Municipal Electric Company has a firm contract demand of 9,000 KW with SMMPA
2. The Cities historical peak demand is 9,500 KW
3. The City pays SMMPA $ 9.00/KW for electric demand which exceeds 9,000 KW
4. The Hospital purchases and installs a 500 KW diesel engine generator set
5. The Hospital agrees to operate the standby generator set whenever the Cities contract demand exceeds 9,000 KW
6. The Hospital's generator set is operated 200 - 400 hours per year
7. The City and the Hospital agree to share the savings on a 20/80 basis

Description of Equipment

- One (1) 500 KW diesel engine generator set and controls or similar equipment (unit located outside)
- A switchgear system to connect the engine generator to operate in parallel with the City of St. Peter Municipal Electric Utility

An economic analysis of a diesel engine standby generator is shown below:

Annual Cost Savings

Demand Cost Savings = 500 KW x 12 months x $ 9.00/Kw = $ 54,000/Year

Operating Costs

(1) Diesel Fuel = 500 KW x 300 Hrs x 15,000 BTU/KWH ÷ 140,000 BTU/Gal x $ 1.00/Gal x .50 Diversity * = $ 8,035

(2) Maintenance = 500 KW x 300 Hrs x $ .01/KWH x .50 Diversity = $ 750

* Based on an average load of 250 KW

Net Annual Cost Savings = $ 45,215

City of St. Peter share = $ 45,215 x .20 = $ 9,043

St. Peter State Hospital share = $ 45,215 x .80 = $ 36,172

Hospital Investment

Diesel engine generator set	$ 90,000
Miscellaneous	10,000
	$ 100,000

$$\text{Payback} = \frac{\$\ 100,000}{\$\ 36,172} = 2.76 \text{ Years}$$

8.2 OPTION #8 - MODIFY THE ELECTRIC METERS

This option analyzes the electric demand cost savings that could be achieved if the Upper and Lower Campus electric meter readings were combined into one electric bill. Table 12 shows electric demand readings for individual electric metering and for combined billing. The combined billing column assumes the combined monthly demand is 95 % of the individual demands due to diversity.

Table 12

	Lower Campus		Upper Campus		Combined Billing	
	Demand	Primary Voltage	Demand	Secondary Voltage	Demand	Secondary Voltage
Jan	736		400			
Feb	712		400			
Mar	680		410			
Apr	664		425			
May	680		450			
June	880		500			
July	912		500			
Aug	864		450			
Sep	824		425			
Oct	712		410			
Nov	728		400			
Dec	728 E		400			
	9,120	+	5,170	=	14,290 x .95 = 13,575	

Lower Campus	Upper Campus	Combined Billing
3,000 x 10.05 = $ 30,150	3,000 x 10.05 = $ 30,150	3,000 x 10.05 = $ 30,150
6,120 x 9.10 = 55,692	2,170 x 9.10 = 19,747	10,575 x 9.10 = 90,232
	5,170 x .50 2,585	13,575 x .50 = 6,787
$ 85,842	$ 52,482	$ 133,169

$ 138,324

Annual Cost Savings = $ 5,155

APPENDIX A

CURRENT ELECTRIC AND GAS RATES

January 3, 1986

MINNEGASCO
RATE SCHEDULES
MINNESOTA

Effective December 27, 1985

SMALL VOLUME RATE SCHEDULES

Firm	Customer Charge		$ 3.00
	Energy Charge:	First 3 CCF[1]	.02771 per CCF
		Excess	.51354 per CCF
Interruptible		Customer Charge	$30.00
		Energy Charge	.37951 per CCF

NOTES

1. CCF - 100 cubic feet of gas, also referred to as a therm.

   The firm energy charge includes a Purchased Gas Adjustment (PGA) of $.02771 per CCF and the interruptible energy charge a PGA of $.00046 per CCF.

LARGE VOLUME RATE SCHEDULES

Firm	Customer Charge		$ 3.00
	Energy Charge:	First 3 CCF[1]	.00050 per CCF
		Excess	.48633 per CCF
Interruptible		Customer Charge	$45.00
		Energy Charge	.35230 per CCF

NOTES

1. CCF - 100 cubic feet of gas, also referred to as a therm.

   The firm energy charge includes a Purchased Gas Adjustment (PGA) of $.00050 per CCF and the interruptible energy charge a negative PGA of .02675 PER CCF.

