Fall 2011

Cornell Green Consulting Group

Cornell University
CEE 5910

Feasibility Study of Renewable Energy Sources at the Emerson Plant in Ithaca, NY

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Acknowledgment and Disclaimer:

Cornell Green Consulting Group (CGCG) wishes to thank Abbott Lund-Hansen, LLC (ALH) for their input into and support of this project. While their contribution is gratefully acknowledged, the contents of this report do not reflect the official position of Abbott Lund-Hansen, nor of Cornell University or Emerson Power Transmission Corporation, and responsibility for any and all errors rests with the authors.

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1. EXECUTIVE SUMMARY

With rising energy costs as well as an increased awareness of the environmental impact of meeting growing energy demands, the need to strongly consider alternative energy sources has quickly developed. While the use of some renewable energy sources (such as hydroelectric and wind power) is largely constricted to the power grid, other sources (such as solar thermal and solar photovoltaic) are increasingly becoming directly available to the consumer. This report examines the economic and technological feasibility of applying some of these alternative energy sources for localized use by the consumer. With this purpose in mind, Abbott Lund-Hansen (ALH) and the Cornell University College of Engineering have collaborated to assess the potential of repurposing a former manufacturing plant in Ithaca, New York.

The facility under consideration is an abandoned complex owned by Emerson Industrial Automation (Emerson). Due to pollution on the premises and the substantial cleanup that will be required, Emerson has a vested interest in the future repurposing of the complex. As a potential buyer, ALH is interested in developing a plan to convert the complex into an energy generation facility that would provide electricity and hot water to tenants within the bounds of the complex. If possible, generation and transmission could be extended to serve several potential local customers like Ithaca College and Center Ithaca.

The focus of the study was to determine a cost effective combination of alternative energy sources that could be installed at the complex to meet future energy demands. This study examines the merits of renewable energy technologies such as solar photovoltaic (PV) arrays, solar thermal power, wind power, and biomass powered plants. Cogeneration, or combined heat and power (CHP), is also thoroughly discussed because of its important contribution to creating more efficient power generation systems. By capturing the by-product waste heat that is created during electricity generation, CHP systems can recover some of the lost energy and use it to produce domestic hot water (DHW).

The team created a customizable tool that analyzes the available energy sources to determine the most cost effective system that meets both the DHW and electricity demands of the building as well as any constraints regarding the carbon footprint of the building. To act as a control, the team analyzed a scenario where all of the electricity is purchased from the grid and the DHW is produced using onsite boilers. This acted as a baseline in comparison to several other scenarios created to examine possible combinations of the alternative energy sources. The Net Present Cost (NPC) of each system was calculated over a 25 year life cycle to determine its economic feasibility. The amount of CO_2 emitted for each scenario was also determined to allow the user to weigh economic feasibility versus environmental mindfulness.

The most important conclusions that can be drawn from the results of the model are that regardless of environmental concerns, CHP is the most cost effective solution for providing both electricity and DHW. Since there is a direct correlation between the electricity and DHW output by the CHP system, the amount of electricity that can be provided by the CHP system is bounded by the demand for hot water. The remaining demand for electricity can be met by a number of sources; the source that is chosen depends on its availability and the importance placed on reducing the carbon footprint of the building. The least expensive way to meet the demand is to simply draw the remaining demand from the grid. If it is important to reduce the CO_2 output of the building, both solar PV and wind power are feasible options. However, wind power is less expensive if available.

Scenario Number	Description	Page
1	100% electricity from grid + onsite conversion of natural gas to heat	57
2	CHP system + remaining electricity from grid	58
3	CHP system + PV system + grid electricity	60
3A	CHP system + PV system + solar hot water + grid electricity	62
3B	CHP system + PV system + electricity storage + grid electricity	64
3C	CHP system + PV system + biomass system + grid electricity	65
4	CHP system + wind electricity + grid electricity	66

Table i

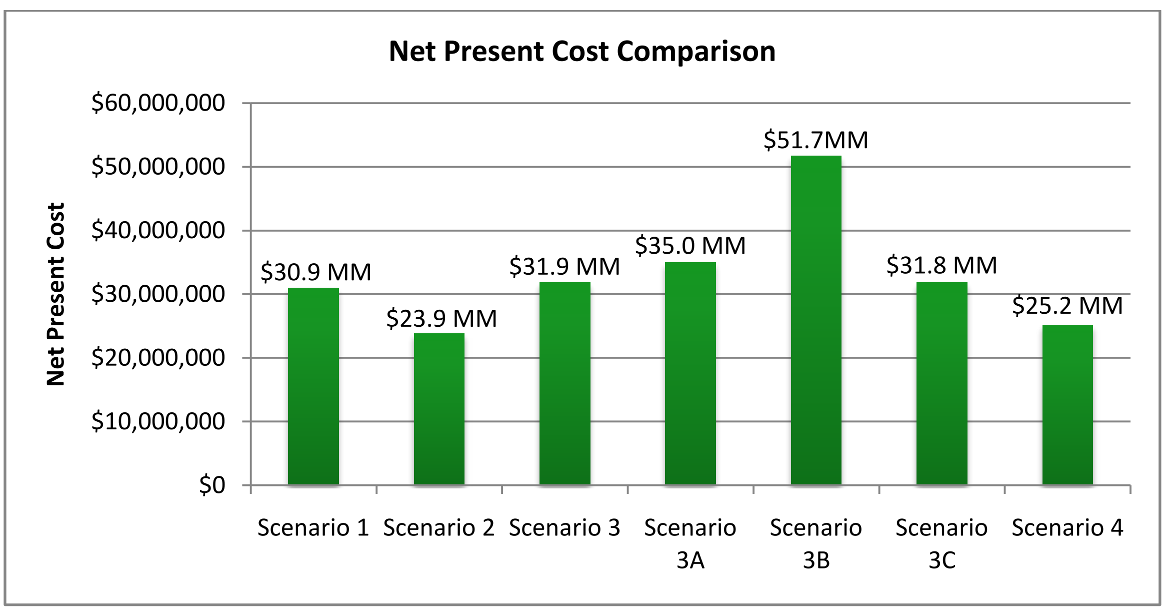

Figure i

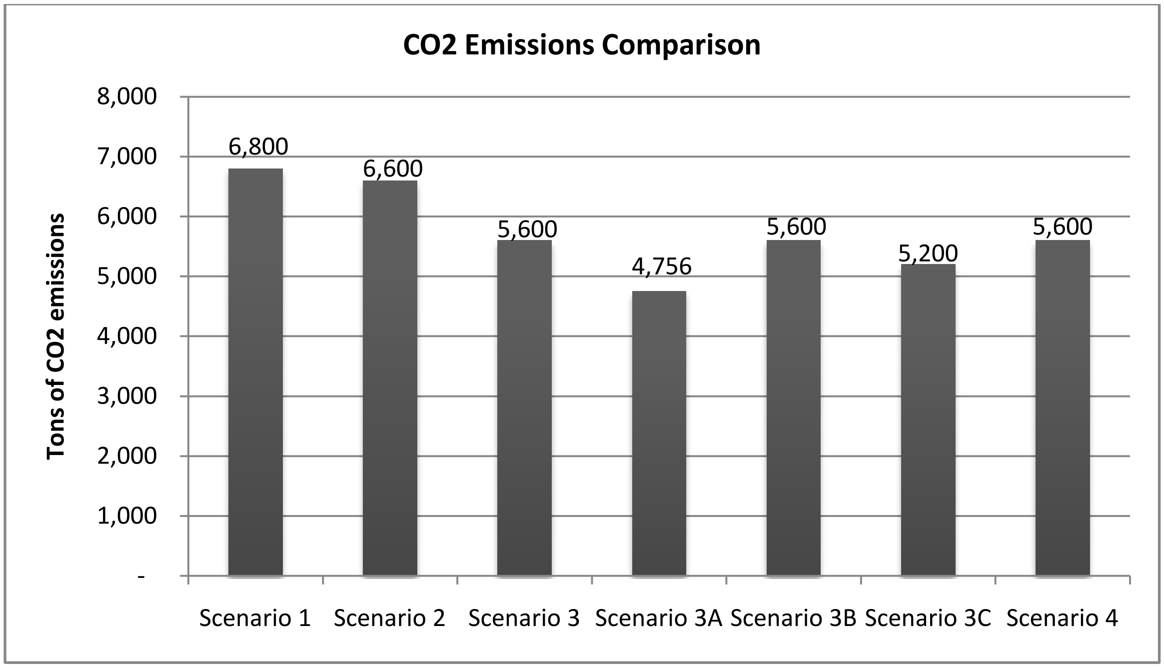
CO2 Emissions Comparison
Tons of CO2 emissions
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
6,800
6,600
5,600
4,756
5,600
5,200
5,600
Scenario 1
Scenario 2
Scenario 3
Scenario 3A
Scenario 3B
Scenario 3C
Scenario 4

Figure ii

2. BACKGROUND AND MOTIVATION

A recent report from *The New York Times* stated that the demand for global energy will increase 53% by 2035.[1] Because of the high demand for energy, the high pollution rate, and increased consciousness of climate change, alternate energy sources are becoming increasingly viable options. Emerson Industrial Automation (Emerson), Abbott Lund-Hansen (ALH) and a team of Cornell University Engineering Management graduate students (known as the Cornell Green Consulting Group – CGCG) have embarked on a project which involves converting a former heavy manufacturing plant into a clean energy generation facility for Ithaca, New York and the rest of Tompkins County.

