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Thermodynamic Analysis of the Application of Thermal Energy Storage to a Combined Heat and Power Plant

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THERMODYNAMIC ANALYSIS OF THE APPLICATION OF THERMAL ENERGY STORAGE TO A COMBINED HEAT AND POWER PLANT

A Thesis Presented

by

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Finally, I wish to thank and dedicate this work to my grandparents, Florence and George, who instilled in me the importance of education, hard work and compassion. It is through reflection on their tireless example that I have been able to achieve the work at hand.

ABSTRACT

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The main objective of this paper is to show the economic and environmental benefits that can be attained through the coupling of borehole thermal energy storage (BTES) and combined heat and power (CHP). The subject of this investigation is the University of Massachusetts CHP District Heating System. Energy prices are significantly higher during the winter months due to the limited supply of natural gas. This dearth not only increases operating costs but also emissions, due to the need to burn ultra low sulfur diesel (ULSD). The application of a TES system to a CHP plant allows the plant to deviate from the required thermal load in order to operate in a more economically and environmentally optimal manner. TES systems are charged by a heat input when there is excess or inexpensive energy, this heat is then stored and discharged when it is needed. The scope of this paper is to present a TRNSYS model of a BTES system that is designed using actual operational data from the campus CHP plant. The

TRNSYS model predicts that a BTES efficiency of 88% is reached after 4 years of operation. It is concluded that the application of BTES to CHP enables greater flexibility in the operation of the CHP plant. Such flexibility can allow the system to produce more energy in low demand periods. This operational attribute leads to significantly reduced operating costs and emissions as it enables the replacement of ULSD or liquefied natural gas (LNG) with natural gas.

TABLE OF CONTENTS

Page

ACKNOWLEDGEMENTS iv

ABSTRACT vi

LIST OF TABLES xi

LIST OF FIGURES xii

NOMENCLATURE xiv

CHAPTER

1. INTRODUCTION 1

    1.1 Thermal Energy Storage & Combined Heat and Power 2

    1.2 Thermal Energy Storage 3

    1.3 Sensible Heat Storage 3

        1.3.1 Tank Thermal Energy Storage 5

        1.3.2 Pit Thermal Energy Storage 6

        1.3.3 Borehole Thermal Energy Storage 6

        1.3.4 Aquifer Thermal Energy Storage 8

    1.4 Latent Heat Storage 8

        1.4.1 Phase Change Material Thermal Energy Storage 10

    1.5 Objective of Research 12

2. INTRODUCTION OF CASE STUDY 13

    2.1 The University of Massachusetts Amherst Combined Heat and Power Plant 13

2.2 Hour Profiles of Current Operation 17
2.2.1 Combustion Gas Turbine (CGT) Hourly Profile 17
2.2.2 Heat Recovery Steam Generator (HRSG) Hourly Profile 17
2.2.3 High Pressure Boiler (HBP) Hourly Profile 18
2.2.4 Low Pressure Boiler 1 (LPB1) Hourly Profile 19
2.2.5 Low Pressure Boiler 2 (LPB2) Hourly Profile 19
2.2.6 High Pressure Steam Turbine (HPST) Hourly Profile..................... 20
2.2.7 Low Pressure Steam Turbine (LPST) Hourly Profile...................... 21
2.3 Proposed Operation.. 21
2.4 Natural Gas & Steam Assessment due to Additional HRSG Firing......... 23
2.5 Selection of TES Technology 24
2.6 TES Modeling and Design Tool 25
2.7 Duct Storage Model Description and Analysis... 27
2.7.1 Numerical Procedure 28
2.7.2 Global Problem 28
2.7.3 Local Problem... 30
2.7.4 Steady Flux Problem.. 31
2.8 BTES TRNSYS Model Description 32
3. PRELIMINARY RESULTS...35
3.1 TRNSYS Multiple Simulations 35

3.1.1 Selection of TRNSYS Simulation Range 35

3.1.2 TRNSYS Simulation Results for Selected Range 36

3.2 Results for TRNSYS Multiple Simulations.. 38

4. RESULTS AND DISCUSSION..44

4.1 BTES & System Efficiency 45

4.2 BTES System Performance.. 46

4.3 Economics & Emissions Results (ULSD) 51

4.4 Economics & Emissions Results (LNG).. 53

4.5 Discussion and Comparison of Results... 54

4.6 System Cost, Simple Payback & Net Present Value (NPV)..................... 55

5. CONCLUSIONS 57

5.1 Summary.. 57

5.2 Recommendations for Future Work.. 58

APPENDICES

A TRNSYS INPUT FILE 59

B TRNSYS TYPE DOCUMENTATION 75

C LIST OF MEASURED DATA... 103

D EMISSION REDUCTIONS 116

REFERENCES 120

LIST OF TABLES

Table Page

2.1 Summary of Current CHP Operation ... 15

2.2 Summary of Current CHP Steam & Electricity Generation and Fuel Usages ... 15

2.3 Fuel Cost and Usages (2013-2014) ... 22

2.4 Marginal Fuel Costs ... 22

2.5 Ground Properties [21] ... 25

4.1 Current & Proposed CHP Plant Operation (ULSD Reduction) ... 45

4.2 Current & Proposed CHP Plant Operation (LNG Reduction) ... 45

4.3 System Performance Summary ... 50

4.4 Emission Factors for Natural Gas & ULSD ... 53

4.5 Annual ULSD Cost Savings and Emissions Change ... 53

4.6 Annual LNG Cost Savings ... 54

4.7 ACS, Estimated System Cost and Simple Payback ... 55

4.8 NPV ... 56

LIST OF FIGURES

Figure Page

1.1 Types of sensible seasonal thermal energy systems 4

1.2 Construction of a tank thermal energy storage system in Germany 5

1.3 Cross section of the PTES in Marstal 6

1.4 Types of borehole heat exchangers.. 7

1.5 ATES system 8

1.6 Temperature increase profile as a function of supplied heat 9

1.7 700 kWh PCM storage module.. 11

2.1 UMASS District Heating Plant Flow Diagram... 16

2.2 Hourly power produced by the CTG 17

2.3 Hourly steam produced by the HRSG 18

2.4 Hourly steam produced by the HPB 18

2.5 Hourly steam produced by the LPB1... 19

2.6 Hourly steam produced by the LPB2... 20

2.7 Hourly power produced by the HPST... 20

2.8 Hourly power produced by the LPST 21

2.9 Annual Fuel Usage.. 23

2.10 Schematic and Nomenclature for Borehole and U-tube 27

2.11 Charge and Discharge Pump Power & Ambient Temperature..................... 33

2.12 BTES TRNSYS Model 34

3.1 TRNSYS Plotter for 5 Year Simulation at 11,750 Boreholes 37

3.2 Comparison of Ground Temperatures 38

3.3 Comparison of Energy into the BTES (200 hour period) 39

3.4 Comparison of BTES Energy Remianing After Losses 40

3.5 Comparison of Charging Pump Power Consmuption 41

3.6 Comparison of Charging Pump Power Consmuption Totals 42

3.7 Comparison of BTES System Efficiency 43

4.1 Year 5 Ground, Inlet & Outlet Temperature 47

4.2 Year 5 BTES Energy Injection/Extraction 48

4.3 Charge and Discharge Pump Power, Ambient and Ground Temperatures ... 49

4.4 HPST & LPST TRNSYS Model 51

NOMENCLATURE

CHP	*Combined Heat & Power*
TES	*Thermal Energy Storage*
HRST	*Heat Recovery Steam Generator*
HPB	*High Pressure Boiler*
LPB	*Low Pressure Boiler*
CGT	*Combustion Gas Turbine*
HPST	*High Pressure Steam Turbine*
LPST	*Low Pressure Steam Turbine*
DE	*District Energy*
NG	*Natural Gas*
ULSD	*Ultra Low Sulfur Diesel*
LNG	*Liquefied Natural Gas*
TTES	*Tank Thermal Energy Storage*
PTES	*Pit Thermal Energy Storage*
BTES	*Borehole Thermal Energy Storage*
ATES	*Aquifer Thermal Energy Storage*
PCM	*Phase Change Material*
SCR	*Selective Catalytic Reduction*
NPV	*Net Present Value*

CHAPTER 1

INTRODUCTION

As the global demand for energy continues to rise, it is becoming increasingly important to find efficient ways to utilize energy and to lessen the use of fossil fuels. It is projected that the world's total energy consumption will increase by 71% from 2003 to 2030, with an increase in natural gas and oil consumption of 91.6% and 47.5%, respectively [1]. This trend presents serious environmental challenges to humanity, as current greenhouse gas emissions within the atmosphere have reached troubling concentrations [2]. Thus, if measures are not taken to lessen the production of greenhouse gas emissions the effects of climate change will be further exacerbated. Through the production of electricity, and in many other industrial processes, there is a great deal of waste heat generated. Utilizing this waste heat through the application of combined heat and power (CHP) can greatly increase the efficiency of a system when compared to centralized electricity production and independent heat generation [3,4]. The efficiency of a power producing system can be increased from 35-55% to more than 90% by simply utilizing waste heat [5,6]. Cogeneration plants produce electricity and thermal energy simultaneously by utilizing the hot effluent exhaust from a combustion gas turbine (CGT) to produce steam or hot water. This thermal energy can be then transferred with a district energy (DE) system to buildings close to the CHP plant. District heating systems using CHP are particularly popular in Europe, for example, 75% of the district heating energy in Denmark is generated by cogeneration [7] and in Sweden it is about 30% [6]. Although the coupling of CHP and DE increases the overall system efficiency, when compared to centralized power production, there are still economic and environmental shortcomings due to the operational limitations of CHP systems and the seasonal variation in fossil fuel availability. Electricity production is limited by the thermal load and peak periods in the demand for energy often do not align with supply. These limitations lead to inflated energy rates and short supplies in the periods of highest demand. One promising method to mitigate this discrepancy between the supply and demand for energy and to increase the electrical generation capacity of the CHP system is through the application of thermal energy storage (TES).

1.1 Thermal Energy Storage & Combined Heat and Power

TES can enable thermal systems to operate at an overall higher effectiveness, whether it is thermodynamic or economic effectiveness. These systems are often utilized when the demand for energy is not coincident with the most economically advantageous supply for energy. Dincer has identified some of the benefits that can be achieved through the use of TES with CHP plants [8]. Typically, CHP plants are controlled to match the requirements of the system's thermal load. TES can allow CHP plants to diverge operation from the required demand (thermal load) in order to operate in more favorable ways. This deviation can occur daily, seasonally or both and is aimed at shifting the purchase of energy to low-cost periods. Additionally, higher efficiencies are realized for CHP systems when they operate at full load with constant demand [9]. This is rarely attainable in CHP systems, since thermal loads are seldom constant. However, a full and constant thermal load can be attained through the use of a properly sized TES system. The uncoupling of electricity production and heat generation can lead to considerable savings as it allows more electricity to be produced during peak hours as well as the potential to offset peak heating loads. In summary, the application of an optimal TES system can allow the CHP plant to extend its operating hours leading to increased energy savings and reduced emissions [10].

1.2 Thermal Energy Storage

Thermal energy storage systems of all types operate on the same basic principle. Energy is delivered to a storage device for use at a more advantageous time. The main distinction between systems is the time-scale of storage, working temperature and the storage medium used. These design parameters are dependent on the requirements of the thermal system that the storage system is integrated to. Solar thermal power plants typically require TES systems that are designed for daily cycling and high working temperatures. Diurnal TES systems allow solar power plants to produce power continuously, thus countering the intermittency of the solar resource. However, district heating systems require TES systems with immense storage capacities that cycle daily and/or seasonally. The complete cycle of a storage system consists of 3 stages: charging, storing and discharging.

1.3 Sensible Heat Storage

In general, TES systems can be classified into three categories; sensible, latent and chemical thermal energy storage [11]. Sensible heat is the energy that is absorbed or released as the temperature in a substance is changed (with no change in phase experience in the material) [12]. The temperature of a storage medium increases proportionally to the energy input to the system. The quantity of energy accumulated in a storage medium is dependent on the specific heat, the mass of the storage medium and the temperature change [13] and can be expressed as follows:

$$Q = \int_{T_i}^{T_f} mC_P dT = \mathrm{m}\mathrm{C}_P(\mathrm{T}_f - \mathrm{T}_i) \quad (1)$$

Where,

Q	=	Sensible heat stored; J
T_f	=	Final temperature; ^{o}C
T_i	=	Initial temperature; ^{o}C
m	=	Mass of storage medium; kg
C_p	=	Specific heat of the storage medium; J/kg ^{o}C

Typical sensible storage materials are liquid (water, oil) and solid (rocks, concrete, metal). The most common sensible energy storage systems in operation are tank, pit, borehole and aquifer thermal energy storage.

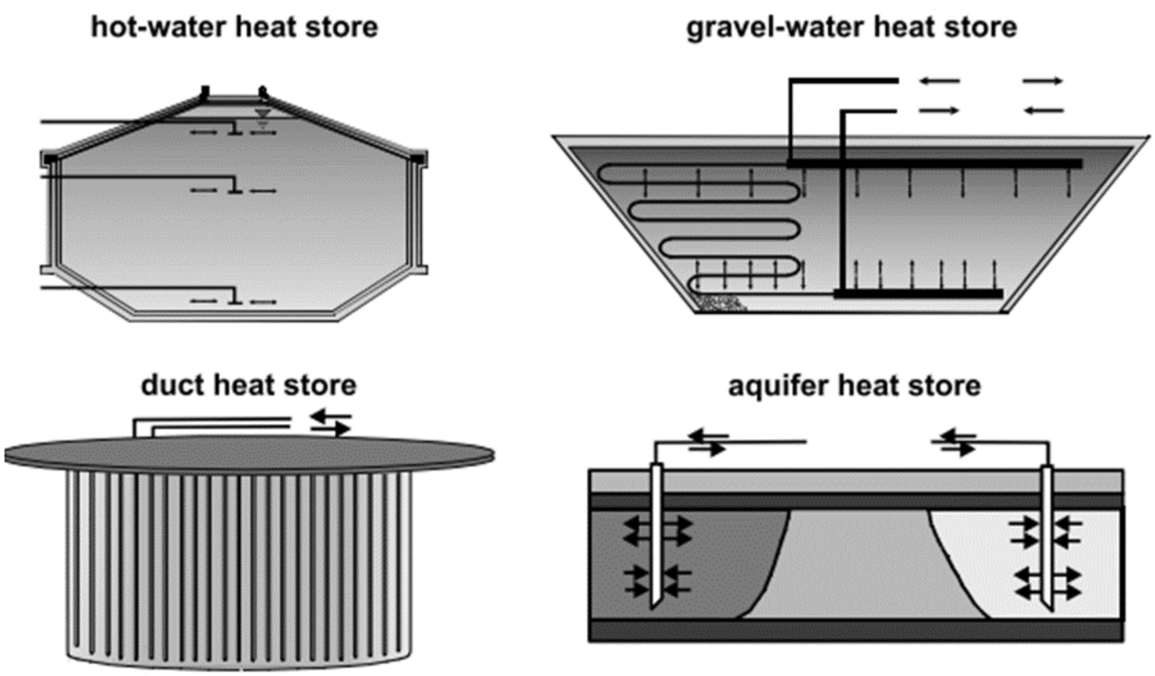


Figure 1.1 Types of sensible seasonal thermal energy systems

[14]

1.3.1 Tank Thermal Energy Storage

Tank thermal energy storage (TTES) systems are generally made of reinforced concrete, with the interior layer lined with stainless steel to create a watertight seal. The storage medium is typically water because of its high specific heat capacity. These tanks are insulated and buried underground and working temperatures are in the range of 30-90^{o}C [15]. Bauer investigated the performance of German central heating plants with seasonal energy storage [16]. One of the studied systems was a tank thermal energy storage (TTES) system in Friedrichshafen, Germany. The tank was made of reinforced concrete with a storage volume of 12,000m^3 (with a height of 20m and diameter of 32m). The efficiency of this TTES system was found to be 60%. Solar collectors with a solar fraction of approximately 33% and two condensing gas boilers provide the energy input to the TTES system.

Figure 1.2 Construction of a tank thermal energy storage system in Munich, Germany [17]

1.3.2 Pit Thermal Energy Storage

A pit thermal energy storage (PTES) system consists of an excavated pit that is lined with plastic. These systems are generally insulated on the top only, as the losses from the sides/bottom to the soil are relatively low (temperature dependent). Due to the low cost of construction when compared to tank storage, PTES storage capacities can be immense. Dannemand studied a district heating system in the town of Marstal, Denmark (one of the largest of its kind) that had been coupled with solar thermal collectors, a biomass boiler, heat pumps and seasonal pit thermal energy system [15]. This system has a storage volume of 80,000m^3 [18] and operates at temperatures in the range of 30-90^{o}C, with a efficiency of approximately 55% [15].

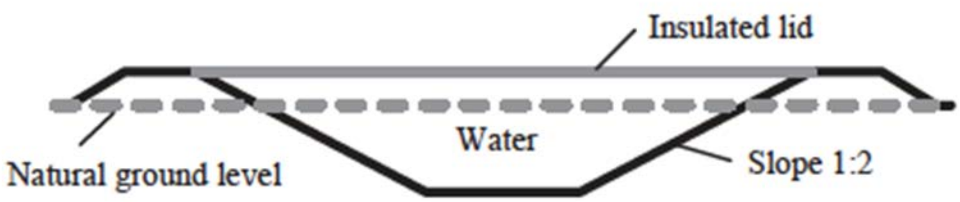


Figure 1.3 Cross section of the PTES in Marstal [15]

1.3.3 Borehole Thermal Energy Storage

Borehole thermal energy storage (BTES) systems are made up of a sizeable number of boreholes, where each borehole is typically filled with thermally conductive bentonite grout and a heat exchange pipe (typically PEX tubing). The ground (soil) is used as the storage device, where heat is transferred to the ground by circulating water or propylene glycol through the piping. Typical borehole depths are 20-200 meters, with operational temperatures in the range of 20-90^{o}C and an efficiency of approximately 40-90% [19–21]. Because the specific heat capacity of soil is low, large storage volumes are needed. It is important to minimize the surface area as it is directly proportional to thermal losses. Moreover, since the volume of the system is proportional to the energy storage capacity it is desired to maximize the volume while minimizing the surface area within the constraints of the geographic and geotechnical features of the site in order to find an optimal volume to area ratio [21]. One of the largest systems in Neckarsulm, Germany has a storage volume of 63,360m^3, with 538 boreholes [16]. Sibbitt investigated the performance of a solar seasonal energy storage system in Alberta, Canada. This system utilized seasonal borehole thermal energy storage to provide space heating for 52 homes through a district-heating network. The system was designed to provide 90% of the spacing heating requirements. In this study, Sibbitt compared the actual performance and operation over 5 years against a TRNSYS model of the system. The outcome of this study found that the system was able to reach its design target of 90% (space heating load) over the 5 years of operation. Additionally, TRNSYS accurately predicted the performance of the BTES system. The actual efficiency of the BTES system after 5 years of operation was realized at 36% [19].

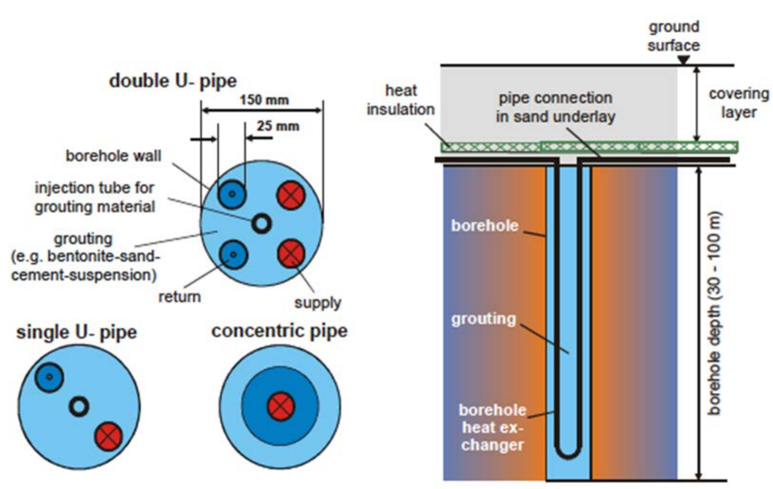


Figure 1.4 Types of borehole heat exchangers [14]

1.3.4 Aquifer Thermal Energy Storage

Aquifer thermal energy storage (ATES) systems store heat in ground water aquifers. Information about the aquifer must be known before this application of TES is to be considered, as water is typically drawn from one well and discharged into another. Thus, a drawdown test must be performed to ensure the well is able to replenish itself at the same rate or faster than it is extracted. The typical operating temperature for this system is in the range of 5-90^{o}C, with efficiencies up to approximately 87% [3,15,16,22]. These systems are often coupled with heat pumps and used for summertime cooling [15]. However, in Rostock, DE there is an ATES system that is used for space heating, cooling and preheating hot water. This system is charged with solar thermal collectors and utilizes a heat pump [16].

Figure 1.5 ATES system [16]

1.4 Latent Heat Storage

Heating a substance until a change in phase is experienced is known as latent heating. The transition from solid to liquid or liquid to gas is an example of this transformation. A substance absorbs a great deal of heat to undergo a phase transformation once the phase change temperature is reached. This is known as the latent heat of fusion or vaporization [23]. Latent heat storage can be as explained as follows: the temperature of a solid material increases proportional to the energy input until its melting point is reached. At this point energy is added isothermally until the material has transitioned from solid to liquid. After the once solid material is completely liquid, the temperature again increases until the liquid transitions to a vapor, where again energy is added isothermally. The cooling process is the same as the above described heating process, meaning that stored energy can be extracted isothermally as latent heat [13]. Figure 1.6 below illustrates this process.

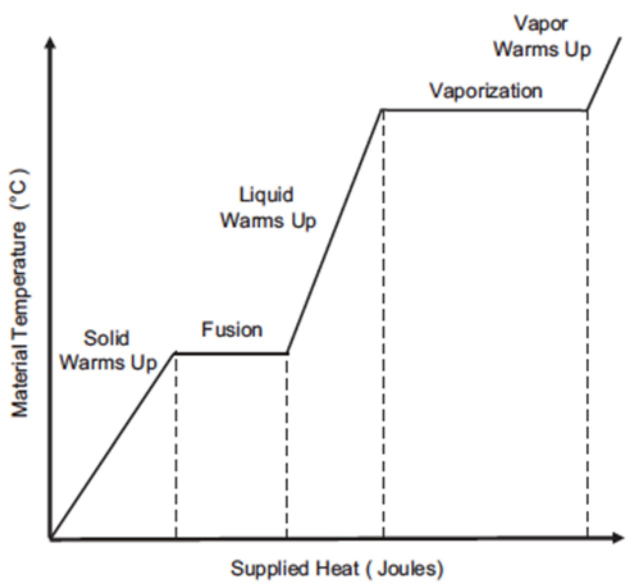


Figure 1.6 Temperature increase profile as a function of supplied heat [23]

Latent heat storage is expressed as follows [13]:

$$Q = \int_{T_i}^{T_m} mC_P dT + ma_m \Delta h_m + \int_{T_m}^{T_f} mC_P dT \qquad (2)$$

Where,

Q	=	Heat stored; J
T_m	=	Phase change temperature; ^{o}C
T_i	=	Initial temperature; ^{o}C
m	=	Mass of storage medium; kg
a_m	=	Fraction of material that has experienced transformation; %
h_m	=	Latent heat of fusion; J/kg

Cp = Specific heat of the storage medium; J/kg ^{o}C

It is not possible to store only latent heat, as a temperature increase is required to reach the change of phase point. Thus, the first term in the expression for latent heating above is the sensible heat stored as the substance's temperature is raised from the initial state to its phase change temperature. The second term reflects the energy stored throughout the change of phase by the latent heat of the substance, this accumulated energy is a function of the specific latent heat of the substance, its mass and the percentage of material that has changed phase [23]. The final term would appear if the change in phase were complete throughout the material, thus leading to more sensible heat gain. Typical latent heat storage materials consist of paraffin, salt hydrates ($NaNO_3$, KNO_3, $NaNO_2$, ect) and others salts [12].

1.4.1 Phase Change Material Thermal Energy Storage

The German Aerospace Center (DLR) built a promising phase change material (PCM) latent storage prototype using sodium nitraite (NaNO3) as the storage medium. This system is the world's largest high temperature PCM storage module, at 700kWh, with 14 tons of NaNO3 and a melting temperature of 306^{o}C [24]. The storage efficiency for this type of system can be upwards of 91% [25]. This system is pictured in figure 1.7 below.

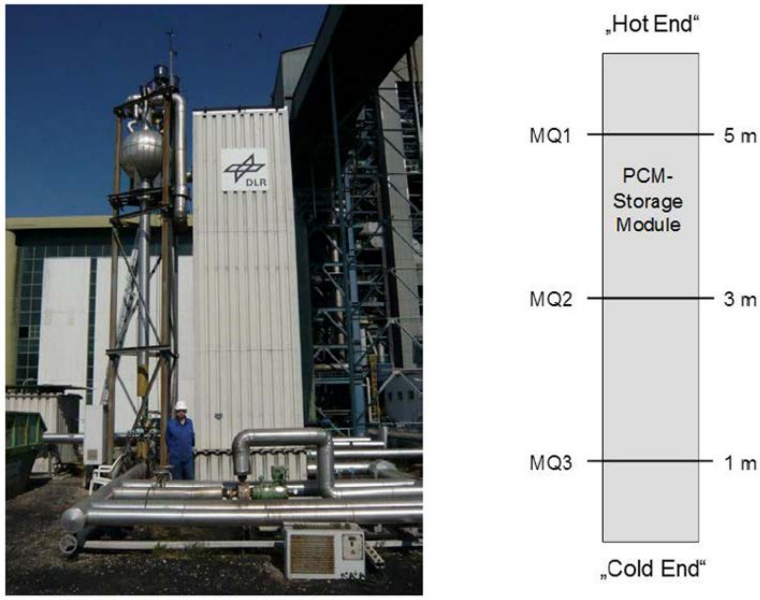


Figure 1.7: 700kWh PCM storage module [24]

Laing studied the use of nitrate salts for high temperature latent thermal energy storage applications. With 4,000 hrs of testing and 172 cycles (with no degradation) the designed heat transfer rate was achieved. The most economically promising option was a sandwich concept utilizing fins of graphite or aluminum. A latent heat capacity of 93kWh/m^3 at an estimated cost of \$9.5/kWh and a melting temperature of 305^{o}C was achieved using $NaNO_3$ (sodium nitrate). Laing later demonstrated and tested a 700kWh (14 tons of $NaNO_3$) phase change material (PCM) module that was able of achieving high discharge/charge rates of 350 kW [25].

Newmarker evaluated the performance of a 100kWh prototype heat exchanger for PCM thermal energy storage. Using commercially available heat exchanger materials, Newmarker developed a unique PCM storage module. This prototype used an agitation mechanism to improve heat transfer during the discharge process. TRNSYS was used to model the performance of this system, with a calculated round trip efficiency upwards of

93%. The purpose of this project was to design and validate a PCM storage system at a prototype level. In order to demonstrate at an industrial scale (800MWh), a PCM storage module with an efficiency of over 93%. The prototype system did not perform as well as the model predicted nor did the final cost align with the goals set by the DOE. With 56% of the costs attributed to the phase change material and 27% of the cost for the heat exchanger surface. Though the tested performance and estimated cost did not meet DOE goals in the early stages of its development, with a multiyear RD&D plan it is believed that costs and performance goals can be met [26].

1.5 Objective of Research

TES systems have greatly developed over the last 40-50 years as industrialized nations have become increasingly electrified. As Dincer has brought to light, “in many countries energy is produced and transferred in the form of heat. Thus, the potential for thermal energy storage warrants investigation in great detail” [8]. The results from the prior literature have provided sound validation for the following research into the modeling of a seasonal TES system for the UMass CHP plant. Additionally, it was observed that there is limited research using actual CHP plant data to model a seasonal TES system of this scale. Thus, what makes this study unique is that actual operating data for a year was used from the UMass CHP plant to design and model a TES system. In summary, the objectives of this research are as follows:

1. Utilize current CHP operating data to asses a proposed operation with TES
2. Design & model the performance of a TES system in TRNSYS
3. Asses the economic and environmental benefits of TES to CHP
4. Investigate system cost and payback

CHAPTER 2

INTRODUCTION OF CASE STUDY

2.1 The University of Massachusetts Amherst Combined Heat and Power Plant

The University of Massachusetts's CHP plant has been in operation since 2009 and currently produces approximately 75% of the campus's power and 100% of the steam load, representing over 200 campus buildings. Electrical power is produced by a 10 MW combustion gas turbine (CGT), a 2 MW high-pressure steam turbine (HPST) and a 4 MW low-pressure steam turbine (LPST). Steam is produced by a heat recovery steam generator (HRSG), capable of producing 40,000 pph (unfired) using exhaust heat from the CGT and up to 100,000 pph by firing its' duct burners. Additionally, steam is produced by a high-pressure boiler (HPB) and two low-pressure boilers (LPB), each capable of producing 125,000 pph. The boilers are used in the fall, winter and spring months to help provide additional steam capacity to meet the campus load. Steam is delivered to the campus via two 20-inch main stream transmissions lines, one high pressure (200 psig) line and one low pressure (20 psig) line. A 13.8 kV bus is used to connect the plant's electrical output to the campus. Condensate is returned from the campus (approximately 65%) to a condensate return storage tank. This tank uses three 250 hp pumps to provide feed water to the boilers and HRSG. Additionally, raw water is stored in the condensate storage tank to make up for the loss in condensate returned. This raw water is mixed with the remaining condensate return. In order to prevent corrosion damage to the system, a de-aerator (DA) is utilized. The DA removes oxygen and other dissolved gases from the feedwater. This process is accomplished by utilizing steam at 60 psig and 443^{o}F to strip the dissolved gasses from the feedwater and to preheat the feedwater to its saturation temperature of 228^{o}F by using a DA pegging steam control valve. The steam utilized for this process is extracted from the main line at 200 psig and 475^{o}F. The CGT, HRSG, HPB and LPBs can operate on natural gas or ULSD. Natural gas is utilized throughout the year, although limited supplies in the heating season necessitate supplementing the fuel requirements of the plant with ULSD and LNG. The UMass CHP plant has a Supervisory Control and Data Acquisition (SCADA) system, which is capable of storing and transmitting instantaneous data about the plant's operation from 675 points in the system. This data includes, steam flows, fuel flows, temperature, pressure, power produced and other critical data. Table 2.1 below displays a component-by-component summary of the current CHP plant operation. Table 2.2 shows the total steam & electricity generated and the fuel input to the plant. Figure 2.1 shows a process flow diagram of the plant.

Table 2.1 Summary of Current CHP Operation

Summary of Current CHP Plant Operation			
Current Power Produced			
CHP Plant Component	Power Produced (MWh)	Fuel Input	
		MMBtu	MWh
CGT	68,485	804,108	235,843
HPST	8,473	-	-
LPST	12,409	-	-
Total	89,367	804,108	235,843
Current Steam Produced			
CHP Plant Component	Steam Produced (lbs)	Fuel Input	
		MMBtu	MWh
HRSG	489,989,002	208,604	61,183
HPB	218,928,324	274,091	80,390
LPB1	165,396,343	195,238	57,263
LPB2	152,190,471	198,406	58,192
Total	1,026,504,140	876,339	257,028

Table 2.2 Summary of Current CHP Steam & Electricity Generation and Fuel Usages

Summary of CHP Plant Results							
Power Produced (MWh)	Steam Produced (lbs)	Natural Gas Fuel Input		LNG Fuel Input		ULSD Fuel Input	
		MMBtu	MWh	MMBtu	MWh	MMBtu	MWh
89,367	1,026,504,140	1,193,600	350,079	158,197	46,399	328,651	96,392

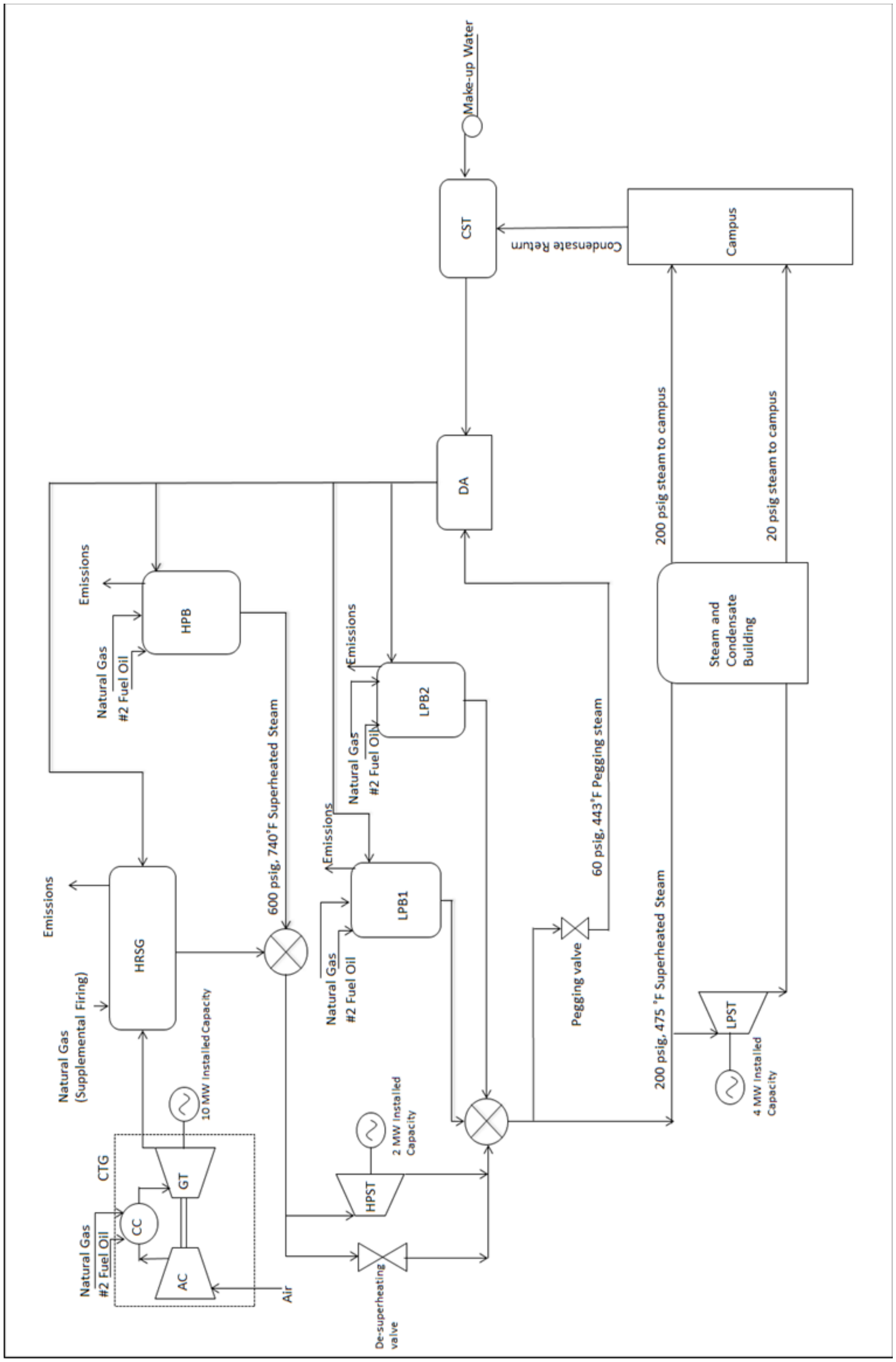


Figure 2.1 UMASS District Heating Plant Flow Diagram

2.2 Hour Profiles of Current Operation

Hourly profiles for the current operation of the UMass CHP district heating plant are presented in order to create a baseline for current operation. The data shown is for the 2011 operating year from January 1st to December 31st.