Minnegasco
SDS 10-0031
MINNEAPOLIS, MN 55486

88 LB
PV 765

Due Date	Account Number
Dec 21 85	240-002-822-200

Amount You Are Paying		Please Pay	
Gas	$	Gas	$43110.24
Other Charges	$	Other Charges	$.00
Total	$	Total	$43110.24

See other side for late payment details

RECEIVED
DEC 9 1985
BUSINESS OFFICE

ST PETER STATE HOSP
100 FREEMAN DR
ST PETER MN 56082

H

d13240002822200004311024

ST PETER STATE HOSP

Service Address:
100 FREEMAN DR
ST PETER MN 56082

Account Number:
240-002-822-200

Billing Date
Dec 5 85

Account Summary		Other Charges		Gas Charges	
Previous Balance		$.00		$29867.03	
Payments Received		.00	-	29867.03	Nov 25 - Thank You
Adjustments		.00		.00	
Balance		$.00		$.00	
Current Billing	+	.00	+	43110.24	
New Balance		$.00		$43110.24	

Amount Due By Dec 21 85: $43110.24 = $43110.24

Other Charges Detail

Gas Charges Detail **Meter Number:**

Service To Date	Nov 27 85
Service From Date	Oct 27 85
Gas Used in 31 Days	116270 CCF
Large Volume Interruptible Service	
Customer Charge	$45.00
Gas Charge (116270 CCF @ $.37905)	44072.14
Purchased Gas Adjustment (116270 CCF @ $.00866CR)	1006.90CR
Total Current Billing	$43110.24

A54 V
240 002822 200
55105 669230 01 391
43110.24 112585 G44
120985

Average Daily Gas Usage

Next Meter Reading

Next Billing Date

Minnegasco
MINNEGASCO, INC
315 MINNESOTA AV SO
ST. PETER, MN 56082

612-372-4790
We Accept Collect Calls

Minnegasco
P. O. BOX 1297
MINNEAPOLIS, MN 55472-0061

20
PMT5 765

Due Date:		Account Number:	
Dec 17 85		240-002-756-200	
Amount You Are Paying		Please Pay:	
Gas	$	Gas	$930.36
Other Charges	$	Other Charges	$.00
Total	$	Total	$930.36

See other side for late payment details

ST PETER STATE HOSPITAL
DOMESTIC
ST PETER MN 56082

H

d79240002756200000093036

Send This Part

Keep This Part

ST PETER STATE HOSPITAL

Service Address:
DOMESTIC
ST PETER MN 56082

Account Number:
240-002-756-200
Billing Date:
Nov 29 85

Account Summary		Other Charges		Gas Charges	
Previous Balance		$.00		$692.47	
Payments Received		.00	-	692.47	Nov 14 - Thank You
Adjustments		.00		.00	
Balance		$.00		$.00	
Current Billing	+	.00	+	930.36	
New Balance		$.00		$930.36	

Amount Due By Dec 17 85: $930.36 = $930.36

Other Charges Detail

VENDOR NUMBER				TYPE
24				V
INVOICE NUMBER				
240 002 756 200				
ORGANIZATION	SEQUENCE NO	SUB	OBJECT	
55705	06923	01	391	
AMOUNT OF INVOICE	DATE PAYABLE			
930.36	121785	G44		
COST CODE 4				
120385				

I hereby certify that the goods or materials covered by this claim have been received or the services have been performed and are in accordance ... and are in proper form, kind, amount, and quality ... is hereby recommended

SYSTEM ASSIGNED TRANS NO

Gas Charges Detail

Meter Number:	708631
Reading on Nov 27 85	14431
Reading on Oct 28 85	13312
BTU Multiplier:	0.9995
Pressure Multiplier:	1.5290
Temperature Multiplier:	1.0176
FPV Multiplier:	1.0012
Gas Used in 30 Days	1742 CCF
Customer Charge (Includes 3 CCF)	$3.00
Gas Charge (1739 CCF @ $.48583)	844.86
Purchased Gas Adjustment (1742 CCF @ $.04736)	82.50
Total Current Billing	$930.36

Commercial customers in MN will see a decrease of about 0.335 cents per CCF in their cost of gas because of a price reduction by Minnegasco's gas supplier effective Oct 27,1985

RECEIVED
DEC 03 1985
BUSINESS OFFICE

Average Daily Temperature

Average Daily Gas

Next Meter Reading
Dec 26 85
Next Billing Date
Jan 2 86

Minnegasco
MINNEGASCO, INC
315 MINNESOTA AV SO
ST. PETER, MN 56082

507-931-2100
We Accept Collect Calls

CITY OF ST. PETER

MUNICIPAL UTILITIES
P.O. BOX 299
ST. PETER, MN 56082

ACCOUNT NO.	17 109
DUE DATE	12/16/85
AMOUNT DUE	$201.77
LATE AMOUNT	$201.77
SERVICE ADDRESS	STREET LIGHTING

A PENALTY EQUAL TO 10% OF ELECTRIC, WATER & SEWER CHARGE IS ADDED IF PAYMENT IS NOT RECEIVED BY THE DUE DATE

ST. PETER STATE HOSP
ST. PETER, MN 56082

RETURN THIS STUB WITH REMITTANCE

- 106 -

ST. PETER MUNICIPAL UTILITIES

P.O. BOX 299
ST. PETER, MN 56082

ACCT NO 17 109

DESCRIPTION	CURRENT READING	PREVIOUS READING	USAGE	AMOUNT
ARREARS	Pd arrears			102.15
ELECT 1	29790	28530	1260	99.62
FUEL ADJUSTMENT	PER KWH - .0025908			

