ENERGIZE MISSOURI

RENEWABLE ENERGY STUDY SUBGRANT

Missouri Department of Natural Resources

Solar Thermal Study

MU Combined Heat and Power Plant

Subgrant Award No: G11-SEP-RES-07

Prepared for

Missouri Department of Natural Resources

June 17, 2011

Prepared by

University of Missouri
Columbia, Missouri

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Solar Thermal Study

MU CHP Plant

University of Missouri
Columbia, MO

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Missouri DNR Subgrant G11-SEP-RES-07
University of Missouri Project CP110501
Burns & McDonnell Project 59875

Prepared for University of Missouri by

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St. Louis, Missouri

INDEX AND CERTIFICATION

University of Missouri
Solar Thermal Study - MU Combined Heat & Power Plant

Missouri DNR Subgrant G11-SEP-RES-07
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LIST OF ABBREVIATIONS AND ACRONYMS

AC	Alternating Current
BMcD	Burns & McDonnell Engineering Company, Inc.
Btu	British thermal unit
Btu/hr	British thermal unit per hour
Btu/ft^2	British thermal unit per square foot
CHP	Combined Heat & Power
CT	Cooling Tower
DC	Direct Current
deg.	degree
°F	degrees Fahrenheit
DNR	Missouri Department of Natural Resources
$/MMBtu	dollar per million British thermal units
EFF.	efficiency
ft^2	square feet
gal	gallon
gpm	gallons per minute
HAP	Hazardous Air Pollutants
HE	heat exchanger
hp	horsepower
hr	hour
I/O	Input/Output
kWh	kilo-Watt hour
lb/hr	pound per hour
mA	milliamp
MCC	Motor Control Center
MISO	Midwest Independent Transmission System Operator
MMBtu	Million British thermal units
MU	University of Missouri - Columbia, Missouri
MW	Megawatt
NEC	National Electric Code
NSPS	New Source Performance Standards

LIST OF ABBREVIATIONS AND ACRONYMS (CONTINUED)

O&M	Operation and Maintenance or Operating and Maintenance
PLC	Programmable Logic Controller
PPA	Power Purchase Agreement
PV	Photovoltaic
PWT	Plant Water Treatment
RO	Reverse Osmosis
STG	Steam Turbine/Generator
TOS	Top of Steel
UTC	United Technologies Corporation
V	Volt
VFD	Variable Frequency Drive

* * * * *

CHAPTER 1.0

EXECUTIVE SUMMARY

1.0 EXECUTIVE SUMMARY

1.1 OBJECTIVE

The University of Missouri (MU), Campus Facilities-Energy Management Department retained the services of Burns & McDonnell Engineering Company Inc. (BMcD) to conduct a feasibility study of solar thermal heating (Study) as a potential renewable energy resource to serve the MU campus. The Study determined the best types of solar thermal heating systems for industrial and commercial process heating in Missouri, the anticipated costs, and the associated benefits. MU plans to use the results of the Study to determine if this technology is a viable renewable energy choice for its campus and will share the Study summary with others in Missouri to evaluate applicability with their facilities. MU is evaluating ways to become more sustainable in its use of resources, including energy. This study determined whether or not solar thermal heating is a renewable source of energy that Missouri colleges, universities, schools, hospitals, industries, etc., could justifiably utilize to meet their long-term energy needs.

1.2 GENERAL CONCLUSIONS

Solar thermal technology is defined as a technology used to harness energy from the sun for use in a thermal process. There are a wide variety of applications for this technology including, but not limited to, water/process heating, radiant heating, and air conditioning. In each application, solar energy is obtained through a solar collector and transferred directly, or through a heat exchanger, to a thermal process. Given the proper conditions and system design, solar thermal technology can provide a reliable and cost-effective energy source in residential, commercial, and industrial applications. Solar thermal technology can be broken into three categories of solar collectors: flat-plate collectors, evacuated-tube collectors, and concentrated solar collectors. Each category offers different advantages and disadvantages depending on operating and climate conditions.

Missouri climate conditions are most suitable for evacuated-tube solar thermal collectors. Major advantages of evacuated-tube collectors include higher output temperatures (when compared to flat-plate collectors), greater overall efficiencies, better performance on cloudy/cold days, better performance in snowy climates, and more flexibility on collector configuration.

There are many things to consider when retrofitting a new solar thermal system into an existing facility. The solar thermal system must be integrated into an existing plant so that that it functions properly and solar energy can be transferred to the designated target efficiently. The condition of existing plant systems, equipment, and mounting structure is a critical aspect of the overall project feasibility and must

be evaluated prior to design. Existing site conditions could affect the cost of installation. They could also allow for thermal storage. Solar thermal storage could increase the system efficiency and savings, which would reduce the solar thermal system payback period.

The cost to engineer, procure, and construct a solar thermal system with evacuated-tube collectors varies depending on site conditions, number of collectors, and system arrangement. Generally the cost can be broken down into three different categories; direct costs, indirect costs, and contingency. The direct cost is usually the highest among these categories because it encompasses all the equipment, installation, materials, and startup assistance required. The indirect costs to consider when estimating the installation of a solar thermal system include engineering, owner's cost, and permitting. A contingency must be included as a provision for an event or circumstance that is possible but cannot be predicted with certainty. Table 1-1 shows the estimated costs for 50-collector, 100-collector, and 150-collector evacuated-tube systems. The costs presented should be considered ±40-percent budgetary values.

Table 1-1: Evacuated-Tube Solar Thermal System Cost Summary

	50-Collector System	100-Collector System	150-Collector System
Equipment	$68,000	$132,000	$196,000
Installation and Material	$145,000	$200,000	$255,000
Engineering	$21,000	$33,000	$45,000
Total	$234,000	$365,000	$496,000

Notes:
1) Financing costs are not included.
2) Installation and Material costs will vary depending on site conditions. Values for 50-Array, 100-Array, and 150-Array are estimated typical installation costs.

The savings associated with installing a solar thermal system are primarily driven by the size of the system and the type of fuel the solar thermal system is replacing. Generally, depending on site conditions, the larger the solar thermal system the shorter the payback period. Table 1-2 shows the estimated annual savings and payback period for 50-collector, 100-collector, and 150-collector evacuated-tube systems that replace a coal, coal/biomass, natural gas, electric, or propane-powered heat generation system. Replacing an electric or propane-powered heat generation system with a solar thermal system has the fastest payback of the aforementioned fuels. For replacement of natural gas-powered heat generation, the payback period is less than the estimated useful life of an evacuated-tube solar thermal system. Therefore, the solar thermal system should, at least, pay for itself. The payback period for replacing coal or coal/biomass-powered heat generation exceeds the estimated useful life of an evacuated-tube solar thermal system. At these estimated industrial fuel prices, replacing a coal-powered heat generation system

may not be as lucrative as the other fuels. However, supplementing a portion of the capital costs with government funding or reducing the payback period with a larger system or thermal storage, would make this option more appealing. Ultimately, the higher fuel the cost and system output, the shorter the payback period.

Table 1-2: Evacuated-Tube Solar Thermal System Savings Summary

	50-Collector System	100-Collector System	150-Collector System
Collector Absorber Area (ft^2)	31	31	31
# of collectors	50	100	150
System Absorber Area (ft^2)	1,550	3,100	4,650
Hourly Output (Btu/ft^2)	226	226	226
Hourly System Output (90% EFF.) (Btu)	350,000	700,000	1,050,000
Annual Output (MMBtu)	703	1,405	2,108
Estimated System Cost	$234,000	$365,000	$496,000
Estimated First Year Savings			
Coal	$2,600	$5,200	$7,900
Coal/Biomass Blend	$3,200	$6,400	$9,600
Natural Gas	$4,500	$9,000	$13,400
Purchased Power	$16,000	$31,900	$47,900
Propane	$21,000	$42,100	$63,100
Payback Period (years)			
Coal	>40	>40	>40
Coal/Biomass Blend	>40	39	37
Natural Gas	32	27	25
Purchased Power	14	11	10
Propane	11	9	8

Notes:
1) Payback periods are based forcasted costs of fuels from the DNR 2011 Annual Energy Outlook, Appendix C, Table C3 - Energy Prices by Sector and Source utilizing industrial pricing in nominal dollars/MMBtu.
2) Savings include an 85% efficiency on exising heat generating system.
3) Solar thermal system output is based on 90% system efficency and 5.5 hours/day of sunlight.
4) Savings and payback values do not include possible savings from emission reduction
5) The 123-collector system @ MU cost estimate inludes site specific installation costs.
6) Financing costs are not included.

There are several alternatives to paying capital costs up-front for a solar thermal system. Some solar thermal suppliers may provide finance options or help to develop a Power Purchase Agreement (PPA). Solar thermal system finance options are relatively similar to most financing opportunities. Usually, an initial deposit of 10 to 20 percent of the total system cost would be required. Then, over the financing period, the buyer pays off the remaining costs in installments with interest. During and after the financing period, the buyer is responsible for the solar thermal system operation and maintenance. With a solar

thermal PPA, the solar thermal system is investor owned. The solar thermal system is financed, built, owned and maintained for the property owner. This is typically achieved by bringing together investment teams and installation partners. The solar thermal PPA entity would provide the solar thermal system on the host's property and sell the solar thermal energy back to the host at an agreed upon rate. This is typically done with no up-front capital investment. In both alternatives, there may be opportunities for state/federal funding, tax credits, and/or utility rebates. For example, under the American Recovery and Reinvestment Act of 2009, qualified applicants may receive funding in the amount of 30 percent.

In addition to the savings associated with installing a solar thermal system, there are also environmental benefits. Table 1-3 summarizes the emission reduction of replacing a fuel-powered heat generation system with a solar thermal system. The calculations used to generate this table are based on the National Emission Standards for HAPs. Information regarding these limits was extracted from the Industrial Boiler MACT Rule and New Source Performance Standards (NSPS). These values should be considered a conservative estimate of the reduced environmental impact because the majority of pollution sources are not in compliance with the Industrial boiler MACT rule or the NSPS regulations. Furthermore, there are many fuel-powered heat generation systems that do not fit the criteria to have emission limits. These systems likely produce harmful emissions, which should be determined when considering a solar thermal system so the full benefit of the system may be realized.

Table 1-3: Emissions Reduction Estimate

Fuel/System	Estimated Annual Emission Reduction (lb)					
	Particulate Matter (PM)	Hydrogen Chloride (HCl)	Mercury (Hg)	Mono-Nitrogen Oxides (No_x)	Carbon Monoxide (CO)	Volatile Organic Compounds (VOC)
Coal[1]						
100-Collector System	64	58	0.0076	n/a[4]	446,374	n/a[4]
Biomass[2]						
100-Collector System	64	58	0.0076	n/a[4]	810,085	n/a[4]
Natural Gas[3]						
100-Collector System	n/a[4]	n/a[4]	n/a[4]	165	5,224	2,808

Notes:
1) Coal emission limits are based on the Industrial Boiler MACT Rule Emission Limits for a Coal Stoker Boiler
2) Biomass emission limits are based on the Industrial Boiler MACT Rule Emission Limits for a Biomass Stoker Boiler
3) Natural gas emission limits are based NSPS Subpart Db requirements for industrial, commercial, and institutional steam generating units
4) Denotes that an emission limit has not been established

The potential CO_2 emissions reduction that would result from the installation of a solar thermal system was also evaluated. For this estimate, it was assumed that any thermal energy produced by the solar thermal system would offset steam production in existing coal-fired boilers. Based on the 2010 EPA eGRID CO_2 emission rate and 85-percent boiler efficiency, it was determined that a 100-collector evacuated-tube solar thermal system could save 166 tons of CO_2 per year.

1.3 MU CONCLUSIONS

The MU Combined Heat and Power (CHP) Plant reliably and efficiently generates steam and electricity for the MU campus. Due to winter humidification and normal system losses a portion of the steam distributed to campus is not returned to the MU CHP Plant in the form of condensate. This system loss, combined with normal boiler blowdown losses, requires MU to provide make-up water in order to continually meet the thermal energy loads of the campus. Make up water is heated from an average incoming temperature of 60°F to approximately 227°F utilizing deaerator auxiliary steam generated by the boilers. Based on MU data, the average make up water flow rate is approximately 57,400 lb/hr. The total energy required to heat up the make-up water prior to it entering the boiler feed pumps is approximately 9.77 MMBtu/hr or 85,585 MMBtu per year. It is possible to reduce or eliminate the need to use auxiliary steam to heat the make-up water by implementing a solar thermal system. This would reduce fuel costs and reduce the MU CHP Plant environmental impact. In addition to that, the overall plant efficiency would improve.