2.2.1 Combustion Gas Turbine (CGT) Hourly Profile

In 2011 the CGT was in operation for 7,787 hours and the average power generated was 8,795 kW. Figure 2.2 shows the power production by the CGT during this period.

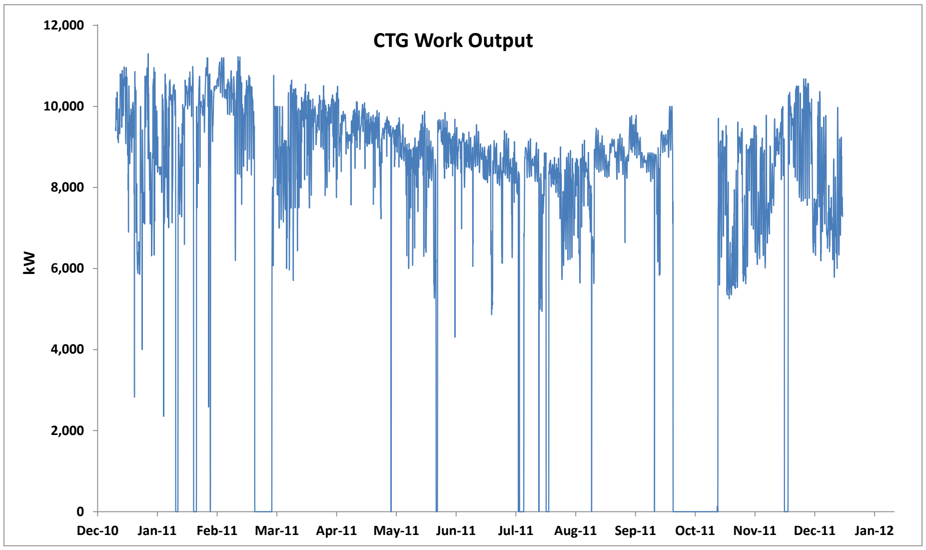


Figure 2.2 Hourly power produced by the CTG

2.2.2 Heat Recovery Steam Generator (HRSG) Hourly Profile

The HRSG was in operation for 6,469 hours with supplementary firing and 1,318 hours by purely utilizing exhaust gases from the CGT. On average the product mass flow to the HRSG from the CGT is approximately 43.11 kg/s. Figure 2.3 shows the steam production by the HRSG during this period.

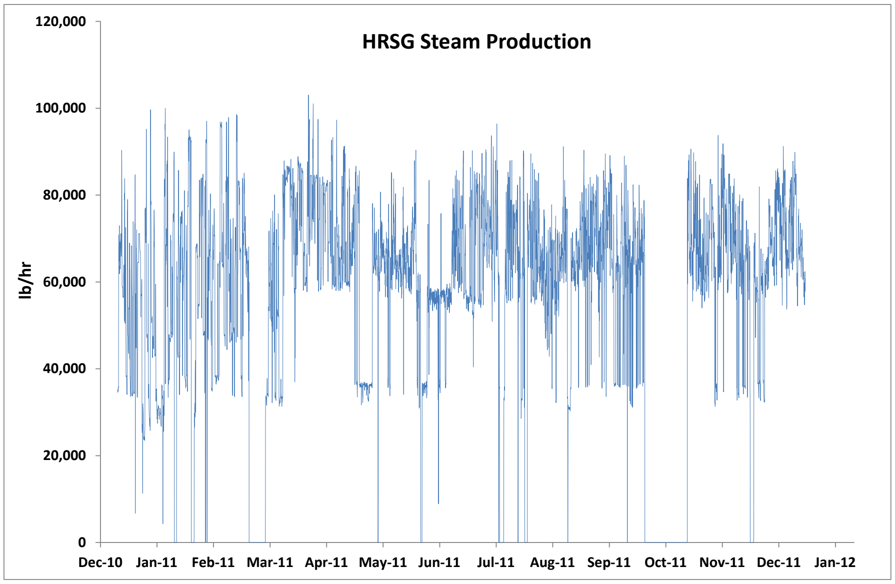


Figure 2.3 Hourly steam produced by the HRSG

2.2.3 High Pressure Boiler (HBP) Hourly Profile

During 2011, the HBP was in operation for 4,097 hours. The steam produced by the HPB contributes to the HRSG steam production at the 600 psig header. Figure 2.4 shows the steam production by the HPB during this period.

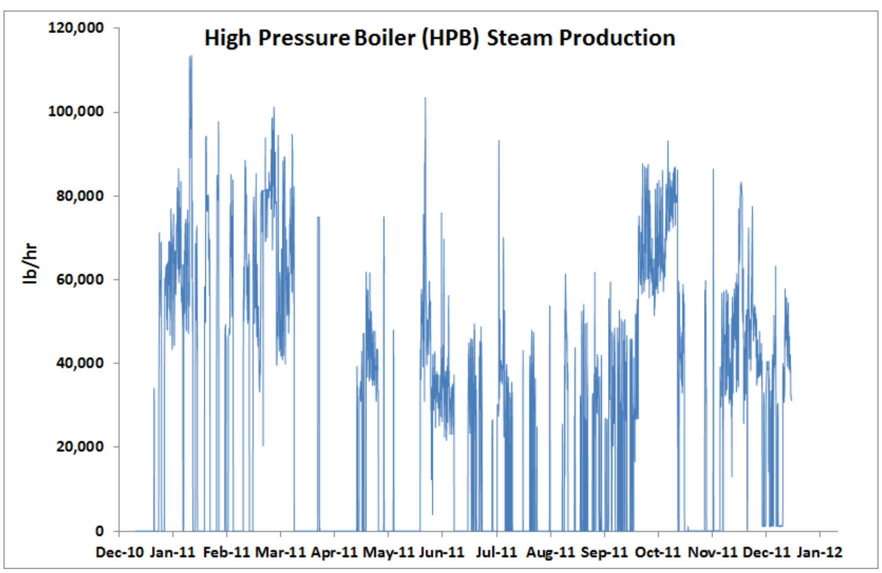


Figure 2.4 Hourly steam produced by the HPB

2.2.4 Low Pressure Boiler 1 (LPB1) Hourly Profile

In 2011 the LPB1 was in operation for 2,993 hours. The steam generated by the LPB1 contributes to the production of steam at the 200 psig header. Figure 2.5 shows the steam production by the LPB1 during this period.

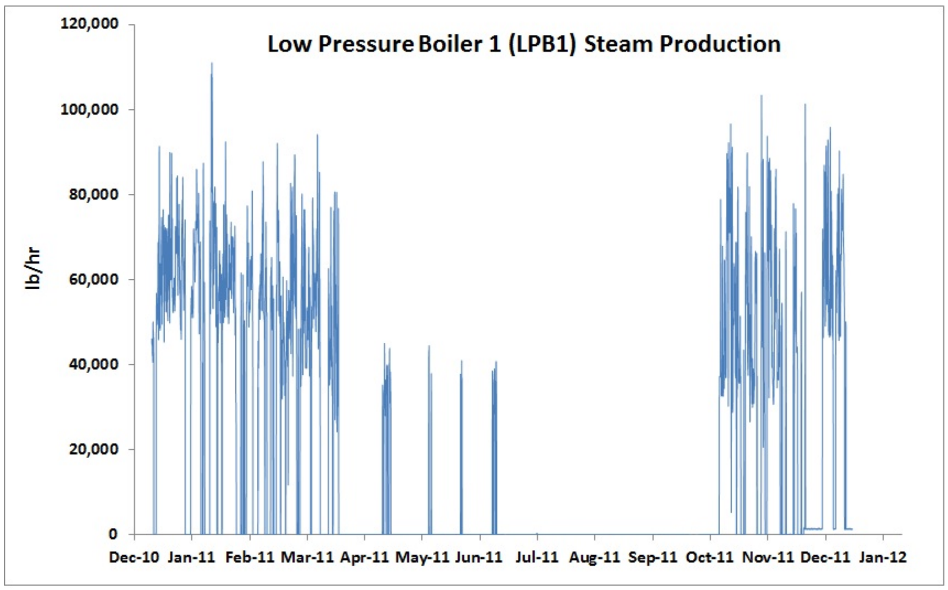


Figure 2.5 Hourly steam produced by the LPB1

2.2.5 Low Pressure Boiler 2 (LPB2) Hourly Profile

In 2011 the LPB2 was in operation for 2,850 hours. The steam generated by the LPB2 also contributes to the production of steam at the 200 psig header. Figure 2.6 shows the steam production by the LPB2 during this period.

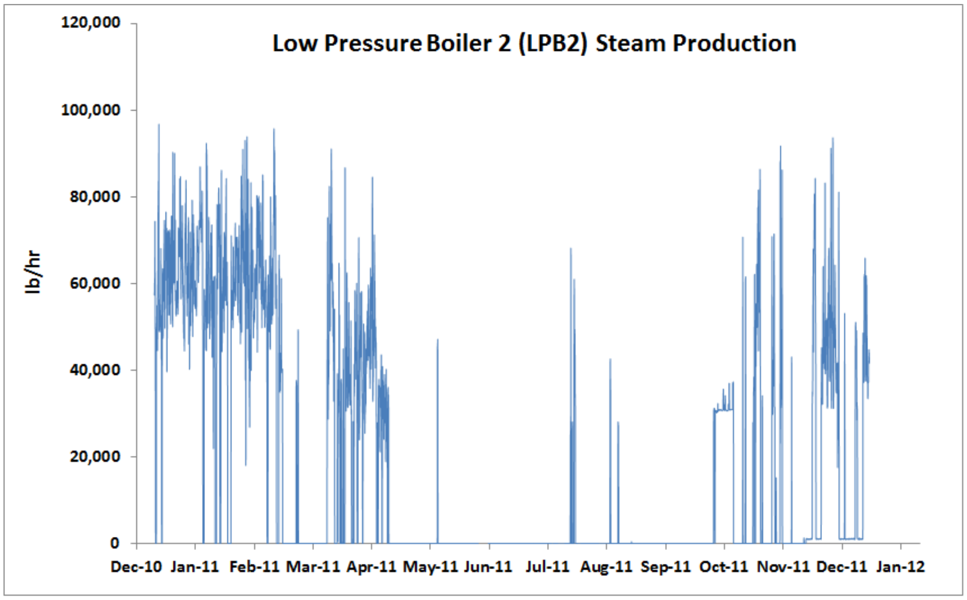


Figure 2.6 Hourly steam produced by the LPB2

2.2.6 High Pressure Steam Turbine (HPST) Hourly Profile

In 2011 the HPST was in use for 7,407 hours. The electricity produced by this turbine is delivered to the campus via the 13.8 kW bus. Figure 2.7 shows the power production by the HPST during this period.

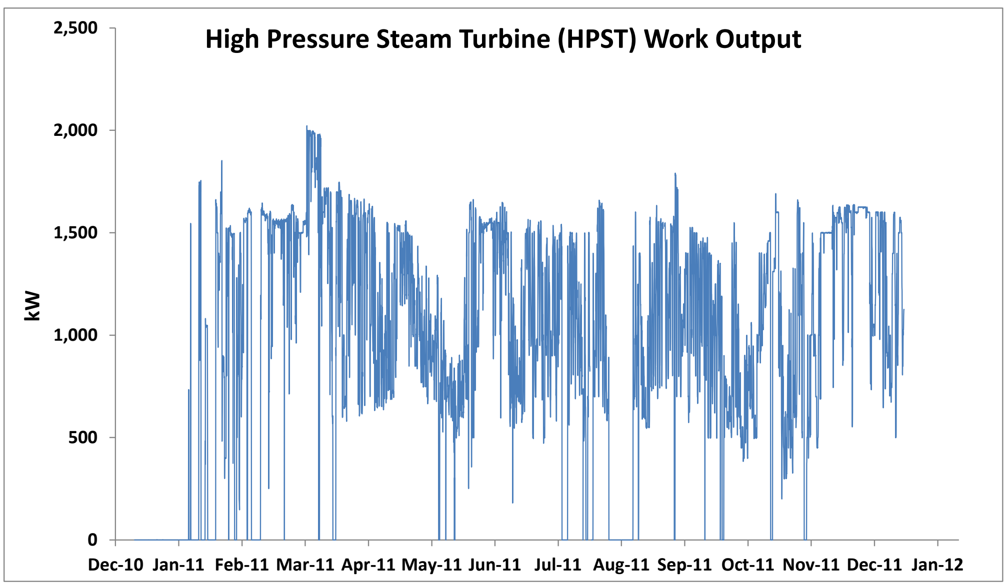


Figure 2.7 Hourly power produced by the HPST

2.2.7 Low Pressure Steam Turbine (LPST) Hourly Profile

In 2011 the LPST was in use for 7,492 hours. The electricity produced by this turbine is delivered to the campus via the 13.8 kW bus. Figure 2.8 shows the power production by the LPST during this period.

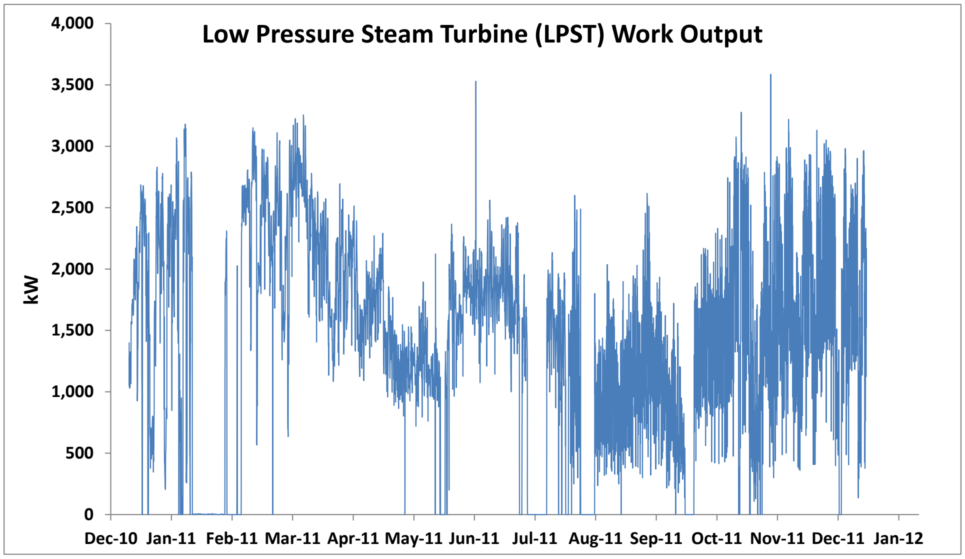


Figure 2.8 Hourly power produced by the LPST

2.3 Proposed Operation

Hourly data from 2011 was used to observe the current operation of the campus CHP plant in order to help model the proposed operation of the plant with TES. When the spring semester ends in early May, the thermal load of the campus is reduced and it increases again as the fall semester begins in September. The average hourly steam produced by the HRSG for May through September is approximately 60,000 pph. Thus, there is an opportunity to increase the steam production of the HRSG to 100,000 pph during this period to accommodate the application of a TES system. Table 2.3 below shows the cost and fuel usage (both in MMBtu & MWh) for the three fuels used at the plant from July 2013 to June 2014. The most recent cost and usage data was used rather than the data from 2011, as it better represents the marginal cost of fuel at its current rates.

Table 2.3 Fuel Cost and Usages (2013-2014)

Month	Natural Gas Cost ($)	Natural Gas Usage		LNG Cost ($)	LNG Usage		ULSD Cost ($)	ULSD Usage	
		MMBtu	MWh		MMBtu	MWh		MMBtu	MWh
July	$1,272,636	133,400	39,126	$0	0	0	$0	0	0
August	$1,110,961	120,888	35,456	$0	0	0	$0	0	0
September	$1,151,994	125,353	36,766	$0	0	0	$45,815	1,754	514
October	$1,240,269	136,895	40,151	$0	0	0	$98,333	3,764	1,104
November	$1,470,589	153,027	44,882	$465,998	18,760	5,502	$203,931	7,807	2,290
December	$1,383,342	144,701	42,440	$1,030,863	47,309	13,876	$558,338	21,375	6,269
January	$1,148,866	119,549	35,063	$1,082,689	41,546	12,185	$2,092,689	80,113	23,497
February	$1,306,598	135,934	39,869	$1,078,886	46,705	13,698	$1,041,089	39,856	11,690
March	$1,300,617	135,934	39,869	$964,258	49,884	14,631	$429,037	16,425	4,817
April	$1,475,646	150,884	44,254	$318,499	6,701	1,965	$93,604	3,583	1,051
May	$1,194,080	122,219	35,846	$0	0	0	$0	0	0
June	$1,099,135	112,501	32,996	$0	0	0	$24,588	941	276
Total	**$15,154,730**	**1,591,285**	**466,719**	**$4,941,192**	**210,905**	**61,858**	**$4,587,422**	**175,618**	**51,508**

Using the above fuel usage and cost data for the campus CHP plant, it was determined that the weighted average marginal cost of natural gas, LNG and ULSD are as follows:

Table 2.4 Marginal Fuel Costs

Weighted Average Marginal Cost		
	($/MMBtu)	**($/MWh)**
NG	9.52	32.46
LNG	23.43	79.88
ULSD	26.12	89.06

As is illustrated in table 2.4 above, the marginal cost of natural gas is considerably lower than that of LNG or ULSD. Figure 2.9 below shows the annual fuel usage in terms of MWh and MMBtu for the three fuels. The shortage of natural gas in the winter months requires the additional use of LNG and ULSD. This directly increases costs and also increases emissions, as burning ULSD produces higher emissions when compared to natural gas.

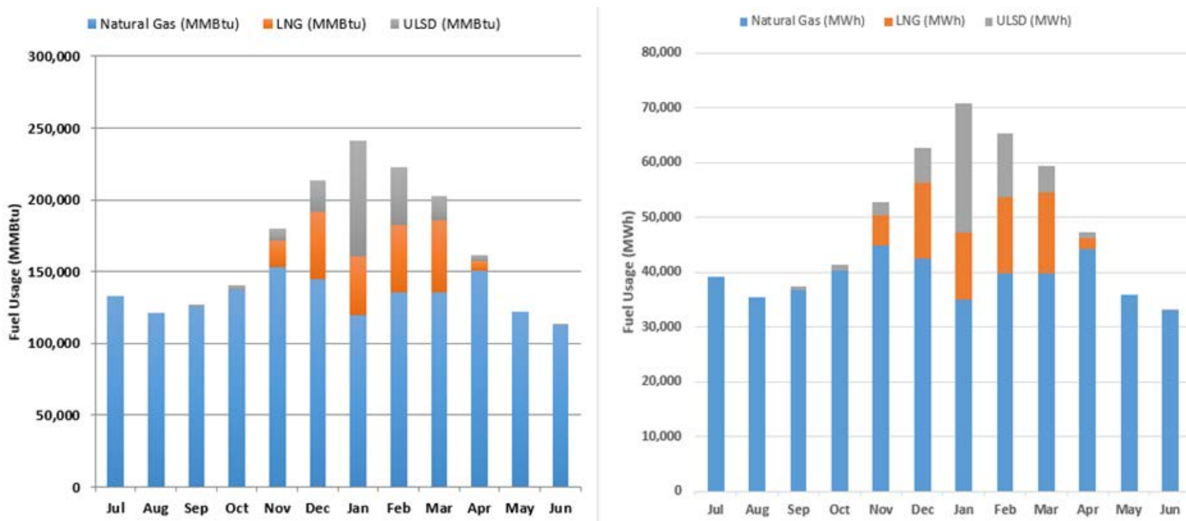


Figure 2.9 Annual Fuel Usage

2.4 Natural Gas & Steam Assessment due to Additional HRSG Firing

To determine the additional natural gas needed to operate the HRSG at full capacity for the charging period, the following expression is used. The fuel energy input (MMBtu) to the HRSG as a function of steam production is as follows [27]:

$$F_{hrsg} = \begin{cases} 0, \text{ for } 0 < \dot{m}_{s,hrsg} <= 40,000 \text{ lb/hr} \\ 0.001\dot{m}_{s,hrsg} - 36.39, \text{ for } 40,000 < \dot{m}_{s,hrsg} <= 100,000 \text{ lb/hr} \end{cases} \quad (3)$$

Where,

$m_{s,hrsg}$	=	Steam flow from HRSG; pph
F_{hrsg}	=	Fuel input for HRSG; MMBtu

By setting the steam flow to 100,000 pph, it was determined that an additional 141,086,294 lbs of steam will be produced. This requires an additional 232,932 MMBtus

(68,318 MWh) of natural gas. Using the temperature and pressure at the exit of the HRSG, it was determined that the average enthalpy is 1369 Btu/lb. This corresponds to an overall energetic steam input to the system of 193,139 MMBtus (56,647 MWh).

2.5 Selection of TES Technology

Past studies have concluded that the UMass campus has favorable geological features for a BTES system, as the campus sits on saturated clay and silt with a depth of more than 100 feet [20]. This clay deposit is a remnant of the glacier Lake Hitchcock, which was formed over 10,000 years ago. A comprehensive geotechnical and hydrogeological investigation was conducted to determine if the site was well suited for a seasonal TES system. These studies concluded that there is a negligible effect on the energy stored as a result of ground water flow. This is due to the minimal ground water gradient and the low permeability of the clay [28]. These geological attributes make BTES highly viable for this site. High ground water flows can have adverse effects on storage efficiency because convective heat transport losses increase greatly with higher flows [21]. Additionally, the soil at this location has a relatively high thermal conductivity of 1.22W/m^{o}C which is needed in order to attain the required heat transport to and from the soil [21,28]. Table 2.5 shows thermal conductivities, volumetric heat capacities and densities for many different thermal storage materials.

Table 2.5 Ground Properties [21]

Material	Thermal conductivity (W/mK)	Volumetric heat capacity (MJ/m^3)	Density (10^3 kg/m^3)
Unconsolidated			
Clay/silt, dry	0.4–1.0	1.5–1.6	1.8–2.0
Clay/silt, water-saturated	1.1–3.1	2.0–2.8	2.0–2.2
Sand, dry	0.3–0.9	1.3–1.6	1.8–2.2
Sand, water-saturated	2.0–3.0	2.2–2.8	1.9–2.3
Gravel/stones, dry	0.4–0.9	1.3–1.6	1.8–2.2
Gravel/stones, water-saturated	1.6–2.5	2.2–2.6	1.9–2.3
Till/loam	1.1–2.9	1.5–2.5	1.8–2.3
Sedimentary rock			
Clay/silt stone	1.1–3.4	2.1–2.4	2.4–2.6
Sandstone	1.9–4.6	1.8–2.6	2.2–2.7
Conglomerate/breccia	1.3–5.1	1.8–2.6	2.2–2.7
Marlstone	1.8–2.9	2.2–2.3	2.3–2.6
Limestone	2.0–3.9	2.1–2.4	2.4–2.7
Dolomitic rock	3.0–5.0	2.1–2.4	2.4–2.7
Magmatic and metamorphic rock			
Basalt	1.3–2.3	2.3–2.6	2.6–3.2
Granite	2.1–4.1	2.1–3.0	2.4–3.0
Gabbro	1.7–2.9	2.6	2.8–3.1
Clay shale	1.5–2.6	2.2–2.5	2.4–2.7
Marble	2.1–3.1	2.0	2.5–2.8
Quartzite	5.0–6.0	2.1	2.5–2.7
Gneiss	1.9–4.0	1.8–2.4	2.4–2.7
Other materials			
Bentonite	0.5–0.8	~3.9	
Water (+10°C)	0.59	4.15	0.999

For higher temperature applications where large storage volumes are needed (as in the coupling of TES and CHP), BTES is one of the lowest in cost per m^3 when compared to other seasonal TES systems of similar a scale [14,21].

2.6 TES Modeling and Design Tool

A transient system simulation tool was chosen to effectively model the thermal performance of a seasonal BTES system coupled to the campus CHP plant. TRNSYS is an internationally recognized tool developed to simulate solar processes by the Solar Energy Laboratory at the University of Wisconsin, Madison. TRNSYS is comprised of a series of subroutines, where the performance of each component in the system is modeled by a subroutine. There are two main parts to TRNSYS, the kernel and the library of components. The kernel takes and processes inputs, iteratively solves the system and determines convergence. The second feature of TRNSYS is a vast library of components, where each model represents one component in the system. Each model has specific parameters, inputs and outputs that directly correlate to the physics and performance of the component [29].

TRNSYS was chosen because it allows for great flexibility and a high level of transparency when modeling such a complex system. For instance, design parameters for components in the system may be specified and adjusted.

The modular nature of TRNSYS allows users to easily simulate and add/remove individual components (e.g., pumps heat exchangers, storage tanks, etc.) to the system. This allows for immense flexibility in simulating a multitude of control strategies and system configurations. Additionally, the time step and length of a simulation can be easily varied which proves helpful for both steady state and transient analysis of a system. However, the flexibility and transparency of TRNSYS can make multiple runs for system optimization cumbersome. The modular nature of TRNSYS allows for realistic simulation of the interconnections of controllers and subsystems in a way that closely depicts the operation of a physical system. Components in TRNSYS are called “Types”, where each type has a corresponding number in order to identify and distinguish it from the multitude of other models.

2.7 Duct Storage Model Description and Analysis

To simulate a BTES system in TRNSYS the Type557 component is utilized. The Type557 model in TRNSYS is based on the duct ground heat storage model (DST) created at the University of Lund [30]. The DST program assumes that the cylindrical volume of the BTES system is comprised of uniformly spaced U-tube boreholes. The ground temperature throughout the storage volume is then computed by three solutions: the global temperature solution, a local heat transfer solution and a steady flux solution. The variation of temperatures from the center of the storage volume to the surrounding ground represents the global solution and is solved via the explicit finite difference method. The thermal processes around each individual U tube represents the local heat transfer, and this is again solved using the explicit finite difference method. Analytical solutions are used to obtain the steady flux problem.

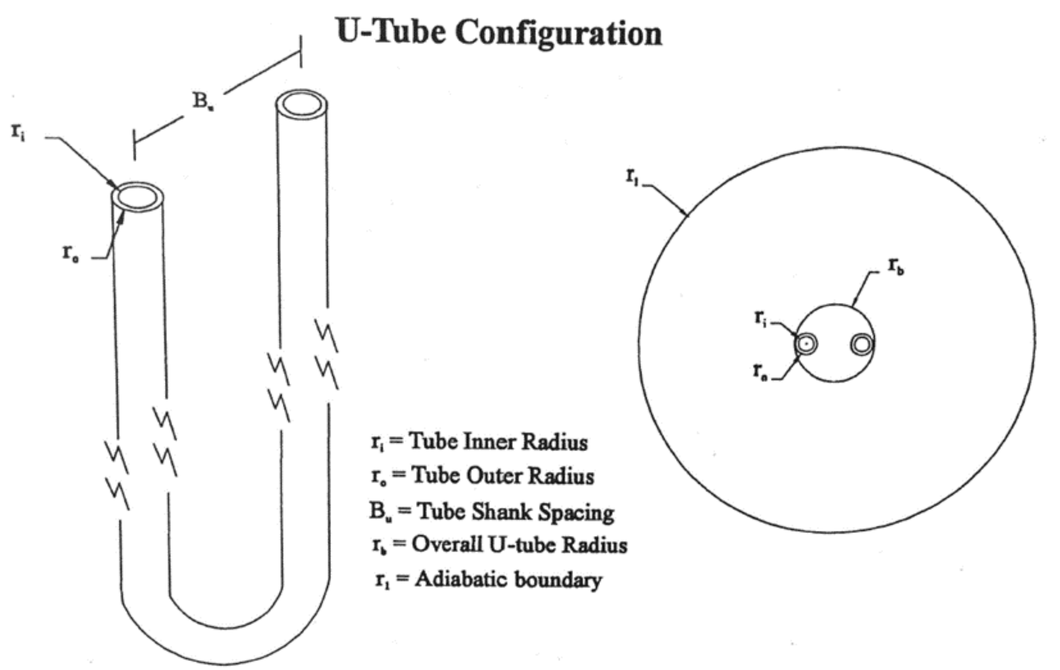


Figure 2.10 Schematic and Nomenclature for Borehole and U-Tube [20]

2.7.1 Numerical Procedure

The numerical DST model uses an explicit finite difference method. The storage volume simulated is then divided into a two dimensional mesh in the vertical coordinate z and radial coordinate r. The expressions and descriptions for the DST model in the following section are based on the descriptions given by Hellstrom [30] and El Hasnaoui [20]. The following assumptions are made by the model;

i. Conductive heat transfer is the sole form of heat transfer throughout the storage volume;

ii. It is assumed that the boreholes (with outer radius r_0) make up the pattern of a equilateral triangle;

iii. The area of each borehole is πr_1^2, where the distance between two boreholes is approximately equal to $\frac{r_1}{2}$;

iv. Conductive heat transfer occurs in the area from r_0 to r_1;

v. The flow of heat to the ground from the piping is a function of the fluid temperature, the heat transfer properties (of the fluid, piping and ground) and the ground temperature around the pipe;

vi. With respect to the central axis of the storage volume, the thermal properties, the placement of ducts, the storage volume and the temperature fields all show cylindrical symmetry;

vii. Thermal properties (heat capacity and thermal conductivity) within the storage volume are constant;

viii. All the boreholes receive the same amount of heat and as a result have the same temperature distributions. This is because all the boreholes are all in parallel to each other, unless otherwise specified in the set of parameters.

2.7.2 Global Problem

The global solution is a typical heat conduction problem. It encompasses large-scale thermal processes. For example, the effect of surface conditions, the interaction between the storage volume and the ground surrounding it and the interaction between individual parts inside the storage volume. The numerical solution of this process is established on a two-dimensional mesh in the radial and vertical directions. The radial heat flow component between cell i and cell i-1, is expressed as:

$$q_r(i,j) = \frac{(T_{i-1,j} - T_{i,j})}{R_r(i,j)} \tag{4}$$

Where,

$$R_r(i,j) = \frac{1}{2\pi k} \ln \frac{r_i}{r_{i-1}} \tag{5}$$

the z-component is given by

$$q_z(i,j) = \frac{(T_{i-1,j} - T_{i,j})}{R_z(i,j)} \tag{6}$$

Thus, the next temperature for cell (i,j) is determined by:

$$T(i,j)_{t+\Delta t} = T(i,j)_t + \left[q_r + q_z + q_{sf}\right] \frac{\Delta t}{C(i,j)} \tag{7}$$

Where,

q_r	=	contribution of radial heat flow to cell (i,j);
q_z	=	contribution of vertical heat flow to cell (i,j);
q_{sf}	=	contribution of steady flux heat flow to cell (i,j);
$T(i,j)$	=	global temperature of to cell (i,j);
$R_r(i,j)$	=	thermal resistance between two cells;
k	=	thermal conductivity of ground;
$C(i,j)$	=	heat capacity of cell (i,j);
Δt	=	time step;
r	=	radial location of the cell from the center of the storage volume;

2.7.3 Local Problem

A one-dimensional radial mesh is used to model the temperature distribution around each tube. This mesh is used to model short-term variations of thermal processes around each duct. The storage volume is divided into vertical subregions, where the quantity of subregions is dependent on the change in temperature along the pipe. It is assumed that the local problem is the same around each pipe in the particular subregion. Thus, there is a single local problem for each corresponding subregion. The transient effect is considered negligible in the calculation of the temperature change along the pipe. The energy balance along the z-axis (depth) of the borehole, from the fluid of temperature T_f, to a local point in the storage region of temperature T_a, is expressed as:

$$mC_p \frac{\partial T}{\partial z} = h(T_f - T_a) \tag{8}$$

Where,

h	=	heat transfer coefficient per unit length between T_f and T_a;
Cp	=	Specific heat of the fluid;
m	=	fluid flow rate;

Equation (7) is then solved using the following expression:

$$T_f = T_a + Ae^{-\frac{hz}{C_P m}} \tag{9}$$

Given the following boundary conditions:

i. At the inlet of the pipe, $z = 0$, $T_f = T_{in}$. Thus, $A = T_{in} - T_a$

ii. At the exit of the pipe, $z = l$, $T_f = T_{out}$.

