Design, Simulation, and Analysis of Domestic Solar Water Heating Systems

in Phoenix, Arizona

by

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ABSTRACT

Research was conducted to quantify the energy and cost savings of two different domestic solar water heating systems compared to an all-electric water heater for a four-person household in Phoenix, Arizona. The knowledge gained from this research will enable utilities to better align incentives and consumers to make more informed decisions prior to purchasing a solar water heater.

Daily energy and temperature data were collected in a controlled, closed environment lab. Three mathematical models were designed in TRNSYS 17, a transient system simulation tool. The data from the lab were used to validate the TRNSYS models, and the TRNSYS results were used to project annual cost and energy savings for the solar water heaters.

The projected energy savings for a four-person household in Phoenix, Arizona are 80% when using the SunEarth® system with an insulated and glazed flat-plate collector, and 49% when using the FAFCO® system with unglazed, non-insulated flat-plate collectors. Utilizing all available federal, state, and utility incentives, a consumer could expect to recoup his or her investment after the fifth year if purchasing a SunEarth® system, and after the eighth year if purchasing a FAFCO® system. Over the 20-year analysis period, a consumer could expect to save $2,519 with the SunEarth® system, and $971 with the FAFCO® system.

DEDICATION

This work is dedicated to my family,

Edouard, Nathalie, Sibylle, Benjamin, and Kayci,

who have given me the inspiration that has made this effort possible.

ACKNOWLEDGMENTS

The following people have assisted and influenced my work. I thank each one of them for the role they played in the completion of my thesis.

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CHAPTER 1

INTRODUCTION

Over the past decade, there has been a renewed interest in renewable and sustainable electricity generation. With the world's population and energy demands continuing to grow, citizens and governments have begun adopting long-term energy strategies and environmental restrictions. These policies are enacted due to several factors, including finite fossil fuel availability, increasing energy costs, and a renewed focus on environmental protection. In the United States, and specifically in Arizona, this has led to renewable energy mandates for electrical utilities [1]. In order to facilitate and promote new renewable energy targets, federal governments, state governments, and utilities offer tax rebates, credits, and other incentives to help companies and consumers make investments in renewable energy. One such incentive is for the replacement of electric- and gas-powered water heaters with solar water heating systems [2]. In order to accurately assign incentives and set cost saving expectations for its customers, utilities have begun testing and modeling solar water heating systems to determine their effectiveness.

1.1 Problem Statement

Currently, federal and state governments and local utilities provide financial incentives to install solar water heaters. These incentives, and the cost savings expectations of the consumer, are often based on national averages that may vary greatly in different geographic regions. As a result, utilities and consumers are often uncertain of the cost savings and payback periods of these investments, and may be left to rely on marketing materials or sales pitches. The objective of this research was to quantify the energy and cost savings of two different domestic solar water heating systems compared to an all-electric water heater. This was done for a four-person household in the Phoenix, Arizona metropolitan area. Using location-specific data, local Phoenix-area utilities will be able to better align incentives and consumers will be able to make more informed and accurate decisions.

1.2 Objectives

The following objectives will be the focus of this research:

- Quantify Phoenix-area hot water usage and environmental conditions for a four-person household
- Install three water heaters in a controlled lab environment and develop an automated water draw system
- Collect energy usage data on-site
- Develop a TRNSYS simulation for each water heater
- Validate TRNSYS energy usage outputs with lab results
- Use TRNSYS to quantify annual energy and cost savings of solar water heaters
- Provide recommendations for future research

1.3 Research Summary

The following research was conducted in order to determine the energy and cost savings of the two solar water heating systems compared to the all-electric control unit. First, the three water heating systems were installed in the lab. These were the Bradford White® all-electric heater, used as a control unit, the SunEarth® SolaRay™ solar water heating system, and the FAFCO® 500 Series solar water heating system. The water draw schedule, inlet cold water temperature, outlet hot water temperature, and ambient air temperature were controlled, and energy usage data was collected in the lab. Next, detailed technical specifications of the water heating systems, as well as the controlled water draw schedule and water and ambient air temperatures, were input into a transient system simulation software tool (TRNSYS). Performance ratings from the Solar Rating and Certification Corporation were also utilized for analytical modeling in the TRNSYS simulations. The data collected in the lab were then used to validate the TRNSYS models. Then, a separate set of TRNSYS models were developed using historical average Phoenix, Arizona water main and ambient air temperatures from the National Renewable Energy Laboratory database. The results of these models were used to determine annual energy savings. The forecast annual energy savings were then used to conduct an economic analysis, which determined the payback period as well as the total cost to operate the three water heaters over a twenty-year analysis period. The economic analysis was done with and without available federal, state, and utility incentives.

CHAPTER 2

REVIEW OF LITERATURE

2.1 Solar Water Heating History and Overview

Consumers purchasing residential solar water heaters have several different types of technologies from which to choose. These different options can be segmented into two functional areas: circulation types and collector types. In order to effectively match a system to a residence and obtain the best results, it is imperative to understand the strengths and weaknesses of each system before making a selection.

2.1.1 Circulation Systems

There are two main types of circulation systems: the direct system and the indirect system. In the direct system, potable water flows directly through the collector. In the indirect system, a non-freezing heat transfer fluid (HTF) runs through the collector and then passes on its heat to the water through a heat exchanger.

The simplest form of circulation types is the direct system. In this system, water is circulated through roof-mounted solar collectors and is heated by the sun's energy. This heated water can be used directly or can be sent to a tank to be stored until it is used. Since the water is sent directly to the solar water collector, this type of system is at risk of freezing in cold climates, and can only be used in warm climates where freezing temperatures do not occur. Because direct systems are not protected from freezing, they are not very common.

Water in direct systems can be either actively cycled or passively cycled. In an active system, pumps are used to force water through the collectors. In a passive system, the hot water rising, through natural convection, will move the water from the collector to the storage tank as it heats up. With passive systems, it is recommended that the storage tank be at a greater height than the solar collector, or the system may not function effectively. It is also necessary to protect the hot water from moving from the storage tank back down to the solar collector when the sun is not shining. Because of this added uncertainty, consumers prefer the actively pumped method. In direct systems, a backup electric heating element or a natural gas water heater is generally used to keep the water at a set minimum temperature.

A passive, direct circulated system is depicted in Figure 1 below.

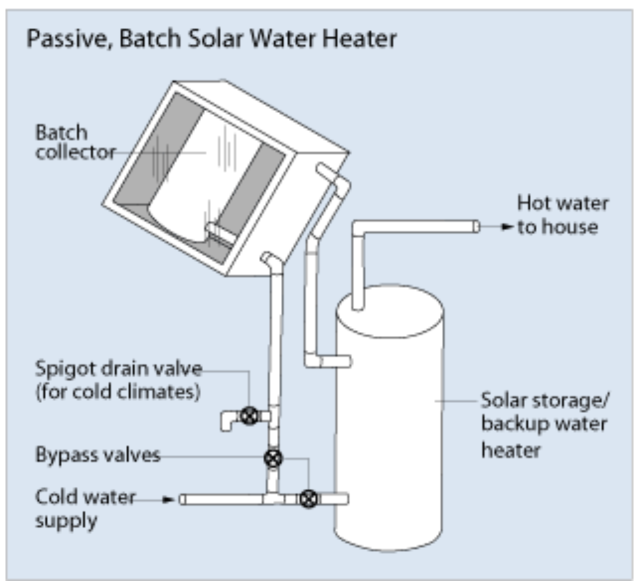

Figure 1. Direct System with Passive Circulation [3].

The second type of circulation system is the indirect, or closed-loop system. In climates where freezing does or may occur, it is necessary to utilize an indirect system. In this system, a non-freezing HTF is cycled through the collector instead of the potable water. The most commonly used fluid is a mixture of water and propylene glycol. It is recommended that the minimum amount of propylene glycol necessary to avoid freezing be used, as water is a better transfer agent of heat than propylene glycol [4]. After the HTF is heated in the collector, it passes through a heat exchanger and transfers its heat to the potable water. Then, the HTF continues its loop and returns to the solar collector to reheat. While the indirect system is necessary for climates where freezing temperatures occur, it also works well in hot climates. As in direct systems, a backup electric heating element or a natural gas water heater is generally used to keep the water at a set minimum temperature.

Indirect systems are configured with either one or two storage tanks. When configured with a single tank, the tank has one or two backup electric heating elements and a heat exchanger. The tank can also be heated with natural gas instead of electric elements. When configured with two tanks, the first tank is used as a preheat tank with a heat exchanger, and the second tank is used as a storage tank prior to use, and includes the heating elements. Water from the preheat tank will be used to fill the final storage tank, reducing the amount of heating required by natural gas or electricity.

The HTF in direct systems is typically actively cycled. A combination of electric pumps, valves, and controllers is necessary to force the HTF up to the solar collector and then back down to the heat exchanger. An active system is depicted in Figure 2 on the following page.

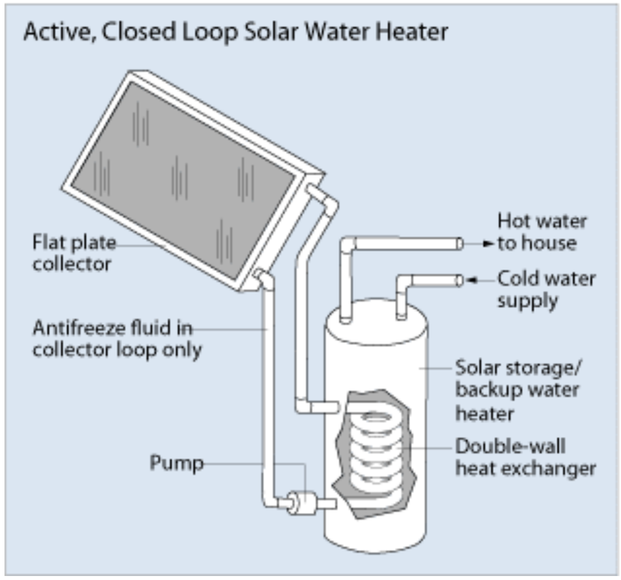

Figure 2. Indirect System with Active Circulation [3].

2.1.2 Collector Types

There are four main types of collectors used in domestic solar water heating systems. These are the batch collectors, glazed and insulated flat-plate collectors, unglazed and non-insulated flat-plate collectors, and evacuated tube collectors [4].

A batch collector, otherwise known as an integrated collector storage system (ICS), is only used in direct systems where the potable water is pumped directly through the collector. These systems do not have freeze protection, and therefore should not be used in cold climates where freezing temperatures occur. Batch collectors heat water in either dark tanks or in tubes placed in an insulated box. The water can remain in the collector until it is hot, or for extended periods of time. As a result, the water temperature can get dangerously hot, and the system should incorporate a tempering valve to mix in cold water which prevents scalding at the tap. The batch collector is depicted in Figure 3 on the next page.

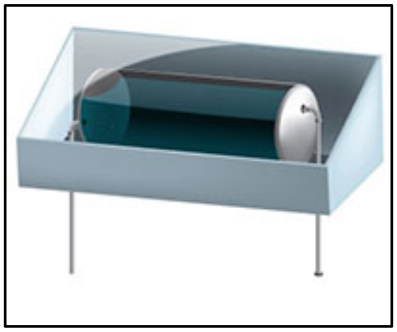

Figure 3. Batch Solar Collector [5].

Flat-plate collectors are the most commonly used collector type for domestic solar water heating [4]. A glazed and insulated flat-plate collector consists of an insulated rectangular box that is typically four feet wide by eight feet long, with a depth of approximately one-half foot. Inside the box is a series of copper tubes surrounded by flat absorber plates. The copper tubes are configured three to six inches apart and are connected at one end to an inlet pipe and at the other end to an outlet pipe. The water runs through the pipes inside the insulated box, which is covered by a glazed and tempered sheet of glass. In a direct circulation system, water runs through the collector, while in an indirect circulation system, the HTF will run through the collector. The insulation helps prevent heat loss due to convection and improves performance in cooler weather. A glazed flat-plate collector is depicted in Figure 4 on the following page.

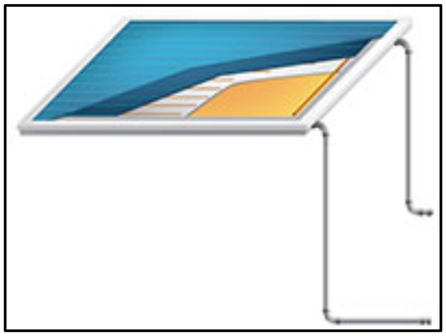

Figure 4. Glazed Flat-Plate Solar Collector [5].

Unglazed copolymer collectors are similar to the glazed flat-plate collectors, except that they are not encased in a box and are not insulated. They are comprised of proprietary plastics with ultra violet coatings which resist degradation caused by extreme temperatures and direct sunlight [6]. While most commonly used in direct circulation pool systems, this collector design is also used in indirect domestic solar water heating systems, which use an HTF. The collectors are black, unglazed, and configured in a web and tube extruded mat. At the top of the collector is a riser header, which is followed by riser tubes separated by a web. The collector ends at the bottom with another header. The fluid will flow from the top header, through the plastic tubes, down to the bottom header. Unglazed copolymer collectors have recently become popular in indirect domestic solar water heating applications due to their low cost of materials and simplicity. Unglazed and non-insulated collectors are less efficient in winter months than the glazed and insulated type, since the fluid loses heat when the outdoor ambient temperature is low or when wind increases convection losses around the collectors. An unglazed flat-plate collector is depicted in Figure 5 on the following page.

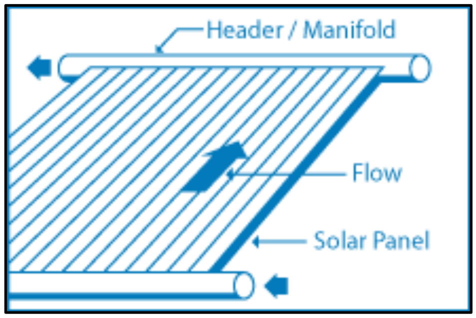

Figure. 5. Unglazed Flat-Plate Copolymer Solar Collector [6].

The fourth common design is an evacuated tube collector. These systems work by heating water or an HTF inside a glass or metal pipe, which is surrounded by a larger glass tube. The space between the inner tube and the outer tube is a vacuum, so very little heat will be lost. This heat retention potential is similar to a vacuum Thermos®. Since the tubes are well insulated, these systems can maintain high efficiency even in very cold conditions down to minus 40° F [4]. The downside of this highly efficient system is that it costs twice as much as a flat-plate collector. The evacuated tubes are also more fragile than a flat-plate collector, and may not be as aesthetically pleasing on a roof as the thinner flat-plate collector. Finally, since these systems are more fragile, they are not recommended in climates where significant snow may accumulate. In climates with minimal snow accumulation, these systems still need to be installed at higher angles than the roof, which reduces the amount of snow accumulation. An evacuated tube collector is depicted in Figure 6 on the following page.

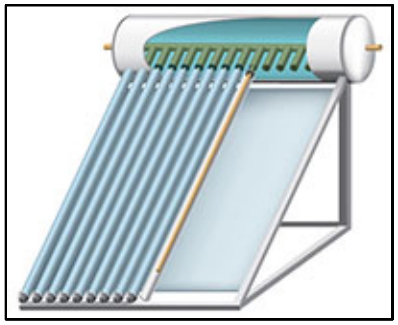

Figure 6. Evacuated Tube Solar Collector [5].

2.2 Solar Rating and Efficiency Corporation Ratings

In this thesis, performance ratings and specifications obtained from the Solar Rating and Efficiency Corporation (SRCC) were necessary for analytical modeling of the solar thermal systems using the TRNSYS software. The SRCC was incorporated in 1980 by the trade association for the solar energy industry and a national consortium of state energy offices with the goal of providing nationalized ratings for the solar thermal industry. Today, through a network of accredited testing facilities, the SRCC works as an independent agency to test and certify solar thermal components [7].

Certifications for the solar collectors are titled OG-100. The SRCC provides specific testing requirements under its Document OG-100, "Operating Guidelines for Certifying Solar Collectors," and its accompanying document, SRCC Standard 100, "Test Methods and Minimum Standards for Certifying Solar Collectors." Testing is done to determine both durability and performance. The test procedures for performance are specified by the American Society of Heating, Refrigerating, and Air Conditioning Engineers using the ASHRAE Standard 93, "Methods of Testing to Determine the Thermal Performance of

Solar Collectors," and ASHRAE Standard 96, "Methods to Testing to Determine the Thermal Performance of Unglazed, Flat Plate, Liquid Solar Collectors [7]."

Performance ratings are reported in either linear equations or quadratic equations. The more precise quadratic equations were used in the TRNSYS models, when available, in order to accurately reflect the changing efficiency slope [8]. The quadratic performance equation is below in Equation 1:

$$Performance = a_0 - \frac{a_1(T - T_{Amb})}{G} - \frac{a_2(T - T_{amb})^2}{G} \tag{1}$$

where:

a_0	is the dimensionless intercept parameter (dimensionless)
a_1	is the 1st order efficiency coefficient ($W/m^2 \cdot K$)
T	is the heat transfer fluid temperature (C)
a_2	is the 2nd order efficiency coefficient ($W/m^2 \cdot K^2$)
T_{amb}	is the ambient air temperature (C)
G	is the total solar radiation incident on the collector (W)

When collector tests are performed on clear days at normal solar incidence levels, the transmittance-absorbance product is essentially the same as the normal incidence value for beam radiation. To account for variations, the intercept efficiency is corrected for non-perpendicular solar incidence by the use of incidence angle modifiers (IAM). The SRCC performs an incident angle modifier test to determine how the collector will perform over a varying range of sun angles, and these modifiers alter the efficiency curve to account for these changes in performance. For flat-plate collectors, two incidence angle modifier

(IAM) coefficients are given, which are represented as b_0 and b_1, and are based on Equation 2 below [8].

$$IAM = 1 - (b_0 * S) - (b_1 * S^2) \quad (2)$$

where:

S is $1 / [cos\ (Incidence\ angle) - 1]$

b_0 is the first order modifying factor (dimensionless)

b_1 is the second order modifying factor (dimensionless)

Using the above equations, combined with geographic parameters such as temperatures, latitude, and solar radiation data, the overall performance of the collectors can be modeled in TRNSYS in any location and in any environment.

CHAPTER 3

METHODOLOGY

3.1 Overview

The TRNSYS simulations and field study were both designed to mimic the average usage of a four-person household in the Phoenix, Arizona metropolitan area. Research was conducted to best estimate hot water temperatures and usage, and the results were used to design distinct water draws. All other parameters were set to simulate weather conditions in Phoenix, Arizona.

3.2 Water Heating Systems

Three different water heating systems were utilized in the study: an all-electric Bradford White® water heater, a SunEarth® SolaRay™ glazed flat-plate collector system with a single tank, and a FAFCO® 500-Series unglazed flat-plate collector system with two storage tanks. First, an overview of each system will be presented, followed by a detailed explanation of the solar collector technology.

3.2.1 All-Electric System Overview

The all-electric control unit was a Bradford White®, 50-gallon, 2-element electric water heater. The unit, model number M-2-50T6DS, includes automated temperature controls for its two immersed, copper screw-in elements. Each element is rated at 4,500 watts, and the two elements do not work simultaneously. The elements work in a master/slave relationship. If the top element is on, the bottom element will remain off. The system operates at 240 volts and a maximum of 4,500 watts. The inside of the tank features Bradford White's Vitraglas® lining to reduce the corrosive effects of hot water, and the outside of the tank is lined with two inches of non-Chlorofluorocarbon foam insulation [9]. In the lab and simulations, the water temperature was set at 125° F.

3.2.2 Glazed Flat-Plate Collector System Overview

The first solar water heating system was a SunEarth® SolaRay™ unit with a glazed flat-plate collector. The unit actively cycles the HTF through the solar collector using a single pump. The HTF consists of 30% DowFrost™ HD propylene glycol and 70% water, which keeps the fluid from freezing to 9° F. The SunEarth® system is a single tank unit with an 80-gallon capacity. The tank serves the dual purpose of preheating the water using solar thermal energy and heating the water using electric heating elements.

The tank includes a single 240-volt, 4,500-watt immersed copper element at the middle of the unit. The wrap-around coil heat exchanger is made of type L copper and is 5/8 inches in diameter and 120 feet in length. The coil is wrapped around the outside of the lower end of the tank and is double-walled and vented to ensure that leakage of the HTF does not contaminate the water inside the tank. The coil spans 24 inches of the tank, between two and 26 inches from the bottom. The capacity of the coil is 2.2 gallons [10].

The electronic unit, or differential temperature controller, utilizes temperature sensors to monitor the temperatures of the potable water in the tank and the HTF in the solar collector. The controller used was a SunEarth® model TR 0301 U. When there is usable heat in the HTF, the system turns on the pump to cycle HTF through the heat exchanger coil, which heats the water at the bottom of the tank. When usable heat is not available, the pump is turned off and the system's water is heated by electricity through the electric heating element. The system is set to turn on when the temperature of the HTF in the rooftop collector is 16° F greater than the temperature of the water at the bottom of the tank. When the temperature difference falls below 8° F, the pump is turned off. Also, when the temperature of the water at the bottom of the tank reaches the set point (150° F), the pump is turned off. Once the water temperature has fallen 6° F below the maximum set point, the pump will resume, as long as the temperature differential between the collector and the water is still 16° F or greater. Finally, for safety purposes, the system will also shut off the pump when the HTF reaches 266° F. The system can be adjusted to have an on/off differential between 8 and 20° F and a maximum water temperature set point between 32 and 205° F [11]. In the lab and in simulations, the backup electrical heating element was set to keep temperatures in the tank at a minimum of 125° F. A diagram of the single tank system can be seen in Figure 7 on the following page.

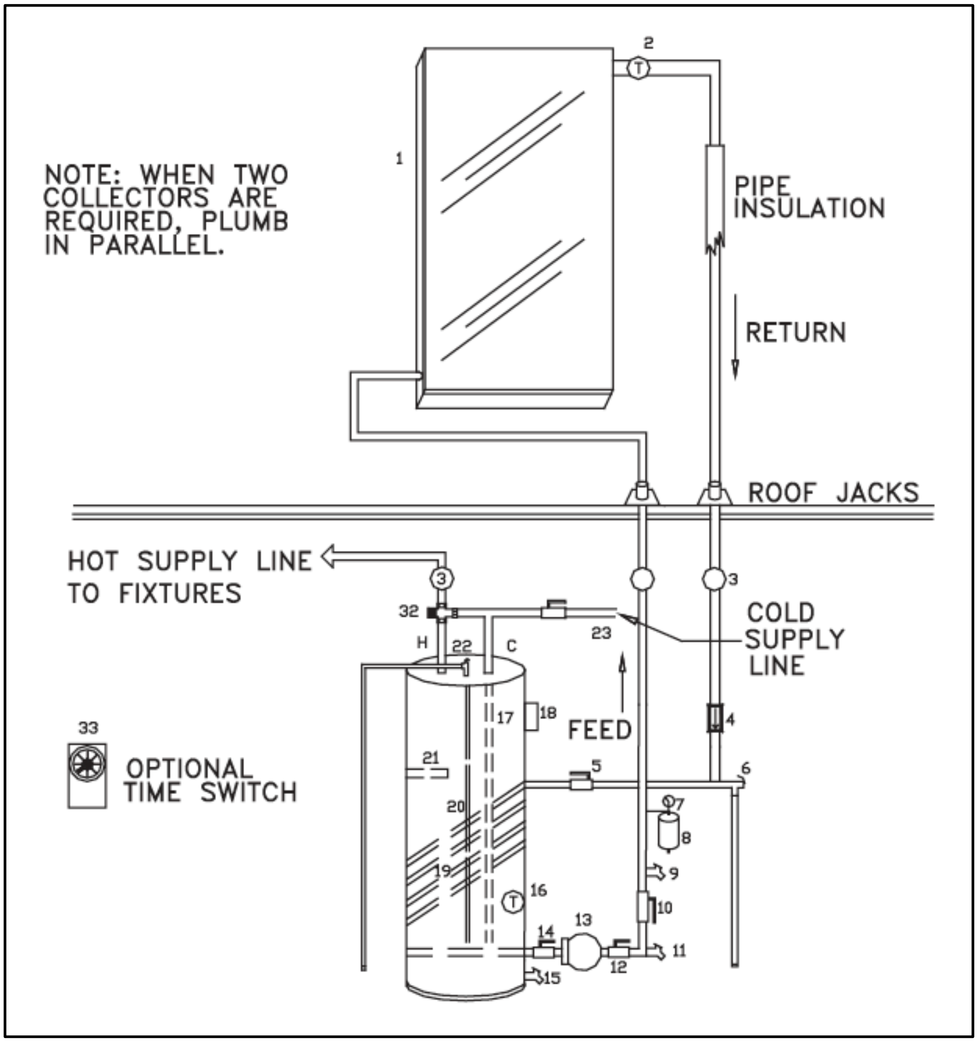

Figure 7. SunEarth® Single Tank Schematic [10]

3.2.3 Unglazed Flat-Plate Collector System Overview

The second solar water heater was a FAFCO® 500 Series dual-tank system. The system is an active-cycled system and uses an HTF consisting of 30% FAFCO®-branded propylene glycol and 70% water, which is sufficient to keep the system from freezing to 9° F. Both the preheat tank and the backup tank are 50-gallon Bradford White® tanks with the same model number as the all-electric experimental control unit. The preheat tank does not contain any electrical elements, but instead has affixed to it a FAFCO® Integrated Circulation Module (ICM) and heat exchanger. The second electric tank has two 4,500-watt heating elements, which are the same as the all-electric unit, which do not run simultaneously and utilize the same master/slave relationship.

Behind the ICM is an external heat exchanger made of 10 copper brazed plates inside a stainless steel enclosure. The HTF is pumped to the roof-mounted solar collectors and back down into the heat exchanger. The ICM will activate the HTF circulation pump and potable water circulation pump when the HTF on the roof is 10° F greater than the water at the bottom of the preheat tank. The system will deactivate the pumps when the HTF temperature on the roof is less than 4° F greater than the temperature of the water at the bottom of the tank. The ICM will also shut off the pumps once the maximum water temperature has been reached, which was set at 150° F, but can also optionally be set to 120° F or 135° F, depending on the requirements of the user [12].

Potable water is filled into the dual-tank FAFCO® system directly into the preheat tank. Water in the preheat tank is cycled through the heat exchanger, which preheats the water before it is pumped into the electric backup tank. When water is drawn from the electric backup tank into the household, hot water from the preheat tank is backfilled into the backup tank, minimizing the use of the electric heating elements in the backup tank. In the lab and simulation, the backup tank's water temperature was set at 125° F. The dual tank setup can be seen in Figure 8 on the following page. The electric backup tank with heating elements is on the left, while the preheat tank with external heat exchanger and ICM is on the right.

Figure 8. FAFCO® 500 Dual Tank Setup [12].

Summary information for the three water heating systems can be seen in Table 1 below, and were taken from the manufacturer specifications sheets [9] [10] [12].

Table 1. Summary System Specifications

	Bradford White®	**SunEarth®**	**FAFCO®**
Model	Energy Saver Upright	SolaRay™	500 Series
System Type	All-electric	Solar w/ electric backup	Solar w/ electric backup
Solar Type	N/A	Indirect, active loop	Indirect, active loop
Product ID	M2-50T6DS-1NCWW	TE40P-80-1	AC-16UX3-50E-50S
Electric Tank	50 gal	80 gal	50 gal
Preheat Tank	N/A	Same as electric	50 gal
Electric Max Watts	4500 W	4500 W	4500 W
Solar Heat Exchanger	N/A	10 brazed copper plates in stainless steel enclosure, measuring 7.51” X 2.87” X 1.94”	120 ft of 5/8” double-walled copper tubing wrapped around tank

3.2.4 Glazed Flat-Plate Collector

The two solar water heating systems were purposefully chosen to reflect the most commonly used domestic solar water heater types and to demonstrate the differences in the two solar collector technologies. While both solar water systems use indirect, forced-circulation systems, they heat the HTF using very different types of collectors.

The SunEarth® collector is the more complex of the two collector technologies. The single, glazed flat-plate collector is comprised of a box insulated with polyisocyanurate and fiberglass. It is also covered with a glazed and tempered sheet of glass. Inside the box resides a series of copper tubes and plates. The HTF is pumped up to the copper riser tubes and manifolds, and flows through parallel copper pipes inside the insulated box. This type of insulated flat-plate collector allows the HTF fluid to rise to higher temperatures than can be obtained by the unglazed flat-plate FAFCO® collectors. The size of the collector is 48.125 inches wide by 122.25 inches long, with a depth of 3.25 inches. The capacity of the fluid in the collector is 1.3 gallons. SunEarth® claims the collector has a design life of 25 to 30 years [13].

The SunEarth® collector was installed parallel to the roof, with a 4/12 pitch, and faces directly south. A diagram of the collector can be seen in Figure 9 on the following page.

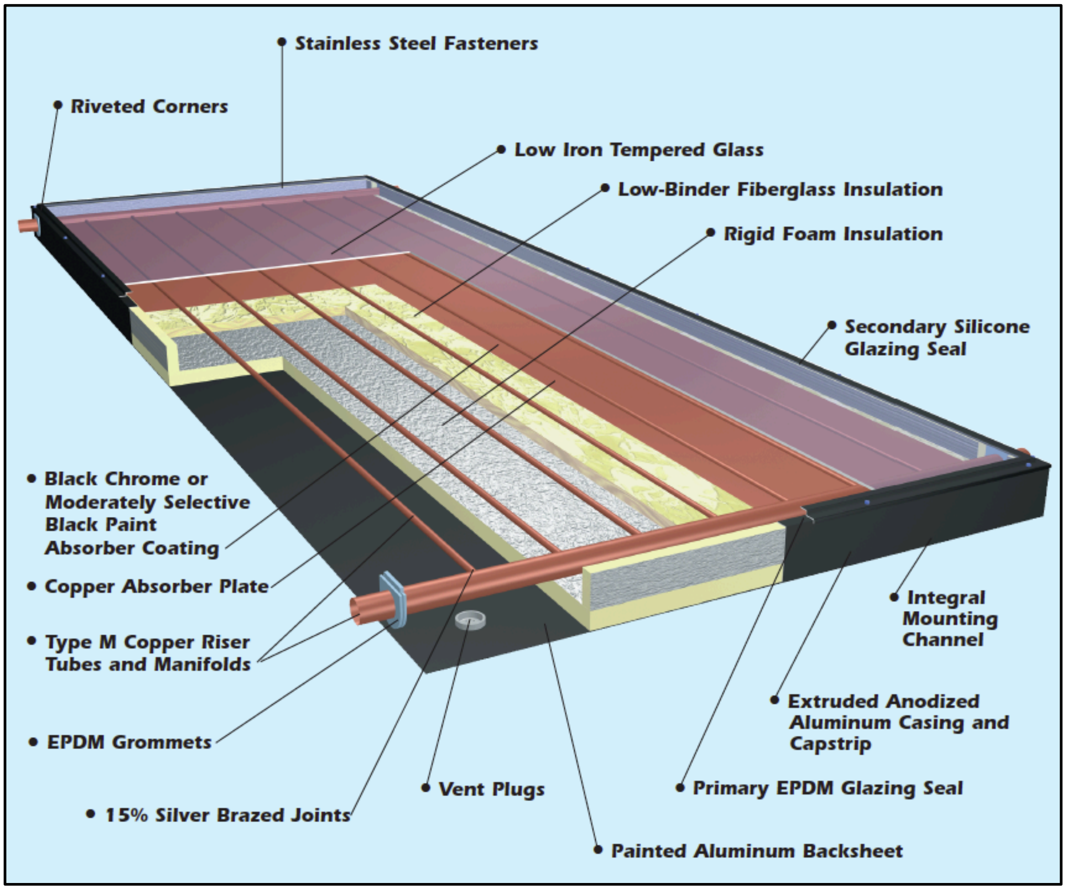

Figure 9: Diagram of the SunEarth® Flat-Plate Collector [13].

The quadratic performance equation from the SRCC for the SunEarth® solar collector is shown on the following page in Equation 3.

$$Performance = a_0 - \frac{a_1(T - T_{Amb})}{G} - \frac{a_2(T - T_{amb})^2}{G} \quad (3)$$

where:

a_0 is the dimensionless intercept parameter (0.718)

a_1 is the 1st order efficiency coefficient (2.29060 $W/m^2 \cdot K$)

T is the heat transfer fluid temperature (C)

a_2 is the 2nd order efficiency coefficient (0.04398 $W/m^2 \cdot K^2$)

T_{amb} is the ambient air temperature (C)

G is the total solar radiation incident on the collector (W)

The incident angle modifiers use the following formula:

$$IAM = 1 - (b_0 * S) - (b_1 * S^2) \quad (4)$$

where:

S is $1 / [cos\ (Incidence\ angle) - 1]$

b_0 is the first order modifying factor (0.322, dimensionless)

b_1 is the second order modifying factor (-0.031, dimensionless)

The flow rate used during the SRCC test was 72 $kg/hr \cdot m^2$, with the test fluid being water at 1 kilogram per liter. The above parameters were also used in the TRNSYS model. A photo of the SunEarth® flat-plate collector is shown in Figure 10 on the following page.

Figure 10. SunEarth® Flat-Plate Collector

3.2.5 Unglazed Flat-Plate Collector

The FAFCO® system uses an uncovered and unglazed ultraviolet-stabilized copolymer solar collector; a material also commonly used for direct-circulation solar pool heaters. The three solar collectors run in parallel and are each eight feet long and two feet wide, with a thickness of 3/16 of an inch. The gross area of the collectors is 48 square feet, and the total combined capacity is 3.3 gallons. According to FAFCO®, the collectors have a corrosion and chemical resistance that is beyond that of any metal, and the panels are expected to last for over 30 years in situations where the temperature reaches not more than 200° F [14]. A vented bladder expansion reservoir is also installed at the top of the panels and can withstand up to 200° F at 1 psi.

As with the SunEarth® collector, the FAFCO® collectors were installed parallel to the roof, with a 4/12, or 18.43 degree, pitch. The collectors also face directly south.

The quadratic performance equation from the SRCC for the FAFCO® solar collector is:

$$Performance = a_0 - \frac{a_1(T - T_{Amb})}{G} - \frac{a_2(T - T_{amb})^2}{G} \quad (5)$$

where:

a_0 is the dimensionless intercept parameter (0.887)

a_1 is the 1st order efficiency coefficient (22.61780 $W/m^2 \cdot K$)

T is the heat transfer fluid temperature (C)

a_2 is the 2nd order efficiency coefficient (-0.17107 $W/m^2 \cdot K^2$)

T_{amb} is the ambient air temperature (C)

G is the total solar radiation incident on the collector (W)

The incident angle modifiers were set using the following formula:

$$IAM = 1 - (b_0 * S) - (b_1 * S^2) \quad (6)$$

where:

S is $1 / [cos\ (Incidence\ angle) - 1]$

b_0 is the first order modifying factor (0.322, dimensionless)

b_1 is the second order modifying factor (-0.031, dimensionless)

The flow rate used during the SRCC test was 250.9 $kg/hr \cdot m^2$, with the test fluid being water at 1 kilogram per liter. Since the unglazed and non-insulated flat plate collector available in TRNSYS did not utilize the quadratic equation in Equation 6 above, the linear Y intercept and linear slope were instead used. Both incident angle modifiers noted above were also used. The linear Y intercept used in the TRNSYS model was 0.882, while the linear slope was 18.858 W/m^2·K. A photo of the three FAFCO® collectors mounted on the roof can be seen in Figure 11 below.

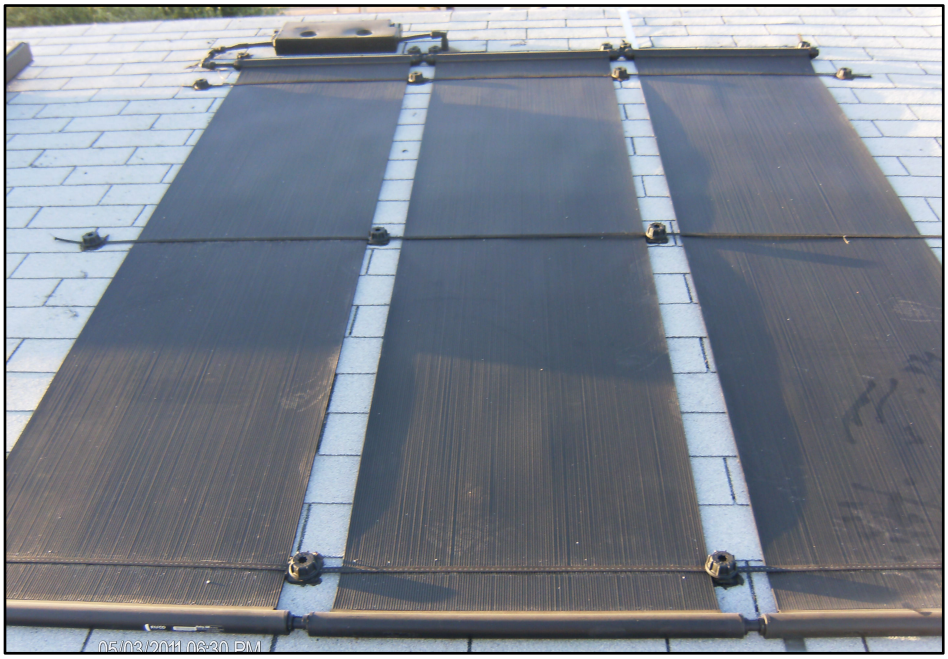

Figure 11. FAFCO® Flat-Plate Collectors

Table 2 below depicts the summary statistics of the FAFCO® and SunEarth® solar collectors, taken from the manufacturer spec sheets [10] [14].

Table 2. Solar Collector Specifications

	SunEarth®	**FAFCO®**
Collector Panel	Empire EP-40	Revolution – 08890
Solar Collector SRCC OG-100 Certification	2007032A	2007030B
Collector Type	Flat-plate with copper tube and plate and glazed glass cover	UV stabilized unglazed plastic polymer tube and web with no cover
Insulation	Polyisocyanurate and fiberglass	None
Gross Area (ft^2)	40.9	48
Net Aperture (ft^2)	37.1	48
Fluid Capacity (gal)	1.3	3.3
Fluid Type	30% DowFrost™ HD Propylene Glycol / 70% Water	30% Propylene Glycol / 70% Water
Installed Angle	18.43 degrees	18.43 degrees

3.3 Water Draws

The water draws were designed to be representative of the hot water usage of an average four-person American household. While many different reasonable scenarios for water draws can be created, it would not be feasible to model and compare them all. Instead, a distinct schedule of six water draws was created to represent average usage. According to research published by the NREL, day-to-day hot water usage has a standard deviation of around 60%, signifying usage levels are highly volatile and hard to model [15]. Furthermore, because inlet tap water temperatures vary by day and climate, water heaters are set to varying temperatures, and households use hot water at different temperatures, it would be impossible to define what a typical usage is for a four-person household. Because of the large amount of variables possible and their respective ranges, approximations were used in distinct schedules.

Instead of simulating each time a hot water tap was opened, the total water usage was combined into six distinct water draws. Research conducted at the University of Wisconsin determined that hot water usage peaks in the both the early mornings and early evenings. These peaks are caused by people bathing prior to work, and their use of hot water after work for washing dishes, washing clothes, or bathing. Since not all members of a household work a typical 8 am to 5 pm job, hot water is also used sporadically throughout the day. Total daily hot water usage in the University of Wisconsin research ranged between 60 and 70 gallons [16]. Finally, hot water draws will vary between weekdays and weekends, but in order to simplify the LabVIEW program used to collect data and the TRNSYS simulations, weekday and weekend draws were combined into a single daily average water draw schedule. The six water draws used in both the TRNSYS models and in the lab are shown in Table 3 below.

Table 3. Water Draw Timetable

Hot Water Draws at 110° F	
Time	**Gallons Drawn**
7:30 AM	22.5
1:00 PM	16.25
3:00 PM	2.5
6:00 PM	5
8:00 PM	10
10:00 PM	7.5

Hot water temperatures, which vary by usage type, also had to be modeled. In order to simplify the temperature of the hot water for the draws in TRNSYS and in the lab, a constant hot water temperature was used for all draws. Data compiled and published by the NREL shows that temperatures for clothes washers and dishwashers tend to be 120° F, while showers, baths, and sinks use mixed hot and cold water at about 105° F [15]. Therefore, in the TRNSYS models and in the lab, water was regulated in the storage tanks by electric elements to 125° F, and a thermostatic mixing valve was utilized to temper the hot water with cold tap water to 110° F for all hot water draws.

The temperature of the water from the city main lines was set at 70° F in the lab. This was set to a static temperature because the water was being recycled in a closed loop environment instead of being piped in from the city water main. In the TRNSYS simulations, true water main temperatures were imported from the NREL's database, which will be discussed further in section 3.4.2. The true water main temperature fluctuated based on the day and time of the water draw, accurately representing Phoenix-area temperatures.