RECEIVED
DEC 05 1985
BUSINESS OFFICE

CUST. TYPE	SERVICE ADDRESS	TOTAL DUE
COM	STREET LIGHTING	$201.77

RATE SCHEDULE	AFTER 12/16/85 LATE AMOUNT	
1985-3	PERIOD ENDING DATE 11/13/85	$201.77

054	VENDOR NUMBER			TYPE V
17 109	INVOICE NUMBER			
ORGANIZATION 55705	SEQUENCE NO 069221	SUFF 01	OBJECT NO	231
AMOUNT OF INVOICE 99.62	DATE PAYMENT 111385	G44		
COST CODE 3	COST CODE 4 120585	COST CODE 5		

I hereby certify that the goods or materials covered by this claim have been ordered and received or the services have been performed, and are in accordance with specifications, and are in proper form, kind, amount, and quality, and payment therefor is hereby recommended.

SYSTEM ASSIGNED TRANS NO

DEPT AUTHORIZED SIGNATURE

MARK your meter and pay your bill the FIRST DAY of each month. If payment is not received by the 25th of the month we will add a late payment charge of 1½% (but not less than $1.00) of the unpaid balance of $10.00 or more. This results in an Annual percentage rate of 18%.

REGISTER ANY INQUIRY TO:
FROST-BENCO ELECTRIC
P O BOX 8
MANKATO, MN 56001

See Reverse Side For Phone Numbers

SERVICE CODE	METER READING PREVIOUS	METER READING PRESENT	CONSUMPTION	CHARGES
14				5.00
01	33695	35830	2135	159.07

RECEIVED
DEC 02 1985
BUSINESS OFFICE

LAST PAYMENT AND DATE
51.80
11/06/85
IGNORE METER DIALS

STATE HOSPITAL
~~JAMES LITTIG~~
REC BLDG
~~ST PETER~~ MN 56082

SERVICE THROUGH DATE	LOCATION NUMBER	POWER COST ADJ. PER KWH	ACCOUNT NUMBER	DATE DUE	BALANCE DUE
11/01/85	016 30 115	.007200	011370	12/20/85	164.07

A64
VENDOR NUMBER
TYPE V
011370
INVOICE NUMBER

ORGANIZATION	SEQUENCE NO	SUFF	CHECK NO	
55105	06921	01		031

AMOUNT OF INVOICE	DATE PAYED	
164.07	110185	644

COST CODE 3	COST CODE 4
	120285

I hereby certify that the goods or materials covered by this claim have been inspected and received or the services have been performed ... in accordance with specifications and are in proper form, kind ... quality, and payment therefor is hereby recommended

SYSTEM ASSIGNED TRANS NO

DEPT AUTHORIZED SIGNATURE

IN ACCOUNT WITH

CITY OF ST. PETER MUNICIPAL UTILITIES

BOX 299

ST. PETER, MINNESOTA 56082

NAME: ST. PETER STATE HOSPITAL

Meter Reading Period

From: November 1 19 85

To: December 2 19 85

DEMAND CHARGE

Demand Indicator	.91	First	250 Kw @ $	10.05 = $	2,512.50	
Multiplier	800		478 Kw @ $	9.10 = $	4,349.80	
Total Kw Demand	728	Total	728 Kw Demand			$ 6,862.30

ENERGY CHARGE

Date	Meter Reading			
December 2 19 85	0845			
November 1 19 85	0424			
Difference	421			
Multiplier	800			
Total Kwhrs	336,800	336,800 Kwhrs @ $	.0281	$ 9,464.08
Fuel Adjustment		336,800 Kwhrs $	$ .00259CR	$ (872.31)
		TOTAL DEMAND AND ENERGY CHARGE		$ 15,454.07

Average Power Factor 85.5 %

4

11-1-85 to 12-2-85

55105 | 06921 01 | 231

15 454.07 | 120285 644

120385

SYSTEM ASSIGNED TRANS. NO. | DEPT. AUTHORIZED SIGNATURE

RECEIVED
DEC 03 1985
BUSINESS OFFICE

IN ACCOUNT WITH

CITY OF ST. PETER MUNICIPAL UTILITIES

BOX 299

ST. PETER, MINNESOTA 56082

NAME: St. Peter Security Hospital

Meter Reading Period

From October 10, 19 85

To November 19 19 85

DEMAND CHARGE

Demand Indicator	8	First	250 Kw @ $ 10.05 = $	2,512.50	
Multiplier	500		150 Kw @ $ 9.10 = $	1,365.00	
Total KW Demand	400		400 Kw Demand		$ 3,877.50