Thus, the temperature at the outlet is given as:

$$T_{out} = T_a + (T_{in} - T_a)e^{-\frac{hl}{C_P m}} \tag{10}$$

By letting $\beta = e^{-\frac{hl}{C_P m}}$, T_{out} can be rewritten as:

$$T_{out} = \beta T_{in} + (1-\beta)T_a \tag{11}$$

Using the above expression, T_{out} can be determined for each subregion. Furthermore, the numerical model relates T_{in} and T_{out} for a given region *r* as follows:

$$T_{out}^{r} = \beta T_{in}^{r-1} + (1-\beta)T_a^{r} \tag{12}$$

The quantity of heat transferred from the fluid to each subregion is calculated as:

$$Q = mC_p(T_{in} - T_{out}) \tag{13}$$

2.7.4 Steady Flux Problem

The constant heat injection/extraction from the pipe to the ground that forms a temperature field around a pipe is the steady flux solution. The steady flux redistributes heat in the storage as a result of the fluid flow. It is utilized for pulses that vary slowly in time. The steady flux temperature for region k, around the heat exchanger is given as:

$$T_{sf} = (T_g^{k} - T_{g(i,j)}^{k})\frac{r_1^2}{2l^2}h\left(\frac{r}{r_1}\right) \tag{14}$$

Where,

$$h\left(\frac{r}{r_1}\right) = \frac{1}{2}\left(\frac{r^2}{r_1^2}\right) - \ln\left(\frac{r}{r_1}\right) - \frac{3}{4} \tag{15}$$

The superposition of the global, local and steady flux temperatures are then used to calculate the temperatures throughout the storage volume [20,30].

2.8 BTES TRNSYS Model Description

A detailed simulated model was created in TRNSYS to model the performance of the CHP-BTES system (figure 2). To import hourly steam flow data from the CHP plant to the BTES system a data reader component (Type9) was utilized. The output steam flow from this component is connected to the input of the condenser model (Type598), where heat is transferred to the charging loop during the designated charging period (May 1st- Sept. 30th). The proposed steam flow (excess steam) is a result of running the HRSG at 100,000 pph for the entire charging period. The flow in the charging loop is controlled using a proportional controller (Type1669) and a variable speed pump (Type741). The pump is controlled to follow the incoming steam flow to the condenser, accounting for a scaling factor in order to keep the loop temperature below 90^{o}C.

This charging flow is then sent to the BTES system (Type557). During charging hot fluid is circulated through the condenser and injected into the ground via a network of vertical U-tube heat exchangers. When discharging, heat is extracted from the ground and delivered to the load. When discharging (Oct 1st- April 30th), a forcing function (Type14) is employed to change the position of the diverting and mixing valves in order to engage the discharge pump. The variable speed discharge pump (Type741) is then used to extract heat from the BTES by circulating fluid to the load. The load is modeled using a Type682, where a load is simply imposed on the fluid steam to represent the campus. A proportional controller (Type1669) is utilized to control the discharge pump and load, where the load and flow are varied based on the outside air temperature. Thus, as the outside air temperature decreases the imposed load and flow increase. Conversely, as the outside air temperature rises the load and flow decrease. An example of this control strategy is shown in figure 2.11 below.

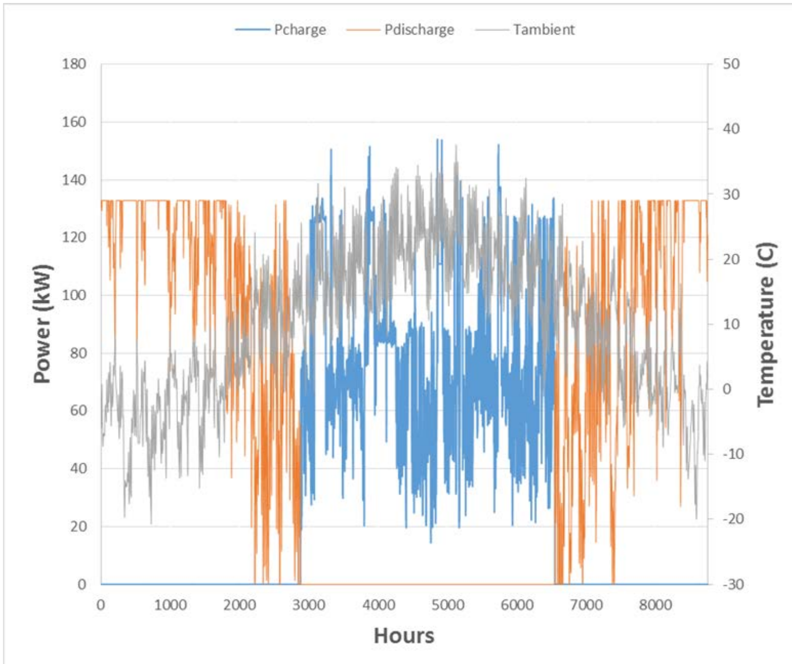


Figure 2.11 Charge and Discharge Pump Power & Ambient Temperature

The BTES TRNSYS model is shown in figure 2.12, where the charging loop is designated by red, the discharging loop is designated by blue and the portion of the system that is shared is shown in teal.

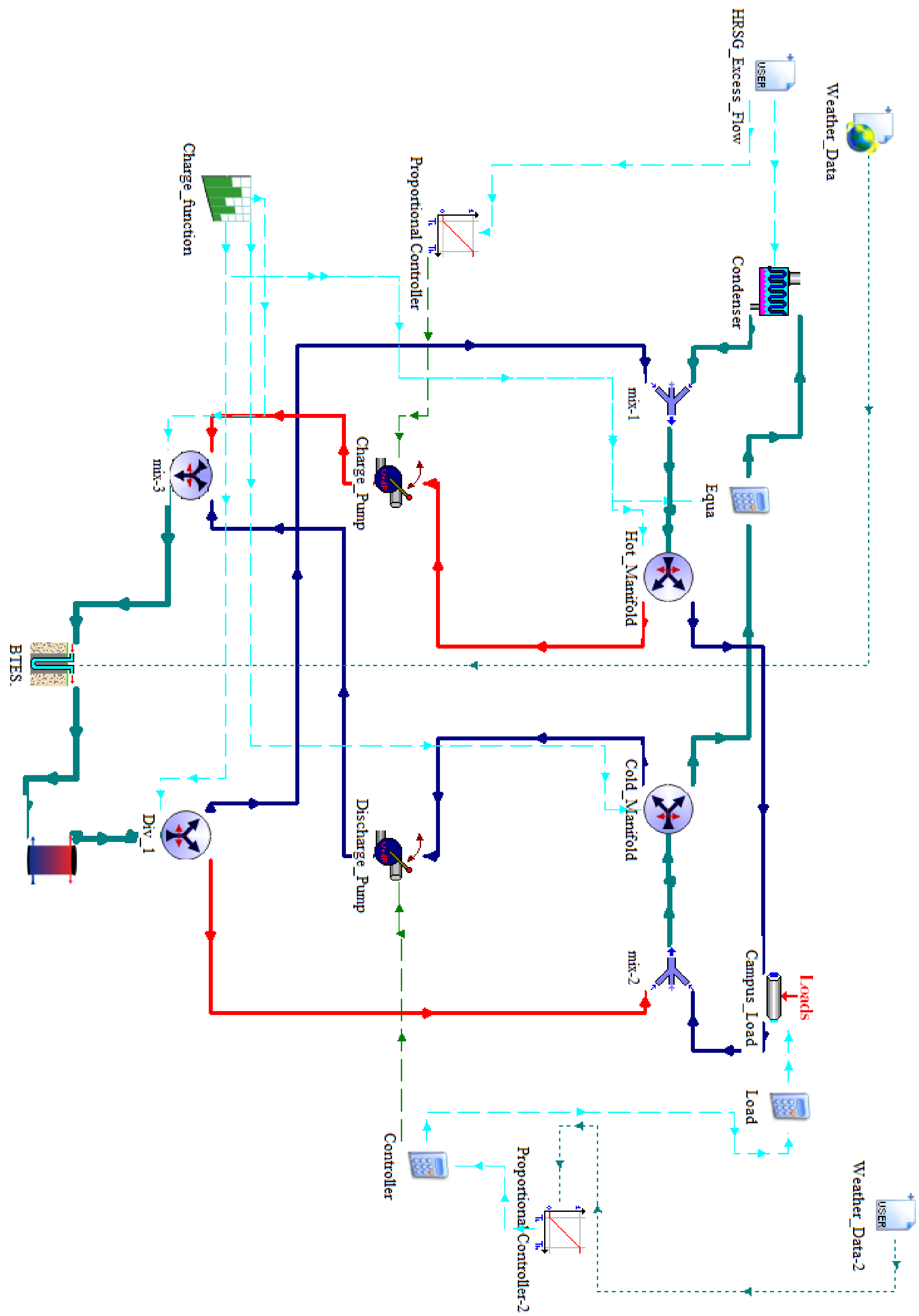


Figure 2.12 BTES TRNSYS Model

CHAPTER 3

PRELIMINARY RESULTS

3.1 TRNSYS Multiple Simulations

A multitude of simulations were performed in order to determine an optimal system configuration. The proposed systems were designed to maintain a charging loop temperature below <90^{o}C, as operational temperatures above this limit can cause damage to the plastic U-tubes [21]. The number of boreholes varied from 11,250 to 12,250, in increments of 250. In order to maintain a loop temperature below the upper bound of 90^{o}C, the rated charging flow for each system size was adjusted. Furthermore, the rated load was tuned for each system size to ensure a balanced system after steady state operation is reached; energy into BTES after losses equals energy to load. Numerous simulations at each increment of system size were performed to obtain a balanced system at the required temperature. Each simulation was run for a five year span at one hour time steps in order to attain steady state performance. Depending on the number of boreholes each five year simulation runs for approximately 10-30 minutes

3.1.1 Selection of TRNSYS Simulation Range

Before deciding on this range of borehole sizing (11,250-12,250), many other system sizes were tested from 6,000 to 20,000 boreholes. It was found that for systems smaller than this range, the charging loop temperature rapidly exceeded 90^{o}C during the charging period. One way to mitigate the rapid temperature rise was to increases the load and charge loop flow rate. However, this resulted in significant depletion of the storage system to the point that the minimum ground temperature was lower than the initial ground temperature before charging. Thus, the ground was unable to heat up over the five year simulations. Additionally, the pumping power required for the smaller systems greatly impacted the overall performance of the system. Thus, it was concluded that the chosen range demonstrated the highest performance with the most benefit to the campus building load. This is because low temperature radiators require a minimum of approximately 40^{o}C to be effective [31]. Conversely, for system sizes larger than this range, it was found that the minimum ground temperature fell below 40^{o}C, as the increased storage volume requires more thermal input to heat up to the necessary levels. Thus, the chosen range of 11,250-12,250 boreholes was selected, as ground temperatures within this range never fell below 40^{o}C.

3.1.2 TRNSYS Simulation Results for Selected Range

Once a general range for the system size was determined, each 250 borehole increment required 5-10 simulations to produce a balanced system. Figure 3.1 is an example of a five year simulation in the TRNSYS plotter. The inlet, outlet and ground temperatures are plotted on the left axis, and the energy to the BTES system and energy to the load are plotted on the right axis.

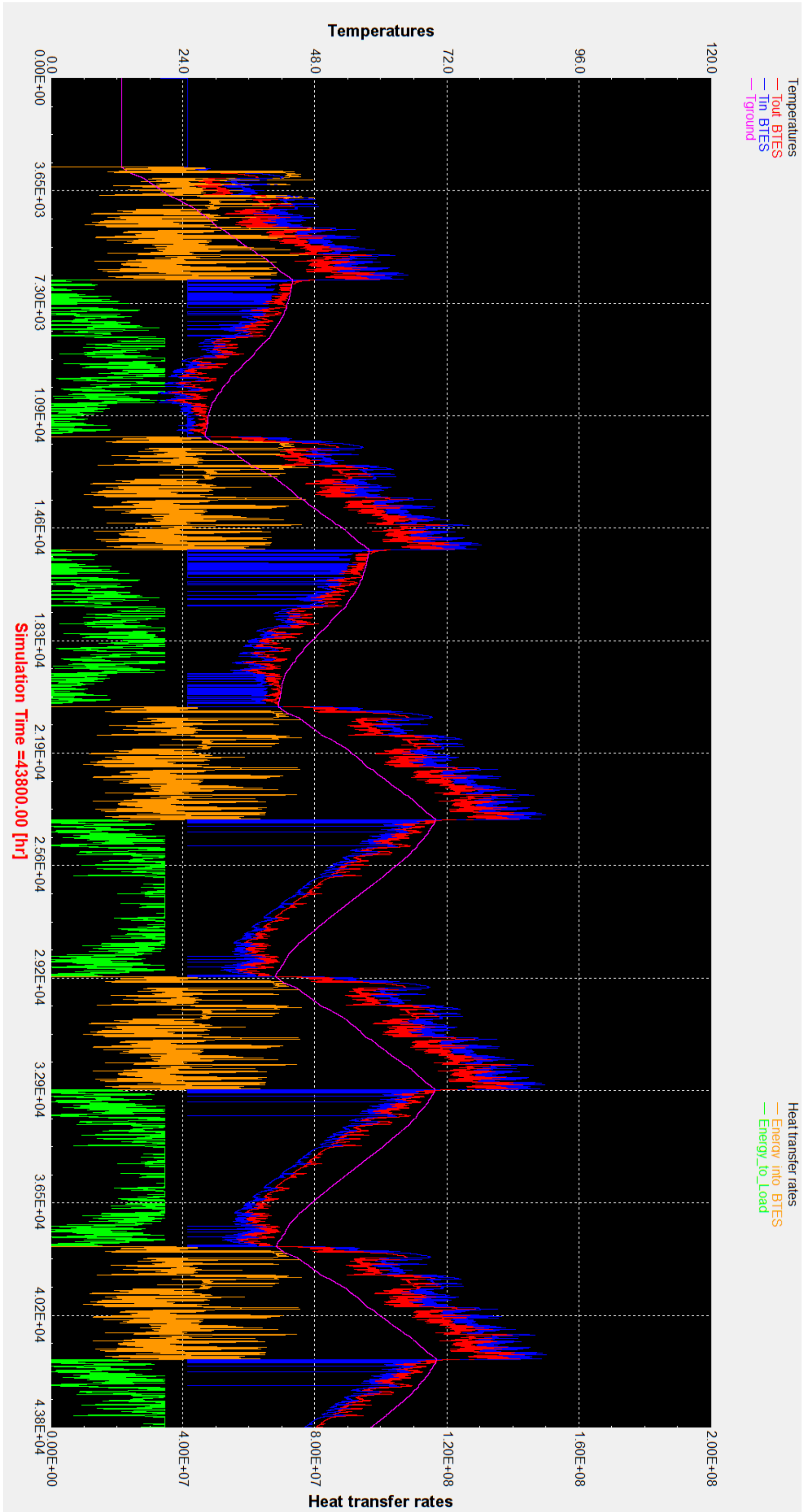


Figure 3.1 TRNSYS Plotter for 5 Year Simulation at 11,750 Boreholes

3.2 Results for TRNSYS Multiple Simulations

The following comparative results are from the 5th year of operation for each of the five system sizes simulated. The following information is shown: the annual ground temperature, energy input into the BTES system, the energy remaining after losses, the charge pump power consumption and the BTES system efficiency. It can be seen that as the number of boreholes increases, the ground temperature decreases. With 11,250 boreholes, the maximum and minimum storage temperatures reached are 72°C and 42°C, respectively. Conversely, with 12,250 boreholes the maximum and minimum storage temperatures reached are 68°C and 40°C, respectively. A higher ground temperature is preferable as it reduces the need for auxiliary heating at the low temperature campus load.

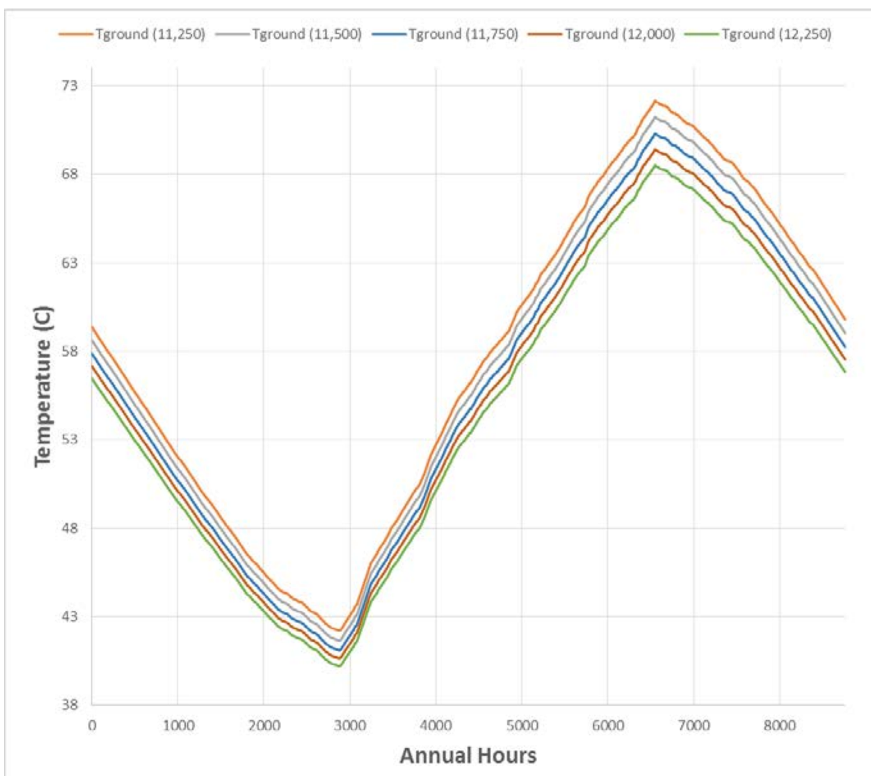


Figure 3.2 Comparisons of Ground Temperatures

Figure 3.3 shows the diminishing returns, in terms of heat input, to the BTES for increments less than 11,750 boreholes. This is due to the significantly higher flow rate needed to maintain a loop temperature below 90^{o}C. From 12,000 to 11,750 boreholes the percent energy into the BTES is reduced by 0.53%. However, from 11,750 to 11,500 boreholes the percent decrease is 0.79% and from 11,500 to 11,250 the percent decrease is 0.94%.

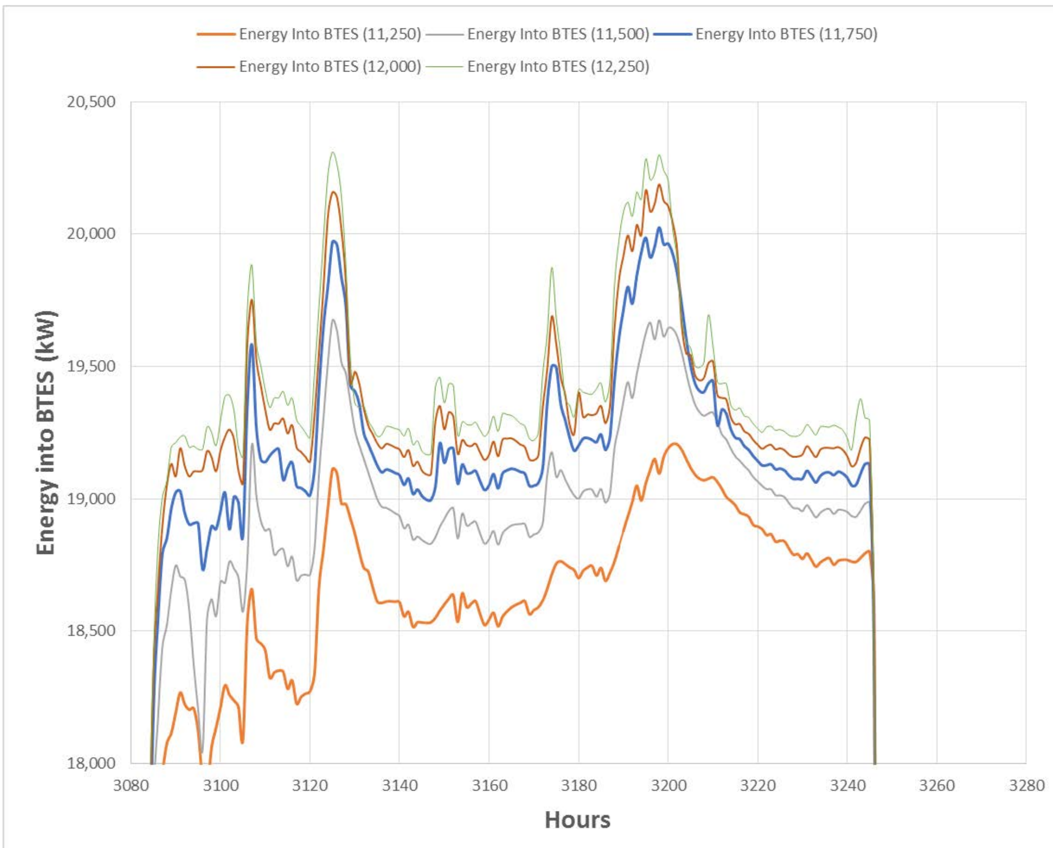


Figure 3.3 Comparison of Energy into the BTES (200 hour period)

Figure 3.4 shows the BTES energy stored after losses. The results again show the trend of diminishing performance for increments less than 11,750 boreholes. From 12,000 to 11,750 boreholes the percent of BTES energy remaining is reduced by 0.58%, from 11,750 to 11,500 boreholes the percent decrease is 0.90% and from 11,500 to 11,250 the percent decrease is 1%.

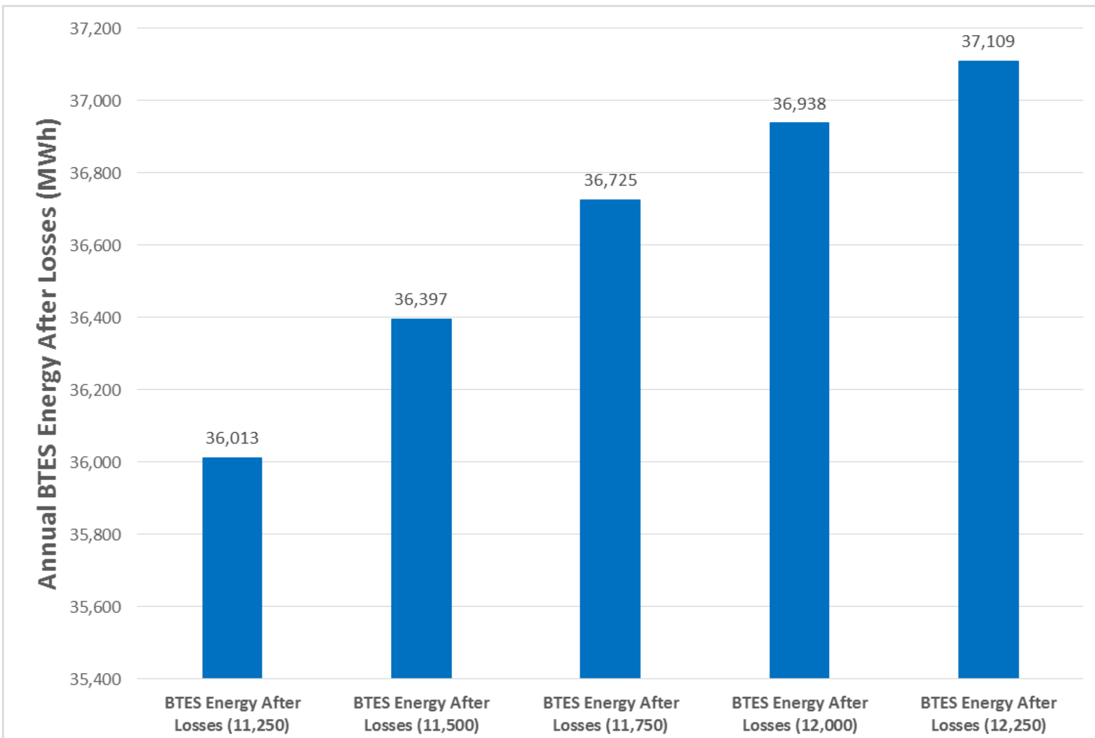


Figure 3.4 Comparison of BTES Energy Remaining After Losses

Figure 3.5 shows the pump power over a 200 hour span during the charging period. A 200 hour time span was chosen as it better illustrates the additional pumping power required as the system size is reduced. Figure 3.6 shows the total pumping power for the 5th year of operation. It can be clearly seen that there is a significant increase in pumping power as the number of boreholes is reduced. From 12,000 to 11,750 boreholes the pumping power increases by 50%, from 11,750 to 11,500 boreholes the pumping power increases by 100% and from 11,500 to 11,250 the percent increases by 83%. The increase in pumping power is due to the need to keep the loop temperature below 90^{o}C.

Figure 3.5 Comparison of Charging Pump Power Consumption (200 hour period)

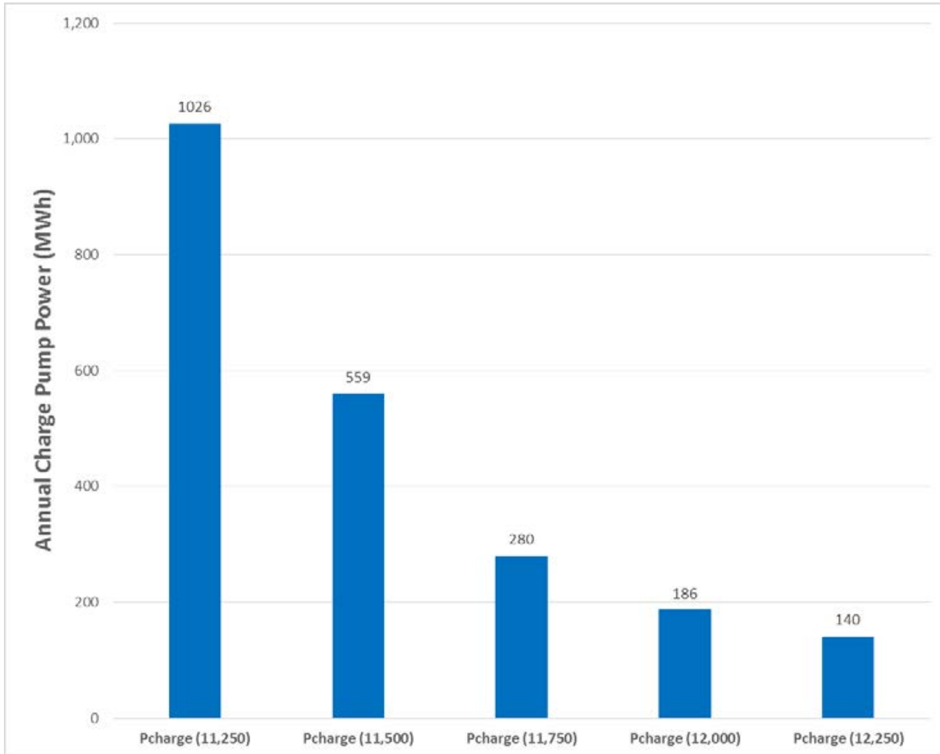
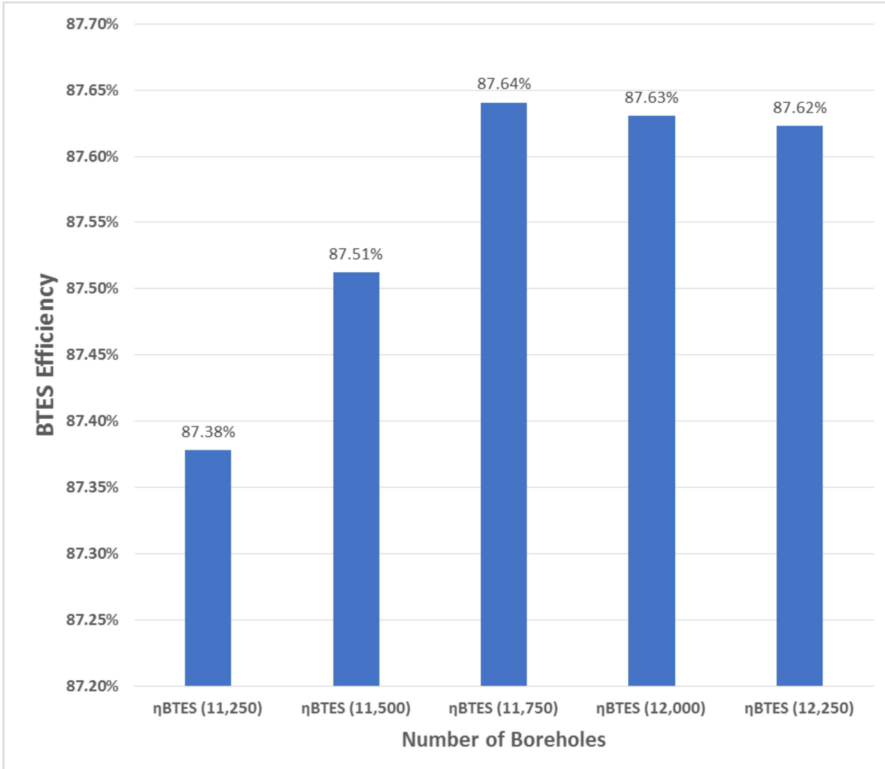


Figure 3.6 Comparison of Charging Pump Power Consumption Totals

Figure 3.7 shows the BTES efficiency for each increment of boreholes. Table 3.1 illustrates the change in efficiency for the BTES system. (Note, the definition for the BTES efficiency is provided in the following chapter.) The results conclude the highest BTES efficiency is reached at 11,750 boreholes, with a 0.01% decrease in efficiency observed for each additional increment. Furthermore, there is a 0.13% decrease in BTES efficiency as the number of boreholes is reduced.



|Figure 3.7 Comparison of BTES Efficiency

The results from this analysis conclude that as the size of the storage system decreases, the pumping power required increases and the energy input decreases, and as a result the system performance drops. In order to maximize the offset to the campus building load and to reduce capital costs, it is important to choose a system with the lowest number of boreholes while maintaining high performance. For these reasons, a system comprised of 11,750 boreholes was chosen as it provides a lower capital cost, without compromising system performance. Although the larger systems use marginally less pumping power and deliver slightly more energy to the load, the additional capital cost incurred for the larger systems doesn't justify the small increase in performance. Moreover, though smaller systems are feasible, the precipitous drop in performance for systems under 11,750 boreholes doesn't substantiate the capital cost savings.

CHAPTER 4

RESULTS AND DISCUSSION

The UMass CHP plant has a SCADA system, which is capable of storing and transmitting instantaneous data about the plant's operation from 675 points in the system. This data includes, steam flows, fuel flows, temperature, pressure, power produced, and other critical data. Hourly data from 2011 was used to observe the current operation of the campus CHP plant in order to help model the proposed operation of the plant with BTES. When the spring semester ends in early May, the thermal load of the campus is reduced and it increases again as the fall semester begins in September. The average hourly steam produced by the HRSG for May through September is approximately 60,000 pph. Thus, there is an opportunity to increase the steam production of the HRSG to 100,000 pph during this period to accommodate the application of a BTES system. By setting the steam flow to 100,000 pph, it was determined that an additional 141,086,294 lbs of steam will be produced. This requires an additional 232,932 MMBtus (68,318 MWh) of natural gas. Using the temperature and pressure at the exit of the HRSG, it was determined that the average enthalpy is 1369 Btu/lb. This corresponds to an overall energetic steam input to the system of 193,139 MMBtus (56,647 MWh). A BTES system comprised of 11,750 boreholes was designed and simulated in TRNSYS, utilizing the proposed operational data of the CHP plant. The results from this assessment are presented in this chapter.

A summary of the current and proposed operation (with TES charging) is given in tables 4.1 & 4.2. Table 4.1 assumes that the thermal energy storage is used solely to offset ULSD. Table 4.2 assumes that the thermal energy stored is used to offset LNG.