3.4 TRNSYS Simulations

TRNSYS 17 was utilized to model the energy usage of the three water heating systems. Two separate simulations were run for each water heating system. The first set of simulations was designed to copy the exact environmental parameters used in the lab. Results from this set of simulations were compared to the data collected in the lab and were used to validate the TRNSYS models. The second simulation set was based on true historical temperature averages in Phoenix, Arizona. Results from this simulation set were used to estimate annual energy and cost savings. All simulations used the water draw profiles discussed in section 3.3, approximating the usage of a four-person household. All simulations also used historical averages for sunlight incident on the collectors.

3.4.1 Lab Environmental Specifications

When running the TRNSYS models for the first simulation set, the inlet water and ambient air temperatures were set to duplicate those in the lab. In the lab, the ambient air temperature was fixed at 77° F, so all ambient air parameters that affected heat loss in the tanks and piping were set to 77° F. It should be noted that the air conditioning unit in the lab was only able to cool, and not heat. While winter ambient temperatures will cause the temperatures in the lab to fall below 77° F, this was not the case during the period of data collection, since data was only collected during May and June, when night time temperatures do not drop below this level. Therefore, the ambient temperature stayed close to 77° F twenty-four hours a day. Temperatures were fixed at 77° F not to model real-world parameters, but instead to facilitate the comparison of

TRNSYS results to the data collected. Once the TRNSYS models were validated, separate models were utilized to model real-world temperatures.

Inlet water temperatures in the lab and in the first set of TRNSYS models were fixed to a constant 70° F. In the lab, this was done with a thermostatic mixing valve.

3.4.2 Phoenix Environmental Specifications

Weather data from the National Renewable Energy Laboratory were used to simulate average air and water temperatures and sunlight in the TRNSYS models. Specifically, the NREL's TMY3 weather data were utilized. TMY, or typical meteorological year, comprises data from the National Solar Radiation Data Base archives from 1961-1990, and 1991 to 2005 [17]. TMY3 is the most up-to-date data available, and the Phoenix Sky Harbor Intl AP 722780 file was utilized [18].

TMY3 data were used to set all weather parameters in the second set of models. They were used to set the inlet water temperature from the city water main. They were also used to set the ambient temperature of the air around the storage tanks and all piping and collectors. Finally, they were used to calculate solar radiation data incident on the solar collectors in both the first and second set of simulations. Since most water heaters in Arizona are placed outdoors in a garage, the ambient dry-bulb temperature was used instead of an artificial or static temperature, such as a controlled indoor temperature. This enabled TRNSYS to best estimate the energy used to heat the water and to calculate the heat lost to the environment over time. Figure 12 on the following page shows the TMY3 ambient air and water main temperatures in Phoenix, AZ, over the course of one year.

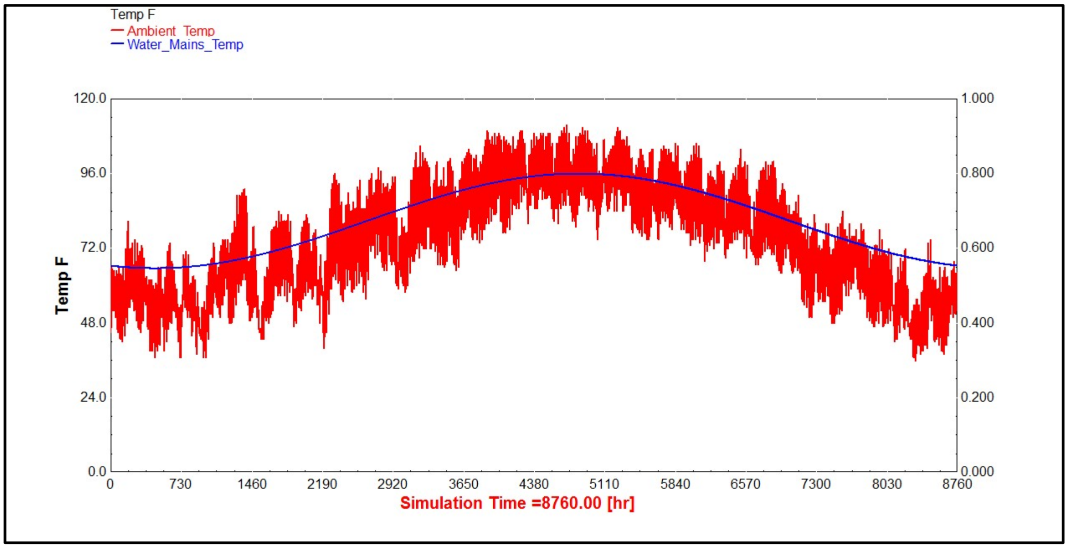

Figure 12. TMY3 Ambient Air and Water Main Temperatures in Phoenix, AZ [18].

3.4.3 Tank Heat-Loss Coefficients

Instead of utilizing the manufacturers' specified insulation values for the water storage tanks, tests were run in the lab to determine the specific heat transfer coefficient of each tank. Two tanks were tested: the all-electric tank, which is also the same tank used for both of the FAFCO® system tanks, and the SunEarth® tank. Water in the tanks was heated and then allowed to cool over time. Temperature measurements were taken every 30 minutes for 117 hours. This process was characterized by a dimensionless temperature, Θ, and was calculated at each temperature reading, using the following equation:

$$\Theta = \frac{T_{\text{water}} - T_{\text{room}}}{T_{w\_initial} - T_{\text{room}}} \tag{7}$$

where:

T_{water} is the temperature of the water at each time instance (°F)

T_{room} is the ambient air temperature in the room (65° F)

$T_{w\_initial}$ is the initial water temperature (°F)

The system was assumed to behave as a first order system with Θ approaching zero, as follows in Equation 8.

$$\Theta = e^{-t/\tau} \tag{8}$$

where:

t is the elapsed time from the initial start time (s)

τ is the average time constant from 6 to 48 hours (s)

Next, the time constant, τ, was calculated at each 30 minute interval, using the following formula:

$$\tau = -\frac{t}{ln(\Theta)} \tag{9}$$

where:

t is the elapsed time from the initial start time (s)

Θ is $\Theta = \frac{T_{\text{water}} - T_{\text{room}}}{T_{w\_initial} - T_{\text{room}}}$, as noted above

Then, the average time constant was taken beginning with hour six and ending with hour 48. Finally, the heat transfer coefficient was calculated, using the following formula:

$$Heat\ Transfer\ Coefficient = \frac{V * C}{\tau * \mathrm{SA}} \tag{10}$$

where:

V is the volume of the tank (L)

C is the fluid specific heat of water (4.186 kJ/kg·K)

τ is the average time constant from 6 to 48 hours (s)

SA is the surface area of storage tank (m^2)

The resulting heat transfer coefficients were 1.49 $W/m^2 \cdot K$ for the all-electric unit and FAFCO® tanks, and 0.75 $W/m^2 \cdot K$ for the SunEarth® tank, which reflects the observed better insulation of the SunEarth® tank.

3.4.4 System specifications

The specifications of all three water heating systems were carefully documented and entered into TRNSYS. This included the diameter, length, thickness, density, material, specific heat, and conductivity of all tanks, pipes, and insulation. Fluid specifications, such as density, thermal conductivity, viscosity, and expansion coefficients were also documented for each type of fluid and were temperature dependent. The specification of the pumps, heat exchangers, and control units were also used in the TRNSYS programs. These detailed specifications, which were used in the TRNSYS input files, can be seen in their entirety in Appendices 2-4.

3.5 Field Experiment and Data Collection

In order to validate the TRNSYS simulations, a field study was conducted to collect data. A prior Capstone Team at Arizona State University, in partnership with Salt River Project, installed a shed with the three water heaters, created a closed system environment, and coded a computer program in LabVIEW 2011 to run the field experiment. The design of the laboratory experiment is detailed below.

3.5.1 Physical Layout

The field experiment was located in the Phoenix, Arizona suburb of Mesa, on Arizona State University's Polytechnic campus. A 10 foot by 24 foot Tuff Shed® was installed at this location. The roof pitch of the Tuff Shed® is 4/12, or 18.43 degrees, and the sloped roof faces directly south for optimal sun orientation. Insulation was installed inside the Tuff Shed® on the walls and ceiling and a wall-mounted air conditioning unit provided cooling and temperature control.

The three water heating units were installed in the Tuff Shed®, and the solar collectors for the two solar water heaters were installed on the roof of the shed at the same 4/12 pitch.

3.5.2 Water Circulation

In order to recycle the water used at the site, a closed-loop water circulation system was designed and installed. This was done to avoid having to take in city water each time a water draw was initiated. Water was drawn into the system only once to fill the four storage tanks from the three water heating systems and the two water storage drums used to store recycled water. A complete system diagram can be seen in Figure 13 below.

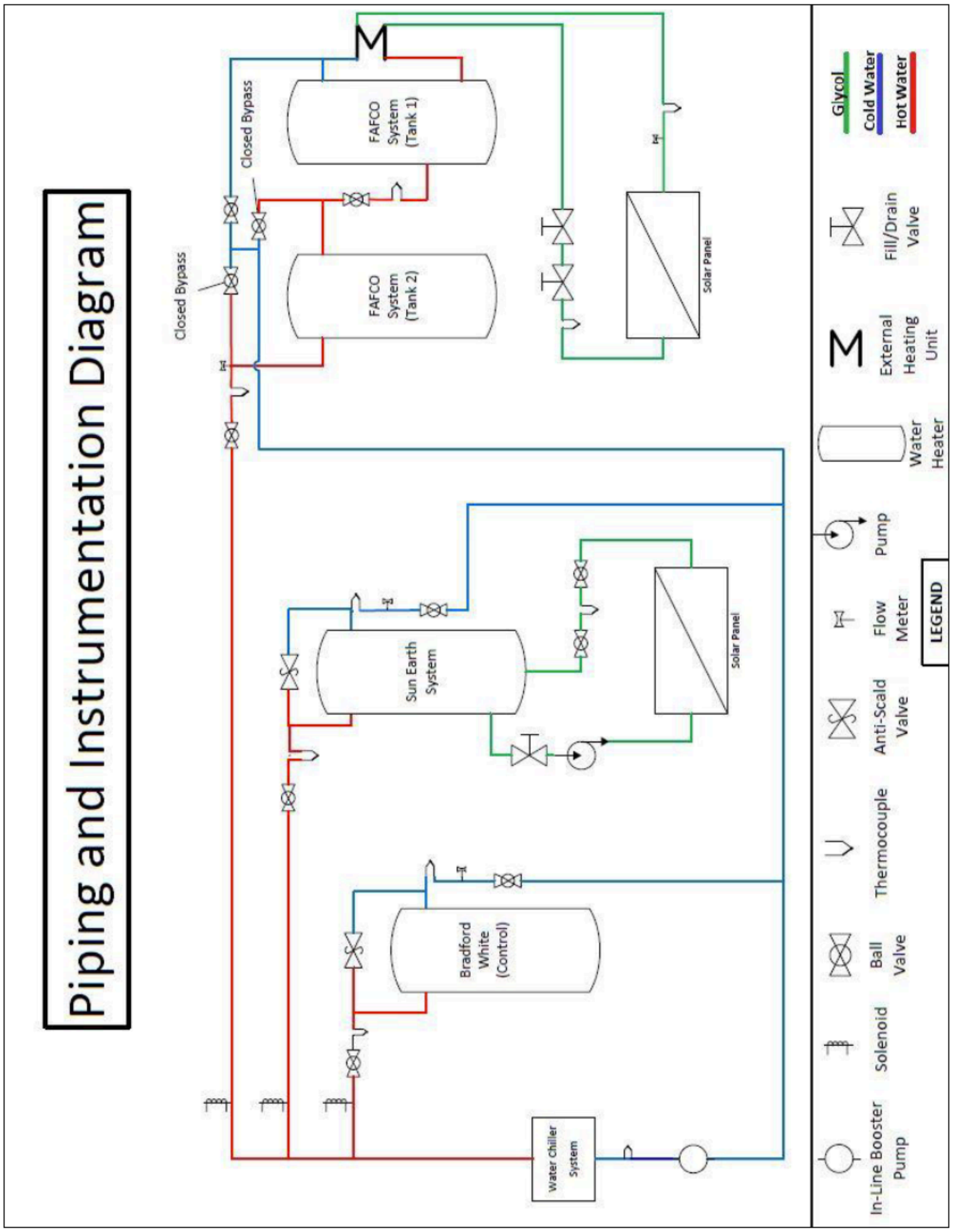

Figure 13. Piping and Instrumentation Diagram of Three Heating Systems.

The water began in a 55-gallon plastic drum located on the ground next to the Tuff Shed®. Hot water that exited the water heaters during scheduled draws was pumped to this outdoor drum for storage until more water was needed inside the system. A photo depicting the hot-water storage and inline pump can be seen in Figure 14 below. All of the pumps used in the system were Intex® Krystal Clear™ model 637R filter pumps, which run continuously. The pumps are rated to move 1,000 gallons per hour. Since the pumps ran continuously, the flow of water was managed by the opening and closing of valves, which was handled by the LabVIEW software.

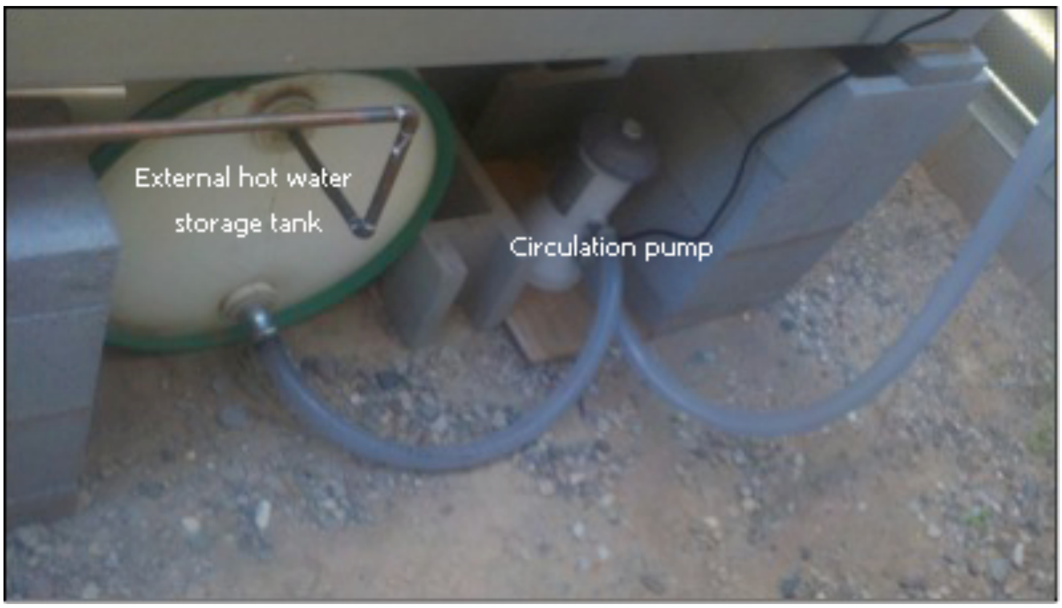

Figure 14. External Hot-Water Storage Tank and Circulation Pump.

Water from the hot-water storage tank was then pumped to a Y pipe that sent the water either to the chiller system or bypassed the chiller system and headed directly towards the thermostatic mixing valve (see Figure 15 on the following page). Hot water that had entered the chiller was then pumped into the 50-gallon cold-water storage tank. After the water exited the cold-water storage tank, it came to a Y pipe and was either recirculated through the chiller to continue cooling, or was pumped to the thermostatic mixing valve. Water in the cold-water storage tank was continuously recycled through the chiller, and the chiller was set to 56° F. Once the water had reached the set temperature, it continued to cycle through the chiller, but it was not cooled further. At the thermostatic mixing valve, which was the entrance point for the water to reenter the water heating storage tanks, the chilled water from the indoor cold-water storage tank met with hot water from the outdoor hot-water storage tank, which had bypassed the chiller, and passed through the mixing valve set at 70° F.

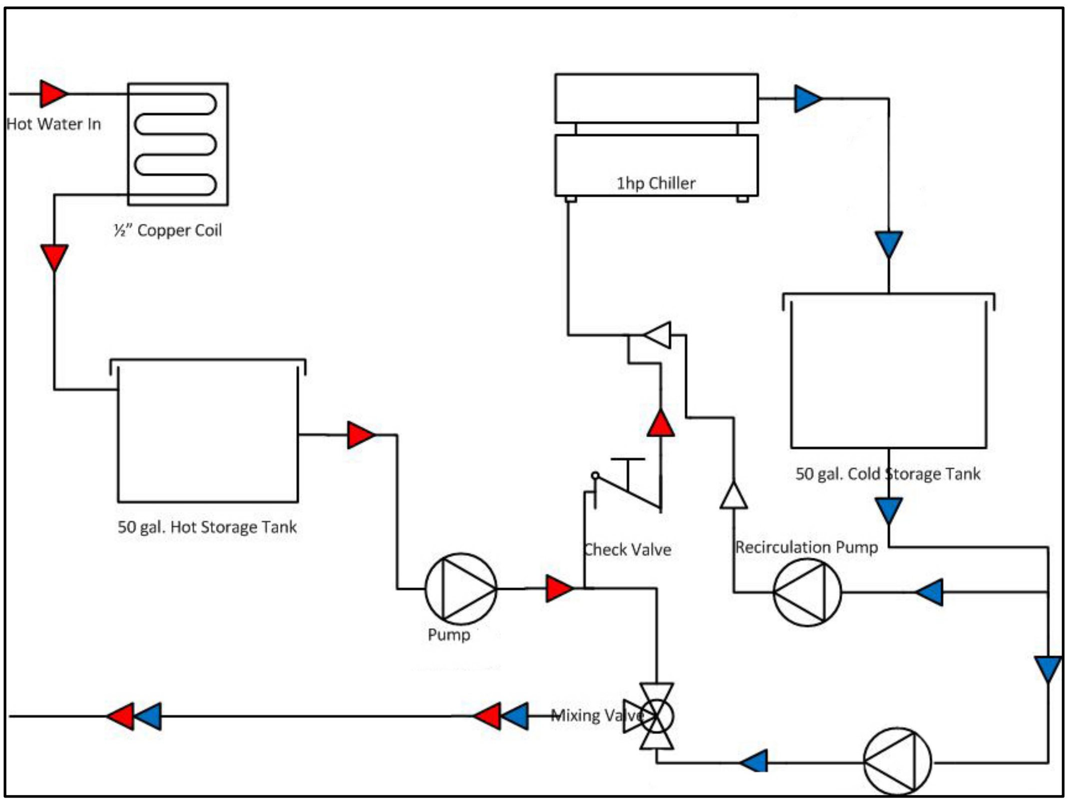

Figure 15. Chiller Diagram.

A photo of the cold-water storage tank and the chiller system can be seen in Figure 16 on the following page. The drum is on top, covered in R-13 insulation, and the black chiller is below, connected via tubing and two continuously running Intex® pumps.

Figure 16. Cold-Water Storage Tank and Chiller.

When the LabVIEW program specified a hot water draw, a valve opened to enable water to be drawn out of the tank, and this water exited through a pipe on the north side of the shed. The water then flowed through 15 feet of copper coils to begin cooling, and came to its final storage location inside the outdoor 55-gallon hot-water storage tank. At this point, the water was allowed to cool to near ambient temperature.

3.5.3 LabVIEW Software and Hardware Components

A LabVIEW program was written to control the water draws, track the inlet and outlet water temperatures of each system, and record the amount of electricity utilized by the three water heating systems. Electricity usage included the electric heating elements, the single SunEarth® pump, and the two FAFCO® pumps. Data was compiled and exported each day.

LabVIEW accomplished this task through the use of data acquisition components (DAQs), temperature sensors, flow meters, and energy meters. The DAQ components utilized were a National Instruments™ (NI) USB-9213 16-Channel USB Thermocouple Measurement Module, an NI 9263-4 4-Channel Analog Output Module, an NI 9201 8-Channel Input Module, an NI 9411 6-Channel Digital Input Module, and an NI 9474 8-Channel Sourcing Digital Output Module. The temperature sensors used to measure the inlet and outlet water temperatures at each unit were Omega Engineering® pipe plug thermocouples, model TC-J-NPT-G-72. The flow meters used to measure water draws were Omega™ turbine style flow meters, model FTB4605. Finally, the energy meters utilized were inductive analogue current sensors by Honeywell®. The model number for the units was CSLT6B100.

Each day, the water and HTF temperatures and energy used by the three water heaters and solar pumps were exported to an Excel file.

3.5.4 Data Collection

Data was collected for one system at a time. Simultaneous data collection for all three systems was not possible due to the power limitations of the pumps and the chiller system. The original goal was to collect data from the winter solstice on December 22, 2011 to the summer solstice on June 20, 2012, but this was not possible due to multiple challenges. The two largest issues with the design of the system included the flow rate limitations of the pumps and the capacity of the chiller system. In addition, there were serious equipment malfunctions with one of the installed systems.

Originally, the LabVIEW program was designed to run all three systems at once. During testing, the team realized that the pumps were not powerful enough to provide a significant flow to all three systems simultaneously. The flow rate was so low at times that not enough water would flow through each system to meet the total draw volume requirement prior to the next water draw beginning. In situations where one water draw began before another was completed, the latter water draw was skipped by the LabVIEW program. At other times, air pockets in the pipes brought the flow rate to zero, and the pumps had to be manually purged.

The second issue was that during the longest water draws, hot water entering the cold-water storage drum overwhelmed the chiller, and the targeted 70° F at the thermostatic mixing valve could not be achieved. Once the water in the cold-water storage tank exceeded 70° F, the mixing valve would not let sufficient water through and the flow rate dropped to nearly zero.

Finally, data collection was halted until all three systems were fully operational. The FAFCO® system did not run properly for the first several months, until warranty repairs were completed. Several components were replaced during warranty visits, including the collectors, pumps, and ICM control unit. In the end, it was determined that the ball bearing in the HTF loop check valve was of improper size, and would stop the flow of HTF. Once this ball bearing was replaced, the system functioned and data collection was resumed.

In order to collect accurate data, the LabVIEW program was modified to only run one water heating system per day. Data for each system were collected between May 23 and June 13, 2012. The data were collected in 24-hour increments in order to determine the energy usage of one full day.

CHAPTER 4

RESULTS

4.1 Lab Results

Data were collected in the lab from late May through early June, and only on days with sunny skies. While long-term data has not yet been collected (and will be the subject of future research), a sample set of data was obtained to validate the TRNSYS models. The average daily energy usage was 10.30 kilowatt-hours for the all-electric system, 0.71 kWh for the SunEarth® system, and 1.56 kWh for the FAFCO® system. The average daily amounts of energy used by the auxiliary pumps and single electric element for the SunEarth® system were 0.23 kWh and 0.48 kWh, respectively. The average daily amounts of energy used by the two auxiliary pumps and the two electric heating elements for the FAFCO® system were 0.21 kWh and 1.35 kWh, respectively.

During hot summer days in Mesa, Arizona, very little energy was used by the solar systems. To reiterate, the ambient temperature in the lab was controlled at a constant 77° F, and the simulated incoming water main temperature was set at a constant 70° F. Using actual data, the warmer water and ambient temperatures would result in even less energy usage, but were the subject of the second set of TRNSYS simulations, which are discussed in section 4.3. A summary of the data collected in the lab is shown in Table 4 on the following page.

Table 4. Lab Results

Energy Usage in kWh								
	All Electric	SunEarth®			FAFCO®			
Date	**Element**	**Pump**	**Element**	**Total**	**Pumps**	**Elements**	**Total**	
5/23/12	10.04							
5/25/12	10.57							
5/30/12		0.18	0.25	0.43				
5/31/12		0.17	0.22	0.39				
6/2/12					0.17	0.15	0.32	
6/8/12		0.33	0.54	0.87				
6/9/12		0.26	0.89	1.14				
6/10/12					0.23	1.43	1.66	
6/11/12					0.25	2.96	3.22	
6/13/12					0.20	0.86	1.07	
Daily Average	10.30	0.23	0.48	0.71	0.21	1.35	1.56	
Monthly Total	**309**	**7**	**14**	**21**	**6**	**41**	**47**	

4.2 Data Validation of TRNSYS Models

The average daily energy usage in the first set of TRNSYS models from the months of May and June was compared to the lab data collected on site. In order to match the lab environments, the first set of TRNSYS models fixed the inlet water temperature to 70° F and the ambient temperature to 77° F. The results of the TRNSYS simulations for the months of May and June are shown in Table 5 below.

Table 5. TRNSYS Simulation Set One Results

TRNSYS Results (kWh per month)			
	May	**June**	**May/June Avg**
All-Electric	234	242	238
SunEarth®	12	14	13
FAFCO®	55	53	54

In order smooth out daily temperature and sunlight fluctuations, daily results from the lab were averaged, and then extrapolated to a full month. The extrapolation was necessary because a full month's worth of data was not available. This extrapolated average monthly data from the lab was then compared to an average full month of electricity usage from TRNSYS. The TRNSYS energy-usage average of the full months of May and June was used for comparison. This was done instead of comparing unique days (i.e. June 5 in TRNSYS to June 5 in the lab), because TRNSYS cannot predict the exact temperatures and cloud coverage on a particular day, and instead, uses long-term averages. A comparison of the monthly results from the lab and TRNSYS, as well as the differences, can be seen in Table 6 below.

Table 6. Validation of TRNSYS Results with Lab Data

Electricity Usage per Month (kWh)			
	Lab	**TRNSYS**	**Difference**
All-Electric	309	238	71
SunEarth	21	13	8
FAFCO	47	54	(7)

The results of the TRNSYS models were reasonably close to the collected lab data since some variances were observed. There are several factors that would have caused these variations. First, the temperature of the incoming water in the lab was set by a thermostatic mixing valve, which was not accurate enough to keep the temperature at a constant and exact 70° F, as was done in TRNSYS. The same can be said for the mixing valves regulating the hot water exiting the tanks. While the mixing valves were set as close to 110° F as possible, the actual temperature fluctuated by up to ten degrees Fahrenheit in each direction. The temperature of the ambient air inside the lab also fluctuated by +/- 4° F from the air conditioning unit's set temperature of 77° F. This was due to the deadband of the thermostat and the difficultly of the air conditioning unit to quickly cool the room after the door had been opened. Finally, the outdoor ambient temperatures and sunlight experienced in Phoenix at the time the data were recorded may not have been equal to the average temperatures and solar radiation data used in the TRNSYS models, which are based on long-term averages. Overall, the results of the lab were very close to that of TRNSYS, and further research with more data will aid in supporting this claim.

4.3 Full-Year TRNSYS Analysis

A second set of TRNSYS 17 simulations were used to estimate the annual energy consumption of the three different water heating systems. In the second set of TRNSYS simulations, the fixed inlet water temperature and ambient air temperatures were replaced with data from the TMY3 weather data files, as seen in Figure 12 on page 30. For the all-electric system, energy usage (in units of kilowatt-hours) was recorded for each of the two elements. For the SunEarth® system, energy usage was recorded for the single electric element and for the single HTF circulation pump. For the FAFCO® system, energy usage was recorded for the two electric elements in the electric backup tank, for the HTF circulation pump, and for the potable water circulation pump. Power was recorded in one minute intervals and energy usage was calculated by integrating these power curves. A summary of total energy usage per month for each unit is displayed in Table 7 on the following page. The '% Saving' row represents energy savings (in kWh) of the solar water heating systems compared to the all-electric system.

Table 7. TRNSYS Energy Usage Results

Energy Usage by Month (kWh)			
Month	**All-Electric**	**SunEarth®**	**FAFCO®**
January	294	119	217
February	249	71	167
March	250	41	152
April	196	16	80
May	159	10	53
June	113	7	11
July	101	6	8
August	111	7	13
September	137	8	28
October	188	16	85
November	231	42	151
December	280	112	217
Annual Total	**2,310**	**453**	**1,182**
% Saving	**0.0%**	**80.4%**	**48.8%**

In Phoenix, the SunEarth® system is projected to use only 19.6% (80.4% savings) of the energy of an all-electric system. The FAFCO® system is projected to use 51.2% (48.8% savings) of the energy of the all-electric system. The abundance of sunlight and cloudless days in Phoenix, combined with the warm temperatures of the inlet tap water and high ambient temperatures, allow the solar systems to work very effectively. The all-electric system in the same environment also reaps the benefits of the high ambient and inlet water temperatures, but cannot take advantage of the sunlight.

As seen in Figure 17 on the following page, the FAFCO® system runs nearly as efficiently as the SunEarth® system during the hottest summer months between June and September. But, during cooler months with less sunlight, its efficiency drops significantly.

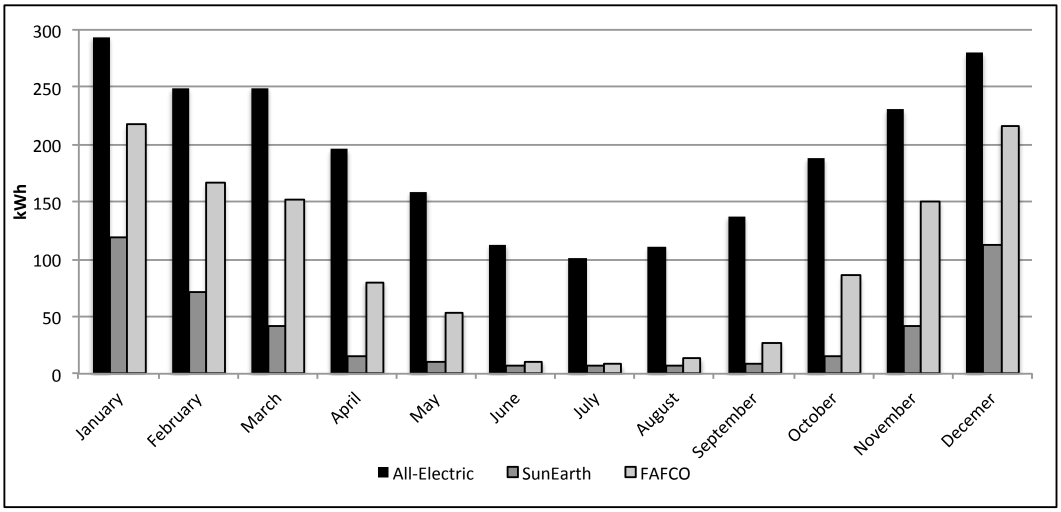

Figure 17. TRNSYS Projected Monthly Energy Usage.

There are four main factors that lower the efficiency of the FAFCO® system as compared to the SunEarth® system. The first and most important factor is that the FAFCO® system uses unglazed collectors that are not insulated. During hot summer months, when ambient temperatures exceed 100° F during solar operation, the lack of insulation is not as important. However, in cooler months, the heat lost due to the lack of insulation decreases the efficiency. Even during the summer months, the insulated collectors of the SunEarth® system allow for the temperatures of the HTF on the roof to remain much hotter in the late afternoon than for the FAFCO® system. This means that at 5 PM, the HTF of the SunEarth® system is still heating the water, while the FAFCO® system has already shut off its pumps. Also, the convective cooling effects of wind chill are stronger on the non-insulated collectors.

The second factor is that the FAFCO® water storage tanks are not as well insulated as the SunEarth® tank. The single SunEarth® tank has a heat transfer coefficient of only 0.75 W/m^2·K, while the two FAFCO® tanks have a heat transfer coefficient of 1.49 $W/m^2 \cdot K$, enabling more heat to be lost to the environment.

The third factor is that the FAFCO® system has a greater exposed surface area over its two tanks. The surface area of the SunEarth® system's single 80-gallon tank is 3.54m^2, while each of the two FAFCO® 50-gallon tanks have a surface area of 2.74m^2, combining for a total of 5.47 m^2. The combined factors of lower insulation and greater surface area result in increased heat lost from the FAFCO® system.

Finally, in the FAFCO® system, having two tanks also means that after water is transferred from the preheat tank to the backup tank, it can no longer be kept warm or reheated using solar energy. If the hot water transferred from the preheat tank to the backup tank is not used quickly, it must be kept warm using the two electric elements. Therefore, the FAFCO® tank is more efficient when water is consistently used, and is less efficient when water is stored for extended periods of time. On the other hand, the SunEarth® system's single tank can continuously heat the water using solar energy, and must only use its electrical element when the solar loop is not running or is insufficient to heat the tank to the specified temperature.

4.4 Economic Analysis

In order to determine the lifecycle cost of each individual system, initial capital, replacement and maintenance costs, and operating (fuel) costs were compiled. Quotes were requested from local dealers to determine the initial installed cost of the systems and recommended service intervals. The initial and replacement costs of the systems include both parts and labor costs. For the cost of electricity consumed, current rates from Salt River Project were utilized, and future rates were forecast using information from the U.S. Energy Information Administration (EIA).

Maintenance and repair work are pertinent in the cost estimates. Regular water flushes are necessary to rid the tank of deposits that can reduce the lifetime of the storage tanks. The all-electric system will have its electric heating element and sacrificial anode rod replaced every four years at a cost of $10 for the 4,500-watt heating element and $25 for the sacrificial anode rod. A surcharge of $75 per visit was added to pay a plumber to come perform the work. Due to the labor charge, some trips were combined if separate maintenance items happened on consecutive years. Only the bottom heating element would be replaced, as it is used the majority of the time, and it was deemed that the top element would survive until the full tank replacement. The entire all-electric water heating tank would need to be replaced after eight years of use.

The SunEarth® system would also have its sacrificial anode rod replaced every four years at a cost of $25, plus $75 for labor. The heating element would only be replaced every eight years, instead of four, because its use would be much less than that of the all-electric tank. The storage tank would need to be replaced on the 15th year, at an installed cost of $1,200. All piping and collectors are projected by the manufacturer to survive the duration of the 20-year analysis period.

For the FAFCO® dual tank system, the sacrificial anode rods would also be replaced every four years, on each tank, at a combined cost of $50 for the two tanks plus $75 for labor. The heating element would be replaced on the electric tank every eight years, similar to the SunEarth® system. Again, the replacement cycle is longer than that of the all-electric tank because the element would not be used as often. Also, only the bottom element would need to be replaced, as it is the element doing the majority of the heating, and the top element only turns on during periods of lengthy hot water draws. The electric tank would be replaced after ten years, and the preheat tank would be replaced on the 15th year. The cost of replacing the tanks is the same as the all-electric tank, and is $785, including the cost of installation. For the preheat tank, the heating elements are removed prior to use. The manufacturer expects the collectors and piping to be maintenance-free for the duration of the 20-year analysis period.

A twenty-year period was utilized for the cost projections, as both the SunEarth® and FAFCO® systems are projected to last at least this long. No discount rate or inflation rate was used because the discount rate is nearly equal to the inflation rate, cancelling each other out. This is a conservative assumption that removes the burden and uncertainty of projecting 20 years of risk-free rates and inflation rates.

Electricity rates were taken from SRP's current rate tables for the Basic Plan as of June 2012. The rates change depending on the month of the year and the amount of kilowatt-hours used in a given month. Tier 1 rates are for the first 700 kilowatt-hours used, and Tier 2 rates are for the 701 to 2,000 kilowatt-hours used. Because the projections are for a four-person household in Arizona, a blended rate was used, which weights Tier 1 prices at 50%, and Tier 2 prices at 50%. The prices used are shown in Table 8 below [19].

Table 8. Electricity Rates by Month and Tier

Electricity Rates per Kilowatt-Hour				
Tier	**kWh Range**	**May – June** **Sept – Oct**	**Jul – Aug**	**Nov - Apr**
Tier 1	First 700 kWh	10.10 ¢	10.64 ¢	7.80 ¢
Tier 2	701-2,000 kWh	10.93 ¢	11.41 ¢	7.80 ¢
Tier 3	> 2,000 kWh	11.62 ¢	12.12 ¢	7.80 ¢
Blended	0 – 2,000 kWh avg.	10.52 ¢	11.02 ¢	7.80 ¢

While local Arizona residential electricity rates rose at an annualized rate of over 3.5% between 2002 and 2008, an annual rate increase of 0% will be utilized for future projections [20]. According to research published by the U.S. Energy Information Administration (EIA) in its 2012 Annual Energy Outlook, electricity rates are not projected to increase between now and 2035. The falling price of natural gas, often used to set wholesale prices, will offset the expected increased prices of coal and renewable energy, and result in a relatively steady price over the next 13 years. The EIA projects electricity prices in 2035 to average 9.5 cents per kilowatt-hour, as compared to 9.8 cents per kilowatt-hour in 2010 [21]. Because these prices are so similar, and are based on many assumptions, for the purpose of this paper, it will be assumed that electricity prices will remain flat for the duration of the analysis period.

Tables 9, 10, and 11 on the following pages show the cost of the all-electric, SunEarth®, and FAFCO® systems, respectively, over twenty years. These costs include materials, labor, and the annual cost of electricity. These tables represent the costs prior to federal, state, and local utility incentives.

Table 9. All-Electric System Costs Prior to Incentives

Year	Capital Cost	Electricity	Annual Cost	Running Cost
1	$785	$203	$988	$988
2		$203	$203	$1,191
3		$203	$203	$1,395
4		$203	$203	$1,598
5	$110	$203	$313	$1,911
6		$203	$203	$2,114
7		$203	$203	$2,318
8		$203	$203	$2,521
9	$785	$203	$988	$3,509
10		$203	$203	$3,712
11		$203	$203	$3,916
12		$203	$203	$4,119
13	$110	$203	$313	$4,432
14		$203	$203	$4,635
15		$203	$203	$4,839
16		$203	$203	$5,042
17	$785	$203	$988	$6,030
18		$203	$203	$6,233
19		$203	$203	$6,436
20		$203	$203	$6,640
Total	**$2,575**	**$4,065**	**$6,640**	**$6,640**

Table 10. SunEarth® Costs Prior to Incentives

Year	Unit Cost	Electricity	Annual Cost	Running Cost
1	$5,500	$37	$5,537	$5,537
2		$37	$37	$5,574
3		$37	$37	$5,611
4		$37	$37	$5,648
5	$100	$37	$137	$5,784
6		$37	$37	$5,821
7		$37	$37	$5,858
8	$85	$37	$122	$5,980
9	$100	$37	$137	$6,117
10		$37	$37	$6,154
11		$37	$37	$6,191
12		$37	$37	$6,228
13	$100	$37	$137	$6,365
14		$37	$37	$6,402
15	$1,200	$37	$1,237	$7,638
16		$37	$37	$7,675
17		$37	$37	$7,712
18		$37	$37	$7,749
19	$100	$37	$137	$7,886
20		$37	$37	$7,923
Total	**$7,185**	**$738**	**$7,923**	**$7,923**

Table 11. FAFCO® Costs Prior to Incentives

Year	Unit Cost	Electricity	Annual Cost	Running Cost
1	$5,000	$98	$5,098	$5,098
2		$98	$98	$5,195
3		$98	$98	$5,293
4		$98	$98	$5,391
5	$125	$98	$223	$5,613
6		$98	$98	$5,711
7		$98	$98	$5,809
8	$135	$98	$233	$6,041
9		$98	$98	$6,139
10		$98	$98	$6,237
11	785	$98	$883	$7,119
12		$98	$98	$7,217
13	$100	$98	$198	$7,415
14		$98	$98	$7,512
15	$885	$98	$983	$8,495
16		$98	$98	$8,593
17		$98	$98	$8,690
18		$98	$98	$8,788
19	$125	$98	$223	$9,011
20		$98	$98	$9,108
Total	**$7,155**	**$1,953**	**$9,108**	**$9,108**

The initial out-of-pocket cost to install each of the three systems without incentives was $785 for the all-electric system, $5,500 for the SunEarth® system, and $5,000 for the FAFCO® system. Without federal, state, and utility incentives, the FAFCO® system was the most expensive to own and operate over the twenty year period, at $9,108. The SunEarth® system was the second most expensive, at $7,923, while the all-electric system was the cheapest, at $6,640. Without incentives or subsidies, neither system would pay for itself in savings when compared to the all-electric unit.

With incentives available as of June 2012, the net result of the initial and 20-year cost analyses change significantly. The available incentives include a federal rebate for 30% of the initial installed cost, a 25% Arizona tax credit based on the initial installed cost, which is capped at $1,000, and a utility incentive from SRP [22] [23]. The utility incentive that SRP had available at the time of experimentation was $0.40 per kilowatt-hour of annual energy savings from the SRCC's OG-300 rating [24]. For the SunEarth® system, this was equal to 40 cents times 2,880 kWh, for a total of $1,152. The FAFCO® system reported average annual savings of 2,350 kWh, for an SRP rebate of $940. After incentives, the initial out-of-pocket cost to install each of the three systems was $785 for the all-electric, $1,698 for the SunEarth® system, and $1,560 for the FAFCO® system. The initial costs, rebates, and net out-of-pocket cost for each system are depicted in Table 12 below.