The available solar energy technologies were evaluated for generating and supplying heat to the make-up water. The factors considered when selecting a solar energy technology for the MU campus included; capacity, climate, seasonal change, available space, equipment availability, required maintenance, and capital cost. The priority for each of these factors varied based on the requirements set by MU staff. Based on these requirements, the most suitable solar thermal technology for the MU CHP Plant was determined to be evacuated-tube collectors. Solar PV technologies were included in this study as an option to power the solar thermal system pump. However, solar PV technologies proved to be an inefficient use of available space in this particular instance and were not included in the preliminary system design.

Two different basic designs were considered as starting platforms for the solar thermal system design. Design Option #1 involved heating the make-up water directly and Design Option #2 used a heat transfer fluid and heat exchanger to heat the make-up water. Both design options were considered similar in cost, maintenance, and complexity. However, due to the seasonal changes, Design Option #1 had higher risks associated with failure. Therefore, the preliminary design was based on Design Option #2, using a glycol mixture as the heat transfer fluid. The major equipment involved in the solar thermal system design for the MU CHP Plant includes solar thermal collectors, a solar thermal glycol pump, and a heat exchanger. The solar thermal collectors would be located on three different rooftops of the MU CHP Plant. Area A is located on the roof above Turbine/Generator 6. Areas B and C are located on the roofs above Turbine/Generator 9 and the north deaerator, respectively. Areas A and B are the former locations of cooling towers and the cooling tower support steel would be utilized for the installation of the solar

thermal collectors. Area C was also the location of a now demolished cooling tower, but for the purposes of this Study, it was assumed that a new roof suitable for the installation of solar thermal collectors would be installed by MU. The solar thermal pump and heat exchanger would be located near the existing make-up water pumps.

The electrical considerations for this Study include a small pump and basic instrumentation. The 5-HP pump would be fed from a spare breaker in PWT MCC. PWT MCC serves all the make-up water equipment and is located on the 5th floor, adjacent to the RO units. The instrumentation and pump VFD provided with the solar thermal system would be tied directly into the water treatment PLC by MU CHP staff.

The existing MU CHP Plant equipment that is directly related to the addition of a solar thermal system was evaluated. This condition assessment is a vital consideration for adding a solar thermal system to the MU CHP Plant. It is a way to ensure that the new addition would be an adequate use of capital funds and that the solar thermal system integration would be a smooth process. The major mechanical and electrical components of the make-up water system were assessed and there were no indications that this equipment would not be reliable in the future. The MU CHP Plant maintenance plans are sufficient for continued reliable use of this equipment.

The proposed rooftop Areas A, B, and C, selected for installation of new solar thermal collectors, were also evaluated. The cooling towers in Areas A and B were supported above the rooftop by structural steel. The solar thermal collectors in these areas would utilize the existing steel that used to support the cooling towers. Based on the data collected for the previously-supported cooling towers, visual observation, and engineering judgment, the existing structural steel appears to be structurally adequate to support the weight of the proposed solar thermal collectors. However, new secondary steel and grating would be required so that the solar thermal collectors can be mounted in the preliminary design configuration. In addition to that, access and safety lifelines would have to be provided due to the existing steel elevation. The cooling tower in Area C was elevated from the rooftop using a wooden structure and the roof itself was used as a containment basin. For the purposes of this Study, it was assumed that Area C would have a new roof suitable for the direct installation of the solar thermal collectors.

Based on the installation of a solar thermal system with 123 evacuated-tube collectors, MU could reduce its annual fossil fuel usage by at least 1,728 MMBtu. This translates to about a two-percent reduction in fuel usage required to heat the make-up water at the MU CHP Plant. This reduction translates to approximately $6,400 to $11,000 in first year savings, depending on the type of fuel the solar thermal

system is replacing. Table 1-4 summarizes the general savings and payback for a solar thermal system installed at MU. Other factors that affect the level of fuel reduction and cost savings include, but are not limited to, the following:

- Available Sunlight
- Fuel Costs
- Boiler Efficiency
- Solar Thermal System Efficiency

Table 1-4: MU Evacuated-Tube Solar Thermal System Savings Summary

	123-Collector System @ MU
Collector Absorber Area (ft^2)	31
# of collectors	123
System Absorber Area (ft^2)	3,813
Hourly Output (Btu/ft^2)	226
Hourly System Output (90% EFF.) (Btu)	861,000
Annual Output (MMBtu)	1,728
Estimated System Cost	$553,000
Estimated First Year Savings	
Coal	$6,400
Coal/Biomass Blend	$7,900
Natural Gas	$11,000
Payback Period (years)	
Coal	>40
Coal/Biomass Blend	>40
Natural Gas	31

Notes:
1) Payback periods are based forcasted costs of fuels from the DNR 2011 Annual Energy Outlook, Appendix C, Table C3 - Energy Prices by Sector and Source utilizing industrial pricing in nominal dollars/MMBtu.
2) Savings include an 85% efficiency on exising heat generating system.
3) Solar thermal system output is based on 90% system efficency and 5.5 hours/day of sunlight.
4) Savings and payback values do not include possible savings from emissions reduction.
5) The 123-collector system @ MU cost estimate inludes site specific installation costs.
6) Financing costs are not included.

Table 1-3 summarizes the estimated emission reduction of installing a solar thermal system at MU CHP plant. Not included in the table, is the CO_2 emissions reduction. Based on the 2010 EPA eGRID CO_2 emission rate and 85-percent boiler efficiency, it was determined that the 123-collector evacuated-tube solar thermal system at MU could save 204 tons of CO_2 per year.

Table 1-5: MU Emissions Reduction Estimate

Fuel/System	Estimated Annual Emission Reduction (lb)					
	Particulate Matter (PM)	Hydrogen Chloride (HCl)	Mercury (Hg)	Mono-Nitrogen Oxides (No_x)	Carbon Monoxide (CO)	Volatile Organic Compounds (VOC)
Coal[1]						
123-Collector System @ MU	79	71	0.0094	n/a[4]	549,039	n/a[4]
Biomass[2]						
123-Collector System @ MU	79	71	0.0094	n/a[4]	996,405	n/a[4]
Natural Gas[3]						
123-Collector System @ MU	n/a[4]	n/a[4]	n/a[4]	203	6,426	3,454

Notes:
1) Coal emission limits are based on the Industrial Boiler MACT Rule Emission Limits for a Coal Stoker Boiler
2) Biomass emission limits are based on the Industrial Boiler MACT Rule Emission Limits for a Biomass Stoker Boiler
3) Natural gas emission limits are based NSPS Subpart Db requirements for industrial, commercial, and institutional steam generating units
4) Denotes that an emission limit has not been established

1.4 MU RECOMMENDATIONS

The following are the recommendations derived from the Study. These recommendations are valid if MU chooses to proceed with the installation of a solar thermal system at the MU CHP Plant.

- Utilize evacuated-tube solar thermal collectors. This recommendation is based on higher output temperatures (when compared to flat-plate collectors), better overall efficiencies, and the best performance on cloudy/cold days and in snowy climates, which should lead to a faster payback period.
- Install the maximum number of solar thermal collectors in all three designated areas so that the solar thermal system output can be as high as possible. This reduces the payback period and the impact that MU CHP Plant has on the environment.
- Locate the solar thermal equipment near the existing make-up water pumps at elevation 702’-3”. This recommendation is based on MU CHP Plant available space. Locating this equipment closer to the roof elevation would reduce the capital cost of the solar thermal system.
- Utilize the existing spare heat exchangers near the existing make-up water pumps. Utilizing the existing heat exchangers reduces the capital cost of the solar thermal system.

- Replace the roof above the north deaerator prior to the installation of the solar thermal system. The new roof should be designed and constructed in such a manner that solar thermal collectors could be mounted directly to it.
- Insulate the un-insulated sections of the existing make-up water piping for efficiency and personnel burn protection.
- Explore the utilization of PPA agreement to avoid capital costs and to take advantage of available government funding.

* * * * *

CHAPTER 2.0

INTRODUCTION

2.0 INTRODUCTION

2.1 STUDY OBJECTIVE

The objective of the Solar Thermal Study was to develop an understanding of the technologies available to harness energy from the sun with the intention of using it to heat make-up water. This would give MU an opportunity to decrease the amount of fossil fuel required to operate the MU CHP Plant. After an understanding of the different technologies was established, it was possible to continue into the preliminary design stages of adding the sun as a source of energy for the MU CHP Plant. The preliminary design portion of the Study explored system design options, equipment placement, and tie-in points. The costs associated with equipment, existing plant modifications, and installation along with a savings analysis was also considered in the Study.

2.2 BACKGROUND

On July 7, 2010, BMcD presented a Renewable Energy Feasibility Study to MU. This report was prepared and submitted pursuant to the contract between MU and BMcD, dated March 5, 2010. It covered the evaluation of the available and feasible renewable energy resources to serve the MU campus. The purpose of the report was to aid MU in assessing future energy investments and address long-term desires to increase the energy that the campus received from renewable sources. As a result of the report, MU requested that BMcD assist with the acquisition of grant money from the Missouri Department of Natural Resources (DNR). This joint effort resulted in the DNR providing a grant to MU to complete the Study.

2.3 SOURCES OF DATA

Information to complete this Study was collected from a variety of sources, including vendors, solar energy articles and reports, and previously-completed BMcD solar energy projects. These sources provided information on available technology, technology application, equipment specifications, solar resource data, and pricing. Sixteen different solar energy companies were contacted to collect some of the aforementioned technology options. Four of the 16 companies do not work with roof mounted systems, considered the MU project to be too small in scale, or the company simply did not respond. The 12 companies that did provide information are listed below.

- Abengoa Solar
- Brightergy
- Cinco Solar
- Heliodynamics

- Heliodyne
- Midwest Solar Distributors
- Solaire Power Technologies
- Solid Solar
- Sopogy
- Sun Systems
- SunMaxx Solar
- SunSource Energy, LLC

SunSouce Energy, LLC, a wholly-owned subsidiary of United Technologies Corporation (UTC), provided useful information regarding the available solar thermal technologies and provided preliminary design details for the MU CHP Plant. UTC also participated in an onsite, preliminary project review to help BMcD obtain accurate budgetary pricing.

Articles and reports were helpful in evaluating the application of the different solar technologies. In some cases, this information was published by solar energy companies. Because vendors have a vested interest in the products they sell, many different sources of information were explored. Reviewing articles and reports from a variety of sources, in addition to speaking with vendors, made it possible to obtain unbiased recommendations.

2.4 STATEMENT OF LIMITATIONS

In completing this Study, information provided by MU and other sources were utilized by BMcD to make certain assumptions with respect to conditions that may exist in the future. While BMcD believes the assumptions made are reasonable for the purposes of this Study, no representation is made that the conditions assumed will, in fact, occur. In addition, while BMcD has no reason to believe that the information provided by MU and other parties, and on which BMcD has relied, is inaccurate in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided by MU and other parties the actual results will vary from those projected.

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CHAPTER 3.0

SOLAR ENERGY TECHNOLOGIES

3.0 SOLAR ENERGY TECHNOLOGIES

3.1 SOLAR THERMAL TECHNOLOGY

Solar thermal technology is defined as a technology used to harness energy from the sun for use in a thermal process. There is a wide variety of applications for this technology including, but not limited to, water/process heating, radiant heating, and air conditioning. In each application, solar energy is obtained through a solar collector and transferred directly, or through a heat exchanger, to a thermal process. Given the proper conditions and system design, solar thermal technology can provide a reliable and cost-effective energy source in residential, commercial, and industrial applications. Solar thermal technology can be broken into three categories of solar collectors: flat-plate collectors, evacuated-tube collectors, and concentrated solar collectors. Each category offers different advantages and disadvantages, depending on operating and climate conditions. Table 3-1 is a high level comparison of each category.