Table 4.1 Current & Proposed CHP Plant Operation (ULSD Reduction)

Summary of Results (ULSD Offset)								
	Power Produced (MWh)	Steam Produced (lbs)	Natural Gas Fuel Input		LNG Fuel Input		ULSD Fuel Input	
			MMBtu	MWh	MMBtu	MWh	MMBtu	MWh
Current Operation	89,367	1,026,504,140	1,193,600	350,079	158,197	46,399	328,651	96,392
Proposed Operation	97,880	1,167,590,434	1,426,531	418,398	158,197	46,399	178,404	52,325
Increase (+) Decrease (-)	8,513	141,086,294	232,932	68,318	0	0	-150,247	-44,067

Table 4.2 Current & Proposed CHP Plant Operation (LNG Reduction)

Summary of Results (LNG Offset)								
	Power Produced (MWh)	Steam Produced (lbs)	Natural Gas Fuel Input		LNG Fuel Input		ULSD Fuel Input	
			MMBtu	MWh	MMBtu	MWh	MMBtu	MWh
Current Operation	89,367	1,026,504,140	1,193,600	350,079	158,197	46,399	328,651	96,392
Proposed Operation	97,880	1,167,590,434	1,426,531	418,398	6,525	1,914	328,651	96,392
Increase (+) Decrease (-)	8,513	141,086,294	232,932	68,318	-151,672	-44,485	0	0

4.1 BTES & System Efficiency

The overall BTES efficiency is defined as the energy recovered divided by the energy input and is as follows [8]:

$$\eta_{BTES} = \frac{\text{Energy Recovered}}{\text{Energy Input}} = \frac{\text{Energy to Load}}{\text{Energy into BTES}} \tag{16}$$

Additionally, it is vital to determine the effect that the TES system has on the overall efficiency of the CHP plant. Past research on the UMass CHP plant has concluded that the overall plant efficiency is 73%. Where the overall CHP plant efficiency (η_{CHP}) is defined as follows [27]:

$$\eta_{CHP} = \frac{P_{total} + \Delta Q_s}{Q_{fuel,in}} \tag{17}$$

Where,

$Q_{fuel,in}$	=	Fuel input to the plant in the form of thermal energy
P_{total}	=	Total energy produced by the plant
ΔQ_s	=	Total thermal energy gain of steam delivered to the campus

By using the prior expression, the effect that the TES system has on the efficiency of the CHP plant can be calculated as follows:

$$\eta_{CHP} = \frac{P_{total} + \Delta P + \Delta Q_s}{Q_{fuel,in} + \Delta Q_{fuel,in}} \tag{18}$$

Where,

ΔP	=	Additional power produced by the HPST & LPST
$\Delta Q_{fuel,in}$	=	Additional fuel input for TES charging

It was determined that the addition of a TES system reduces the CHP plant efficiency by 0.7% resulting in an overall plant efficiency of 72.3%.

4.2 BTES System Performance

The TRNSYS simulation was performed for a five year period in one hour time steps. The BTES utilizes 11,750 single U-tube heat exchangers at a depth of 30m for an approximate storage volume of 1,477,000 m^3. The simulation was run for five years in order to observe how the performance changed over time and to allow the system to reach steady state operation. It is expected that 80% of the steady state efficiency values will be obtained after approximately three years of operation [21]. At the fifth year of operation the maximum ground temperature and charging fluid inlet and outlet temperatures were found to remain constant at 70°C, 90°C and 86°C, respectively. See figure 4.1 below.

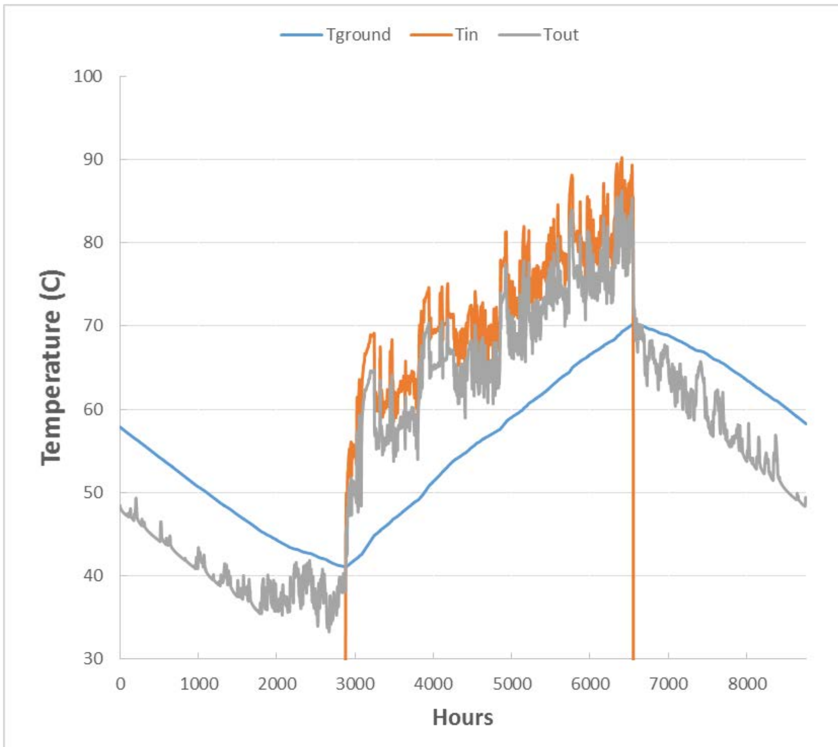


Figure 4.1 Year 5 Ground, Inlet & Outlet Temperatures

The following figures show the performance of the system over a year. Figure 4.2 shows the energy injection during the charging period and energy extraction during the discharging period. Figure 4.3 shows the charge and discharge pump power, as well as the ground and ambient temperatures for the 5th year of operation.

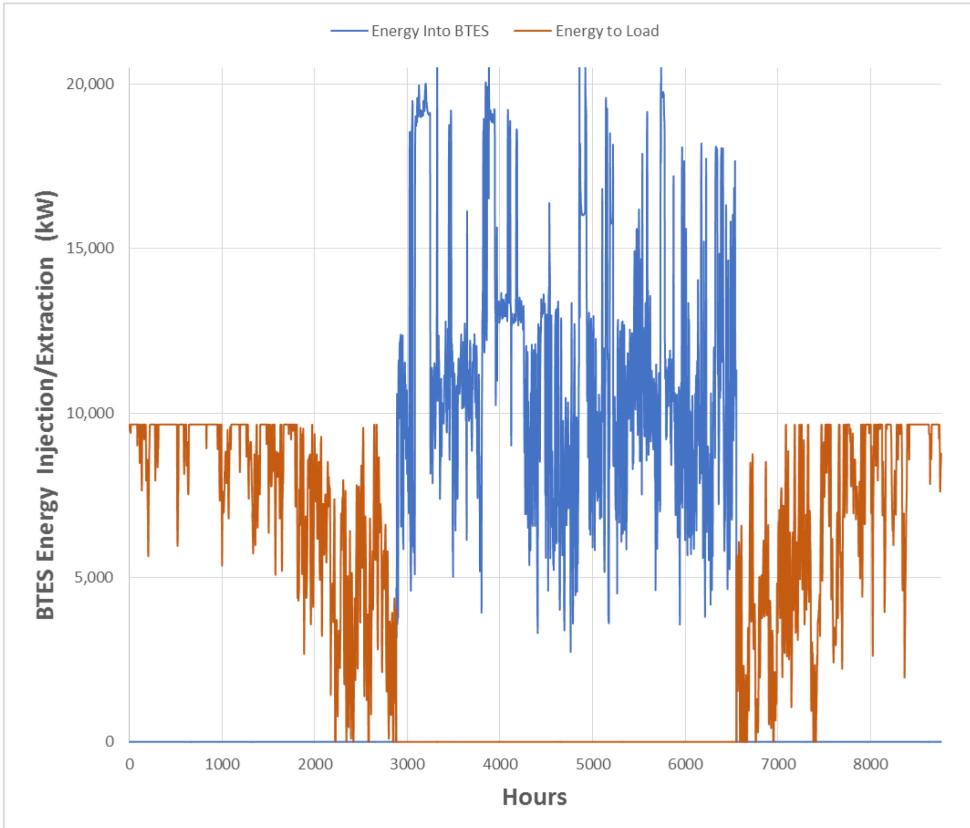


Figure 4.2 Year 5 BTES Energy Injection/Extraction

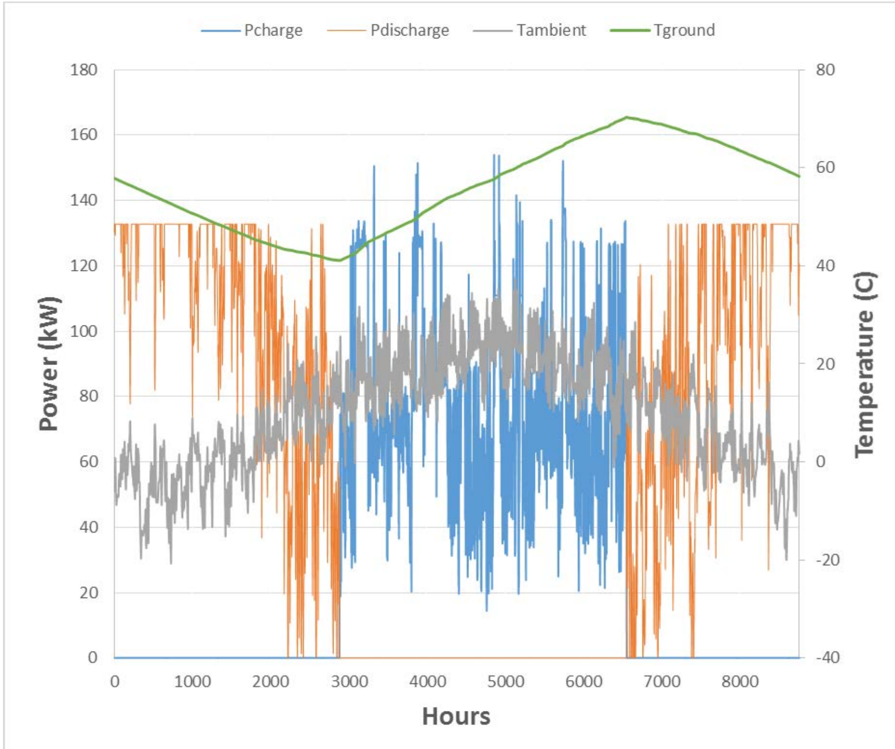


Figure 4.3 Charge and Discharge Pump Power, Ambient and Ground Temperatures

The summary of the system performance as presented in Table 4.3 is separated into four categories: a summary of the BTES system, the distribution system (charge and discharge pumps), the steam turbines and a system energy balance. It is shown that after the third year the system begins to approach its steady state average ground temperature of approximately 56^{o}C and after the fourth year of operation the BTES system efficiency remains constant at 88%. The model predicts that as the temperature of the soil increases, the BTES efficiency increases from 15% to 88%.

Table 4.3 System Performance Summary

	Heat Flow Summary					
	Year of Operation	**1**	**2**	**3**	**4**	**5**
	BTES System					
	Energy into BTES (MWh)	44,034	42,896	41,916	41,937	41,919
	BTES Losses (MWh)	3,784	5,666	6,838	5,688	5,194
	Total	40,250	37,230	35,078	36,248	36,725
	η_{BTES}	15%	44%	64%	88%	88%
	$T_{average}$ (°C)	27	43	55	56	56
	T_{max} (°C)	44	58	70	70	70
	T_{min} (°C)	13	28	41	41	41
	Distribution Pumps					
	P_{Charge} (MWh)	280	280	280	280	280
	$P_{Discharge}$ (MWh)	91	261	371	506	506
	Total	371	540	651	785	785
	Steam Turbine Analysis					
	P_{HPST} (MWh)	2,721	2,721	2,721	2,721	2,721
	P_{LPST} (MWh)	5,792	5,792	5,792	5,792	5,792
	Total	8,513	8,513	8,513	8,513	8,513
	System Energy Balance					
In	**Steam Energy Into System (MWh)**	56,647	56,647	56,647	56,647	56,647
Out	**Steam Turbine Power (MWh)**	-8,513	-8,513	-8,513	-8,513	-8,513
Out	**BTES Losses (MWh)**	-3,784	-5,666	-6,838	-5,688	-5,194
Out	**Energy to Load (MWh)**	-6,608	-18,942	-26,955	-36,738	-36,738
Out	**Condensate Return Energy (MWh)**	-4,220	-5,283	-6,207	-6,184	-6,202
	Energy Balance (MWh)	**33,522**	**18,243**	**8,134**	**-476**	**0**

As the steam flow during the charging period is increased to accommodate the charging of the BTES, additional electricity is produced by the HPST and LPST. These turbines were modeled in TRNSYS using flow following turbine (Type592) and the generators were modeled using a Type599. Where the maximum power produced from the HPST and LPST is limited to 2 MW and 4 MW, respectively. The additional steam flow in the summer months enables these turbines to produce on addition 8,513 MWh combined. This increased generation of onsite power by the CHP plant directly corresponds to a reduction in power purchased from the grid. This offset results in an annual reduction of CO_2, NO_x and SO_2 emissions by 3,900,057 kg, 2,201 kg and 4,826, respectively. Note, more information on emission factors is provided in appendix D.

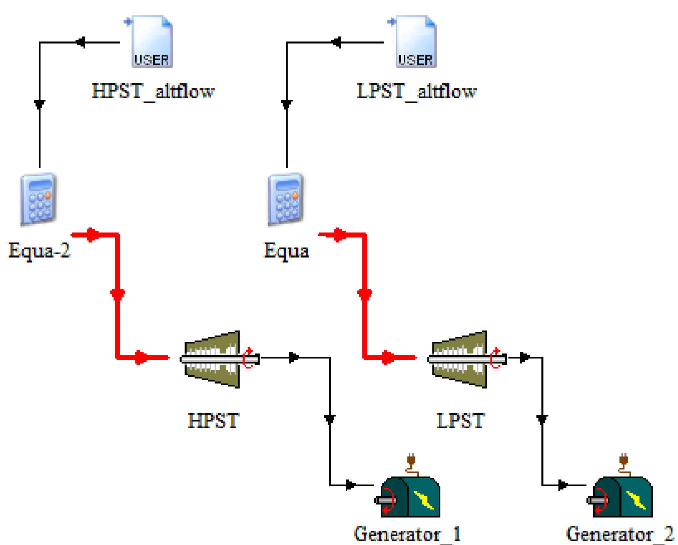


Figure 4.4. HPST & LPST TRNSYS Model

4.3 Economics & Emissions Results (ULSD)

A summary of the system economics and change in emissions for a five year span is presented. The energy to the load represents the energy discharged from the storage system that is used to offset campus heating. The boiler energy offset represents the equivalent boiler fuel input needed to generate the energy to the load. It is expressed as follows:

$$Q_{Boiler,\,Oil} = \frac{Q_{Load}}{\eta_{Boiler,\,Oil}} \tag{20}$$

Where,

$Q_{Boiler,Oil}$	=	Boiler fuel input; MWh
Q_{Load}	=	Energy to load; MWh
$\eta_{Boiler,Oil}$	=	Average boiler efficiency when using oil; 83.4%

ACR_{ULSD}, represents the annual cost reduction of ULSD as a result of the energy offset by the BTES system. Due to the reduced thermal load in the summer months, the campus is typically forced to purchase electricity at $0.15/kWh. However, the application of BTES and the resultant increased thermal load allows the campus to produce more energy during the summer months at a rate of $0.055/kWh. Thus, $ACR_{Elec.}$, represents the annual cost reduction of electricity due to the lower cost of CHP electricity generation. This corresponds to a savings of $0.085 for every kWh generated. The increased production of steam during the charging period by the HRSG increases the amount of natural gas used. ACI_{NG}, represents the annual cost increase due to this increase in natural gas usage. ACS, represents the difference between the annual cost reductions and annual cost increase. Furthermore, the offset of ULSD usage with natural gas allows for a change of emissions produced. APR, represents the annual pollutant reduction (-) or increase (+) as a result of this offset. Emission pollutant factors for natural gas and ULSD are presented in table 4.4 below.

Table 4.4 Emission Factors for Natural Gas & ULSD

Emission Factor for Pollutant	Natural Gas		ULSD	
	lb/MMBtu	kg/MWh	lb/MMBtu	kg/MWh
EF_{CO2}	131.70	203.68	159.23	246.25
EF_{NOx}	0.108	0.167	0.129	0.200
EF_{SO2}	0.00068	0.00105	0.00051	0.00079

The economic cost savings, as presented in table 4.5, show that once the BTES has reached steady state operation (year 4) an annual cost savings of $2,430,343 is achieved, leading to an 8% reduction in total campus utility expenditures. Furthermore, annual CO_2 and SO_2 emissions are reduced by 836,700 kg and 4,790 kg, respectively, while annual NO_x emissions increase by 418 kg.

Table 4.5 Annual ULSD Cost Savings and Emissions Change

Year of Operation	η_{BTES}	Energy to Load (MWh)	Boiler Energy Offset (MWh)	ACR_{ULSD} ($)	$ACR_{Elec.}$ ($)	ACI_{NG} ($)	ACS ($)	APR_{CO2} (kg)	APR_{NOx} (kg)	APR_{SO2} (kg)	% Reduction Of Total Utility Bills
1	15%	6,608	7,926	$705,892	$723,600	$2,217,900	-$788,409	8,063,071	7,629	-4,761	-2.6%
2	44%	18,942	22,720	$2,023,503	$723,600	$2,217,900	$529,203	4,419,907	4,677	-4,773	1.7%
3	64%	26,955	32,332	$2,879,519	$723,600	$2,217,900	$1,385,219	2,053,042	2,760	-4,780	4.6%
4	88%	36,738	44,067	$3,924,643	$723,600	$2,217,900	$2,430,343	-836,700	418	-4,790	8.0%
5	88%	36,738	44,067	$3,924,643	$723,600	$2,217,900	$2,430,343	-836,700	418	-4,790	8.0%

4.4 Economics & Emissions Results (LNG)

A second summary of the system economics over a five year span is presented. This summary examines offsetting LNG in the winter months instead of ULSD. The energy to the load represents the energy discharged from the storage system that is used to offset campus heating. The boiler energy offset represents the equivalent boiler fuel input needed to generate the energy to the load. It is expressed as follows:

$$Q_{Boiler,\,Gas} = \frac{Q_{Load}}{\eta_{Boiler,\,Gas}} \tag{21}$$

Where,

$Q_{Boiler,Gas}$ = Boiler fuel input; MWh
Q_{Load} = Energy to load; MWh
$\eta_{Boiler,Gas}$ = Average boiler efficiency when using gas; 82.6%

ACR_{LNG}, represents the annual cost reduction of LNG as a result of the energy offset by the BTES system.

Table 4.6 Annual LNG Cost Savings

Year of Operation	η_{BTES}	Energy to Load (MWh)	Boiler Energy Offset (MWh)	ACR_{LNG} (\$)	$ACR_{Elec.}$ (\$)	ACI_{NG} (\$)	ACS (\$)	APR_{CO2} (kg)	APR_{NOx} (kg)	APR_{SO2} (kg)	% Reduction Of Total Utility Bills
1	15%	6,608	8,001	\$639,135	\$723,600	\$2,217,900	-\$855,165	8,385,177	7,873	-4,763	-2.8%
2	44%	18,942	22,936	\$1,832,139	\$723,600	\$2,217,900	\$337,839	5,343,254	5,379	-4,779	1.1%
3	64%	26,955	32,639	\$2,607,202	\$723,600	\$2,217,900	\$1,112,901	3,366,999	3,758	-4,789	3.7%
4	88%	36,738	44,485	\$3,553,487	\$723,600	\$2,217,900	\$2,059,187	954,159	1,780	-4,802	6.8%
5	88%	36,738	44,485	\$3,553,487	\$723,600	\$2,217,900	\$2,059,187	954,159	1,780	-4,802	6.8%

The economic cost savings, as presented in table 4.6, show that once the BTES has reached steady state operation (year 4) an annual cost savings of \$2,059,187 is achieved, leading to a 6.8% reduction in total campus utility expenditures. Furthermore, annual CO_2 and NO_x emissions are increased by 954,159 kg and 1,790 kg, respectively, while annual SO_2 emissions decrease by 4,802 kg.

4.5 Discussion and Comparison of Results

Offsetting ULSD instead of LNG leads to an increase in ACS of approximately \$370,000. The increase in annual savings is a result of the lower marginal cost of LNG (\$79.88/MWh) when compared to ULSD (\$89.06/MWh). The drop in ULSD usage, as opposed to LNG usage, leads to a reduction in emissions generated as it creates the opportunity to offset a higher emissions producing fuel (ULSD) with a lower emissions producing fuel (natural gas). Furthermore, the plant utilizes selective catalytic reduction (SCR) to reduce the amount of NO_x in exhaust gases. Thus, the overall rise of NO_x for both cases leads to increased costs, as the quantity of reagent needed (typically ammonia or urea) is increased. In summary, it is concluded that solely offsetting ULSD is economically and environmentally more beneficial than offsetting LNG.

4.6 System Cost, Simple Payback & Net Present Value (NPV)

The prior assessments have proven that the application of BTES is both thermodynamically and economically feasible. However, it is also important to look at the cost, simple payback and NPV of this system in order to better gauge its financial viability to the campus. The simple payback and NPV are only given for the ULSD case, as the economic and environmental benefits of offsetting ULSD were greater than that of LNG. Based on a prior detailed cost assessment conducted at UMass on the installation of a seasonal BTES system, industry quotes and the scale of this system, it is estimated that the system will cost approximately \$18.5/m^3 [32]. The distribution of system costs is separated into three parts: the BTES system, the distribution system and the mechanical system. A summary of system costs and paybacks is shown in table 4.7.

Table 4.7 ACS, Estimated System Cost and Simple Payback

Fuel to Be Offset	ACS (\$)	BTES System Cost (\$)	Distribution System Cost (\$)	Mechanical System Cost (\$)	Total System Cost (\$)	Simple Payback
ULSD	\$2,430,343	\$9,576,250	\$9,418,633	\$8,338,888	\$27,333,771	11

The simple payback for offsetting ULSD was found to be approximately 11 years. It is important to also consider the NPV of the investment as the simple payback does not account for inflation. Thus, the present value of a future annual cost savings (cash flow) is neglected. This makes it difficult to compare the viability of this project to that of other cash flow producing projects. The NPV was calculated utilizing the initial investment cost of $27,333,711. The discount rate used is 3.1% and is based on the DOE nominal rate [33]. The time horizon considered is 50 years, as the life expectancy of the U-tube heat exchangers is approximately 50 years [21]. Additionally, the NPV at time horizons of 20, 30, & 40 years is also included. The NPV is defined as follows:

$$NPV = -C_0 + \sum_{t=1}^{t} \frac{C_n}{(1+r)^t} \tag{22}$$

Where,

C_0	=	Initial investment
C_n	=	Cash flow at the n^{th} year
r	=	Discount rate
t	=	time

Using the above expression, the NPV was computed. Table 4.8 shows the NPV at the differing time horizons.

Table 4.8 NPV

NPV			
50 Year	**40 Year**	**30 Year**	**20 Year**
$28,164,032	$22,081,748	$13,827,960	$2,627,394

It was found that the NPV was greater than zero after the 19^{th} year of operation. This is well within the life expectancy of the system. Furthermore, using the 50 year time horizon the NPV was found to be $28,164,032. This entails that it has a greater value of investment when compared to other investment opportunities at the discount rate of 3.1%.

CHAPTER 5

CONCLUSIONS

5.1 Summary

The scope of this research was to assess the benefits of a seasonal BTES system for a CHP plant. Benefits were realized by mitigating the high cost of fuel in the winter months by charging the TES system when fossil fuel costs are low. Using data from the campus CHP plant and district heating system, a BTES system model was designed using TRNSYS. This simulation was performed over a five year period in order to observe the system performance at steady state operation. The simulation showed that the BTES system could achieve an efficiency of 88% with an offset to campus heating energy of approximately 36,700 MWh. Furthermore, an additional 8,513 MWh of electricity could be produced due to the increased thermal load in the summer months. A summary of two cases was presented, where offsetting ULSD was compared to offsetting LNG. It was determined that offsetting ULSD is preferable as it allows for higher cost savings and emissions reductions. The results for offsetting ULSD indicate that the proposed BTES system achieved an annual cost savings of $2,430,343 for an 8% reduction in total campus utilities. In additional to the economic benefits, a reduction of 836,700 kg of CO_2 and 4,790 kg of SO_2 was also realized through this application of TES. Conversely, offsetting LNG with the thermal energy stored enabled an annual cost savings of $2,059,187 for a 6.8% reduction in total campus utilities. In all, the application of TES to CHP proves to be economically and environmentally promising as it enables greater flexibility in CHP operation. This added flexibility allows for strategic operation of the plant, where additional thermal energy can be produced at economically advantageous times in order to hedge against seasonal variations in fossil fuel rates.

5.2 Recommendations for Future Work

To further improve the performance and flexibility of a TES-CHP system, the use of latent storage systems should be assessed. Medrano stated that “regarding efficiency, an essential requirement for thermal storage is to minimize the difference between the working fluid and the storage medium” [34]. This could be facilitated through the application of a isothermal storage system, where a promising solution would be the use of latent heat storage media.

Ibanez has adapted a TRNSYS tank storage component (TYPE 60), to incorporate phase change materials. The merits of this type of system would allow for tank storage volumes to be drastically decreased through the use of PCM. This new component is called TYPE 60PCM and its accuracy was verified through experimentation [35]. The attributes attained through the coupling of CHP with latent storage warrant further investigation, as performance can be increased and storage volume can be drastically reduced. The reduction in storage size is particularly important for CHP systems that have limited space for storage systems.