Table 12. Post-Incentive Costs of Installation

	All-Electric	**SunEarth®**	**FAFCO®**	**Details**
Installed Cost	$785	$5,500	$5,000	
- Federal	$0	($1,650)	($1,500)	30% of total cost
- State	$0	($1,000)	($1,000)	25% of total cost, max $1000
- SRP	$0	($1,152)	($940)	$0.40 / annual kWh saved
Net Cost	**$785**	**$1,698**	**$1,560**	**Out-of-pocket cost**

The annual costs, after accounting for the incentives, can be seen for the all-electric system, SunEarth® system, and FAFCO® system in Tables 13, 14, and 15 on the following pages, respectively. Again, a 0% annual increase in the cost of electricity was factored into the analysis. During the 20-year analysis period, the all-electric system would cost the most, at $6,640. The FAFCO® system would be the second most expensive to own and operate, at $5,668, while the SunEarth® system would cost the least to own and operate, at $4,121.

Table 13. All-Electric Costs Post-Incentives

Year	Capital Cost	Electricity	Annual Cost	Running Cost
1	$785	$203	$988	$988
2		$203	$203	$1,191
3		$203	$203	$1,395
4		$203	$203	$1,598
5	$110	$203	$313	$1,911
6		$203	$203	$2,114
7		$203	$203	$2,318
8		$203	$203	$2,521
9	$785	$203	$988	$3,509
10		$203	$203	$3,712
11		$203	$203	$3,916
12		$203	$203	$4,119
13	$110	$203	$313	$4,432
14		$203	$203	$4,635
15		$203	$203	$4,839
16		$203	$203	$5,042
17	$785	$203	$988	$6,030
18		$203	$203	$6,233
19		$203	$203	$6,436
20		$203	$203	$6,640
Total	**$2,575**	**$4,065**	**$6,640**	**$6,640**

Table 14. SunEarth® Costs Post-Incentives

Year	Unit Cost	Electricity	Annual Cost	Running Cost
1	$1,698	$37	$1,735	$1,735
2		$37	$37	$1,772
3		$37	$37	$1,809
4		$37	$37	$1,846
5	$100	$37	$137	$1,982
6		$37	$37	$2,019
7		$37	$37	$2,056
8	$85	$37	$122	$2,178
9	$100	$37	$137	$2,315
10		$37	$37	$2,352
11		$37	$37	$2,389
12		$37	$37	$2,426
13	$100	$37	$137	$2,563
14		$37	$37	$2,600
15	$1,200	$37	$1,237	$3,836
16		$37	$37	$3,873
17		$37	$37	$3,910
18		$37	$37	$3,947
19	$100	$37	$137	$4,084
20		$37	$37	$4,121
Total	**$3,383**	**$738**	**$4,121**	**$4,121**

Table 15. FAFCO® Costs Post-Incentives

Year	Unit Cost	Electricity	Annual Cost	Running Cost
1	$1,560	$98	$1,658	$1,658
2		$98	$98	$1,755
3		$98	$98	$1,853
4		$98	$98	$1,951
5	$125	$98	$223	$2,173
6		$98	$98	$2,271
7		$98	$98	$2,369
8	$135	$98	$233	$2,601
9		$98	$98	$2,699
10		$98	$98	$2,797
11	$785	$98	$883	$3,679
12		$98	$98	$3,777
13	$100	$98	$198	$3,975
14		$98	$98	$4,072
15	$885	$98	$983	$5,055
16		$98	$98	$5,153
17		$98	$98	$5,250
18		$98	$98	$5,348
19	$125	$98	$223	$5,571
20		$98	$98	$5,668
Total	**$3,715**	**$1,953**	**$5,668**	**$5,668**

As depicted in the above tables, after accounting for incentives, the SunEarth® system will break even with the all-electric system after year 5, and the FAFCO® system will break even after year 8, though it should be noted that the FAFCO® and all-electric systems nearly break even after year 6. A consumer can expect a post-incentive savings of $971 for the FAFCO® as compared to the all-electric, and a savings of $2,519 for the SunEarth® as compared to the all-electric. After accounting for incentives, the solar-powered units will save a homeowner money over time, albeit at the cost of public and utility funding. On the other hand, energy savings are guaranteed, to the benefit of the homeowner and the public, due to a reduction in pollution from electricity generation using the current blend of fuels.

4.5 Reliability

Reliability was observed over the course of the study. Both the all-electric system and the SunEarth® system ran seamlessly, with zero issues. Although the SunEarth® system ran with no issues, it is still recommended that a homeowner check the temperatures on the screen periodically to ensure that the HTF is flowing correctly and heating the water in the tank. This is done by spot checking the display screen and cycling between the temperature of the water at the bottom of the tank and the temperature of the HTF on the roof. A small fan-like symbol on the display will confirm that the pump is running during the day. There is also a small flow meter next to the pump to monitor the flow of the HTF.

The FAFCO® system required warranty repairs after the initial installation to run properly. The system is configured to show a 'FLO' error when the solar preheat system is not functioning properly. In order to remedy the error, FAFCO® replaced both pumps, the three solar collectors, the ball bearing in the HTF loop check valve, and the ICM, under its warranty agreement. Flow meters were added to both the potable water loop and the HTF loop to monitor the flow and aid in troubleshooting. Although multiple components were replaced, it was determined that the ball bearing in the HTF loop's check valve was manufactured in an improper size, which caused the ball bearing to cut the flow of HTF in the loop. Once all the components were replaced, the system ran well, although there were times when the potable water loop stopped flowing, and the FLO error was triggered. The flow error was usually removed upon resetting the system. When a reset was insufficient, water was manually primed into the loop to ensure that there were no air pockets keeping the pumps from flowing.

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS FOR FURTHER STUDY

5.1 Conclusion

Both the SunEarth® and the FAFCO® systems had substantial energy savings when compared to the all-electric unit. Over the course of a year, the SunEarth® system is projected to use only 19.6% (80.4% savings) of the energy of the all-electric system, while the FAFCO® system is projected to use 51.2% (48.8% savings) of the energy.

After utilizing all available incentives as of June 2012, both solar water heating systems also produced monetary savings when compared to the all-electric unit. While the SunEarth® system has a higher initial cost than the FAFCO® system, it breaks even with the all-electric unit after five years versus eight years for the FAFCO® system. By the third year, the running cost of the SunEarth® system becomes lower than that of the FAFCO® system due to its greater energy savings that offset its higher initial cost. At the end of the twenty-year period, the SunEarth® system would save $2,519 compared to the all-electric unit, while the FAFCO® system would save $971. The SunEarth® system is recommended due to its greater energy savings, lower ownership cost, and greater reliability.

5.2 Recommendations for Further Study

Recommendations for improvements and further research are detailed in the following sections.

5.2.1 System Improvements

Several changes must be made to the lab environment to enable further research and improve data collection. These changes include increasing the water flow rates of the pumps and the cooling capacity of the chiller system. Currently, only one system may be run at a time. This is due to the pumps not being able to supply enough water to all three systems simultaneously, and also due to the chiller system not being able to cool the water quickly enough during the two largest water draws.

There are two issues with the pumps, which are not powerful enough and therefore have trouble pumping enough water at a high enough flow rate through the systems. The first problem is caused by the outdoor pump that sends water from the outside hot-water storage tank to the chiller system and thermostatic mixing valve. A 'Y' pipe splits the piping, but there is no mechanism to control how much volume is routed to each location. When the system is running during a water draw there is insufficient flow from this pump to meet the demands of both the hot water needed at the mixing valve and water going into the chiller to reside in the cold-water storage tank.

The second issue is with the flow of water coming out of the cold-water storage tank. This outlet also goes to a 'Y' pipe, which sends water to two different pumps. The first is a pump that sends water to the chiller, then back to the cold-water storage tank, and the second is a pump that sends water into the water heating systems via the thermostatic mixing valve. In such a 'Y' configuration, the water tends to flow to the path of least resistance, which is to the chiller pump. With nearly all the water going to the chiller pump, not enough water is delivered to the thermostatic mixing valve, causing insufficient flow rates.

During testing, the most common issue was a lack of flow through the systems. This flow error occurred even when only one system was running at a time. The systems would be running at about 1 GPM and then would suddenly stop. The stoppage would generally happen between water draws, when small air pockets in the pipes or pumps were capable of producing so much resistance that the pumps were only able to recirculate the water through the chiller and not send any water past the thermostatic mixing valve into the systems.

The insufficient water flow also made it impossible to use the inline booster pump, as there was not adequate water coming into the booster pump to boost the water pressure. This would result in the pump reporting a fault error and shutting off. The inline booster pump has been installed but has not yet been used, and will serve the purpose of boosting the pressure and flow rate to the equivalent of city water pressure and domestic flow rates.

The flow rate problems could be remedied by either utilizing more powerful pumps, or by removing all 'Y' pipes and using dedicated pumps for each purpose. This would enable the inline booster pump to increase system pressure, and enable all three systems to run simultaneously. The issue with the chiller not being able to cool the water in time for the remaining portion of the longest hot water draws could be remedied by using a more powerful chiller or by increasing the storage capacity of the chilled water.

5.2.2 Further Research

Further research should include collecting daily data between the winter and summer solstice, and can be conducted using the current water heating systems. Additional research should also include adding new water heating technology to the lab.

The next phase of this project should include collecting data from the winter solstice to the summer solstice, or for a full year, which would aid in further validating the TRNSYS simulations. More daily data over different seasons would smooth out weather patterns and irregularities and allow for the validation of the TRNSYS models during winter months. Also, daily data from one solstice to the next would allow for statistical tests to be conducted to compare the lab data to the TRNSYS results. Currently, statistical analysis using a few days worth of data would not be statistically significant as the sample size is too small. Furthermore, it is recommended that daily data is collected simultaneously for all three systems, as this would enable results to be compared without differing weather and temperatures of consecutive days.

Additionally, different technologies should be added to the lab for further comparison. Three new types of water heaters would be of particular interest. The first is a gas-fired water heater, which is cheaper to operate than the all-electric unit currently being used as a control unit. The second is an on-demand, or tankless, water heater. Tankless water heaters tend to use less energy than traditional tanked electric water heaters, but are also more expensive. The tankless water heater would offer an additional point of comparison for both efficiency and cost comparison, and could be tested using both electricity or gas as a heating source. Finally, an evacuated tube solar water heating system would provide further data on energy and cost savings of different solar water heating technologies.

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APPENDIX A

LABVIEW AND TRNSYS SOFTWARE

LabVIEW 2011 software was utilized to program the automated data collection in the lab. LabVIEW is published by National Instruments, and requires a purchased license. It is a graphical development environment used to create applications through the use of graphical icons connected together as in a flowchart [25]. The software was used to turn the valves in the lab on and off to simulate hot water draws, and to collect energy and temperature data. LabVIEW did this by collecting and recording data from the DAQs, which were connected to the thermocouples and energy sensors.

TRNSYS 17 is a transient systems simulation software package with modular structure. Using TRNSYS, a user specifies the components of a system and connects them using a visual user interface. TRNSYS has the ability to model solar thermal and photovoltaic systems, low energy buildings, HVAC systems, renewable energy systems, cogeneration, and fuel cells [26]. TRNSYS was utilized to model the energy usage of the three water heaters in this thesis. TRNSYS is a joint project between the following entities: Solar Energy Laboratory at the University of Wisconsin-Madison, TRANSSOLAR Energietechnik GmbH, CSTB – Centre Scientifique et Technique du Bâtiment, and TESS – Thermal Energy Systems Specialists. TRNSYS requires a purchased license. A TRNSYS user guide is available in the software suite, and has been published online by the Massachusetts Institute of Technology [27].

APPENDIX B

ALL-ELECTRIC TRNSYS INPUT FILE

```
VERSION 17
*******************************************************************************
*** TRNSYS input file (deck) generated by TrnsysStudio
*** on Thursday, June 28, 2012 at 23:55
*** from TrnsysStudio project: Y:\Documents\Docs\School\Alt
Masters\Thesis\TRNSYS Files\OFFICIAL FILES\Thesis - All
Electric\Bradford_White_true_ambient.tpf
***
*** If you edit this file, use the File/Import TRNSYS Input File function in
*** TrnsysStudio to update the project.
***
*** If you have problems, questions or suggestions please contact your local
*** TRNSYS distributor or mailto:software@cstb.fr
***
*******************************************************************************


*******************************************************************************
*** Units
*******************************************************************************

*******************************************************************************
*** Control cards
*******************************************************************************
* START, STOP and STEP
CONSTANTS 3
START=0
STOP=8760.000229455
STEP=0.016666666
SIMULATION 	 START	 STOP	 STEP	! Start time	End time	Time step
TOLERANCES 0.001 0.001			! Integration	 Convergence
LIMITS 30 500 50				! Max iterations	Max warnings	Trace limit
DFQ 1					! TRNSYS numerical integration solver method
WIDTH 80				! TRNSYS output file width, number of characters
LIST 					! NOLIST statement
					! MAP statement
SOLVER 0 1 1				! Solver statement	Minimum relaxation factor	Maximum relaxation factor
```

```
NAN_CHECK 0                    ! Nan DEBUG statement
OVERWRITE_CHECK 0                    ! Overwrite DEBUG statement
TIME_REPORT 0                  ! disable time report
EQSOLVER 0                     ! EQUATION SOLVER statement
* User defined CONSTANTS


* Model "Water Draw Profile" (Type 14)
*

UNIT 2 TYPE 14     Water Draw Profile
*$UNIT_NAME Water Draw Profile
*$MODEL .\Utility\Forcing Functions\Water Draw\Type14b.tmf
*$POSITION 72 457
*$LAYER Main #
PARAMETERS 52
0           ! 1 Initial value of time
0           ! 2 Initial value of function
7.5         ! 3 Time at point-1
0           ! 4 Water draw at point -1
7.5         ! 5 Time at point-2
340.69      ! 6 Water draw at point -2
7.75        ! 7 Time at point-3
340.69      ! 8 Water draw at point -3
7.75        ! 9 Time at point-4
0           ! 10 Water draw at point -4
13          ! 11 Time at point-5
0           ! 12 Water draw at point -5
13          ! 13 Time at point-6
340.69      ! 14 Water draw at point -6
13.181      ! 15 Time at point-7
340.69      ! 16 Water draw at point -7
13.181      ! 17 Time at point-8
0           ! 18 Water draw at point -8
15          ! 19 Time at point-9
0           ! 20 Water draw at point -9
15          ! 21 Time at point-10
340.69      ! 22 Water draw at point -10
15.028      ! 23 Time at point-11
340.69      ! 24 Water draw at point -11
15.028      ! 25 Time at point-12
0           ! 26 Water draw at point -12
18          ! 27 Time at point-13
0           ! 28 Water draw at point -13
18          ! 29 Time at point-14
340.69      ! 30 Water draw at point -14
18.056      ! 31 Time at point-15
```

```
340.69          ! 32 Water draw at point -15
18.056          ! 33 Time at point-16
0               ! 34 Water draw at point -16
20              ! 35 Time at point-17
0               ! 36 Water draw at point -17
20              ! 37 Time at point-18
340.69          ! 38 Water draw at point -18
20.111          ! 39 Time at point-19
340.69          ! 40 Water draw at point -19
20.111          ! 41 Time at point-20
0               ! 42 Water draw at point -20
22              ! 43 Time at point-21
0               ! 44 Water draw at point -21
22              ! 45 Time at point-22
340.69          ! 46 Water draw at point -22
22.083          ! 47 Time at point-23
340.69          ! 48 Water draw at point -23
22.083          ! 49 Time at point-24
0               ! 50 Water draw at point -24
24              ! 51 Time at point-25
0               ! 52 Water draw at point -25
*------------------------------------------------------------------------------

* EQUATIONS "kJ/h to kW"
*
EQUATIONS 3
kW_element1 = [10,1]/3600
kW_element2 = [11,1]/3600
kW_combined = kW_element1+kW_element2
*$UNIT_NAME kJ/h to kW
*$LAYER Main
*$POSITION 917 168

*------------------------------------------------------------------------------


* Model "Energy Usage" (Type 46)
*

UNIT 7 TYPE 46          Energy Usage
*$UNIT_NAME Energy Usage
*$MODEL .\Output\Printegrator\Unformatted\Type46.tmf
*$POSITION 1104 242
*$LAYER Main #
*$# PRINTEGRATOR
PARAMETERS 5
34              ! 1 Logical unit
```

```
-1                ! 2 Logical unit for monthly summaries
0                 ! 3 Relative or absolute start time
24.000001                 ! 4 Printing & integrating interval
0                 ! 5 Number of inputs to avoid integration
INPUTS 3
kW_element1          ! kJ/h to kW:kW_element1 ->Input to be integrated &
printed-1
kW_element2          ! kJ/h to kW:kW_element2 ->Input to be integrated &
printed-2
kW_combined          ! kJ/h to kW:kW_combined ->Input to be integrated &
printed-3
*** INITIAL INPUT VALUES
kWh_elem1 kWh_elem2 kWh_comb
LABELS 0

*** External files
ASSIGN "BW_true_ambient_TMY3.txt" 34
*|? Output file for integrated results? |1000
*------------------------------------------------------------------------------

* Model "Temp_kWH_Graph" (Type 65)
*

UNIT 8 TYPE 65         Temp_kWH_Graph
*$UNIT_NAME Temp_kWH_Graph
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 542 49
*$LAYER Main #
PARAMETERS 12
7                 ! 1 Nb. of left-axis variables
6                 ! 2 Nb. of right-axis variables
0.0               ! 3 Left axis minimum
220               ! 4 Left axis maximum
0.0               ! 5 Right axis minimum
5                 ! 6 Right axis maximum
1                 ! 7 Number of plots per simulation
12                ! 8 X-axis gridpoints
0                 ! 9 Shut off Online w/o removing
-1                ! 10 Logical unit for output file
0                 ! 11 Output file units
0                 ! 12 Output file delimiter
INPUTS 13
0,0               ! [unconnected] Left axis variable-1
0,0               ! [unconnected] Left axis variable-2
0,0               ! [unconnected] Left axis variable-3
0,0               ! [unconnected] Left axis variable-4
MixedHotWater_F               ! C to F:MixedHotWater_F ->Left axis variable-5
```

```
ColdWater_in_Main_F          ! C to F:ColdWater_in_Main_F ->Left axis variable-
6
HotWater_outofBW_F           ! C to F:HotWater_outofBW_F ->Left axis variable-
7
GPM_main_in           ! lit/hr to GPM:GPM_main_in ->Right axis variable-1
GPM_hot               ! lit/hr to GPM:GPM_hot ->Right axis variable-2
GPM_main_out                 ! lit/hr to GPM:GPM_main_out ->Right axis
variable-3
kW_element1           ! kJ/h to kW:kW_element1 ->Right axis variable-4
kW_element2           ! kJ/h to kW:kW_element2 ->Right axis variable-5
kW_combined           ! kJ/h to kW:kW_combined ->Right axis variable-6
*** INITIAL INPUT VALUES
Tank_Node1_temp Tank_Node3_temp Tank_Node8_temp Tank_Node9_temp
Mix_hot_out Cold_in_mains TankOut_F GPM_main_in GPM_hot_tank
GPM_main_out
kW_elem1 kW_elem2 kW_comb
LABELS  3
"Temp F"
"GPM and kW"
"Temps kW GPM"
*------------------------------------------------------------------------------

* Model "Bradford White" (Type 534)
*

UNIT 9 TYPE 534       Bradford White
*$UNIT_NAME Bradford White
*$MODEL .\Storage Tank Library (TESS)\Cylindrical Storage Tank\Vertical
Cylinder\Version without Plug-In\No HXs\Type534-NoHX.tmf
*$POSITION 467 350
*$LAYER Main #
*$# CYLINDRICAL STORAGE TANK
PARAMETERS 37
-1              ! 1 LU for data file
9               ! 2 Number of tank nodes
1               ! 3 Number of ports
0               ! 4 Number of immersed heat exchangers
0               ! 5 Number of miscellaneous heat flows
0.189272               ! 6 Tank volume
1.461           ! 7 Tank height
0               ! 8 Tank fluid
4.032           ! 9 Fluid specific heat
988.5           ! 10 Fluid density
2.3112          ! 11 Fluid thermal conductivity
2.00            ! 12 Fluid viscosity
0.00026                ! 13 Fluid thermal expansion coefficient
5.364           ! 14 Top loss coefficient
```

```
5.364           ! 15 Edge loss coefficient for node-1
5.364           ! 16 Edge loss coefficient for node-2
5.364           ! 17 Edge loss coefficient for node-3
5.364           ! 18 Edge loss coefficient for node-4
5.364           ! 19 Edge loss coefficient for node-5
5.364           ! 20 Edge loss coefficient for node-6
5.364           ! 21 Edge loss coefficient for node-7
5.364           ! 22 Edge loss coefficient for node-8
5.364           ! 23 Edge loss coefficient for node-9
5.364           ! 24 Bottom loss coefficient
0               ! 25 Additional thermal conductivity
1               ! 26 Inlet flow mode
9               ! 27 Entry node
1               ! 28 Exit node
0               ! 29 Flue loss coefficient for node-1
0               ! 30 Flue loss coefficient for node-2
0               ! 31 Flue loss coefficient for node-3
0               ! 32 Flue loss coefficient for node-4
0               ! 33 Flue loss coefficient for node-5
0               ! 34 Flue loss coefficient for node-6
0               ! 35 Flue loss coefficient for node-7
0               ! 36 Flue loss coefficient for node-8
0               ! 37 Flue loss coefficient for node-9
INPUTS 24
17,3            ! Diverter:Temperature at outlet 2 ->Inlet temperature for port
17,4            ! Diverter:Flow rate at outlet 2 ->Inlet flow rate for port
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Top loss
temperature
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-1
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-2
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-3
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-4
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-5
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-6
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-7
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-8
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-9
```

```
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Bottom loss
temperature
21,1            ! PHX Weather -TMY3:Dry bulb temperature ->Gas flue
temperature
0,0             ! [unconnected] Inversion mixing flow rate
0,0             ! [unconnected] Auxiliary heat input for node-1
0,0             ! [unconnected] Auxiliary heat input for node-2
10,1            ! Upper Element:Fluid energy ->Auxiliary heat input for node-3
0,0             ! [unconnected] Auxiliary heat input for node-4
0,0             ! [unconnected] Auxiliary heat input for node-5
0,0             ! [unconnected] Auxiliary heat input for node-6
0,0             ! [unconnected] Auxiliary heat input for node-7
11,1            ! Lower Element:Fluid energy ->Auxiliary heat input for node-8
0,0             ! [unconnected] Auxiliary heat input for node-9
*** INITIAL INPUT VALUES
37.7778 0.0 ambient_temp_C ambient_temp_C ambient_temp_C
ambient_temp_C
ambient_temp_C ambient_temp_C ambient_temp_C ambient_temp_C
ambient_temp_C
ambient_temp_C ambient_temp_C ambient_temp_C -100 0.0 0.0 0.0 0.0 0 0.0
0.0 0.0 0.0
DERIVATIVES 9
20.0            ! 1 Initial Tank Temperature-1
20.0            ! 2 Initial Tank Temperature-2
20.0            ! 3 Initial Tank Temperature-3
20.0            ! 4 Initial Tank Temperature-4
20.0            ! 5 Initial Tank Temperature-5
20.0            ! 6 Initial Tank Temperature-6
20.0            ! 7 Initial Tank Temperature-7
20.0            ! 8 Initial Tank Temperature-8
20.0            ! 9 Initial Tank Temperature-9
*------------------------------------------------------------------------------

* Model "Upper Element" (Type 1226)
*

UNIT 10 TYPE 1226    Upper Element
*$UNIT_NAME Upper Element
*$MODEL .\Storage Tank Library (TESS)\Tank Heating Device\Electric\Type1226-
Elec.tmf
*$POSITION 652 259
*$LAYER Main #
INPUTS 3
0,0             ! [unconnected] Heating capacity
0,0             ! [unconnected] Thermal efficiency
12,2            ! Top Thermostat:Conditioning signal ->Control signal
*** INITIAL INPUT VALUES
```

```
16199.999571 1. 1.
*------------------------------------------------------------------------------

* Model "Lower Element" (Type 1226)
*

UNIT 11 TYPE 1226     Lower Element
*$UNIT_NAME Lower Element
*$MODEL .\Storage Tank Library (TESS)\Tank Heating Device\Electric\Type1226-
Elec.tmf
*$POSITION 663 428
*$LAYER Main #
INPUTS 3
0,0             ! [unconnected] Heating capacity
0,0             ! [unconnected] Thermal efficiency
13,1            ! Bottom Thermostat:Control signal for stage heating ->Control
signal
*** INITIAL INPUT VALUES
16199.999571 1. 1.
*------------------------------------------------------------------------------

* Model "Top Thermostat" (Type 1502)
*

UNIT 12 TYPE 1502     Top Thermostat
*$UNIT_NAME Top Thermostat
*$MODEL .\Storage Tank Library (TESS)\Aquastats\Heating Mode\Type1502.tmf
*$POSITION 652 142
*$LAYER Main #
PARAMETERS 4
1               ! 1 Number of heating stages
5               ! 2 # oscillations permitted
6.111111                ! 3 Temperature dead band
0               ! 4 Number of stage exceptions
INPUTS 3
9,17            ! Bradford White:Tank nodal temperature-3 ->Fluid temperature
0,0             ! [unconnected] Lockout signal
0,0             ! [unconnected] Setpoint temperature for stage
*** INITIAL INPUT VALUES
20.0 0 51.666689
*------------------------------------------------------------------------------

* Model "Bottom Thermostat" (Type 1502)
*

UNIT 13 TYPE 1502     Bottom Thermostat
*$UNIT_NAME Bottom Thermostat
```

```
*$MODEL .\Storage Tank Library (TESS)\Aquastats\Heating Mode\Type1502.tmf
*$POSITION 661 553
*$LAYER Main #
PARAMETERS 4
1		! 1 Number of heating stages
5		! 2 # oscillations permitted
6.111111		! 3 Temperature dead band
0		! 4 Number of stage exceptions
INPUTS 3
9,22		! Bradford White:Tank nodal temperature-8 ->Fluid temperature
12,1		! Top Thermostat:Control signal for stage heating ->Lockout
signal
0,0		! [unconnected] Setpoint temperature for stage
*** INITIAL INPUT VALUES
20.0 0 51.666689
*------------------------------------------------------------------------------

* Model "kWh Graph" (Type 65)
*

UNIT 14 TYPE 65	 kWh Graph
*$UNIT_NAME kWh Graph
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 1097 95
*$LAYER Main #
PARAMETERS 12
3		! 1 Nb. of left-axis variables
0		! 2 Nb. of right-axis variables
0.0		! 3 Left axis minimum
5		! 4 Left axis maximum
0.0		! 5 Right axis minimum
1000.0		! 6 Right axis maximum
1		! 7 Number of plots per simulation
12		! 8 X-axis gridpoints
0		! 9 Shut off Online w/o removing
-1		! 10 Logical unit for output file
0		! 11 Output file units
0		! 12 Output file delimiter
INPUTS 3
kW_element1		! kJ/h to kW:kW_element1 ->Left axis variable-1
kW_element2		! kJ/h to kW:kW_element2 ->Left axis variable-2
kW_combined		! kJ/h to kW:kW_combined ->Left axis variable-3
*** INITIAL INPUT VALUES
kW_elem1 kW_elem2 kW_comb
LABELS  3
"Kilowatts"
""
```

```
"Energy Usage"
*------------------------------------------------------------------------------

* EQUATIONS "Constants"
*
EQUATIONS 1
ambient_temp_C = 24
*$UNIT_NAME Constants
*$LAYER Main
*$POSITION 763 746

*------------------------------------------------------------------------------


* EQUATIONS "lit/hr to GPM"
*
EQUATIONS 3
GPM_hot = [9,2]*0.004403
GPM_main_in = [2,1]*0.004403
GPM_main_out = [17,2]*0.004403
*$UNIT_NAME lit/hr to GPM
*$LAYER Main
*$POSITION 72 146

*------------------------------------------------------------------------------


* Model "Diverter" (Type 11)
*

UNIT 17 TYPE 11        Diverter
*$UNIT_NAME Diverter
*$MODEL .\Hydronics\Flow Diverter\Other Fluids\Right Facing\Type11f.tmf
*$POSITION 203 455
*$LAYER Main #
PARAMETERS 1
2               ! 1 Controlled flow diverter mode
INPUTS 3
21,5            ! PHX Weather -TMY3:Mains water temperature ->Inlet
temperature
2,1             ! Water Draw Profile:Average water draw ->Inlet flow rate
19,1            ! Tempering Control (<110F):Fraction to heat source ->Control
signal
*** INITIAL INPUT VALUES
20.0 0 0.5
*------------------------------------------------------------------------------
```

```
* Model "Tempering Control (<110F)" (Type 953)
*

UNIT 19 TYPE 953      Tempering Control (<110F)
*$UNIT_NAME Tempering Control (<110F)
*$MODEL .\Controllers Library (TESS)\Tempering Valve Controller\Type953.tmf
*$POSITION 470 509
*$LAYER Main #
*$# NOTE: This control strategy can only be used with solver 0 (Successive
substitution)
*$#
PARAMETERS 1
5                ! 1 No. of oscillations
INPUTS 4
0,0              ! [unconnected] Setpoint temperature
9,1              ! Bradford White:Temperature at outlet ->Source temperature
21,5             ! PHX Weather -TMY3:Mains water temperature ->Tempering fluid
temperature (return temperature)
0,0              ! [unconnected] Mode
*** INITIAL INPUT VALUES
43.333355 10.0 20.0 1
*------------------------------------------------------------------------------

* Model "Mixer" (Type 11)
*

UNIT 20 TYPE 11       Mixer
*$UNIT_NAME Mixer
*$MODEL .\Hydronics\Tee-Piece\Other Fluids\Type11h.tmf
*$POSITION 285 244
*$LAYER Water Loop #
PARAMETERS 1
1                ! 1 Tee piece mode
INPUTS 4
17,1             ! Diverter:Temperature at outlet 1 ->Temperature at inlet 1
17,2             ! Diverter:Flow rate at outlet 1 ->Flow rate at inlet 1
9,1              ! Bradford White:Temperature at outlet ->Temperature at inlet 2
9,2              ! Bradford White:Flow rate at outlet ->Flow rate at inlet 2
*** INITIAL INPUT VALUES
20.0 100.0 20.0 100.0
*------------------------------------------------------------------------------

* EQUATIONS "C to F"
*
EQUATIONS 12
BW_Node1_F = [9,15]*(9/5) + 32
BW_Node2_F = [9,16]*(9/5) + 32
```

```
BW_Node3_F = [9,17]*(9/5) + 32
BW_Node4_F = [9,18]*(9/5) + 32
BW_Node5_F = [9,19]*(9/5) + 32
BW_Node6_F = [9,20]*(9/5) + 32
BW_Node7_F = [9,21]*(9/5) + 32
BW_Node8_F = [9,22]*(9/5) + 32
BW_Node9_F = [9,23]*(9/5) + 32
ColdWater_in_Main_F = [21,5]*(9/5) + 32
MixedHotWater_F = [20,1]*(9/5) + 32
HotWater_outofBW_F = [9,1]*(9/5) + 32
*$UNIT_NAME C to F
*$LAYER Main
*$POSITION 341 73

*------------------------------------------------------------------------------


* Model "PHX Weather -TMY3" (Type 15)
*

UNIT 21 TYPE 15        PHX Weather -TMY3
*$UNIT_NAME PHX Weather -TMY3
*$MODEL .\Weather Data Reading and Processing\Standard
Format\TMY3\Type15-TMY3.tmf
*$POSITION 203 618
*$LAYER Main #
PARAMETERS 9
7               ! 1 File Type
35              ! 2 Logical unit
3               ! 3 Tilted Surface Radiation Mode
0.2             ! 4 Ground reflectance: no albedo reported
0.7             ! 5 Not used
1               ! 6 Number of surfaces
1               ! 7 Tracking mode
0.0             ! 8 Slope of surface
0               ! 9 Azimuth of surface
*** External files
ASSIGN "C:\Trnsys17\Weather\US-
TMY3\US_AZ_PHOENIX_INTL_AP_722780.csv" 35
*|? Which file contains the TMY-2 weather data? |1000
*------------------------------------------------------------------------------

END
```

APPENDIX C

SUNEARTH® TRNSYS INPUT FILE

```
VERSION 17
*******************************************************************
*************
*** TRNSYS input file (deck) generated by TrnsysStudio
*** on Friday, June 29, 2012 at 00:11
*** from TrnsysStudio project: Y:\Documents\Docs\School\Alt
Masters\Thesis\TRNSYS Files\OFFICIAL FILES\Thesis -
SunEarth\SunEarth_trueambient.tpf
***
*** If you edit this file, use the File/Import TRNSYS Input File function in
*** TrnsysStudio to update the project.
***
*** If you have problems, questions or suggestions please contact your local
*** TRNSYS distributor or mailto:software@cstb.fr
***
*******************************************************************
*************


*******************************************************************
*************
*** Units
*******************************************************************
*************

*******************************************************************
*************
*** Control cards
*******************************************************************
  *************
* START, STOP and STEP
CONSTANTS 3
START=0
STOP=8760.000229455
STEP=0.016666666
SIMULATION   START STOP   STEP  ! Start time     End time        Time step
TOLERANCES 0.001 0.001                    ! Integration    Convergence
LIMITS 50 50 50                           ! Max iterations         Max warnings
        Trace limit
DFQ 1                             ! TRNSYS numerical integration solver
method
WIDTH 120                         ! TRNSYS output file width, number of
characters
LIST                              ! NOLIST statement
                                  ! MAP statement
SOLVER 0 1 1                      ! Solver statement     Minimum relaxation
factor  Maximum relaxation factor
```

```
NAN_CHECK 0                         ! Nan DEBUG statement
OVERWRITE_CHECK 0                           ! Overwrite DEBUG statement
TIME_REPORT 0                       ! disable time report
EQSOLVER 0                          ! EQUATION SOLVER statement
* User defined CONSTANTS


* Model "Water Draw Profile" (Type 14)
*

UNIT 11 TYPE 14      Water Draw Profile
*$UNIT_NAME Water Draw Profile
*$MODEL .\Utility\Forcing Functions\Water Draw\Type14b.tmf
*$POSITION 64 712
*$LAYER Main #
PARAMETERS 52
0              ! 1 Initial value of time
0              ! 2 Initial value of function
7.5            ! 3 Time at point-1
0              ! 4 Water draw at point -1
7.5            ! 5 Time at point-2
340.69         ! 6 Water draw at point -2
7.75           ! 7 Time at point-3
340.69         ! 8 Water draw at point -3
7.75           ! 9 Time at point-4
0              ! 10 Water draw at point -4
13             ! 11 Time at point-5
0              ! 12 Water draw at point -5
13             ! 13 Time at point-6
340.69         ! 14 Water draw at point -6
13.181         ! 15 Time at point-7
340.69         ! 16 Water draw at point -7
13.181         ! 17 Time at point-8
0              ! 18 Water draw at point -8
15             ! 19 Time at point-9
0              ! 20 Water draw at point -9
15             ! 21 Time at point-10
340.69         ! 22 Water draw at point -10
15.028         ! 23 Time at point-11
340.69         ! 24 Water draw at point -11
15.028         ! 25 Time at point-12
0              ! 26 Water draw at point -12
18             ! 27 Time at point-13
0              ! 28 Water draw at point -13
18             ! 29 Time at point-14
340.69         ! 30 Water draw at point -14
18.056         ! 31 Time at point-15
```

```
340.69          ! 32 Water draw at point -15
18.056          ! 33 Time at point-16
0               ! 34 Water draw at point -16
20              ! 35 Time at point-17
0               ! 36 Water draw at point -17
20              ! 37 Time at point-18
340.69          ! 38 Water draw at point -18
20.111          ! 39 Time at point-19
340.69          ! 40 Water draw at point -19
20.111          ! 41 Time at point-20
0               ! 42 Water draw at point -20
22              ! 43 Time at point-21
0               ! 44 Water draw at point -21
22              ! 45 Time at point-22
340.69          ! 46 Water draw at point -22
22.083          ! 47 Time at point-23
340.69          ! 48 Water draw at point -23
22.083          ! 49 Time at point-24
0               ! 50 Water draw at point -24
24              ! 51 Time at point-25
0               ! 52 Water draw at point -25
*------------------------------------------------------------------------------

* Model "Energy Plotter" (Type 65)
*

UNIT 20 TYPE 65      Energy Plotter
*$UNIT_NAME Energy Plotter
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 949 232
*$LAYER Main #
PARAMETERS 12
3               ! 1 Nb. of left-axis variables
2               ! 2 Nb. of right-axis variables
0.0             ! 3 Left axis minimum
5               ! 4 Left axis maximum
0.0             ! 5 Right axis minimum
2               ! 6 Right axis maximum
1               ! 7 Number of plots per simulation
12              ! 8 X-axis gridpoints
0               ! 9 Shut off Online w/o removing
-1              ! 10 Logical unit for output file
0               ! 11 Output file units
0               ! 12 Output file delimiter
INPUTS 5
kW_element1          ! kJ/h to kW:kW_element1 ->Left axis variable-1
kW_pump              ! kJ/h to kW:kW_pump ->Left axis variable-2
```

```
kW_TOTAL              ! kJ/h to kW:kW_TOTAL ->Left axis variable-3
29,1            ! Pump Controller:Output control function ->Right axis variable-1
24,1            ! Thermostat:Control signal for stage heating ->Right axis variable-
2
*** INITIAL INPUT VALUES
kW_elem kW_pump kW_TOTAL Pump_Cntrl_Sig Thermostat_Cntrl_Sig
LABELS  3
"Kilowatts"
"Control Signal 1 ON 0 OFF"
"Energy Usage"
*------------------------------------------------------------------------------

* EQUATIONS "kJ/h to kW"
*
EQUATIONS 3
kW_element1 = [25,1]/3600
kW_pump = [23,3]/3600
kW_TOTAL = kW_element1+kW_pump
*$UNIT_NAME kJ/h to kW
*$LAYER Main
*$POSITION 811 178

*------------------------------------------------------------------------------


* Model "Energy Usage Output" (Type 46)
*

UNIT 22 TYPE 46       Energy Usage Output
*$UNIT_NAME Energy Usage Output
*$MODEL .\Output\Printegrator\Unformatted\Type46.tmf
*$POSITION 1067 226
*$LAYER Main #
*$# PRINTEGRATOR
PARAMETERS 5
33              ! 1 Logical unit
-1              ! 2 Logical unit for monthly summaries
0               ! 3 Relative or absolute start time
24.000001             ! 4 Printing & integrating interval
0               ! 5 Number of inputs to avoid integration
INPUTS 3
kW_element1           ! kJ/h to kW:kW_element1 ->Input to be integrated &
printed-1
kW_pump               ! kJ/h to kW:kW_pump ->Input to be integrated & printed-
2
kW_TOTAL              ! kJ/h to kW:kW_TOTAL ->Input to be integrated &
printed-3
```

```
*** INITIAL INPUT VALUES
kWh_element kWh_pump kWh_TOTAL
LABELS 0

*** External files
ASSIGN "SE_trueambient_results_TMY3.txt" 33
*|? Output file for integrated results? |1000
*------------------------------------------------------------------------------

* Model "Thermostat" (Type 1502)
*

UNIT 24 TYPE 1502     Thermostat
*$UNIT_NAME Thermostat
*$MODEL .\Storage Tank Library (TESS)\Aquastats\Heating Mode\Type1502.tmf
*$POSITION 597 788
*$LAYER Main #
PARAMETERS 4
1                ! 1 Number of heating stages
5                ! 2 # oscillations permitted
2.777778                 ! 3 Temperature dead band
0                ! 4 Number of stage exceptions
INPUTS 3
28,29            ! Storage Tank w/ HX:Tank nodal temperature-5 ->Fluid
temperature
0,0              ! [unconnected] Lockout signal
0,0              ! [unconnected] Setpoint temperature for stage
*** INITIAL INPUT VALUES
20.0 0 51.666689
*------------------------------------------------------------------------------

* Model "Electric Element" (Type 1226)
*

UNIT 25 TYPE 1226     Electric Element
*$UNIT_NAME Electric Element
*$MODEL .\Storage Tank Library (TESS)\Tank Heating Device\Electric\Type1226-
Elec.tmf
*$POSITION 596 660
*$LAYER Main #
INPUTS 3
0,0              ! [unconnected] Heating capacity
0,0              ! [unconnected] Thermal efficiency
24,1             ! Thermostat:Control signal for stage heating ->Control signal
*** INITIAL INPUT VALUES
16199.999571 1. 1.
*------------------------------------------------------------------------------
```

```
* Model "Plat-Plate Collector" (Type 539)
*

UNIT 26 TYPE 539	Plat-Plate Collector
*$UNIT_NAME Plat-Plate Collector
*$MODEL .\Solar Library (TESS)\Glazed Flat Plate Collectors\OG100 Quadratic
Efficiency Approach\Type539.tmf
*$POSITION 451 190
*$LAYER Main #
*$# This component sets the flow rate for all connected flow loop components if
the variable speed option is enabled.
PARAMETERS 16
1		! 1 Number in series
3.799703		! 2 Collector area
3.91		! 3 Fluid specific heat
1		! 4 Collector test mode
.718		! 5 Intercept efficiency (a0)
8.24616		! 6 1st order efficiency coefficient (a1)
0.158328		! 7 2nd order efficiency coefficient (a2)
72		! 8 Tested flow rate per unit area
3.91		! 9 Fluid specific heat at test conditions
0.322		! 10 1st-order IAM coefficient
-0.031		! 11 2nd-order IAM coefficient
0.0		! 12 Minimum flowrate
600		! 13 Maximum flowrate
100.0		! 14 Capacitance of Collector
10		! 15 Number of Nodes
20		! 16 Initial Temperature
INPUTS 10
23,1		! Glycol Pump:Outlet fluid temperature ->Inlet temperature
23,2		! Glycol Pump:Outlet flow rate ->Inlet flowrate
39,1		! PHX Weather -TMY3:Dry bulb temperature ->Ambient
temperature
39,25		! PHX Weather -TMY3:Beam radiation for surface ->Beam radiation
on the tilted surface
39,26		! PHX Weather -TMY3:Sky diffuse radiation for surface ->Sky
diffuse radiation on tilted surface
39,27		! PHX Weather -TMY3:Ground reflected diffuse radiation for surface
->Ground-reflected diffuse radiation on tilted surface
39,29		! PHX Weather -TMY3:Angle of incidence for surface ->Incidence
angle
39,30		! PHX Weather -TMY3:Slope of surface ->Collector slope
0,0		! [unconnected] Pump Control Specification
0,0		! [unconnected] Outlet Temperature Setpoint
*** INITIAL INPUT VALUES
20.0 398 10.0 0.0 0.0 0.0 45.0 0. 0 60.0
```

```
*------------------------------------------------------------------------------

* Model "Temp Plotter" (Type 65)
*

UNIT 27 TYPE 65        Temp Plotter
*$UNIT_NAME Temp Plotter
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 1109 532
*$LAYER Main #
PARAMETERS 12
9               ! 1 Nb. of left-axis variables
4               ! 2 Nb. of right-axis variables
0.0             ! 3 Left axis minimum
220             ! 4 Left axis maximum
0.0             ! 5 Right axis minimum
5               ! 6 Right axis maximum
1               ! 7 Number of plots per simulation
12              ! 8 X-axis gridpoints
0               ! 9 Shut off Online w/o removing
-1              ! 10 Logical unit for output file
0               ! 11 Output file units
0               ! 12 Output file delimiter
INPUTS 13
Tank_Node1_F                ! C to F:Tank_Node1_F ->Left axis variable-1
Tank_Node5_F                ! C to F:Tank_Node5_F ->Left axis variable-2
Tank_Node8_F                ! C to F:Tank_Node8_F ->Left axis variable-3
Tank_Node9_F                ! C to F:Tank_Node9_F ->Left axis variable-4
MixedHotWater_F             ! C to F:MixedHotWater_F ->Left axis variable-5
ColdWater_in_Main_F         ! C to F:ColdWater_in_Main_F ->Left axis variable-6
HotWater_outofBW_F          ! C to F:HotWater_outofBW_F ->Left axis variable-7
HTF_Roof_F          ! C to F:HTF_Roof_F ->Left axis variable-8
HTF_TankHX_F                ! C to F:HTF_TankHX_F ->Left axis variable-9
GPM             ! lit/hr to GPM:GPM ->Right axis variable-1
29,1            ! Pump Controller:Output control function ->Right axis variable-2
24,1            ! Thermostat:Control signal for stage heating ->Right axis variable-
3
kW_TOTAL            ! kJ/h to kW:kW_TOTAL ->Right axis variable-4
*** INITIAL INPUT VALUES
Tank_Node1_temp Tank_Node5_temp Tank_Node8_temp Tank_Node9_temp
Mix_hot_water_out Cold_mains_in HotWater_frTank HTF_Temp_Roof
HTF_Temp_HX
GPM Pump_Signal Thermostat_signal kW_Total
LABELS  3
"Temp F"
"GPM  /  Control Signal  /  kW"
"Temperatures"
```

```
*---------------------------------------------------------------------------

* Model "Storage Tank w/ HX" (Type 1237)
*

UNIT 28 TYPE 1237     Storage Tank w/ HX
*$UNIT_NAME Storage Tank w/ HX
*$MODEL .\Storage Tank Library (TESS)\Cylindrical Storage Tank\Vertical Cylinder
With Wrap-Around HX\With Diptube\Type1237-4.tmf
*$POSITION 320 564
*$LAYER Main #
*$# Vertical Cylindrical Storage Tank with Wrap-Around Heat Exchanger
PARAMETERS 96
9             ! 1 Number of tank nodes
1             ! 2 Number of ports
0             ! 3 Number of miscellaneous heat flows
0.302835            ! 4 Tank volume
1.4859        ! 5 Tank height
4.032         ! 6 Fluid specific heat
988.5         ! 7 Fluid density
2.3112        ! 8 Fluid thermal conductivity
2             ! 9 Fluid viscosity
0.00026             ! 10 Fluid thermal expansion coefficient
3.91          ! 11 HX fluid specific heat
1014.9        ! 12 HX fluid density
1.7172        ! 13 HX fluid thermal conductivity
3.29          ! 14 HX fluid viscosity
2.7           ! 15 Top loss coefficient
3.6           ! 16 Edge loss coefficient for node-1
3.6           ! 17 Edge loss coefficient for node-2
3.6           ! 18 Edge loss coefficient for node-3
3.6           ! 19 Edge loss coefficient for node-4
3.6           ! 20 Edge loss coefficient for node-5
3.6           ! 21 Edge loss coefficient for node-6
3.6           ! 22 Edge loss coefficient for node-7
3.6           ! 23 Edge loss coefficient for node-8
3.6           ! 24 Edge loss coefficient for node-9
3.6           ! 25 Bottom loss coefficient
5             ! 26 HX loss coefficient
0             ! 27 Additional thermal conductivity
0.00635             ! 28 Tank wall thickness
150.          ! 29 Tank wall thermal conductivity
0.016916            ! 30 HX pipe inner diameter
0.01905             ! 31 HX pipe outer diameter
36.576        ! 32 HX pipe length
1443.599962         ! 33 HX pipe thermal conductivity
0.6096        ! 34 Height of HX wrap
```