The building in consideration is owned by Emerson. Located in Ithaca, NY, the manufacturing complex had been in use since the early 1900’s until 2009 and contains 17.5 acres of floor space split between several floors, as well as an additional 95 acres of property. The Emerson plant previously employed 74 full-time and 154 part-time employees before ceasing production in 2009.

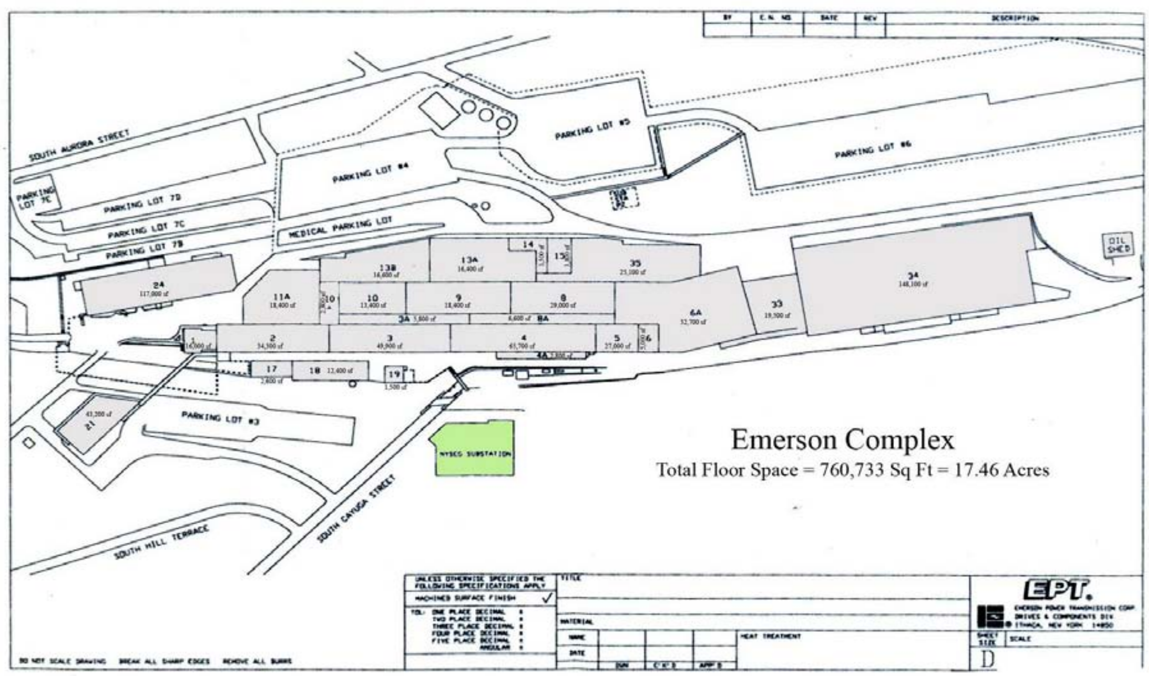

Figure 1: Map of the Emerson Complex[2]

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[1] *The New York Times, Energy and Environment. http://www.nytimes.com/2011/09/20/business/energy-environment/energy-demand-is-expected-to-rise-53-by-2035.html*
[2] *Courtesy of Pyramid Brokerage, Ithaca, NY*

Project stakeholder ALH is a property developer with a focus on cogenerated district heating. As a distributor of district heating systems, ALH is focused on developing Tompkins County as its next project. They have decided to develop a plan to convert the former Emerson plant into an energy generation and transmission facility that serves the surrounding Ithaca community with clean and affordable energy. Three tiers of installation are considered for development of the Emerson complex: 1) the existing buildings, 2) the rest of the property within the complex, and 3) outside the properties boundaries (e.g., Ithaca College, Center Ithaca). The future tenants of the complex are currently unknown but are assumed to be either commercial or industrial.

In order to ensure that the environmental benefits of using alternative energies in the complex are fully realized, the building energy efficiencies must first be upgraded (possibly to that of a LEED or Energy-Star level). The specifics of these upgrades (as well as other structural upgrades for things like supporting roof installation of photovoltaic arrays) are out of the scope of this project and have been omitted. Ideally, the repurposed plant will serve as a shining example of renewable energy technologies for other abandoned factories across the country.

CGCG has been given the opportunity to propose a plan to use the building for energy generation. The team researched the availability and economic impact of energy sources ranging from solar photovoltaic (PV) cells to combined heat and power (CHP), and assembled the most energy efficient and economically viable system. The project gave the team an opportunity to both develop a proposal in a real-life scenario and provide ALH with detailed options for repurposing the Emerson facility.

3. PROJECT SCOPE & ASSUMPTIONS

After a meeting with the project stakeholders, CGCG defined the scope of this project with the following specifications:

- The economic feasibility study is based on a designated budget of $100MM
- The scenarios presented include solutions that are "green" and economically feasible
- Costs will be calculated based on a 25 year life cycle (justification for this life cycle provided in Appendix C)
- The building will not be used as a residential facility in the immediate future, and therefore, the potential tenants will be commercial or industrial
- The study will include a combination of the following alternative energy sources:
    - Solar
    - Natural gas (using CHP)
    - Wind
    - Biomass
- The economic and technological studies will evaluate the possibility of developing solutions that are modular and scalable
- Net metering is available to the project, and any electricity not consumed instantaneously on site can be sent to the grid with the expectation that it will later be credited against sales from the grid to the site.
- Constant price of grid electricity is assumed, even though the actual project may be subject to variable pricing by time of day or time of year, which may affect the economics of the project.
- The purchase of wind-generated electricity specifically from Black Oak wind in Enfield, NY, is a different arrangement from the usual purchase of wind electricity generally from a wholesaler that aggregates wind from many wind farms, and may therefore pose legal or logistical challenges that are ignored in this analysis.

Some aspects that fall outside of the scope of this project include:

- Building improvements and energy efficiency upgrades
- Project funding
- Site remediation

4. ENERGY DEMAND

4.1 MONTHLY DEMAND

1.1 Summary

Determining the best combination of energy systems for the Emerson complex required CGCG to estimate electrical and heat demand for the facility. These demand estimates not only helped determine the necessary size and capacity of each potential system, but also informed the energy output that could be expected for seasonally-dependent systems (e.g. CHP, PV, and solar thermal).

1.2 Heat Demand

CGCG estimated heat demand (hot water) for the Emerson facility using data from the Department of Energy's (DOE) Commercial Buildings Energy Consumption Survey (CBECS), which provided an average annual natural gas consumption of 43 cubic feet per square foot of building space.[3] Given the total area of the Emerson facility, this equates to an annual consumption of 32.7 million ft^3 (2.73 million ft^3 monthly).[4] Note that these are rather conservative estimates, since an energy star level building would probably have lower consumption rates.

In order to incorporate seasonal variation, CGCG utilized a demand pattern from New York State natural gas consumption data, provided by DOE.[5] However, these estimates are not specific to commercial/industrial customers and may under represent the actual heat demand. Thus, a process demand of 400kW and 288,000kWh was added to month's heat demand to accommodate for the extra demand that the Emerson will likely experience. Again, note that these are conservative estimates and an energy star level building would be lower. The corrected estimates were then scaled to reflect the demand specific to the Emerson plant, illustrated below.