APPENDIX A

TRNSYS INPUT FILE

```
VERSION 17
*******************************************************************************
*** TRNSYS input file (deck) generated by TrnsysStudio
*** on Monday, April 27, 2015 at 17:52
*** from TrnsysStudio project: C:\Trnsys17\MyProjects\BTES\Opt_1\BTES_HRSG1.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=43800
STEP=DELT
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
EQUATIONS 2
DELT = 1
nPlots = (STOP-START)/43800
```

```
* Model "Charge_function" (Type 14)
*

UNIT 14 TYPE 14     Charge_function
*$UNIT_NAME Charge_function
*$MODEL .\Utility\Forcing Functions\General\Type14h.tmf
*$POSITION 215 596
*$LAYER Controls #
PARAMETERS 12
0            ! 1 Initial value of time
0            ! 2 Initial value of function
2880         ! 3 Time at point
0            ! 4 Value at point
2880         ! 5 Time at point
1            ! 6 Value at point
6551         ! 7 Time at point
1            ! 8 Value at point
6551         ! 9 Time at point
0            ! 10 Value at point
8760         ! 11 Time at point
0            ! 12 Value at point
*------------------------------------------------------------------------------

* Model "HRSG_Excess_Flow" (Type 9)
*

UNIT 6 TYPE 9      HRSG_Excess_Flow
*$UNIT_NAME HRSG_Excess_Flow
*$MODEL .\Utility\Data Readers\Generic Data Files\Expert Mode\Free Format\Type9e.tmf
*$POSITION 117 159
*$LAYER Weather - Data Files #
PARAMETERS 10
6            ! 1 Mode
0            ! 2 Header Lines to Skip
1            ! 3 No. of values to read
1.0          ! 4 Time interval of data
1            ! 5 Interpolate or not
1.0          ! 6 Multiplication factor
0            ! 7 Addition factor
1            ! 8 Average or instantaneous value
45           ! 9 Logical unit for input file
-1           ! 10 Free format mode
*** External files
ASSIGN "C:\Users\Benjamin\Desktop\Steamflows Analysis\HRSG\csv\100lbtokg.csv" 45
*|? Input file name |1000
*------------------------------------------------------------------------------
```

```
* Model "Weather_Data" (Type 15)
*

UNIT 3 TYPE 15     Weather_Data
*$UNIT_NAME Weather_Data
*$MODEL .\Weather Data Reading and Processing\Standard Format\TMY2\Type15-2.tmf
*$POSITION 161 84
*$LAYER Weather - Data Files #
PARAMETERS 9
2            ! 1 File Type
30           ! 2 Logical unit
3            ! 3 Tilted Surface Radiation Mode
0.2          ! 4 Ground reflectance - no snow
0.7          ! 5 Ground reflectance - snow cover
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-TMY2\US-CT-Hartford-14740.tm2" 30
*|? Which file contains the TMY-2 weather data? |1000
*------------------------------------------------------------------------------

* Model "Weather_Data-2" (Type 9)
*

UNIT 32 TYPE 9     Weather_Data-2
*$UNIT_NAME Weather_Data-2
*$MODEL .\Utility\Data Readers\Generic Data Files\Expert Mode\Free Format\Type9e.tmf
*$POSITION 1025 63
*$LAYER Main #
PARAMETERS 10
6            ! 1 Mode
0            ! 2 Header Lines to Skip
1            ! 3 No. of values to read
1.0          ! 4 Time interval of data
1            ! 5 Interpolate or not
1.0          ! 6 Multiplication factor
0            ! 7 Addition factor
1            ! 8 Average or instantaneous value
49           ! 9 Logical unit for input file
-1           ! 10 Free format mode
*** External files
ASSIGN "F:\Results\Load Controller Included\T_ambient5yearlimitedload.csv" 49
*|? Input file name |1000
*------------------------------------------------------------------------------
```

```
* Model "Cold_Manifold" (Type 11)
*

UNIT 22 TYPE 11     Cold_Manifold
*$UNIT_NAME Cold_Manifold
*$MODEL .\Hydronics\Flow Diverter\Other Fluids\Type11f.tmf
*$POSITION 702 244
*$LAYER Water Loop #
PARAMETERS 1
2            ! 1 Controlled flow diverter mode
INPUTS 3
23,1         ! mix-2:Outlet Temperature ->Inlet temperature
23,2         ! mix-2:Outlet Flowrate ->Inlet flow rate
14,1         ! Charge_function:Average value of function ->Control signal
*** INITIAL INPUT VALUES
100 100.0 0.5
*------------------------------------------------------------------------------

* EQUATIONS "Equa"
*
EQUATIONS 2
Tsim_CM = 25.*(1-[14,1]) + [22,3]*[14,1]
mSim_CM = [22,4]
*$UNIT_NAME Equa
*$LAYER Main
*$POSITION 455 180

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


* Model "Hot_Manifold" (Type 11)
*

UNIT 13 TYPE 11     Hot_Manifold
*$UNIT_NAME Hot_Manifold
*$MODEL .\Hydronics\Flow Diverter\Other Fluids\Type11f.tmf
*$POSITION 517 244
*$LAYER Main #
PARAMETERS 1
2            ! 1 Controlled flow diverter mode
INPUTS 3
15,1         ! mix-1:Outlet Temperature ->Inlet temperature
15,2         ! mix-1:Outlet Flowrate ->Inlet flow rate
14,1         ! Charge_function:Average value of function ->Control signal
*** INITIAL INPUT VALUES
100 100.0 0.5
*------------------------------------------------------------------------------
```

```
* Model "Div_1" (Type 11)
*

UNIT 18 TYPE 11    Div_1
*$UNIT_NAME Div_1
*$MODEL .\Hydronics\Flow Diverter\Other Fluids\Type11f.tmf
*$POSITION 720 628
*$LAYER Main #
PARAMETERS 1
2            ! 1 Controlled flow diverter mode
INPUTS 3
27,1         ! Type534-NoHX:Temperature at Outlet ->Inlet temperature
27,2         ! Type534-NoHX:Flowrate at Outlet ->Inlet flow rate
14,1         ! Charge_function:Average value of function ->Control signal
*** INITIAL INPUT VALUES
20.0 100.0 0.5
*------------------------------------------------------------------------------

* Model "mix-3" (Type 11)
*

UNIT 20 TYPE 11    mix-3
*$UNIT_NAME mix-3
*$MODEL .\Hydronics\Flow Mixer\Other Fluids\Type11d.tmf
*$POSITION 433 624
*$LAYER Water Loop #
PARAMETERS 1
3            ! 1 Controlled flow mixer mode
INPUTS 5
19,1         ! Discharge_Pump:Outlet Fluid Temperature ->Temperature at inlet 1
19,2         ! Discharge_Pump:Outlet Fluid Flowrate ->Flow rate at inlet 1
17,1         ! Charge_Pump:Outlet Fluid Temperature ->Temperature at inlet 2
17,2         ! Charge_Pump:Outlet Fluid Flowrate ->Flow rate at inlet 2
14,1         ! Charge_function:Average value of function ->Control signal
*** INITIAL INPUT VALUES
20.0 100.0 20.0 99.999998 0.5
*------------------------------------------------------------------------------
```

```
* Model "Condenser" (Type 598)
*

UNIT 21 TYPE 598   Condenser
*$UNIT_NAME Condenser
*$MODEL .\Cogeneration (CHP) Library (TESS)\Steam System Components\Condenser\Floating
 Condensing Pressure\Type598.tmf
*$POSITION 287 159
*$LAYER Main #
*$# Condenser for Steam Applications
PARAMETERS 6
15.0         ! 1 Pinchpoint Temperature Difference
4.190        ! 2 Cooling Fluid Specific Heat
4.190        ! 3 Specific Heat of Steam Condensate
6.894745           ! 4 Minimum Condensing Pressure
15           ! 5 Degrees of Subcooling
1            ! 6 Configuration
INPUTS 6
Tsim_CM            ! Equa:Tsim_CM ->Cooling Fluid Inlet Temperature
mSim_CM            ! Equa:mSim_CM ->Cooling Fluid Inlet Flowrate
0,0          ! [unconnected] Steam Inlet Temperature
6,1          ! HRSG_Excess_Flow:Output 1 ->Steam Inlet Flowrate
0,0          ! [unconnected] Steam Inlet Pressure
0,0          ! [unconnected] Steam Inlet Enthalpy
*** INITIAL INPUT VALUES
25.0 100000.002559 126.666691 1000.000012 6.894745 2726.069644
*------------------------------------------------------------------------------

* Model "Proportional Controller" (Type 1669)
*

UNIT 7 TYPE 1669   Proportional Controller
*$UNIT_NAME Proportional Controller
*$MODEL .\Controllers Library (TESS)\Proportional Controller\Type1669.tmf
*$POSITION 242 415
*$LAYER Controls #
PARAMETERS 3
1            ! 1 Number of Signals
1            ! 2 Maximum Rate of Increase
1            ! 3 Maximum Rate of Decrease
INPUTS 3
0,0          ! [unconnected] Upper Setpoint Value
0,0          ! [unconnected] Lower Setpoint Value
6,1          ! HRSG_Excess_Flow:Output 1 ->Input Value
*** INITIAL INPUT VALUES
39713 0 25.0
*------------------------------------------------------------------------------
```

```
* Model "Type46" (Type 46)
*

UNIT 29 TYPE 46     Type46
*$UNIT_NAME Type46
*$MODEL .\Output\Printegrator\Unformatted\Type46.tmf
*$POSITION 1008 823
*$LAYER Outputs #
*$# PRINTEGRATOR
PARAMETERS 5
48          ! 1 Logical unit
-1          ! 2 Logical unit for monthly summaries
0           ! 3 Relative or absolute start time
STEP        ! 4 Printing & integrating interval
0           ! 5 Number of inputs to avoid integration
INPUTS 18
8,8         ! BTES.:Internal Energy Variation ->Input to be integrated & printed-1
21,7        ! Condenser:Heat Transfer Rate ->Input to be integrated & printed-2
8,4         ! BTES.:Average Heat Transfer Rate ->Input to be integrated & printed-3
8,5         ! BTES.:Heat Loss Through Top of Storage ->Input to be integrated & printed-4
8,6         ! BTES.:Heat Loss Through Side of Storage ->Input to be integrated & printed-5
8,7         ! BTES.:Heat Loss Through Bottom of Storage ->Input to be integrated & printed-6
21,6        ! Condenser:Condensate Enthalpy ->Input to be integrated & printed-7
10,3        ! Campus_Load:Heating Load Met ->Input to be integrated & printed-8
21,4        ! Condenser:Condensate Flowrate ->Input to be integrated & printed-9
8,3         ! BTES.:Average Storage Temperature ->Input to be integrated & printed-10
21,1        ! Condenser:Cooling Fluid Outlet Temperature ->Input to be integrated & printed-11
8,1         ! BTES.:Outlet Temperature ->Input to be integrated & printed-12
17,3        ! Charge_Pump:Power Consumption ->Input to be integrated & printed-13
19,3        ! Discharge_Pump:Power Consumption ->Input to be integrated & printed-14
21,3        ! Condenser:Condensate Outlet Temperature ->Input to be integrated & printed-15
8,2         ! BTES.:Outlet Flowrate (Total) ->Input to be integrated & printed-16
21,2        ! Condenser:Cooling Fluid Flowrate ->Input to be integrated & printed-17
3,1         ! Weather_Data:Dry bulb temperature ->Input to be integrated & printed-18
*** INITIAL INPUT VALUES
InternalEVariation_kJ/hr Q_hx_kJ/hr Qavg_borehole_kJ/hr Qloss_top_kJ/hr
Qloss_side_kJ/hr Qloss_bottom_kJ/hr CondensateEnthalpy_kJ/kg Qload_kJ/hr
M_condensate T_ground Tin Tout_btes Pump_charge Pump_discharge Tout_condensate
M_BTES M_coolingfluid Tamb
LABELS 0

*** External files
ASSIGN "heattrans.xls" 48
*|? Output file for integrated results? |1000
*------------------------------------------------------------------------------
```

```
* Model "BTES." (Type 557)
*

UNIT 8 TYPE 557    BTES.
*$UNIT_NAME BTES.
*$MODEL .\GHP Library (TESS)\Ground Heat Exchangers\Vertical\U-Tube\Standard\Type557a.tmf
*$POSITION 585 735
*$LAYER Main #
PARAMETERS 44
1477313.12183673        ! 1 Storage Volume
30          ! 2 Borehole Depth
1           ! 3 Header Depth
11750       ! 4 Number of Boreholes
0.075       ! 5 Borehole Radius
3           ! 6 Number of Boreholes in Series
3           ! 7 Number of Radial Regions
5           ! 8 Number of Vertical Regions
4.5         ! 9 Storage Thermal Conductivity
3300        ! 10 Storage Heat Capacity
-1          ! 11 Negative of U-Tubes/Bore
0.0142875         ! 12 Outer Radius of U-Tube Pipe
0.0109601         ! 13 Inner Radius of U-Tube Pipe
0.0407125         ! 14 Center-to-Center Half Distance
4.5         ! 15 Fill Thermal Conductivity
1.512       ! 16 Pipe Thermal Conductivity
5.04        ! 17 Gap Thermal Conductivity
0           ! 18 Gap Thickness
1000        ! 19 Reference Borehole Flowrate
30          ! 20 Reference Temperature
0           ! 21 Pipe-to-Pipe Heat Transfer
4.19        ! 22 Fluid Specific Heat
1000        ! 23 Fluid Density
2           ! 24 Insulation Indicator
0.2         ! 25 Insulation Height Fraction
0.4         ! 26 Insulation Thickness
0.18        ! 27 Insulation Thermal Conductivity
7           ! 28 Number of Simulation Years
150         ! 29 Maximum Storage Temperature
13          ! 30 Initial Surface Temperature of Storage Volume
0           ! 31 Initial Thermal Gradient of Storage Volume
0           ! 32 Number of Preheating Years
75          ! 33 Maximum Preheat Temperature
55          ! 34 Minimum Preheat Temperature
90          ! 35 Preheat Phase Delay
14          ! 36 Average Air Temperature - Preheat Years
17          ! 37 Amplitude of Air Temperature - Preheat Years
240         ! 38 Air Temperature Phase Delay - Preheat Years
1           ! 39 Number of Ground Layers
4.5         ! 40 Thermal Conductivity of Layer
3300        ! 41 Heat Capacity of Layer
30          ! 42 Thickness of Layer
0           ! 43 Not Used (Printing 1)
0           ! 44 Not Used (Printing 2)
```

```
INPUTS 5
20,1         ! mix-3:Outlet temperature ->Inlet Fluid Temperature
20,2         ! mix-3:Outlet flow rate ->Inlet Flowrate (Total)
3,1          ! Weather_Data:Dry bulb temperature ->Temperature on Top of Storage
3,1          ! Weather_Data:Dry bulb temperature ->Air Temperature
0,0          ! [unconnected] Circulation Switch
*** INITIAL INPUT VALUES
100 9999.999902 20 20 1
*------------------------------------------------------------------------------

* Model "Pump_Power" (Type 65)
*

UNIT 33 TYPE 65     Pump_Power
*$UNIT_NAME Pump_Power
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 1016 234
*$LAYER Outputs #
PARAMETERS 12
4            ! 1 Nb. of left-axis variables
4            ! 2 Nb. of right-axis variables
0.0          ! 3 Left axis minimum
160          ! 4 Left axis maximum
0.0          ! 5 Right axis minimum
1000000            ! 6 Right axis maximum
nPlots             ! 7 Number of plots per simulation
7            ! 8 X-axis gridpoints
-1           ! 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 8
17,1         ! Charge_Pump:Outlet Fluid Temperature ->Left axis variable-1
19,1         ! Discharge_Pump:Outlet Fluid Temperature ->Left axis variable-2
32,1         ! Weather_Data-2:Output 1 ->Left axis variable-3
3,1          ! Weather_Data:Dry bulb temperature ->Left axis variable-4
17,3         ! Charge_Pump:Power Consumption ->Right axis variable-1
17,2         ! Charge_Pump:Outlet Fluid Flowrate ->Right axis variable-2
19,3         ! Discharge_Pump:Power Consumption ->Right axis variable-3
19,2         ! Discharge_Pump:Outlet Fluid Flowrate ->Right axis variable-4
*** INITIAL INPUT VALUES
T_chargepump T_dischargepump T_ambientK T_ambientC P_chargepump mChargepump
P_dischargepump mDishchargepump
LABELS  3
"Temperatures"
"Power"
"Pumping Power"
*------------------------------------------------------------------------------
```

```
* Model "Proportional Controller-2" (Type 1669)
*

UNIT 31 TYPE 1669  Proportional Controller-2
*$UNIT_NAME Proportional Controller-2
*$MODEL .\Controllers Library (TESS)\Proportional Controller\Type1669.tmf
*$POSITION 1036 330
*$LAYER Controls #
PARAMETERS 3
1            ! 1 Number of Signals
1            ! 2 Maximum Rate of Increase
1            ! 3 Maximum Rate of Decrease
INPUTS 3
0,0          ! [unconnected] Upper Setpoint Value
0,0          ! [unconnected] Lower Setpoint Value
32,1         ! Weather_Data-2:Output 1 ->Input Value
*** INITIAL INPUT VALUES
293.15 273.15 25.0
*------------------------------------------------------------------------------

* Model "Discharge_Pump" (Type 741)
*

UNIT 19 TYPE 741   Discharge_Pump
*$UNIT_NAME Discharge_Pump
*$MODEL .\Hydronics Library (TESS)\Pumps\Sets the Mass Flow Rate\Variable-Speed\Power from Efficiency
and Pressure Drop\Type741.tmf
*$POSITION 739 458
*$LAYER Main #
*$# Variable-Speed Pump - Efficiency and Pressure Drop Known
PARAMETERS 4
4000000            ! 1 Rated Flowrate
4.19         ! 2 Fluid Specific Heat
1000         ! 3 Fluid Density
0            ! 4 Motor Heat Loss Fraction
INPUTS 6
22,1         ! Cold_Manifold:Temperature at outlet 1 ->Inlet Fluid Temperature
22,2         ! Cold_Manifold:Flow rate at outlet 1 ->Inlet Fluid Flowrate
y_heating          ! Controller:y_heating ->Control Signal
0,0          ! [unconnected] Overall Pump Efficiency
0,0          ! [unconnected] Motor Efficiency
0,0          ! [unconnected] Pressure Drop
*** INITIAL INPUT VALUES
20 0 1.0 0.75 0.9 89.631691
*------------------------------------------------------------------------------
```

```
* Model "System" (Type 65)
*

UNIT 24 TYPE 65     System
*$UNIT_NAME System
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 604 52
*$LAYER Weather - Data Files #
PARAMETERS 12
10            ! 1 Nb. of left-axis variables
10            ! 2 Nb. of right-axis variables
0.0           ! 3 Left axis minimum
160           ! 4 Left axis maximum
0.0           ! 5 Right axis minimum
500000              ! 6 Right axis maximum
nPlots              ! 7 Number of plots per simulation
7             ! 8 X-axis gridpoints
-1            ! 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 20
21,1          ! Condenser:Cooling Fluid Outlet Temperature ->Left axis variable-1
15,1          ! mix-1:Outlet Temperature ->Left axis variable-2
13,1          ! Hot_Manifold:Temperature at outlet 1 ->Left axis variable-3
13,3          ! Hot_Manifold:Temperature at outlet 2 ->Left axis variable-4
10,1          ! Campus_Load:Outlet Temperature ->Left axis variable-5
23,1          ! mix-2:Outlet Temperature ->Left axis variable-6
22,1          ! Cold_Manifold:Temperature at outlet 1 ->Left axis variable-7
22,3          ! Cold_Manifold:Temperature at outlet 2 ->Left axis variable-8
19,1          ! Discharge_Pump:Outlet Fluid Temperature ->Left axis variable-9
20,1          ! mix-3:Outlet temperature ->Left axis variable-10
21,2          ! Condenser:Cooling Fluid Flowrate ->Right axis variable-1
15,2          ! mix-1:Outlet Flowrate ->Right axis variable-2
13,2          ! Hot_Manifold:Flow rate at outlet 1 ->Right axis variable-3
13,4          ! Hot_Manifold:Flow rate at outlet 2 ->Right axis variable-4
10,2          ! Campus_Load:Outlet Flowrate ->Right axis variable-5
23,2          ! mix-2:Outlet Flowrate ->Right axis variable-6
22,2          ! Cold_Manifold:Flow rate at outlet 1 ->Right axis variable-7
22,4          ! Cold_Manifold:Flow rate at outlet 2 ->Right axis variable-8
0,0           ! [unconnected] Right axis variable-9
20,2          ! mix-3:Outlet flow rate ->Right axis variable-10
*** INITIAL INPUT VALUES
T_CoolingFluid T_mix1 T_HM2load T_HM2cPmp T_loadRet T_mix2 T_CM2dcPmp
T_CM2HX T_discharPmp T_mix3 m_CoolingFluid mMix1 mHM2load mHM2cPmp
mLoadRet mMix2 mCM2dcPmp mCM2HX m_discharPmp mMix3
LABELS  3
"Temperatures"
"Heat transfer rates"
"System"
*------------------------------------------------------------------------------
```

```
* Model "Charge_Pump" (Type 741)
*

UNIT 17 TYPE 741   Charge_Pump
*$UNIT_NAME Charge_Pump
*$MODEL .\Hydronics Library (TESS)\Pumps\Sets the Mass Flow Rate\Variable-Speed\Power
from Efficiency and Pressure Drop\Type741.tmf
*$POSITION 443 458
*$LAYER Main #
*$# Variable-Speed Pump - Efficiency and Pressure Drop Known
PARAMETERS 4
5228400            ! 1 Rated Flowrate
4.19         ! 2 Fluid Specific Heat
1000.0             ! 3 Fluid Density
0            ! 4 Motor Heat Loss Fraction
INPUTS 6
13,3         ! Hot_Manifold:Temperature at outlet 2 ->Inlet Fluid Temperature
13,4         ! Hot_Manifold:Flow rate at outlet 2 ->Inlet Fluid Flowrate
7,1          ! Proportional Controller:Control Signal ->Control Signal
0,0          ! [unconnected] Overall Pump Efficiency
0,0          ! [unconnected] Motor Efficiency
0,0          ! [unconnected] Pressure Drop
*** INITIAL INPUT VALUES
100 0.0 1 0.75 0.9 89.631691
*------------------------------------------------------------------------------

* Model "Campus_Load" (Type 682)
*

UNIT 10 TYPE 682   Campus_Load
*$UNIT_NAME Campus_Load
*$MODEL .\Loads and Structures (TESS)\Flowstream Loads\Other Fluids\Type682.tmf
*$POSITION 849 148
*$LAYER Main #
*$# Loads to a Flow Stream
PARAMETERS 1
4.190        ! 1 Fluid Specific Heat
INPUTS 5
13,1         ! Hot_Manifold:Temperature at outlet 1 ->Inlet Temperature
13,2         ! Hot_Manifold:Flow rate at outlet 1 ->Inlet Flowrate
Load         ! Load:Load ->Load
0,0          ! [unconnected] Minimum Heating Temperature
0,0          ! [unconnected] Maximum Cooling Temperature
*** INITIAL INPUT VALUES
10.0 100.0 -28799997.869134 -999 999
*------------------------------------------------------------------------------
```

```
* Model "mix-2" (Type 649)
*

UNIT 23 TYPE 649   mix-2
*$UNIT_NAME mix-2
*$MODEL .\Hydronics Library (TESS)\Valves\Mixing Valve (100 Ports)\Other Fluids\Type649.tmf
*$POSITION 827 244
*$LAYER Main #
*$# Mixing Valve
PARAMETERS 1
2           ! 1 Number of Inlets
INPUTS 4
10,1        ! Campus_Load:Outlet Temperature ->Temperature at Inlet-1
10,2        ! Campus_Load:Outlet Flowrate ->Flowrate at Inlet-1
18,3        ! Div_1:Temperature at outlet 2 ->Temperature at Inlet-2
18,4        ! Div_1:Flow rate at outlet 2 ->Flowrate at Inlet-2
*** INITIAL INPUT VALUES
20 200.0 20 200.0
*------------------------------------------------------------------------------

* Model "mix-1" (Type 649)
*

UNIT 15 TYPE 649   mix-1
*$UNIT_NAME mix-1
*$MODEL .\Hydronics Library (TESS)\Valves\Mixing Valve (100 Ports)\Other Fluids\Type649.tmf
*$POSITION 378 244
*$LAYER Main #
*$# Mixing Valve
PARAMETERS 1
2           ! 1 Number of Inlets
INPUTS 4
21,1        ! Condenser:Cooling Fluid Outlet Temperature ->Temperature at Inlet-1
21,2        ! Condenser:Cooling Fluid Flowrate ->Flowrate at Inlet-1
18,1        ! Div_1:Temperature at outlet 1 ->Temperature at Inlet-2
18,2        ! Div_1:Flow rate at outlet 1 ->Flowrate at Inlet-2
*** INITIAL INPUT VALUES
20 200.0 20 200.0
*------------------------------------------------------------------------------
```

```
* Model "BTES" (Type 65)
*

UNIT 25 TYPE 65    BTES
*$UNIT_NAME BTES
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 828 810
*$LAYER Outputs #
PARAMETERS 12
5            ! 1 Nb. of left-axis variables
7            ! 2 Nb. of right-axis variables
0.0          ! 3 Left axis minimum
160          ! 4 Left axis maximum
0.0          ! 5 Right axis minimum
200000000          ! 6 Right axis maximum
1            ! 7 Number of plots per simulation
12           ! 8 X-axis gridpoints
-1           ! 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 12
8,1          ! BTES.:Outlet Temperature ->Left axis variable-1
15,1         ! mix-1:Outlet Temperature ->Left axis variable-2
8,3          ! BTES.:Average Storage Temperature ->Left axis variable-3
21,6         ! Condenser:Condensate Enthalpy ->Left axis variable-4
21,3         ! Condenser:Condensate Outlet Temperature ->Left axis variable-5
8,2          ! BTES.:Outlet Flowrate (Total) ->Right axis variable-1
8,5          ! BTES.:Heat Loss Through Top of Storage ->Right axis variable-2
8,6          ! BTES.:Heat Loss Through Side of Storage ->Right axis variable-3
8,7          ! BTES.:Heat Loss Through Bottom of Storage ->Right axis variable-4
8,4          ! BTES.:Average Heat Transfer Rate ->Right axis variable-5
21,2         ! Condenser:Cooling Fluid Flowrate ->Right axis variable-6
21,4         ! Condenser:Condensate Flowrate ->Right axis variable-7
*** INITIAL INPUT VALUES
Tout_BTES Tin_BTES Tavg_storage h_condensate Tout_condensate mBTES
Qloss_top Qloss_side Qloss_bottom Q_BTES mBTES mBTES_steam
LABELS  3
"Temperatures"
"Heat transfer rates"
"BTES"
*------------------------------------------------------------------------------
```

```
* Model "Type534-NoHX" (Type 534)
*

UNIT 27 TYPE 534   Type534-NoHX
*$UNIT_NAME Type534-NoHX
*$MODEL .\Storage Tank Library (TESS)\Cylindrical Storage Tank\Vertical
Cylinder\Version without Plug-In\No HXs\Type534-NoHX.tmf
*$POSITION 740 735
*$LAYER Main #
*$# Cylindrical Storage Tank
PARAMETERS 21
-1           ! 1 LU for Data File
1            ! 2 Number of Tank Nodes
1            ! 3 Number of Ports
0            ! 4 Number of Immersed Heat Exchangers
0            ! 5 Number of Miscellaneous Heat Flows
1000         ! 6 Tank Volume
10           ! 7 Tank Height
0            ! 8 Tank Fluid
4.19         ! 9 Fluid Specific Heat
1000         ! 10 Fluid Density
2.14         ! 11 Fluid Thermal Conductivity
3.21         ! 12 Fluid Viscosity
0.00026            ! 13 Fluid Thermal Expansion Coefficient
5.0          ! 14 Top Loss Coefficient
5.0          ! 15 Edge Loss Coefficient for Node
5.0          ! 16 Bottom Loss Coefficient
0            ! 17 Additional Thermal Conductivity
1            ! 18 Inlet Flow Mode
1            ! 19 Entry Node
1            ! 20 Exit Node
0            ! 21 Flue Overall Loss Coefficient for Node
INPUTS 8
8,1          ! BTES.:Outlet Temperature ->Inlet Temperature for Port
8,2          ! BTES.:Outlet Flowrate (Total) ->Inlet Flowrate for Port
0,0          ! [unconnected] Top Loss Temperature
0,0          ! [unconnected] Edge Loss Temperature for Node
0,0          ! [unconnected] Bottom Loss Temperature
0,0          ! [unconnected] Gas Flue Temperature
0,0          ! [unconnected] Inversion Mixing Flowrate
0,0          ! [unconnected] Auxiliary Heat Input for Node
*** INITIAL INPUT VALUES
20.0 0.0 20.0 20.0 20.0 20.0 -100 0.0
DERIVATIVES 1
20.0         ! 1 Initial Tank Temperature
*-------------------------------------------------------------------------------
```

```
* EQUATIONS "Controller"
EQUATIONS 1
y_heating = 1-([31,1]/1)
*$UNIT_NAME Controller
*$LAYER Controls
*$POSITION 986 436

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


* EQUATIONS "Load"
*
EQUATIONS 1
Load = y_heating*(-9650)*3600
*$UNIT_NAME Load
*$LAYER Controls
*$POSITION 938 148

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


* Model "BTES-2" (Type 65)
*

UNIT 35 TYPE 65    BTES-2
*$UNIT_NAME BTES-2
*$MODEL .\Output\Online Plotter\Online Plotter Without File\Type65d.tmf
*$POSITION 412 831
*$LAYER Main #
PARAMETERS 12
3            ! 1 Nb. of left-axis variables
2            ! 2 Nb. of right-axis variables
0.0          ! 3 Left axis minimum
120          ! 4 Left axis maximum
0.0          ! 5 Right axis minimum
200000000          ! 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
8,1          ! BTES.:Outlet Temperature ->Left axis variable-1
20,1         ! mix-3:Outlet temperature ->Left axis variable-2
8,3          ! BTES.:Average Storage Temperature ->Left axis variable-3
8,4          ! BTES.:Average Heat Transfer Rate ->Right axis variable-1
10,3         ! Campus_Load:Heating Load Met ->Right axis variable-2
*** INITIAL INPUT VALUES
Tout_BTES Tin_BTES Tground Energy_into_BTES Energy_to_Load
LABELS  3
"Temperatures"
"Heat transfer rates"
"BTES"
*------------------------------------------------------------------------------
```

APPENDIX B

TRNSYS TYPE DOCUMENTATION

13.11. Type 598: Steam Condenser (Pinch-point Model)

This component models a steam condenser for which the condensing pressure is *not* known but the pinch-point temperature difference *is* known. The component relies on the pinch-point temperature difference approach to solve for the heat transfer between the condensing steam and the cooling liquid. The saturation pressure of the steam is calculated such that the pinch-point temperature is just reached at the critical location in the condenser. For parallel flow applications, the pinch-point occurs at the outlet of the steam (and therefore at the outlet of the cooling fluid) stream. For counter-flow applications, the pinch-point can occur at one of four locations; the steam inlet (and cooling fluid outlet), the steam saturated vapor point, the steam saturated liquid point, or the steam outlet (cooling fluid inlet). The pinch-point is defined as the smallest temperature difference between the steam and the cooling fluid stream.

13.11.1. Nomenclature

Cp_{cond}	[kJ/kg.K]	Specific heat of condensing fluid.
$T_{out,steam}$	[ºC]	Temperature of steam exiting the condenser.
$T_{sat,steam}$	[ºC]	The saturation temperature of steam in the condenser.
$T_{in,steam}$	[ºC]	Temperature of steam entering the condenser.
$T_{in,cond}$	[ºC]	Temperature of condensing fluid entering the condenser.
$T_{out,cond}$	[ºC]	Temperature of condensing fluid leaving the condenser.
$\Delta T_{subcool}$	[ºC]	Degree of subcooling for the steam exiting the condenser.
ΔT_{pinch}	[ºC]	Pinch-point temperature difference; the minimum temperature difference between the steam and the condensing fluid.
ΔT_{cond}	[ºC]	Temperature rise in the condensing fluid stream across the condenser.
$\dot{Q}_{steam}$	[kJ/h]	Rate at which energy is transferred from the steam
$\dot{Q}_{cond}$	[kJ/h]	Rate at which energy is transferred to the condensing fluid stream.
$\dot{m}_{steam}$	[kg/h]	Mass flow rate of steam entering and condensate exiting the condenser.
$\dot{m}_{cond}$	[kg/h]	Mass flow rate of condensing fluid entering and exiting the condenser.
$h_{in,steam}$	[kJ/kg]	Enthalpy of steam entering the condenser
$h_{out,steam}$	[kJ/kg]	Enthalpy of steam exiting the condenser.

13.11.2. Mathematical Description

A steam condenser (sometimes also known as a surface condenser) is essentially a heat exchanger that cools steam while heating water or some other liquid stream. Commonly, steam condensers are used on the exhaust side of a steam turbine to recuperate the waste heat in that steam, simultaneously increasing turbine efficiency and preheating water for some other application. In this model, it is assumed that the user does not know the pressure at which the steam exits the condenser but instead knows the pinch-point temperature difference for the condenser. A pinch-point is the spot in the condenser where the condensing steam and the cooling water are closest to one another in temperature. A schematic representation of a steam condenser is shown in Figure 13.11-1.

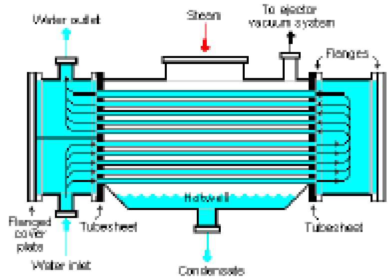


Figure 13.11-1: Steam Condenser Schematic Representation [1]

13.11.2.1. No-Flow Condition

If the mass flow rate of either steam or cooling liquid is zero, the steam and condenser fluid properties are computed as follows. The saturation temperature of the steam is obtained by:

$$T_{sat,steam} = T_{in,cond} + \Delta T_{pinch} \qquad \textbf{Eq 13.11.2-1}$$

The TRNSYS steam properties routine is called with this saturation temperature assuming that the steam is a saturated liquid (ie its quality is zero). The steam properties routine returns the temperature, pressure and enthalpy of the steam. The steam outlet temperature is simply the saturation temperature minus the degrees of subcooling that the user supplied as a parameter.

Type598 next checks that the returned steam pressure is above the minimum condensing pressure (also supplied as a parameter by the user). If it is then the outlet steam state is already known. If the returned outlet pressure is lower than the minimum condensing pressure then the steam properties routine is called again, this time with a quality of zero and the minimum condensing pressure.

13.11.2.2. Parallel Flow Condenser

In a parallel flow steam condenser, the minimum temperature difference between the steam and the condensing fluid occurs at the condenser outlet. Since only the inlet conditions of both the steam and the condensing fluid are known, an iterative process is used to determine an outlet condition for both fluid steams that satisfies the user-specified pinch-point requirement and which balances energy across the heat exchanger. First, Type598 fully determines the steam inlet state by calling the steam properties routine with inlet pressure and enthalpy. Type598 will generate an error if the inlet state is determined to be subcooled. In order to start the iteration, a temperature rise for the condensing fluid side is guessed (ΔT_{cond}). The condensing fluid outlet temperature is then:

$$T_{out,cond} = T_{in,cond} + \Delta T_{cond} \qquad \textbf{Eq 13.11.2-2}$$

Since it is known already that the pinch-point occurs at the outlet, the steam outlet temperature can now be calculated as:

$$T_{out,steam} = T_{out,cond} + \Delta T_{pinch} \qquad \text{Eq 13.11.2-3}$$

The steam saturation temperature is higher than the outlet temperature by the user-specified degrees of subcooling. Type598 limits the steam saturation temperature to 373K in order to avoid errors in the steam properties routine.

$$T_{sat,steam} = T_{out,steam} + \Delta T_{subcool} \qquad \text{Eq 13.11.2-4}$$

By definition, the saturated steam has a quality of zero. The TRNSYS steam properties routine is called with the saturation temperature and a quality of zero, and returns steam pressure and enthalpy. The energy transferred on the steam side of the condenser can be calculated using the returned enthalpy of outlet steam:

$$\dot{Q}_{steam} = \dot{m}_{steam}\left(h_{in,steam} - h_{out,steam}\right) \qquad \text{Eq 13.11.2-5}$$

The energy transfer on the condenser fluid side is:

$$\dot{Q}_{cond} = \dot{m}_{cond}\ Cp_{cond}\left(T_{out,cond} - T_{in,cond}\right) \qquad \text{Eq 13.11.2-6}$$

The two energy transfers are compared. If their difference is smaller than 1% of the steam side energy transfer, they are assumed to be balanced. If, however, the condenser side energy transfer is smaller than the steam side energy transfer, a higher ΔT_{cond} is guessed and the energy transfers are calculated and compared again. If the guessed condenser side delta T gets too small (0.005 °C) then iteration stops.

13.11.2.3. Ideal Condenser

In an ideal condenser, there is no temperature rise in the condenser fluid and the steam saturation temperature is simply the condenser fluid outlet temperature plus the pinch-point temperature difference. The steam properties routine is called with the saturation temperature and a quality of zero and returns pressure and enthalpy. The steam outlet temperature is then the steam saturation temperature minus the degrees of subcooling and the energy transferred on the steam side is the mass flow rate of steam multiplied by the change in enthalpy of the steam between inlet and outlet.

13.11.2.4. Counter Flow Condenser

A counter flow condenser is a bit more laborious to asses because the pinch-point temperature difference could occur at any of four locations: the steam inlet / condenser fluid outlet, the steam saturated vapor point, the steam saturated liquid point, or the steam outlet / condenser fluid inlet. All four cases much be checked each time; the pinch-point will occur at the point that has the maximum steam pressure. First, the steam properties routine is called with steam inlet temperature and pressure, returning steam enthalpy and quality.

STEAM INLET / CONDENSING FLUID OUTLET (SETTING P1)

If the inlet quality is greater than one then Type598 can check pressure assuming that the pinch-point is at the steam inlet. If the inlet quality is less than 1, the pressure at this point is set to zero. If this is the location of the pinch-point then the condensing fluid outlet temperature is the steam inlet temperature plus the pinch-point temperature difference.

$$T_{out,cond} = T_{in,steam} + \Delta T_{pinch}$$ **Eq 13.11.2-7**

With the condensing fluid outlet temperature known, the energy transfer on the condensing fluid side can be calculated:

$$\dot{Q}_{cond} = \dot{m}_{cond}\ Cp_{cond}\left(T_{out,cond} - T_{in,cond}\right)$$ **Eq 13.11.2-8**

The energy transfer on the steam side must be the same in order for energy to balance so the outlet enthalpy of the steam side can be computed:

$$h_{out,steam} = h_{in,steam} - \frac{\dot{Q}_{cond}}{\dot{m}_{steam}}$$ **Eq 13.11.2-9**

Taking subcooling into account, the enthalpy of the saturated steam is calculated:

$$h_{sat,steam} = h_{out,steam} + Cp_{cond}\ \Delta T_{subcool}$$ **Eq 13.11.2-10**

If the enthalpy of saturated steam is a positive number then the steam properties routine is called with that enthalpy and a quality of zero to determine the steam pressure at the steam inlet point (P1). If the calculated enthalpy of saturated steam is zero, P1 is set to zero.

Saturated Steam Point (setting P2)

If the quality of steam at the inlet is greater than 1 then Type598 can also check the pressure at the saturated steam point (in other words the point at which the inlet steam has condensed to the point that it enters the vapor dome). If the steam inlet quality is smaller than 1, it is not worth checking this point and P2 is automatically set to zero. Checking the saturated steam point is very similar to the parallel flow configuration in that neither the outlet state of the steam nor the outlet state of the condensing fluid can be directly determined and an iterative solution is needed. A condenser side temperature rise (ΔT_{cond}) is guessed and the condenser fluid outlet temperature is calculated:

$$T_{out,cond} = T_{in,cond} + \Delta T_{cond}$$ **Eq 13.11.2-11**

For this case it is being assumed that the pinch-point occurs at this point in the steam side. Therefore the saturation temperature of the steam is:

$$T_{sat,steam} = T_{out,cond} + \Delta T_{pinch}$$ **Eq 13.11.2-12**

The saturation temperature with a quality of 1 (saturated steam) are given to the steam properties routine to determine the saturation pressure. The outlet temperature of the steam is.

$$T_{out,steam} = T_{sat,steam} - \Delta T_{subcool}$$ **Eq 13.11.2-13**

Now that the steam outlet temperature and saturation pressure are known, they are passed to the steam properties routine to determine outlet steam enthalpy, which is used to calculate the steam-side energy transfer:

$$\dot{Q}_{steam} = \dot{m}_{steam}\left(h_{in,steam} - h_{out,steam}\right) \qquad \text{Eq 13.11.2-14}$$

The energy transfer on the condenser fluid side is:

$$\dot{Q}_{cond} = \dot{m}_{cond}\ Cp_{cond}\left(T_{out,cond} - T_{in,cond}\right) \qquad \text{Eq 13.11.2-15}$$

As in the parallel flow case, the energy transfers are compared. If the condenser side energy transfer is smaller than that of the steam side, a larger condenser side delta T is guessed. Once the two energy transfers balance, the saturation pressure is set to P2.

Saturated Liquid Point (setting P3)

P3 is the steam pressure at the saturated liquid point assuming that the pinch-point occurs at that point. In this case, the energy transfer on the steam side is given by:

$$\dot{Q}_{steam} = \dot{m}_{steam}\ Cp_{cond}\ \Delta T_{subcool} \qquad \text{Eq 13.11.2-16}$$

The condenser fluid outlet temperature is obtained based on balancing energy across the condenser:

$$T_{out,cond} = T_{in,cond} + \frac{\dot{Q}_{steam}}{\dot{m}_{cond}\ Cp_{cond}} \qquad \text{Eq 13.11.2-17}$$

As in other cases, the steam saturation temperature is the outlet condenser temperature plus the pinch-point temperature difference. The steam properties routine is called with the saturated steam temperature and a quality of zero (saturated liquid) to obtain the saturation pressure, which is set to P3.