0.008128	! 35 HX tube spacing
0.005	! 36 HX bond resistance
0.6	! 37 F' factor
11	! 38 Number of HX nodes
0	! 39 Fraction of HX cover for node-1
0	! 40 Fraction of HX cover for node-2
0	! 41 Fraction of HX cover for node-3
0	! 42 Fraction of HX cover for node-4
0	! 43 Fraction of HX cover for node-5
1	! 44 Fraction of HX cover for node-6
1	! 45 Fraction of HX cover for node-7
1	! 46 Fraction of HX cover for node-8
0.7	! 47 Fraction of HX cover for node-9
6	! 48 Tank node adjacent to HX node-1
0.091	! 49 Fraction of HX length for HX node-1
6	! 50 Tank node adjacent to HX node-2
0.091	! 51 Fraction of HX length for HX node-2
6	! 52 Tank node adjacent to HX node-3
0.091	! 53 Fraction of HX length for HX node-3
7	! 54 Tank node adjacent to HX node-4
0.091	! 55 Fraction of HX length for HX node-4
7	! 56 Tank node adjacent to HX node-5
0.091	! 57 Fraction of HX length for HX node-5
7	! 58 Tank node adjacent to HX node-6
0.091	! 59 Fraction of HX length for HX node-6
8	! 60 Tank node adjacent to HX node-7
0.091	! 61 Fraction of HX length for HX node-7
8	! 62 Tank node adjacent to HX node-8
0.091	! 63 Fraction of HX length for HX node-8
8	! 64 Tank node adjacent to HX node-9
0.091	! 65 Fraction of HX length for HX node-9
9	! 66 Tank node adjacent to HX node-10
0.091	! 67 Fraction of HX length for HX node-10
9	! 68 Tank node adjacent to HX node-11
0.091	! 69 Fraction of HX length for HX node-11
4	! 70 Inlet flow mode: diptube
1	! 71 Exit node
0	! 72 Fraction of inlet flow to node-1
0	! 73 Fraction of inlet flow to node-2
0	! 74 Fraction of inlet flow to node-3
0	! 75 Fraction of inlet flow to node-4
0	! 76 Fraction of inlet flow to node-5
0	! 77 Fraction of inlet flow to node-6
0	! 78 Fraction of inlet flow to node-7
0	! 79 Fraction of inlet flow to node-8
1	! 80 Fraction of inlet flow to node-9
1.3716	! 81 Diptube length

```
0.016916              ! 82 Inner diptube diameter
0.01905               ! 83 Outer diptube diameter
1414.8          ! 84 Diptube thermal conductivity
0.6             ! 85 Multiplier for natural convection
0.25            ! 86 Exponent for natural convection
9               ! 87 Number of diptube nodes
1               ! 88 Tank node for diptube node-1
2               ! 89 Tank node for diptube node-2
3               ! 90 Tank node for diptube node-3
4               ! 91 Tank node for diptube node-4
5               ! 92 Tank node for diptube node-5
6               ! 93 Tank node for diptube node-6
7               ! 94 Tank node for diptube node-7
8               ! 95 Tank node for diptube node-8
9               ! 96 Tank node for diptube node-9
INPUTS 25
36,3            ! Diverter:Temperature at outlet 2 ->Inlet diptube temperature
36,4            ! Diverter:Flow rate at outlet 2 ->Inlet diptube flow rate
30,1            ! Pipe - Glycol from Collector to HX:Temperature at Outlet A -
>Inlet temperature for HX
30,2            ! Pipe - Glycol from Collector to HX:Flow Rate at Outlet A ->Inlet
flow rate for HX
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Top loss
temperature
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-1
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-2
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-3
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-4
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-5
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-6
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-7
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-8
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Edge loss
temperature for node-9
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Bottom loss
temperature
0,0             ! [unconnected] Inversion mixing flow rate
0,0             ! [unconnected] Auxiliary heat input for node-1
0,0             ! [unconnected] Auxiliary heat input for node-2
```

```
0,0             ! [unconnected] Auxiliary heat input for node-3
0,0             ! [unconnected] Auxiliary heat input for node-4
25,1            ! Electric Element:Fluid energy ->Auxiliary heat input for node-5
0,0             ! [unconnected] Auxiliary heat input for node-6
0,0             ! [unconnected] Auxiliary heat input for node-7
0,0             ! [unconnected] Auxiliary heat input for node-8
0,0             ! [unconnected] Auxiliary heat input for node-9
*** INITIAL INPUT VALUES
20 0.0 20.0 0.0 AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes
AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes
-100 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0
DERIVATIVES 9
20              ! 1 Initial tank temperature for node-1
20.0            ! 2 Initial tank temperature for node-2
20.0            ! 3 Initial tank temperature for node-3
20.0            ! 4 Initial tank temperature for node-4
20.0            ! 5 Initial tank temperature for node-5
20.0            ! 6 Initial tank temperature for node-6
20.0            ! 7 Initial tank temperature for node-7
20.0            ! 8 Initial tank temperature for node-8
20.0            ! 9 Initial tank temperature for node-9
*------------------------------------------------------------------------------

* Model "Glycol Pump" (Type 114)
*

UNIT 23 TYPE 114      Glycol Pump
*$UNIT_NAME Glycol Pump
*$MODEL .\Hydronics\Pumps\Single Speed\Type114.tmf
*$POSITION 620 293
*$LAYER Main #
*$# SINGLE-SPEED PUMP
PARAMETERS 4
398             ! 1 Rated flow rate
3.91            ! 2 Fluid specific heat
287.999992              ! 3 Rated power
0.0             ! 4 Motor heat loss fraction
INPUTS 5
31,1            ! Pipe - Glycol from HX to Collector:Temperature at Outlet A -
>Inlet fluid temperature
31,2            ! Pipe - Glycol from HX to Collector:Flow Rate at Outlet A ->Inlet
fluid flow rate
29,1            ! Pump Controller:Output control function ->Control signal
0,0             ! [unconnected] Overall pump efficiency
```

0,0 ! [unconnected] Motor efficiency
*** INITIAL INPUT VALUES
20.0 398 1.0 0.6 0.9
*--

* Model "Pump Controller" (Type 2)
*

UNIT 29 TYPE 2 Pump Controller
*$UNIT_NAME Pump Controller
*$MODEL .\Controllers\Differential Controller w_ Hysteresis\for Temperatures\Solver 0 (Successive Substitution) Control Strategy\Type2b.tmf
*$POSITION 729 351
*$LAYER Controls #
*$# NOTE: This control strategy can only be used with solver 0 (Successive substitution)
*$#
PARAMETERS 2
5 ! 1 No. of oscillations
65.555578 ! 2 High limit cut-out
INPUTS 6
26,1 ! Plat-Plate Collector:Outlet temperature ->Upper input temperature Th
28,32 ! Storage Tank w/ HX:Tank nodal temperature-8 ->Lower input temperature Tl
28,32 ! Storage Tank w/ HX:Tank nodal temperature-8 ->Monitoring temperature Tin
34,2 ! Glycol Max Cutoff:Conditioning signal ->Input control function
0,0 ! [unconnected] Upper dead band dT
0,0 ! [unconnected] Lower dead band dT
*** INITIAL INPUT VALUES
20.0 10.0 20.0 0 8.89 4.44
*--

* Model "Pipe - Glycol from Collector to HX" (Type 604)
*

UNIT 30 TYPE 604 Pipe - Glycol from Collector to HX
*$UNIT_NAME Pipe - Glycol from Collector to HX
*$MODEL .\NREL Models\Noded Pipe Model\Calculated Convection Coefficient\Type604a.tmf
*$POSITION 265 222
*$LAYER Main #
PARAMETERS 23
3.048 ! 1 Pipe Length
0.020599 ! 2 Pipe Inner Diameter
0.022225 ! 3 Pipe Outer Diameter

```
8940            ! 4 Pipe Density
1443.599962             ! 5 Pipe Thermal Conductivity
0.386           ! 6 Pipe Specific Heat
0.019           ! 7 Insulation Thickness
72              ! 8 Insulation Density
0.144           ! 9 InsulationThermal Conductivity
1.045           ! 10 Insulation Specific Heat
1014.9          ! 11 Fluid Density
1.7172          ! 12 Fluid Thermal Conductivity
3.91            ! 13 Fluid Specific Heat
3.29            ! 14 Fluid Viscosity
5               ! 15 Number of Fluid Nodes
5               ! 16 Number of Pipe and Insulation Nodes
32.222244               ! 17 Initial Fluid Temperature
25.555577               ! 18 Initial Pipe Temperature
25.555577               ! 19 Initial Insulation Temperature
0.9             ! 20 Surface Emissivity
0.              ! 21 Contact Resistance
1               ! 22 Convection Mode
1               ! 23 Pipe Orientation
INPUTS 7
26,1            ! Plat-Plate Collector:Outlet temperature ->Temperature at Inlet A
26,2            ! Plat-Plate Collector:Outlet flow rate ->Flow Rate at Inlet A
0,0             ! [unconnected] Temperature at Inlet B
0,0             ! [unconnected] Flow Rate at Inlet B
39,1            ! PHX Weather -TMY3:Dry bulb temperature ->Ambient
Temperature
0,0             ! [unconnected] Ambient Pressure
0,0             ! [unconnected] Wind Velocity
*** INITIAL INPUT VALUES
20.0 0. 20.0 0. AmbientTemp_pipes 1. 0.
*------------------------------------------------------------------------------

* Model "Pipe - Glycol from HX to Collector" (Type 604)
*

UNIT 31 TYPE 604       Pipe - Glycol from HX to Collector
*$UNIT_NAME Pipe - Glycol from HX to Collector
*$MODEL .\NREL Models\Noded Pipe Model\Calculated Convection
Coefficient\Type604a.tmf
*$POSITION 507 393
*$LAYER Main #
PARAMETERS 23
4.572           ! 1 Pipe Length
0.020599                ! 2 Pipe Inner Diameter
0.022225                ! 3 Pipe Outer Diameter
8940            ! 4 Pipe Density
```

```
1443.599962            ! 5 Pipe Thermal Conductivity
0.386          ! 6 Pipe Specific Heat
0.019          ! 7 Insulation Thickness
72             ! 8 Insulation Density
0.144          ! 9 InsulationThermal Conductivity
1.045          ! 10 Insulation Specific Heat
1014.9         ! 11 Fluid Density
1.7172         ! 12 Fluid Thermal Conductivity
3.91           ! 13 Fluid Specific Heat
3.29           ! 14 Fluid Viscosity
5              ! 15 Number of Fluid Nodes
5              ! 16 Number of Pipe and Insulation Nodes
32.222244              ! 17 Initial Fluid Temperature
25.555577              ! 18 Initial Pipe Temperature
25.555577              ! 19 Initial Insulation Temperature
0.9            ! 20 Surface Emissivity
0.             ! 21 Contact Resistance
1              ! 22 Convection Mode
1              ! 23 Pipe Orientation
INPUTS 7
28,3           ! Storage Tank w/ HX:Temperature at HX Outlet ->Temperature at
Inlet A
28,4           ! Storage Tank w/ HX:HX flow rate ->Flow Rate at Inlet A
0,0            ! [unconnected] Temperature at Inlet B
0,0            ! [unconnected] Flow Rate at Inlet B
39,1           ! PHX Weather -TMY3:Dry bulb temperature ->Ambient
Temperature
0,0            ! [unconnected] Ambient Pressure
0,0            ! [unconnected] Wind Velocity
*** INITIAL INPUT VALUES
20.0 0. 20.0 0. AmbientTemp_pipes 1. 0.
*------------------------------------------------------------------------------

* EQUATIONS "Constants"
*
EQUATIONS 3
CollectorSlope = 18.43
kJhr_to_watt = 3.6
AmbientTemp_pipes = 23.89 !(degrees C, or 75 F)  ambient temp where pipes
are
*$UNIT_NAME Constants
*$LAYER Main
*$POSITION 230 42

*------------------------------------------------------------------------------
```

```
* EQUATIONS "lit/hr to GPM"
*
EQUATIONS 1
GPM = [11,1]*0.004403
*$UNIT_NAME lit/hr to GPM
*$LAYER Main
*$POSITION 64 925

*------------------------------------------------------------------------------


* Model "Glycol Max Cutoff" (Type 1502)
*

UNIT 34 TYPE 1502	Glycol Max Cutoff
*$UNIT_NAME Glycol Max Cutoff
*$MODEL .\Controllers Library (TESS)\Aquastats\Heating Mode\Type1502.tmf
*$POSITION 620 191
*$LAYER Main #
PARAMETERS 4
1		! 1 Number of heating stages
5		! 2 # oscillations permitted
2.777778		! 3 Temperature dead band
0		! 4 Number of stage exceptions
INPUTS 3
26,1		! Plat-Plate Collector:Outlet temperature ->Fluid temperature
0,0		! [unconnected] Lockout signal
0,0		! [unconnected] Setpoint temperature for stage
*** INITIAL INPUT VALUES
20.0 0 130.000024
*------------------------------------------------------------------------------

* Model "Mixer - Out to taps" (Type 11)
*

UNIT 35 TYPE 11	Mixer - Out to taps
*$UNIT_NAME Mixer - Out to taps
*$MODEL .\Hydronics\Tee-Piece\Other Fluids\Type11h.tmf
*$POSITION 336 847
*$LAYER Main #
PARAMETERS 1
1		! 1 Tee piece mode
INPUTS 4
36,1		! Diverter:Temperature at outlet 1 ->Temperature at inlet 1
36,2		! Diverter:Flow rate at outlet 1 ->Flow rate at inlet 1
28,1		! Storage Tank w/ HX:Temperature at outlet ->Temperature at
inlet 2
```

```
28,2            ! Storage Tank w/ HX:Flow rate at outlet ->Flow rate at inlet 2
*** INITIAL INPUT VALUES
20.0 100.0 20.0 100.0
*------------------------------------------------------------------------------

* Model "Diverter" (Type 11)
*

UNIT 36 TYPE 11      Diverter
*$UNIT_NAME Diverter
*$MODEL .\Hydronics\Flow Diverter\Other Fluids\Right Facing\Type11f.tmf
*$POSITION 203 712
*$LAYER Main #
PARAMETERS 1
2               ! 1 Controlled flow diverter mode
INPUTS 3
39,5            ! PHX Weather -TMY3:Mains water temperature ->Inlet
temperature
11,1            ! Water Draw Profile:Average water draw ->Inlet flow rate
37,1            ! Tempering Control (<110F):Fraction to heat source ->Control
signal
*** INITIAL INPUT VALUES
20.0 0 0.5
*------------------------------------------------------------------------------

* Model "Tempering Control (<110F)" (Type 953)
*

UNIT 37 TYPE 953     Tempering Control (<110F)
*$UNIT_NAME Tempering Control (<110F)
*$MODEL .\Controllers Library (TESS)\Tempering Valve Controller\Type953.tmf
*$POSITION 145 605
*$LAYER Main #
*$# NOTE: This control strategy can only be used with solver 0 (Successive
substitution)
*$#
PARAMETERS 1
5               ! 1 No. of oscillations
INPUTS 4
0,0             ! [unconnected] Setpoint temperature
28,1            ! Storage Tank w/ HX:Temperature at outlet ->Source temperature
39,5            ! PHX Weather -TMY3:Mains water temperature ->Tempering fluid
temperature (return temperature)
0,0             ! [unconnected] Mode
*** INITIAL INPUT VALUES
43.333355 10.0 20.0 1
*------------------------------------------------------------------------------
```

```
* EQUATIONS "C to F"
*
EQUATIONS 14
Tank_Node1_F = [28,25]*(9/5) + 32
Tank_Node2_F = [28,26]*(9/5) + 32
Tank_Node3_F = [28,27]*(9/5) + 32
Tank_Node4_F = [28,28]*(9/5) + 32
Tank_Node5_F = [28,29]*(9/5) + 32
Tank_Node6_F = [28,30]*(9/5) + 32
Tank_Node7_F = [28,31]*(9/5) + 32
Tank_Node8_F = [28,32]*(9/5) + 32
Tank_Node9_F = [28,33]*(9/5) + 32
ColdWater_in_Main_F = [39,5]*(9/5) + 32
MixedHotWater_F = [35,1]*(9/5) + 32
HotWater_outofBW_F = [28,1]*(9/5) + 32
HTF_TankHX_F = [28,3]*(9/5) + 32
HTF_Roof_F = [26,1]*(9/5) + 32
*$UNIT_NAME C to F
*$LAYER Main
*$POSITION 995 535

*------------------------------------------------------------------------------


* Model "PHX Weather -TMY3" (Type 15)
*

UNIT 39 TYPE 15        PHX Weather -TMY3
*$UNIT_NAME PHX Weather -TMY3
*$MODEL .\Weather Data Reading and Processing\Standard
Format\TMY3\Type15-TMY3.tmf
*$POSITION 76 138
*$LAYER Main #
PARAMETERS 9
7               ! 1 File Type
34              ! 2 Logical unit
3               ! 3 Tilted Surface Radiation Mode
0.2             ! 4 Ground reflectance: no albedo reported
0.7             ! 5 Not used
1               ! 6 Number of surfaces
1               ! 7 Tracking mode
CollectorSlope          ! 8 Slope of surface
0               ! 9 Azimuth of surface
*** External files
ASSIGN "C:\Trnsys17\Weather\US-TMY3\US_AZ_PHOENIX_INTL_AP_722780.csv"
34
```

*|? Which file contains the TMY-2 weather data? |1000
*---

END

APPENDIX D

FAFCO® TRNSYS INPUT FILE

```
VERSION 17
*******************************************************************************
*** TRNSYS input file (deck) generated by TrnsysStudio
*** on Friday, June 29, 2012 at 00:13
*** from TrnsysStudio project: Y:\Documents\Docs\School\Alt
Masters\Thesis\TRNSYS Files\OFFICIAL FILES\Thesis -
FAFCO\FAFCO_trueambient.tpf
***
*** If you edit this file, use the File/Import TRNSYS Input File function in
*** TrnsysStudio to update the project.
***
*** If you have problems, questions or suggestions please contact your local
*** TRNSYS distributor or mailto:software@cstb.fr
***
*******************************************************************************


*******************************************************************************
*** Units
*******************************************************************************

*******************************************************************************
*** Control cards
*******************************************************************************
* START, STOP and STEP
CONSTANTS 3
START=0
STOP=8760.000229455
STEP=0.016666666
SIMULATION   START STOP   STEP  ! Start time     End time        Time step
TOLERANCES 0.001 0.001                  ! Integration    Convergence
LIMITS 50 50 50                         ! Max iterations         Max warnings
        Trace limit
DFQ 1                              ! TRNSYS numerical integration solver
method
WIDTH 120                          ! TRNSYS output file width, number of
characters
LIST                               ! NOLIST statement
                                   ! MAP statement
SOLVER 0 1 1                       ! Solver statement     Minimum relaxation
factor  Maximum relaxation factor
```

```
NAN_CHECK 0                              ! Nan DEBUG statement
OVERWRITE_CHECK 0                                ! Overwrite DEBUG statement
TIME_REPORT 0                            ! disable time report
EQSOLVER 0                               ! EQUATION SOLVER statement
* User defined CONSTANTS


* Model "Preheat & Solar Temp Plotter" (Type 65)
*

UNIT 13 TYPE 65        Preheat & Solar Temp Plotter
*$UNIT_NAME Preheat & Solar Temp Plotter
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 1172 398
*$LAYER Outputs #
PARAMETERS 12
6               ! 1 Nb. of left-axis variables
1               ! 2 Nb. of right-axis variables
0               ! 3 Left axis minimum
100             ! 4 Left axis maximum
0.0             ! 5 Right axis minimum
5               ! 6 Right axis maximum
1               ! 7 Number of plots per simulation
12              ! 8 X-axis gridpoints
0               ! 9 Shut off Online w/o removing
-1              ! 10 Logical unit for output file
0               ! 11 Output file units
0               ! 12 Output file delimiter
INPUTS 7
47,1            ! PHX Weather-TMY3:Dry bulb temperature ->Left axis variable-1
25,18           ! Preheat Tank:Tank nodal temperature-1 ->Left axis variable-2
25,25           ! Preheat Tank:Tank nodal temperature-8 ->Left axis variable-3
21,1            ! Solar Collector:Outlet temperature ->Left axis variable-4
28,3            ! Heat Exchanger:Cold-side outlet temperature ->Left axis variable-
5
25,1            ! Preheat Tank:Temperature at outlet-1 ->Left axis variable-6
mains_GPM               ! lit/hr to GPM:mains_GPM ->Right axis variable
*** INITIAL INPUT VALUES
Ambient Preheat_Node1_temp Preheat_Node8_temp Glycol_panel_out
H20_leaving_HX
WaterToBackup GPM
LABELS  3
"Temperatures"
"GPM Water Draw"
"Solar Tank and Collector"
*------------------------------------------------------------------------------
```

```
* EQUATIONS "Equations / Constants"
*
EQUATIONS 3
CollectorSlope = 18.43
kJhr_to_watt = 3.6
AmbientTemp_pipes = 23.89 !(degrees C, or 75 F)  ambient temp where pipes
are
*$UNIT_NAME Equations / Constants
*$LAYER Main
*$POSITION 731 74

*------------------------------------------------------------------------------


* Model "Electric Backup Plot" (Type 65)
*

UNIT 20 TYPE 65      Electric Backup Plot
*$UNIT_NAME Electric Backup Plot
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 1226 1012
*$LAYER Main #
PARAMETERS 12
7            ! 1 Nb. of left-axis variables
4            ! 2 Nb. of right-axis variables
0.0          ! 3 Left axis minimum
220          ! 4 Left axis maximum
0.0          ! 5 Right axis minimum
5            ! 6 Right axis maximum
1            ! 7 Number of plots per simulation
12           ! 8 X-axis gridpoints
0            ! 9 Shut off Online w/o removing
-1           ! 10 Logical unit for output file
0            ! 11 Output file units
0            ! 12 Output file delimiter
INPUTS 11
Tank_Node1_F           ! C to F:Tank_Node1_F ->Left axis variable-1
Tank_Node3_F           ! C to F:Tank_Node3_F ->Left axis variable-2
Tank_Node8_F           ! C to F:Tank_Node8_F ->Left axis variable-3
Tank_Node9_F           ! C to F:Tank_Node9_F ->Left axis variable-4
MixedHotWater_F        ! C to F:MixedHotWater_F ->Left axis variable-5
ColdWater_in_Main_F    ! C to F:ColdWater_in_Main_F ->Left axis variable-6
HotWater_outofBW_F     ! C to F:HotWater_outofBW_F ->Left axis variable-7
kW_element1       ! kJ/h to kW:kW_element1 ->Right axis variable-1
kW_element2       ! kJ/h to kW:kW_element2 ->Right axis variable-2
kW_comb_elements       ! kJ/h to kW:kW_comb_elements ->Right axis
variable-3
```

```
backup_GPM              ! lit/hr to GPM:backup_GPM ->Right axis variable-4
*** INITIAL INPUT VALUES
Node1_temp Node3_temp Node8_temp Node9_temp Mix_Water_out
Cold_mains_in
Hot_fr_tank kW_element1 kW_element2 kW_comb GPM
LABELS  3
"Temp F"
"kW  or  GPM"
"Backup Tank"
*------------------------------------------------------------------------------

* Model "Energy Usage Output" (Type 46)
*

UNIT 22 TYPE 46        Energy Usage Output
*$UNIT_NAME Energy Usage Output
*$MODEL .\Output\Printegrator\Unformatted\Type46.tmf
*$POSITION 1220 823
*$LAYER Main #
*$# PRINTEGRATOR
PARAMETERS 5
33                 ! 1 Logical unit
-1                 ! 2 Logical unit for monthly summaries
0                  ! 3 Relative or absolute start time
24.000001              ! 4 Printing & integrating interval
0                  ! 5 Number of inputs to avoid integration
INPUTS 6
kW_element1            ! kJ/h to kW:kW_element1 ->Input to be integrated &
printed-1
kW_element2            ! kJ/h to kW:kW_element2 ->Input to be integrated &
printed-2
kW_comb_elements             ! kJ/h to kW:kW_comb_elements ->Input to be
integrated & printed-3
kW_potable_pump              ! kJ/h to kW:kW_potable_pump ->Input to be
integrated & printed-4
kW_glycol_pump               ! kJ/h to kW:kW_glycol_pump ->Input to be
integrated & printed-5
kW_TOTAL               ! kJ/h to kW:kW_TOTAL ->Input to be integrated &
printed-6
*** INITIAL INPUT VALUES
kWh_elem1 kWh_elem2 kWh_comb kWh_potable_pump kWh_glycol_pump
kWh_TOTAL

LABELS 0

*** External files
ASSIGN "FAFCO_trueambient_Results_TMY3.txt" 33
```

```
*|? Output file for integrated results? |1000
*------------------------------------------------------------------------------

* Model "Water Draw Profile" (Type 14)
*

UNIT 24 TYPE 14        Water Draw Profile
*$UNIT_NAME Water Draw Profile
*$MODEL .\Utility\Forcing Functions\Water Draw\Type14b.tmf
*$POSITION 90 1022
*$LAYER Main #
PARAMETERS 52
0               ! 1 Initial value of time
0               ! 2 Initial value of function
7.5             ! 3 Time at point-1
0               ! 4 Water draw at point -1
7.5             ! 5 Time at point-2
340.69          ! 6 Water draw at point -2
7.75            ! 7 Time at point-3
340.69          ! 8 Water draw at point -3
7.75            ! 9 Time at point-4
0               ! 10 Water draw at point -4
13              ! 11 Time at point-5
0               ! 12 Water draw at point -5
13              ! 13 Time at point-6
340.69          ! 14 Water draw at point -6
13.181          ! 15 Time at point-7
340.69          ! 16 Water draw at point -7
13.181          ! 17 Time at point-8
0               ! 18 Water draw at point -8
15              ! 19 Time at point-9
0               ! 20 Water draw at point -9
15              ! 21 Time at point-10
340.69          ! 22 Water draw at point -10
15.028          ! 23 Time at point-11
340.69          ! 24 Water draw at point -11
15.028          ! 25 Time at point-12
0               ! 26 Water draw at point -12
18              ! 27 Time at point-13
0               ! 28 Water draw at point -13
18              ! 29 Time at point-14
340.69          ! 30 Water draw at point -14
18.056          ! 31 Time at point-15
340.69          ! 32 Water draw at point -15
18.056          ! 33 Time at point-16
0               ! 34 Water draw at point -16
20              ! 35 Time at point-17
```

```
0               ! 36 Water draw at point -17
20              ! 37 Time at point-18
340.69          ! 38 Water draw at point -18
20.111          ! 39 Time at point-19
340.69          ! 40 Water draw at point -19
20.111          ! 41 Time at point-20
0               ! 42 Water draw at point -20
22              ! 43 Time at point-21
0               ! 44 Water draw at point -21
22              ! 45 Time at point-22
340.69          ! 46 Water draw at point -22
22.083          ! 47 Time at point-23
340.69          ! 48 Water draw at point -23
22.083          ! 49 Time at point-24
0               ! 50 Water draw at point -24
24              ! 51 Time at point-25
0               ! 52 Water draw at point -25
*------------------------------------------------------------------------------

* Model "Preheat Tank" (Type 534)
*

UNIT 25 TYPE 534     Preheat Tank
*$UNIT_NAME Preheat Tank
*$MODEL .\Storage Tank Library (TESS)\Cylindrical Storage Tank\Vertical
Cylinder\Version without Plug-In\No HXs\Type534-NoHX.tmf
*$POSITION 426 574
*$LAYER Main #
*$# CYLINDRICAL STORAGE TANK
PARAMETERS 41
-1              ! 1 LU for data file
9               ! 2 Number of tank nodes
2               ! 3 Number of ports
0               ! 4 Number of immersed heat exchangers
1               ! 5 Number of miscellaneous heat flows
0.189272                ! 6 Tank volume
1.461           ! 7 Tank height
0               ! 8 Tank fluid
4.032           ! 9 Fluid specific heat
988.5           ! 10 Fluid density
2.3112          ! 11 Fluid thermal conductivity
2               ! 12 Fluid viscosity
0.00026                 ! 13 Fluid thermal expansion coefficient
5.364           ! 14 Top loss coefficient
5.364           ! 15 Edge loss coefficient for node-1
5.364           ! 16 Edge loss coefficient for node-2
5.364           ! 17 Edge loss coefficient for node-3
```