[3] *DOE CBECS Natural Gas Consumption and Expenditure Intensities for all buildings,2003: <http://www.eia.gov/emeu/cbecs/cbecs2003/detailed_tables_2003/2003set11/2003pdf/c24.pdf>*
[4] *Abbott Lund-HansenLLC, "Repurposing the Emerson Complex Ithaca, NY," in Industrial Brownfield to Sustainable Power Center, New York. January 2011.*
[5] *DOE: Natural Gas Deliveries to Industrial Consumers, by State, 2009-2011: <http://www.eia.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_monthly/current/pdf/table_14.pdf>*

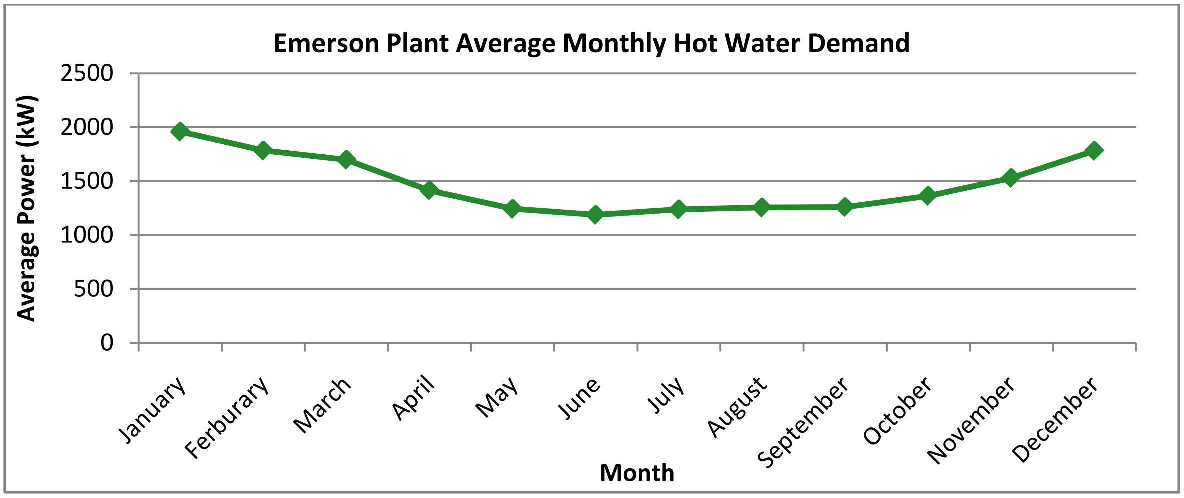


Figure 1: Estimated Monthly Average Hot Water Demand of the Emerson Complex

Month	Heat Demand (kWh)	Average Heat Demand (kW)
January	1,410,980	1,959
February	1,284,446	1,783
March	1,223,517	1,699
April	1,018,543	1,415
May	894,887	1243
June	855,067	1188
July	890,689	1237
August	903,762	1255
September	906,760	1259
October	981,841	1363
November	1,101,780	1,530
December	1,282,887	1,782

Table 1: Monthly Heat Demand Including Additional Industrial Demand

1.3 Electrical Demand

To estimate electrical demand, a 2010 report on electricity consumption was consulted.[6] The seasonal trend provided by this report was normalized to reflect conditions at the Emerson site. The resulting average monthly electricity demand is outlined below.

[6] *Da, Z., Yu, H., "Electricity Consumption and Asset Prices", September 2010. Pages 52-53*

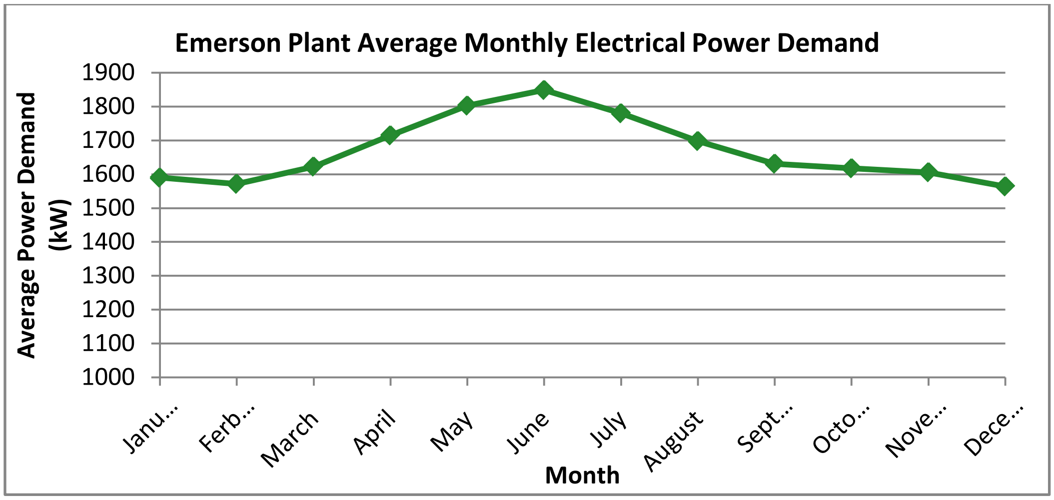


Figure 2: Average Monthly Electrical Demand of the Emerson Complex

4.2 DAILY DEMAND

2.1 Summary

Although average monthly electrical demand is crucial to our optimization model, demand fluctuates just as much over the course of an individual day and must also be considered. Monthly demand curves follow seasonal-scale trends related to weather over the course of the year (e.g. more electricity is needed for air conditioning during the summer months). Daily demand curves follow hourly-scale trends related to sunlight and general business hours (e.g. more electricity is needed for an office building during a 9AM to 5PM workday than overnight). These smaller scale fluctuations in electrical (and heat) demand are important to the energy study, but are not included in the resolution of the current optimization model. With more data and further refinement of the optimization model, daily electricity demand fluctuations for the Emerson facility could be incorporated to improve accuracy in the model.

2.2 Demand Curves

Since the final tenants of the Emerson facility are currently unknown, CGCG has assumed 50% commercial and 50% industrial tenants for the calculations. Each type of tenant (commercial, industrial, residential, etc.) has a specific daily demand curve based on energy usage for that industry. Various peaks and valleys associate with each energy consuming industry, as evidenced by Figure 5 below:

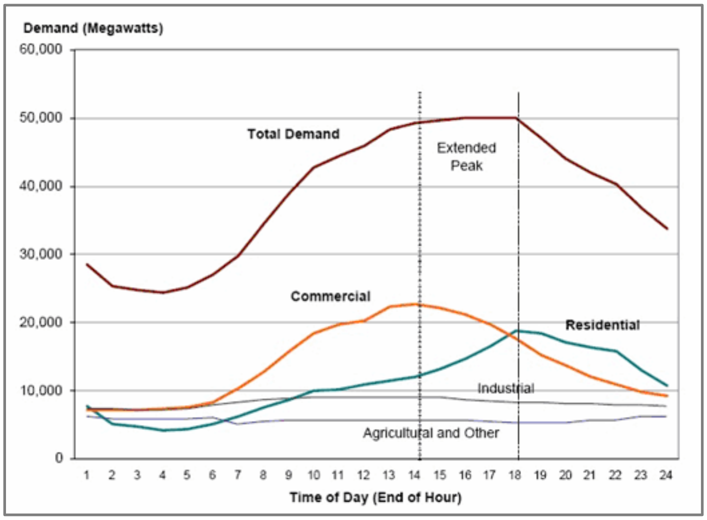


Figure 3: Average Daily Electricity Demand Curves[7]

Using the shapes of the commercial and industrial curves (50% weight each) in the figure above, CGCG estimated a daily demand curve for the Emerson facility. Normalizing the average electricity demand for each month (values shown in Table 3 below), CGCG developed a daily demand curve with an average value of that month and the shape of the weighted curve (see Figures 7 & 8 below).

Month	January	February	March	April	May	June	July	August	September	October	November	December
Average Monthly Electricity Demand (kW)	1590.10	1571.70	1622.72	1714.73	1802.56	1848.56	1779.97	1698.00	1631.09	1617.70	1605.99	1564.17

Table 2: Average Monthly Electricity Demand for Emerson

2.3 Photovoltaic Peaking

Solar energy radiation (and thus photovoltaic output) also follows a variable daily curve. As the sun rises and sets, it casts varying amounts of solar radiation energy to the earth's surface. This pattern is echoed by the output of solar photovoltaic cells over the course of the day. Examples of hourly output rates for Buffalo, NY and Las Vegas, NV for a typical June day are shown in the Figure below:

[7] *"Electricity Demand." Electropaedia. © 2005. 12/2/2011. <http://www.mpoweruk.com/electricity_demand.htm>*