Table 3-1: Solar Thermal Collector Comparison

	Flat-plate Collector	Evacuated-Tube Collector	Concentrated Solar Thermal Systems
Most Readily Available	**1**	2	3
Least Expensive	**1**	2	3
Highest Output Capacity	3	2	**1**
Smallest Typical Footprint Size	**1**	**1**	3
Best Cold/Windy Climate Performance	3	2	**1**
Best Snowy Climate Performance	2	**1**	3
Best Minimal Sun Performance	2	**1**	3
Highest Configuration Flexibility	2	**1**	3
Easiest to Install	**1**	2	3
Least Required Maintenance	**1**	2	3

Notes:

1) 1 denotes the best rating by comparison

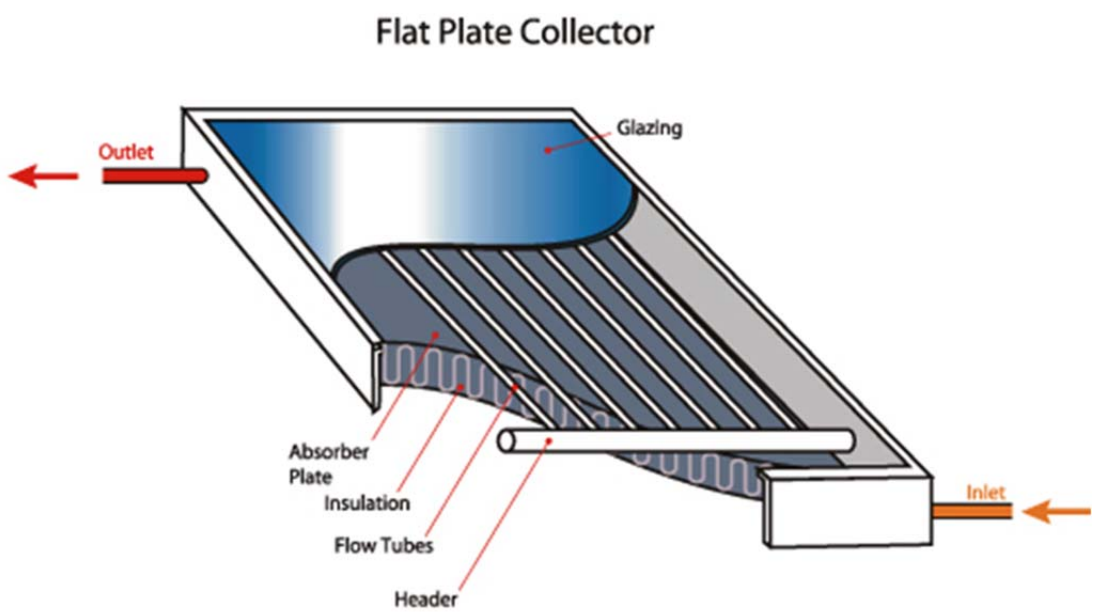
2) 2 denotes the middle rating by comparison

3) 3 denotes the worst rating by comparison

3.1.1 Flat-Plate Collectors

Flat-plate solar collectors are typically used in low temperature applications, such as domestic hot water or heating a small space. Traditionally, they are made up of a flat absorber plate encased in a lightweight frame. The absorber plates are coated to assist with the collection of solar radiation. Absorber coatings vary depending on the supplier and/or model of solar collector. Pipes, referred to in the industry as risers or flow tubes, are bonded to the absorber plates. Risers are used to circulate fluid throughout the solar collector. The ends of the risers connect to headers that protrude from sides of the collector. The headers serve as the collector inlet and outlet for the circulating fluid. Depending on the design of the system, this fluid may be water, a glycol mixture, or another type of heat transfer fluid. The flat-plate collector frame is lined with a layer of insulation and covered with a transparent layer of glass or plastic. This layer is known as collector glazing. Similar to the absorber coating, the collector glazing varies depending on the supplier and/or model of solar collector. The glazing is extremely important to the overall performance of the solar collector because it must allow the maximum amount of solar radiation while keeping the collected heat within the collector. Figure 3-1 is a cut-away image of a flat-plate solar thermal collector.

Figure 3-1: Flat-plate Solar Thermal Collector



In addition to being the most readily available type of solar thermal collector and the easiest to install, flat-plate solar thermal collectors are also traditionally the least expensive. They usually require the lowest capital investment and they are the least expensive to operate and maintain as they contain no

moving parts and require minimal maintenance. Maintenance may include glazing cleaning and annual inspection of the heat transfer fluid. The heat transfer fluid may have to be replaced annually, depending on system operation. In many scenarios, the glazing is “self-cleaning” because the dirt accumulation can usually be washed away by rain. Should the glazing require replacement, many models allow this without removing the collector from its mounted position. Typically, replacing parts on flat-plate collectors is not time-consuming and specialty tools are not required. The industry standard for the useful life of flat-plate thermal collectors is approximately 25 years.

3.1.2 Evacuated-Tube Collectors

The major components of a traditional evacuated-tube solar thermal collector include: an evacuated-tube, heat pipe, header pipe, insulation, manifold casing, and mounting frame. The evacuated-tube and heat pipe form the heat absorption and transfer unit of the evacuated-tube collector. The heat pipe is located at the center of the evacuated-tube configuration. A heat pipe is a heat transfer device that uses phase changes of an internal fluid to continuously transfer heat from a source to a target. Figure 3-2 illustrates the basic operation of a heat pipe. In evacuated-tube collectors, the heat pipe transfers energy from the absorber plate to the collector header. A heat transfer fluid, separate from the internal heat pipe fluid, passes through the header to collect the heat. Depending on the design of the system this fluid may be water, a glycol mixture, or another type of heat transfer fluid.

The heat pipe is surrounded by a heat transfer fin, which maximizes the heat transfer from the absorber plate to the heat pipe. The heat transfer fin is then wrapped in the absorber plate, which is used to collect solar radiation. The absorber plate in an evacuated-tube collector has a similar coating as a flat-plate collector absorber. Outside of the absorber plate is a vacuum space and then a clear outer glass/plastic tube, which gives this collector its name. The vacuum space between the absorber plate and tube is critical for minimizing the convection and conduction heat loss from the ambient air. Figure 3-3 shows the evacuated-tube portion of an example evacuated-tube collector. The remaining components of the evacuated-tube collector function similarly to the flat-plate collector. The header pipe is used to circulate fluid through the solar collector. This pipe is surrounded by insulation, and covered by a manifold casing. The mounting frame supports the casing. Figure 3-4 is a cut-away image of an example evacuated-tube solar thermal collector.

Figure 3-2: Basic Heat Pipe Operation

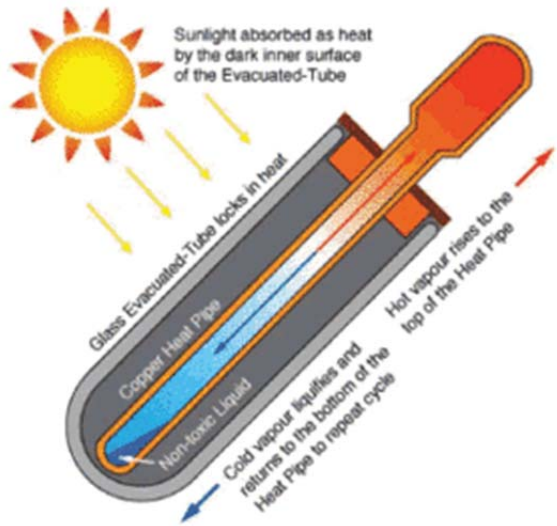


Figure 3-3: Single Evacuated-Tube

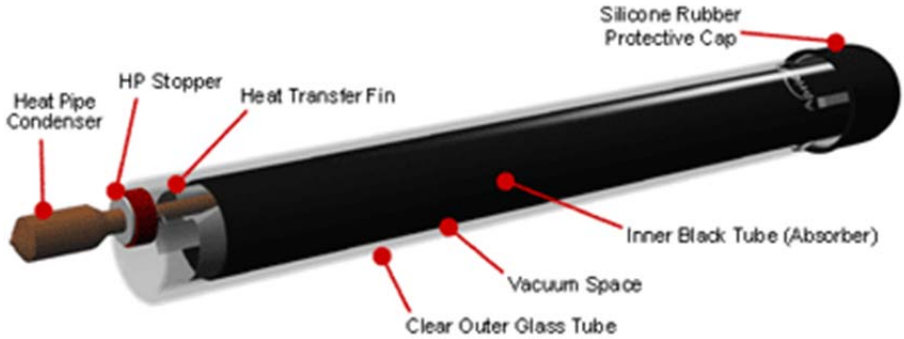
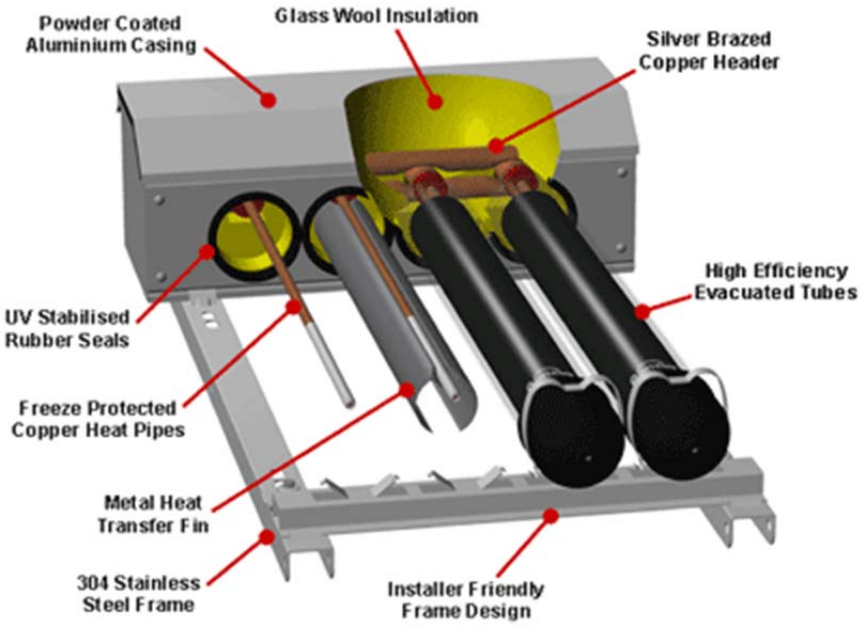


Figure 3-4: Evacuated-Tube Solar Thermal Collector



Although the evacuated-tube collectors are not as readily available as the flat-plate collectors, they do have reasonable lead times. The installation is a little more difficult for evacuated-tube collectors when compared to flat-plate collectors because evacuated-tube collectors have more parts and are generally heavier. The evacuated-tube collectors also have a slightly higher capital cost when compared the flat-plate collector. However, the maintenance costs for evacuated-tube collectors are similar. Maintenance may include outer tube cleaning and annual inspection of the circulating heat transfer fluid. The heat transfer fluid may have to be replaced annually, depending on system operation. In many scenarios the tubes are “self-cleaning” because the dirt accumulation can usually be washed away by precipitation. In most cases, replacement components are available depending on the supplier and/or model. Most component replacement is not time-consuming but some evacuated-tube collectors require special tools. Major advantages of evacuated-tube collectors over flat-plate collectors include higher output temperatures, greater overall efficiencies, better performance on cloudy/cold days, better performance in snowy climates, and more flexibility on collector configuration. According to various suppliers, evacuated-tube collectors have an estimated useful life of 15 to 30 years.

3.1.3 Concentrated Solar Thermal Systems

Concentrated solar thermal systems use concentrated solar energy collectors to focus solar energy on a desired target. These collectors vary in size, shape, and ability, but they all use mirrors and/or lenses to achieve the highest heat transfer rate. The focus points of concentrated solar thermal systems are called

receivers and typically consist of a single pipe or an array that is used to circulate fluid throughout the collector. This is similar to the other types of solar collectors. Depending on the design of the system, this fluid may be water, a glycol mixture, or another type of heat transfer fluid. The different types of concentrated solar energy collectors may be used in solar thermal or solar photovoltaic (PV) applications. Concentrated solar energy collectors and solar PV are described subsequently in this report.

Concentrated solar thermal systems have the greatest capital investment of the different types of solar collectors and they are the most expensive to own and maintain. However, they also have the greatest output capacity and system integration capabilities. The high capital and maintenance cost associated with the concentrated solar thermal systems can be attributed to the comparatively high number of parts, moving components, and various ongoing maintenance activities. Since the solar collectors on the concentrated solar thermal systems focus the solar energy, they must rotate to track the position of the sun. The necessary tracking feature increases the number of parts and requires additional maintenance beyond the cleanliness of the collectors and the condition of heat transfer fluid. Additional maintenance may include, but is not limited to, tracking motor maintenance, belt replacement, and lubrication.

Concentrated solar thermal systems do not perform well in snowy or limited sun conditions. Snow could build up on concentrated solar thermal systems and most of the time removal is required. However, some concentrated solar thermal systems rotate 180 degrees when the sun is not bright, e.g., cloudy days and nighttime. These types of systems would not require snow removal because snow buildup would be on the inactive side of the collector. When the sun activates the collectors and they rotate to collect solar energy, the snow should not be a concern unless there is a large buildup. Collector loading and elevation should all be considered in climates where snow may build up. Concentrated solar thermal systems do not perform as well in limited sun conditions because the receivers are typically small and the solar energy is collected then focused. If there are no sun rays to focus, the absorber would not receive energy from the collector. According to various suppliers, concentrated solar thermal systems have an estimated useful life of about 30 years.