ENERGY CHARGE

Date		Meter Reading			
November 19	19 85	7884			
October 10	19 85	7425			
Difference		459			
Multiplier		500			
Total Kwhrs		229,500	229,500	Kwhrs @ $ .0281	$ 6,448.95
	Fuel Adjustment:		229,500	Kwhrs @ $ .00259CR	$ (594.41)
			TOTAL DEMAND & ENERGY CHARGE		$ 9,732.04

SECONDARY DISTRIBUTION VOLTAGE ADDER

400 Kw Demand @ $ .50 = $ 200.00

DISCOUNTED (5%) AMOUNT DUE December 16, 1985 $ 9,932.04

AMOUNT DUE AFTER 12/16/85 $ 9,932.04

Average Power Factor ------ %

34

10-10-85 to 11-19-85

55105 06921 91 231

9932.04 111985 G44

120385

RECEIVED
DEC 03 1985
BUSINESS OFFICE

STATE OF MINNESOTA
DEPARTMENT OF ADMINISTRATION

UNIFORM MONTHLY POWER PLANT REPORT

Institution St. Peter State Hospital (St. Peter Regional Treatment Center) Code S.P.H.

Location 100 Freeman Drive, St. Peter, MN Report for the month of November 19 85

A. MONTHLY AVERAGE OF DAILY AVERAGE OUTSIDE TEMPERATURES 25.2 F.

B. FUEL CONSUMPTION (HEATING, PROCESSING, GENERATION)

FUEL	QUANTITY	TOTAL COST	AVERAGE UNIT COST
COAL	N A TONS	$	$ /TON
LIGNITE	N A TONS	$	$ /TON
INTERRUPTIBLE GAS	11,627 MCF	$ 43,110.24	$ 3.71 /MCF
firm ~~PILOT~~ GAS	174 MCF	$ 930.36	$ 5.35 /MCF
OIL (# 6)	none GAL.	$	$ /GAL.
	TOTAL FUEL COST:	$ 44,040.60	

BILLING DATES FOR GAS:
10/27 TO 11/27/85
TO

C. STEAM PRODUCED

		METERED	ESTIMATED
Heating	7,100,200 Lb.	[ ]	[X]
Process	3,055,700 Lb.	[ ]	[X]
Elec. Gen.	Lb.	[ ]	[ ]
Resale	Lb.	[ ]	[ ]
TOTAL	10,155,900 Lb.	[X]	[ ]
Peak Demand	24,900 Lb./Hr.	[X]	[ ]

D. BOILER UTILIZATION

BOILER NUMBER	1	2	3	4	5
DAYS FIRED	27½		2½		

E. EMERGENCY ELECTRICAL SYSTEM

Period of test operation 11-4-85 Hr.

Period of emergency operation 11-8-85 - 25 min. ~~Hr.~~

F. ELECTRICAL ENERGY

LOCATION	KWH	DEMAND KW	POWER FACTOR	TOTAL COST	AVERAGE COST/KWH	BILLING DATES
				SELF-GENERATED POWER		
Central Metering Station	336,800	728	85.5	15,454.07	0.05	Nov. 1 to Dec. 2, '85
Minnesota Security Hospital	229,500	400	---	9,932.04	0.04	Oct. 10 to Nov. 19, '85
Gluek Bldg. (Frost-Benco)	2,135	not avail.	not avail.	164.07	0.08	not available
Street Lighting	1,260	not avail.	not avail.	99.62	0.08	not available
	569,695	TOTALS		$ 25,649.80		

APPENDIX B

THERMAL AND ELECTRIC LOAD PROFILES

Month JANUARY

		Thermal Weekday MMBTU's		Thermal Weekend MMBTU's		Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12						
AM	1	18.3	16.5	20.1	18.1	.368	.384
AM	2	19.5	17.6	19.5	17.6	.368	.416
AM	3	19.5	17.6	20.4	18.4	.376	.416
AM	4	19.8	17.8	19.8	17.8	.368	.416
AM	5	19.8	17.8	19.8	17.8	.384	.416
AM	6	20.4	18.4	20.4	18.4	.448	.448
AM	7	21.0	18.9	20.1	18.1	.528	.480
AM	8	21.1	19.0	21.3	19.2	.632	.448
AM	9	24.9	22.4	20.7	18.6	.688	.432
AM	10	22.0	19.8	19.8	17.8	.736	.448
AM	11	24.0	21.6	19.5	17.6	.688	.448
AM	12	22.5	20.3	18.0	16.2	.656	.488
PM	1	20.1	18.9	18.0	16.2	.676	.480
PM	2	19.9	17.9	17.1	15.4	.648	.464
PM	3	16.5	14.9	18.0	16.2	.624	.496
PM	4	18.0	16.2	17.1	15.4	.512	.504
PM	5	18.0	16.2	17.4	15.7	.480	.504
PM	6	18.9	17.0	18.0	16.2	.528	.520
PM	7	19.8	17.8	18.0	16.2	.496	.520
PM	8	16.8	15.1	18.0	16.2	.464	.448
PM	9	19.2	17.3	17.7	15.9	.432	.440
PM	10	18.0	16.2	17.7	15.9	.416	.432
PM	11	17.1	15.4	17.4	15.7	.384	.416
PM	12	17.7	15.9	17.4	15.7	.368	.416