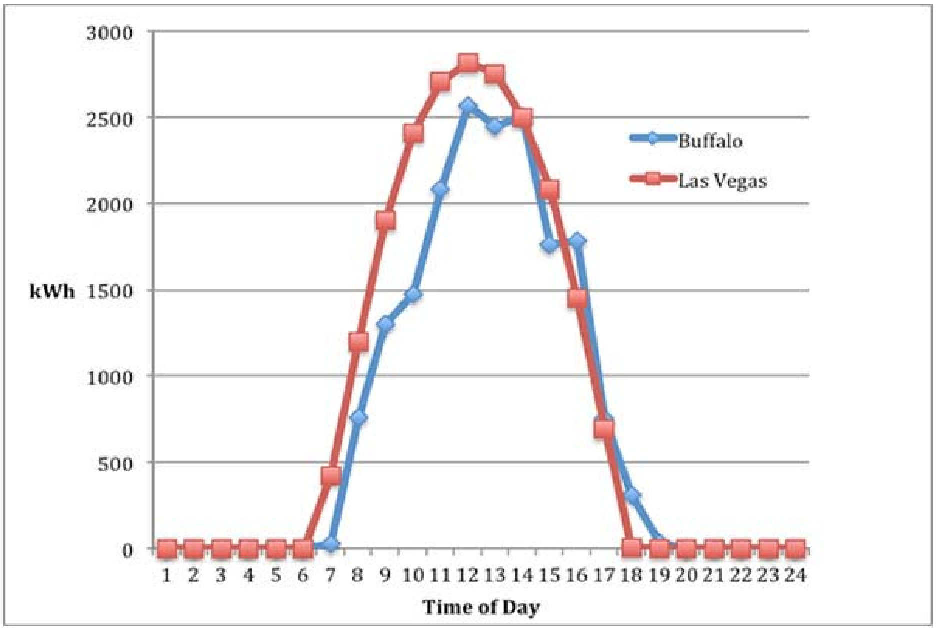


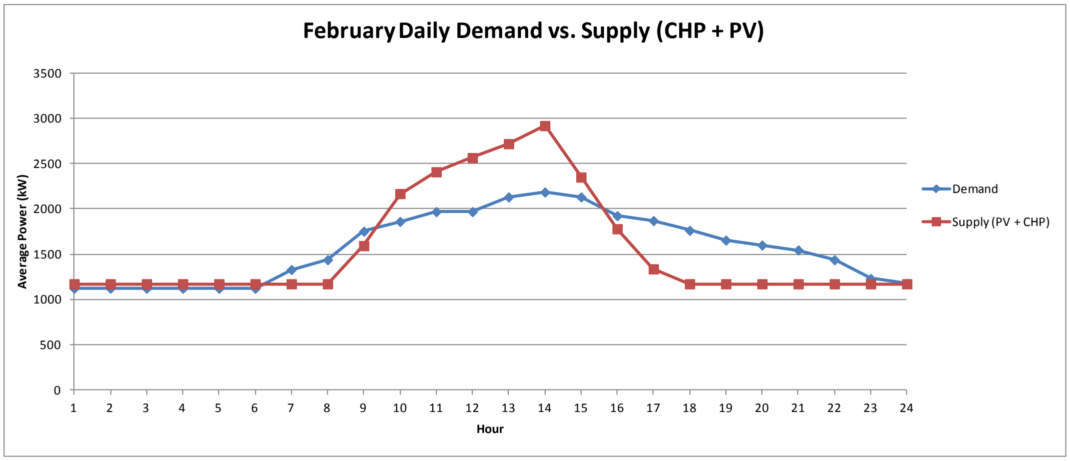
Figure 4: Example Hourly Photovoltaic Output Curves[8]

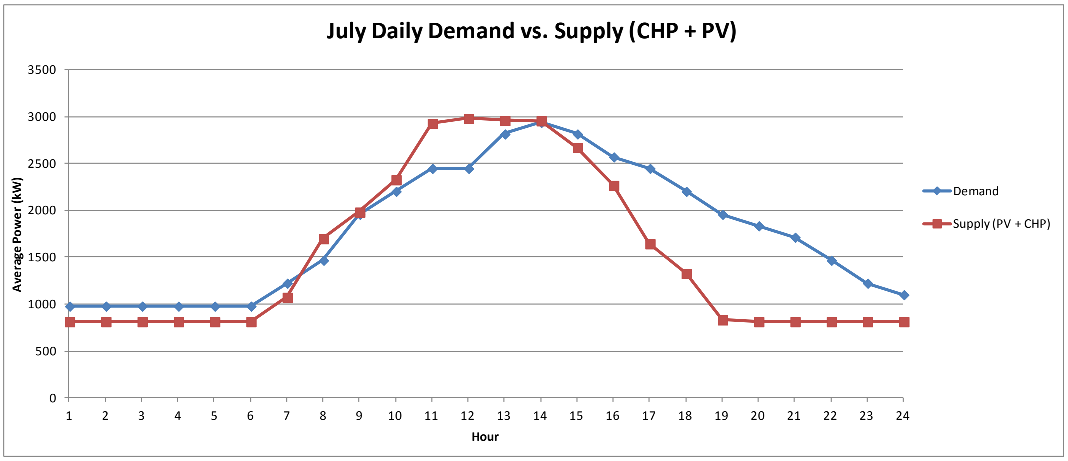
This mid-day peaking in solar energy and power is an issue that must considered when developing comprehensive energy systems. For the Emerson facility, the varying PV supply can be coupled with other systems (like CHP) to provide power output that is more consistent with a higher average. Depending on the demand for energy in the evenings, PV can provide a significant amount of overall energy.

2.4 February and July Examples

Because individual daily fluctuations were not factored into the CGCG model, it was only necessary to look at the demand for February and July (the trough and peak months for energy demand). These months allowed CGCG to compare the demand of energy in these important months to the supply of energy from an example system. As a sample case, CGCG assumed energy production from CHP and PV systems for the demand versus supply comparisons. Figures 7 & 8 below show the daily electricity demand for February and July, respectively, as well as the combined daily CHP and PV energy output.

[8] "*Variables to Consider when Designing Solar Power Applications." Digi-Key Corporation. 12/2/2011. <http://www.digikey.com/us/en/techzone/energy-harvesting/resources/articles/Variables-to-Consider-when-Designing-Solar-Power-Applications.html>*





Figures 5 & 6

The excess of supply over demand during the middle of the day (especially in July) shows a promising result for energy storage. With the mid-day peaking of solar photovoltaic power, there is the potential to store energy and use it later in the day when demand exceeds supply. The area between these curves gives the total excess energy provided by CHP and PV over the estimated demand: 3,183 kWh for February and 1,550 kWh for July. If this energy could be stored during the peak hours using batteries or flywheels, it could be utilized later to save money. Similarly, with a net metering contract with the local utility company, electricity could be sold back to the grid for energy credit during these hours.

5. ENERGY SOURCES

5.1 COMBINED HEAT AND POWER (CHP)

1.1 Summary

To evaluate the potential district heating capabilities of the repurposed Emerson facility, the main energy source taken into consideration was combined heat and power (CHP). In general, a cogeneration system is one in which a single source of energy (such as a fossil fuel) is used for more than one application. CHP is a specific and prominent type of cogeneration system in which a working fluid is used to generate electricity. The heat from the generating process is recovered and used for some other purpose, such as commercial or residential district heating, or industrial process heating. The following is a schematic of an engine/turbine application for a CHP system:

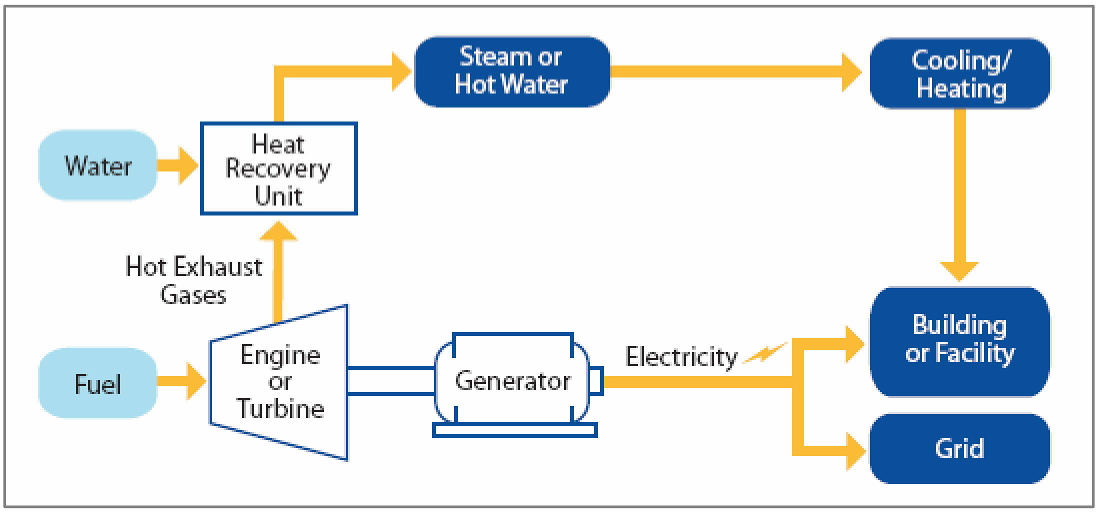


Figure 7: Engine/Turbine based CHP system[9]

As illustrated, an energy source (typically natural gas) is burned in a reciprocating engine or turbine which drives an electricity generator. The hot exhaust gas is used to produce steam or hot water for space heating, or possibly cooling with an absorption chiller.