3.2 SOLAR PV TECHNOLOGY

Solar PV technology is defined as a technology used to harness energy from the sun and convert it to electricity. This conversion is made possible by a phenomenon known as the Photoelectric Effect, which takes place within the material of a solar PV cell.

The Photoelectric Effect is the addition or subtraction of electrons in response to a light source. The chemistry and electrical reactions within the solar PV cell generate a useable source of electrical energy.

The basic building block of a solar PV system is the solar cell. The cell is made of semiconductor material that converts solar energy into electricity. Cells are configured to form modules. Modules are a collection of solar cells and are often referred to as a solar panel. The cells within a module are arranged in series and parallel. The series connections step up the voltage of the module and the parallel connections step up the current. The cells are encased with glass on top and a substrate underneath. The more cells per module, the higher the voltage and/or current become. The module has electrical connections to the electrodes of each individual solar cell, which terminate on a positive and negative terminal block on the back of a module. Positive and negative conductors of modules are connected together to form strings. A string is a set of modules connected in series. Modules are connected in series to achieve a desired voltage. When placing modules in a string, the modules take on a characteristic as a group. Strings are connected in parallel in a combiner. The combiner is a device where the strings are physically terminated and paralleled.

3.2.1 Solar Cells

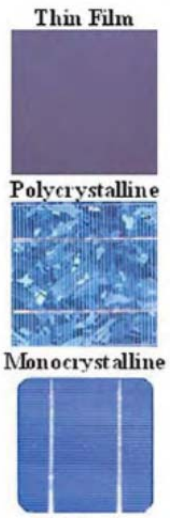
There are currently three main categories of solar cell technology: monocrystalline, polycrystalline, and thin film. The different technologies have varying levels of efficiency and cost. When evaluating which cell technology to utilize for a system, it is often beneficial to review the cost per kilowatt-hour (kWh). Monocrystalline solar PV cells are produced when silicon granulate is put through a drawing process. This process combines granulate to form a solid crystalline structure, creating an efficient solar cell with one silicon lattice. The silicon granulate is enlarged by placing it under extreme temperatures and “spinning” it into what is called an ingot. These ingots are then cut into thin wafers, creating the basic building block of the solar PV cell. Monocrystalline cells have typical efficiency ratings of 15 percent to 18 percent, the highest among current PV technologies. Monocrystalline cells are also the most expensive of the three cell technologies.

Rather than using the drawing process like the monocrystalline technology, polycrystalline cells are formed by heating and cooling the silicon granulate and forming a cube. The cube is sliced and the resulting wafer is a combination of silicon lattice that results in minute differences within the cell. The above-described manufacturing process of polycrystalline is less expensive than the drawing process of monocrystalline, leading to a less expensive polycrystalline module. Along with the lower cost, the efficiency of polycrystalline is lower than monocrystalline, with average efficiencies of 12 percent to 16 percent.

Thin film technology was developed to create a less expensive solution that could meet greater demands compared to traditional silicon manufacturing methods. Thin film uses less material than traditional

silicon manufacturing methods and is basically produced with a printing process. This process is far more efficient and cost effective compared to the monocrystalline and polycrystalline manufacturing procedures. This allows thin film solar PV panels to be produced at a lower cost per kWh. Although thin film is the least expensive cell technology, it is also the least efficient, with typical efficiencies of six percent to 12 percent. Currently, the greatest strides in the solar PV development are being made with thin film technology. Figure 3-5 visually shows the different types of cells and their structures.

Figure 3-5: Solar PV Cell Structures



3.2.2 Solar Arrays

Solar PV arrays are defined as the entire solar PV system. The array is commonly broken into two parts: the modules and the balance of system. While the modules are the heart of the PV system, the system could not operate without each component in the balance of the system, including the cabling, combiners, disconnects, inverters, mounting system, and more. There are several options for mounting solar PV arrays. Some systems are fixed in place (similar to flat plate solar thermal collectors) and others are tracking, meaning they move to follow the path of the sun. Some tracking solar PV systems use concentrated solar energy collectors and are referred to as concentrated solar PV systems. These systems allow less silicon to be utilized, which significantly increases efficiency. The different types of concentrated solar energy collectors are described subsequently in this report. Mounting systems could vary based on the design criteria of each individual system.

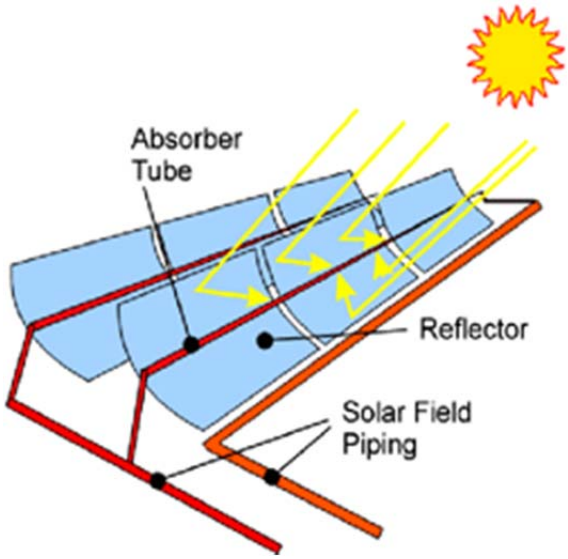
3.3 CONCENTRATED SOLAR ENERGY SYSTEMS

Concentrated solar energy systems use mirrors and/or lenses to achieve the highest possible heat transfer rate and efficiency. These systems use collectors that vary in size, shape, and tracking ability. Concentrated solar thermal systems are used to focus solar energy for thermal processes. Concentrated solar PV systems are used to produce electricity more efficiently than traditional solar PV arrays. Both solar thermal and solar PV applications use the same technologies to focus solar energy. Tracking technologies can be categorized into three groups of concentrated solar thermal collectors: trough systems, power tower systems, and dish systems.

3.3.1 Trough Systems

Trough systems use large parabolic mirrored collectors that focus solar energy onto a receiver. The u-shaped portion of the collector is mirrored and the receiver tube sometimes is coated with an absorber material similar to the other types of solar thermal collectors. Heat transfer fluid is circulated through the center of the receiver and is used to transfer solar energy. Depending on the design of the system, this fluid may be water, a glycol mixture, or another type of heat transfer fluid. In electrical generation systems the fluid is usually oil that is heated as high as 750 °F. This oil heats water through a heat exchanger, which produces steam to operate a conventional steam turbine generator. Figure 3-6 illustrates the basic operation of a trough concentrated solar energy collector.

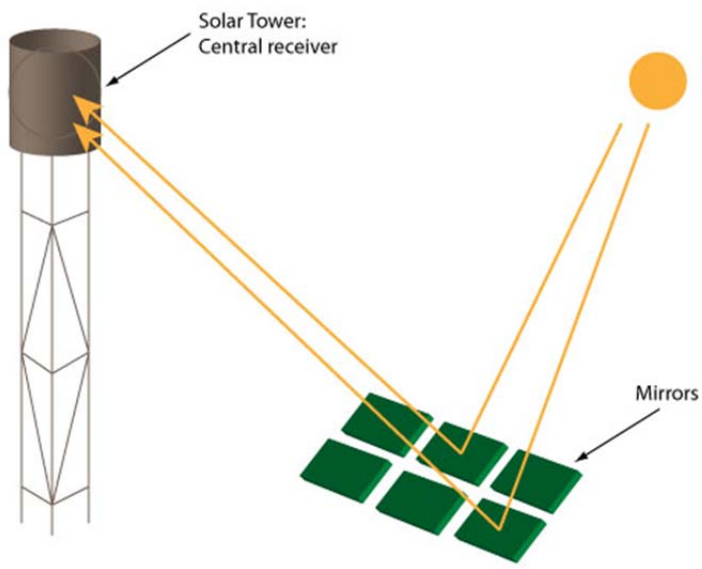
Figure 3-6: Trough Concentrated Solar Energy Collector



3.3.2 Power Tower Systems

Power tower systems use reflective collectors that focus solar energy onto a tower-like receiver. The collectors vary in shapes and sizes, depending on the manufacturer. In solar PV applications, the receiver tower is lined with solar PV cells. In solar thermal applications, the receiver tower is covered in an absorber material and filled with heat transfer fluid. Depending on the design of the system, this fluid may be water, a glycol mixture, or another type of heat transfer fluid. Some electrical generation systems utilize oil as a heat transfer fluid. This oil heats water through a heat exchanger, which produces steam to operate a conventional steam turbine generator. Figure 3-7 illustrates the basic operation of a power tower concentrated solar energy system.

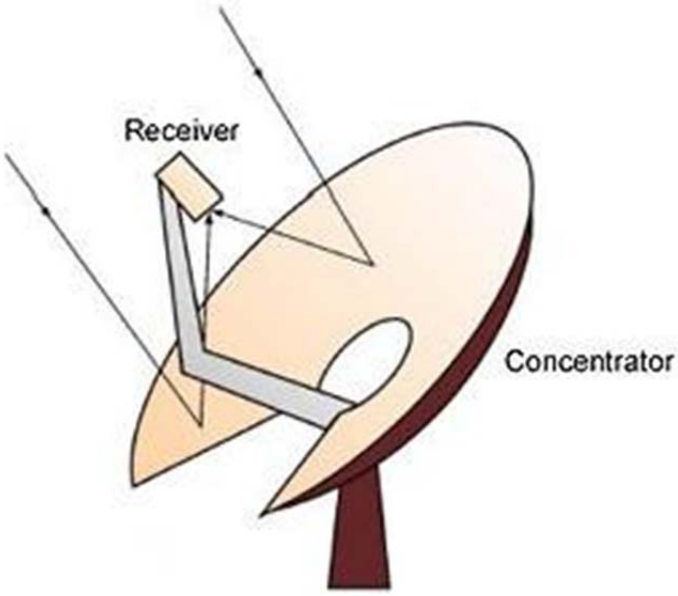
Figure 3-7: Power Tower Concentrated Solar Energy System



3.3.3 Dish Systems

Dish systems use a large dish-shaped reflective collector to focus solar energy onto a receiver. The dish-shaped collector is mirrored and the receiver is often coated with an absorber material similar to the other types of solar thermal collectors. The typical application for a dish system is to couple the collector with a Stirling engine. A Stirling engine is a heat engine that operates by way of cyclic expansion and compression. The rotation created from the Stirling engine is usually used directly to generate electricity. The advantage to a dish system is the ability to collect more solar energy and focus it on a smaller receiver. This creates much higher temperatures, which results in a higher efficiency. Figure 3-8 illustrates the basic operation of a dish concentrated solar energy system.

Figure 3-8: Dish Concentrated Solar Energy System



3.4 SOLAR ENERGY TECHNOLOGY AT THE MU CHP PLANT

Determining the best type of solar energy technology was an important part of the Study. Each technology would perform differently in different parts of the country and have different operating characteristics. The factors that should be considered when selecting a solar energy technology for any given application include thermal capacity, outlet temperatures, climate, seasonal change, available space, equipment availability, load profile, required maintenance, capital cost, and investment payback. The priority for each of these factors would vary based on owner requirements.

MU is considering options for collecting solar energy for the purpose of heating make-up water. Therefore, solar thermal systems are the best suited for this application. However, solar thermal systems require additional pumping horsepower/electrical energy. Therefore, solar PV technologies were considered and evaluated to provide supplemental electrical power to offset the additional electrical pumping load.

MU is interested in obtaining the most cost-effective Btu/hr capacity as reasonably possible for the solar thermal system, within the space allocated. To maximize the thermal capacity within the available space, it is recommended that the solar thermal system be pursued without the optional PV collectors to operate the solar thermal system pump. Solar PV collectors are less efficient than solar thermal collectors and it would be more cost effective to fill the available space with solar thermal collectors. Without the solar PV

panels, the pump would require a plant electrical feed, but the overall solar thermal system capacity and efficiency would increase.

The MU CHP Plant's solar thermal application and plant location weigh heavily on the solar thermal technology recommendation. Since the MU CHP Plant is located in the Midwest where the climate is variable and there are distinct seasons, it is recommended that MU utilize evacuated-tube collectors. Concentrated solar thermal systems are high in cost and are not suitable for the Missouri climate. Flat-plate solar thermal collectors have a few slight advantages over evacuated-tube collectors, but evacuated-tube collectors would provide a higher thermal capacity, which would ultimately lead to a faster investment payback. The available space, equipment availability, and required maintenance of these systems are not different enough to affect the technology selection between flat-plate collectors and evacuated-tube collectors. For the purposes of the Study, it is recommended that evacuated-tube collectors be used for the preliminary design development. This technology fits the needs of MU and any other industrial company in the Midwest considering solar thermal process heating better than the others.