Month February

	Hour	Thermal Weekday MMBTU's	Thermal Weekend MMBTU's	Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12				
A M	1	18.9 17.0	17.4 15.7	.384	.368
A M	2	18.8 16.9	17.4 15.7	.376	.368
A M	3	19.2 17.3	17.1 15.4	.384	.368
A M	4	18.9 17.0	17.7 15.9	.376	.368
A M	5	19.2 17.3	17.4 15.7	.384	.376
A M	6	19.2 17.3	17.7 15.9	.496	.400
A M	7	20.1 18.9	17.7 15.9	.576	.424
A M	8	19.5 17.6	17.4 15.7	.712	.432
A M	9	22.8 20.5	18.9 17.0	.696	.464
A M	10	19.5 17.6	18.6 16.7	.704	.456
A M	11	22.2 20.0	17.7 15.9	.688	.432
A M	12	16.5 14.9	17.4 15.7	.640	.480
P M	1	18.3 16.5	18.3 16.5	.624	.464
P M	2	18.7 16.8	17.4 15.7	.608	.464
P M	3	16.1 14.5	17.1 15.4	.576	.464
P M	4	16.3 14.7	16.8 15.1	.536	.464
P M	5	18.1 16.3	18.0 16.2	.520	.424
P M	6	18.1 16.3	18.6 16.7	.528	.456
P M	7	17.8 16.0	17.4 15.7	.544	.440
P M	8	17.5 15.8	17.8 16.0	.536	.432
P M	9	17.7 15.9	17.8 16.0	.496	.400
P M	10	17.8 16.0	18.6 16.7	.480	.384
P M	11	17.7 15.9	18.0 16.2	.424	.368
P M	12	17.1 15.4	18.3 16.5	.384	.368

Month March

		Thermal Weekday MMBTU's		Thermal Weekend MMBTU's		Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12						
A M	1	15.3	13.8	14.7	13.2	.360	.400
	2	15.9	14.3	14.4	13.0	.352	.400
	3	15.3	13.8	13.5	12.2	.352	.392
	4	15.3	13.8	14.1	12.7	.360	.368
	5	15.9	14.3	15.3	13.8	.384	.376
	6	16.8	15.1	14.7	13.2	.464	.416
	7	16.8	15.1	14.1	12.7	.544	.416
	8	18.6	16.7	16.8	15.1	.600	.416
	9	18.9	17.0	15.0	13.5	.616	.424
	10	18.6	16.7	14.7	13.2	.680	.448
	11	14.7	13.2	15.3	13.8	.632	.480
	12	15.0	13.5	13.8	12.4	.624	.456
P M	1	14.0	12.6	15.3	13.8	.544	.432
	2	12.0	10.8	13.8	12.4	.528	.424
	3	11.1	10.0	14.4	13.0	.528	.432
	4	11.1	10.0	14.4	13.0	.448	.464
	5	13.5	12.2	14.7	13.2	.440	.480
	6	14.1	12.7	14.4	13.0	.432	.464
	7	13.8	12.4	13.5	12.2	.432	.464
	8	13.5	12.2	15.3	13.8	.440	.456
	9	13.5	12.2	14.4	13.0	.416	.416
	10	14.1	12.7	14.1	12.7	.384	.384
	11	13.8	12.4	15.0	13.5	.360	.368
	12	14.1	12.7	13.8	12.4	.368	.368

Month April

	Hour	Thermal Weekday MMBTU's		Thermal Weekend MMBTU's		Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12						
AM	1	10.5	9.5	9.9	8.9	.352	.344
AM	2	9.9	8.9	9.3	8.4	.336	.336
AM	3	10.5	9.5	11.1	10.0	.336	.336
AM	4	10.8	9.7	10.5	9.5	.336	.336
AM	5	10.8	9.7	9.3	8.4	.344	.344
AM	6	11.4	10.3	10.2	9.2	.384	.360
AM	7	12.3	11.1	9.9	8.9	.432	.384
AM	8	12.7	11.4	9.3	8.4	.504	.400
AM	9	15.3	13.8	11.1	10.0	.616	.408
AM	10	12.3	11.1	11.7	10.5	.664	.448
AM	11	13.8	12.4	8.9	8.0	.600	.440
AM	12	11.1	10.0	9.9	8.9	.584	.456
PM	1	10.5	9.5	10.5	9.5	.576	.416
PM	2	9.3	8.4	8.7	7.8	.560	.424
PM	3	9.3	8.4	8.7	7.8	.536	.400
PM	4	9.0	8.0	8.7	7.8	.456	.400
PM	5	8.5	7.7	8.4	7.6	.400	.376
PM	6	9.3	8.4	9.0	8.1	.400	.384
PM	7	9.4	8.5	9.0	8.1	.400	.384
PM	8	9.3	8.4	9.0	8.1	.400	.392
PM	9	9.6	8.6	9.0	8.1	.376	.368
PM	10	9.9	8.9	9.3	8.4	.352	.360
PM	11	9.6	8.6	9.6	8.6	.336	.336
PM	12	10.2	9.2	9.0	8.1	.336	.336