Steam Outlet / Condensing Fluid Inlet (setting P4)

The steam saturation temperature if the pinch-point occurs at the steam outlet is given by:

$$T_{sat,steam} = T_{in,cond} + \Delta T_{pinch} + \Delta T_{subcool} \qquad \text{Eq 13.11.2-18}$$

The saturation temperature and a quality of zero are sent to the steam properties routine to obtain the saturation pressure, which is set to P4.

Actual Outlet Conditions

The actual pinch-point temperature difference occurs at the maximum pressure point in the condenser. P1 through P4 are compared and the maximum pressure is selected. If this pressure is below the user-specified minimum condensing pressure, it is assumed that the pinch-point occurs at the minimum condensing pressure. The maximum pressure and a quality of zero (saturated liquid) are sent to the steam properties routine in order to determine the outlet steam enthalpy. The actual energy transferred on the steam side is:

$$\dot{Q}_{steam} = \dot{m}_{steam}\left(h_{in,steam} - h_{out,steam}\right) \qquad \text{Eq 13.11.2-19}$$

And the actual condensing fluid outlet temperature is:

$$T_{out,cond} = T_{in,cond} + \frac{\dot{Q}_{steam}}{\dot{m}_{cond}\ Cp_{cond}} \qquad \text{Eq 13.11.2-20}$$

13.11.3. References

[1] picture credit: http://en.citizendium.org/images/8/8b/Surface_Condenser.png

3.15. Type 741: Variable Speed Pump, Control Signal Input, Power Calculated From Pressure Rise And Pump Efficiency

Type741 models a variable speed pump that is able to produce any mass flow rate between zero and its rated flow rate. The pump's power draw is calculated from pressure rise, overall pump efficiency, motor efficiency and fluid characteristics. Pump starting and stopping characteristics are not modeled. As with most pumps and fans in TRNSYS, Type741 takes mass flow rate as an input but ignores the value except in order to perform mass balance checks. Type741 sets the downstream flow rate based on its rated flow rate parameter and the current value of its control signal input.

3.15.1. Nomenclature

Δp	[Pa]	Pressure rise across the pump.
ρ_{fluid}	[kg/m³]	Fluid density
$\dot{m}_{rated}$	[kg/hr]	Rated mass flow rate of fluid passing though the pump.
$\dot{m}$	[kg/hr]	Mass flow rate of fluid currently passing through the pump.
η_{motor}	[0..1]	Efficiency of the pump motor
$\eta_{overall}$	[0..1]	Overall pump efficiency (motor efficiency * pumping efficiency)
$\eta_{pumping}$	[0..1]	Efficiency of pumping the fluid
$\dot{Q}_{fluid}$	[kJ/hr]	Energy transferred from the pump motor to the fluid stream passing through the pump.
$f_{motorloss}$	[0..1]	Fraction of pump motor inefficiencies that contribute to a temperature rise in the fluid stream passing through the pump. The remainder of these inefficiencies contributes to an ambient temperature rise.
$\dot{P}$	[kJ/hr]	Power drawn by the pump.
$\dot{P}_{shaft}$	[kJ/hr]	Shaft power required by the pumping process (does not include motor inefficiency)
$\dot{W}_{pumping}$	[kJ/hr]	Shaft work performed in the pumping process (does not include motor or pumping inefficiency). This value is also called the ideal work performed.

$\dot{Q}_{ambient}$	[kJ/hr]	Energy transferred from the pump motor to the ambient air surrounding the pump.
$T_{fluid,out}$	[kJ/kg]	Temperature of fluid exiting the pump
$T_{fluid,in}$	[kJ/kg]	Temperature of fluid entering the pump

3.15.2. Mathematical Description

If the pump is determined to be OFF due to it's control signal being set to 0, the pump mass flow rate, power drawn, energy transferred from the pump to ambient and energy transferred from the pump to the fluid stream are all set to zero. The temperature of fluid exiting the pump under the OFF condition is set to the temperature of fluid at the pump inlet. If however the pump is determined to be ON (control signal greater than 0) then the mass flow rate of fluid exiting the pump is set based on Equation 3.15.1.

$$\dot{m} = \gamma \, \dot{m}_{rated} \qquad \textbf{Equation 3.15.1}$$

Where γ is the user specified pump control signal varying between 0 and 1. The efficiency of pumping the fluid from its inlet to its outlet pressure is given by Equation 3.15.2.

$$\eta_{pumping} = \frac{\eta_{overall}}{\eta_{motor}} \qquad \textbf{Equation 3.15.2}$$

If it is not specifically listed in available data, the overall efficiency of the pump may be calculated from nameplate values using a consistent set of units as:

$$\eta_{overall} = \frac{\dot{v}_{rated} \, \Delta p_{rated}}{\dot{P}_{rated}} \qquad \textbf{Equation 3.15.3}$$

The ideal work done in pumping the fluid is given by:

$$\dot{W}_{pumping} = \frac{\Delta p \, \dot{m}}{1000 \, \rho_{fluid}} \qquad \textbf{Equation 3.15.4}$$

The factor of 1000 is needed to convert the units of work to kJ/h when pressure difference is specified in Pa. The work done at the pump shaft takes into account the inefficiency of the pumping process as calculated in Equation 3.15.3.

$$\dot{P}_{shaft} = \frac{\dot{W}_{pumping}}{\eta_{pumping}}$$ **Equation 3.15.5**

The total power drawn by the pump includes the effects of motor inefficiency as shown in Equation 3.15.6.

$$\dot{P} = \frac{\dot{P}_{shaft}}{\eta_{motor}}$$ **Equation 3.15.6**

Energy transferred from the pump motor to the fluid stream is calculated as shown in Equation 3.15.7.

$$\dot{Q}_{fluid} = \dot{P}_{rated} \cdot \eta_{motor}\left(1-\eta_{pumping}\right) + \dot{P}_{rated}\left(1-\eta_{motor}\right)f_{motorloss}$$ **Equation 3.15.7**

In which $\eta_{pumping}$ is the pumping process efficiency and $f_{motorloss}$ is a value between 0 and 1 that determines whether the pump motor inefficiencies cause a temperature rise in the fluid stream that passes through the pump or whether they cause a temperature rise in the ambient air surrounding the pump. Through use of the $f_{motorloss}$ fraction, the user can in effect specify whether the pump has an inline motor, in which case all waste heat would impact the fluid stream temperature and $f_{motorloss}$ would have a value of 1, or whether the pump motor is housed outside of the fluid stream such that it's waste heat impacts the ambient and $f_{motorloss}$ would have a value of 0.

The energy transferred from the pump motor to the ambient is given by Equation 3.15.8.

$$\dot{Q}_{ambient} = \dot{P}_{rated}\left(1-\eta_{motor}\right)\left(1-f_{motorloss}\right)$$ **Equation 3.15.8**

The temperature of fluid exiting the pump can now be calculated as shown in Equation 3.15.9.

$$T_{fluid,out} = T_{fluid,in} + \frac{\dot{Q}_{fluid}}{\dot{m}_{fluid}}$$ **Equation 3.15.9**

Type741 does not model pump starting and stopping characteristics. As soon as the control signal indicates that the pump should be ON, the outlet flow of fluid jumps to the corresponding condition because the time constants with which pumps react to control signal changes is much shorter than the typical time steps used in hydronic simulations. Type741 also operates as many pump and fan models do in TRNSYS. That is to say that they ignore the fluid mass flow rate provided as an input to the model except so as to perform a mass balance on the pump. Therefore care must be taken in specifying fluid loops with multiple pumps that inlet mass flow rates greater than the rated mass flow rate for a given pump are not specified. The total number of time steps during which the fluid inlet mass flow rate for Type741 is not equal to its outlet flow rate is reported to the list file at the end of each simulation.

3.8. Type 649: Flow Mixer With Up To 100 Ports

Type649 models a mixing valve that combines up to 100 individual liquid streams into a single outlet mass flow. The limit of 100 inlet flows can be modified in the Fortran source code.

3.8.1. Nomenclature

$T_{in,i}$	[°C]	The temperature of fluid at inlet port i.
$\dot{m}_{in,i}$	[kg/hr]	The mass flow rate of fluid at inlet port i.
Cp	[kJ/kg.K]	The specific heat of the fluid
T_{out}	[°C]	The temperature of fluid exiting the mixing valve.
$\dot{m}_{out}$	[kg/hr]	The mass flow rate of fluid exiting the mixing valve
T_{mix}	[°C]	The temperature of mixed inlet fluid.
$nPorts$	[-]	Number of inlet air ports.

3.8.2. Mathematical Description

Type649 models a mixing valve by performing an energy balance on the system shown in Figure 3.8.1 in which there can be as many as 100 inlet flows but only one outlet flow.

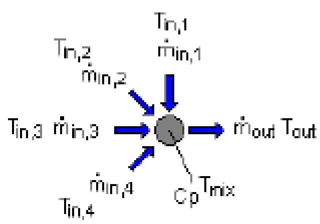


Figure 3.8.1: Mixing Valve Schematic

The energy balance can be written as shown in Equation 3.8.1

$$\dot{m}_{in,1}Cp(T_{in,1}-T_{mix})+\dot{m}_{in,2}Cp(T_{in,2}-T_{mix})+\dot{m}_{in,3}Cp(T_{in,3}-T_{mix})+\\ \dot{m}_{in,4}Cp(T_{in,4}-T_{mix})=\dot{m}_{out}Cp(T_{out}-T_{mix}) \qquad \textbf{Equation 3.8.1}$$

In fact since T_{mix} and T_{out} are the same, the energy balance could be written more simply still. It has been written with T_{mix} and T_{out} separated for clarity sake. Since Cp is assumed to be the same for all inlet flows to the mixing valve and since the outlet flow is the sum of the inlet flows, the energy balance can be simplified and solved for the outlet temperature as shown in Equation 3.8.2.

$$T_{out}=\frac{\sum_{i=1}^{nPorts}\dot{m}_i T_{in,i}}{\sum_{j=1}^{nPorts}\dot{m}_j} \qquad \textbf{Equation 3.8.2}$$

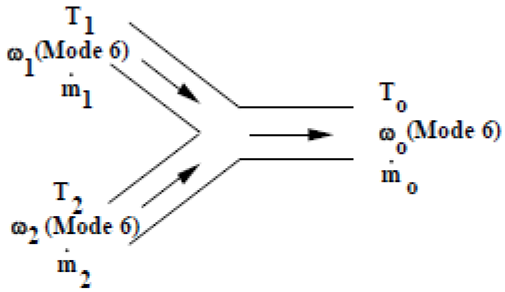
4.6.2 Type 11: Tee Piece, Flow Diverter, Flow Mixer, Tempering Valve

The use of pipe or duct 'tee-pieces', mixers, and diverters, which are subject to external control, is often necessary in thermal systems. This component has ten modes of operation. Modes 1 through 5 are normally used for fluids with only one important property, such as temperature. Modes 6 through 10 are for fluids, such as moist air, with two important properties, such as temperature and humidity. Modes 1 and 6 simulate the function of a tee-piece that completely mixes two inlet streams of the same fluid at different temperatures and or humidities as shown in Figure 4.6.2–1. Modes 2 and 7 simulate the operation of a flow diverter with one inlet which is proportionally split between two possible outlets, depending on the value of g , an Input control function as shown in Figure 4.6.2–2. Modes 3 and 8 simulate the operation of a flow mixer whose outlet flow rate, temperature, and/or humidity is determined by mixing its two possible inlets in the proportion determined by g as shown in Figure 4.6.2–3. For modes 2, 3, 7, and 8, g must have a value between 0 and 1. Modes 4, 5, 9 and 10 are temperature controlled flow diverters that may be used to model tempering valves.

4.6.2.1 Nomenclature

$\dot{m}_i$	mass flow rate of inlet fluid
$\dot{m}_o$	mass flow rate of outlet fluid
$\dot{m}_1$	mass flow rate at position 1 (See Figures)
$\dot{m}_2$	mass flow rate at position 2 (See Figures)
T_h	heat source fluid temperature
T_i	temperature of inlet fluid
T_o	temperature of outlet fluid
T_{set}	maximum temperature of fluid supplied to load
T_1	temperature at position 1 (See Figures)
T_2	temperature at position 2 (See Figures)
γ	control function having a value between 0 and 1
ω_1	humidity ratio at position 1
ω_2	humidity ratio at position 2
ω_i	humidity ratio of inlet fluid
ω_o	humidity ratio of outlet fluid

4.6.2.2 *Mathematical Description*

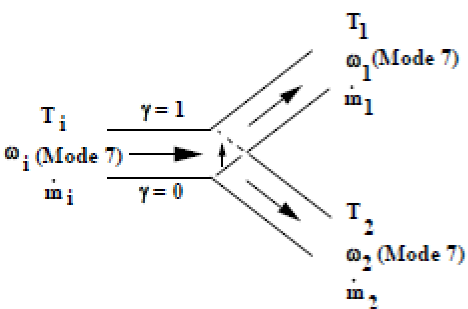


$$T_o = \frac{\dot{m}_1 T_1 + \dot{m}_2 T_2}{\dot{m}_1 + \dot{m}_2}$$

$$\omega_o = \frac{\dot{m}_1 \omega_1 + \dot{m}_2 \omega_2}{\dot{m}_1 + \dot{m}_2} \quad \text{(Mode 6)}$$

$$\dot{m}_o = \dot{m}_1 + \dot{m}_2$$

Figure 4.6.2–1: Mode 1 and 6: (Tee Piece)



$$T_1 = T_i$$

$$\omega_1 = \omega_i \quad \text{(Mode 7)}$$

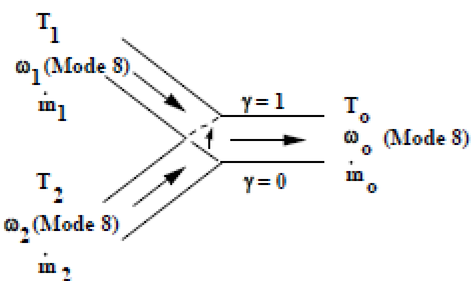
$$\dot{m}_1 = \dot{m}_i \, (1-\gamma)$$

$$T_2 = T_i$$

$$\omega_2 = \omega_i \quad \text{(Mode 7)}$$

$$\dot{m}_2 = \dot{m}_i \, \gamma$$

Figure 4.6.2–2: Mode 2 and 7: (Flow Diverter)



$$T_o = \frac{\dot{m}_1 T_1 \, (1-\gamma) + \dot{m}_2 T_2 \, \gamma}{\dot{m}_1 \, (1-\gamma) \; + \dot{m}_2 \, \gamma}$$

$$\omega_o = \frac{\dot{m}_1 \omega_1 \, (1-\gamma) + \dot{m}_2 \omega_2 \, \gamma}{\dot{m}_1 \, (1-\gamma) \; + \dot{m}_2 \, \gamma} \quad \text{(Mode 8)}$$

$$\dot{m}_o = \dot{m}_1 \, (1-\gamma) + \dot{m}_2 \, \gamma$$

Figure 4.6.2–3: Mode 3 and 8: (Flow Mixer)

WARNING: In TRNSYS v.16 and earlier, the outlet temperatures were left unchanged from the previous call under no-flow conditions to avoid unnecessary calls to downstream components. As a result, the outlet temperatures could not be used for any control decisions. With the release of TRNSYS v.17, the outlet temperatures were set to the inlet 1 temperature under no-flow conditions so that these temperatures could be used for control decisions.

Modes 4, 5, 9 and 10 are similar to modes 2 and 7 except that γ is calculated by the Type 11 routine. In domestic, commercial and industrial heating applications, it is common to mix heated fluid with colder supply fluid so that the flow stream to the load is no hotter than necessary. Often this is accomplished by placing a "tempering valve" in the storage outlet stream (position A on Figure 4.6.2–4 below). Such a valve relies on the supply pressure to drive fluid through the heat source and bypass lines in proportion to the valve setting.

Although thermally equivalent, it is better for simulation purposes to place a temperature controlled flow diverter at point B (in the figure below) than to place a temperature controlled mixer at point A. Modes 4 and 5 of Type 11 are designed for this purpose. The control function γ is set so that if flow stream 1 displaces fluid of temperature T_h, the mixed fluid temperature will not exceed the temperature T_{set}. Modes 4 and 9 differ from 5 and 10 in that Modes 4 and 9 send the entire flow stream through outlet 1 when $T_h < T_l$, while Modes 5 and 10 send the entire flow stream through outlet 2 when $T_h < T_l$

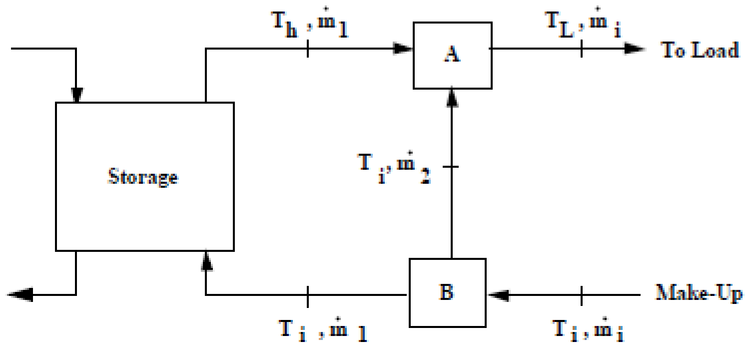


Figure 4.6.2–4: Example of Tempering Valve Use

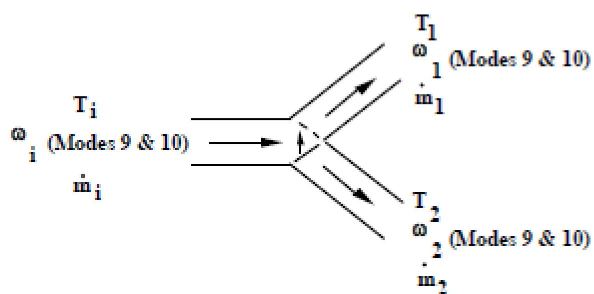


Figure 4.6.2–5: Modes 4, 5, 9, and 10 (Tempering Valve)

Table 4.6.2–1:

$T_1 = T_i$	$\gamma = (T_{set} - T_i)/(T_h - T_i)$	if $T_h > T_{set}$
$\omega_1 = \omega_i$ (Modes 9 & 10)	$\gamma = 1$	if $T_i \le T_h \le T_{set}$

$\dot{m}_1 = \dot{m}_i\,(\gamma)$	$\gamma = 1$	if $T_h < T_i$ (Modes 4 & 9)
$T_2 = T_i$	$\gamma = 0$	if $T_h < T_i$ (Modes 5 & 10)
$\omega_2 = \omega_i$ (Modes 9 & 10)	Note: The control function γ will not be changed after NSTK iterations at the same time step.	
$\dot{m}_2 = \dot{m}_1\,(1 - \gamma)$	Also Note: T_{set} must be $\geq$ T_i at all times.	

8.2. Type 682:Heating And Cooling Loads Imposed On A Flow Stream

Often in simulating an HVAC system, the heating and cooling loads on the building have already been determined, either by measurement or through the use of another simulation program and yet the simulation task at hand is to simulate the effect of these loads upon the system. This component allows for there to be an interaction between such pre-calculated loads and the HVAC system by imposing the load upon a liquid flowing through a device. This model simply imposes a user-specified load (cooling = positive load, heating = negative load) on a flow stream and calculates the resultant outlet fluid conditions. Boiling and freezing effects are ignored so be careful when using this component. This simple model can represent any number of devices such as chillers, water-loop building loads, radiators, heat pumps etc. where the physics of the device are not important and the removal of the correct amount of energy from a flow stream IS important.

8.2.1. Nomenclature

$\dot{Q}$	-	[kJ/h]	the rate at which energy is added to or removed from the liquid stream.
$\dot{m}$	-	[kg/h]	the rate at which fluid flows past the load
C_p	-	[kJ/kg.K]	the specific heat of the liquid
T_{in}	-	[°C]	the temperature of liquid arriving at the load.
T_{out}	-	[°C]	the temperature of the liquid leaving the load.

8.2.2. Detailed Description

Type682 can be thought of as an interaction point between a building load and the liquid working fluid in an HVAC system. If the interaction point is between the building and an air stream, Type693 may be used instead.

Mathematically, this model is very simple, the user provides the flow rate, specific heat, and temperature of liquid at a point in the system loop. The building loads are added to, or subtracted from that liquid, resulting in an outlet temperature just past the interaction point.

$$T_{out} = T_{in} + \frac{\dot{Q}}{\dot{m}C_p} \quad \text{(Eq. 682.1)}$$

According to the sign convention, a positive load will result in an outlet temperature higher than the inlet temperature and vice versa; a negative load results in an outlet temperature lower than the inlet temperature.

Example

Type682 is used in an example that can be found in:

" . \TESS Models\Examples\Loads and Structures Library\Synthetic Building.tpf"

3.15. Type 1669: Proportional Controller

This component returns a control signal between 0 and 1 that is related to the current value of an input as compared to a user defined minimum and maximum value. The component was built from the TESS Type669 of the previous version and improved to have a maximum rate of increase and a minimum rate of increase for the control signal.

3.15.1. Mathematical Description

Type1669 takes the values of up to 100 input signals. Those signals are compared to the current values of upper and lower set points. If an input value is equal to or greater than the upper set point, Type1669 will output a value of 1. If the input value is equal to or less than the lower set point value, Type1669 will report a control signal value of 0. The control scheme is described in the figure below.

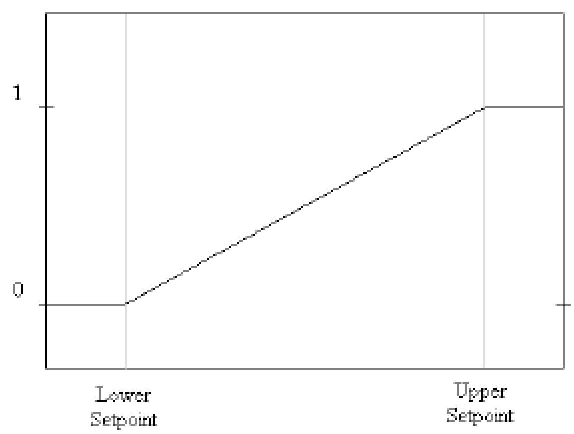


Figure 1669: Proportional Control Diagram

Mathematically, the simple proportion of the input to the values is described by Equation 1669.1. This was the primary function of the previous Type669 component

$$\gamma = \max\left(0,\left(\min\left(1,\frac{Value - LowerSetPt}{UpperSetpt - LowerSetPt}\right)\right)\right) \qquad \text{(Eq. 1669.1)}$$

Oppose to the former Type669, Type1669 now has the maximum rate of increase per hour and the maximum rate of decrease per hour as parameters. When both of these parameters are equal to 1, the above equation still applies. However, when those parameters are not equal to 1 (there is a maximum rate of increase per hour or maximum rate of decrease per hour for the controller), the following applies. When the control signal value is more than the previous value, the following is the control signal.

If $\gamma_{i-1} < \gamma_i$,

$$\gamma = \min(\gamma_i, \gamma_{i-1} + MaxRateIncrease * Timestep) \qquad \text{(Eq. 1669.2)}$$

When the control signal value is less than the previous control signal, the following is the control signal.

If $\gamma_{i-1} > \gamma_i$,

$$\gamma = \min(\gamma_i, \gamma_{i-1} - MaxRateDecrease * Timestep) \qquad \text{(Eq. 1669.3)}$$

When the control signal value is less than the previous control signal, the following is the control signal.

It will occasionally be desired to implement this component in the opposite conditioning mode (i.e. heating instead of cooling). The simplest way to implement this is with an EQUATION block in TRNSYS. Make an input in the EQUATION block; this input will be the output control signal from Type1669. Next, implement an output equation such as the following.

$$\gamma_{\mathrm{Heating}} = 1 - \frac{\gamma}{1} \qquad \text{(Eq. 1669.4)}$$

Example

Type1669 is used in an example that can be found in:
" . \TESS Models\Examples\Controllers Library\ Controls Example 1.tpf"

4.13.2 Type14: Time Dependent Forcing Function

In a transient simulation, it is sometimes convenient to employ a time-dependent forcing function which has a behavior characterized by a repeated pattern. The purpose of this routine is to provide a means of generating a forcing function of this type. The pattern of the forcing function is established by a set of discrete data points indicating its values at various times through one cycle. Linear interpolation is provided in order to generate a continuous forcing function from this discrete data.

4.13.2.1 Nomenclature

TIME current value of time in simulation

C_T the cycle time (the time span after which the pattern repeats itself, which may be the total simulation time)

N the number of segments defining the function (N+1 points must be specified)

V_o the initial value of the forcing function (occurs at TIME = 0, CT, 2CT, 3CT etc.)

V_i the value of the forcing function at point i

t_i the elapsed time from the start of the cycle at which point i and Vi are reached

$\overline{V}$ the linearly interpolated average value of the function over the timestep

t_o the initial value of time. Must be zero if the function repeats itself. IF CT is the total simulation time, t_o can be less than or equal to the initial simulation time

Δt the simulation timestep

4.13.2.2 Mathematical Description

The cycle must be completely specified requiring that t_N ($t_N = t_i$ at i = N) be greater than or equal to C_T.

$\overline{V}$, the average value of the function, is calculated as follows:

$$t_c = \text{MOD}(\text{TIME}, C_T) - \Delta t/2 \qquad \textbf{Eq 4.13.2-1}$$

i is then found satisfying $t_{i-1} < t_c < t_i$ then

$$R = \frac{t_c - t_{i-1}}{t_i - t_{i-1}} \qquad \textbf{Eq 4.13.2-2}$$

$$\overline{V} = V_{i-1} + R\left(V_i - V_{i-1}\right) \qquad \textbf{Eq 4.13.2-3}$$

4.13.2.3 Special considerations

Both the instantaneous value of the forcing function are available as outputs. When step-like functions are to be defined, it is recommended to define the function by repeating each time value with two different values of V, and then use the average value (output(1)) in the simulation. This will guarantee the use of the exact same profile for any value of the time step.

E.g. to define an occupancy in a building between 8 AM and 5PM (occupancy is 0 at night, 1 during the day, and must change instantly from 0 to 1 and 1 to 0):

- Define the origin (time = 0, V = 0)
- Define the time at which the occupancy starts, repeating the value 0 (time = 8, V = 0)
- Repeat the time at which the occupancy stops with the value 1 (time = 8, V = 1)
- Define the time at which the occupancy stops, repeating the value 1 (time = 17, V = 1)
- Repeat the time at which the occupancy stops with the value 1 (time = 17, V = 0)
- Define the end of the period t_c (after that the cycle is repeated) (time = 24, V = 0)
- Use output(1) (average value over the time step)

4.14.1 Type 15: Weather Data Processor

This component reads and interprets weather data available in a series of standardized formats. The data files implemented are: Typical Meteorological Year (TMY), Typical Meteorological Year version 2 (TMY2), EnergyPlus Weather, International Weather for Energy Calculations (IWEC), Canadian Weather for Energy Calculations (CWEC), Typical Meteorological Year version 3 (TMY3), German TRY 2004, and German TRY 2010. In addition to reading data files, Type15 calculates total, beam, sky diffuse, ground reflected solar radiation, the angle of incidence of beam solar radiation, the slope and azimuth of as many surfaces as the user cares to define. The Type further includes calculation of mains water temperature and effective sky temperature for radiation calculations. It also outputs a number of indicators such as heating and cooling season, monthly and annual maximum, minimum and average temperature.

4.14.1.1 Nomenclature

Eo,sky	[0..1]	Clear sky emissivity
Tdewpt	[ºC]	Dew point temperature
time	[hr]	The hour of the year (simulation time)
pressure	[millibars]	Atmospheric pressure
E_{sky}	[0..1]	Emissivity of the sky in the presence of clouds
f_{cloud}	[0..1]	Fraction of sky covered by opaque clouds
E_{cloud}	[0..1]	Emissivity of clouds
T_{amb}	[ºC]	Ambient temperature
T_{mains}	[ºC]	Mains temperature
$\overline{T}_{amb}$	[ºC]	Average annual air temperature
$T_{amb,max}$	[ºC]	Maximum difference between monthly average ambient temperatures
day	[1..365]	Julian day of the year

4.14.1.2 Mathematical Description

Most of Type15 is devoted to reading standard format data files. With the raw data read from the file, it calls the TRNSYS kernel subroutine getIncidentRadiation to compute the amount of solar radiation falling on surfaces of arbitrary user-defined orientation. Since the getIncidentRadiation subroutine is used by various other TRNSYS components and may be called by user-written components, it is fully documented in the 07-Programmer's Guide manual. Type15 also includes an algorithm for calculating the effective sky temperature. This algorithm came from a Thermal Energy System Specialists Utility Library component (Type575). In addition to these three main components, Type15 also calculates a number of other useful weather related values based on algorithms published by the United States Department of Energy's Building America Program [6]. This section is devoted to a discussion of the sky temperature model [7], Building America algorithms, and other Type15 outputs. Please refer to the getIncidentRadiation section of the 07-Programmer's Guide manual for information about Type15's solar radiation processing algorithms.

OPERATION MODES AND ACCEPTED FILE FORMATS

In TRNSYS 17, the following standard weather data formats can be read and processed by Type15:

Mode	Format	Description & references
1	TMY (TMY1)	Original TMY format used by the NSRDB (National Solar Radiation Data Base) [4]
2	TMY2	TMY2 format originally used for the US NSRDB database. Also used by all Meteonorm-generated weather files distributed with TRNSYS (beginning with version 16). [1]
3	EPW	EnergyPlus / ESP-r weather format [2]. A large database of weather files is available on the EnergyPlus website: http://www.eere.energy.gov/buildings/energyplus/weatherdata.html
4	IWEC	ASHRAE's International Weather for Energy Calculation data format [3]
5	CWEC	Canadian Weather for Energy Calculation [5]
6	Meteonorm (TMY2)	Identical to the TMY2 format originally used for the US NSRDB database. Provided as a separate mode for user convenience.
7	TMY3	Typical Meteorological Year version 3 format.
8	German TRY 2004	German TRY version 2004 format.
9	German TRY 2010	German TRY version 2010 format.

NOTE: Fundamentaly, the wind direction in TRNSYS depends on the convention given in the weather data file. The standard file-formats indicated in the above table use as convention N=0°, E=90°, etc. The user must check that this convention is in accordancd with the specific component that will use the information later in the simulation (i.e., COMIS or CONTAM).

SKY TEMPERATURE

Calculation of the sky temperature begins with an estimation of the clear sky emissivity based on the dew point temperature. The dew point correlation for clear sky emissivity is:

$$E_{o,sky} = 0.711 + 0.56 * \left(\frac{T_{dewpt}}{100}\right) + 0.73 * \left(\frac{T_{dewpt}}{100}\right)^2 \qquad \textbf{Eq 4.14.1-1}$$

The clear sky emissivity is then corrected for time of day in order to account for the differences in radiative transfer between the night time black sky and the day time blue sky, as shown in the following equation in which time is the hour of the year.

$$E_{o,sky} = E_{o,sky} + 0.013 * \cos\left(2\pi * \frac{MOD(time,24)}{24}\right) \qquad \textbf{Eq 4.14.1-2}$$

The clear sky emissivity is then corrected for atmospheric pressure. While Type15 reads pressure from data files in Pascals or atmospheres (depending on the file format), the model takes makes an internal conversion to millibars, the pressure units for which the equation was developed.

$$E_{o,sky} = E_{o,sky} + 0.00012 * (pressure - 1000) \quad \text{Eq 4.14.1-3}$$

The emissivity of the sky in the presence of clouds is calculated by multiplying the clear sky emissivity by the fraction of the sky that is covered by clouds and by the emissivity of the clouds themselves, as shown in the following equation. The fraction of sky covered by opaque clouds has a value between 0 (no cloud cover) and 1 (complete cloud cover). Depending upon the mode of this component, the fraction of sky covered by opaque clouds may be entered either as a value between 0 and 1 or as a percentage (0 to 100).

$$E_{sky} = E_{o,sky} + (1.0 - E_{o,sky}) * f_{cloud} * \varepsilon_{cloud} \quad \text{Eq 4.14.1-4}$$

Finally, the sky temperature is computed using the correlation shown in the equation.

$$T_{sky} = E_{sky}^{1/4} (T_{amb} + 273.13) - 273.13 \quad \text{Eq 4.14.1-5}$$

Mains Water Temperature

Type15 provides an output of the temperature at which water might be expected to exit a buried distribution system. The algorithm was developed by Christensen and Burch at the U.S. National Renewable Energy Laboratory. The mains water temperature algorithm is:

$$T_{mains} = (\overline{T}_{amb} + offset) + ratio\left(\frac{T_{amb,max}}{2}\right)\sin\left(\frac{360}{365}(day - 15 - lag) - 90\right) \quad \text{Eq 4.14.1-6}$$

In which offset is defined as 3 °C (6 °F), *ratio* is defined by the equation:

$$ratio = 0.22 + 0.0056(\overline{T}_{amb} - 6.67) \quad \text{Eq 4.14.1-7}$$

And in which *lag* is defined by:

$$lag = 1.67 - 0.56(\overline{T}_{amb} - 6.67) \quad \text{Eq 4.14.1-8}$$

The offset, lag, and ratio values were obtained by fitting data compiled by Abrams and Shedd [8], the Florida Solar Energy Center [9], and Sandia National Labs [10].