There are numerous benefits to CHP, in addition to the efficient use of heat produced. According to a recent report from the US Department of Energy, there is great potential in the use of CHP to improve the nation's energy security and reduce greenhouse gas emissions.[10] CHP systems represent approximately 9% of the nation's total electricity capacity. According to a study by Oak

[9] *Union of Concerned Scientists: 2009.<http://www.ucsusa.org/publications/catalyst/combined-heat-and-power.html>*
[10] *"Combined Heat and Power: A decade of Progress, A Vision for the Future." US Department of Energy. <http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_accomplishments_booklet.pdf>*

Ridge National Laboratory referred to in the same report, increasing CHP usage to 20% of the nation's capacity by 2030 can offset 60% of the potential growth in CO_2 emissions.

Numerous institutions have successfully implemented CHP technology, resulting in increased energy efficiency and reduced CO_2 emissions. Cornell University adopted CHP technology in order to provide clean and reliable energy for its campus and reduce CO_2 emissions by 20%. In some communities, CHP provides energy for a great number of residential and commercial customers. In Denmark, CHP technology produces electricity for over 1.2 million people. District Energy St. Paul, Minnesota, which began as a partnership between the city of St. Paul and the DOE, uses CHP to heat more than 185 buildings, and 300 single family homes in the downtown area.[11]

1.2 Application of the CHP system in the Emerson Building

One major constraint of the CHP system is its dependence on heat production. In consideration of the heat demand constraint, CGCG first considered the following assumptions:

- CHP was responsible for meeting all of Emerson's heat demand
- All of the natural gas used by the facility is consumed solely by CHP

With these assumptions, CGCG used 2003 CBECS data and building footprint information to estimate Emerson's consumption of amount of natural gas. [12]

From Section 4.1 Monthly Demand, the maximum monthly heat demand of 1,959 kW occurs in January. The information acquired from this estimate helped the team evaluate various CHP systems for the Emerson facility. CGCG considered only the reciprocal engine CHP systems because although turbine systems have a longer life cycle (33 years), they have a lower electrical efficiency and are more expensive. [13, 14]

[11] District Energy St. Paul. 2011.<http://www.districtenergy.com/index.html>
[12] Vanek, Francis, "Energy Systems Engineering", Pages 142-143.
[13] CENERGY Advanced clean energy technologies: 2011. <http://www.2g-cenergy.com/PDFs/Product%20Program%20Cogen%20Natural%20Gas%2060Hz.pdf>
[14] BHP Energy. 2011. <http://www.bhpenergy.com>

Reciprocal Engines			
Product name	160 NG	200 NG	**265 NG**
Installation Cost for 1 Unit	$ 213,760	$ 259,600	**$ 319,325**
Electrical output (kW)	160	200	**265**
Thermal Output (kW)	248	296	**403**
Number Required	8.06	6.76	**4.96**
Final Number	9	7	**5**
Total Installation Cost	$ 1,282,560	$ 1,298,000	**$ 1,277,300**
Maintenance Cost per Unit	1cent/kWh	1cent/kWh	**1cent/kWh**
Gas Consumption (ft^3/hr)	1,585	2,002	**2,655**
Natural Gas Cost ($/hour)	$37.01	$46.75	**$61.99**
Life Cycle(Years)	7	7	**7**
Maintenance Cost Yearly	$ 14,016	$ 17,520	**$ 23,214**
Electrical Efficiency	35.8%	35.3%	**35.3%**
Thermal Efficiency	55.2%	52.3%	**55.5%**
Total Efficiency	91.0%	87.6%	**90.8%**

Table 3: Comparison of Various CHP Systems

Using the data above, CGCG chose the 265NG because it has the highest electrical efficiency, the lowest cost, and requires the fewest number of units to meet the demand while still allowing for modularity.

Given that amount of heat produced by the CHP system must match estimated heat demand for Emerson, the following table details the resulting monthly electrical outputs and number of units required using the 265NG engine:

Month	Number of CHP Systems Required	Electrical Energy by the CHP System (kWh)	Average Electrical Power by the CHP System (kW)
January	5	927,816	1288
February	5	844,610	1173
March	5	804,546	1117
April	4	669,761	930
May	4	588,449	817
June	3	562,265	781
July	4	585,688	813
August	4	594,285	825
September	4	596,257	828
October	4	645,628	897
November	4	724,495	1006
December	5	843,585	1171

Table 4: Estimated Monthly Electrical Output of the 265NG CHP system

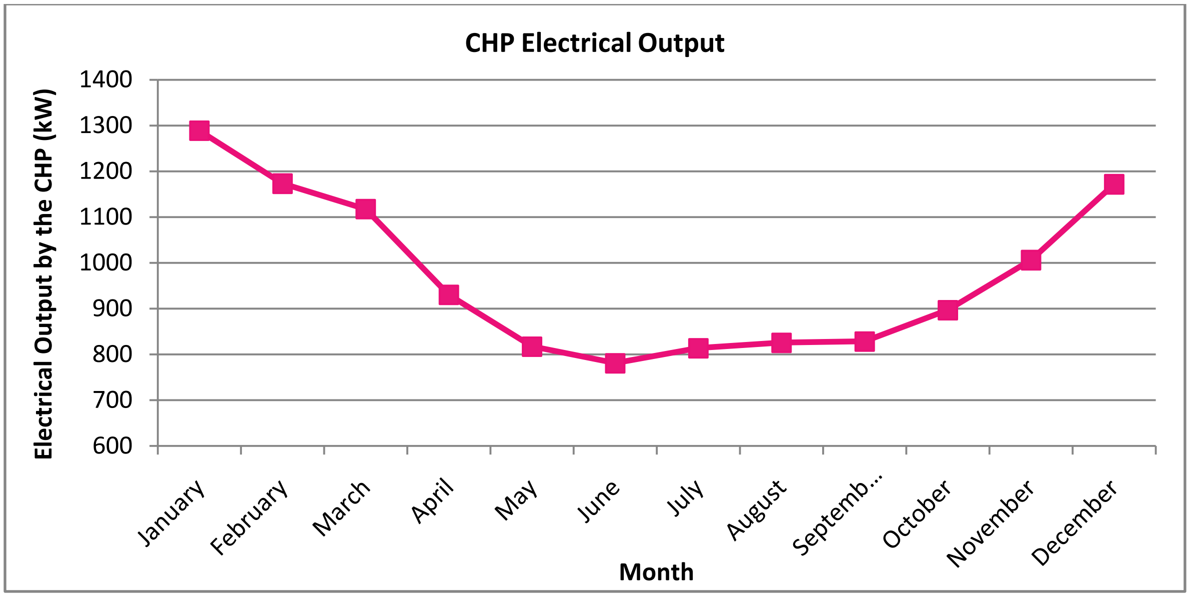


Figure 8: CHP Electrical Output of the 265NG CHP system

1.3 Economic Analysis Calculation

Life Cycle Analysis: In reference to Table 4, the 265NG system life cycle is 60,000 hours. Converting this life cycle to a number of years was crucial to determining the net present cost of the CHP system for the 25 year project cycle.

To convert this life cycle into years, CGCG needed the total heat demand for the year, 12.7 GWh. This number is then divided by the product of the thermal output (403kW) and the number of systems used (5 engines) to get the number of hours the CHP system is used during the year. Thus, the system will run approximately 6,330 hours each year. A life cycle of 60,000 hours converts to a 9 year life cycle at this operation rate.

From this calculation, and considering a 25 year life cycle, the suggested CHP system must be installed three times during the life of the project.

Cost per kWh Calculation:

$$Cost\ per\ kWh = \frac{Annual\ \sum Payment + Maintenance + Fuel}{Annual\ Maximum\ Output}$$

From this calculation and the data given in Table 4, the resulting cost is \$0.0729/kWh for electricity and \$0.048/kWh for heat (hot water).

Conclusion: Comparing the above CHP electrical output with the estimated Emerson complex electrical demand in Figure 11, it is clear that the CHP system cannot meet the electrical demand of the Emerson complex. Thus, other energy sources like PV, biomass, wind, or purchasing from the grid must be considered.