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CHAPTER 4.0

PROJECT EXECUTION

4.0 PROJECT EXECUTION

4.1 SOLAR THERMAL SYSTEM DESIGN OPTIONS

There are two primary options for transferring the solar thermal energy from the collectors to the make-up water at the MU CHP Plant. The first option is to directly heat of the make-up water by circulating it through the collectors. The second option is to indirectly heat the make-up water through a heat exchanger. The hot side of the heat exchanger in this option would be a heat transfer fluid circulated though the solar thermal collectors. These design options are described below.

4.1.1 Design Option #1

Design Option #1 would utilize solar thermal collectors to heat the make-up water directly. By installing a new three-way control valve and utilizing the existing capacity of the four treated water pumps, treated water would be directed through the solar thermal collectors and back to the existing treated water system. The flow would be controlled by several new control valves, flow elements, and temperature sensors. As the solar collectors get hot, the three-way and open/close block valves would open and allow the treated water to flow through the collectors. The flow through the collectors would be monitored by a flow element, which would maintain a set flow rate by sending a signal to the three-way control valve. This flow rate would be dependent on the number and type of solar thermal collectors. When there is a lack of solar energy, or the temperature of the collectors drops below the set point, the three-way and open/close block valves would isolate the solar thermal collectors and the outdoor piping. Then the vent and drain valves would open to drain the system. This is necessary to prevent freezing of the lines during the winter. The system would be gravity-drained back into the condensate tank so that treated water is not wasted. Figure 4-1 shows a flow diagram of Design Option #1.

4.1.2 Design Option #2

Design Option #2 would utilize solar thermal collectors to heat the make-up water indirectly. Instead of using the existing capacity of the four treated water pumps to provide flow through the solar thermal collectors, the pumps would provide flow through a heat exchanger. A new pump would be required to circulate the heat transfer fluid through the solar thermal collectors and back to the new heat exchanger. The heat transfer fluid would most likely be a glycol mixture so that the system would not have to be drained when solar energy is not available, e.g. cloudy days and nighttime. Similar to Design Option #1, flow would be controlled by a control valve and temperature elements tied into the existing plant PLC. As the solar collectors get hot, the solar thermal system pump would be activated. Once the glycol mixture reaches the temperature set point, a three-way valve would open and allow the treated water to flow

through the heat exchanger. The treated water flow through the heat exchanger would be monitored by a temperature element that would maintain full flow, as long as the temperature of the solar thermal system is greater than the make-up water system temperature. When there is a lack of solar energy, or the temperature of the heat exchanger drops below the set point, the solar thermal pump would shut down and the three-way valve would divert flow from the heat exchangers. Figure 4-2 shows a flow diagram of Design Option #2.

Figure 4-1: Design Option #1 Flow Diagram

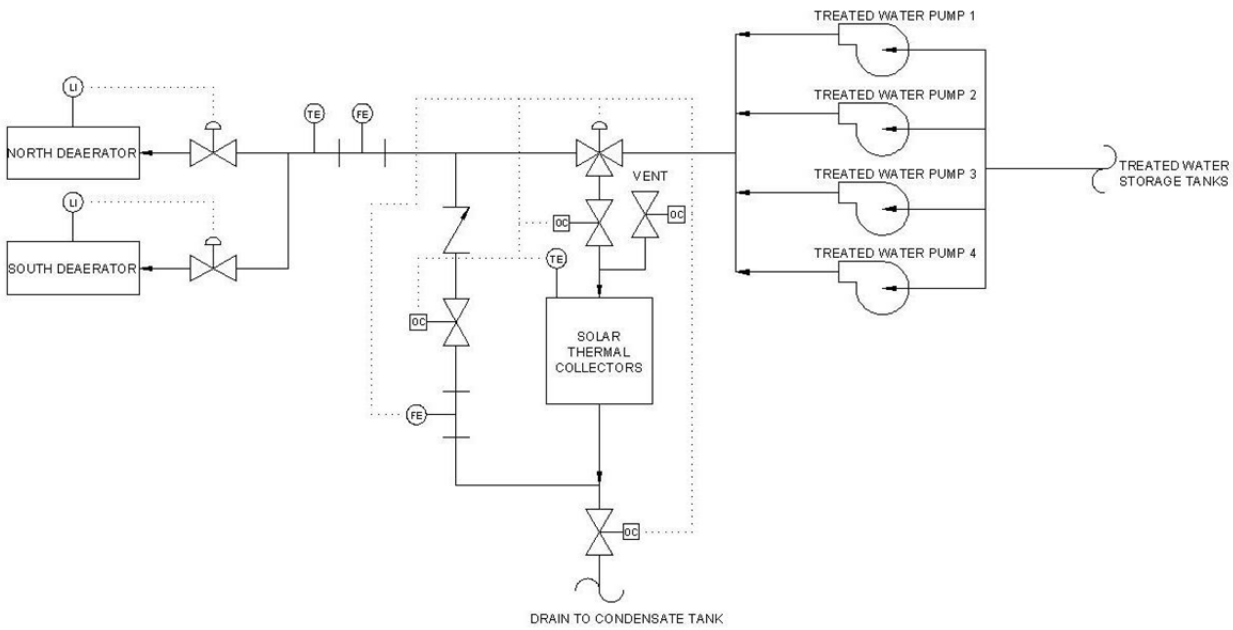
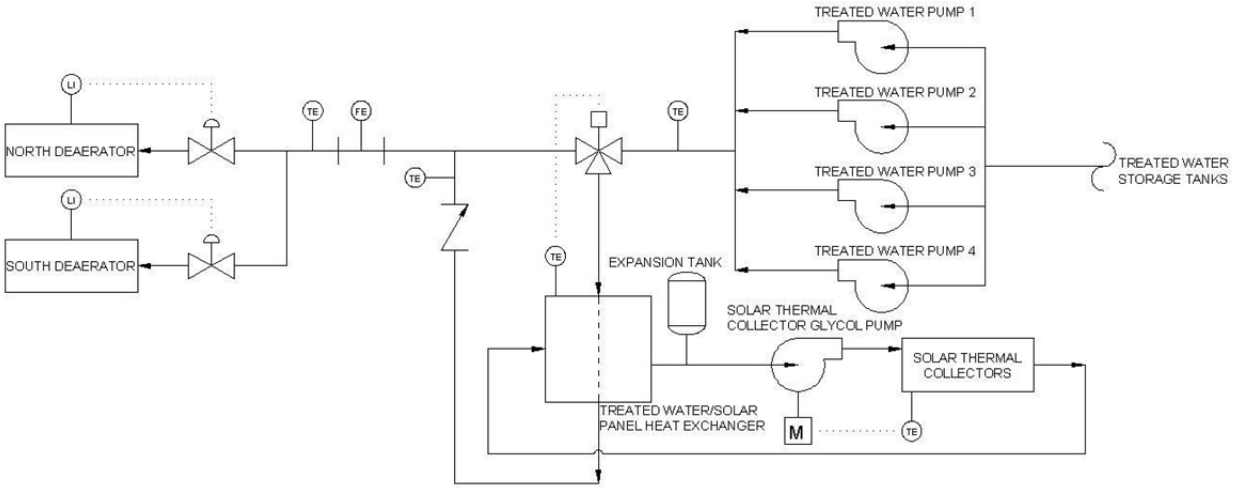


Figure 4-2: Design Option #2 Flow Diagram



4.1.3 Design Option Comparison

There are both pros and cons to each of the design options considered. From a mechanical equipment point of view, Design Option #1 is less complicated than Design Option #2 and would likely have lower equipment cost. However, from an electrical and instrumentation stance, Design Option #2 is less complicated and would likely have lower costs associated with instrumentation and controls. The difference in capital costs between the two options is assumed to be negligible.

The operation and maintenance (O&M) and expense associated with each design option is the differentiator for design option selection. Design Option #1 requires more controls-related events for proper function. The more steps required to operate a system, the more opportunities there are for the system to fail, e.g., opening/closing vent valves and opening/closing drain valves. Even with new equipment and a strong controls platform, accidents can happen. The fact that Design Option #1 must be drained on a daily basis in the winter months is a concern. Failure to drain the system each night would likely result in freezing, causing costly damage to piping and equipment. Design Option #2 would also have opportunities to fail, but failure of Design Option #2 would not have as large of an impact. The impact of failure for design option #2 would be the loss of the solar thermal system while the failed component is replaced. The major preventative maintenance associated with Design Option #1 would be less than Design Option #2 since there is not a solar thermal system pump or glycol mixture. However, this lower preventative maintenance expense does not outweigh the cost risk associated with failure of Design Option #1.

BMcD recommends Design Option #2 to minimize daily O&M and to alleviate the potential for catastrophic failure. Only Design Option #2, an indirect solar thermal heating system that utilizes evacuated-tube solar thermal collectors, was considered further for preliminary design development.

4.2 MU SOLAR THERMAL SYSTEM EQUIPMENT AND INTEGRATION

The solar thermal system integration at the MU CHP Plant was an important part of this study. The solar thermal system must be integrated into the existing plant so that it functions properly and solar energy is efficiently transferred to the make-up water. System integration can be grouped into two categories:

1. The mechanical system integration involves physically merging the solar thermal system with the make-up water system.

2. The electrical system integration involves modifying the plant control system to monitor and operate the solar thermal system. It also involves bringing power to the new solar thermal system pump and installing the required instrumentation.

4.2.1 Mechanical

Mechanical system integration brings the solar energy from the solar thermal collectors to the make-up water. This is done by way of the solar thermal system heat exchanger. The hot inlet of the heat exchanger would be a glycol/water mixture, circulated by the solar thermal system pump from the solar thermal collectors. The cold inlet of the heat exchanger would be the 60 °F treated make-up water. The tie-in point to the existing make-up water system must be between the make-up water pumps and the plant deaerators to ensure that the make-up water is treated and to utilize the surplus make-up water pump capacity. There are four existing Ingersoll-Dresser make-up water pumps, with a total capacity of about 560 gpm. The MU CHP Plant staff typically operates no more than two of the four pumps to meet the make-up water demands. It is assumed that the head loss from the added solar thermal system heat exchanger should not be an issue for the existing make-up water pumps. The other new solar thermal system equipment would not directly interface with the existing MU CHP Plant systems. Therefore, would not impact them. Table 4-1 shows the design specifications for the new mechanical solar thermal system equipment.

Table 4-1: Solar Thermal System Mechanical Equipment

Equipment Description	Equipment type	Quantity	Capacity	Total Capacity	Sizing Details	Installed Footprint (L x W x H)
Solar Thermal Collectors	Evacuated Tube	123 Collectors	226 Btu/(hr*ft^2)	0.861 MMBtu/hr	31 ft^2 absorber area per collector	8'6" x 6' x 4'
Solar Thermal Pump	Variable Speed	1 pump	63 gpm	63 gpm	5 hp	-
Solar Thermal Expansion Tank	Tank	2 Tank	250 gal	500 gal	-	-
Solar Thermal Heat Exchanger	Existing Plate & Frame	2 HE	-	-	150 psi @ 230 deg. F	-

With respect to the existing MU CHP Plant, the only mechanical modification that may be required would be the addition of pipe insulation to a portion of the make-up water piping. Pipe insulation would reduce the amount of heat loss that may be experienced when the make-up water flows from the solar thermal system heat exchanger to the plant deaerators. It would also serve as personnel burn protection.

4.2.2 Electrical

The make-up water water treatment system is operated by the Water Treating Control Panel located on the 5th floor of Building C. The solar thermal system would tie directly into this main control panel and the MU CHP Plant staff would program the controller to operate the solar thermal system, in addition to the water treatment system. The solar thermal pump would be powered from the plant water treatment motor control center (PWT MCC), a 480-volt, 3-phase motor control center. PWT MCC contains multiple spare breakers and is located next to the Water Treating Control Panel. The solar thermal pump, a 480-volt, 5-HP glycol pump, would support all three solar thermal collector areas. This pump would be controlled by a VFD motor controller tied directly back to the Water Treating Control Panel. The VFD would be located near the solar thermal pump and would be modulated to maintain a preset level of water temperature. The solar thermal system control valve and temperature elements would also be tied into the MU CHP Plant PLC. Table 4-2 shows a summary of the electrical equipment and instrumentation representative of the solar thermal system being considered.