Month May

	Hour	Thermal Weekday MMBTU's	Thermal Weekend MMBTU's	Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12				
AM	1	3.9 3.5	4.3 3.9	.336	.328
AM	2	4.0 3.6	4.3 3.9	.336	.320
AM	3	4.0 3.6	4.2 3.8	.336	.320
AM	4	4.2 3.8	4.3 3.9	.336	.320
AM	5	4.2 3.8	4.5 4.1	.344	.320
AM	6	4.5 4.1	4.3 3.9	.368	.336
AM	7	4.8 4.3	4.9 4.4	.448	.384
AM	8	5.7 5.1	5.1 4.6	.528	.400
AM	9	7.9 7.1	5.1 4.6	.576	.384
AM	10	5.8 5.2	4.6 4.1	.592	.400
AM	11	8.1 7.3	4.2 3.8	.680	.400
AM	12	8.2 7.4	4.2 3.8	.592	.432
PM	1	7.2 6.5	4.3 3.9	.592	.400
PM	2	6.3 5.7	3.9 3.5	.584	.384
PM	3	7.2 6.5	4.3 3.9	.560	.400
PM	4	6.1 5.5	3.7 3.3	.496	.376
PM	5	5.2 4.7	4.0 3.6	.480	.384
PM	6	5.5 5.0	4.2 3.8	.416	.368
PM	7	5.2 4.7	4.0 3.6	.432	.368
PM	8	4.8 4.3	3.9 3.5	.416	.360
PM	9	5.1 4.6	4.2 3.8	.424	.368
PM	10	4.9 4.4	4.0 3.6	.416	.360
PM	11	4.3 3.9	4.0 3.6	.368	.344
PM	12	4.2 3.8	3.9 3.5	.368	.344

Month June

	Hour	Thermal Weekday MMBTU's	Thermal Weekend MMBTU's	Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12				
AM	1	3.9 3.5	3.6 3.2	.344	.400
AM	2	3.6 3.2	3.7 3.3	.336	.384
AM	3	4.0 3.6	3.7 3.3	.328	.376
AM	4	3.9 3.5	3.6 3.2	.320	.376
AM	5	3.9 3.5	4.0 3.6	.320	.368
AM	6	4.0 3.6	3.7 3.3	.352	.392
AM	7	4.2 3.8	3.7 3.3	.448	.416
AM	8	7.0 6.3	4.2 3.8	.560	.464
AM	9	5.6 5.0	4.2 3.8	.584	.472
AM	10	5.9 5.3	3.7 3.3	.584	.488
AM	11	6.3 5.7	4.2 3.8	.880	.520
AM	12	6.5 5.9	4.2 3.8	.608	.528
PM	1	5.0 4.5	4.3 3.9	.576	.496
PM	2	4.8 4.3	3.9 3.5	.576	.512
PM	3	4.2 3.8	3.9 3.5	.528	.440
PM	4	4.0 3.6	3.9 3.5	.464	.440
PM	5	4.2 3.8	3.9 3.5	.440	.464
PM	6	4.5 4.1	4.2 3.8	.440	.464
PM	7	4.3 3.9	4.2 3.8	.408	.432
PM	8	4.2 3.8	3.9 3.5	.392	.448
PM	9	4.2 3.8	3.7 3.3	.416	.416
PM	10	4.0 3.6	4.0 3.6	.384	.400
PM	11	4.2 3.8	3.9 3.5	.368	.384
PM	12	3.9 3.5	3.6 3.2	.352	.368