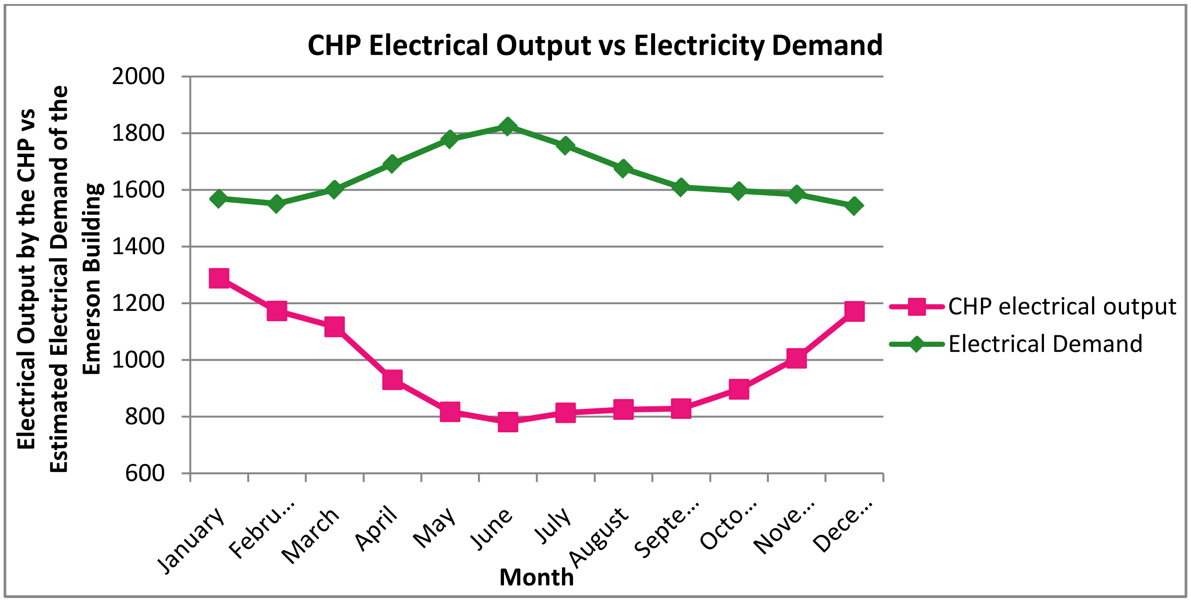


Figure 9: CHP Electrical Output and Estimated Electrical Demand of the Emerson Complex

5.2 SOLAR ENERGY

5.2.1 SOLAR THERMAL

1.1 Introduction

Solar energy is a valuable renewable source of energy that can be harnessed to generate electricity. This can be achieved most simply by exploiting the heat contained in the sun's radiation, but can also be generated directly from light using an electronic device called a solar cell. There are two main technologies of solar photovoltaic panels: Monocrystailline panels and Polycrystalline panels.

Monocrystalline panels are among the top performers of silicon solar cells, with solar to electrical conversion efficiencies of up to 24%[15]. However, the cost of this technology remains relatively high. Table I summarizes the characteristics of a typical Monocrystalline panel produced by Sun power Company.

[15] *"Solar Thermal System & Collector Manufacturer." SunMaxx Solar, <www.sunmaxxsolar.com>*

Product Name	E19/315
Manufacturer	Sun Power
Nominal Power	315 W
Solar to Electrical Efficiency	% 19.3
Weight	18.6 Kg
Overall Size	1559 x 1046 x 46 mm

Table 5 – Technical Specifications of a Typical Monocrystalline Silicon Photovoltaic Panel

A less expensive option to this technology is Polycrystalline silicon, which is much cheaper to produce but has proved less efficient than the single crystal material (18% efficiency). Table II summarizes the characteristics of a typical Monocrystalline panel produced by Yingli Solar.[16]

Product Name	YL245P-32b
Manufacturer	Yingli
Nominal Power	245 W
Solar to Electrical Efficiency	% 13.7
Weight	22.5 Kg
Overall Size	1810 x 990 x 50 mm

Table 6 – Technical Specifications of a typical Polycrystalline silicon photovoltaic Panel

1.2 Solar Photovoltaic Costs

The main market for solar photovoltaic technology in 2003 was grid-connected residential and domestic installations. These accounted for 365 MW of total annual production of 744 MW, or roughly 50%.[17]

The price of Solar Panels has experienced a rapid decrease in recent years. The price of each Watt of installed capacity of Polycrystalline Solar Photovoltaic systems including inverters, wiring, racks and installation was around $10/Watt in 1993.[18] Prices have been decreasing continuously for the last 20 years due to new production technologies. To determine the current cost of this technology, multiple reports were researched and companies who install PV arrays in New York State were contacted to evaluate the price per Watt of installed capacity.

16 "Multicrystalline." Yingli Solar. 2011. <http://www.yinglisolar.com/us/products/multicrystalline/>
17 "Renewable Energy Focus Handbook", Academic Press, Elsevier , 2009, ISBN: 978-0-12-374705-1
18 Renewable Energy Annual 1995. United States. Office of Coal, Nuclear, Electric and Alternate Fuels. pp. 111.

Table 8 shows the final prices for solar photovoltaic systems considered in this report. These prices are valid for large applications (more than a MW of installed capacity) and include panel cost, inverter cost, racks and installation cost. Note that Monocrystalline panels are more expensive than Polycrystalline panels, due to their superior efficiency.

Technology	Price
Monocrystalline Panels	$ 3.65/Watt
Polycrystalline Panels	$ 3.50/Watt

Table 7 – Prices of Solar Photovoltaic Systems

It should be noted that since economics of scale have been considered in determining these prices, residential projects or small size commercial projects would have higher prices per Watt of installed capacity. It should also be noted that these prices do not include any costs related to any upgrades to the Emerson plant's roof.

1.3 Practical Application

The next step was to determine the maximum size of the solar array that can be installed on the roof of the Emerson complex. CGCG considered that 80% of the roof area is available for installing the solar panels, which equates to approximately 320,000 ft^2.

To capture the maximum amount of solar energy that can be gathered from the roof, Monocrystalline panels were chosen for subsequent calculations. Table 9 summarizes the technical specifications specific to installing Monocrystalline panels at the Emerson site. Note that a maximum installed capacity of 4 MW could be installed.

Panel Type	CSUN 295-72M by Sunergy
Size of panels	1.93644 (m^2)
Theoretical number of panels installed	15430
Practical number of panels installed (90%)	13887
Total installed Capacity	4,096 (kW)
Installation cost of the system ($/Watt)	$ 3.65
Total Cost of the system	$ 14,953,228

Table 8 – System Size and Cost using Monocrystalline panels

1.4 Energy Production

A very important issue about solar energy is the fact that it is highly dependent on location, season, and time of day. The output of the solar photovoltaic panels depends on the solar radiation received by the location, shown in Figure 12.[19]

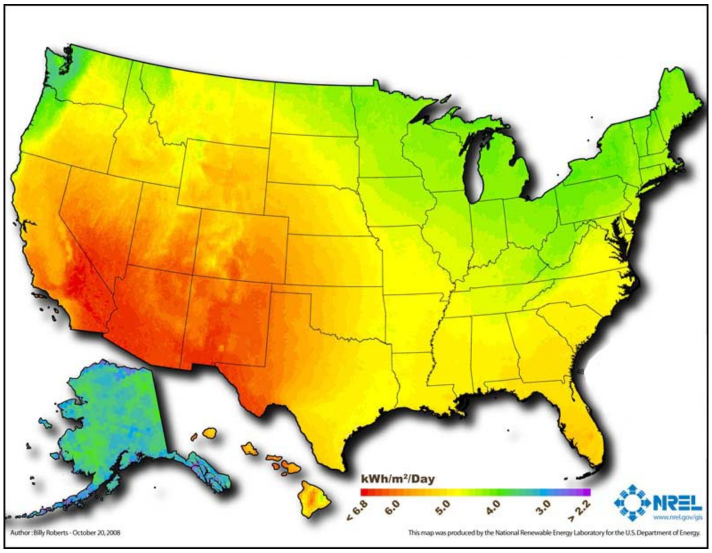


Figure 10: Map of Solar Power Resource in the USA

Upstate New York is not located in the best location for absorbing high solar radiation, which reduces the power produced by the Solar Photovoltaic panels. Although Ithaca doesn't get the high solar radiation of California, the solar radiation received is still large enough to allow the practical use of Solar Photovoltaic panels.

In addition to the effect of location, the output power of solar panels is highly seasonal. As a result the electrical power produced by the solar panels is higher during the summer and lower during the winter. Also, the electricity is only available during the day and decreases during the evening and becomes zero about an hour prior to sunset. Data on the seasonal output of PV systems was obtained from Dr. Vanek, based on his measurement of output from existing systems in the Ithaca area.