5.364 ! 18 Edge loss coefficient for node-4
5.364 ! 19 Edge loss coefficient for node-5
5.364 ! 20 Edge loss coefficient for node-6
5.364 ! 21 Edge loss coefficient for node-7
5.364 ! 22 Edge loss coefficient for node-8
5.364 ! 23 Edge loss coefficient for node-9
5.364 ! 24 Bottom loss coefficient
0 ! 25 Additional thermal conductivity
1 ! 26 Inlet flow mode-1
9 ! 27 Entry node-1
1 ! 28 Exit node-1
1 ! 29 Inlet flow mode-2
9 ! 30 Entry node-2
1 ! 31 Exit node-2
0 ! 32 Flue loss coefficient for node-1
0 ! 33 Flue loss coefficient for node-2
0 ! 34 Flue loss coefficient for node-3
0 ! 35 Flue loss coefficient for node-4
0 ! 36 Flue loss coefficient for node-5
0 ! 37 Flue loss coefficient for node-6
0 ! 38 Flue loss coefficient for node-7
0 ! 39 Flue loss coefficient for node-8
0 ! 40 Flue loss coefficient for node-9
9 ! 41 Node for miscelaneous heat gain
INPUTS 27
43,3 ! Diverter:Temperature at outlet 2 ->Inlet temperature for port-1
43,4 ! Diverter:Flow rate at outlet 2 ->Inlet flow rate for port-1
31,1 ! Pipe - Water to Preheat Tank:Temperature at Outlet A ->Inlet temperature for port-2
31,2 ! Pipe - Water to Preheat Tank:Flow Rate at Outlet A ->Inlet flow rate for port-2
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Top loss temperature
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-1
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-2
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-3
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-4
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-5
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-6
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-7

```
47,1            ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss
temperature for node-8
47,1            ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss
temperature for node-9
47,1            ! PHX Weather-TMY3:Dry bulb temperature ->Bottom loss
temperature
0,0             ! [unconnected] Gas flue temperature
0,0             ! [unconnected] Inversion mixing flow rate
0,0             ! [unconnected] Auxiliary heat input for node-1
0,0             ! [unconnected] Auxiliary heat input for node-2
0,0             ! [unconnected] Auxiliary heat input for node-3
0,0             ! [unconnected] Auxiliary heat input for node-4
0,0             ! [unconnected] Auxiliary heat input for node-5
0,0             ! [unconnected] Auxiliary heat input for node-6
0,0             ! [unconnected] Auxiliary heat input for node-7
0,0             ! [unconnected] Auxiliary heat input for node-8
0,0             ! [unconnected] Auxiliary heat input for node-9
0,0             ! [unconnected] Miscellaneous heat input
*** INITIAL INPUT VALUES
20.0 0.0 20.0 0.0 AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes
AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes
20.0 -100 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0
DERIVATIVES 9
AmbientTemp_pipes        ! 1 Initial Tank Temperature-1
AmbientTemp_pipes        ! 2 Initial Tank Temperature-2
AmbientTemp_pipes        ! 3 Initial Tank Temperature-3
AmbientTemp_pipes        ! 4 Initial Tank Temperature-4
AmbientTemp_pipes        ! 5 Initial Tank Temperature-5
AmbientTemp_pipes        ! 6 Initial Tank Temperature-6
AmbientTemp_pipes        ! 7 Initial Tank Temperature-7
AmbientTemp_pipes        ! 8 Initial Tank Temperature-8
AmbientTemp_pipes        ! 9 Initial Tank Temperature-9
*------------------------------------------------------------------------------

* Model "Potable Water Pump" (Type 110)
*

UNIT 27 TYPE 110     Potable Water Pump
*$UNIT_NAME Potable Water Pump
*$MODEL .\Hydronics\Pumps\Variable Speed\Type110.tmf
*$POSITION 668 486
*$LAYER Main #
*$# VARIABLE-SPEED PUMP
PARAMETERS 6
```

```
341             ! 1 Rated flow rate
4.032           ! 2 Fluid specific heat
57.599998               ! 3 Rated power
0               ! 4 Motor heat loss fraction
1               ! 5 Number of power coefficients
1.0             ! 6 Power coefficient
INPUTS 5
32,1            ! Pipe - Water to HX:Temperature at Outlet A ->Inlet fluid
temperature
32,2            ! Pipe - Water to HX:Flow Rate at Outlet A ->Inlet fluid flow rate
30,1            ! Differential Controller:Output control function ->Control signal
0,0             ! [unconnected] Total pump efficiency
0,0             ! [unconnected] Motor efficiency
*** INITIAL INPUT VALUES
20 0 1 0.6 0.9
*------------------------------------------------------------------------------

* Model "Heat Exchanger" (Type 91)
*

UNIT 28 TYPE 91        Heat Exchanger
*$UNIT_NAME Heat Exchanger
*$MODEL .\Heat Exchangers\Constant Effectiveness\Type91a.tmf
*$POSITION 451 398
*$LAYER Main #
PARAMETERS 3
.584            ! 1 Heat exchanger effectiveness
3.91            ! 2 Specific heat of hot side fluid
4.032           ! 3 Specific heat of cold side fluid
INPUTS 4
34,1            ! Pipe - Glycol to Collector:Temperature at Outlet A ->Hot side inlet
temperature
34,2            ! Pipe - Glycol to Collector:Flow Rate at Outlet A ->Hot side flow
rate
27,1            ! Potable Water Pump:Outlet fluid temperature ->Cold side inlet
temperature
27,2            ! Potable Water Pump:Outlet flow rate ->Cold side flow rate
*** INITIAL INPUT VALUES
20.0 0. 20.0 0.
*------------------------------------------------------------------------------

* Model "Glycol Pump" (Type 110)
*

UNIT 29 TYPE 110       Glycol Pump
*$UNIT_NAME Glycol Pump
*$MODEL .\Hydronics\Pumps\Variable Speed\Type110.tmf
```

```
*$POSITION 665 282
*$LAYER Main #
*$# VARIABLE-SPEED PUMP
PARAMETERS 6
227             ! 1 Rated flow rate
3.91            ! 2 Fluid specific heat
43.199999               ! 3 Rated power
0               ! 4 Motor heat loss fraction
1               ! 5 Number of power coefficients
1               ! 6 Power coefficient
INPUTS 5
21,1            ! Solar Collector:Outlet temperature ->Inlet fluid temperature
21,2            ! Solar Collector:Outlet flow rate ->Inlet fluid flow rate
30,1            ! Differential Controller:Output control function ->Control signal
0,0             ! [unconnected] Total pump efficiency
0,0             ! [unconnected] Motor efficiency
*** INITIAL INPUT VALUES
20 0 1 0.6 0.9
*------------------------------------------------------------------------------

* Model "Differential Controller" (Type 911)
*

UNIT 30 TYPE 911     Differential Controller
*$UNIT_NAME Differential Controller
*$MODEL .\Controllers Library (TESS)\Differental Controller with Lock-
Outs\Type911.tmf
*$POSITION 875 344
*$LAYER Main #
*$# NOTE: This control strategy can only be used with solver 0 (Successive
substitution)
*$#
PARAMETERS 3
5               ! 1 No. of oscillations
0.083333                ! 2 Minimum run-time
0.083333                ! 3 Minimum reset time
INPUTS 7
21,1            ! Solar Collector:Outlet temperature ->Upper input temperature Th
25,25           ! Preheat Tank:Tank nodal temperature-8 ->Lower input
temperature Tl
25,25           ! Preheat Tank:Tank nodal temperature-8 ->Monitoring
temperature Tin
0,0             ! [unconnected] High limit cut-out
0,0             ! [unconnected] Upper dead band dT
0,0             ! [unconnected] Lower dead band dT
0,0             ! [unconnected] Lock-out control signal
*** INITIAL INPUT VALUES
```

```
20 40 20 65.555578 5.555556 2.222222 0
*------------------------------------------------------------------------------

* Model "Solar Collector" (Type 553)
*

UNIT 21 TYPE 553	Solar Collector
*$UNIT_NAME Solar Collector
*$MODEL .\Solar Library (TESS)\Unglazed Collector (No Covers)\OG100 Quadratic
Efficiency Approach\Type553.tmf
*$POSITION 489 225
*$LAYER Main #
*$# This component sets the flow rate for all connected flow loop components if
the variable speed option is enabled.
PARAMETERS 15
1		! 1 Number in series
4.459309		! 2 Collector array area
3.91		! 3 Fluid specific heat
1		! 4 Collector test mode
250.9		! 5 Tested flow rate per unit area
4.190		! 6 Fluid specific heat at test conditions
0.0		! 7 Minimum flowrate
250.9		! 8 Maximum flowrate
20.000001		! 9 Capacitance of Collector
0.9		! 10 Emissivity of collector surface
0.96		! 11 Absorptivity of collector surface
15		! 12 Number of Nodes
20		! 13 Initial Temperature
-0.159		! 14 Linear IAM term (b0)
0.107		! 15 Quadratic IAM term (b1)
INPUTS 14
33,1		! Pipe - Glycol Return:Temperature at Outlet A ->Inlet temperature
33,2		! Pipe - Glycol Return:Flow Rate at Outlet A ->Inlet flowrate
47,1		! PHX Weather-TMY3:Dry bulb temperature ->Ambient
temperature
47,4		! PHX Weather-TMY3:Effective sky temperature ->Sky temperature
47,25		! PHX Weather-TMY3:Beam radiation for surface ->Beam radiation
on the tilted surface
47,26		! PHX Weather-TMY3:Sky diffuse radiation for surface ->Sky
diffuse radiation on tilted surface
47,27		! PHX Weather-TMY3:Ground reflected diffuse radiation for surface
->Ground-reflected diffuse radiation on tilted surface
47,29		! PHX Weather-TMY3:Angle of incidence for surface ->Incidence
angle
CollectorSlope		! [equation] Collector slope
0,0		! [unconnected] Pump Control Specification
0,0		! [unconnected] Outlet Temperature Setpoint
```

```
0,0             ! [unconnected] Collector intercept efficiency
0,0             ! [unconnected] Collector efficiency slope
0,0             ! [unconnected] Collector efficiency curvature
*** INITIAL INPUT VALUES
20.0 100.0 10.0 10.0 0.0 0.0 0.0 0 CollectorSlope 0 93.333357 .882 67.888797
0
*------------------------------------------------------------------------------

* EQUATIONS "kJ/h to kW"
*
EQUATIONS 6
kW_element1 = [39,1]/3600
kW_element2 = [35,1]/3600
kW_comb_elements = kW_element1+kW_element2
kW_potable_pump = [27,3]/3600
kW_glycol_pump = [29,3]/3600
kW_TOTAL = kW_comb_elements+kW_potable_pump+kW_glycol_pump
*$UNIT_NAME kJ/h to kW
*$LAYER Main
*$POSITION 1011 928

*------------------------------------------------------------------------------


* Model "Pipe - Water to HX" (Type 604)
*

UNIT 32 TYPE 604     Pipe - Water to HX
*$UNIT_NAME Pipe - Water to HX
*$MODEL .\NREL Models\Noded Pipe Model\Calculated Convection
Coefficient\Type604a.tmf
*$POSITION 570 551
*$LAYER Main #
PARAMETERS 23
1.524           ! 1 Pipe Length
0.013843                ! 2 Pipe Inner Diameter
0.015875                ! 3 Pipe Outer Diameter
935             ! 4 Pipe Density
93.599998               ! 5 Pipe Thermal Conductivity
.0021           ! 6 Pipe Specific Heat
0.019           ! 7 Insulation Thickness
72.             ! 8 Insulation Density
0.144           ! 9 InsulationThermal Conductivity
1.045           ! 10 Insulation Specific Heat
988.5           ! 11 Fluid Density
2.3112          ! 12 Fluid Thermal Conductivity
4.032           ! 13 Fluid Specific Heat
```

```
2.00             ! 14 Fluid Viscosity
3                ! 15 Number of Fluid Nodes
3                ! 16 Number of Pipe and Insulation Nodes
25.555577              ! 17 Initial Fluid Temperature
25.555577              ! 18 Initial Pipe Temperature
25.555577              ! 19 Initial Insulation Temperature
0.9              ! 20 Surface Emissivity
0.               ! 21 Contact Resistance
1                ! 22 Convection Mode
1                ! 23 Pipe Orientation
INPUTS 7
25,3             ! Preheat Tank:Temperature at outlet-2 ->Temperature at Inlet A
25,4             ! Preheat Tank:Flow rate at outlet-2 ->Flow Rate at Inlet A
0,0              ! [unconnected] Temperature at Inlet B
0,0              ! [unconnected] Flow Rate at Inlet B
47,1             ! PHX Weather-TMY3:Dry bulb temperature ->Ambient
Temperature
0,0              ! [unconnected] Ambient Pressure
0,0              ! [unconnected] Wind Velocity
*** INITIAL INPUT VALUES
20.0 0. 20.0 0. AmbientTemp_pipes 1. 0.
*------------------------------------------------------------------------------

* Model "Pipe - Water to Preheat Tank" (Type 604)
*

UNIT 31 TYPE 604      Pipe - Water to Preheat Tank
*$UNIT_NAME Pipe - Water to Preheat Tank
*$MODEL .\NREL Models\Noded Pipe Model\Calculated Convection
Coefficient\Type604a.tmf
*$POSITION 286 418
*$LAYER Main #
PARAMETERS 23
1.524            ! 1 Pipe Length
0.013843               ! 2 Pipe Inner Diameter
0.015875               ! 3 Pipe Outer Diameter
935              ! 4 Pipe Density
93.599998              ! 5 Pipe Thermal Conductivity
.0021            ! 6 Pipe Specific Heat
0.019            ! 7 Insulation Thickness
72               ! 8 Insulation Density
0.144            ! 9 InsulationThermal Conductivity
1.045            ! 10 Insulation Specific Heat
988.5            ! 11 Fluid Density
2.3112           ! 12 Fluid Thermal Conductivity
4.032            ! 13 Fluid Specific Heat
2.00             ! 14 Fluid Viscosity
```

```
3               ! 15 Number of Fluid Nodes
3               ! 16 Number of Pipe and Insulation Nodes
25.555577               ! 17 Initial Fluid Temperature
25.555577               ! 18 Initial Pipe Temperature
25.555577               ! 19 Initial Insulation Temperature
0.9             ! 20 Surface Emissivity
0.              ! 21 Contact Resistance
1               ! 22 Convection Mode
1               ! 23 Pipe Orientation
INPUTS 7
28,3            ! Heat Exchanger:Cold-side outlet temperature ->Temperature at
Inlet A
28,4            ! Heat Exchanger:Cold-side flow rate ->Flow Rate at Inlet A
0,0             ! [unconnected] Temperature at Inlet B
0,0             ! [unconnected] Flow Rate at Inlet B
47,1            ! PHX Weather-TMY3:Dry bulb temperature ->Ambient
Temperature
0,0             ! [unconnected] Ambient Pressure
0,0             ! [unconnected] Wind Velocity
*** INITIAL INPUT VALUES
20.0 0. 20.0 0. AmbientTemp_pipes 1. 0.
*------------------------------------------------------------------------------

* Model "Pipe - Glycol Return" (Type 604)
*

UNIT 33 TYPE 604     Pipe - Glycol Return
*$UNIT_NAME Pipe - Glycol Return
*$MODEL .\NREL Models\Noded Pipe Model\Calculated Convection
Coefficient\Type604a.tmf
*$POSITION 341 228
*$LAYER Main #
PARAMETERS 23
4.572           ! 1 Pipe Length
0.013843                ! 2 Pipe Inner Diameter
0.015875                ! 3 Pipe Outer Diameter
935             ! 4 Pipe Density
93.599998               ! 5 Pipe Thermal Conductivity
.0021           ! 6 Pipe Specific Heat
0.019           ! 7 Insulation Thickness
72              ! 8 Insulation Density
0.144           ! 9 InsulationThermal Conductivity
1.045           ! 10 Insulation Specific Heat
1014.9          ! 11 Fluid Density
1.7172          ! 12 Fluid Thermal Conductivity
3.91            ! 13 Fluid Specific Heat
3.29            ! 14 Fluid Viscosity
```

```
5               ! 15 Number of Fluid Nodes
5               ! 16 Number of Pipe and Insulation Nodes
32.222244               ! 17 Initial Fluid Temperature
25.555577               ! 18 Initial Pipe Temperature
25.555577               ! 19 Initial Insulation Temperature
0.9             ! 20 Surface Emissivity
0.              ! 21 Contact Resistance
1               ! 22 Convection Mode
1               ! 23 Pipe Orientation
INPUTS 7
28,1            ! Heat Exchanger:Hot-side outlet temperature ->Temperature at
Inlet A
28,2            ! Heat Exchanger:Hot-side flow rate ->Flow Rate at Inlet A
0,0             ! [unconnected] Temperature at Inlet B
0,0             ! [unconnected] Flow Rate at Inlet B
47,1            ! PHX Weather-TMY3:Dry bulb temperature ->Ambient
Temperature
0,0             ! [unconnected] Ambient Pressure
0,0             ! [unconnected] Wind Velocity
*** INITIAL INPUT VALUES
20.0 0. 20.0 0. AmbientTemp_pipes 1. 0.
*------------------------------------------------------------------------------

* Model "Pipe - Glycol to Collector" (Type 604)
*

UNIT 34 TYPE 604     Pipe - Glycol to Collector
*$UNIT_NAME Pipe - Glycol to Collector
*$MODEL .\NREL Models\Noded Pipe Model\Calculated Convection
Coefficient\Type604a.tmf
*$POSITION 598 347
*$LAYER Main #
PARAMETERS 23
3.048           ! 1 Pipe Length
0.013843                ! 2 Pipe Inner Diameter
0.015875                ! 3 Pipe Outer Diameter
935             ! 4 Pipe Density
93.599998               ! 5 Pipe Thermal Conductivity
.0021           ! 6 Pipe Specific Heat
0.019           ! 7 Insulation Thickness
72              ! 8 Insulation Density
0.144           ! 9 InsulationThermal Conductivity
1.045           ! 10 Insulation Specific Heat
1014.9          ! 11 Fluid Density
1.7172          ! 12 Fluid Thermal Conductivity
3.91            ! 13 Fluid Specific Heat
3.29            ! 14 Fluid Viscosity
```

```
5               ! 15 Number of Fluid Nodes
5               ! 16 Number of Pipe and Insulation Nodes
37.7778                 ! 17 Initial Fluid Temperature
25.555577               ! 18 Initial Pipe Temperature
25.555577               ! 19 Initial Insulation Temperature
0.9             ! 20 Surface Emissivity
0.              ! 21 Contact Resistance
1               ! 22 Convection Mode
1               ! 23 Pipe Orientation
INPUTS 7
29,1            ! Glycol Pump:Outlet fluid temperature ->Temperature at Inlet A
29,2            ! Glycol Pump:Outlet flow rate ->Flow Rate at Inlet A
0,0             ! [unconnected] Temperature at Inlet B
0,0             ! [unconnected] Flow Rate at Inlet B
47,1            ! PHX Weather-TMY3:Dry bulb temperature ->Ambient
Temperature
0,0             ! [unconnected] Ambient Pressure
0,0             ! [unconnected] Wind Velocity
*** INITIAL INPUT VALUES
20.0 0. 20.0 0. AmbientTemp_pipes 1. 0.
*------------------------------------------------------------------------------

* Model "Lower Element" (Type 1226)
*

UNIT 35 TYPE 1226    Lower Element
*$UNIT_NAME Lower Element
*$MODEL .\Storage Tank Library (TESS)\Tank Heating Device\Electric\Type1226-
Elec.tmf
*$POSITION 831 980
*$LAYER Main #
INPUTS 3
0,0             ! [unconnected] Heating capacity
0,0             ! [unconnected] Thermal efficiency
36,1            ! Bottom Thermostat:Control signal for stage heating ->Control
signal
*** INITIAL INPUT VALUES
16199.999571 1. 1.
*------------------------------------------------------------------------------

* Model "Bottom Thermostat" (Type 1502)
*

UNIT 36 TYPE 1502    Bottom Thermostat
*$UNIT_NAME Bottom Thermostat
*$MODEL .\Storage Tank Library (TESS)\Aquastats\Heating Mode\Type1502.tmf
*$POSITION 836 1091
```

```
*$LAYER Main #
PARAMETERS 4
1		! 1 Number of heating stages
5		! 2 # oscillations permitted
6.111111		! 3 Temperature dead band
0		! 4 Number of stage exceptions
INPUTS 3
37,22		! Bradford White:Tank nodal temperature-8 ->Fluid temperature
38,1		! Top Thermostat:Control signal for stage heating ->Lockout signal
0,0		! [unconnected] Setpoint temperature for stage
*** INITIAL INPUT VALUES
20.0 0 51.666689
*------------------------------------------------------------------------------

* Model "Bradford White" (Type 534)
*

UNIT 37 TYPE 534	 Bradford White
*$UNIT_NAME Bradford White
*$MODEL .\Storage Tank Library (TESS)\Cylindrical Storage Tank\Vertical
Cylinder\Version without Plug-In\No HXs\Type534-NoHX.tmf
*$POSITION 584 902
*$LAYER Main #
*$# CYLINDRICAL STORAGE TANK
PARAMETERS 37
-1		! 1 LU for data file
9		! 2 Number of tank nodes
1		! 3 Number of ports
0		! 4 Number of immersed heat exchangers
0		! 5 Number of miscellaneous heat flows
0.189272		! 6 Tank volume
1.461		! 7 Tank height
0		! 8 Tank fluid
4.032		! 9 Fluid specific heat
988.5		! 10 Fluid density
2.3112		! 11 Fluid thermal conductivity
2		! 12 Fluid viscosity
0.00026		! 13 Fluid thermal expansion coefficient
5.364		! 14 Top loss coefficient
5.364		! 15 Edge loss coefficient for node-1
5.364		! 16 Edge loss coefficient for node-2
5.364		! 17 Edge loss coefficient for node-3
5.364		! 18 Edge loss coefficient for node-4
5.364		! 19 Edge loss coefficient for node-5
5.364		! 20 Edge loss coefficient for node-6
5.364		! 21 Edge loss coefficient for node-7
5.364		! 22 Edge loss coefficient for node-8
```

5.364 ! 23 Edge loss coefficient for node-9
5.364 ! 24 Bottom loss coefficient
0 ! 25 Additional thermal conductivity
1 ! 26 Inlet flow mode
9 ! 27 Entry node
1 ! 28 Exit node
0 ! 29 Flue loss coefficient for node-1
0 ! 30 Flue loss coefficient for node-2
0 ! 31 Flue loss coefficient for node-3
0 ! 32 Flue loss coefficient for node-4
0 ! 33 Flue loss coefficient for node-5
0 ! 34 Flue loss coefficient for node-6
0 ! 35 Flue loss coefficient for node-7
0 ! 36 Flue loss coefficient for node-8
0 ! 37 Flue loss coefficient for node-9
INPUTS 24
40,1 ! Pipe - Water from Preheat to Backup:Temperature at Outlet A ->Inlet temperature for port
40,2 ! Pipe - Water from Preheat to Backup:Flow Rate at Outlet A ->Inlet flow rate for port
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Top loss temperature
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-1
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-2
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-3
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-4
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-5
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-6
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-7
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-8
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Edge loss temperature for node-9
47,1 ! PHX Weather-TMY3:Dry bulb temperature ->Bottom loss temperature
0,0 ! [unconnected] Gas flue temperature
0,0 ! [unconnected] Inversion mixing flow rate
0,0 ! [unconnected] Auxiliary heat input for node-1
0,0 ! [unconnected] Auxiliary heat input for node-2
39,1 ! Upper Element:Fluid energy ->Auxiliary heat input for node-3

```
0,0             ! [unconnected] Auxiliary heat input for node-4
0,0             ! [unconnected] Auxiliary heat input for node-5
0,0             ! [unconnected] Auxiliary heat input for node-6
0,0             ! [unconnected] Auxiliary heat input for node-7
35,1            ! Lower Element:Fluid energy ->Auxiliary heat input for node-8
0,0             ! [unconnected] Auxiliary heat input for node-9
*** INITIAL INPUT VALUES
48.888911 0.0 AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes
AmbientTemp_pipes AmbientTemp_pipes AmbientTemp_pipes
AmbientTemp_pipes
20.0 -100 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0
DERIVATIVES 9
48.888911           ! 1 Initial Tank Temperature-1
48.888911           ! 2 Initial Tank Temperature-2
48.888911           ! 3 Initial Tank Temperature-3
48.888911           ! 4 Initial Tank Temperature-4
48.888911           ! 5 Initial Tank Temperature-5
48.888911           ! 6 Initial Tank Temperature-6
48.888911           ! 7 Initial Tank Temperature-7
48.888911           ! 8 Initial Tank Temperature-8
48.888911           ! 9 Initial Tank Temperature-9
*------------------------------------------------------------------------------

* Model "Top Thermostat" (Type 1502)
*

UNIT 38 TYPE 1502    Top Thermostat
*$UNIT_NAME Top Thermostat
*$MODEL .\Storage Tank Library (TESS)\Aquastats\Heating Mode\Type1502.tmf
*$POSITION 842 720
*$LAYER Main #
PARAMETERS 4
1               ! 1 Number of heating stages
5               ! 2 # oscillations permitted
6.111111            ! 3 Temperature dead band
0               ! 4 Number of stage exceptions
INPUTS 3
37,17           ! Bradford White:Tank nodal temperature-3 ->Fluid temperature
0,0             ! [unconnected] Lockout signal
0,0             ! [unconnected] Setpoint temperature for stage
*** INITIAL INPUT VALUES
20.0 0 51.666689
*------------------------------------------------------------------------------

* Model "Upper Element" (Type 1226)
```

```
*

UNIT 39 TYPE 1226     Upper Element
*$UNIT_NAME Upper Element
*$MODEL .\Storage Tank Library (TESS)\Tank Heating Device\Electric\Type1226-
Elec.tmf
*$POSITION 833 829
*$LAYER Main #
INPUTS 3
0,0              ! [unconnected] Heating capacity
0,0              ! [unconnected] Thermal efficiency
38,1             ! Top Thermostat:Control signal for stage heating ->Control signal
*** INITIAL INPUT VALUES
16199.999571 1. 1.
*------------------------------------------------------------------------------

* Model "Pipe - Water from Preheat to Backup" (Type 604)
*

UNIT 40 TYPE 604      Pipe - Water from Preheat to Backup
*$UNIT_NAME Pipe - Water from Preheat to Backup
*$MODEL .\NREL Models\Noded Pipe Model\Calculated Convection
Coefficient\Type604a.tmf
*$POSITION 587 660
*$LAYER Main #
PARAMETERS 23
1.6764           ! 1 Pipe Length
0.020599                 ! 2 Pipe Inner Diameter
0.022225                 ! 3 Pipe Outer Diameter
8940             ! 4 Pipe Density
1443.599962              ! 5 Pipe Thermal Conductivity
0.386            ! 6 Pipe Specific Heat
0.019            ! 7 Insulation Thickness
72               ! 8 Insulation Density
0.144            ! 9 InsulationThermal Conductivity
1.045            ! 10 Insulation Specific Heat
988.5            ! 11 Fluid Density
2.3112           ! 12 Fluid Thermal Conductivity
4.032            ! 13 Fluid Specific Heat
2.00             ! 14 Fluid Viscosity
3                ! 15 Number of Fluid Nodes
3                ! 16 Number of Pipe and Insulation Nodes
48.888911                ! 17 Initial Fluid Temperature
25.555577                ! 18 Initial Pipe Temperature
25.555577                ! 19 Initial Insulation Temperature
0.9              ! 20 Surface Emissivity
0.               ! 21 Contact Resistance
```

```
1                ! 22 Convection Mode
1                ! 23 Pipe Orientation
INPUTS 7
25,1             ! Preheat Tank:Temperature at outlet-1 ->Temperature at Inlet A
25,2             ! Preheat Tank:Flow rate at outlet-1 ->Flow Rate at Inlet A
0,0              ! [unconnected] Temperature at Inlet B
0,0              ! [unconnected] Flow Rate at Inlet B
AmbientTemp_pipes          ! [equation] Ambient Temperature
0,0              ! [unconnected] Ambient Pressure
0,0              ! [unconnected] Wind Velocity
*** INITIAL INPUT VALUES
20.0 0. 20.0 0. AmbientTemp_pipes 1. 0.
*------------------------------------------------------------------------------

* Model "Electricity Usage Plot" (Type 65)
*

UNIT 41 TYPE 65      Electricity Usage Plot
*$UNIT_NAME Electricity Usage Plot
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 1219 925
*$LAYER Main #
PARAMETERS 12
6                ! 1 Nb. of left-axis variables
0                ! 2 Nb. of right-axis variables
0.0              ! 3 Left axis minimum
5                ! 4 Left axis maximum
0.0              ! 5 Right axis minimum
5                ! 6 Right axis maximum
1                ! 7 Number of plots per simulation
12               ! 8 X-axis gridpoints
0                ! 9 Shut off Online w/o removing
-1               ! 10 Logical unit for output file
0                ! 11 Output file units
0                ! 12 Output file delimiter
INPUTS 6
kW_element1          ! kJ/h to kW:kW_element1 ->Left axis variable-1
kW_element2          ! kJ/h to kW:kW_element2 ->Left axis variable-2
kW_comb_elements           ! kJ/h to kW:kW_comb_elements ->Left axis
variable-3
kW_potable_pump            ! kJ/h to kW:kW_potable_pump ->Left axis variable-
4
kW_glycol_pump             ! kJ/h to kW:kW_glycol_pump ->Left axis variable-5
kW_TOTAL             ! kJ/h to kW:kW_TOTAL ->Left axis variable-6
*** INITIAL INPUT VALUES
kW_element1 kW_element2 kW_CombElements kW_potable_pump
kW_glycol_pump
```

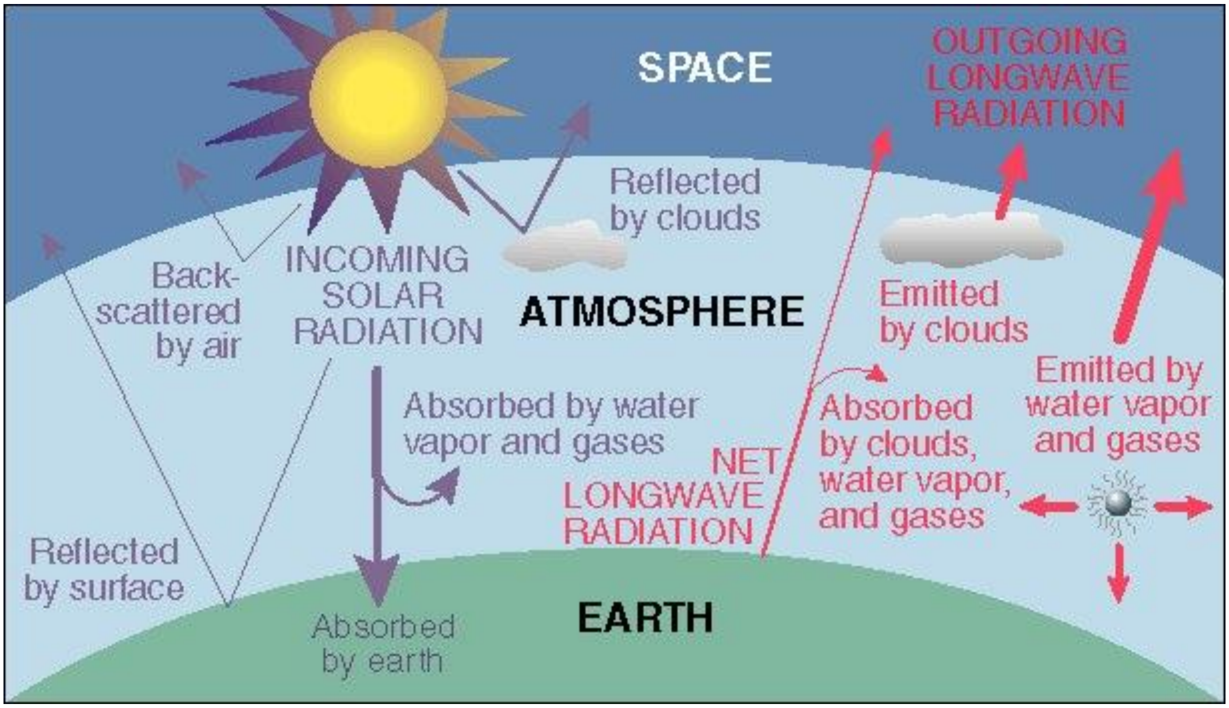
```
kW_TOTAL
LABELS  3
"kW"
""
"Electricity Usage"
*------------------------------------------------------------------------------

* EQUATIONS "lit/hr to GPM"
*
EQUATIONS 2
mains_GPM = [24,1]*0.004403
backup_GPM = [37,2]**0.004403
*$UNIT_NAME lit/hr to GPM
*$LAYER Main
*$POSITION 149 786

*------------------------------------------------------------------------------


* Model "Diverter" (Type 11)
*

UNIT 43 TYPE 11        Diverter
*$UNIT_NAME Diverter
*$MODEL .\Hydronics\Flow Diverter\Other Fluids\Right Facing\Type11f.tmf
*$POSITION 235 1022
*$LAYER Main #
PARAMETERS 1
2                ! 1 Controlled flow diverter mode
INPUTS 3
47,5             ! PHX Weather-TMY3:Mains water temperature ->Inlet
temperature
24,1             ! Water Draw Profile:Average water draw ->Inlet flow rate
45,1             ! Tempering Control (<110F):Fraction to heat source ->Control
signal
*** INITIAL INPUT VALUES
20.0 0 0.5
*------------------------------------------------------------------------------

* Model "Mixer - Out to taps" (Type 11)
*

UNIT 44 TYPE 11        Mixer - Out to taps
*$UNIT_NAME Mixer - Out to taps
*$MODEL .\Hydronics\Tee-Piece\Other Fluids\Type11h.tmf
*$POSITION 427 1059
*$LAYER Main #
```

```
PARAMETERS 1
1		! 1 Tee piece mode
INPUTS 4
43,1		! Diverter:Temperature at outlet 1 ->Temperature at inlet 1
43,2		! Diverter:Flow rate at outlet 1 ->Flow rate at inlet 1
37,1		! Bradford White:Temperature at outlet ->Temperature at inlet 2
37,2		! Bradford White:Flow rate at outlet ->Flow rate at inlet 2
*** INITIAL INPUT VALUES
20.0 100.0 20.0 100.0
*------------------------------------------------------------------------------

* Model "Tempering Control (<110F)" (Type 953)
*

UNIT 45 TYPE 953	 Tempering Control (<110F)
*$UNIT_NAME Tempering Control (<110F)
*$MODEL .\Controllers Library (TESS)\Tempering Valve Controller\Type953.tmf
*$POSITION 364 905
*$LAYER Main #
*$# NOTE: This control strategy can only be used with solver 0 (Successive
substitution)
*$#
PARAMETERS 1
5		! 1 No. of oscillations
INPUTS 4
0,0		! [unconnected] Setpoint temperature
37,1		! Bradford White:Temperature at outlet ->Source temperature
47,5		! PHX Weather-TMY3:Mains water temperature ->Tempering fluid
temperature (return temperature)
0,0		! [unconnected] Mode
*** INITIAL INPUT VALUES
43.333355 10.0 20.0 1
*------------------------------------------------------------------------------

* EQUATIONS "C to F"
*
EQUATIONS 12
Tank_Node1_F = [37,15]*(9/5) + 32
Tank_Node2_F = [37,16]*(9/5) + 32
Tank_Node3_F = [37,17]*(9/5) + 32
Tank_Node4_F = [37,18]*(9/5) + 32
Tank_Node5_F = [37,19]*(9/5) + 32
Tank_Node6_F = [37,20]*(9/5) + 32
Tank_Node7_F = [37,21]*(9/5) + 32
Tank_Node8_F = [37,22]*(9/5) + 32
Tank_Node9_F = [37,23]*(9/5) + 32
ColdWater_in_Main_F = [47,5]*(9/5) + 32
```

```
MixedHotWater_F = [44,1]*(9/5) + 32
HotWater_outofBW_F = [37,1]*(9/5) + 32
*$UNIT_NAME C to F
*$LAYER Main
*$POSITION 1226 1128

*-------------------------------------------------------------------------------


* Model "PHX Weather-TMY3" (Type 15)
*

UNIT 47 TYPE 15        PHX Weather-TMY3
*$UNIT_NAME PHX Weather-TMY3
*$MODEL .\Weather Data Reading and Processing\Standard
Format\TMY3\Type15-TMY3.tmf
*$POSITION 96 92
*$LAYER Main #
PARAMETERS 9
7               ! 1 File Type
34              ! 2 Logical unit
3               ! 3 Tilted Surface Radiation Mode
0.2             ! 4 Ground reflectance: no albedo reported
0.7             ! 5 Not used
1               ! 6 Number of surfaces
1               ! 7 Tracking mode
CollectorSlope          ! 8 Slope of surface
0               ! 9 Azimuth of surface
*** External files
ASSIGN "C:\Trnsys17\Weather\US-TMY3\US_AZ_PHOENIX_INTL_AP_722780.csv"
34
*|? Which file contains the TMY-2 weather data? |1000
*-------------------------------------------------------------------------------

END
```

Basics of Solar Energy

The Sun is always there; and is the ultimate source of Energy How many photons (energy) reach the surface of the Earth on Average? The energy balance in the atmosphere is shown here:



The main components in this diagram are the following:

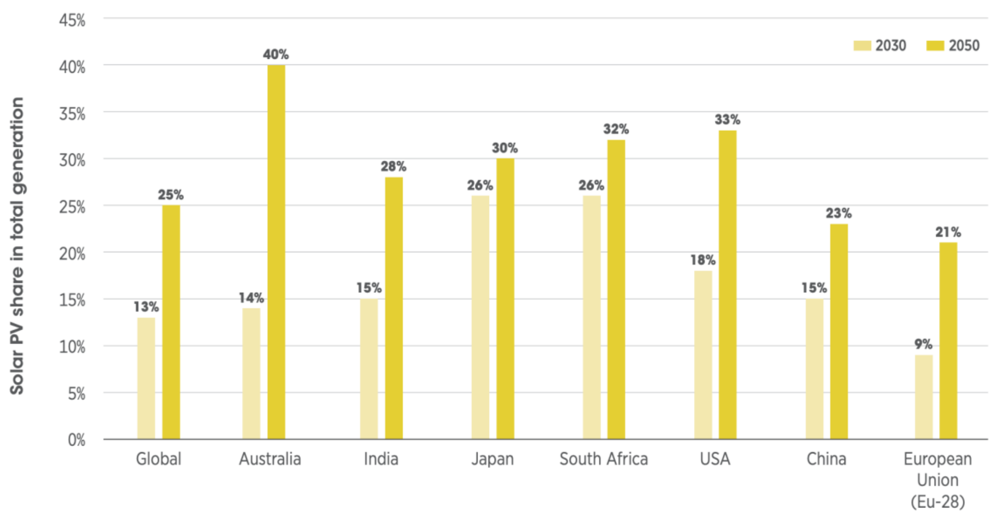
- Short wavelength (optical wavelengths) radiation from the Sun reaches the top of the atmosphere.
- Clouds reflect 17% back into space. If the earth gets more cloudy, as some climate models predict, more radiation will be reflected back and less will reach the surface
- 8% is scattered backward by air molecules:
- 6% is actually directly reflected off the surface back into space
- So the total reflectivity of the earth is 31%. This is technically known as an Albedo . Note that during Ice Ages, the Albedo of the earth increases. Note: that we measure energy in units of Watt-hours. A watt is not a unit of Energy; it is a measure of power

ENERGY = POWER x TIME

1 Kilowatt Hour = 1KWH = 1000 watts used in one hour = 10 100 watt light bulbs left on for an hour Incident Solar Energy on the ground:

- Average over the entire earth = 164 Watts per square meter over a 24 hour day So the entire planet receives 84 Terawatts of Power our current worldwide consumption is about 12 Terawatts.
- There is a large amount of infrastructure (e.g. cost) required to convert from potential to deliverable energy. 8 hour summer day, 40-degree latitude - 600 Watts per sq. meter.
- So over this 8 hour day, one receives: 8 hours x 600 Watts per sq. m = 4800 watt-hours per sq. m which equals 4.8 kilowatthours per sq. m. This is equivalent to 0.13 gallons of gasoline. For 1000 square feet of horizontal area (typical roof area) this is equivalent to 12 gallons of gas or about 450 kWh

Figure 17: A higher penetration of solar power in electricity grids is foreseen in various countries by 2030 and 2050



Source: IRENA (2019a)

Basic Solar Maths How much electricity is produced by a solar panel? What about a roof-top installation? You will find some basic calculations here below. The Watt measures the rate of energy conversion and it is the main unit of power used in photovoltaic. 1 kilowatt (kW) 1000 watts 1 megawatt (MW) 1000 kW or 1000000 watts 1 gig watt (GW) 1000 MW or 1000000000 watts 1 Terawatt (TW) 1000 GW or 1000000000000 watts PW P = peak (peak-performance of a module)

How much energy does one panel produce? Electrical energy is generally measured in kilowatt-hours (kWh). If a solar panel produces 100 watts for 1 hour, it has produced 100 watt-hours or 0.1 kWh. The amount of energy produced per day will depend on the area, shading, orientation, and watt-class of the panel. In areas with high irradiation, a properly oriented panel that produces 100 Watts at noon on a sunny day will produce an average of about 0.5 kWh/day during the winter and 0.8 kWh/day during the summer months. In an area with low irradiation, the same panel will still produce about 0.25 kWh/day during the winter and 0.6 kWh/day during summer months. An effective orientation for a solar panel installation is 100 per cent south, at an angle of 10- 20°. There are several standard measurements to describe a solar panel installation.

System Sizing Calculation Method -This is a simplified, "laypersons" overview of how solar energy systems calculations are made. The solar estimates provided via our Agencies and Earth Ambassador Agents are much more complex and complete. This simplified overview is meant only to provide the reader with a very basic understanding of some solar energy system calculation methods. The easy way is to use the My Solar Estimator – Solar Calculator link below but you should read this entire page to gain an understanding of how Solar PV system is properly sized and outputs calculated.

Photovoltaic (PV) is the direct conversion of light into electricity. Certain materials, like silicon, naturally release electrons when they are exposed to light, and these electrons can then be harnessed to produce an electric current. Several thin wafers of silicon are wired together and enclosed in a rugged protective casing or panel. PV panels produce direct current (DC) electricity, which must be converted to alternating current (AC) electricity to run standard household appliances.

An inverter connected to the PV panels is used to convert the DC electricity into AC electricity. The amount of electricity produced ¡s measured in watts (W). A kilowatt (kW) is equal to 1,000 watts. A Megawatt (MW) is equal to 1,000,000 Watts or 1,000 Kilowatts. The amount of electricity used over a given period of time is measured in kilowatt-hours (KWh). What is a solar rating? The solar rating is a measure of the average solar energy (also called "Solar Irradiance") available at a location in an average year. Radiant power is expressed in power per unit area: usually Watts/sq-meter, or kW/sq-meter. The total daily Irradiation (Wh/sq-meter) is calculated by the integration of the irradiance values (W/sq-meter). Solar Electric (Photovoltaic) System Calculations – Off grid system only Estimating Solar Electric (PV) System Size: Are of Solar Panels On average (as a general "rule of thumb") modern photovoltaic (PV) solar panels will produce 8 – 10 watts per square foot of solar panel area. For example, a roof area of 20 feet by 10 feet is 200 square feet (20 ft x 10 ft). This would produce, roughly, 9 watts per sq-foot, or 200 sqft x 9 watts/sqft = 1,800 watts (1.8 kW) of electric power.

Converting Power (watts or kW) to Energy (kWh) One kilowatt-hour (1 kWh) means an energy source supplies 1,000 watts (1 kW) of energy for one hour. Generally, a solar energy system will provide output for about 5 hours per day. So, if you have a 1.8 kW system size and it produces for 5 hours a day, 365 days a year: This solar energy system will produce 3,285 kWh in a year (1.8 kW x 5 hours x 365 days). If the PV panels are shaded for part of the day, the output would be reduced in accordance with the shading percentage. For example, if the PV panels receive 4 hours of direct sun shine a day (versus the standard 5 hours), the panels are shaded 1 divided by 5 = 20% of the time (80% of assumed direct sunshine hours received). In this case, the output of a 200 squarefoot PV panel system would be 3,285 kWh per year x 80% = 2,628 kWh per year.

PV systems

Types of PV systems PV systems can be very simple, consisting of just a PV module and load, as in the direct powering of a water pump motor, which only needs to operate when the sun shines. However, when for example a whole house should be powered, the system must be operational day and night. It also may have to feed both AC and DC loads, have reserve power and may even include a back-up generator. Depending on the system configuration, we can distinguish three main types of PV systems: stand-alone, grid-connected, and hybrid. The basic PV system principles and elements remain the same. Systems are adapted to meet particular requirements by varying the type and quantity of the basic elements. A modular system design allows easy expansion, when power demands change.

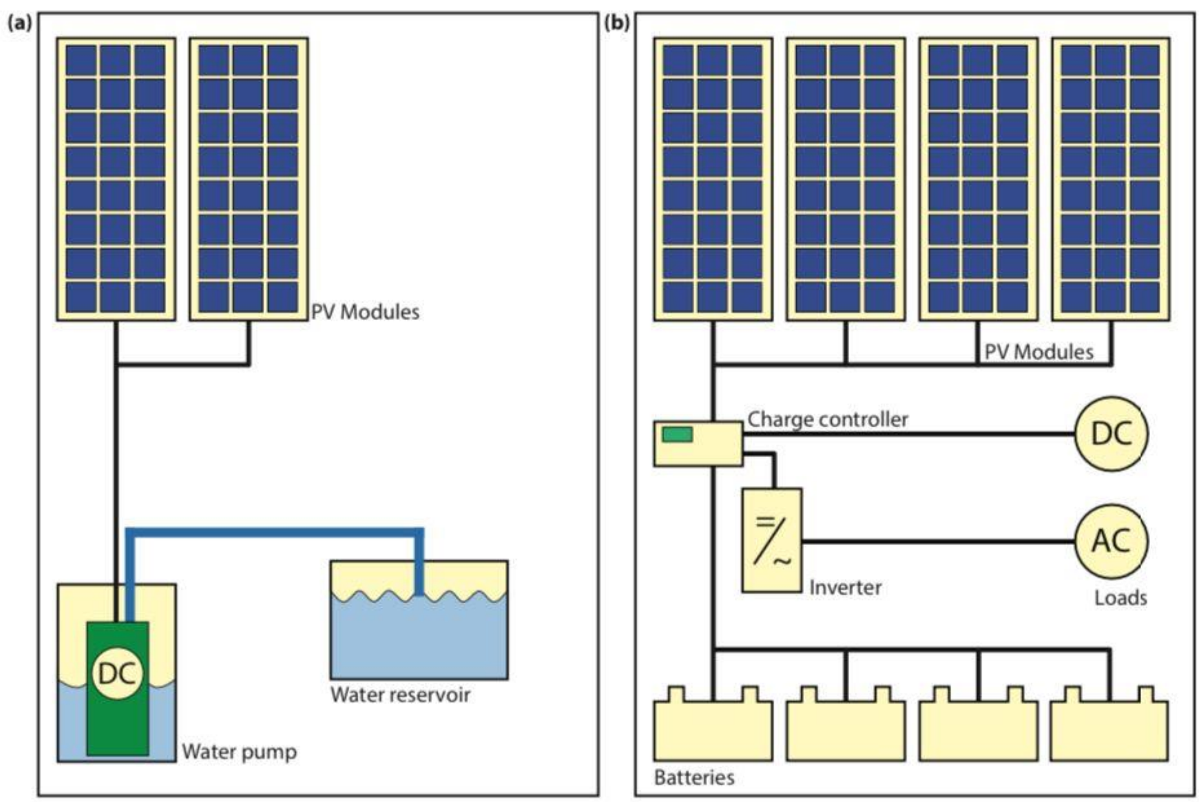


Figure 15.1: Schematic representation of (a) a simple DC PV system to power a water pump with no energy storage and (b) a complex PV system including batteries, power conditioners, and both DC and AC loads

Stand-alone systems -Stand-alone systems rely on solar power only. These systems can consist of the PV modules and a load only or they can include batteries for energy storage. When using batteries charge regulators are included, which switch off the PV modules when batteries are fully charged, and may switch off the load to prevent the batteries from being discharged below a certain limit. The batteries must have enough capacity to store the energy produced during the day to be used at night and during periods of poor weather. Figure 15.1 shows schematically examples of stand-alone systems; (a) a simple DC PV system without a battery and (b) a large PV system with both DC and AC loads.