Ground Reflectance

The user is asked to supply values of ground reflectance for snow covered and non-snow covered ground among Type15's parameters. Because all of the standard data file formats include data fields for whether or not the ground is covered by snow, it is relatively easy for Type15 to change the ground reflectance accordingly. The ground reflectance computed by Type15 follows a step function and depends only on the value of the "snow covered ground" flag in the data file being read. The ground reflectance is set as its own output and is also used in calculating the amount of ground reflected solar radiation that falls on each surface defined in Type15.

Heating and Cooling Season Indicators

The Building America Program Performance Analysis Procedures document includes a method by which indicators for typical heating equipment use and typical cooling equipment use can be calculated. Type15 sets one of its outputs (the heating season indicator)to a value of "1" if heating equipment is typically used during that month and to a value of "0" otherwise. Type15 sets another output (the cooling season indicator) to a value of "1" if cooling equipment is typically used and to a value of "0" otherwise. The methodology for determining heating season is as follows:

The heating system is typically enabled during a month in which the monthly average temperature is less than 21.94 °C and during December and January if the annual minimum air temperature is less than 15 °C. The cooling system is typically enabled during a month in which the monthly average temperature is above 18.89 °C and during July and August. Lastly, if there are two consecutive months during which the heating system is enabled the first month and the cooling system is enabled the second month (or vice versa) then both systems should be allowed to operate during both months.

Monthly and Annual Conditions

Type15 outputs the minimum, maximum and average monthly and annual temperature as the simulation progresses. The values are all calculated during Type15's initialization at the beginning of the simulation so the values do not represent running averages, minima or maxima.

4.14.1.3. References

[1] National Renewable Energy Laboratory. 1995. User's Manual for TMY2s (Typical Meteorological Years), NREL/SP-463-7668, and TMY2s, Typical Meteorological Years Derived from the 1961-1990 National Solar Radiation Data Base, June 1995, CD-ROM. Golden: NREL.

[2] Crawley, Drury B., Jon W. Hand, Linda K. Lawrie. 1999. "Improving the Weather Information Available to Simulation Programs," in *Proceedings of Building Simulation '99*, Volume II, pp. 529-536, Kyoto, Japan, September 1999. IBPSA.

[3] ASHRAE. 2001. International Weather for Energy Calculations (IWEC Weather Files) Users Manual and CD-ROM, Atlanta: ASHRAE

[4] National Climatic Data Center. 1981. Typical Meteorological Year User's Manual, TD-9734, Hourly Solar Radiation—Surface Meteorological Observations, May 1981. Asheville: National Climatic Data Center, U.S. Department of Commerce.

[5] Numerical Logics. 1999. *Canadian Weather for Energy Calculations, Users Manual and CD-ROM*. Downsview, Ontario: Environment Canada.

[6] Hendron, R. et. al., "Building America Performance Analysis Procedures" (revision 1), Building America, U.S. Department of Energy, NREL/TP-550-35567

[7] Berdahl, Martin M., "Characteristics of Infrared Sky Radiation in the U.S.A.", Solar Energy Journal, 33.4 (1984): 321.

[8] Abrams, D.W., and Shedd, A.C., 1996. "Effect of Seasonal Changes in Use Patterns and Cold Inlet Water Temperature on Water Heating Load", ASHRAE Transactions, AT-96-18-3.

[9] Parker, D., 2002. "Research Highlights from a Large Scale Residential Monitoring Study in a Hot Climate". FSEC-PF369-02. Cocoa, FL, Florida Solar Energy Center.

[10] Kolb, G., 2003. Private communication. Sandia National Laboratories, Albuquerque, NM.

4.1. Type 557: Vertical Ground Heat Exchanger

This subroutine models a vertical heat exchanger that interacts thermally with the ground. This ground heat exchanger model is most commonly used in ground source heat pump applications. This subroutine models either a U-tube ground heat exchanger or a concentric tube ground heat exchanger. A heat carrier fluid is circulated through the ground heat exchanger and either rejects heat to, or absorbs heat from the ground depending on the temperatures of the heat carrier fluid and the ground.

In typical U-tube ground heat exchanger applications, a vertical borehole is drilled into the ground. A U-tube heat exchanger is then pushed into the borehole. The top of the ground heat exchanger is typically several feet below the surface of the ground. Finally, the borehole is filled with a fill material; either virgin soil or a grout of some type.

In typical concentric tube heat exchanger application, the borehole is just slightly larger than the outer pipe of the ground heat exchanger, but the same process applies. The borehole is drilled into the ground, and the heat exchanger is pushed into the borehole.

The two types of ground heat exchangers available in this subroutine are shown in Figures 1 and 2. Figure 1 shows one U-tube per borehole; although this subroutine allows the user to have up to 10 U-tubes per borehole.

The program assumes that the boreholes are placed uniformly within a cylindrical storage volume of ground. There is convective heat transfer within the pipes, and conductive heat transfer to the storage volume. The temperature in the ground is calculated from three parts; a global temperature, a local solution, and a steady-flux solution. The global and local problems are solved with the use of an explicit finite difference method. The steady flux solution is obtained analytically. The temperature is then calculated using superposition methods.

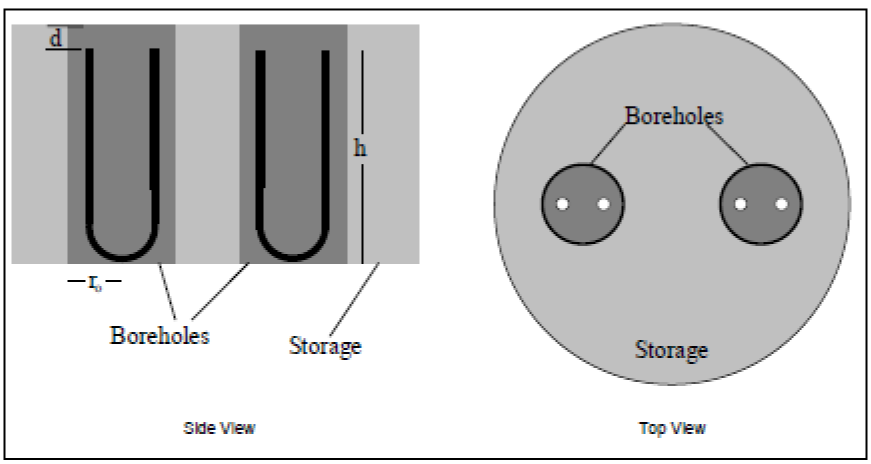


Figure 1: U-Tube Ground Heat Exchanger

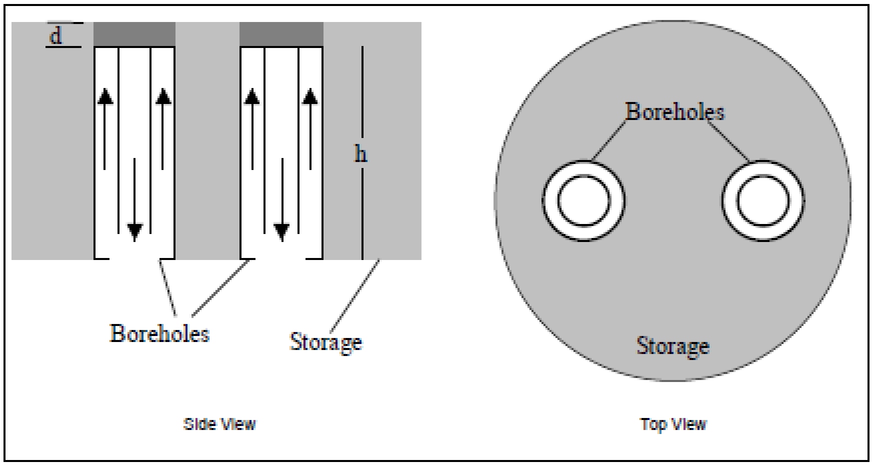


Figure 2: Concentric Tube Ground Heat Exchanger

4.1.1. Mathematical Description

The subroutine at the heart of Type557 was written by the Department of Mathematical Physics at the University of Lund, Sweden and is considered to be the state-of-the-art in dynamic simulation of ground heat exchangers. Instead of duplicating information already available, a portable document format (PDF) version of the original subroutine manual has been provided. The document is called *Type557-DST_manual.pdf* and is taken verbatim from the reference below.

4.1.2. References

Hellstrom, Goran, "Duct Ground Heat Storage Model, Manual for Computer Code", Department of Mathematical Physics, University of Lund, Sweden.

APPENDIX C

LIST OF MEASURED DATA

	DatabaseID	Description	EngUnits
1	125001	'BatchHistorian Demo - Resin Totalizer'	'Lbs'
2	125002	'BatchHistorian Demo - Solvent Totalizer'	'Lbs'
3	125003	'BatchHistorian Demo - Agitation Time'	'seconds'
4	125004	'BatchHistorian Demo - Mix tank temperature'	'Deg. F'
5	1000197	'Deaerator Tank 1 Level'	'Inches'
6	1000198	'Desuper. 1 HPS Temp. Valve Actual Pos.'	'% Open'
7	1000199	'Deaerator Tank 1 Level Valve Actual Pos.'	'% Open'
8	1000200	'Deaerator Tank 1 Press. Valve Actual Pos.'	'% Open'
9	1000201	'Desuper. 1 IPS Press. Valve Actual Pos.'	'% Open'
10	1000202	'Desuper. 1 IPS Temp. Valve Actual Pos.'	'% Open'
11	1000203	'Deaerator Tank 2 Level Valve Actual Pos.'	'% Open'
12	1000204	'Deaerator Tank 2 Press. Valve Actual Pos.'	'% Open'
13	1000205	'Desuper. 2 IPS Press. Valve Actual Pos.'	'% Open'
14	1000206	'Desuper. 2 IPS Temp. Valve Actual Pos.'	'% Open'
15	1000207	'Desuper. 2 HPS Temp. Valve Actual Pos.'	'% Open'
16	1000208	'Raw Water Stor. Tank Level Valve Actual Pos.'	'% Open'
17	1000209	'Desuper. 1 HPS Press. Valve Actual Pos.'	'% Open'
18	1000210	'Desuper. 2 HPS Press. Valve Actual Pos.'	'% Open'
19	1000217	'MPS Temp. Valve #2 Actual Pos.'	'% Open'
20	1000219	'Raw Water Stor. Tank Recirc. Valve Actual Pos.'	'% Open'
21	1000220	'Cond. Stor. Tank Recirc. Press. Valve Pos.'	'% Open'
22	1000221	'MS Plant Master PID Out'	'%'
23	1000222	'HPS Plant Master PID Out'	'%'
24	1000223	'Desuper. 1 HPS Press. PID Out'	'% Open'
25	1000224	'Desuper. 1 HPS Temp. PID Out'	'% Open'
26	1000225	'Desuper. 2 HPS Press. PID Out'	'% Open'
27	1000226	'Desuper. 2 HPS Temp. PID Out'	'% Open'
28	1000227	'Desuper. 1 MPS Press. PID Out'	'% Open'
29	1000228	'Desuper. 1 MPS Temp. PID Out'	'% Open'
30	1000229	'Desuper. 1 IPS Press. PID Out'	'% Open'
31	1000230	'Desuper. 1 IPS Temp. PID Out'	'% Open'
32	1000231	'Desuper. 1 LPS Press. PID Out'	'% Open'
33	1000232	'Desuper. 1 LPS Temp. PID Out'	'% Open'
34	1000233	'Deaerator Tank 1 Level PID Out'	'% Open'
35	1000234	'Deaerator Tank 2 Level PID Out'	'% Open'
36	1000235	'Deaerator Tank 1 Press. PID Out'	'% Open'
37	1000236	'Deaerator Tank 2 Press. PID Out'	'% Open'
38	1000237	'Cooling Tower Water Temp. PID Out'	'% Speed'
39	1000238	'Cooling Tower Fan 1 Spd Command'	'% Speed'
40	1000239	'Cooling Tower Fan 2 Spd Command'	'% Speed'
41	1000240	'Makeup Water Recirc Valve Press. PID Out'	'% Open'
42	1000241	'Raw Water Storage Tank Level PID Out'	'% Open'
43	1000242	'Cond. Receiver Tank Level PID Out'	'% Open'
44	1000243	'Cond. Supply Pumps Press. PID Out'	'% Speed'
45	1000244	'Cond. Transfer Pump 1 Spd Command'	'% Speed'
46	1000245	'Cond. Transfer Pump 2 Spd Command'	'% Speed'
47	1000246	'Cond. Transfer Pump 3 Spd Command'	'% Speed'
48	1000247	'Cond. Transfer Pump 4 Spd Command'	'% Speed'
49	1000248	'Cond. Receiver Tank Outlet pH PID Out'	'%'
50	1000249	'Desuper. 2 IPS Press. PID Out'	'% Open'
51	1000250	'Desuper. 2 IPS Temp. PID Out'	'% Open'

52	1000251	'Desuper. 2 MPS Press. PID Out'	'% Open'
53	1000252	'Desuper. 2 MPS Temp. PID Out'	'% Open'
54	1000253	'Desuper. 2 LPS Press. PID Out'	'% Open'
55	1000254	'Desuper. 2 LPS Temp. PID Out'	'% Open'
56	1000255	'Neutralization Tank Disch. pH Acid PID Out'	'% Speed'
57	1000256	'Neutralization Tank Disch. pH Caustic PID Out'	'% Speed'
58	1000257	'Outside Air Relative Humidity'	'%RH'
59	1000258	'Ammonia Header Pressure'	'PSIG'
60	1000259	'IPS Header Pressure'	'PSIG'
61	1000260	'Cond. Supply Header Pressure'	'PSIG'
62	1000261	'CHP Instrument Air Header Pressure'	'PSIG'
63	1000262	'Fuel Gas Comp. 100 Inlet Gas Press.'	'PSIG'
64	1000263	'Ammonia Storage Tank 1 Temp.'	'DegF'
65	1000264	'Ammonia Storage Tank 2 Temp.'	'DegF'
66	1000265	'Cooling Tower Discharge Temp.'	'DegF'
67	1000266	'Cooling Tower Return Water Temp.'	'DegF'
68	1000267	'Cooling Water Pumps Disch. Header Press.'	'PSIG'
69	1000268	'SCB Instrument Air Header Press.'	'PSIG'
70	1000269	'Cond. Receiver CR-4106 Conductivity'	'uS/cm'
71	1000270	'Cond. Receiver CR-4107 Conductivity'	'uS/cm'
72	1000271	'Cond. Receiver CR-4108 Conductivity'	'uS/cm'
73	1000272	'Makeup Mixing Water Temperature'	'DegF'
74	1000273	'Deaerator Tank 1 Pressure'	'PSIG'
75	1000274	'Deaerator Tank 1 Temperature'	'DegF'
76	1000275	'Cooling Tower 1 Level'	'Inches'
77	1000276	'IPS Deaerator Tank Steam Pressure'	'PSIG'
78	1000277	'IPS Deaerator Tank Steam Temp.'	'DegF'
79	1000278	'Deaerator Tank 2 Level'	'Inches'
80	1000279	'Deaerator Tank 2 Pressure '	'PSIG'
81	1000280	'Deaerator Tank 2 Temperature'	'DegF'
82	1000281	'Cooling Tower 2 Level '	'Inches'
83	1000282	'Outside Air Wet Bulb Temperature'	'DegF'
84	1000283	'Raw Water Storage Tank Level'	'Inches'
85	1000284	'Ammonia Storage Tank 1 Level'	'Inches'
86	1000285	'Ammonia Storage Tank 1 Pressure'	'PSIG'
87	1000286	'Ammonia Storage Tank 2 Level'	'Inches'
88	1000287	'Ammonia Storage Tank 2 Pressure'	'PSIG'
89	1000288	'Condensate Storage Tank Level'	'Inches'
90	1000289	'Neutralization Tank Level'	'Inches'
91	1000290	'Neutralization Tank Disch. pH'	'pH'
92	1000291	'Neutralization Tank Recirc. pH'	'pH'
93	1000292	'Gas Meter Inlet Gas Press.'	'PSIG'
94	1000293	'Gas Meter 50 PSIG Delivery Press.'	'PSIG'
95	1000294	'Gas Meter 100 PSIG Delivery Press.'	'PSIG'
96	1000295	'BFPM_001 Bearing Temp. A'	'DegF'
97	1000296	'BFPM_001 Bearing Temp. B'	'DegF'
98	1000297	'BFPM_002 Bearing Temp. A'	'DegF'
99	1000298	'BFPM_002 Bearing Temp. B'	'DegF'
100	1000299	'BFPM_003 Bearing Temp. A'	'DegF'
101	1000300	'BFPM_003 Bearing Temp. B'	'DegF'
102	1000301	'BFPM Discharge Header Pressure'	'PSIG'
103	1000302	'Desuper. 2 HPS Press. Valve Outlet Temp.'	'DegF'

104	1000303	'Boiler Feedwater Pump DH Pressure'	'PSIG'
105	1000304	'Desuper. Pumps Disch. Header Press.'	'PSIG'
106	1000305	'HPS Header Temperature'	'DegF'
107	1000306	'Chemical Feed Skid ORP'	'null'
108	1000307	'Chemical Feed Skid Conductivity'	'uS/cm'
109	1000308	'SCB HPS Steam Header Temp. #1'	'DegF'
110	1000309	'Condensate Receiver Level'	'Inches'
111	1000310	'MPS Press. Valve Outlet Temp.'	'DegF'
112	1000311	'LPS Header Temperature'	'DegF'
113	1000312	'SCB HPS Steam Header Temp. #2'	'DegF'
114	1000313	'Condensate Receiver Outlet pH'	'pH'
115	1000314	'Amine Chemical Feed Tank 6 Level'	'Inches'
116	1000315	'Makeup Water Pumps Disch. Header Press.'	'PSIG'
117	1000316	'Cond. Cartridge Filters dP'	'PSID'
118	1000317	'Pumped Condensate Return pH'	'pH'
119	1000318	'Amine Storage Tank Level'	'Inches'
120	1000319	'Scavenger Storage Tank Level'	'Inches'
121	1000320	'HP Polymer Storage Tank Level'	'Inches'
122	1000321	'HP Phosphates Storage Tank Level'	'Inches'
123	1000322	'Makeup Water Chlorine Residual'	'ppm'
124	1000323	'LP Polymer Storage Tank Level'	'Inches'
125	1000324	'Acid Chemical Storage Tank Level'	'Inches'
126	1000325	'Caustic Chemical Storage Tank Level'	'Inches'
127	1000326	'Cooling Tower Water Temp. PID SP'	'DegF'
128	1000327	'MS Plant Master PID SP'	'PSIG'
129	1000328	'HPS Plant Master PID SP'	'PSIG'
130	1000329	'Desuper. 1 HPS Press. PID SP'	'PSIG'
131	1000330	'Desuper. 1 HPS Temp. PID SP'	'DegF'
132	1000331	'Desuper. 2 HPS Press. PID SP'	'PSIG'
133	1000332	'Desuper. 2 HPS Temp. PID SP'	'DegF'
134	1000333	'Desuper. 1 MPS Press. PID SP'	'PSIG'
135	1000334	'Desuper. 1 MPS Temp. PID SP'	'DegF'
136	1000335	'Desuper. 1 IPS Press. PID SP'	'PSIG'
137	1000336	'Desuper. 1 IPS Temp. PID SP'	'DegF'
138	1000337	'Desuper. 1 LPS Press. PID SP'	'PSIG'
139	1000338	'Desuper. 1 LPS Temp. PID SP'	'DegF'
140	1000339	'Deaerator Tank 1 Level PID SP'	'Inches'
141	1000340	'Deaerator Tank 2 Level PID SP'	'Inches'
142	1000341	'Deaerator Tank 1 Press. PID SP'	'PSIG'
143	1000342	'Deaerator Tank 2 Press. PID SP'	'PSIG'
144	1000343	'Makeup Water Recirc Valve Press. PID SP'	'PSIG'
145	1000344	'Raw Water Storage Tank Level PID SP'	'Inches'
146	1000345	'Cond. Receiver Tank Level PID SP'	'Inches'
147	1000346	'Cond. Supply Pumps Press. PID SP'	'PSIG'
148	1000347	'Cond. Receiver Tank Outlet pH PID SP'	'pH'
149	1000348	'Neutralization Tank Disch. pH Acid PID SP'	'pH'
150	1000349	'Neutralization Tank Disch. pH Caustic PID SP'	'pH'
151	1000350	'Desuper. 2 MPS Press. PID SP'	'PSIG'
152	1000351	'Desuper. 2 MPS Temp. PID SP'	'DegF'
153	1000352	'Desuper. 2 LPS Press. PID SP'	'PSIG'
154	1000353	'Desuper. 2 LPS Temp. PID SP'	'DegF'
155	1000354	'Desuper. 2 IPS Press. PID SP'	'PSIG'

156	1000355	'Desuper. 2 IPS Temp. PID SP'	'DegF'
157	1000356	'Cooling Tower Fan 1 VFD Current Draw'	'Amps'
158	1000357	'Cooling Tower Fan 1 Actual Spd'	'% Speed'
159	1000358	'Cooling Tower Fan 2 VFD Current Draw'	'Amps'
160	1000359	'Cooling Tower Fan 2 Actual Spd'	'% Speed'
161	1000360	'Desuper. 1 HPS Press. Valve Outlet Temp.'	'DegF'
162	1000361	'Cond. Transfer Pump 1 VFD Current Draw'	'Amps'
163	1000362	'Cond. Transfer Pump 1 Actual Spd'	'% Speed'
164	1000363	'Cond. Transfer Pump 2 VFD Current Draw'	'Amps'
165	1000364	'Cond. Transfer Pump 2 Actual Spd'	'% Speed'
166	1000365	'Cond. Transfer Pump 3 VFD Current Draw'	'Amps'
167	1000366	'Cond. Transfer Pump 3 Actual Spd'	'% Speed'
168	1000367	'Cond. Transfer Pump 4 VFD Current Draw'	'Amps'
169	1000368	'Cond. Transfer Pump 4 Actual Spd'	'% Speed'
170	1000369	'IPS Deaerator Tank Steam Flow'	'SCFM'
171	1000370	'Raw Water Flow'	'GPM'
172	1000371	'Fuel Gas Comp. 100 Outlet Gas Press.'	'PSIG'
173	1000372	'Fuel Gas Accum. 100 Outlet Press.'	'PSIG'
174	1000373	'Gas Meter Gas Flow'	'SCFM'
175	1000374	'MS Header Pressure #1'	'PSIG'
176	1000375	'HPS Header Pressure #1'	'PSIG'
177	1000377	'MS Header Pressure #2'	'PSIG'
178	1000378	'HPS Header Pressure #2'	'PSIG'
179	1000380	'SCB HPS Steam Header Press. #1'	'PSIG'
180	1000381	'Cond. Return Header Pressure'	'PSIG'
181	1000382	'MPS Press. Valve Outlet Press.'	'PSIG'
182	1000383	'LPS Header Pressure'	'PSIG'
183	1000384	'SCB HPS Steam Header Press. #2'	'PSIG'
184	1000385	'Totalized Fuel Gas Consumption'	'SCF'
185	1000386	'Totalized Ammonia Consumption'	'Gals'
186	1000387	'Totalized Raw Water Consumption'	'Gals'
187	1000388	'Totalized Steam Production'	'SCF'
188	1000389	'Totalized Utility Import Power Consumption'	'kWh'
189	1000390	'Totalized Power Production'	'kWh'
190	1000391	'MPS Press. Valve #1 Actual Pos.'	'% Open'
191	1000392	'LPS Press. Valve #1 Actual Pos.'	'% Open'
192	1000393	'MPS Temp. Valve #1 Actual Pos.'	'% Open'
193	1000395	'MPS Press. Valve #2 Actual Pos.'	'% Open'
194	1000398	'LPS Press. Valve #1 Outlet Temp.'	'DegF'
195	1000399	'LPS Press. Valve #2 Outlet Temp.'	'DegF'
196	1000400	'Boiler 2 Air Flow'	'SCFM'
197	1000401	'Boiler 2 Exhaust Pressure'	'PSIG'
198	1000402	'Boiler 2 Drum Level'	'inWC'
199	1000403	'Boiler 2 Drum Pressure'	'PSIG'
200	1000404	'Boiler 2 Drum Actual Level'	'inWC'
201	1000405	'Boiler 2 Fuel/Air Ratio Actual'	'null'
202	1000406	'Boiler 2 FD Fan Speed'	'%'
203	1000407	'Boiler 2 Feedwater Flow'	'SCFM'
204	1000408	'Boiler 2 Flue Gas CO'	'null'
205	1000409	'Boiler 2 Flue Gas Oxygen'	'%O2'
206	1000410	'Boiler 2 FGR Damper Position'	'%'
207	1000411	'Boiler 2 FGR Fan Speed'	'%'

208	1000412	'Boiler 2 FGR Temperature'	'DegF'
209	1000413	'Boiler 2 Flue Gas Economizer Inlet Temperature'	'DegF'
210	1000414	'Boiler 2 Flue Gas Economizer Outlet Temperature'	'DegF'
211	1000415	'Boiler 2 Flame Signal 1'	'null'
212	1000416	'Boiler 2 Flame Signal 2'	'null'
213	1000417	'Boiler 2 Furnace Output'	'%'
214	1000418	'Boiler 2 Furnace Pressure'	'inWC'
215	1000419	'Boiler 2 Gas Flow Control Valve'	'%'
216	1000420	'Boiler 2 Gas Flow'	'SCFH'
217	1000421	'Boiler 2 Gas Flow dP'	'PSID'
218	1000422	'Boiler 2 Gas Measured Flow'	'InWC'
219	1000423	'Boiler 2 Gas Pressure'	'PSIG'
220	1000424	'Boiler 2 Gas Temperature'	'DegF'
221	1000425	'Boiler 2 Header Gas Flow'	'SCFH'
222	1000426	'Boiler 2 Header Gas Pressure'	'PSIG'
223	1000427	'Boiler 2 Inlet Box Damper Position'	'%'
224	1000428	'Boiler 2 Inlet Draft Fan Speed'	'%'
225	1000429	'Boiler 2 Inlet Vain Damper Position'	'%'
226	1000430	'Boiler 2 Jack Position'	'%'
227	1000431	'Boiler 2 Master Control Output'	'%'
228	1000432	'Boiler 2 Master Demand'	'%'
229	1000433	'Boiler 2 Ammonia Flow'	'SCFM'
230	1000434	'Boiler 2 Ammonia Tank Temperature'	'DegF'
231	1000435	'Boiler 2 Ammonia Vapor Outlet Temperature'	'DegF'
232	1000436	'Boiler 2 NOx'	'PPM'
233	1000437	'Boiler 2 Oil Flow'	'GPM'
234	1000438	'Boiler 2 Oil Measured Flow'	'GPM'
235	1000439	'Boiler 2 Oil Pressure'	'PSIG'
236	1000440	'Boiler 2 Oil Temperature'	'DegF'
237	1000441	'Boiler 2 Remote Demand'	'%'
238	1000442	'Boiler 2 SCR Catalyst Temperature'	'DegF'
239	1000443	'Boiler 2 Superheated Steam Measured Flow'	'PPH'
240	1000444	'Boiler 2 Stack Opacity'	'null'
241	1000445	'Boiler 2 Steam Drum Pressure'	'PSIG'
242	1000446	'Boiler 2 Steam Drum Temperature'	'DegF'
243	1000447	'Boiler 2 Steam Flow'	'PPH'
244	1000448	'Boiler 2 Steam Flow dP'	'PSID'
245	1000449	'Boiler 2 Steam Flow Precent'	'%'
246	1000450	'Boiler 2 Steam Header Pressure'	'PSIG'
247	1000451	'Boiler 2 Steam Header Temperature'	'DegF'
248	1000452	'Boiler 2 Steam Outlet Pressure'	'PSIG'
249	1000453	'Boiler 2 Steam Outlet Temperature'	'DegF'
250	1000454	'Boiler 3 Air Flow'	'SCFM'
251	1000455	'Boiler 3 Exhaust Pressure'	'InWC'
252	1000456	'Boiler 3 Drum Level Actual'	'InWC'
253	1000457	'Boiler 3 Drum Pressure'	'PSIG'
254	1000458	'Boiler 3 Drum Level'	'InWC'
255	1000459	'Boiler 3 Fuel/Air Ratio Actual'	'null'
256	1000460	'Boiler 3 FD Fan Speed'	'%'
257	1000461	'Boiler 3 Feedwater Flow'	'SCFM'
258	1000462	'Boiler 3 Flue Gas CO'	'null'
259	1000463	'Boiler 3 Flue Gas Oxygen'	'%O2'

260	1000464	'Boiler 3 FGR Damper Position'	'%'
261	1000465	'Boiler 3 FGR Fan Speed'	'%'
262	1000466	'Boiler 3 FGR Temperature'	'DegF'
263	1000467	'Boiler 3 Flue Gas Economizer Inlet Temperature'	'DegF'
264	1000468	'Boiler 3 Flue Gas Economizer Outlet Temperature'	'DegF'
265	1000469	'Boiler 3 Flame Signal 1'	'null'
266	1000470	'Boiler 3 Flame Signal 2'	'null'
267	1000471	'Boiler 3 Furnace Output'	'%'
268	1000472	'Boiler 3 Furnace Pressure'	'InWC'
269	1000473	'Boiler 3 Gas Flow Control Valve Position'	'%'
270	1000474	'Boiler 3 Gas Flow'	'SCFH'
271	1000475	'Boiler 3 Gas Flow dP'	'PSID'
272	1000476	'Boiler 3 Gas Measured Flow'	'SCFH'
273	1000477	'Boiler 3 Gas Pressure'	'PSIG'
274	1000478	'Boiler 3 Gas Temperature'	'DegF'
275	1000479	'Boiler 3 Header Gas Flow'	'SCFH'
276	1000480	'Boiler 3 Header Gas Pressure'	'PSIG'
277	1000481	'Boiler 3 Inlet Box Damper Position'	'%'
278	1000482	'Boiler 3 ID Fan Speed'	'%'
279	1000483	'Boiler 3 Inlet Vane Damper Position'	'%'
280	1000484	'Boiler 3 Jack Position'	'%'
281	1000485	'Boiler 3 Master Control Output'	'%'
282	1000486	'Boiler 3 Master Demand'	'%'
283	1000487	'Boiler 3 Ammonia Flow'	'SCFM'
284	1000488	'Boiler 3 Ammonia Tank Temperature'	'DegF'
285	1000489	'Boiler 3 Ammonia Vapor Outlet Temperature'	'DegF'
286	1000490	'Boiler 3 NOx'	'PPM'
287	1000491	'Boiler 3 Oil Flow'	'GPM'
288	1000492	'Boiler 3 Oil Measured Flow'	'GPM'
289	1000493	'Boiler 3 Oil Pressure'	'PSIG'
290	1000494	'Boiler 3 Oil Temperature'	'DegF'
291	1000495	'Boiler 3 Remote Demand'	'%'
292	1000496	'Boiler 3 SCR Catalyst Temperature'	'DegF'
293	1000497	'Boiler 3 Superheater Steam Flow'	'PPH'
294	1000498	'Boiler 3 Stack Opacity'	'null'
295	1000499	'Boiler 3 Steam Drum Pressure'	'PSIG'
296	1000500	'Boiler 3 Steam Drum Temperature'	'DegF'
297	1000501	'Boiler 3 Steam Flow'	'PPH'
298	1000502	'Boiler 3 Steam Flow dP'	'PSID'
299	1000503	'Boiler 3 Steam Flow Percent'	'%'
300	1000504	'Boiler 3 Steam Header Pressure'	'PSIG'
301	1000505	'Boiler 3 Steam Header Temperature'	'DegF'
302	1000506	'Boiler 3 Steam Outlet Pressure'	'PSIG'
303	1000507	'Boiler 3 Steam Outlet Temperature'	'DegF'
304	1000508	'Boiler 4 Air Flow'	'SCFM'
305	1000509	'Boiler 4 Exhaust Pressure'	'InWC'
306	1000510	'Boiler 4 Drum Level Actual'	'InWC'
307	1000511	'Boiler 4 Drum Pressure'	'PSIG'
308	1000512	'Boiler 4 Drum Level'	'InWC'
309	1000513	'Boiler 4 Fuel/Air Ratio Actual'	'null'
310	1000514	'Boiler 4 FD Fan Speed'	'%'
311	1000515	'Boiler 4 Feedwater Flow'	'SCFM'