Figure 13 shows the energy produced by a solar system installed in Ithaca in each month. Having the energies produced by Solar Panels for Ithaca, the output power of larger or smaller system can be easily calculated. The table containing the monthly energy productions could be found in the

[19] *"PV-Watts, Version 2" National Renewable Energies Laboratory (NREL)*

related appendix. The average power output of the system is calculated by simply averaging the energy during the day, assuming that the system is providing a fixed output in each month. This is a simplification that ignores the variations of electrical output of PV systems between day and night.

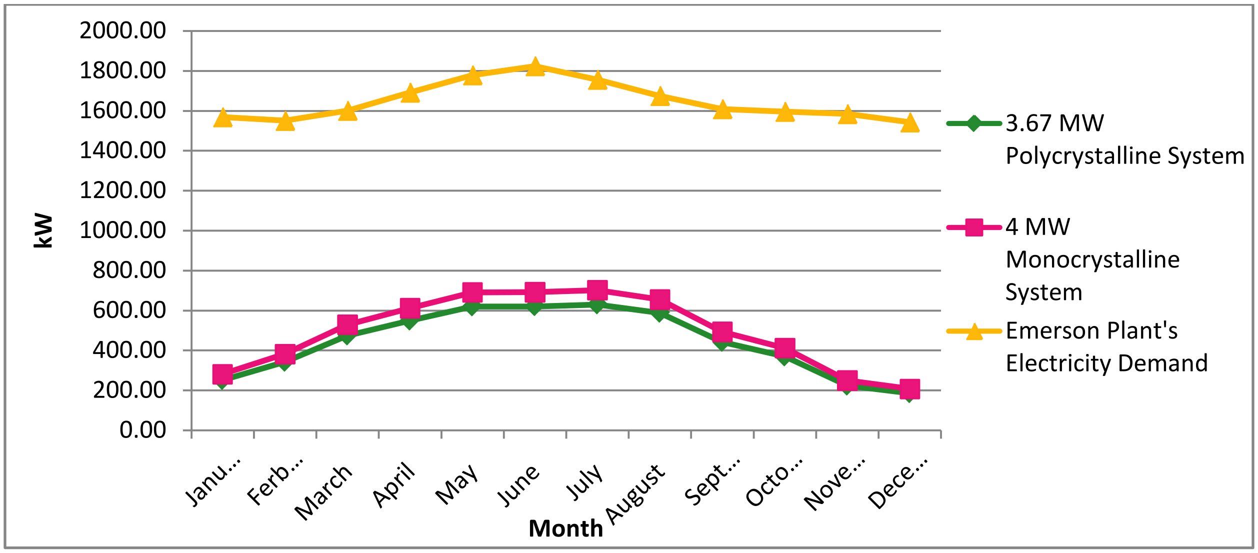


Figure 11: Comparison of output powers of solar photovoltaic systems and Emerson plant's power demand

1.5 Economics of the System

In this part the price of each kWh of energy produced by the Solar Photovoltaic system is calculated. The installation cost of PV panels over the 25 years life cycle all occurs in one year, and there are no other costs (maintenance cost) during their life cycle.

The project life has been considered as 25 years with a 7% discount rate, with the associated costs shown in Table 10.

	Monocrystalline System	Polycrystalline System
Installed Capacity	4096.77 kW	3676.85 kW
Energy Produced per year	4308.27 MWh	3866.67 MWh
Installation Cost	$ 14,953,228	$ 12,868,991
Cost in each year (Distributed and discounted)	$ 1,283,144.24	$ 1,104,294.74
Cost of output energy ($/kWh)	$ 0.297	$ 0.285
Incentives	$ 0.10	$ 0.10
Cost of output energy with incentive ($/kWh)	$ 0.197	$ 0.185
Grid's Cost	$ 0.129	$ 0.129
Yearly Saving of System	$ 558,998	$ 501,700

Table 9 – The economic calculations for two different Solar Photovoltaic Systems

The amount of incentives considered here is considered to be a reasonable approximation of the incentives that could be received for the project, and are discussed in further detail in Section 5.9. To determine how sensitive the annual savings are to these inputs, an uncertainty analysis was conducted that incorporated uncertainty into each of these estimates. The results of this analysis can be found in Appendix PV.

5.2.2 SOLAR THERMAL

2.1 Introduction

Solar energy could also be used for heating water and then using the produced hot water for heating. The solar thermal collector is the most important part of a solar water heating system and it also forms a large portion of total system's cost. A solar collector consists of a network of pipes through which water (or in colder climates, antifreeze) is heated. Solar water heater collectors used for domestic and commercial buildings, are divided into two main types, Flat Plate collectors and Vacuum Tube collectors. Both technologies must be supplemented by another water heating system, and primarily intended to preheat the water before being fed to the central heating system.

Flat plate collectors are the most common, and consist of (1) a dark flat-plate absorber of solar energy, (2) a transparent cover that allows solar energy to pass through but reduces heat losses, (3) a heat-transport fluid (air, antifreeze or water) to remove heat from the absorber, and (4) a heat insulating backing. Table 11 shows the technical specifications of a typical flat plate collector by Solar Hot Company.

Product name	Equinox 4x10
Company	Solar Hot
Size	4 by 10 *feet*
Weight	137 (*lb)*
Fluid Capacity	1.2 *Gal*
Absorptivity	95%
Output in a clear day	51.2 *kBtu* (15 *kWh*)
Output Power	10.6 *kBtu/hour* (3.1 *kW*)
Price per Collector	$ 890

Table 10 – Technical Specifications of a Typical Flat Plate Collector

Vacuum tube collectors (Evacuated Tube Collector) use heat pipes for their core instead of passing liquid directly through them. Evacuated tubes perform better than flat plate collectors in cloudy weather, and can achieve higher temperatures compared to other collector types, but are typically more expensive. The vacuum that surrounds the outside of the tube greatly reduces convection and conduction heat loss to the outside, therefore achieving greater efficiency than flat-plate collectors, especially in colder conditions. Table 12 shows the technical specifications of a typical flat plate collector by Solar Hot Company.

Product name	Thermo Power VHP-30 Vacuum Tube Collector
Company	Sunmaxx
Size	102.9 by 79 *inch*
Weight	252 (*lb*)
Number of Tubes	30
Tube Material	Borosilicate Glass
Fluid Capacity	0.61 *Gal*
Absorptivity	>92%
Output in a clear day	45 *kBtu* (13.1 *kWh*)
Output Power	8 *kBtu/hour* (2.3 *kW*)
Price per Collector	$ 1050

Table 11 – Technical Specifications of a Typical Vacuum Tube Collector

The price of Flat plate collectors are more than $ 1500 per collector for residential users. But prices decrease as the economics of scale apply. The price of the flat plate collector considered in this report is $1050.

2.2 Practical Application

In this part the current situation in Emerson plant's location has been considered for calculating the maximum size of a system of solar water heaters installed on the roof of the buildings. Since the solar water heating system should work alongside with the CHP system, the system should be connected to tanks and other components in the building that contains the CHP system. Thus, it has been assumed that only the largest building (Building Number 34) is available for installing Solar Water Heaters. Again, only 80% of the roof area is available for installing solar water heater collectors. By dividing the total available roof area by the area of one solar panel, the total number of panels that could be fitted on the roof could be obtained. It should also be considered that solar collectors are installed with a tilt degree of 38 degrees. As a result the occupied space on the ground is different from the size of the collectors. Due to the practical issues in installation of panels and the need for piping, there should be a space between panels. It has also been assumed that 80% of the available area will be covered by panels, which equates to approximately 80,000 ft^2.

Considering each of the different collectors types presented earlier a certain amount of collectors could be installed on the roof of building 34. A similar project done by DOE suggests that collector cost is responsible for 57% of total cost of the system.[20] Table 13 shows the installed capacity using Flat Plate collectors presented earlier in this section. The collector presented in Table 14 shows the installed capacity using Vacuum Tube Collectors.

Panel Type	Equinox 4x10 by Solar Hot
Panel Output	3100 (Watt)
Size of panels	3.65 (m^2)
Size on ground (38 degree tilt)	2.87 (m^2)
Theoretical number of panels installed	2448
Practical number of panels installed (90%)	2203
Total installed Capacity	5,811 (kW)
Installation cost of the system	$ 1561 ($/Collector)
Total Cost of the system	$ 3,440,319

Table 12 – System Size and Cost using Flat Plate Collectors

Panel Type	Thermo Power VHP-30 y SunMaxx
Panel Output	2340 (Watt)
Size of panels	4.12 (m^2)
Size on ground (38 degree tilt)	3.2 (m^2)
Theoretical number of panels installed	2169
Practical number of panels installed (90%)	1952
Total installed Capacity	4,578 (kW)
Installation cost of the system	$ 1842 ($/Collector)
Total Cost of the system	$ 3,597,612

Table 13 – System Size and Cost using Vacuum Tube Collectors

As presented in Table 14, a maximum installed capacity of 4.57 MW could be installed on the roof of Emerson's plant using vacuum tube collectors. Considering the cold weather of Ithaca, the Vacuum

[20] *US Department of Energy*

Tube is assumed to be best for Emerson's needs. From here after in this report the solar water heater systems refers to the 4.57 MW system using Vacuum Tube Collectors unless stated.