Table 4-2: Solar Thermal System Electrical Equipment/Instrumentation

Equipment Description	Quantity	HP	Voltage/ Phase	Controller / Signal Type
Solar Thermal System Pump w/ VFD	1	4	480/3	VFD
Solar Thermal System Temperature Element	4	N/A	120V	4/20 mA
3-Way Control Valve	1	N/A	120V	4/20 mA

4.2.3 Equipment Placement

The new major equipment associated with the solar thermal system at the MU CHP Plant would include solar thermal collectors, a solar thermal system pump, a solar thermal system heat exchanger, and an expansion tank. The existing equipment involved with the addition of a solar thermal system includes the equipment utilized in the production, distribution, and consumption of make-up water. All the equipment involved can be divided into two groups: interior and rooftop.

The majority of the new equipment and all of the existing equipment associated with the solar thermal system would be located within the MU CHP Plant and considered interior equipment. It would not be necessary to relocate any of the existing plant equipment for the addition of the solar thermal system. There is an excess of space near the existing four make-up water pumps. This area already contains the existing spare heat exchangers that may be utilized for the solar thermal system, which would be ideal for the placement of the solar thermal system pump. This location minimizes the amount of piping required to tie the solar thermal system and make-up water system together. Since the solar thermal system piping

must circulate the heat transfer fluid from the solar thermal collectors to the heat exchanger, and the space is available, it is logical to locate the new solar thermal glycol pump near the existing make-up water pumps. The solar thermal expansion tank could also be located in this space.

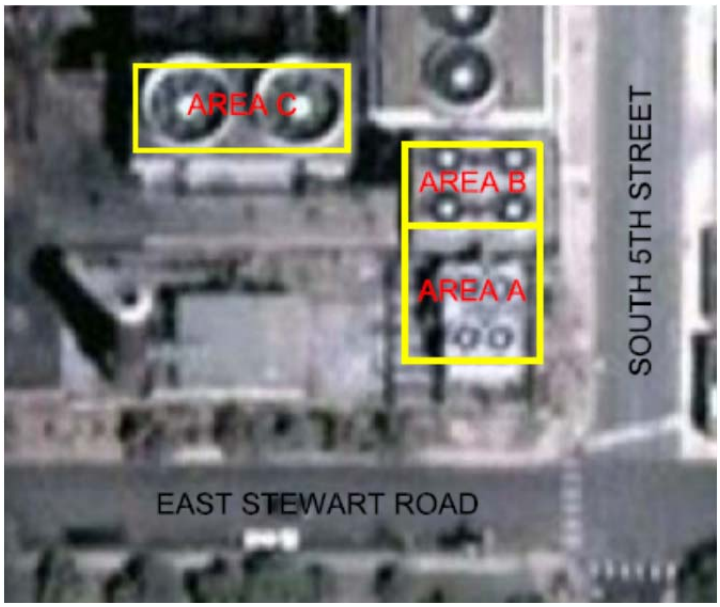
The only equipment to be located outside the MU CHP Plant building would be the solar thermal collectors themselves. The solar thermal collectors would be divided into three groups, each located on a different MU CHP Plant rooftop/structure. These rooftops are described in Table 4-3 and an aerial view is shown in Figure 4-3. There are approximately 6,700 square feet in total available space for solar thermal collectors. Depending on the manufacturer, this equates to roughly 123 evacuated-tube solar thermal collectors.

Table 4-3: Solar Thermal Collector Available Space

Rooftop Reference	Description	Length (ft)	Width (ft)	Area (ft^2)	Approximate # of Collectors*
Area A	Roof above Steam Turbine/Generator 6	51	51	2,601	48
Area B	Roof above Steam Turbine/Generator 9	51	31	1,581	30
Area C	Roof above North Deaerator	80	32	2,560	45
			total:	6,742	123

*Based on evacuated-tube solar thermal collectors supplied by SunSource Energy, LLC (8'-6" x 6')

Figure 4-3: Solar Thermal Collector Available Space - Aerial View



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CHAPTER 5.0

CONDITION ASSESSMENT

5.0 CONDITION ASSESSMENT

The condition of existing plant systems, equipment, and structural steel is a critical aspect of the overall project feasibility.

5.1 MAKE-UP WATER SYSTEM

The major equipment in the make-up water system at the MU CHP Plant includes three water softeners, three reverse osmosis (RO) units, a degasifier, two make-up water storage tanks, and four pumps.

The water softeners condition the make-up water before it enters the RO units. Specifically, they remove the water "hardness" by extracting the calcium and magnesium. At the MU CHP Plant, two of the softeners are in service at any given time. The other softener serves as a backup for when the ion exchange resin in a spent softener needs to be replaced. The frequency in which the ion exchange resin needs to be replaced depends on the hardness of the water. Having a "capacity plus one" configuration keeps the water softeners reliable and prevents the MU CHP Plant from having to stop producing make-up water during maintenance.

The RO units are also in a "capacity plus one" configuration. However, instead of ion exchange resin, ROs use a membrane to filter the make-up water. This membrane must be replaced periodically to maintain functionality in the RO units. The frequency of the RO maintenance is dependent on water quality. Due to the "capacity plus one" RO arrangement, make-up water production is not affected by this maintenance.

The degasifier is used to remove dissolved gases and other contaminants from the make-up water. The degasifier at the MU CHP Plant has a capacity of 420 gpm. It was re-lined in 2000 due to corrosion in the bottom of tank. Since then, the degasifier has been reliable.

The two make-up water storage tanks at the MU CHP Plant were manufactured by Edwards Fiberglass and were placed in service in the year 2000. They each have a capacity of 27,000 gallons and have been maintenance-free and reliable since their installation.

The four make-up water pumps were also placed in service in 2000. These pumps were manufactured by Ingersol Dresser and have a capacity of 140 gpm each. Regular inspection and maintenance has been performed on the make-up water pumps and they have been reliable. Furthermore, usually only two of the

pumps are in service at any given time. This extra pump capacity allows routine maintenance to be performed without stopping the production of make-up water. Overall the make-up water system is in excellent condition and should remain reliable for many years.

5.2 ELECTRICAL SYSTEM AND CONTROLS

The power source for the solar thermal system would originate from PWT MCC, which has been determined to have sufficient spare capacity to feed the main control panel at 480-volts, 3-phase. PWT MCC is located on the 5th floor of Building C, which results in a significant run of cable to the proposed location of the new solar thermal system equipment. A combination of conduit and/or cable tray could be utilized to route the cabling. The PLC system would need to be configured to accept the available I/O associated with the solar thermal system. Any additional hardware, including I/O cards and modifications to the processors logic, would be handled by the MU CHP Plant staff. The MU CHP Plant staff would also need to evaluate the water treatment PLC processor to determine what communications could be established with the solar thermal system. The water treatment PLC should have the capability to communicate via Ethernet with the solar thermal pump VFD, which is the preferred method for communication. Both PWT MCC and the water treatment PLC are in acceptable condition for the addition of a solar thermal system.

5.3 SOLAR THERMAL COLLECTOR SUPPORT

5.3.1 STG Rooftop

Area A previously supported cooling tower (CT) #6 on structural steel framing above the STG #6 rooftop. CT #6 consisted of four CTs that have since been removed and only primary steel members exist. Based on the old aerial photographs and CT shop drawings, the CTs were substantial in size compared to the proposed solar thermal collectors. Therefore, the existing primary structural steel is assumed to be adequate to support the proposed solar thermal collectors and associated loads. Solar thermal system loading should be verified during detailed design. From visual observation, the existing steel should be in fairly good condition. It is proposed that secondary steel members and grating be added to support the solar thermal collectors and provide access to them during installation and maintenance. Access would be required from the existing roof to Area A. The existing top of steel (TOS) elevation is approximately 15’-0” above the roof elevation of 738’-0”.

Area B previously supported CT # 9 on structural steel framing above the STG #9 rooftop. CT #9 consisted of four CTs that have since been removed and only primary steel members exist. MU has provided shop drawings for the CTs. Based on the shop drawings, the wet condition (operating) weight for four CTs is approximately 91,864 pounds. This weight is considered to be substantial compared to

that of the, proposed solar thermal collectors. Therefore, the existing structural steel is assumed be adequate to support the new gravity and lateral loads of the solar thermal collectors. Solar thermal system loading should be verified during detailed design. From visual observation, the existing steel appears to be in fairly good condition. It is proposed that secondary steel members and grating be added to support the solar thermal collectors. Access would be required from the existing roof to Area B. The existing TOS elevation is 776’-0”.

5.3.2 North Deaerator Rooftop

Area C references the rooftop above the north deaerator. Previously, a wood structure supported two CTs that have since been removed. The rooftop itself acted as a basin for these CTs. Based on the old aerial photographs and CT shop drawings, the CTs were substantial in size compared to the proposed solar thermal collectors. Therefore, the existing primary structural steel is assumed to be adequate to support the gravity and lateral loads of the proposed solar thermal system. From visual observation, the existing steel appears to be in fairly good condition. It is assumed that this rooftop would be stripped down to its primary structural steel and a new roof would be installed. It is recommended that MU have the roof designed in such a way that the solar thermal collectors may be mounted directly to it. The existing stair access to Area C should be adequate for solar thermal collector installation and maintenance access. The existing TOS elevation is 776’-0”.

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CHAPTER 6.0

ECONOMIC AND ENVIRONMENTAL ANALYSIS

6.0 ECONOMIC AND ENVIRONMENTAL ANALYSIS

6.1 COST

The costs associated with the design, purchase, and installation of a solar thermal system utilizing evacuated-tube collectors was evaluated. The vendor pricing, included in Appendix B, is specific to an installation at the MU CHP Plant, but equipment costs can be considered universal. Cost data was provided by UTC and obtained through a preliminary design walkthrough at the MU CHP Plant. The costs presented should be considered ±40-percent budgetary values. Information on the equipment specified by UTC may be reviewed in Appendix A.

Based on the equipment and installation proposals and internal estimates, the overall cost to engineer, procure, and construct the proposed MU CHP Plant solar thermal system is approximately $553,000. This cost can be broken down to two different categories: direct costs and indirect costs. The direct cost is the highest among these categories because it encompasses all the equipment, installation, materials, and startup assistance required. A large portion of the direct cost in this estimate is associated with the required structural modifications. This is not a typical cost for the installation of a solar thermal system, but for the MU CHP Plant, this is a requirement. The steel portion of the estimate is approximately $116,000. The other direct costs total approximately $387,000: $162,000 for equipment and $225,000 for installation. The indirect costs only include engineering, because all contractor mark-up is included in the equipment costs. No amount has been included for permitting, owner's costs. These indirect/engineering costs are estimated to be approximately $50,000.

Since these are ±40-percent budgetary values, no contingency has been included in the cost estimate. For planning purposes, a contingency may be necessary for an event or circumstance that is possible but cannot be predicted with certainty. Table 6-1 illustrates the estimated cost to implement the proposed solar thermal system at the MU CHP Plant.

Table 6-1: MU Evacuated-Tube Solar Thermal System Cost Summary

	123-Collector System @ MU
Equipment	$162,000
Installation and Material	$341,000
Engineering	$50,000
Total	$553,000

Notes:
1) Financing costs are not included.

Table 6-2 illustrates a generic cost summary for 50-collector, 100-collector, and 150-collector systems. These systems are similar to the solar thermal system described in this report without the site specific requirements at the MU CHP Plant. The costs presented should be considered ±40-percent budgetary values.

Table 6-2: Evacuated-Tube Solar Thermal System Cost Summary

	50-Collector System	100-Collector System	150-Collector System
Equipment	$68,000	$132,000	$196,000
Installation and Material	$145,000	$200,000	$255,000
Engineering	$21,000	$33,000	$45,000
Total	$234,000	$365,000	$496,000

Notes:
1) Financing costs are not included.
2) Installation and Material costs will vary depending on site conditions. Values for 50-Array, 100-Array, and 150-Array are estimated typical installation costs.

6.2 SAVINGS

The savings and payback analysis associated with the design, purchase, and installation of a solar thermal system that utilizes evacuated-tube collectors are shown in Table 6-3. This analysis is based on the projected industrial fuel prices for coal, coal/biomass blend, natural gas, electric, and propane. Fuel prices were extracted from the DNR 2011 Annual Energy Report and are shown in Figure 6-1.

The savings and payback period were calculated on the assumption that all the thermal energy provided by the solar thermal system would replace the thermal energy provided by an existing heat generation system, operating on one of the evaluated fuels. The savings in accordance with this assumption are derived from the cost of fuel, since there are no fuel costs associated with a solar thermal system. An efficiency of 85 percent was included in the savings calculations for the hypothetical heat generation system.