312	1000516	'Boiler 4 Flue Gas CO'	'null'
313	1000517	'Boiler 4 Flue Gas Oxygen'	'%O2'
314	1000518	'Boiler 4 FGR Damper Position'	'%'
315	1000519	'Boiler 4 FGR Fan Speed'	'%'
316	1000520	'Boiler 4 FGR Temperature'	'DegF'
317	1000521	'Boiler 4 Flue Gas Economizer Inlet Temperature'	'DegF'
318	1000522	'Boiler 4 Flue Gas Economizer Outlet Temperature'	'DegF'
319	1000523	'Boiler 4 Flame Signal 1'	'null'
320	1000524	'Boiler 4 Flame Signal 2'	'null'
321	1000525	'Boiler 4 Furnace Output'	'%'
322	1000526	'Boiler 4 Furnace Pressure'	'PSIG'
323	1000527	'Boiler 4 Gas Flow Control Valve Position'	'%'
324	1000528	'Boiler 4 Gas Flow'	'SCFH'
325	1000529	'Boiler 4 Gas Flow dP'	'PSID'
326	1000530	'Boiler 4 Gas Measured Flow'	'SCFH'
327	1000531	'Boiler 4 Gas Pressure'	'PSIG'
328	1000532	'Boiler 4 Gas Temperature'	'DegF'
329	1000533	'Boiler 4 Gas Header Flow'	'SCFH'
330	1000534	'Boiler 4 Gas Header Pressure'	'PSIG'
331	1000535	'Boiler 4 Inlet Box Position'	'%'
332	1000536	'Boiler 4 ID Fan Speed'	'%'
333	1000537	'Boiler 4 Inlet Vane Damper Position'	'%'
334	1000538	'Boiler 4 Jack Position'	'%'
335	1000539	'Boiler 4 Master Control Output'	'%'
336	1000540	'Boiler 4 Master Demand'	'%'
337	1000541	'Boiler 4 Ammonia Flow'	'SCFM'
338	1000542	'Boiler 4 Ammonia Tank Temperature'	'DegF'
339	1000543	'Boiler 4 Ammonia Vapor Outlet Temperature'	'DegF'
340	1000544	'Boiler 4 NOx'	'PPM'
341	1000545	'Boiler 4 Oil Flow'	'GPM'
342	1000546	'Boiler 4 Oil Measured Flow'	'GPM'
343	1000547	'Boiler 4 Oil Pressure'	'PSIG'
344	1000548	'Boiler 4 Oil Temperature'	'DegF'
345	1000549	'Boiler 4 Remote Demand'	'%'
346	1000550	'Boiler 4 SCR Catalyst Temperature'	'DegF'
347	1000551	'Boiler 4 Superheater Steam Flow'	'PPH'
348	1000552	'Boiler 4 Steam Outlet Temperature'	'DegF'
349	1000553	'Boiler 4 Stack Opacity'	'null'
350	1000554	'Boiler 4 Steam Drum Pressure'	'PSIG'
351	1000555	'Boiler 4 Steam Drum Temperature'	'DegF'
352	1000556	'Boiler 4 Steam Flow'	'PPH'
353	1000557	'Boiler 4 Steam Flow dP'	'PSID'
354	1000558	'Boiler 4 Steam Flow Percent'	'%'
355	1000559	'Boiler 4 Steam Header Pressure'	'PSIG'
356	1000560	'Boiler 4 Steam Header Temperature'	'DegF'
357	1000561	'Boiler 4 Steam Outlet Pressure'	'PSIG'
358	1000562	'CTG Speed'	'%'
359	1000563	'CTG Generator Speed'	'%'
360	1000564	'CTG Generator Average Current'	'Amps'
361	1000565	'CTG Air Inlet Temperature'	'DegF'
362	1000566	'CTG Average T5 Temperature'	'DegF'
363	1000567	'CTG T5 Setpoint'	'DegF'

364	1000568	'CTG Generator Average Line to Line Voltage'	'Volts'
365	1000569	'CTG Lube Oil Filter dP'	'PSID'
366	1000570	'CTG Lube Oil Header Pressure'	'PSIG'
367	1000571	'CTG Lube Oil Header Temperature'	'DegF'
368	1000572	'CTG Engine 1 Bearing Drain Temperature'	'DegF'
369	1000573	'CTG Bus Average Line to Line Voltage'	'Volt'
370	1000574	'CTG Engine 2&3 Bearing Drain Temperature'	'DegF'
371	1000575	'CTG Engine 4&5 Bearing Drain Temperature'	'DegF'
372	1000576	'CTG Engine 1 Bearing X Axial Vibration'	'mil pp'
373	1000577	'CTG Engine 1 Y Axial Vibration'	'mil pp'
374	1000578	'CTG Engine 2 X Axial Vibration'	'mil pp'
375	1000579	'CTG Engine 2 Y Axial Vibration'	'mil pp'
376	1000580	'CTG Engine 3 X Axial Vibration'	'mil pp'
377	1000581	'CTG Engine 3 Y Axial Vibration'	'mil pp'
378	1000582	'CTG Engine 4 X Axial Vibration'	'mil pp'
379	1000583	'CTG Bus Phase AB Voltage'	'Volt'
380	1000584	'CTG Engine 4 Y Axial Vibration'	'mil pp'
381	1000585	'CTG Engine 5 X Axial Vibration'	'mil pp'
382	1000586	'CTG Engine 5 Y Axial Vibration'	'mil pp'
383	1000587	'CTG Engine GP Bearing Axial Displacement'	'mil'
384	1000588	'CTG Engine PT Bearing Axial Displacement'	'mil'
385	1000589	'CTG Engine GP Thrust Bearing Temperature'	'DegF'
386	1000590	'CTG Bus Phase BC Voltage'	'Volt'
387	1000591	'CTG Engine PT Thrust Bearing Temperature'	'DegF'
388	1000592	'CTG Gearbox Vibration'	'g'
389	1000593	'CTG Generator DE Bearing Temperature'	'DegF'
390	1000594	'CTG Generator DE Velocity Vibration'	'in/sec'
391	1000595	'CTG Generator EE Bearing Temperature'	'DegF'
392	1000596	'CTG Generator EE Velocity Vibration'	'in/sec'
393	1000597	'CTG Bus Phase CA Voltage'	'Volt'
394	1000598	'CTG Generator Power Factor'	'null'
395	1000599	'CTG Generator Frequency'	'Hz'
396	1000600	'CTG Generator Apparent Power'	'kVA'
397	1000601	'CTG Generator Reactive Power'	'kVAR'
398	1000602	'CTG Generator Phase AB Voltage'	'Volts'
399	1000603	'CTG Generator Phase A Current'	'Amps'
400	1000604	'CTG Generator Phase BC Voltage'	'Volts'
401	1000605	'CTG Generator Phase B Current'	'Amps'
402	1000606	'CTG Generator Phase CA Voltage'	'Volts'
403	1000607	'CTG Generator Phase C Current'	'Amps'
404	1000608	'CTG Generator Real Power'	'kW'
405	1000609	'CTG Instrument Air Supply Pressure'	'PSIG'
406	1000610	'CTG Gas Flow'	'lb/hr'
407	1000611	'CTG Gas Supply Pressure'	'PSIG'
408	1000612	'CTG Air Inlet dP'	'InH2O'
409	1000613	'CTG Liquid Fuel Boost Pressure'	'PSIG'
410	1000614	'CTG Liquid Fuel Flow'	'lb/min'
411	1000615	'CTG Liquid Fuel Filter dP'	'PSID'
412	1000616	'CTG Exhaust Temperature'	'DegF'
413	1000617	'FGC Compressor Amps'	'Amps'
414	1000618	'FGC Compressor Discharge Pressure'	'PSIG'
415	1000619	'FGC Compressor Discharge Temperature'	'DegF'

416	1000620	'FGC Compressor Lube Oil Pressure'	'PSIG'
417	1000621	'FGC Compressor Lube Oil Temperature'	'DegF'
418	1000622	'FGC Compressor Lube Oil dP'	'PSID'
419	1000623	'FGC Compressor Gas Supply Pressure'	'PSIG'
420	1000624	'FGC Compressor SS Position'	'%'
421	1000625	'FGC Compressor Suction Temperature'	'DegF'
422	1000626	'Fuel Oil Conditioning Pump 1A Inlet Pressure'	'PSIG'
423	1000627	'Fuel Oil Conditioning Pump 1A Inlet Temperature'	'DegF'
424	1000628	'Fuel Oil Conditioning Pump 1A Outlet Pressure'	'PSIG'
425	1000629	'Fuel Oil Conditioning Pump 1A Speed'	'%'
426	1000630	'Fuel Oil Conditioning Pump 1A Vibration'	'mm'
427	1000631	'Fuel Oil Conditioning Pump 1B Inlet Pressure'	'PSIG'
428	1000632	'Fuel Oil Conditioning Pump 1B Inlet Temperature'	'DegF'
429	1000633	'Fuel Oil Conditioning Pump 1B Outlet Pressure'	'PSIG'
430	1000634	'Fuel Oil Conditioning Pump 1B Speed'	'%'
431	1000635	'Fuel Oil Conditioning Pump 1B Vibration'	'mm'
432	1000636	'Fuel Oil Conditioning Fuel Oil Tank 3 Level'	'%'
433	1000637	'Fuel Oil Conditioning Heater 1 Temperature'	'DegF'
434	1000638	'Fuel Oil System Discharge Header Pressure'	'PSIG'
435	1000639	'Fuel Oil System Forwarding Discharge Pressure'	'PSIG'
436	1000640	'Fuel Oil System Unloading Pump 1 Speed'	'%'
437	1000641	'Fuel Oil System Unloading Pump 2 Speed'	'%'
438	1000642	'Fuel Oil System Supply Pressure'	'PSIG'
439	1000643	'Fuel Oil System Tank 1 Level'	'inches'
440	1000644	'Fuel Oil System Tank 2 Level'	'Inches'
441	1000645	'Fuel Oil System Unloading Flow'	'GPM'
442	1000646	'HRSG Air Flow'	'SCFM'
443	1000647	'HRSG Duct Bruner Firing Rate'	'null'
444	1000648	'HRSG Drum Level'	'Inches'
445	1000649	'HRSG Drum Pressure'	'PSIG'
446	1000650	'HRSG Evaporator Outlet Temperature'	'DegF'
447	1000651	'HRSG Fuel Gas Ammonia Level'	'ppm'
448	1000652	'HRSG Flue Gas NOx'	'ppm'
449	1000653	'HRSG Flue Gas Oxygen'	'%O2'
450	1000654	'HRSG Feedwater Flow Control Valve Position'	'%'
451	1000655	'HRSG Heater A1 Temperature'	'DegF'
452	1000656	'HRSG Heater A2 Temperature'	'DegF'
453	1000657	'HRSG Heater A3 Temperature'	'DegF'
454	1000658	'HRSG Heater B1 Temperature'	'DegF'
455	1000659	'HRSG Heater B2 Temperature'	'DegF'
456	1000660	'HRSG Heater B3 Temperature'	'DegF'
457	1000661	'HRSG Heater Outlet Temperature'	'DegF'
458	1000662	'HRSG Main Steam Pressure'	'PSIG'
459	1000663	'HRSG Ammonia Flow'	'SCFM'
460	1000664	'HRSG Ammonia Flow Control Valve Position'	'%'
461	1000665	'HRSG SCR dP'	'InWC'
462	1000666	'HRSG SCR Inlet Temperature'	'DegF'
463	1000667	'HRSG Steam Header Temperature'	'DegF'
464	1000668	'HRSG Ammonia Strainer dP'	'PSID'
465	1000669	'HRSG Steam Ventilation Valve'	'%'
466	1000670	'HRSG Spray Water Temperature Control Valve'	'%'
467	1000671	'HVAC City Water Control Valve'	'%'

468	1000672	'HVAC Effluent Pressure'	'PSIG'
469	1000673	'HVAC GRC Pressure at Main'	'PSIG'
470	1000674	'HVAC Library Pressure'	'PSIG'
471	1000675	'HVAC Meter House Temperature'	'DegF'
472	1000676	'HVAC Orchard Hill Pressure'	'PSIG'
473	1000677	'HVAC RO Trailer Temperature'	'DegF'
474	1000678	'HVAC Sylvan Dorms Pressure'	'PSIG'
475	1000679	'HVAC Southwest Pressure'	'PSIG'
476	1000680	'HRSG Main Fuel Gas Flow'	'lb/hr'
477	1000681	'HRSG Main Fuel Gas Pressure'	'PSIG'
478	1000682	'HRSG Main Fuel Gas Temperature'	'DegF'
479	1001303	'HRSG Feedwater Flow'	'lb/hr'
480	1001304	'HRSG Main Steam Flow'	'lb/hr'
481	1001305	'CTG Actual Real Power'	'kW'
482	1001306	'CTG Real Power'	'kW'
483	1001307	'LPS Press. Valve #2 Actual Pos.'	'% Open'
484	1001308	'LPS Temp. Valve #1 Actual Pos.'	'% Open'
485	1001309	'LPS Temp. Valve #2 Actual Pos.'	'% Open'
486	1001310	'Boiler 200 Fuel Oil Daily Total'	'Gals'
487	1001311	'Boiler 200 Fuel Oil Weekly Total'	'Gals'
488	1001312	'Boiler 200 Fuel Oil Monthly Total'	'Gals'
489	1001313	'Boiler 200 Fuel Gas Daily Total'	'lbs'
490	1001314	'Boiler 200 Fuel Gas Weekly Total'	'SCF'
491	1001315	'Boiler 200 Fuel Gas Monthly Total'	'SCF'
492	1001316	'Boiler 200 Ammonia Daily Total'	'lbs'
493	1001317	'Boiler 200 Ammonia Weekly Total'	'lbs'
494	1001318	'Boiler 200 Ammonia Monthly Total'	'lbs'
495	1001319	'Boiler 200 Steam Daily Total'	'lbs'
496	1001320	'Boiler 200 Steam Weekly Total'	'lbs'
497	1001321	'Boiler 200 Steam Monthly Total'	'lbs'
498	1001322	'Boiler 200 Feedwater Daily Total'	'lbs'
499	1001323	'Boiler 200 Feedwater Weekly Total'	'lbs'
500	1001324	'Boiler 200 Feedwater Monthly Total'	'lbs'
501	1001325	'Boiler 300 Fuel Oil Daily Total'	'Gals'
502	1001326	'Boiler 300 Fuel Oil Weekly Total'	'Gals'
503	1001327	'Boiler 300 Fuel Oil Monthly Total'	'Gals'
504	1001328	'Boiler 300 Fuel Gas Daily Total'	'SCF'
505	1001329	'Boiler 300 Fuel Gas Weekly Total'	'SCF'
506	1001330	'Boiler 300 Fuel Gas Monthly Total'	'SCF'
507	1001331	'Boiler 300 Ammonia Daily Total'	'lbs'
508	1001332	'Boiler 300 Ammonia Weekly Total'	'lbs'
509	1001333	'Boiler 300 Ammonia Monthly Total'	'lbs'
510	1001334	'Boiler 300 Steam Daily Total'	'lbs'
511	1001335	'Boiler 300 Steam Weekly Total'	'lbs'
512	1001336	'Boiler 300 Steam Monthly Total'	'lbs'
513	1001337	'Boiler 300 Feedwater Daily Total'	'lbs'
514	1001338	'Boiler 300 Feedwater Weekly Total'	'lbs'
515	1001339	'Boiler 300 Feedwater Monthly Total'	'lbs'
516	1001340	'Boiler 400 Fuel Oil Daily Total'	'Gals'
517	1001341	'Boiler 400 Fuel Oil Weekly Total'	'Gals'
518	1001342	'Boiler 400 Fuel Oil Monthly Total'	'Gals'
519	1001343	'Boiler 400 Fuel Gas Daily Total'	'SCF'

520	1001344	'Boiler 400 Fuel Gas Weekly Total'	'SCF'
521	1001345	'Boiler 400 Fuel Gas Monthly Total'	'SCF'
522	1001346	'Boiler 400 Ammonia Daily Total'	'lbs'
523	1001347	'Boiler 400 Ammonia Weekly Total'	'lbs'
524	1001348	'Boiler 400 Ammonia Monthly Total'	'lbs'
525	1001349	'Boiler 400 Steam Daily Total'	'lbs'
526	1001350	'Boiler 400 Steam Weekly Total'	'lbs'
527	1001351	'Boiler 400 Steam Monthly Total'	'lbs'
528	1001352	'Boiler 400 Feedwater Daily Total'	'lbs'
529	1001353	'Boiler 400 Feedwater Weekly Total'	'lbs'
530	1001354	'Boiler 400 Feedwater Monthly Total'	'lbs'
531	1001355	'Raw Water Daily Total'	'Gals'
532	1001356	'Raw Water Weekly Total'	'Gals'
533	1001357	'Raw Water Monthly Total'	'Gals'
534	1001358	'HRSG Fuel Gas Weekly Total'	'SCF'
535	1001359	'HRSG Fuel Gas Monthly Total'	'SCF'
536	1001360	'HRSG Ammonia Daily Total'	'lbs'
537	1001361	'HRSG Ammonia Weekly Total'	'lbs'
538	1001362	'HRSG Ammonia Monthly Total'	'lbs'
539	1001363	'HRSG Steam Daily Total'	'lbs'
540	1001364	'HRSG Steam Weekly Total'	'lbs'
541	1001365	'HRSG Steam Monthly Total'	'lbs'
542	1001366	'HRSG Feedwater Daily Total'	'lbs'
543	1001367	'HRSG Feedwater Weekly Total'	'lbs'
544	1001368	'HRSG Feedwater Monthly Total'	'lbs'
545	1001369	'HRSG Fuel Gas Daily Total'	'SCF'
546	1001370	'CTG Fuel Oil Daily Total'	'lbs'
547	1001371	'CTG Fuel Oil Weekly Total'	'lbs'
548	1001372	'CTG Fuel Oil Monthly Total'	'lbs'
549	1001373	'CTG Fuel Gas Daily Total'	'lbs'
550	1001374	'CTG Fuel Gas Weekly Total'	'lbs'
551	1001375	'CTG Fuel Gas Monthly Total'	'lbs'
552	1001376	'CTG Real Power Daily Total'	'kWh'
553	1001377	'CTG Real Power Weekly Total'	'kWh'
554	1001378	'CTG Real Power Monthly Total'	'kWh'
555	1001379	'STG2_kw_actual'	'kw'
556	1001380	'STG2_kw_hourly_TOT'	'kw'
557	1001381	'STG2_kw_daily_TOT'	'kwh'
558	1001382	'STG2_kw_weekly_TOT'	'kwh'
559	1001383	'STG2_kw_monthly_TOT'	'kwh'
560	1001384	'STG2 Inlet Steam Flow'	'lbs/hr'
561	1001385	'STG2 Inlet Steam Pressure'	'PSIG'
562	1001386	'STG2 Outlet Steam Pressure'	'PSIG'
563	1001387	'STG2 Outlet Steam Temperature'	'DegF'
564	1001388	'Boiler 2 NH3 Slip'	'PPM'
565	1001389	'Boiler 2 Hot Bypass1 Req Pos'	'% Open'
566	1001390	'Boiler 2 Hot Bypass 2 Req Pos'	'%Open'
567	1001391	'Boiler 2 Hot Bypass 1 Act Position'	'%Open'
568	1001392	'Boiler 2 Hot Bypass 2 Act Pos'	'% Open'
569	1001393	'Boiler 3 NH3 Slip'	'PPM'
570	1001394	'Boiler 3 Hot Bypass 1 Req Pos'	'%Open'
571	1001395	'Boiler 3 Hot Bypass 2 Req Pos'	'%Open'

572	1001396	'Boiler 3 Hot Bypass 1 Act Pos'	'%Open'
573	1001397	'Boiler 3 Hot Bypass 2 Act Pos'	'%Open'
574	1001398	'Boiler 4 NH3 Slip'	'PPM'
575	1001399	'Boiler 4 Hot Bypass 1 Req Pos'	'%Open'
576	1001400	'Boiler 4 Hot Bypass 2 Req Pos'	'%Open'
577	1001401	'Boiler 4 Hot Bypass 1 Act Pos'	'%Open'
578	1001402	'Boiler 4 Hot Bypass 2 Act Pos'	'%Open'
579	1001403	'HRSG NH3 Slip'	'PPM'
580	1001404	'Demin Skid Caustic Injection Flow'	'GPM'
581	1001405	'Demin Skid Cation B Inlet Flow'	'GPM'
582	1001406	'Demin Skid Cation A Inlet Flow'	'GPM'
583	1001407	'Demin Skid Acid Injection Flow'	'GPM'
584	1001408	'Demin Skid Acid Concentration'	'%'
585	1001409	'Demin Skid Anion A Resistivity'	'K-Ohm'
586	1001410	'Demin Skid Anion B Resistivity'	'K-Ohm'
587	1001411	'Demin Skid Anion A Silica Content'	'Mg/Ltr'
588	1001412	'Demin Skid Anion B Silica Content'	'Mg/Ltr'
589	1001413	'Demin Skid Cation A Inlet Flow Total'	'Gal.'
590	1001414	'Demin Skid Cation B Inlet Flow Total'	'Gal.'
591	1001415	'Demin Skid Caustic Concentration'	'%'
592	1001416	'RO_Permeate_Tank_Level'	'Percent'
593	1001417	'Boiler_200_Stack_outlet_temp'	'Degrees F'
594	1001418	'Boiler_300_Stack_outlet_temp'	'Degrees F'
595	1001419	'Boiler_400_Stack_outlet_temp'	'Degrees F'
596	1001420	'Boiler_400_outside_stack_temp'	'Degrees F'
597	1001421	'Boiler_feed_pump1_kw'	'kw'
598	1001422	'Boiler_feed_pump2_kw'	'kw'
599	1001423	'Boiler_feed_pump3_kw'	'kw'
600	1001424	'Desup_pump_flow'	'gpm'
601	1001425	'Gas_compressor_kw'	'kw'
602	1001426	'Boiler2 CO Catalyst Temperature'	'DegF'
603	1001427	'Boiler2 NOx Catalyst Temperature'	'DegF'
604	1001428	'Boiler3 CO Catalyst Temperature'	'DegF'
605	1001429	'Boiler3 NOx Catalyst Temperature'	'DegF'
606	1001430	'Boiler4 CO Catalyst Temperature'	'DegF'
607	1001431	'Boiler4 NOx Catalyst Temperature'	'DegF'
608	1001432	'CTG_Oil_Accumulator_Pressure'	'PSI'
609	1001433	'Boiler2_outside_stack_humidity'	'%'
610	1001434	'Boiler2_outside_stack_temp'	'Degrees F'
611	1001435	'Boiler3_outside_stack_humidity'	'%'
612	1001436	'Boiler3_outside_stack_temp'	'Degrees F'
613	1001437	'Boiler4_outside_stack_humidity'	'%'
614	1001438	'Boiler4_outside_stack_temp'	'Degrees F'
615	1001439	'HSRG_outside_stack_temp'	'Degrees F'
616	1001440	'STG1 Inlet Steam Flow'	'lbs/hr'
617	1001441	'STG1 Steam Press'	'PSIG'
618	1001442	'STG1 Steam Temp'	'DegF'
619	1001443	'STG1 Hourly kW'	'kWh'
620	1001444	'STG1 Daily kW Output'	'kWh'
621	1001445	'STG1 Weekly kW'	'kWh'
622	1001446	'STG1 Monthly kW'	'kWh'
623	1001447	'STG1 Hourly Steam Flow'	'lbs'

624	1001448	'STG1 Daily Steam Flow'	'lbs'
625	1001449	'STG1 Weekly Steam Flow'	'lbs'
626	1001450	'STG1 Monthly Steam Flow'	'lbs'
627	1001451	'STG1 kW Output'	'kW'
628	1001452	'HPST Gen Output Power'	'kW'
629	1001453	'HPST Speed'	'RPM'
630	1001454	'HPST Exhaust Pressure'	'PSIG'
631	1001455	'HPST Inlet Pressure'	'PSIG'
632	1001456	'HPST Lube Oil Pressure'	'PSIG'
633	1001457	'HPST Axial Vibr A'	'mils'
634	1001458	'HPST Axial Vibr B'	'mils'
635	1001459	'HPST Steam End X Radial Vibr'	'mils'
636	1001460	'HPST Steam End Y Radial Vibr'	'mils'
637	1001461	'HPST Exhaust End X Radial Vibr'	'mils'
638	1001462	'HPST Exhaust End Y Radial Vibr'	'mils'
639	1001463	'HPST Gear HS Drive End X Radial Vibr'	'mils'
640	1001464	'HPST Gear HS Drive End Y Radial Vibr'	'mils'
641	1001465	'HPST Gear HS NDrive End X Radial Vibr'	'mils'
642	1001466	'HPST Gear HS NDrive End Y Radial Vibr'	'mils'
643	1001467	'HPST Gear LS Drive End X Radial Vibr'	'mils'
644	1001468	'HPST Gear LS Drive End Y Radial Vibr'	'mils'
645	1001469	'HPST Gear LS NDrive End X Radial Vibr'	'mils'
646	1001470	'HPST Gear LS NDrive End Y Radial Vibr'	'mils'
647	1001471	'HPST Inactive Thrust Bearing Temp'	'DegF'
648	1001472	'HPST Active Thrust Bearing Temp'	'DegF'
649	1001473	'HPST Steam End Bearing Temp'	'DegF'
650	1001474	'HPST Exhaust End Bearing Temp'	'DegF'
651	1001475	'HPST Gear HS Drive End Bearing Temp'	'DegF'
652	1001476	'HPST Gear HS NDrive End Bearing Temp'	'DegF'
653	1001477	'HPST Gear LS Drive End Bearing Temp'	'DegF'
654	1001478	'HPST Gear LS NDrive End Bearing Temp'	'DegF'
655	1001479	'HPST Gen Drive End Bearing Temp'	'DegF'
656	1001480	'HPST Gen Exciter End Bearing Temp'	'DegF'
657	1001481	'HPST Gen Phase A Stator Temp 1'	'DegF'
658	1001482	'HPST Gen Phase B Stator Temp 1'	'DegF'
659	1001483	'HPST Gen Phase C Stator Temp 1'	'DegF'
660	1001484	'HPST Gen Phase A Stator Temp 2'	'DegF'
661	1001485	'HPST Gen Phase B Stator Temp 2'	'DegF'
662	1001486	'HPST Gen Phase C Stator Temp 2'	'DegF'
663	1001487	'HPST Gen Phase A Amps'	'Amps'
664	1001488	'HPST Gen Phase B Amps'	'Amps'
665	1001489	'HPST Gen Phase C Amps'	'Amps'
666	1001490	'HPST Gen Phase A to B Volts'	'Volts'
667	1001491	'HPST Gen Phase B to C Volts'	'Volts'
668	1001492	'HPST Gen Phase C to A Volts'	'Volts'
669	1001493	'HPST Generator Avg Line Volts'	'Volts'
670	1001494	'HPST Gen Frequency'	'Hz'
671	1001495	'HPST Gen Power Factor'	'null'
672	1001496	'HPST Gen Real Power'	'MW'
673	1001497	'HPST Gen Reactive Power'	'MVAR'
674	1001498	'HPST Gen Apparent Power'	'MVA'
675	1001499	'HPST Gen Watt Hours'	'MWH'

APPENDIX D

EMISSION REDUCTIONS

In addition to a cost savings associated with the implementation of thermal energy storage, emission reductions will also be seen. Pollutants released through the combustion of fossil fuels, be it for electricity generation or on-site thermal energy needs, can adversely impact human health and the environment. It is also possible to derive financial benefit through the reduction of emissions via government programs, such as the EPA's emission trading program.

Criteria Pollutants:

EPA has designated criteria pollutants for which acceptable levels of exposure have been determined and for which ambient air quality standards have been set. These criteria pollutants were chosen based upon their potential health and welfare impacts. Notable criteria pollutants include: NO_x, SO_2, and Particulate Matter (PM). Definitions of relevant criteria pollutants, provided by the California Air Resource board, are as follows:

NOx: A general term pertaining to compounds of nitric oxide (NO), nitrogen dioxide (NO_2), and other oxides of nitrogen. Nitrogen oxides are typically created during combustion processes, and are major contributors to smog formation and acid deposition (i.e. acid rain). NO_2 may result in numerous adverse health conditions, which include pulmonary congestion and edema. Chronic exposure may lead to Emphysema.

SO_2: A strong smelling, colorless gas that is formed by the combustion of fossil fuels. Power plants, which may use coal or oil high in sulfur content, can be major sources of SO_2. SO_2 and other sulfur oxides contribute to the problem of acid deposition. Acute health effects include tightness in the chest and coughing.

PM_{10} and $PM_{2.5}$: Particulate matter pollution consists of very small liquid and solid particles floating in the air. Of greatest concern to public health are the particles small enough to be inhaled and absorbed by the lungs. These particles are less than 10 microns in diameter and are referred to as PM_{10}. Finer particulate matter is known as $PM_{2.5}$, and refers to particulate matter that is less than 2.5 microns. Particulate matter is a major component of air pollution that threatens human health and the environment. It can increase the number and severity of asthma attacks, cause or aggravate bronchitis and other lung diseases, and reduce the body's ability to fight infections. In addition, PM_{10} is often responsible for much of the haze that we think of as smog.

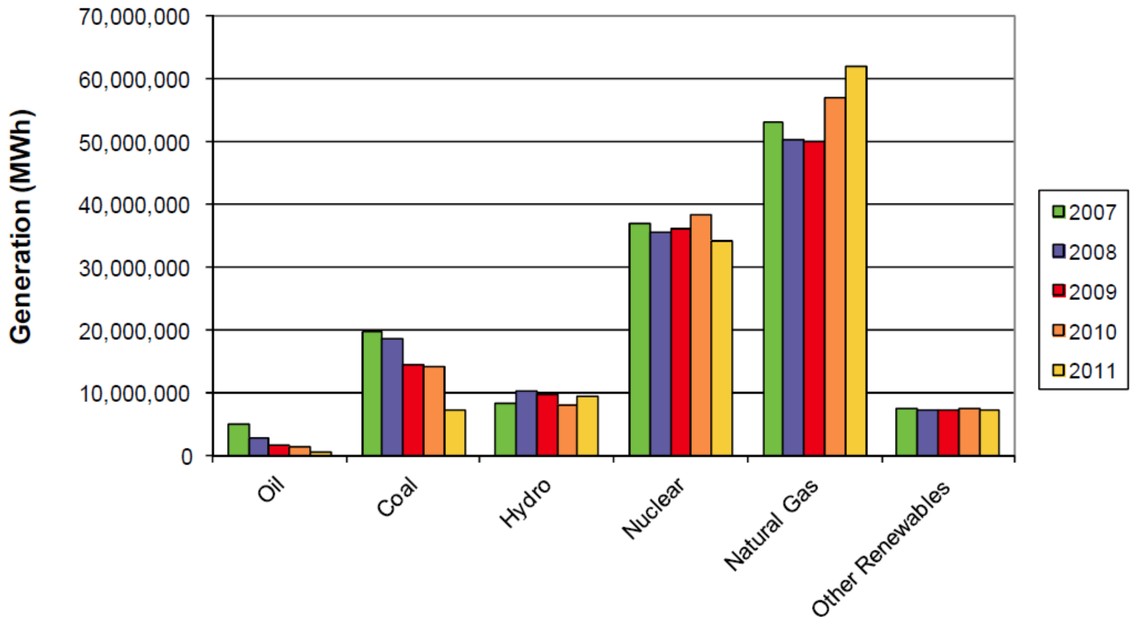
Greenhouse Gases:

A greenhouse gas slows the passage of re-radiated heat through the Earth's atmosphere increasing the Earth's temperature and contributing to global warming. Such gases include carbon dioxide, methane, chlorofluorocarbons, nitrous oxide, ozone, and water vapor[1]. Carbon dioxide (CO_2) is the greenhouse gas that is most often associated with the combustion of fossil fuels and energy generation.

CO_2: A colorless, odorless, non-toxic gas that occurs naturally in the Earth's atmosphere and is produced in large quantities through the combustion of fossil fuels[1]. It is a leading contributor to global warming.

Emission Factors:

The emission profile will vary based upon the method used for the generation of electricity. According to ISO-New England[3], the electrical generating capacity in the New England states, for the year 2011, was met by approximately 50% Gas, 28.2% Nuclear, 6.5% Coal, 8.1% Hydro, 0.7% Oil, and 6.5% other Renewables. The electric generation by the different fuel types is shown in Figure E.1



Electricity Generation by various Fuel types[3]

The emission factors shown in Table E.1, were taken from the 2011 ISO New England Electric Generator Air Emissions Report[3] and U.S. EPA's E-GRID2009 Data[2]. The emission levels (lb/kWh) were calculated by dividing the state's annual emission of each pollutant by the net generation for that state.

Total State Electricity Generation Emission Factors[2, 3]

	CO_2 (lb/kWh)	NO_X (lb/kWh)	SO_2 (lb/kWh)
Connecticut	0.57900	0.00032	0.00012
Maine	0.86100	0.00040	0.00024
Massachusetts	1.01000	0.00057	0.00125
New Hampshire	0.74800	0.00051	0.00281
New York	0.49792	0.00040	0.00098
Rhode Island	0.94800	0.00016	0.00012
Vermont	0.17900	0.00012	0.00002

In addition, there are emission reductions associated with on-site fuel consumption savings. The emission factors (lb/MMBtu) for Natural Gas, Propane, and Butane, as well as No. 2 Oil, No. 4 Oil, and No. 6 Oil, are shown in Table E.2.

Emission Factors for various Fossil Fuel types (lb/MMBtu)[2]

	Natural Gas (lb/MMBtu)	Propane (lb/MMBtu)	Butane (lb/MMBtu)	#2 Oil (lb/MMBtu)	#4 Oil (lb/MMBtu)	#6 Oil (lb/MMBtu)
CO_2 (lb/kWh)	131.70	157.42	152.13	159.23	178.57	181.90
NO_X (lb/kWh)	0.108	0.205	0.160	0.129	0.143	0.393
SO_2 (lb/kWh)	0.00068	0.00000	0.00096	0.00051	1.07100	1.12100

The emission reduction values shown in each AR summary found in the report were calculated as follows:

$$AER_X = AES \times EF_X$$

Where,

AER_X = Emission reduction of pollutant X; lb

AES = Energy savings from AR; kWh or MMBtu

EF = Emission factor; Table E.1 and Table E.2

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