Grid-connected systems Grid-connected PV systems have become increasingly popular for building integrated applications. As illustrated in Fig. 15.2, they are connected to the grid via inverters, which convert the DC power into AC electricity. In small systems as they are installed in residential homes, the inverter is connected to the distribution board, from where the PV-generated power is transferred into the electricity grid or to AC appliances in the house. These systems do not require batteries, since they are connected to the grid, which acts as a buffer into that an oversupply of PV electricity is transported while the grid also supplies the house with electricity in times of insufficient PV power generation. Large PV fields act as power stations from that all the generated PV electricity is directly transported to the electricity grid. They can reach peak powers of up to several hundreds of MWp. Figure 15.3 shows a 25.7 MWp system installed in Germany.

Hybrid systems Hybrid systems consist of combination of PV modules and a complementary method of electricity generation such as a diesel, gas or wind generator. A schematic of an hybrid system shown in Fig. 15.4. In order to optimise the different methods of electricity generation, hybrid systems typically require more sophisticated controls than stand-alone or grid-connected PV systems. For example, in the case of an PV/diesel system, the diesel engine must be started when the battery reaches a given discharge level and stopped again when battery reaches an adequate state of charge. The back-up generator can be used to recharge batteries only or to supply the load as well.

Components of a PV system

As we have seen earlier in this book, a solar cell can convert the energy contained in the solar radiation into electrical energy. Due to the limited size of the solar cell it only delivers a limited amount of power under fixed current-voltage conditions that are not practical for most applications. In order to use solar electricity for practical devices, which require a particular voltage and/or current for their operation, a number of solar cells have to be connected together to form a solar panel, also called a PV module. For large-scale generation of solar electricity solar panels are connected together into a solar array. Although, the solar panels are the heart of a PV system, many other components are required for a working system, that we already discussed very briefly above. Together, these components are called the Balance of System (BOS). Which components are required depends on whether the system is connected to the electricity grid or whether it is designed as a stand-alone system. The most important components belonging to the BOS are:

- A mounting structure is used to fix the modules and to direct them towards the sun.

• Energy storage is a vital part of stand-alone systems because it assures that the system can deliver electricity during the night and in periods of bad wheather. Usually, batteries are used as energystorage units.

• DC-DC converters are used to convert the module output, which will have a variable voltage depending on the time of the day and the weather conditions, to a fixed voltage output that e. g. can be used to charge a battery or that is used as input for an inverter in a grid-connected system.

• Inverters or DC-AC converters are used in gridconnected systems to convert the DC electricity originating from the PV modules into AC electricity that can be fed into the electricity grid.

• Cables are used to connect the different components of the PV system with each other and to the electrical load. It is important to choose cables of sufficient thickness in order to minimise resistive losses. Even though not a part of the PV system itself, the electric load, i.e. all the electric appliances that are connected to it have to be taken into account during the planning phase. Further, it has to be considered whether the loads are AC or DC loads. The different compontents of a PV system are schematically presented in FiG.

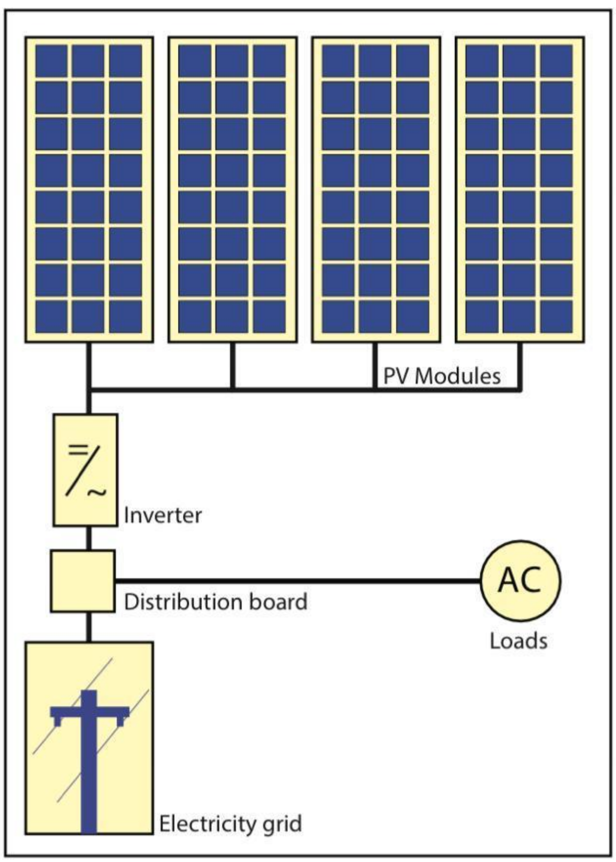


Figure 15.2: Schematic representation of a grid-connected PV system.

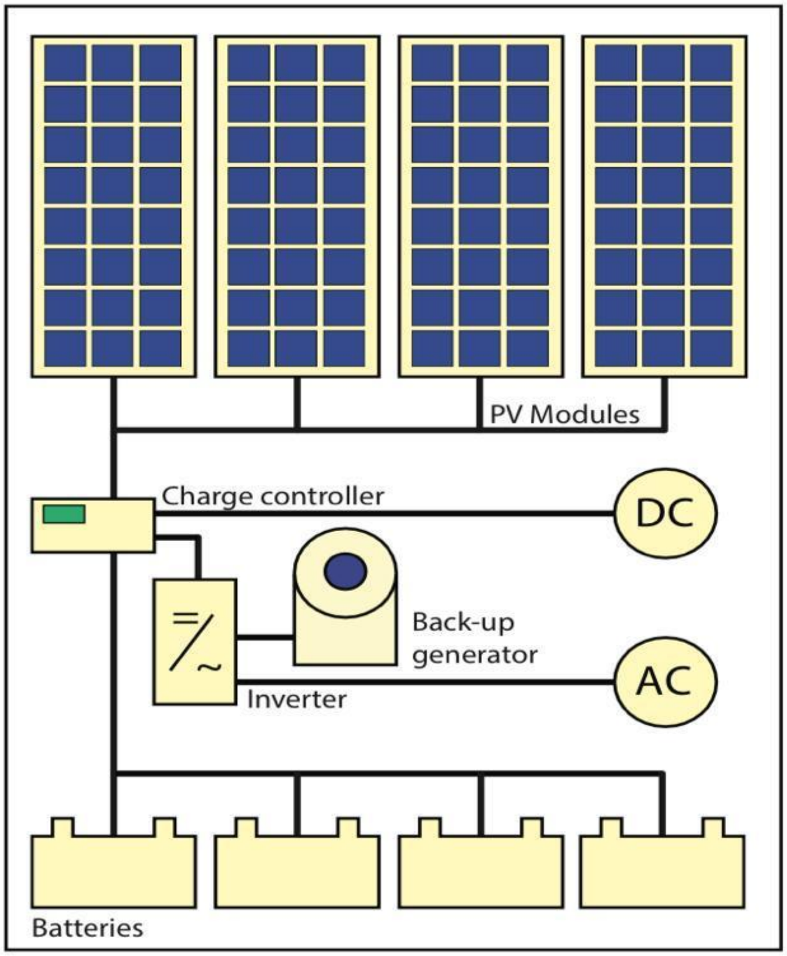


Figure 15.4: Schematic representation of a hybrid PV system that has a diesel generator as alternative electricity source..

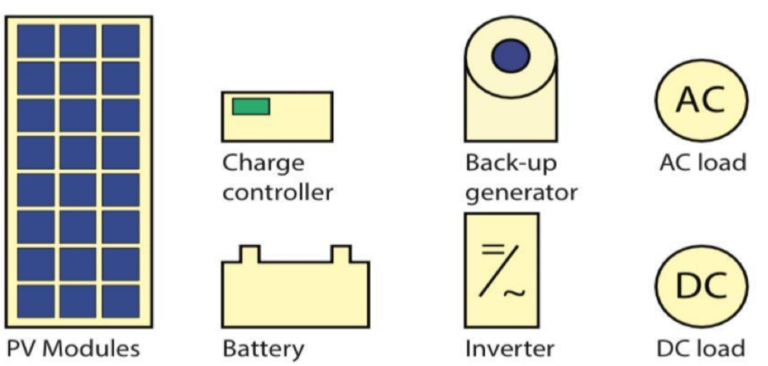


Figure 15.5: A schematic of the different components of a PV system.

Components of PV Systems

PV modules

In this section we will discuss PV modules (or solar modules), their fabrication and how to to determine their performance. Before we start with the actual treatment of PV modules, we briefly want to introduce different terms. Figure 17.1 (a) shows a crystalline solar cell, which we discussed in Chapter 12. For the moment we will consider only modules that are made from this type of solar cells. A PV module, is a larger device in which many solar cells are connected, as illustrated in Fig. 17.1 (b). The names PV module and solar module are often used interchangeably. A solar panel, as illustrated in Fig. 17.1 (c), consists of several PV modules that are electrically connected and mounted on a supporting structure. Finally, a PV array consists of several solar panels. An example of such an array is shown in Fig. 17.1 (d). This array consists of two strings of two solar panels each, where string means that these panels are connected in series.

Series and parallel connections **in PV** modules

If we make a solar module out of an ensemble of solar cells, we can connect the solar cells in different ways: first, we can connect them in a series connection as shown in Fig. 17.2 (a). In a series connection the voltages add up. For example, if the open circuit voltage of one cell is equal to 0.6 V, a string of three cells will deliver an open circuit voltage of 1.8 V. For solar cells with a classical front metal grid, a series connection can be established by connecting the bus bars at the front side with the back contact of the neighbouring cell, as illustrated in Fig. 17.2 (b)

. For series connected cells, the current does not add up but is determined by the photocurrent in each solar cell. Hence, the total current in a string of solar cells is equal to the current generated by one single solar cell. Figure Fig. 17.2 (d) shows the I-V curve of solar cells connected in series. If we connect two solar cells in series, the voltages add up while the current stays the same. The resulting open circuit voltage is two times that of the single cell.

If we connect three solar cells in series, the open circuit voltage becomes three times as large, whereas the current still is that of one single solar cell. Secondly, we can connect solar cells in parallel as illustrated in Fig. 17.2 (c), which shows three solar cells connected in parallel. If cells are connected in parallel, the voltage is the same over all solar cells, while the currents of the solar cells add up. If we connect e.g. three cells in parallel, the current becomes three times as large, while the voltage is the same as for a single cell, as illustrated in Fig. 17.2 (d)

. The reader may have noticed that we used I-V curves, i.e. the current-voltage characteristics, in the previous paragraphs. This is different to Parts II and III, where we used I-V curves instead, i.e. the current density - voltage characteristics. The reason for this switch from J to I is that on module level, the total current that the module can generate is of higher interest than the current density. As the area of a module is a constant, the shapes of the I-V and J-V curves of a module are similar. For a total module, therefore the voltage and current output can be partially tuned via the arrangements of the solar cell connections. Figure 17.3 (a) shows a typical PV module that contains 36 solar cells connected in series. If a single junction solar cell would have a short circuit current of 5 A, and an open circuit voltage of 0.6 V, the total module would have an output of $V_{oc} = 36 \cdot 0.6$ V = 21.6 V and I_{sc} = 5 A.

However, if two strings of 18 series-connected cells are connected in parallel, as illustrated in Fig. 17.3 (b), the output of the module will be $V_{oc} = 18 \cdot 0.6$ V = 10.8 V and $I_{sc} = 2 \times 5$ A = 10 A. In general, for the I-V characteristics of a module consisting of m identical cells in series and n identical cells in parallel the voltage multiplies by a factor m while the current multiplies by a factor n. Modern PV modules often contain 60 (10 × 6), 72 (9 × 8) or 96 (12 × 8) solar cells that are usually all connected in series in order to minimise resistive losses.

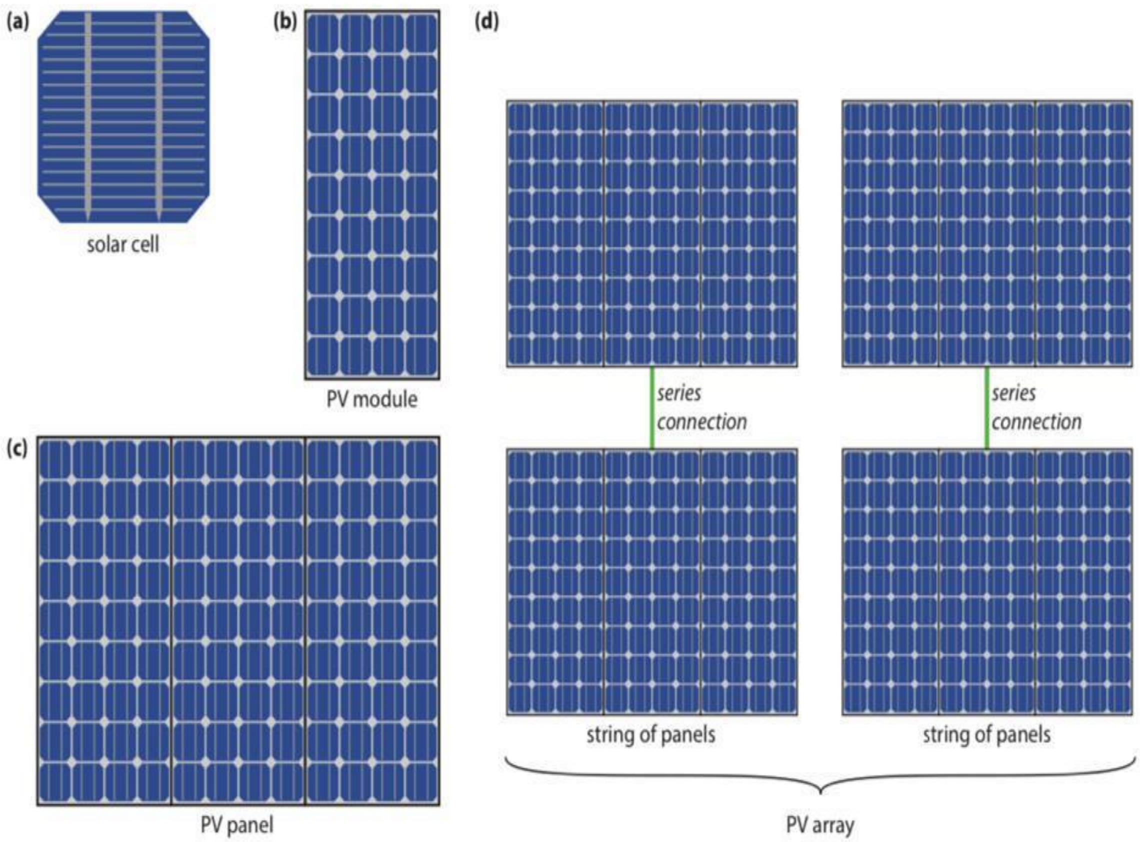


Figure 17.1: Illustrating (a) a solar cell, (b) a PV module, (c) a solar panel, and (d) a PV array.

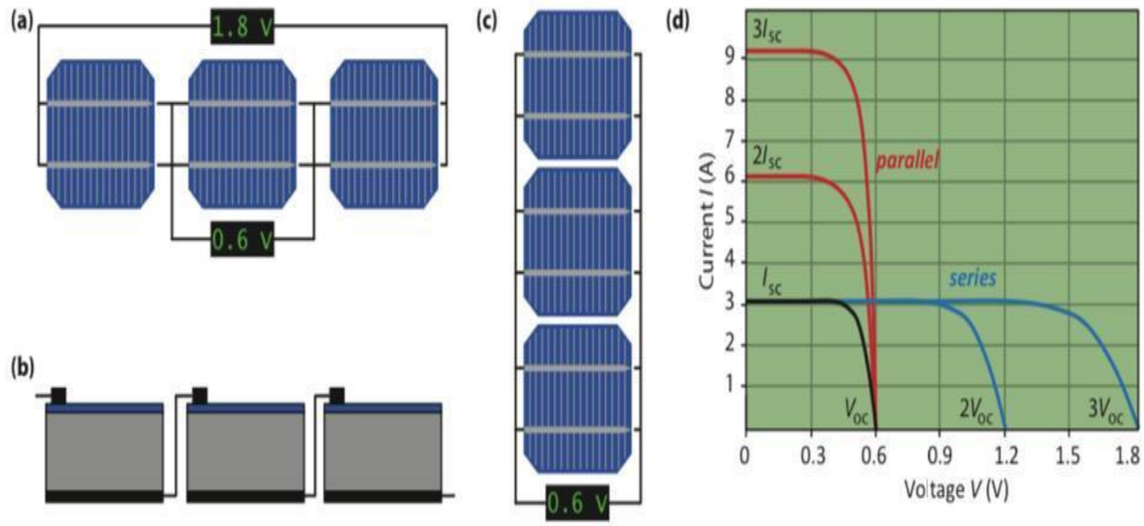


Figure 17.2: Illustrating (a) a series connection of three solar cells and (b) realisation of such a series connection for cells with a classical front metal grid. (c) Illustrating a parallel connection of three solar cells. (d) *I-V* curves of solar cells connected in series and parallel.

PV module parameters In a nutshell, for a PV module a set of parameters can be defined, similar than for solar cells. The most common parameters are the open circuit voltage Voc, the short circuit current Isc and the module fill factor FFM. On module level, we have to distinguish between the aperture area efficiency and the module efficiency. The aperture area is defined as the area of the PV-active parts only. The total module area is given as the aperture area plus the dead area consisting of the interconnections and the edges of the module. Clearly, the aperture area efficiency is larger than the module efficiency. Determining the the efficiency and the fill factor of a PV module is less straight-forward than determining voltage and current. In an ideal world with perfectly matched solar cells and no losses, one would expect that the efficiency and fill factor at both the module and cell levels to be the same. This is not the case in real life. As mentioned above. The cells are connected with each other using interconnects that induce resistive losses. Further, there might be small mismatches in the interconnected cells.

For example, if m × n cells are interconnected, the cell with the lowest current in a string of m cells in series determines the module current. Similarly, the string with the lowest voltage in the n strings that are connected in parallel dictates the module voltage. The reason for mismatch between individual cells are inhomogeneities that occur during the production process. Hence, in practice PV module perform a little less than what one would expect from ideally matched and interconnected solar cells. This loss in performance translates to a lower fill factor and efficiency at module level. If the illumination across the module is not constant or if the module is heats up non-uniformly, the module performance reduces even further.

Often, differences between cell and module performance are mentioned in datasheets that are provide by the module manufacturers. For example, the datasheet of a Sanyo HIT-N240SE10 module gives a cell level efficiency of 21.6%, but a module level efficiency of only 19%. Despite all the technological advancements being made at solar cell level for improving the efficiency, still a lot must be done at the PV systems level to ensure a healthy PV yield. For the performance of a PV system, not only the module performance is important, but also the yield of the PV system.

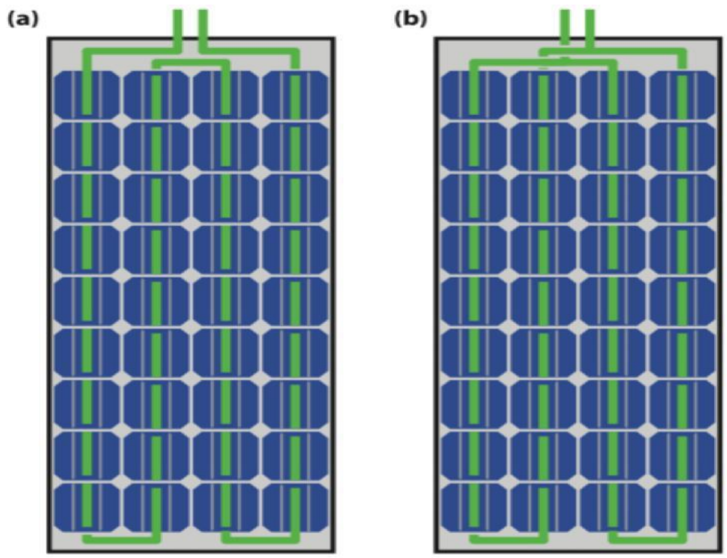


Figure 17.3: Illustrating a PV module consisting (a) of a string of 36 solar cells connected in series and (b) of two strings of 18 solar cells each that are connected in parallel.

Partial shading and bypass diodes

PV modules have so-called bypass diodes integrated. To understand the reason for using such diodes, we have to consider modules in real-life conditions, where they can be partially shaded, as illustrated in Fig. 17.4 (a). The shade can be from an object nearby, like a tree, a chimney or a neighbouring building. It also can be caused by a leaf that has fallen from a tree. Partial shading can have significant consequences for the output of the solar module.

To understand this, we consider the situation in which one solar cell in the module shaded for a large part shaded. For simplicity, we assume that all six cells are connected in series. This means that the current generated in the shaded cell is significantly reduced. In a series connection the current is limited by the cell that generates the lowest current, this cell thus dictates the maximum current flowing through the module. In Fig. 17.4 (b) the theoretical I-V curve of the five unshaded solar cells and the shaded solar cell is shown. If the cells are connected to a constant load R, the voltage across the module is dropping due to the lower current generated.

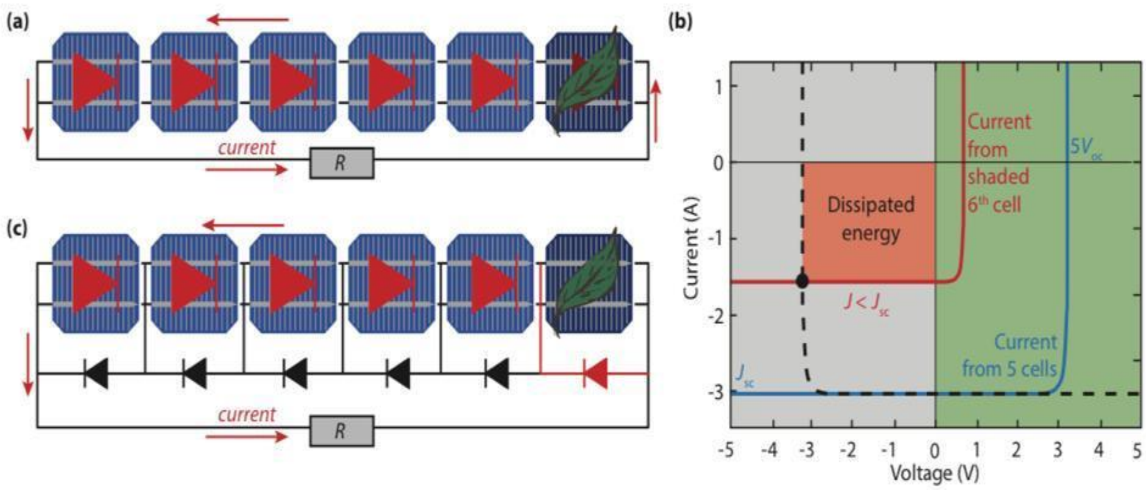


Figure 17.4: Illustrating (a) string of six solar cells of which one is partially shaded, which (b) has dramatic effects on the *I-V* curve of this string. (c) Bypass diodes can solve the problem of partial shading.

However, since the five unshaded solar cells are forced to produce high voltages, they act like a reverse bias source on the shaded solar cell. The dashed line in Fig. 17.4 (b) represents the reverse bias load put on the shaded cell, which is the I-V curve of the five cells, reflected across the vertical axis equal to 0 V. Hence, the shaded solar cell does not generate energy, but starts to dissipate energy and heats up. The temperature can increase to such a critical level, that the encapsulation material cracks, or other materials wear out. Further, high temperatures generally lead to a decrease of the PV output as well. These problems occurring from partial shading can be prevented by including bypass diodes in the module, as illustrated in 17.4 (c). a diode blocks the current when it is under negative voltage, but conducts a current when it is under positive voltage. If no cell is shaded, no current is flowing through the bypass diodes. However, if one cell is (partially) shaded, the bypass diode starts to pass current through because of the biasing from the other cells.

As a result current can flow around the shaded cell and the module can still produce the current equal to that of a unshaded single solar cell. For cells that are connected in parallel, partial shading is less of a problem, because the currents generated in the others cells do not need to travel through the shaded cell. However, a module consisting of 36 cells in parallel have very high currents (above 100 A) combined with a very low voltage (approx. 0.6 V). This combination would lead to very high resistive losses in the cables; further an inverter that has only 0.6 V as input will not be very efficient, as we will see in Section 17.3. Therefore, combining the cells in series and using bypass diodes is much better an option to do.

Fabrication of PV modules

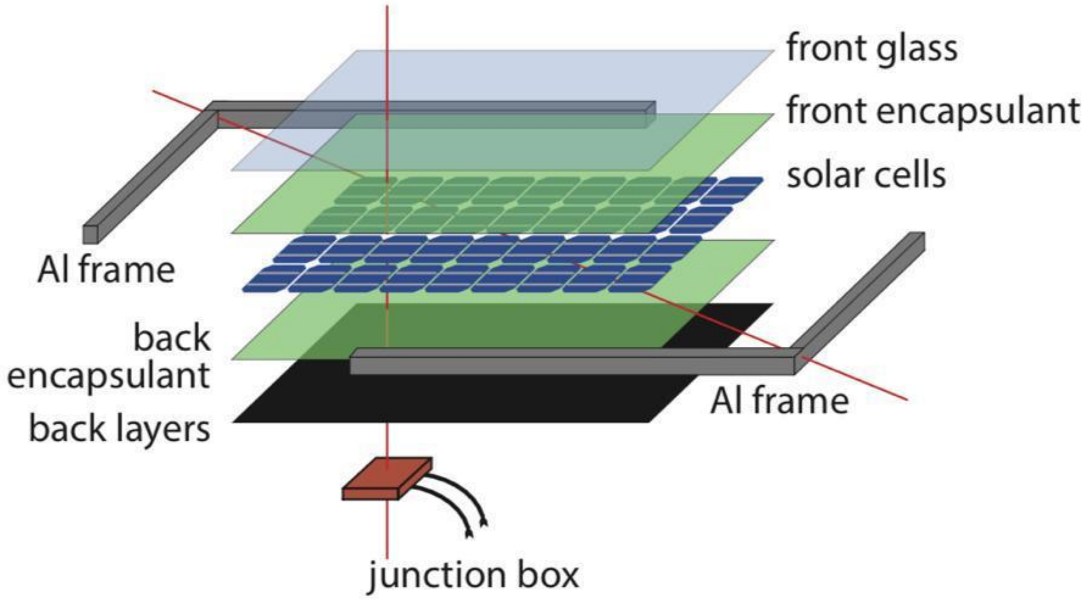


Figure 17.5: The components of a typical c-Si PV module.

As discussed in the subsection 17.1.5, a PV module must withstand various influences in order to survive a lifetime of 25 years or even longer. In order to ensure a long lifetime, the components of that a PV module is built must be well chosen. Fig. 17.5 shows the typical components of a usual crystalline silicon PV module. Of course, the layer stack may consist of different materials dependent on the manufacturer. The major components are:

• Soda-lime glass with a thickness of several millimetres, which provides mechanical stability while being transparent for the incident light. It is important the glass has a low iron content because iron leads to absorption of light in the glass which can lead to losses. Further, the glass must be tempered in order to increase its resistance to impacts.

• The solar cells are sandwiched in between two layers of encapsulants. The most common material is ethylene-vinyl-acetate (EVA), which is a thermoplastic polymer (plastic). This means that it goes into shape when it is heated but that these changes are reversible.

• The back layer acts as a barrier against humidity and other stresses. Depending on the manufacturer, it can be another glass plate or a composite polymer sheet. A material combination that is often used is PVF-polyester-PVF, where PVF stands for polyvinyl fluoride, which is often known by its brand name

Tedlar®. PVF has a low permeability for vapours and is very resistive against weathering. A typical polyester is polyethylene terephthalate (PET)

• A frame usually made from aluminium is put around the whole module in order to enhance the mechanical stability.

• A junction box usually is placed at the back of the module. In it the electrical connections to the solar cell are connected with the wires that are used to connect the module to the other components of the PV system. One of the most important steps during module production is laminating, which we briefly will explain for the case that EVA is used as encapsulant. For lamination, the whole stack consisting of front glass, the encapsulants, the interconnected solar cells, and the back layer are brought together in a laminator, which is heated above the melting point of EVA, which is around 120°C. This process is performed in vacuo in order to ensure that air, moisture and other gasses are removed from within the module stack. After some minutes, when the EVA is molten, pressure is applied and the temperature is increased to about 150°C. Now the curing process starts, i.e. a curing agent, which is present in the EVA layer, starts to cross-link the EVA chains, which means that transverse bonds between the EVA molecules are formed. As a result, EVA has elastomeric, rubberlike properties. The choice of the layers that light traverses before entering the solar cell is also very important from an optical point of view. If this layers have an increasing refractive index, they act as antireflective coating and thus can enhance the amount of light that is in-coupled in the solar cell and finally absorbed, which increases the current produced by the solar cell.

Lifetime testing of PV Modules

The typical lifetime of PV systems is about 25 years. In these as little maintenance as possible should be required on the system components, especially the PV modules are required to be maintenance free. Furthermore, degradation in the different components of that Components of PV Systems the module is made should be little: manufacturers typically guarantee a power between 80% and 90% of the initial power after 25 years. During the lifetime of 25 years or more, PV modules are exposed to various external stress from various sources

• temperature changes between night and day as well as between winter and summer,

• mechanical stress for example from wind, snow and hail,

• stress by agents transported via the atmosphere such as dust, sand, salty mist and other agents,

• moisture originating from rain, dew and frost

, • humidity originating from the atmosphere,

• irradiance consisting of direct and indirect irradiance from the sun; mainly the highly-energetic UV radiation is challenging for many materials.

Before PV modules are brought to the market, they are usually tested extensively in order to assure their stability against these various stresses. The required tests are extensively defined in the standards IEC 61215 for modules based on crystalline silicon solar cells and in IEC 61646 for thin-film modules. Since the modules cannot be tested during a period of 25 years, accelerated stress testing must be performed. The required tests are

- Thermal cycles for studying whether thermal stress leads to broken interconnects, broken cells, electrical bond failure, adhesion of the junction box,

- Damp heat testing to see whether the modules suffer from corrosion, delamination, loss of adhesion and elasticity of the encapsulant, adhesion of the junction box,

- Humidity freeze testing in order to test delamination, adhesion of the junction box,

- UV testing, because UV light can lead to delamination, loss of adhesion and elasticity of the encapsulant, ground fault due to backsheet degradation. Mainly, UV light can lead to a discoloration of the encapsulant and back sheet, which means that they get yellow. This can lead to losses in the amount of light that reaches the solar cells.

- Static mechanical loads in order to test whether strong winds or heavy snow loads lead to structural failures, broken glass, broken interconnect ribbons or broken cells.

- Dynamic mechanical load, which can lead to roken glass, broken interconnect ribbons or broken cells.

- Hot spot testing in order to see whether hot spots due to shunts in cells or inadequate bypass diode protection are present.

- Hail testing to see whether the module can handle the mechanical stress induced by hail.

- Bypass diode thermal testing to study whether overheating of these diodes causes degradation of the encapsulant, backsheet or the junction box.

- Salt spray testing to see whether salt that is present in salty mist or that is used in salty water for snow and ice removal leads to corrosion of PV module components.

How these tests are to be performed is defined in other standards, for example IEC 61345 for UV testing and IV 61701 for salt-mist corrosion testing Usually these tests are carried out by organisations like TÜV Rheinland. Refining the test requirements and understanding which accelerated tests are required to guarantee a lifetime of 25 years and more is subject to ongoing research and development.

Thin-film modules

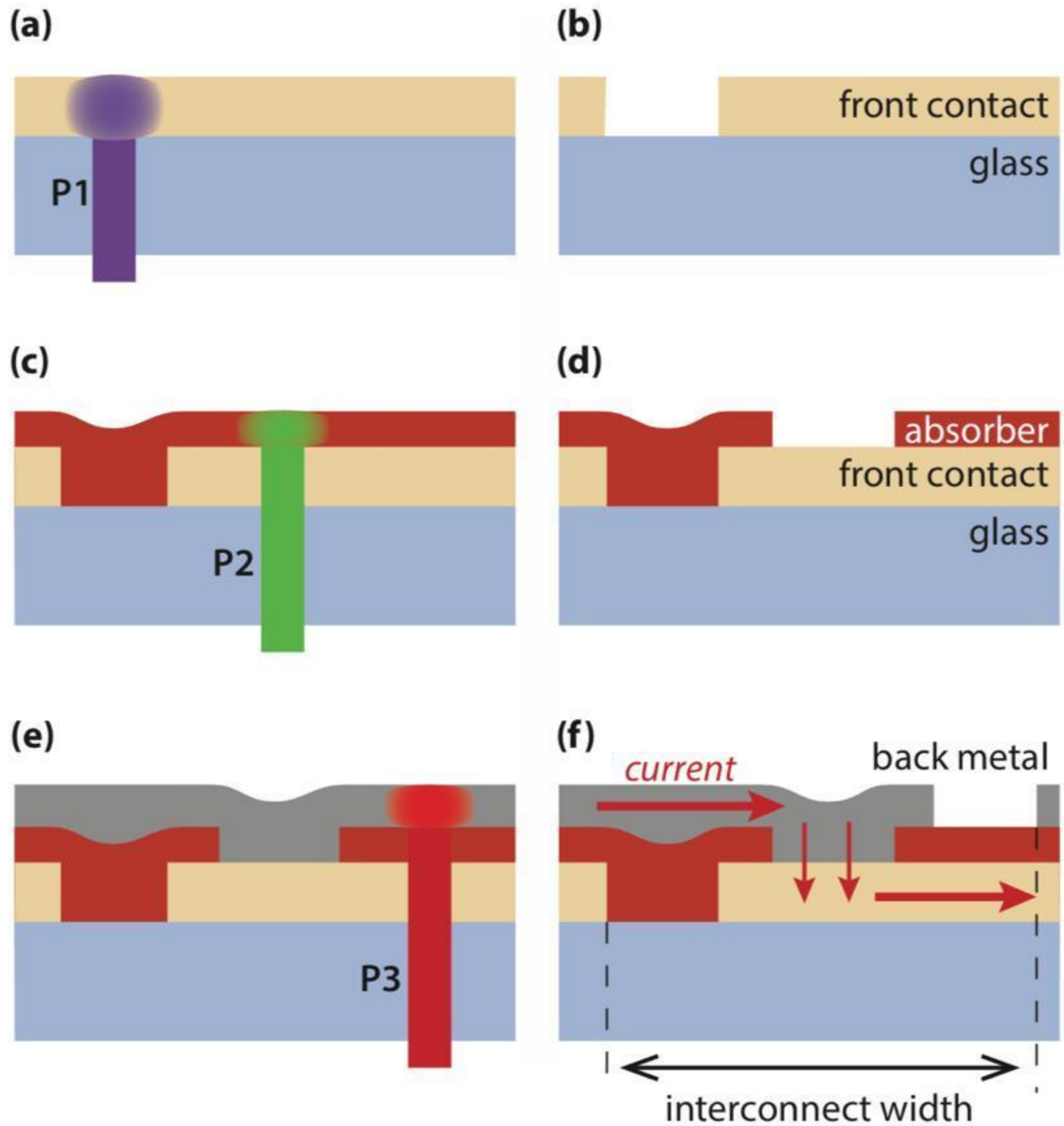


Figure 17.6: Schematic of creating an interconnect in thin-film module. (Explanation given in the text).

Making thin-film modules is very different from making modules from c-Si solar cells. While for c-Si technology producing solar cells and producing PV modules are two distinct steps, in thin-film technology producing cells and modules cannot be separated from each other. To illustrate this we look at a PV module where the thin-films are deposited in superstrate configuration on glass, as illustrated in Fig. 17.6. For making such a module, a transparent front contact, a stack of (photo)active layers that also contain one or more semiconductor junctions, and a metallic back contact are deposited onto each other. In industrial production, the glass plates on that these layers are deposited can be very large, with sizes significantly exceeding 1 × 1 m2 .

Such a stack of layers deposited onto a large glass plate in principle forms one very large solar cell that will produce a very high current. Since all the current would have to be transported across the front and back contacts, which are very thin, resistive losses in the module is even a bigger problem than for c-Si modules. Therefore, the module is produced such that it consists of many very narrow cells of about 1 cm width and the length being equal to the module length. These cells then are connected in series across the width of the module. On the very left and right of the module metallic busbars collect the current and conduct it to the bottom of the module where they are connected with external cables.

The series connection is established with laser scribing. In total, three laser scribes are required for separating two cells from each other and establishing a series connection between them. The first laser scribe, called P1, is performed after the transparent front contact is deposited, as shown in Fig. 17.6 (a). The wavelength of the laser is such that the laser light is absorbed in the front contact and the material is evaporated, leaving a "gap" in the front contact, as shown in Fig. 17.6 (b). Components of PV Systems Then the photoactive layers are deposited onto the front contact and also fill the gaps. Then, the second laser scribe, called P2, is performed, as illustrated in Fig. 17.6 (c). The laser wavelength has to be chosen such that it is not absorbed in the transparent front contact but in the absorber layer. For example, if the absorber consists of amorphous silicon, green laser light can be used. The P2 scribe leaves a gap in the absorber layer, as illustrated in Fig. 17.6 (d). The next step is the deposition of the metallic back contact that also fills the P2 gap. Finally, the third laser scribe (P3) is performed as illustrated in Fig. 17.6 (e). The wavelength for this scribe has to be chosen such that it is neither absorbed in the front contact nor in the absorber stack, so it is, for example, infrared. The P3 scribe shoots a gap into the back contact, as shown in Fig. 17.6 (f).

To understand the action of the laser scribes, we take a look at Fig. 17.6 (f): the P1 scribe filled with absorber material forms an barrier, since the absorber is orders of magnitudes less conductive than the transparent front contact. Similar, the P3 scribes forms an insulating gap in the metallic back contact. However, the P2 scribe that also is filled with metal forms a highly conducting connection between the front and back contacts – here the actual series connection is performed. For example, for making CIGS solar cells, first the molybdenum back contact is deposited on top of the glass substrate and the cell areas are defined by P1 laser scribes. Then the CIGS p layer and the CdS n layer are deposited including a P2 laser scribe step. Finally the intrinsic and n-doped zinc oxide is deposited, followed by a final P3 laser scribe step.

Now the front TCO electrode is connected with the Molybdenum back contact of the next solar cell. The performance of such an interconnect established via laser scribes and hence the total module performance is determined by several things. First, the P2 scribe has to be highly conductive, This means that it has to be wide enough and that there must be no barrier at the interface between the front contact and the metal of the P2 scribe. Further, the P1 and P3 scribes must perform good barriers to effectively separate the cells from each other. Thirdly, the region between the P1 and P3 scribes does not contribute to the the current generated by the module.

Therefore, the ratio between this width and the total cell width (including the scribes) has to be as small as possible. Another issue is the fact that the three laser scribes are performed in different steps of production and thus often in different machines. Further, the distance between the scribes might be different at the different processes when they are performed at different temperatures. This, aligning the glass plates in all the production steps is extremely important for manufacturing high-quality thin-film modules. The production steps and also the exact processing of the laser scribes is of course dependent on which thinfilm technology is used and even on the manufacturer itself. However, the basic principles and the action behind these processes is valid in general. One advantage of thin-film PV technology is that they can be deposited onto flexible substrates. For example, the Dutch company HyET Solar developed a technology, where thin-film silicon layers are deposited onto a temporary aluminium substrate .