Month July

		Thermal Weekday MMBTU's	Thermal Weekend MMBTU's	Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12				
A M	1	2.4 2.2	2.4 2.2	.400	.448
	2	2.4 2.2	2.4 2.2	.400	.440
	3	2.2 2.0	2.2 2.0	.384	.440
	4	2.4 2.2	2.4 2.2	.384	.424
	5	2.5 2.3	2.5 2.3	.384	.400
	6	2.2 2.0	2.2 2.0	.424	.408
	7	3.0 2.7	3.0 2.7	.512	.440
	8	5.8 5.2	3.0 2.7	.640	.464
	9	5.7 5.1	3.0 2.7	.656	.544
	10	5.1 4.6	3.0 2.7	.784	.544
	11	5.1 4.6	3.0 2.7	.752	.544
	12	3.9 3.5	3.0 2.7	.752	.552
P M	1	3.6 3.2	3.0 2.7	.912	.544
	2	3.9 3.5	3.0 2.7	.744	.560
	3	3.1 2.8	3.0 2.7	.672	.560
	4	2.8 2.5	3.0 2.7	.640	.560
	5	2.7 2.4	2.8 2.5	.568	.536
	6	3.3 3.0	3.3 3.0	.568	.528
	7	3.0 2.7	3.1 2.8	.544	.496
	8	2.5 2.3	2.5 2.3	.488	.496
	9	2.5 2.3	2.5 2.3	.496	.480
	10	2.3 2.1	2.3 2.1	.480	.480
	11	2.2 2.0	2.2 2.0	.448	.464
	12	2.2 2.0	2.2 2.0	.416	.432

Month *August*

	Hour	Thermal Weekday MMBTU's	Thermal Weekend MMBTU's	Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12				
A M	1	3.7 3.3	3.8 3.4	.352	.424
	2	3.6 3.2	3.9 3.5	.344	.384
	3	3.4 3.1	4.0 3.6	.344	.376
	4	3.6 3.2	3.7 3.3	.344	.376
	5	3.9 3.5	4.0 3.6	.352	.360
	6	3.7 3.3	3.7 3.3	.400	.376
	7	3.9 3.5	4.0 3.6	.496	.400
	8	6.1 5.5	4.3 3.9	.600	.432
	9	6.2 5.6	4.2 3.8	.632	.464
	10	6.2 5.6	3.7 3.3	.624	.472
	11	6.1 5.5	3.9 3.5	.864	.480
	12	6.1 5.5	3.6 3.2	.600	.480
P M	1	5.7 5.1	4.2 3.8	.624	.448
	2	4.3 3.9	3.9 3.5	.640	.464
	3	4.0 3.6	4.2 3.8	.624	.480
	4	4.2 3.8	3.9 3.5	.512	.464
	5	4.0 3.6	4.0 3.6	.480	.456
	6	4.2 3.8	4.8 4.3	.488	.496
	7	4.0 3.6	4.3 3.9	.432	.448
	8	3.9 3.5	4.2 3.8	.416	.432
	9	3.9 3.5	3.9 3.5	.432	.400
	10	3.9 3.5	3.9 3.5	.408	.376
	11	3.7 3.3	3.9 3.5	.368	.368
	12	3.7 3.3	3.7 3.3	.360	.368

Month *September*

	Hour	Thermal Weekday MMBTU's	Thermal Weekend MMBTU's	Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12				
AM	1	3.6 3.2	3.9 3.5	.368	.344
	2	3.6 3.2	3.9 3.5	.368	.344
	3	3.7 3.3	3.9 3.5	.360	.344
	4	3.7 3.3	4.0 3.6	.352	.352
	5	3.6 3.2	4.0 3.6	.360	.344
	6	3.9 3.5	4.0 3.6	.416	.360
	7	3.7 3.3	4.0 3.6	.456	.368
	8	4.3 3.9	4.6 4.1	.592	.432
	9	6.3 5.7	4.5 4.1	.624	.432
	10	5.5 5.0	4.2 3.8	.624	.432
	11	6.9 6.2	4.2 3.8	.824	.448
	12	7.3 6.6	4.3 3.9	.640	.416
PM	1	5.8 5.2	4.2 3.8	.618	.448
	2	5.8 5.2	3.6 3.2	.600	.432
	3	4.6 4.1	3.9 3.5	.576	.424
	4	4.8 4.3	3.9 3.5	.512	.432
	5	4.2 3.8	4.0 3.6	.440	.416
	6	4.8 4.3	4.0 3.6	.440	.416
	7	4.8 4.3	3.9 3.5	.432	.376
	8	4.8 4.3	4.0 3.6	.432	.400
	9	4.2 3.8	3.9 3.5	.424	.384
	10	4.6 4.1	3.9 3.5	.384	.416
	11	4.5 4.1	3.9 3.5	.368	.400
	12	3.7 3.3	3.9 3.5	.336	.376