The solar thermal production is based on 90-percent solar thermal system efficiency, an hourly output of 226 Btu/ft^2 of absorber area, and 5.5 hr/day of sunlight. The sunlight value is a conservative, full-sun value, obtained from a national database and provided by UTC. The number is considered conservative because evacuated-tube solar thermal collectors still operate during periods of cloud cover (at reduced efficiencies).

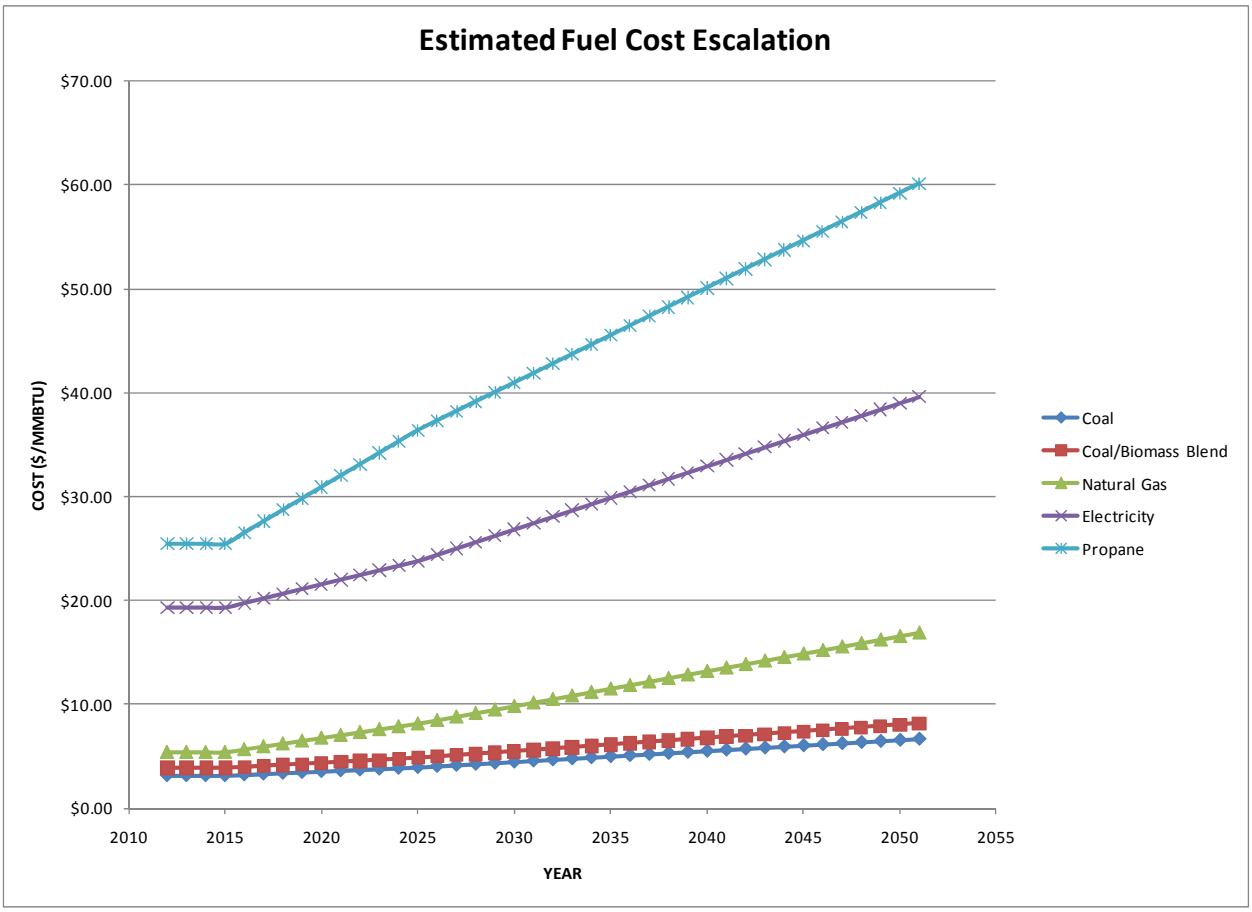
Table 6-3: Evacuated-Tube Solar Thermal System Savings and Payback

	50-Collector System	100-Collector System	123-Collector System @ MU	150-Collector System
Collector Absorber Area (ft^2)	31	31	31	31
# of collectors	50	100	123	150
System Absorber Area (ft^2)	1,550	3,100	3,813	4,650
Hourly Output (Btu/ft^2)	226	226	226	226
Hourly System Output (90% EFF.) (Btu)	350,000	700,000	861,000	1,050,000
Annual Output (MMBtu)	703	1,405	1,728	2,108
Estimated System Cost	$234,000	$365,000	$553,000	$496,000
Estimated First Year Savings				
Coal	$2,600	$5,200	$6,400	$7,900
Coal/Biomass Blend	$3,200	$6,400	$7,900	$9,600
Natural Gas	$4,500	$9,000	$11,000	$13,400
Payback Period (years)				
Coal	>40	>40	>40	>40
Coal/Biomass Blend	>40	39	>40	37
Natural Gas	32	27	31	25
Purchased Power	14	11	-	10
Propane	11	9	-	8

Notes:

1) Payback periods are based forcasted costs of fuels from the DNR 2011 Annual Energy Outlook, Appendix C, Table C3 - Energy Prices by Sector and Source utilizing industrial pricing in nominal dollars/MMBtu.
2) Savings include an 85% efficiency on exising heat generating system.
3) Solar thermal system output is based on 90% system efficency and 5.5 hours/day of sunlight.
4) Savings and payback values do not include possible savings from emission reduction
5) The 123-collector system @ MU cost estimate inludes site specific installation costs.
6) Financing costs are not included.

Figure 6-1: DNR 2011 Annual Energy Report Escalated Fuel Prices



The payback analysis revealed that replacing an electric or propane-powered heat generation system with a solar thermal system has the fastest payback of the evaluated fuels. For replacement of natural gas-powered heat generation, the payback period is less than the estimated useful life of an evacuated-tube solar thermal system. Therefore, the solar thermal system should, at least, pay for itself. The payback period for replacing coal or coal/biomass-powered heat generation exceeds the estimated useful life of an evacuated-tube solar thermal system. At these estimated industrial fuel prices, replacing a coal-powered heat generation system is not a reasonable investment. However, entities with higher coal costs may have an opportunity for a solar thermal system to be a sensible financial investment. Figures 6-2 through 6-6 illustrate the savings generated by a solar thermal system over the years of ownership. These figures are based on the evaluated fuels that may be replaced by a solar thermal system.