After the solar cell layers are encapsulated on the back side, the temporary substrate is etched away, and the front side is encapsulated. This results in a very low weight flexible substrate, which can be integrated for example in curved roof top elements. A very big advantage is that such very light modules can be installed on simple roof top constructions that only can handle little ballast. On such roofs, heave PV panels with glass cannot be installed. Further, if such flexible modules are directly integrated into roofing elements, installation costs can be reduces significantly. Often, installation costs are the largest contributor to the non-modular costs of a PV system. Currently, only thin-film silicon technologies have demonstrated flexible modules with reasonable efficiencies.

LEAD ACID BATTERIES

Introduction Lead acid batteries are the most common large-capacity rechargeable batteries. They are very popular because they are dependable and inexpensive on a cost-per-watt base. There are few other batteries that deliver bulk power as cheaply as lead acid, and this makes the battery cost-effective for automobiles, electrical vehicles, forklifts, marine and uninterruptible power supplies (UPS).

Lead acid batteries are built with a number of individual cells containing layers of lead alloy plates immersed in an electrolyte solution, typically made of 35% sulphuric acid (H_2SO_4) and 65% water (Figure 1). Pure lead (Pb) is too soft and would not support itself, so small quantities of other metals are added to get the mechanical strength and improve electrical properties. The most common additives are antimony (Sb), calcium (Ca), tin (Sn) and selenium (Se). When the sulphuric acid comes into contact with the lead plate, a chemical reaction is occurring and energy is produced.

Lead acid batteries are heavy and less durable than nickel (Ni) and lithium (Li) based systems when deep cycled or discharged (using most of their capacity). Lead acid batteries have a moderate life span and the charge retention is best among rechargeable batteries. The lead acid battery works well at cold temperatures and is superior to lithium-ion when operating in sub-zero conditions. Lead acid batteries can be divided into two main classes: vented lead acid batteries (spillable) and valve regulated lead acid (VRLA) batteries (sealed or non-spillable).

Vented Lead Acid Batteries

Hazards

Vented lead acid batteries are commonly called “flooded”, “spillable” or “wet cell” batteries because of their conspicuous use of liquid electrolyte (Figure 2). These batteries have a negative and a positive terminal on their top or sides along with vent caps on their top. The purpose of the vent caps is to allow for the escape of gases formed, hydrogen and oxygen, when the battery is charging. During normal operation, water is lost due to evaporation. In addition, the vent caps allow water and acid levels of the battery to be checked during maintenance.

The main hazards associated with lead acid batteries are:

1) Chemical (corrosive) hazards

2) Risk of fire or explosion

3) Electrical shocks

4) Ergonomic hazards related to their heavy weight

5) Transportation hazards

Acid burns to the face and eyes comprise about 50% of injuries related to the use of lead acid batteries. The remaining injuries were mostly due to lifting or dropping batteries as they are quite heavy.

Chemical Hazards

Sulphuric Acid

Lead acid batteries are usually filled with an electrolyte solution containing sulphuric acid. This is a very corrosive chemical (pH<2) which can permanently damage the eyes and produce serious chemical burns to the skin. Sulphuric acid is also poisonous, if swallowed. The lead alloys found in batteries are also harmful to humans and can also seriously damage the environment.

When working with battery acid, the following precautions must be taken:

- Wear the proper personal protective equipment (PPE), specifically splash-proof goggles, acidresistant lab coat or apron, safety shoes and rubber gloves. A face shield must also be wornwhen refilling batteries with electrolytes.
- Know where the emergency showers and emergency eyewash stations are located; they must be located near lead acid battery storage and charging areas.

- Slowly pour concentrated acid into water; do not add water to acid. (warning: electrolyte will become hot; do not close battery vents until electrolyte has cooled down).
- Use non-metallic containers and funnels.
- Ensure neutralizers (e.g. baking soda) are available for immediate use.
- Use extreme care to avoid spilling or splashing the sulphuric acid solution.

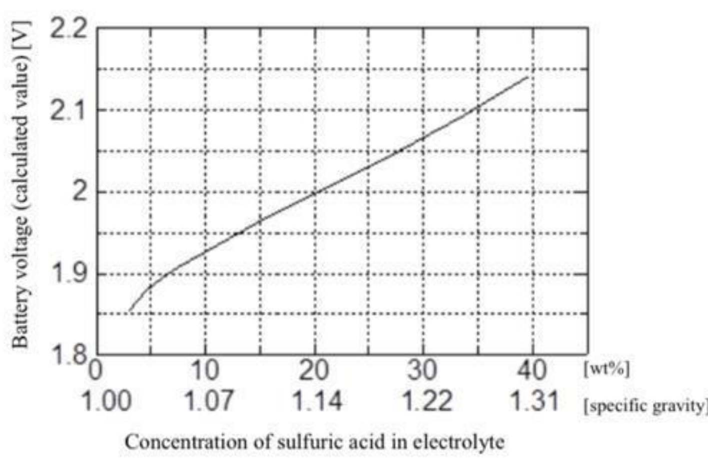
■Principles of lead-acid battery

Lead-acid batteries use a lead dioxide (PbO_2) positive electrode, a lead (Pb) negative electrode, and dilute sulfuric acid (H_2SO_4) electrolyte (with a specific gravity of about 1.30 and a concentration of about 40%). When the battery discharges, the positive and negative electrodes turn into lead sulfate ($PbSO_4$), and the sulfuric acid turns into water. When the battery is charged, the opposite reaction occurs (Equation [1]).

$$\mathbf{PbO_2(Positive\ electrode) + Pb(Negative\ electrode) + 2H_2SO_4(Electrolyte)} \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftharpoons}} \mathbf{2PbSO_4 + 2H_2O} \quad \cdots \ (1)$$

When a lead-acid battery is discharged, the battery's voltage gradually declines because the sulfuric acid in its electrolyte decreases. Theoretically, the concentration of H_2SO_4 is about 39.7% (the specific gravity of about 1.30) when the battery is fully charged at 2.14 V. The concentration will fall to about 6.6% (the specific gravity of about 1.05) when the battery is fully discharged at 1.9V. (In an actual battery, values may diverge from theoretical values depending on the conditions of use.)

Additionally, the specific gravity of the electrolyte in automotive batteries may be measured as part of battery maintenance. Since the sulfuric acid concentration declines when the battery degrades, this measurement serves as an indicator of when the battery needs to be replaced.



Electrolyte concentration and voltage in lead-acid batteries

■Detailed description of the discharge reaction in lead-acid batteries

■Reaction at the negative electrode

When a lead-acid battery is discharged after connecting a load such as a light bulb between its positive and negative electrodes, the lead (Pb) in the negative electrode releases electrons (e^-) to form lead ions (Pb^{2+}).

$$Pb \rightarrow Pb^{2+} + 2e^-$$

Then the lead ions immediately bond with sulfate ions (SO_4^{2-}) in the electrolyte to form lead sulfate ($PbSO_4$) and adhere to the surface of the negative electrode.

$$Pb^{2+} + SO_4^{2-} \rightarrow PbSO_4$$

The above activity at the negative electrode is summarized by Equation (1):

$$\mathbf{Pb + SO_4^{2-} \rightarrow PbSO_4 + 2e^-} \quad \cdots (1)$$

■Reaction at the positive electrode

Electrons (e^-) that have flowed from the negative electrode through the load to the positive electrode give the positive electrode a negative charge, attracting hydrogen ions (H^+) in the electrolyte. The hydrogen ions strip oxygen ions (O^{2-}) from the lead dioxide (PbO_2) in the positive electrode to form water (H_2O). Meanwhile, the lead dioxide from which the oxygen was stripped remains as lead ions (Pb^{2+}).

$$PbO_2 + 4H^+ + 2e^- \rightarrow Pb^{2+} + 2H_2O$$

Those lead ions immediately bond with sulfate ions (SO_4^{2-}) in the electrolyte to become lead sulfate ($PbSO_4$) and adhere to the surface of the positive electrode.

$$Pb^{2+} + SO_4^{2-} \rightarrow PbSO_4$$

The above activity at the positive electrode is summarized by Equation (2):

$$\mathbf{PbO_2 + 4H^+ + SO_4^{2-} + 2e^- \rightarrow PbSO_4 + 2H_2O} \quad \cdots (2)$$

■Overall reaction

Equations (1) and (2) can be summarized to express the overall discharge reaction in a lead-acid battery as shown in Equation (3):

$$\mathbf{Pb + PbO_2 + \underbrace{4H^+ + 2SO_4^{2-}}_{2H_2SO_4} \rightarrow 2PbSO_4 + 2H_2O} \quad \cdots (3)$$

■Detailed description of the charge reaction in lead-acid batteries

■Reaction at the negative electrode

If a power supply is connected between a lead-acid battery's positive and negative electrodes so that electrons (e^-) are forced to flow to the negative electrode, the lead sulfate ($PbSO_4$) that formed while the battery was discharging will revert to lead (Pb) in a reaction that releases sulfate ions (SO_4^{2-}).

$$\mathbf{PbSO_4 + 2e^- \rightarrow Pb + SO_4^{2-}} \quad \cdots (1)$$

■Reaction at the positive electrode

Meanwhile, the positive electrode, from which electrons (e^-) were stripped, will gain a positive charge in a reaction in which water (H_2O) breaks down into oxygen (O_2) and hydrogen ions (H^+).

$$2H_2O \rightarrow O_2 + 4H^+ + 4e^-$$

Then, because the lead sulfate ($PbSO_4$) at the positive electrode lacks electrons, it will immediately react with oxygen to form lead dioxide (PbO_2) in a reaction that releases sulfate ions (SO_4^{2-}).

$$PbSO_4 - 2e^- + O_2 \rightarrow PbO_2 + SO_4^{2-}$$

The above activity at the positive electrode is summarized by Equation (2):

$$\mathbf{PbSO_4 + 2H_2O \rightarrow PbO_2 + SO_4^{2-} + 4H^+ + 2e^-} \quad \cdots (2)$$

■Overall reaction

Equations (1) and (2) can be summarized to express the overall reaction in a lead-acid battery as shown in Equation (3):

$$\mathbf{PbSO_4 + 2H_2O \rightarrow Pb + PbO_2 + \underbrace{4H^+ + 2SO_4^{2-}}_{2H_2SO_4}} \quad \cdots (3)$$

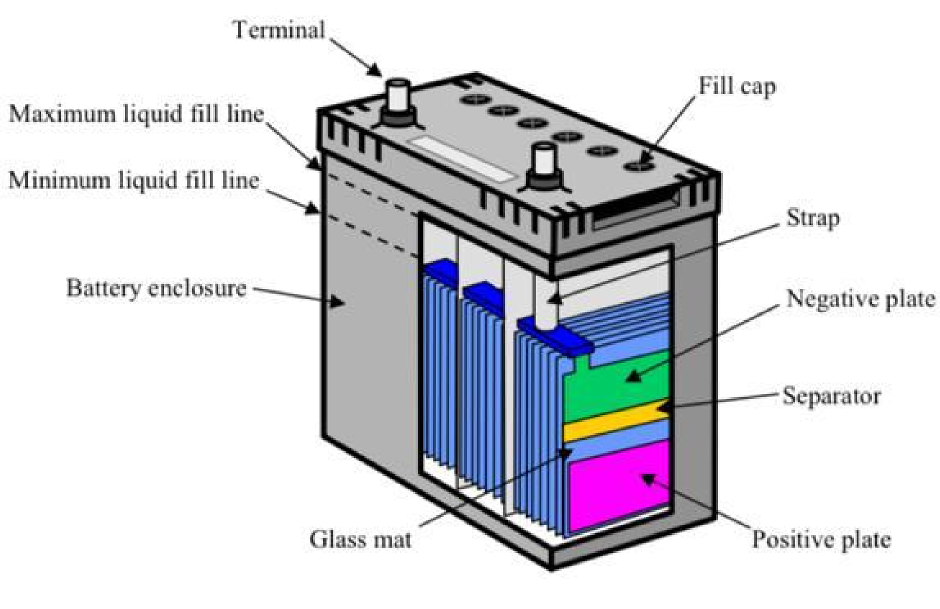
■Types of lead-acid batteries: Vented type

This type of battery is also known as a liquid or flooded battery.

It has a series of air holes to allow the oxygen and hydrogen gas formed by electrolysis of the electrolyte during charging to escape. This design uses the same basic structure that was in use when the lead-acid battery was invented, and most automotive lead-acid batteries use it.

Although it is necessary to replenish water in the electrolyte that is lost due to evaporation and electrolysis by adding purified water (water that is free of impurities), some designs allow longer intervals between replenishments by converting the hydrogen given off by the reaction back into water with a catalyst plug.

Vented batteries can be further classified as either clad or paste types based on the structure of their positive plate. The clad type incorporates the active material into a glass fiber tube so that it is less likely to fall off, giving the design superior durability. In the paste type, the electrode is created by applying the active material in paste form to a lead alloy lattice to increase the reaction area in a design that is used with large currents. In both cases, the negative electrode uses a paste design.



Structure of a vented lead-acid battery

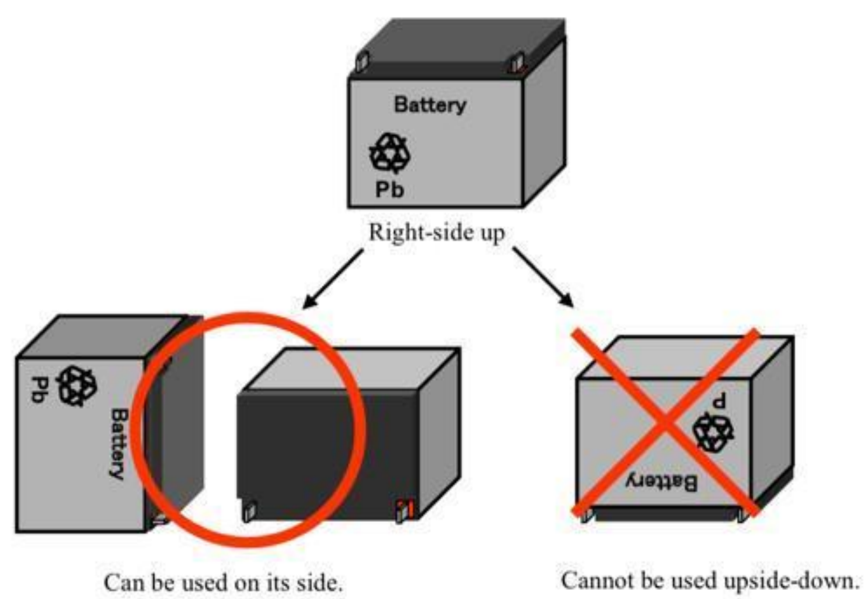
■Types of lead-acid batteries: Valve-regulated type (VRLA)

This type of battery is also known as a sealed battery. It is often used in uninterruptible power supplies (UPSs). Production began in 1970, when the debut of sealed designs, which had been considered impossible, led to a further broadening of the applications in which lead-acid batteries are used.

Lead-acid batteries emit gas when water in the electrolyte breaks down during charging. VRLA batteries incorporate an ingenious mechanism in which this gas is made to react with the battery's negative electrode (cathode) to convert the gas back into water. Since the battery is usually sealed* with a valve, water cannot evaporate, making unnecessary to add water.

Additionally, because the electrolyte is impregnated into a porous glass mat, the electrolyte lacks fluidity, allowing the battery to be placed on its side. However, the design cannot be used upside-down as any electrolyte that oozes out will cause the terminals to corrode. Both the positive and negative electrodes use a paste design.

*In the event a large quantity of gas is produced, the pressure will cause valve to open, releasing the gas.



Orientations in which a VRLA can be used

■Lead-acid battery electrodes

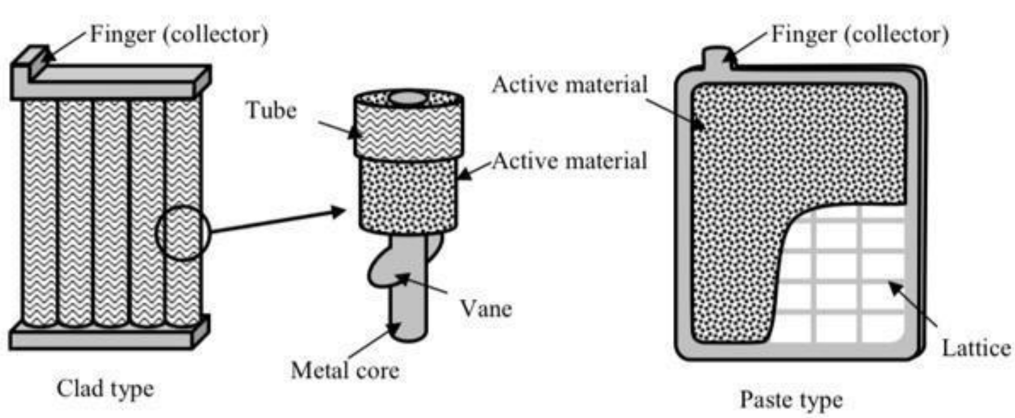
Electrodes in lead-acid batteries use one of the following two designs:

■Clad type

The clad design is used for positive electrodes. Because the lead dioxide powder that serves as the positive electrode's active material is characterized by low binding strength, it tends to fall off during charging and discharging, and when the battery is subjected to vibration. Falling off is prevented by injecting lead dioxide powder into a porous tube made of glass fiber or plastic fiber. Current can be extracted from the tube since it has a comb-shaped metal core made of lead alloy. Since the clad design has a smaller electrode surface area than the paste design, it is not well suited to large-current use, but its resistance to falling off gives it superior service life. It is also well suited to use in environments that are characterized by a large amount of vibration, for example in forklifts.

■Paste type

The paste design is used for both positive and negative electrodes. Active material powder that has been kneaded with sulfuric acid is applied to a lead alloy lattice to produce the electrode. Since the design would allow the active material to immediately degrade in the case of the positive electrode, a glass mat is pressure-bonded to the surface of the positive electrode to prevent falling off. The active material in a paste-type electrode has a sponge-like consistency that increases the electrode's surface area and allows it to be used in large-current applications. In control-valve batteries, both the positive and negative electrodes use the paste design.



Electrode structure in a lead-acid battery

■Causes of self-discharge in lead-acid batteries

Compared to other battery designs, lead-acid batteries have a comparatively high self-discharge rate of 0.5% to 1% per day. Self-discharge, which increases with battery temperature and electrolyte concentration, is primarily caused by the following three factors:

■Electrolysis of water

Water in the electrolyte gradually undergoes electrolysis due to the potential difference between the positive and negative electrodes, causing the battery's energy to be consumed and its voltage to drop. While electrolysis of water theoretically occurs at 1.23V, the large overvoltage of the electrodes in lead-acid batteries means that electrolysis does not progress significantly until the battery voltage exceeds about 2.35 V. However, the low overvoltage of the antimony contained in the electrode lattice's lead alloy causes self-discharge to increase as hydrogen forms at the negative electrode.

■Reaction between electrodes and electrolyte

Because the dilute sulfuric acid in the electrolyte is an acid that reacts readily with metals, it reacts with the electrodes and causes the battery voltage to drop, even if no load is connected to the battery. However, this reaction does not progress rapidly. The overvoltage also affects this process. Since gas is less likely to form in the presence of a large overvoltage, the reaction occurs little by little, causing the battery's voltage to fall gradually.

■Impurities

Various ions contained in tap water oxidize more readily than the lead in the electrodes, causing them to react with the electrodes. In particular, iron ions (Fe^{2+}) are oxidized by the positive electrode to form trivalent iron (Fe^{3+}), which is then reduced at the negative electrode, converting it back into bivalent iron (Fe^{2+}). Since the reaction forms a cycle, even a small quantity of iron ions can cause self-discharge to increase. Consequently, it is necessary to replenish lead-acid batteries with purified water that lacks impurities.

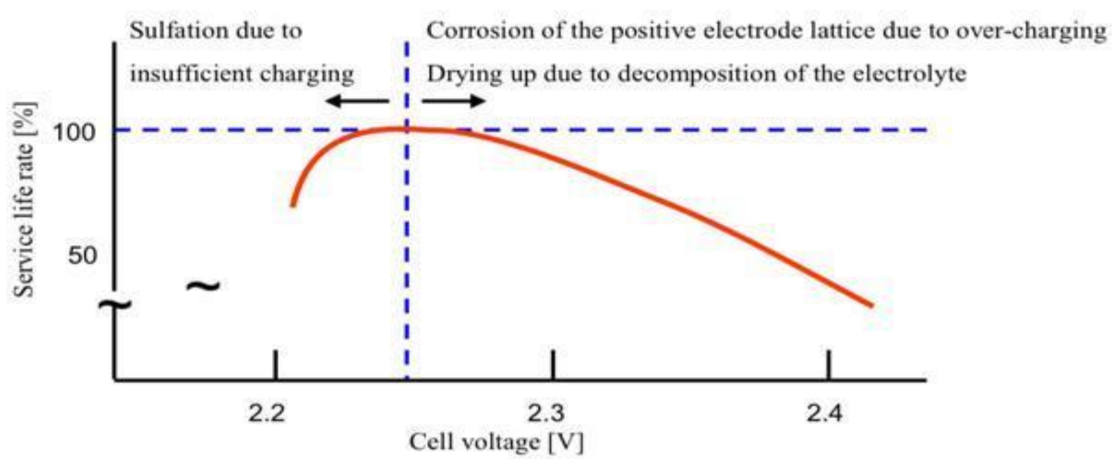
▪Degradation of lead-acid batteries: Chemical degradation

Although completely opposite reactions occur in theory during charging and discharging of lead-acid batteries, as described in Equation (1), in fact irreversible reactions also occur, causing the battery to degrade gradually.

$$\mathbf{PbO_2(Positive\ electrode) + Pb(Negative\ electrode) + 2H_2SO_4(Electrolyte)} \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftharpoons}} \mathbf{2PbSO_4 + 2H_2O} \quad \cdots (1)$$

Discharging causes lead at the negative electrode to change into lead sulfate, which develops a stable crystalline structure over time. Since lead sulfate becomes less conductive once it crystallizes, it will not convert back into lead even if the battery is charged. The crystallization of lead sulfate in this manner is generally known as sulfation. When lead sulfate crystals adhere to the surface of the negative electrode, the reaction area between the electrode and electrolyte decreases, causing the battery's internal resistance to rise. Additionally, the electrolyte concentration will decrease since the sulfate ions in the electrolyte are not converted back into lead sulfate. Consequently, the battery voltage will fall, and no amount of charging will restore the initial voltage.

Crystallization of lead sulfate at the surface of the negative electrode is the most common cause in degradation when batteries such as automobile batteries are frequently charged and discharged or allowed to sit without being charged.



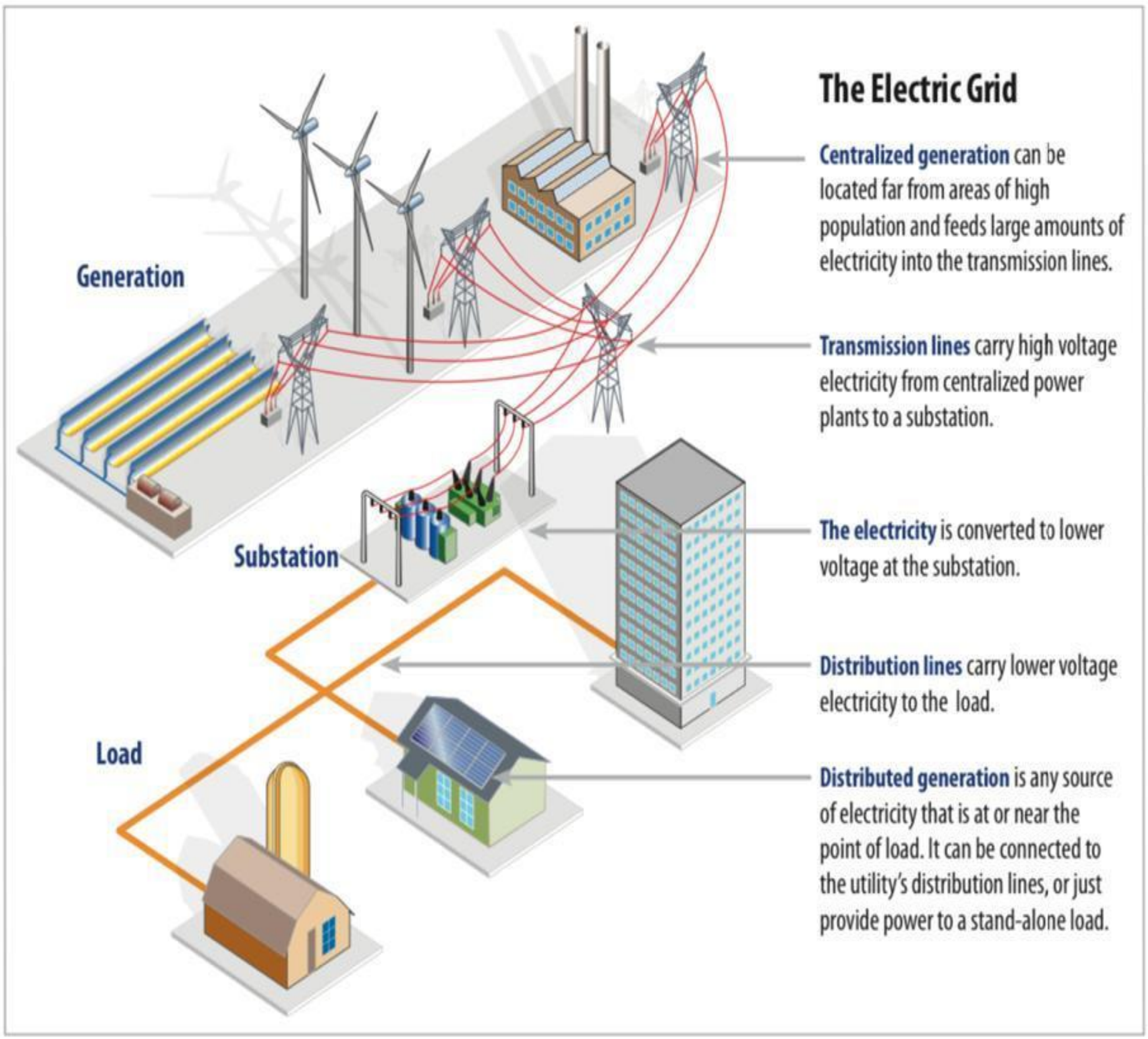
Relationship between charge voltage and service life rate

Solar Power and the Electric Grid

In today's electricity generation system, different resources make different contributions to the electricity grid. This fact sheet illustrates the roles of distributed and centralized renewable energy technologies, particularly solar power, and how they will contribute to the future electricity system. The advantages of a diversified mix of power generation systems are highlighted.

Grid 101: How does the electric grid work?

The electric grid—an interconnected system illustrated in Figure 1—maintains an instantaneous balance between supply and demand (generation and load) while moving electricity from generation source to customer. Because large amounts of electricity are difficult to store, the amount generated and fed into the system must be carefully matched to the load to keep the system operating.



Why do we need an electric grid and what are the benefits?

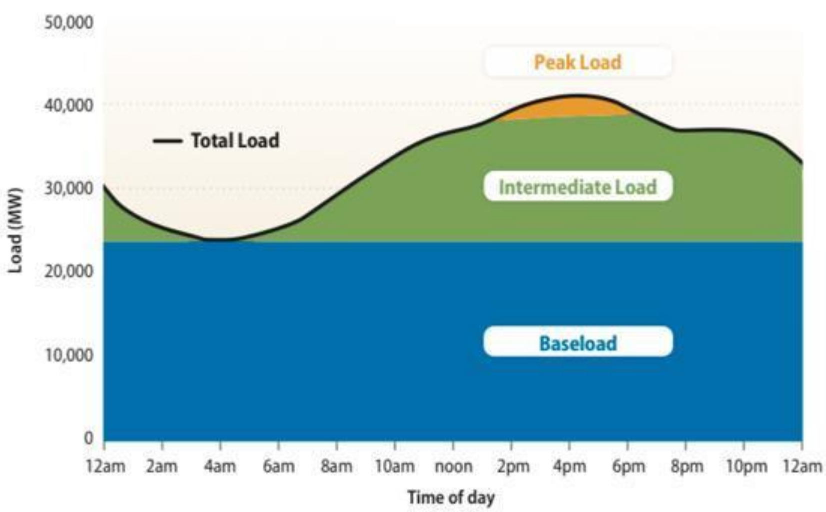
The level of demand for electricity in any one area is so variable that it is more efficient to combine demand from many sites into an overall regional load. This regional electric load is then met by the output of a fleet of generators that can be controlled and managed for optimal performance. In part, the grid was developed to allow generators to provide backup to each other and share load.

The grid also allows generators to be located closer to resources (e.g., fuel supply, water, available land) and ship electricity over the transmission and distribution network to different load centers. Utility-scale solar and wind power plants are conceptually similar to conventional generators—they generate electricity where the necessary resources are located, typically in remote areas where the fuel (sunlight or wind) is most abundant. These attributes—consolidating variable individual loads into more predictable regional loads, siting plants near their resource base, and extensive transmission lines—help the grid provide electric power with good reliability and low cost.

What roles do the various types of generation play in the grid? Where does renewable energy fit in?

Different types of electricity users demand power in different amounts and at different times; this results in a load curve (Figure 2) that varies by time-of-day and season.

Figure 2. 2009 Summer Day Load Curve for California



Generation technologies do not simply provide kilowatt hours to the grid. In varying degrees, they also provide ramping ability to follow load, stay ready to meet demand peaks (dispatchability), and adjust their operating conditions to maintain grid stability. Power plants meeting baseload must run 24/7 with low operating costs. Power plants providing intermediate load must be able to follow demand throughout the day. Peak load occurs only during times of highest demand. Power plants supplying peak load must ramp up and down quickly to meet sharp increases and decreases in demand, but only run for a few hours at a time. No single generation technology meets all these needs.

Table 1 lists the various loads that must be met by the electric grid and outlines which generation technologies typically meet these needs. Generation fleet diversity is important for reliability. Important features are:

- Some renewable energy technologies provide power only when the resource is available. These resources are often contracted as "must-take" generators, where their output is always used when it is available. However it is difficult to integrate a large amount of "must-take" generation into the grid because its availability is uncertain and constantly changing.
- Photovoltaics (PV) may be centrally located in large plants or distributed on rooftops. Distributed PV has benefits, such as low land use and no transmission needs. Both distributed and central PV are usually "must-take" generators.
- Storing large amounts of electricity is difficult, while storing thermal energy is relatively easy (consider the complexity of a car battery versus an insulated bottle). Because concentrating solar power (CSP) plants collect and convert thermal energy into electricity, they can collect and store thermal energy for later conversion into electricity. CSP plants with thermal energy storage provide assurance that the generator will be available when needed. These CSP plants are dispatchable and can meet intermediate and, potentially, baseload demands.

Table 1. The Role of Different Types of Generation in the Grid

Generator type	Attributes of generator	Technology (typical)	
		Conventional	Renewable
Must-take	Dependent on variable resource Requires additional generation capacity		CSP w/o storage PV Wind
Peak Load	Provides power during peak demand Ramps up and down quickly	Natural gas combustion turbine	PV and CSP[1]
Intermediate Load	Varies production to follow demand Predictable availability	Natural gas combined cycle	CSP with storage[2] Hydropower
Baseload	Low fuel and operating costs Constant rate of production Often very large to benefit from economy of scale	Coal Nuclear	Biomass Geothermal Hydropower

CSP = Concentrating Solar Power; PV = Photovoltaics

[1] Although they do not meet the rapid response requirements of peaking generators, solar PV and CSP generation coincide with summer demand peaks caused by air-conditioning loads, especially in the sunny southwest.

[2] With sufficient thermal energy storage, CSP plants can run as baseload generators. The US Dept of Energy is funding research to explore baseload CSP systems.

Why a mix matters

Our electric supply must keep up with a constantly changing demand for electricity. This effort requires generator technologies with different characteristics. Similar to all generation sources, different renewable technologies have different advantages. For example, wind energy is inexpensive compared to solar, distributed PV provides power at the user with little impact to land, CSP with energy storage contributes dispatchable power to the grid, while geothermal and biomass can provide baseload renewable power. Employing a combination of energy efficiency and renewable energy sources—including wind, solar, geothermal, small hydro, biomass, and ocean power—can reduce fossil fuel consumption and minimize the environmental impact of electricity use, while maintaining reliability.

Why can't all future energy needs be met with rooftop PV and energy efficiency?

Grid-connected, distributed generation sources such as rooftop PV and small wind turbines have substantial potential to provide electricity with little impact on land, air pollution, or CO2 emissions. However, these technologies do not provide all of the characteristics necessary for a consistent electricity supply. Primary limitations on distributed PV generation include ability to provide energy at all times that it is needed and cost.

Rooftop PV has potential to help meet environmental goals for electricity generation.

- Analysis of available roof space indicates that a good fraction of electricity supply, perhaps 10% to 25%, could be met with roof-mounted PV arrays [1]. However, per watt produced, rooftop PV is expensive compared to large-scale, ground-mounted systems. Even when transmission is included, centralized PV and CSP power plants remain the least costly deployment of solar power due to economies-of-scale in construction and operation, and the ability to locate in the areas of best solar resource.

- Without energy storage, PV generation does not provide all of the characteristics necessary for stable grid operation. For example, PV provides the most electricity during midday on sunny days, but none during evenings or at night. PV output can increase and fall rapidly during cloudy weather, making it difficult to maintain balance on a grid with a large penetration of PV. Without a steady supply, additional generating capacity must be

Grid-connected photovoltaic system driven by load

Operating principle:

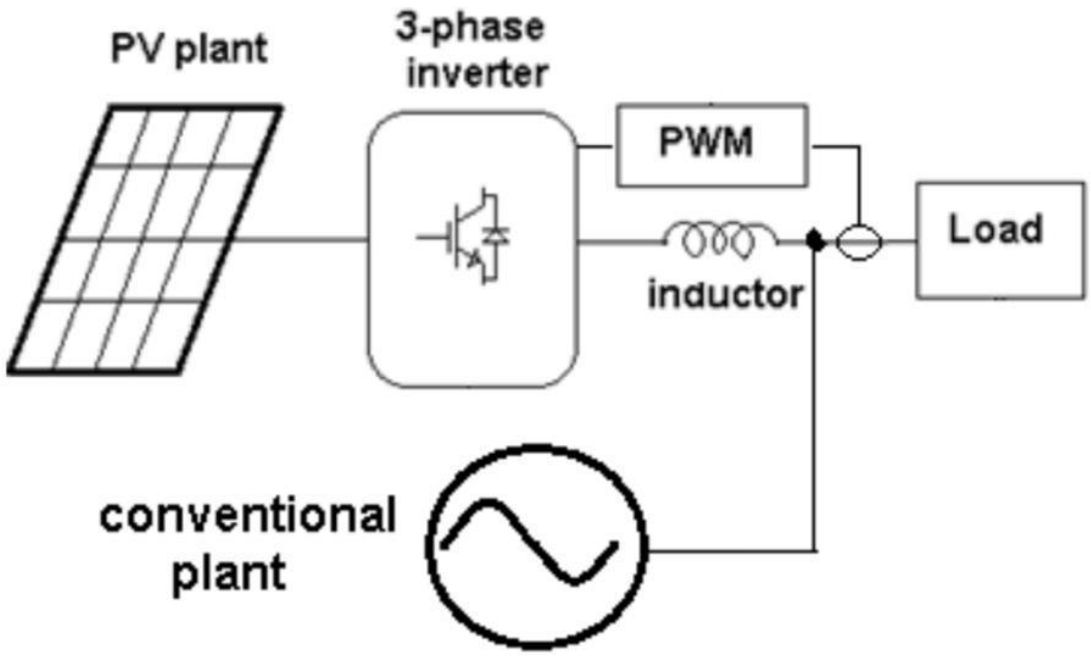


Figure 4.1: Operating principle of grid-connected PV system driven by load

Figure 4.1 describes a common schematic principle for a single stage grid-connected photovoltaic system: where a photovoltaic plant provides a DC voltage, the DC voltage is then transferred to AC voltage by a 3-phase inverter controlled by a PWM technique, the inductor is then used to provide a suitable coupling with the grid and minimize the currents fluctuations in the lines

. A conventional plant is coupled to the network to feed the load in parallel with the photovoltaic plant. The PWM technique which controls the switching of IGBTs in the inverter shall operate in a way that track the current of the load sensed by a current sensor and inject it into the grid as shown in figure 4.2.

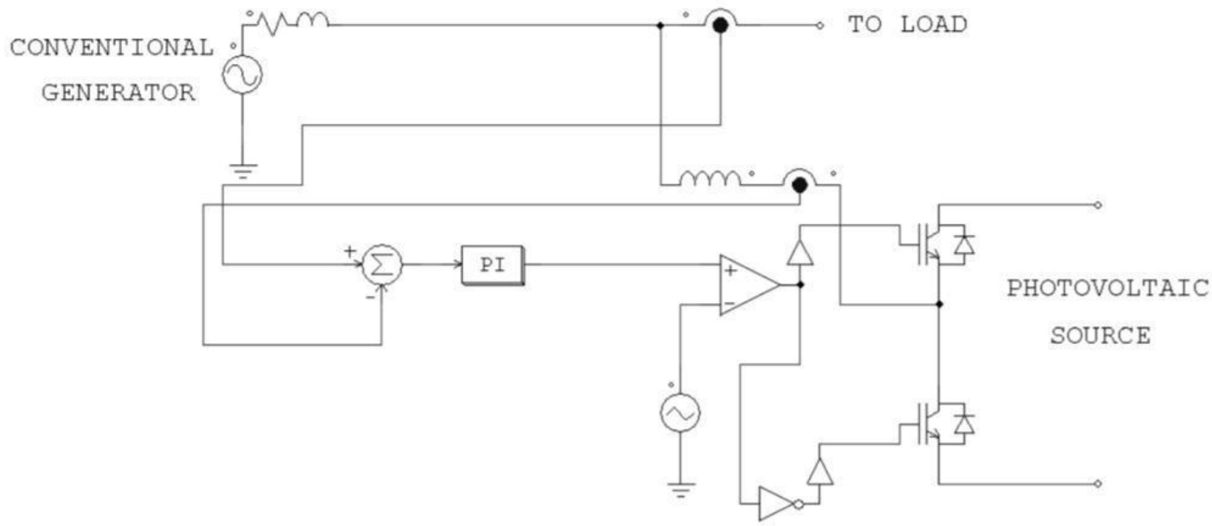


Figure 4.2: Control schematic per phase for grid-connected PV system driven by load

As figure 4.2 shows, the current flowing to the load side is sensed and then injected by the photovoltaic source to compensate for the power drawn from the conventional plant. Proportional Integral controllers with feedbacks are used in the simulation to fasten the compensation process and decrease the oscillations In this type, the DC voltage bus at the input of the inverter must be higher than the grid voltage, and this is very obvious and natural because we know that the current flows inside conductors and semi-conductors from the higher voltage to the lower voltage. So we need to arrange the photovoltaic modules of the photovoltaic plant in a way to have a big number of them in series in each string to reach higher voltages.