Month *October*

		Thermal Weekday MMBTU's	Thermal Weekend MMBTU's	Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12				
AM	1	9,3 8,4	8,8 7,9	,336	,344
AM	2	8,7 7,8	8,7 7,8	,336	,336
AM	3	9,3 8,4	8,8 7,9	,336	,344
AM	4	9,4 8,5	9,1 8,2	,336	,336
AM	5	8,8 7,9	9,0 8,1	,352	,344
AM	6	10,0 9,0	9,2 8,3	,408	,368
AM	7	10,4 9,4	9,7 8,7	,496	,400
AM	8	10,7 9,6	9,9 8,9	,624	,400
AM	9	12,9 11,6	9,8 8,8	,712	,400
AM	10	11,2 10,1	9,0 8,1	,608	,368
AM	11	12,0 10,8	7,9 7,1	,608	,384
	12	9,7 8,7	8,0 7,2	,584	,384
PM	1	8,8 7,9	8,6 7,7	,584	,416
PM	2	8,5 7,7	8,0 7,2	,576	,416
PM	3	8,5 7,7	7,8 7,0	,576	,440
PM	4	9,0 8,1	7,8 7,0	,512	,384
PM	5	8,2 7,4	8,1 7,3	,440	,384
PM	6	8,8 7,9	8,2 7,4	,440	,376
PM	7	8,5 7,7	8,5 7,7	,456	,376
PM	8	8,5 7,7	8,2 7,4	,440	,368
PM	9	8,1 7,3	7,8 7,0	,456	,360
PM	10	8,4 7,6	7,8 7,0	,424	,320
PM	11	8,2 7,4	7,8 7,0	,400	,328
PM	12	7,9 7,1	7,9 7,1	,344	,320

Month *November*

	Hour	Thermal Weekday MMBTU's		Thermal Weekend MMBTU's		Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12						
AM	1	13.2	11.9	14.4	13.0	.368	.384
AM	2	12.9	11.6	14.4	13.0	.368	.384
AM	3	13.5	12.2	14.1	12.7	.368	.376
AM	4	13.5	12.2	14.7	13.2	.400	.368
AM	5	13.8	12.4	14.4	13.0	.400	.368
AM	6	14.4	13.0	14.7	13.2	.408	.416
AM	7	15.6	14.0	15.0	13.5	.488	.440
AM	8	15.3	13.8	14.4	13.0	.600	.456
AM	9	16.6	15.0	15.0	13.5	.624	.456
AM	10	17.5	15.8	13.2	11.9	.728	.472
AM	11	17.4	15.7	14.4	13.0	.624	.432
	12	18.0	16.2	13.5	12.2	.608	.480
PM	1	16.9	15.2	14.4	13.0	.640	.432
PM	2	17.4	15.7	12.9	11.6	.664	.480
PM	3	15.0	13.5	13.2	11.9	.656	.456
PM	4	15.9	14.3	12.6	11.3	.576	.464
PM	5	14.4	13.0	13.2	11.9	.464	.432
PM	6	13.5	12.2	13.5	12.2	.480	.464
PM	7	14.1	12.7	13.2	11.9	.464	.432
PM	8	14.4	13.0	13.5	12.2	.472	.424
PM	9	14.4	13.0	12.9	11.6	.432	.408
PM	10	13.8	12.4	12.9	11.6	.416	.392
PM	11	14.4	13.0	12.9	11.6	.384	.384
PM	12	14.1	12.7	12.6	11.3	.368	.368

Month December

		Thermal Weekday MMBTU's		Thermal Weekend MMBTU's		Electric Weekday KWH x 1,000	Electric Weekend KWH x 1,000
	12						
AM	1	16.2	14.6	18.1	16.3	.376	.368
AM	2	16.5	14.9	17.5	15.8	.376	.384
AM	3	16.8	15.1	18.1	16.3	.368	.368
AM	4	16.5	14.9	18.3	16.5	.368	.400
AM	5	16.5	14.9	18.1	16.3	.368	.408
AM	6	16.8	15.1	18.3	16.5	.416	.448
AM	7	17.7	15.9	19.5	17.6	.512	.504
AM	8	18.0	16.2	19.6	17.6	.640	.488
AM	9	20.1	18.1	19.5	17.6	.656	.456
AM	10	18.9	17.0	18.3	16.5	.736	.480
AM	11	22.5	20.3	17.7	15.9	.672	.480
AM	12	19.2	17.3	18.3	16.5	.688	.464
PM	1	21.3	19.2	18.0	16.2	.656	.464
PM	2	17.7	15.9	16.0	14.4	.648	.448
PM	3	14.4	13.0	16.5	14.9	.608	.448
PM	4	17.4	15.7	16.8	15.1	.528	.464
PM	5	18.9	17.0	16.8	15.1	.512	.480
PM	6	19.8	17.8	17.4	15.7	.496	.512
PM	7	19.2	17.3	17.7	15.9	.480	.496
PM	8	18.9	17.0	17.4	15.7	.456	.488
PM	9	18.6	16.7	16.8	15.1	.432	.464
PM	10	19.2	17.3	16.7	15.0	.400	.432
PM	11	18.7	16.8	17.2	15.5	.400	.400
PM	12	18.7	16.8	17.2	15.5	.400	.400