Figure 6-2: Evacuated-Tube Solar Thermal System Coal Replacement Savings

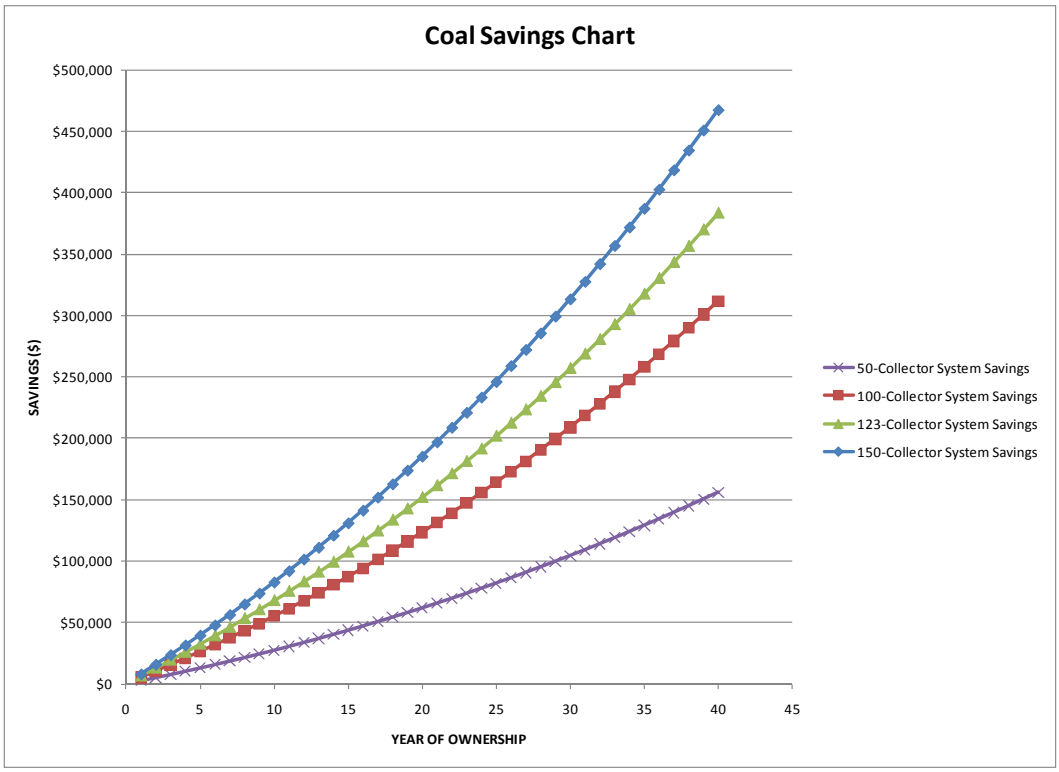


Figure 6-3: Evacuated-Tube Solar Thermal System Coal/Biomass Replacement Savings

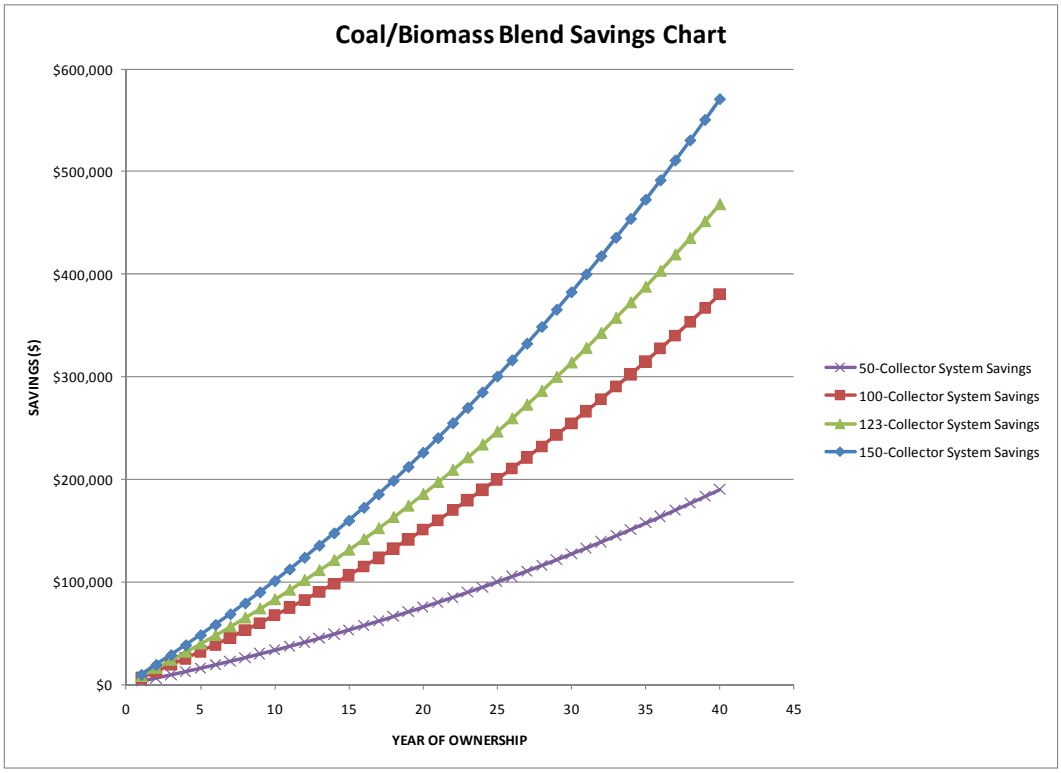


Figure 6-4: Evacuated-Tube Solar Thermal System Natural Gas Replacement Savings

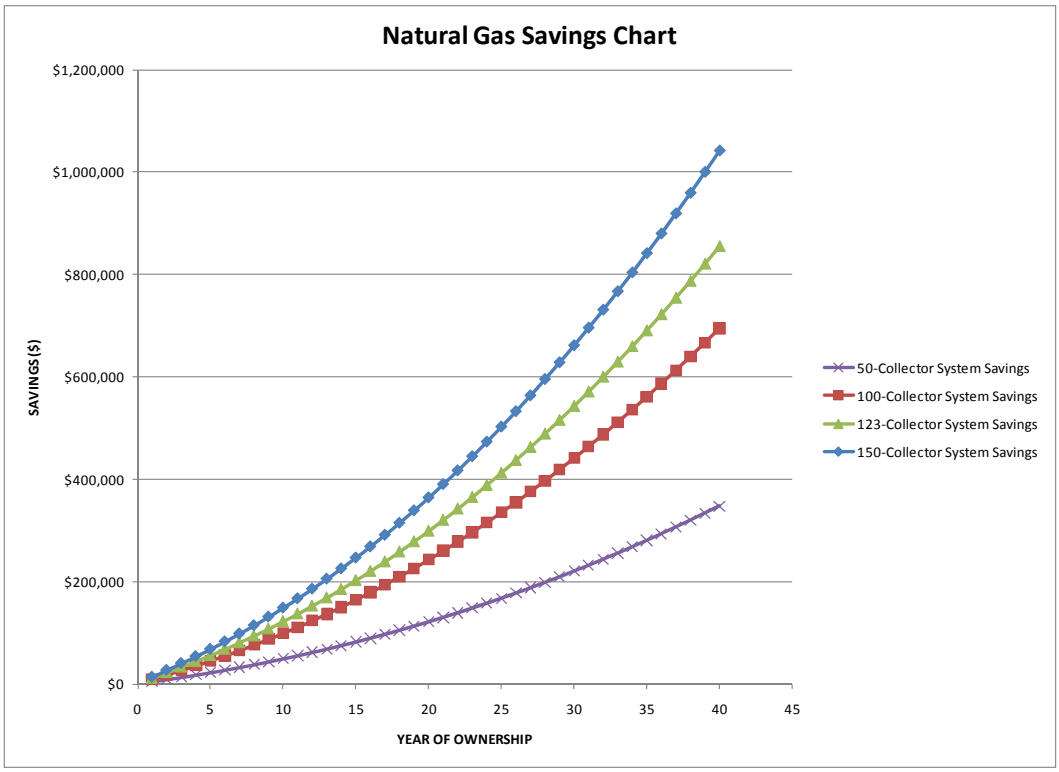


Figure 6-5: Evacuated-Tube Solar Thermal System Electric Replacement Savings

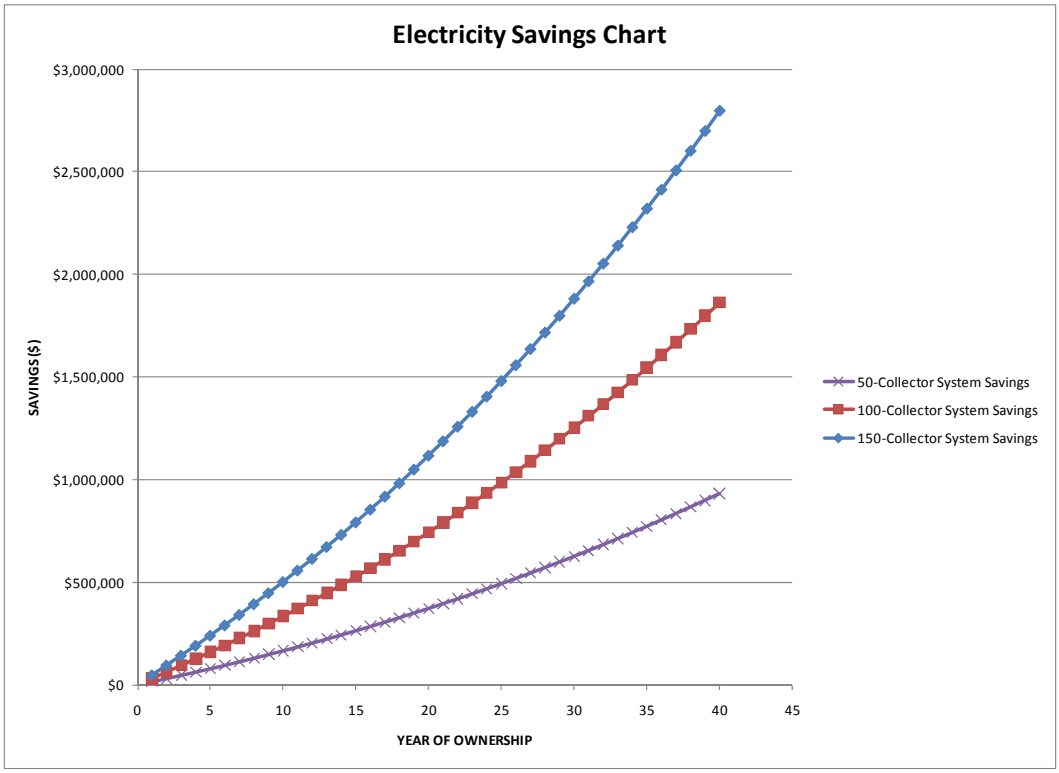
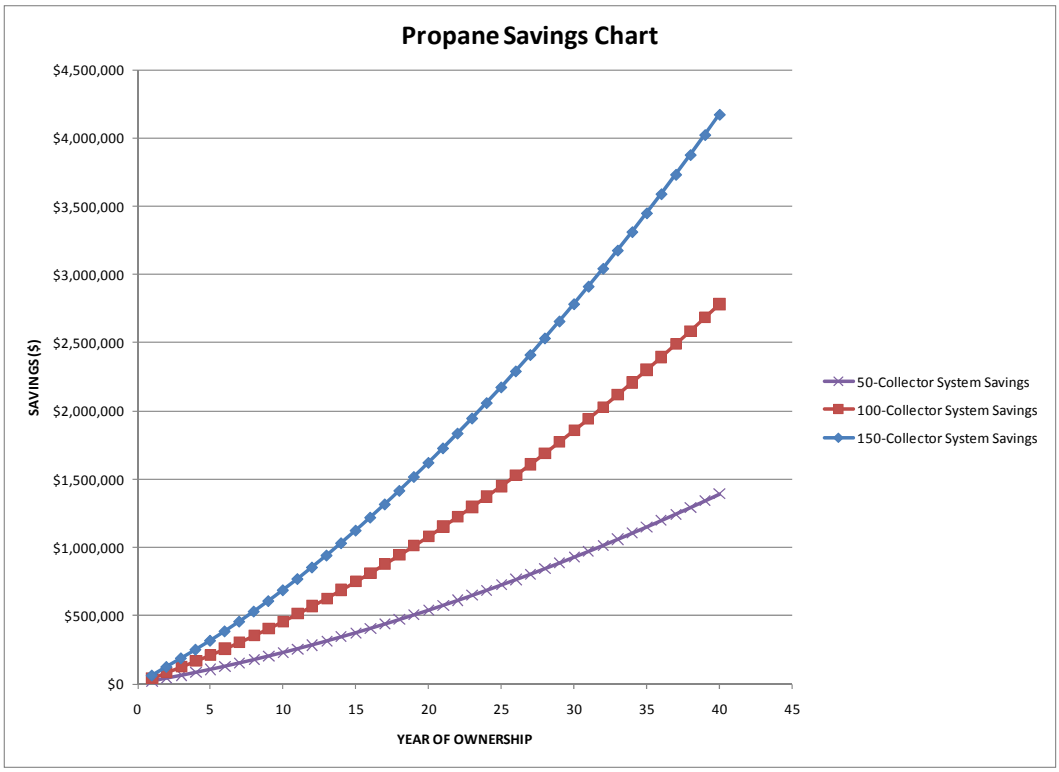


Figure 6-6: Evacuated-Tube Solar Thermal System Propane Replacement Savings



6.3 ENVIRONMENTAL CONSIDERATIONS

In addition to cost savings, another positive attribute of replacing a traditional fuel-powered heat generation system with a solar thermal system is the reduction in environmental impact. Specifically, there is the potential to reduce the greenhouse gas emissions and Hazardous Air Pollutants (HAP). The magnitude of emission reduction is dependent on the type of system and fuel that the solar thermal system would be replacing and the size of said solar thermal system.

Table 6-4 summarizes the emission reductions of replacing a fuel-powered heat generation system with a solar thermal system. The calculations used to generate this table are based on the National Emission Standards for HAPs. Information regarding these limits was extracted from the Industrial Boiler MACT Rule and New Source Performance Standards (NSPS). The Industrial Boiler MACT rule applies to industrial, commercial or institutional boilers or process heaters at facilities deemed a major source of HAP emissions. That includes any facility whose operations collectively emit more than 10 tons per year of any single HAP or 25 tons per year of any combination of HAPs. The rule requires each boiler at a facility to meet emission limits or work practice standards, meet operating limits and demonstrate compliance on both an annual and a continuous basis.

NSPS are standards established by the United States Environmental Protection Agency under the authority of the Clean Air Act. Information on the NSPS was extracted from 40 CFR Part 60 Subpart Db, which applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 MMBtu/hr.

Table 6-4 should be considered a conservative estimate for emission reduction because the majority of sources required to comply with the Industrial Boiler MACT are not in compliance. The Industrial Boiler MACT was recently put on hold and the compliance date would likely be after March 2014. Replacing a fuel-powered heat generation system prior to compliance with the Industrial Boiler MACT rule should have a greater positive environmental impact. Using the NSPS limits adds another level of conservatism. These emission limits only apply to newer and newly modified natural gas boilers. Older boilers have a higher emission limit, which would lead to a greater positive environmental impact if replaced by a solar thermal system. Furthermore, there are many fuel-powered heat generation systems that do not fit the criteria to have emission limits. These systems likely produce harmful emissions and should be evaluated when considering their replacement with a solar thermal system so the full benefit of the system may be realized.

Table 6-4: Emissions Reduction Estimate

Fuel/System	Annual Emission Prevention (lb)					
	Particulate Matter (PM)	Hydrogen Chloride (HCl)	Mercury (Hg)	Mono-Nitrogen Oxides (No_x)	Carbon Monoxide (CO)	Volatile Organic Compounds (VOC)
Coal[1]						
50-Collector System	32	29	0.0038	n/a[4]	223,187	n/a[4]
100-Collector System	64	58	0.0076	n/a[4]	446,374	n/a[4]
123-Collector System @ MU	79	71	0.0094	n/a[4]	549,039	n/a[4]
150-Collector System	97	87	0.0114	n/a[4]	669,560	n/a[4]
Biomass[2]						
50-Collector System	32	29	0.0038	n/a[4]	405,043	n/a[4]
100-Collector System	64	58	0.0076	n/a[4]	810,085	n/a[4]
123-Collector System @ MU	79	71	0.0094	n/a[4]	996,405	n/a[4]
150-Collector System	97	87	0.0114	n/a[4]	1,215,128	n/a[4]
Natural Gas[3]						
50-Collector System	n/a[4]	n/a[4]	n/a[4]	83	2,612	1,404
100-Collector System	n/a[4]	n/a[4]	n/a[4]	165	5,224	2,808
123-Collector System @ MU	n/a[4]	n/a[4]	n/a[4]	203	6,426	3,454
150-Collector System	n/a[4]	n/a[4]	n/a[4]	248	7,836	4,212

1) Coal emission limits are based on the Industrial Boiler MACT Rule Emission Limits for a Coal Stoker Boiler
2) Biomass emission limits are based on the Industrial Boiler MACT Rule Emission Limits for a Biomass Stoker Boiler
3) Natural gas emission limits are based NSPS Subpart Db requirements for industrial, commercial, and institutional steam generating units
4) Denotes that an emission limit has not been established

The potential CO_2 emissions reduction that would result from the installation of a solar thermal system was also evaluated. For this estimate, it was assumed that any thermal energy produced by the solar thermal system would offset steam production in existing coal-fired boilers. Table 6-5 summarizes the estimated CO_2 emissions reduction. The calculations used to populate this table are based on the 2010 EPA eGRID CO_2 emission rate and 85-percent boiler efficiency.

Table 6-5: CO2 Emissions Reduction Estimate

	50-Collector System	100-Collector System	123-Collector System @ MU	150-Collector System
Annual Output (MMBtu)	703	1405	1728	2108
2010 eGRID CO_2 Emission Rate (lb/MMBtu)	236	236	236	236
Estimated Annual CO_2 Reduction (tons)	83	166	204	249

Notes:
1) CO_2 emission rate based on EPA 2010 eGRID values.
2) CO_2 emission rate assumes 85% boiler efficency.

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APPENDIX A

VENDOR INFORMATION

APPENDIX B

COST ESTIMATE AND BUDGETARY PROPOSALS

APPENDIX C

PRELIMINARY DESIGN DOCUMENTS