Figure 4.4 shows the process of ***PWM*** technique in one lag which switches the upper ***IGBT***:

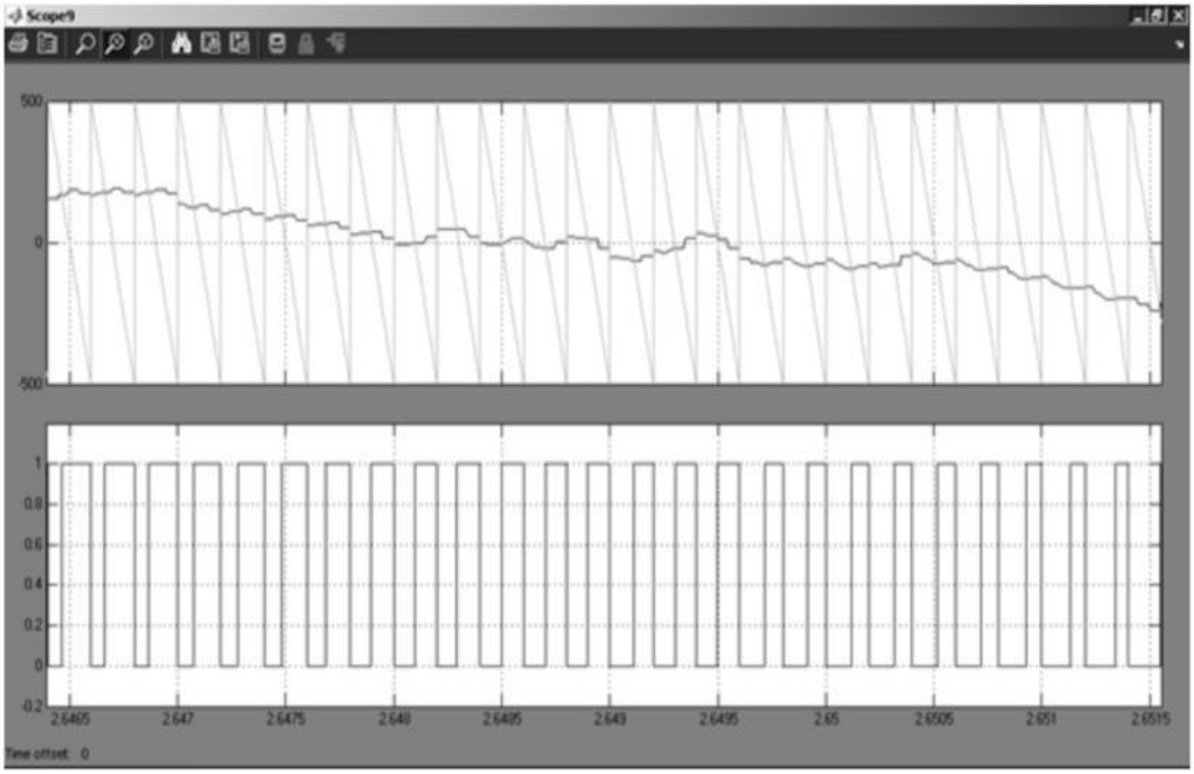


Figure 4.4: PWM technique

In the above figures, the difference between the load current (considered as reference current) and the inverter current for one phase is compared to a saw tooth signal to control the upper ***IGBT*** switch correspondent to the same phase, the below ***IGBT*** switch has just the opposite state of the upper switch. When the difference is above the saw tooth, a positive voltage (which is the voltage of the photovoltaic source) is applied to the output of the inverter for the correspondent phase to inject a positive current into the grid and compensate for the load current, and vice versa.

Figure 4.5 shows the voltage on one phase applied at the output of the inverter by controlling the inverter switches as described above.

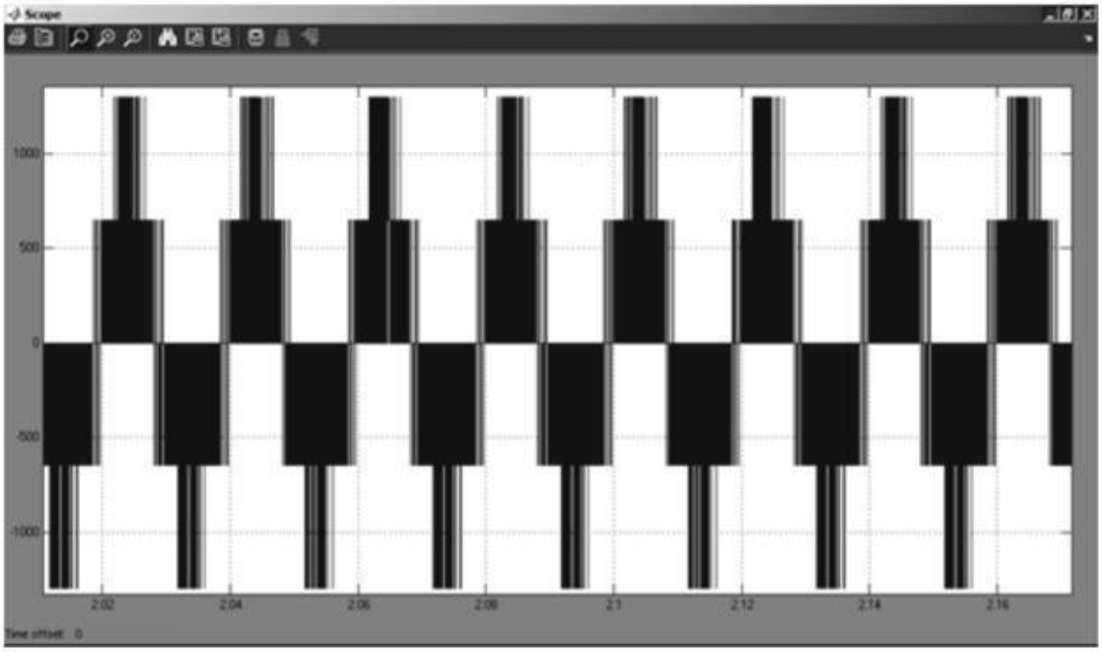


Figure 4.5: voltage on one phase at the output of the inverter

Figure 4.6 shows simultaneously the waveforms of the current pulled by the load, the current delivered by the conventional source, and the current delivered by the photovoltaic source.

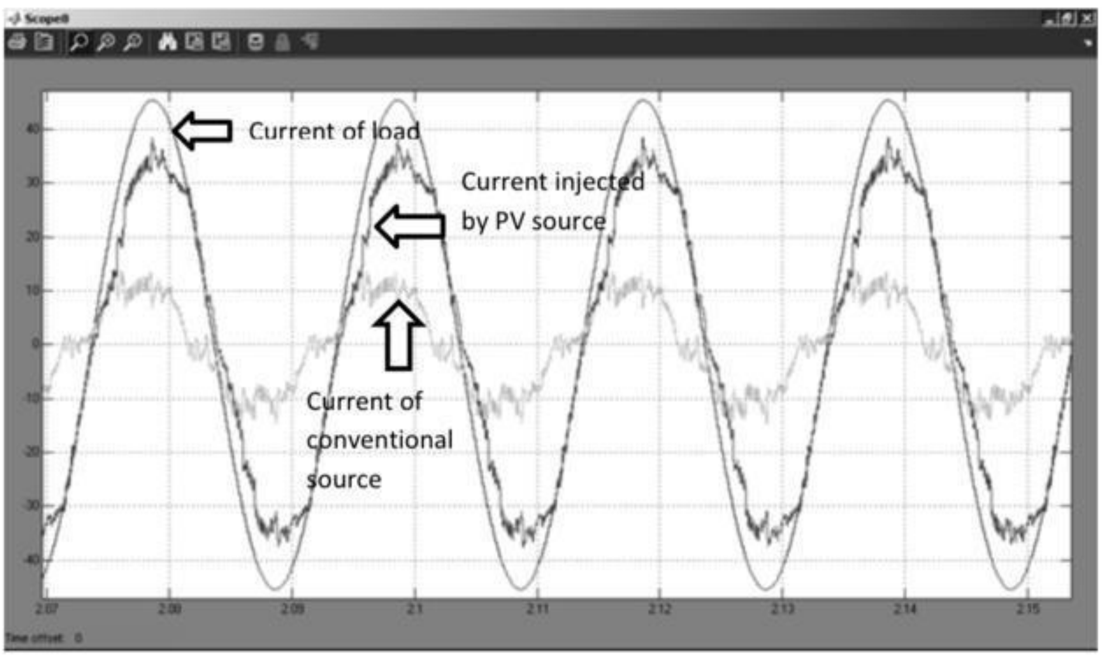


Figure 4.6: Waveforms of various currents

Figure 4.7 shows the value of total harmonic distortion (THD) of the current delivered by the conventional source resulting from switching in the photovoltaic inverter and equal to ***THD = 32%***.

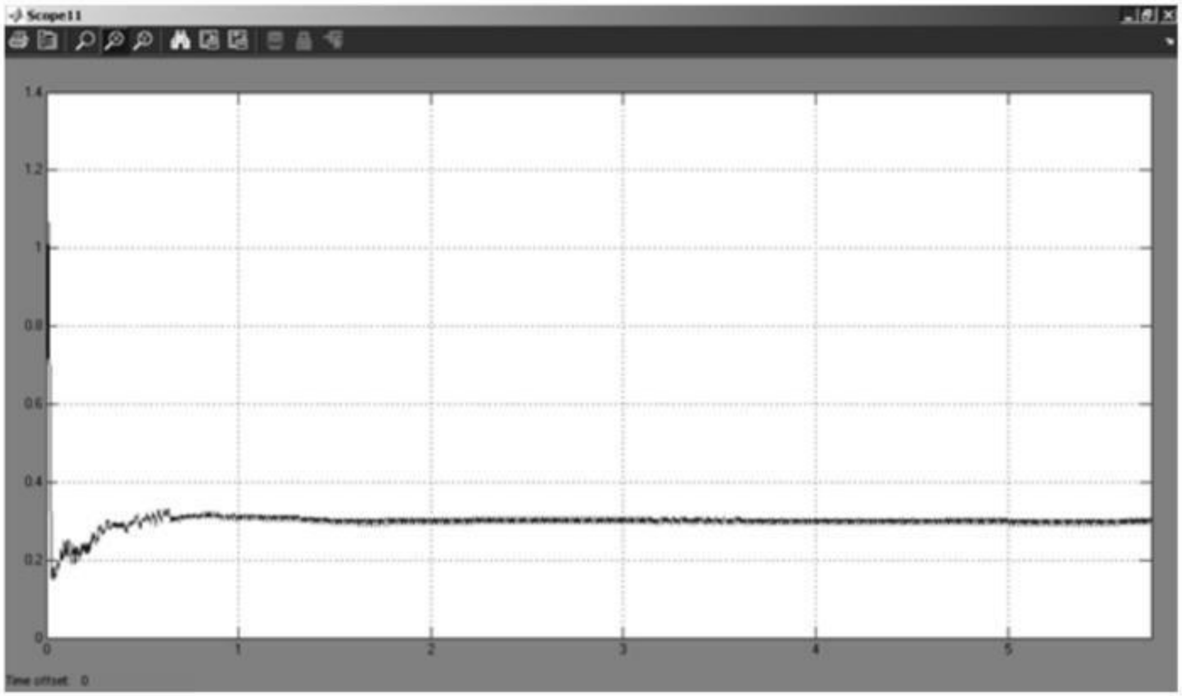


Figure 4.7: THD of conventional source delivered current

4.3- Preliminary conclusion:

According to the above simulation, we noticed the following:

1. The power drawn from the conventional source is partially compensated. So, the conventional source and the photovoltaic source are sharing the power consumption of the load.
2. The current of the conventional source is encountering some harmonics which have several side effects on the generation units. These harmonics are due to frequent switching of inverter ***IGBTs*** at a frequency *5 KHz*.

4.4- Elimination of harmonics:

As an effort to remove the harmonics from the currents waveforms, an ***LC*** filter is inserted in each phase between the inverter and the coupling inductor as shown in figure 4.8 and figure 4.9 (Matlab model).

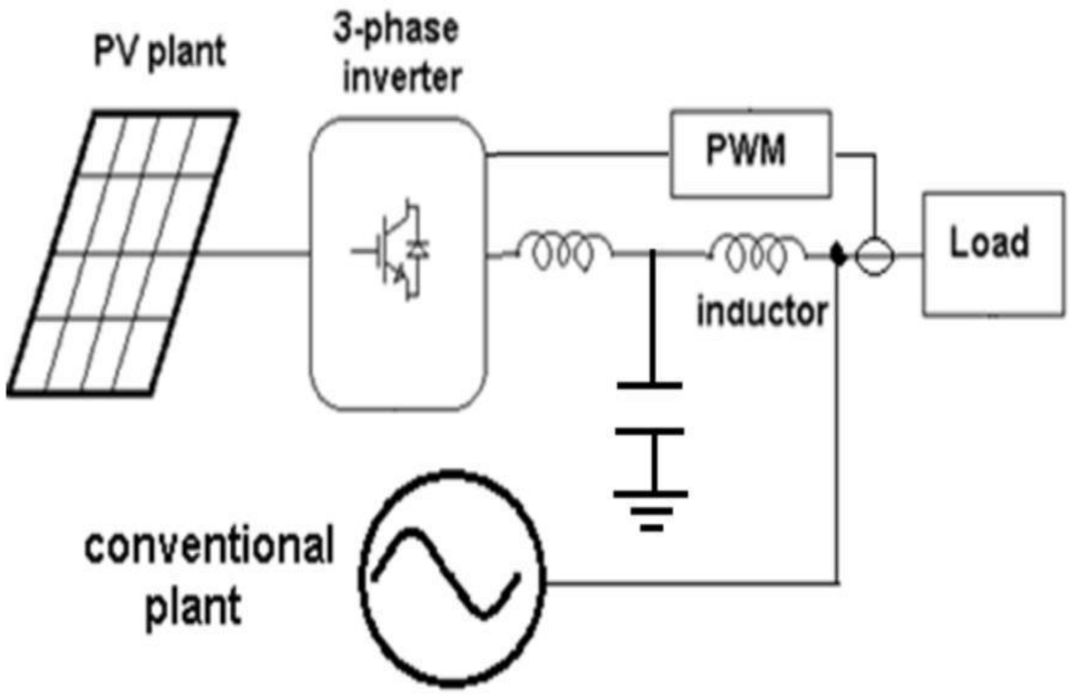


Figure 4.8: circuit schematic with LC filter

This simulation shows us the improvement in the tracking of the load current and in the filtration of harmonics as in figure 4.10. The new THD value of the conventional source delivered current is shown in figure 4.11 where it has decreased from 32% to 20%.However, the LC filter causes phase shifting of the current in reference with the grid voltage, which worsen also the power factor at the conventional source unit. But this issue can be ignored due to the small value of the current drawn from the conventional source.

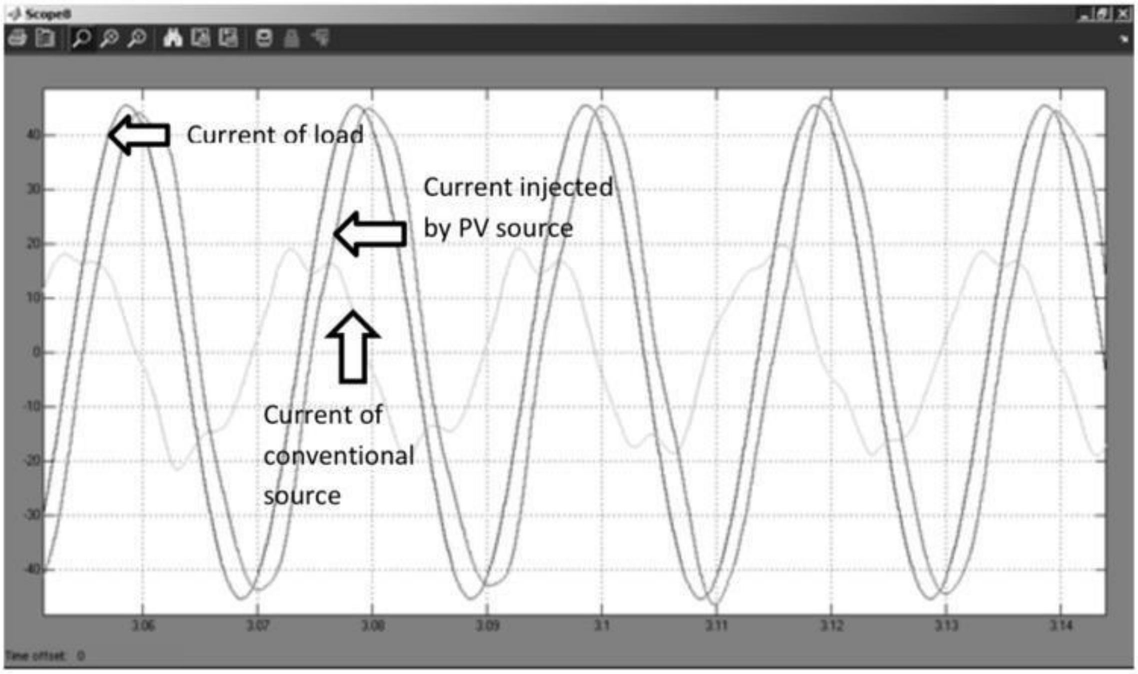


Figure 4.10: Waveforms of the currents with LC filter

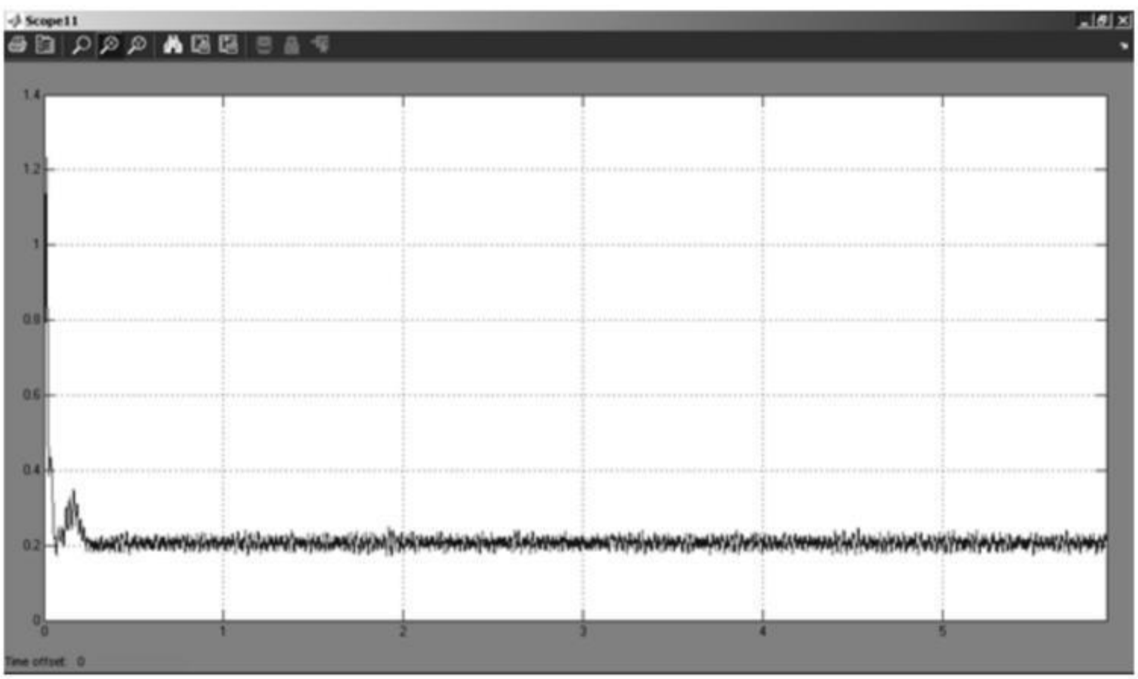


Figure 4.11: THD of conventional source delivered current using ***LC*** filter

off-grid solar power systems

Solar power for everyone – anytime and ANywhere More than 1.3 billion people around the globe still do not have access to electricity. The reason is simple. It is too expensive to build the infrastructure to connect them to the power distribution grid, especially in rural regions. Some communities may attempt to fill the gap with noisy, pollutive diesel generators, but rising fuel and transportation costs often make generators uneconomical. Economic development is impossible without electricity.

Health, education, and clean drinking water all depend on electric power. Ultimately, people can only produce products and services locally thus making their community more prosperous if they live in a place where they can use electricity. Energy independence with solar power There is a simple, reliable, and low-cost solution for a decentralized energy supply: PV-powered off-grid systems. They can be used to build stable, decentralized power distribution grids in remote locations not connected to the public power grid.

Furthermore, because off-grid solar power systems are efficient, require few resources, can be used worldwide and are effective in combating climate change, they help developing countries bypass the "fossil fuel era," a fact especially true for those with large populations. 4 Off-grid solutions for solar power supply Solar home system – power for household use A solar home system provides basic off-grid power service for one household. This is a low-cost, easy-toassemble PV plant consisting of only a few components. One to two solar modules, a charge controller, and a car battery supply enough electricity for the lights, television, and radio.

A solar home system provides users with comfort and improved access to information, but it cannot, however, supply enough power to operate tools, machines or large buildings. It is not a commercial system and cannot be leveraged to drive local economic development. Solar home systems are ideal for sparsely populated regions with long distances between single houses. In industrialized countries, similar technology is used for campers and small gardens not connected to the power distribution grid.

	Solar home system
Benefits	• Basic power supply: lights, TV, radio, etc.
Expansion	• Difficult to expand • Not for commercial use
Energy sources	• Photovoltaics only

SMA solar off-grid systems – empowering people worldwide Many rural regions are too sparsely populated to justify building a central energy supply system. This is where SMA solar hybrid systems excel. They can supply buildings, factories, or even entire towns with reliable off-grid AC power using renewable energies.

In contrast to solar home systems, hybrid systems can integrate other generating systems such as PV, wind, hydropower, or diesel generators, even if they are located relatively far away. Hybrid power systems can power any household appliances, electrical tools, or machines that run on standard AC power.

Being modular, they can grow with users' needs at any time and that helps drive economic growth. After all, people can only establish themselves as local providers of products and services when they can operate machines and equipment locally and cost-effectively. Solar hybrid systems can be used in any location that lacks a stable power supply. In Germany, for example, they supply electricity for remote buildings such as farms, businesses, weekend homes and vacation cabins.

SMA solar off-grid systems

- Reliable grid-quality power supply, worldwide
- Ideal for local economic development and growth
- PV: a regional business model that creates jobs

- Modular design enables expansions months or even years later

- Supports all generators (PV, wind, hydropower, etc.)
- Standard AC technology

SMA SUNNY ISLAND

The Sunny Island battery inverter is the most important component of the off-grid supply system. Together with the battery array, the Sunny Island forms an independent AC power grid accessible to both energy suppliers and consumers. In addition, Sunny Island acts as the system's manager by carrying out all the control processes that maintain system stability and output. SMA hybrid systems are modular and versatile by design making them easy to install and expand to up to 300 kilowatts – anywhere in the world.

① **System house**
Centralized. This is where you'll find the off-grid inverter, the batteries for intermediate storage, and, for large systems, the Multicluster Box.

② **Sunny Island**
Robust and flexible. Sunny Island is a grid and battery manager that controls the off-grid system. The devices can be installed indoors as well as outdoors.

③ **Multicluster Box**
Modular. Off-grid systems with up to 300 kilowatts can be quickly and easily put into practice with the fully preconfigured AC distribution board.

④ **Hydroelectric power plant**
Flowing. New or existing hydroelectric power plants are a smart addition to the off-grid system.

5. **Windy Boy**
   Versatile. The inverter converts the direct current from water and wind power plants into grid-compliant alternating current.

6. **Diesel generator**
   Failsafe. A generator provides backup power during long periods of drought, calm winds, or low solar radiation.

7. **Wind turbine system**
   Complementary. Depending on the site, the integration of wind turbine systems can be an intelligent additional energy source.

8. **Solar electricity generator**
   Direct. The PV module produces power precisely where it is needed. Solar and wind energy complement one another in many locations through all seasons.

9. **Sunny Boy**
   Reliable. The PV inverter converts direct current from the PV module into alternating current for the grid.

SUCCESS STORIES WORLDWIDE

Self-sufficient with solar power

Two solar hybrid systems have been supplying electricity to around 850 homes in the villages of Kolondieba and Ourikela in Mali, Africa since 2011. SMA's Multicluster Technology is used to integrate a school, multiple workshops, a bakery, a hotel, and other businesses into the off-grid system. And that provides a solid foundation for the local economy to develop and grow.

Off-grid system reduces noise

In 2010, an SMA hybrid system was installed on the Reao Atoll in French Polynesia in the South Pacific. The SMA system replaced a diesel generator that consumed 250 liters of fuel per day and has made life much quieter. The noiseless electricity supply offers benefits for everyone - including the island's doctor. The noise had made it difficult for him and his patients, especially expectant mothers.

Reliable electricity supply without a grid connection

The SMA Solar Academy in Niestetal has been a training center and flagship project for the use of renewable energy and energy-efficient systems since 2010. The intelligent combination of various renewable energy sources and state-of-the-art technology makes sure that heating, cooling, and electricity are available at any time and without sacrificing comfort.






Solar Solutions for Off-grid Power Supply






1)CALCULATION FOR ENERGY GENERATED BY 1 SQUARE METER OF SOLAR PANEL

IN 1 SQUARE FEET POWER GENERATED IS 9 WATT (EXPERIMENTAL AND UNIVERSAL APPROXIMATE VALUE)

POWER=ENERGY/TIME

1SQMETER=10.7638SQFEET

POWER PRODUCED IN 1 SQUARE METER OF SOLAR PANEL =9 X 10.7638

=96.875WATT

ENERGY GENERATED IN 1SQMETER OF SOLAR PANEL IS 96.875 WATT HOUR.

2)CALCULATE THE AREA OF SOLAR PANEL TO GENERATE 1MW POWER

TO GENERATE 1MW OF POWER

96.875WATT POWER IS PRODUCE BY 1SQ METER OF SOLAR PANEL

1 WATT IS GENERATED BY 1/96.875 SQ METER OF SOLAR PANEL

1MW POWER IS GENERATED BY 1000000/96.875 SQ METER

=10322.5806 SQUARE METER OF SOLAR PANEL

(ALL THE VALUE IS CALCULATED ONLY FOR 1 HOUR)

JADAVPUR UNIVERSITY

DEPT-POWER ENGINEERING

UG-III ,MAJOR PROJECT

TOPIC- **SOLAR PANEL FUNCTIONS,SYSTEM AND LEAD ACID BATTERIES**

UNDER GUIDANCE OF- PROF SM

STUDENTS UNDER THIS PROJECT-

1)SAYAN BERA -001911501078

2)SALIL KISKU-0019115010

3)JUNAID ALAM-001911501038

WHAT IS SOLAR WATER HEATER?

A solar water heater is a device that utilizes the energy from sunlight to heat water for various domestic or commercial purposes. It consists of solar collectors, a storage tank, and a circulation system.

The solar collectors are typically mounted on the roof or in an area with good sun exposure. They absorb the heat from the sun's rays and transfer it to a fluid, usually a mixture of water and antifreeze or a specialized heat transfer fluid. This fluid carries the captured heat to the storage tank.

The storage tank is insulated to minimize heat loss and stores the heated water until it is needed. In some systems, the tank may have a backup heating element or a secondary heat source to ensure hot water availability during periods of low solar radiation.

The circulation system, which may be passive or active, helps move the fluid between the collectors and the storage tank. In a passive system, natural convection allows the heated fluid to rise and circulate, while in an active system, pumps are used to move the fluid through the system.

Solar water heaters can be used to provide hot water for various applications, including bathing, washing clothes, and heating swimming pools. They are especially effective in regions with abundant sunlight and can significantly reduce the energy consumption and associated costs of heating water using conventional methods.

It's worth noting that there are different types of solar water heaters available, including direct systems, indirect systems, and batch systems, each with its own configuration and functionality.

INTRODUCTION

Limited availability of natural gas and abundant sunshine made solar water heating (SWH) systems an attractive choice for consumers during the end of the 19th and early 20th centuries.

This report focuses on the energy savings and environmental benefits of community-scale solar water heating systems. In this context, “community-scale” describes both the size of the system and an adherence to a set of design principles. Community scale systems occupy an intermediate space between the domestic and utility scales. This report defines community scale systems as those able to meet the hot water demands of tens of residential buildings up to hundreds of residential units with greater that the minimum solar fraction required by law.

The report will specify the following:

1. Solar Collector Technology Type & Thermal Efficiency
2. Energy Storage Time Horizon (i.e. Diurnal vs. Seasonal Storage)
3. Auxiliary or Back-up Heat Source Required
4. Methods for Predicting Solar Fraction and System Performance.

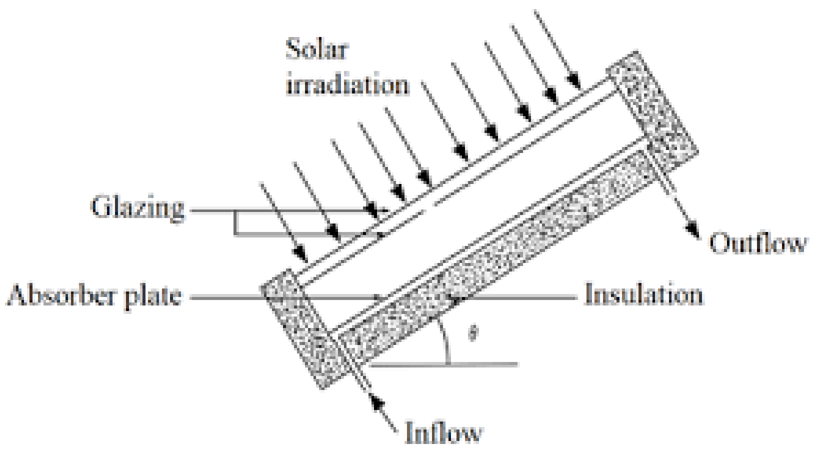
This report will conclude with a basic description of the community scale solar water heating system design for the purposes of this analysis.

Solar Water Heating Components and Systems :-

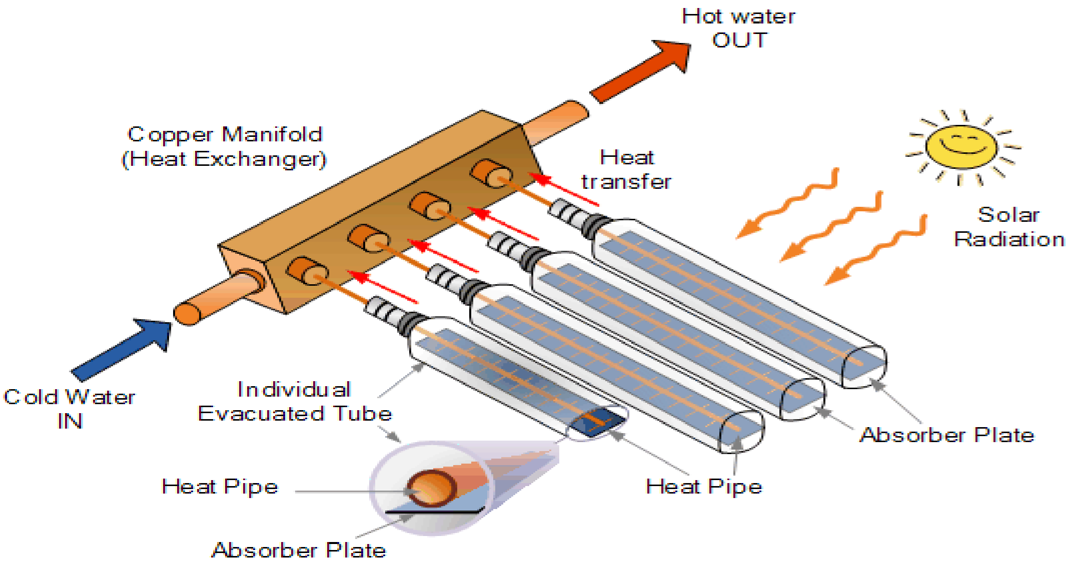
The fundamental elements of solar water heating systems include solar thermal collectors, storage tanks (to store the heated working fluid/ heated water), and piping systems to move heated water and working fluid between collectors, storage tanks, and buildings.

Solar thermal collectors absorb thermal energy from incident solar radiation, and transfer to water or a working fluid. The four most common collector types are:

- **Flat Plate Collectors (FPCs)**

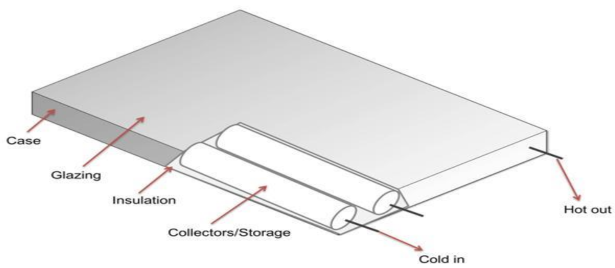


• **Evacuated Tube Collectors (ETCs) :**Evacuated tube collectors consist of an array of evacuated glass tubes, each containing a smaller glass tube within. The inner glass tube houses an absorber plate in thermal contact with a flow tube. A vacuum between the two glass layers serves to thermally insulate the inner tube.

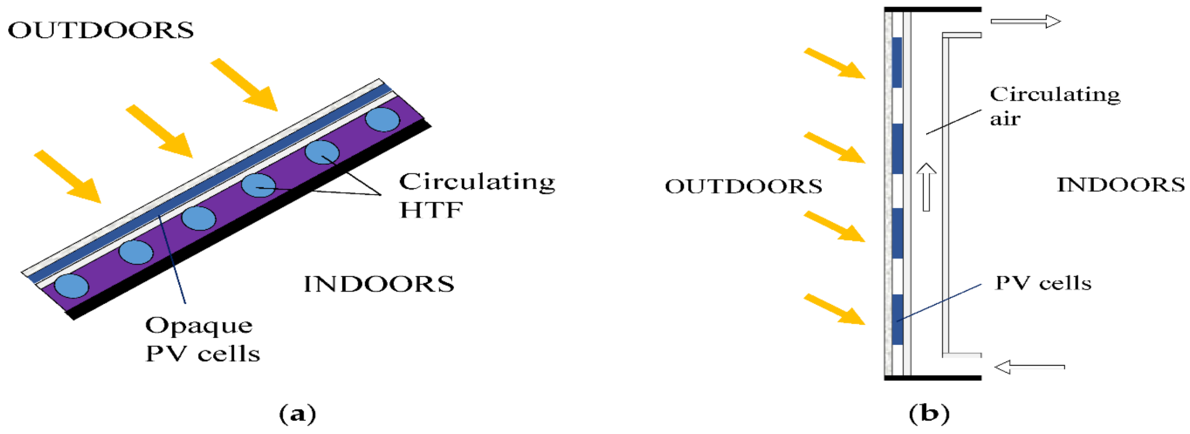


• **Integral Collector-Storage Systems (ICSS)**

Integral collector storage systems are the oldest and simplest type of solar thermal collector technology. Integral collector storage systems store heated water within the solar thermal collection device, rather than in a separate tank (i.e. a distributed system). A wide variety of designs for integral collector storage systems exist. Integral collector storage systems may employ a flat plate design with storage tanks instead of flow tubes, use a series of evacuated tubes that terminate in a storage tank, or employ reflectors and phase-change materials to maximize heat absorption and minimize thermal losses.



• **Integrated Photovoltaic/ Thermal (PV/T) Collectors :** Integrated PV/T collectors couple the generation of electric current from photovoltaic solar cells with the collection thermal energy for water and space heating. The conversion of solar energy into electric current via the photoelectric effect is a process which is a relatively inefficient process that produces a large amount of waste heat.



Storage Tanks : The design and use of storage tanks for water and working fluid has a significant impact on the thermal performance of solar water heating systems. Storage tank insulation and temperature stratification help to minimize thermal losses from solar hot water heating systems. Thermal insulation of tanks helps minimize losses to the ground and air, especially during colder months.

Heat Exchange Fluids and Heat Exchangers : Closed systems with freeze resistant heat exchange fluids are required in climates that experience prolonged freezing temperatures, as most collectors are not designed to withstand such forces. Antifreeze agents are also toxic, requiring a heat exchanger be installed between the collection and storage/ delivery loops.

WORKING OF SOLAR WATER HEATER:

The working principle of a solar water heater involves the following steps:

1. Solar Collector: The solar collector, typically mounted on the roof or in an area with good sun exposure, absorbs solar radiation. It consists of a dark-colored, heat-absorbing material such as blackened metal or selective coating on the surface. The collector's design allows for maximum solar energy absorption.

2. Heat Transfer Fluid: A heat transfer fluid, which is a mixture of water and antifreeze or a specialized heat transfer fluid, flows through the solar collector. As the fluid passes through the collector, it absorbs heat from the absorbed solar energy.

3. Circulation: The heated fluid circulates through the solar water heating system using either a passive or active circulation system.

    - Passive Circulation: In a passive system, natural convection and gravity allow the heated fluid to rise and flow into the storage tank while cooler fluid descends to the collector for reheating. This process continues as long as there is a temperature difference between the collector and the tank.

    - Active Circulation: An active system employs pumps or other mechanical devices to circulate the fluid between the collector and the storage tank. This ensures a more controlled and efficient flow of the heated fluid.

4. Storage Tank: The heated fluid transfers its heat to the water in the storage tank through a heat exchanger. The storage tank is insulated to minimize heat loss and stores the hot water until it is needed.

5. Backup Heating Element: To ensure hot water availability during periods of low solar radiation or high demand, solar water heaters often have a backup heating element. This element, typically powered by electricity or gas, can heat the water in the tank when the solar energy is insufficient to meet the required temperature.

6. Hot Water Distribution: When hot water is required, it is drawn from the storage tank and distributed for various domestic or commercial purposes.

Throughout this process, the solar collector continuously absorbs solar energy and transfers it to the heat transfer fluid, which in turn heats the water in the storage tank. The circulation system ensures the transfer of heat from the collector to the tank, providing a constant supply of hot water.

It's worth noting that there are different types of solar water heater systems, including direct systems, indirect systems, and batch systems, each with slight variations in the working mechanism. However, the general principle of harnessing solar energy to heat water remains consistent across these systems.

Community Scale Approach to Solar Hot Water:

This report focuses on the energy savings and environmental benefits of community-scale solar water heating systems. In this context, “community-scale” describes both the size of the system and an adherence to a set of design principles. Community scale systems occupy an intermediate space between the domestic and utility scales.

This report defines community scale systems as those able to meet the hot water demands of tens of residential buildings up to hundreds of residential units with greater that the minimum solar fraction required by law. Community scale energy systems are intended to make maximally efficient use of local resources where possible and create a range of options for residents to contribute to its operation. According to the CEC and National Renewable Energy Laboratory (NREL), community scale solar energy projects should include the following considerations.

• Primary Considerations

- Make economically optimum use of local space and resources when and where possible.
- Develop community scale energy infrastructure in a socioeconomically equitable manner.

• Secondary Considerations o Improved economies of sale

- Improved project siting

- Exploration of new models for service delivery and project financing. A community scale approach to solar water heating in LA County is consonant with the considerations listed above. LA County has a mild, Mediterranean climate with abundant sunshine, but land use and development patterns range from densely populated urban areas to near-rural exurbs.

In places where residents cannot afford to install separate domestic systems, or where space for system infrastructure is limited, a community scale approach offers opportunities for all participants to receive the benefits of solar water heating and support their system's operation. Residents may contribute by allowing system infrastructure to be installed on their property, or by contributing financially if they do not own property on which collectors or tanks can be placed. Studies of solar district heating in Northern Europe suggest that there are positive returns to scale for solar water heating systems.

WHY SHOULD WE TOOK IT SERIOUSLY ?

1. Energy Efficiency: Solar water heaters are highly energy-efficient as they utilize the sun's energy, which is a free and abundant resource. By converting sunlight into heat, they can provide hot water without relying on traditional energy sources like electricity or gas.
2. Cost Savings: Solar water heaters can significantly reduce energy costs for heating water. Once installed, the operation costs are minimal since the primary energy input, sunlight, is free. This can result in substantial long-term savings on utility bills, particularly in areas with high electricity or gas prices.
3. Environmentally Friendly: Solar water heaters are environmentally friendly because they harness renewable energy and produce zero greenhouse gas emissions during operation. By reducing the reliance on fossil fuels, they contribute to mitigating climate change and promoting a cleaner and more sustainable future.
4. Independence from the Grid: Solar water heaters provide a degree of energy independence. By generating hot water using solar energy, homeowners or businesses can reduce their dependence on external energy providers. This can be particularly advantageous in remote areas or during power outages, ensuring a continuous supply of hot water.
5. Long Lifespan and Low Maintenance: Solar water heaters are designed to be durable and require minimal maintenance. With proper installation and regular inspections, they can have a long lifespan, often exceeding 20 years. This reduces the need for frequent replacements and lowers maintenance costs.
6. Versatility and Adaptability: Solar water heaters can be integrated into both residential and commercial buildings, ranging from single-family homes to large-scale applications. They can be customized to meet specific hot water demand requirements and can be used for various purposes, including domestic hot water, space heating, and swimming pool heating.
7. Government Incentives and Rebates: Many governments and local authorities offer incentives, tax credits, or rebates for installing solar water heaters. These incentives

aim to promote renewable energy adoption, making solar water heating systems more financially attractive and accessible.

8. Increase in Property Value: Installing a solar water heater can increase the value of a property. Potential homebuyers are increasingly interested in energy-efficient and sustainable features, and having a solar water heater in place can make a property more appealing and marketable.

Overall, solar water heaters provide a reliable, cost-effective, and environmentally friendly solution for meeting hot water needs while reducing energy consumption and carbon footprint.

SUMMARY

Reducing greenhouse gas emissions from the residential housing sector is an important part of Worlds attempt to shrink its carbon footprint, and prioritizing the most carbon intensive end-uses is essential to success. Residential water heating in big cities represents a quarter of household energy consumption, and the vast majority of residences use natural gas to heat water. Substantial energy savings can be realized if the share of renewable energy used to heat water were increased. This analysis explores the potential of community scale solar water heating systems to reduce residential natural gas consumption and generate energy savings.

The *Solar Water Heating Report* is the first part of the larger analysis. This report reviews the available solar thermal technologies and system types for community scale solar water heating systems. The resulting community scale system design based on climatic conditions, energy storage requirements, applicable building and energy efficiency codes, and cost. Based on these considerations, community scale systems considered in this analysis will be closed, active systems with flat plate collector arrays. Determination of basic system characteristics is a prerequisite for estimating their potential energy savings.