2.3 Energy Production

Similar to PV, the thermal energy of solar water heaters is not available to the user whenever needed. The output of the solar water heaters depends on the solar radiation received by the location. Since the data on the effect of the ambient temperature on the output of Solar water heater was not available, only the effect of solar radiation variations has been considered for the output of solar water heaters. Since the output power of Flat Plate Collectors is considerably affected by the ambient temperature, their output could not only be evaluated considering solar radiation variations alone. Thus the data presented only considers Vacuum Tube Collectors. The system is able to deliver a total of 4742 MWh of thermal energy each year.

Table 15 shows the output of the solar panel system described in table 18 which uses Vacuum Tube Collectors.

Month	Energy Produced in each month (MWh)	Average Power in each month (kW)
January	262.52	359.70
February	341.59	468.04
March	470.40	644.53
April	469.72	643.59
May	494.60	677.69
June	478.46	655.57
July	496.68	680.53
August	484.17	663.40
September	420.58	576.27
October	367.80	503.94
November	236.00	323.36
December	220.35	301.91
Total	4742.88	-

Table 14 – Electrical output of the 4.57 MW system using Vacuum Tube Collectors with 38 degrees tilt

The output of the system is shown in Figure 14 compared to the power demand of Emerson plant in each month. Note that this system cannot meet 100% of the hot water demand.

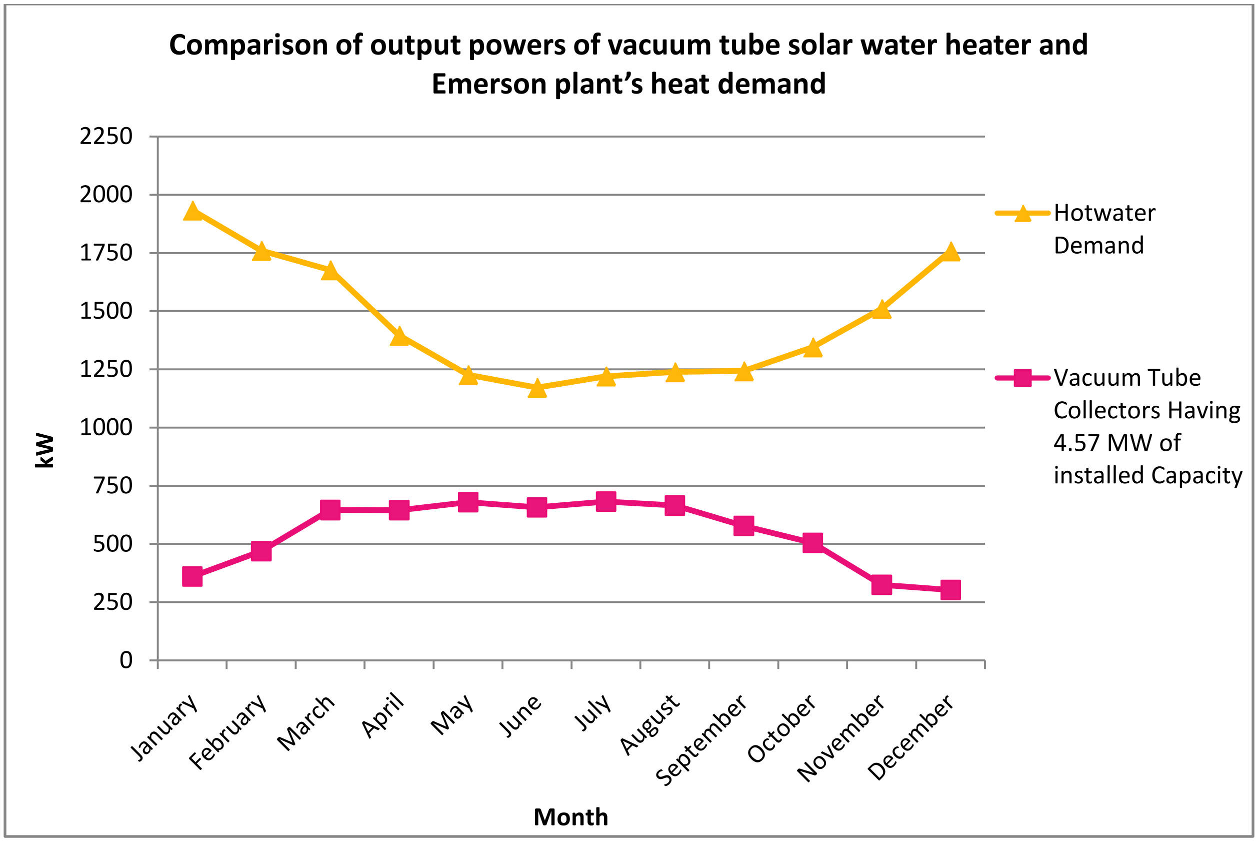


Figure 12

3.8 Economics of the System

In this part the price of each kWh of energy produced by the Solar Water Heater system is calculated. The installation cost of solar thermal panels during the 25 years life all occurs in the first year, and there are no other considerable costs (maintenance cost) throughout its lifecycle.

The project life has been considered as 25 years with a 7% discount rate, with the associated costs shown in Table 16.

	Vacuum Tube System
Installed Capacity	4578.92 kW
Energy Produced per year	4752.13 MWh
Installation Cost	$ 3,597,612
Cost in each year (Distributed and discounted)	$ 308,712.91
Cost of output energy ($/kWh)	$ 0.0650
Yearly Saving of System	$ 228,102.42

Table 15 – The economic calculations for two different Solar Photovoltaic Systems

Note that the price of each kWh of hot water produced by this system is considerably higher than the price of hot water produced by the CHP system (0.048 $/kWh).

5.4 BIOMASS

4.1 Summary

Biomass was also considered as a source of renewable energy for the Emerson facility. The most feasible fuel sources in the New York State area for a biomass plant are wood pellets or wood chips. Wood chips have higher moisture content than wood pellets, and consequently cost more. The difference is due to the fact that wood pellets are a processed material with a higher energy density. Comparatively, wood chips are composed of raw material. A local small-scale biomass plant for strictly heating purposes uses MESA (local wood pellet supplier) as its source for wood pellets. Contact information for a number of New York State biomass suppliers and manufacturers can be found online.[21]

4.2Biomass-fired Electricity Generator

The primary advantages of creating electricity for large-scale industrial use are energy independence from the grid, zero net CO_2 emissions, and reliability. The reliability of biomass-fired electricity plants in comparison to wind or PV energy sources is a substantial advantage. Although the biomass fuel source prices may vary, biomass sources remain available, while wind systems or PV are vulnerable to variations in wind and sunlight respectively.

The technology aspect of the biomass-fired electricity generator is relatively simple. Wood material is burned, and the steam generated from this process is then harnessed and funneled so that it can spin a turbine, thus creating usable power. The cost of a biomass plant such as this is likely to be between $3,000 and $5,000 per kilowatt of installed capacity. For the purpose of the Emerson Complex, the price will be approximately $0.175/kWh to produce electricity. The larger the biomass plant, the cheaper the price per watt of construction (e.g. economy of scale applies).

4.3 Biomass Gasification

The gasification of biomass takes a considerable amount of capital investment to accomplish. After the gasification of the biomass material is accomplished, the resulting gas has an energy content that is just a fraction of that of natural gas. The main factor in determining energy intensity is the type of biomass that is being gasified. Conventional grasses and energy crops are often used, but

[21] *"New York Woody Biomass Feedstock Suppliers and Processed Biomass Fuel Manufacturers." NYC Watershed. 12/1/2011. <http://www.nycwatershed.org/pdfs/biomass_producers_web.pdf>*

animal manure can be used as well. The manure will produce methane under anaerobic conditions. The methane can be used to generate electricity. The biomass type selection also determines the temperatures of digesters and other process parameters from the gasification stage. [22] [23]

It is unlikely that biomass gasification will play a role in the Emerson Plant because of the capital investment necessary in comparison to a conventional, natural gas-driven, combined heat and power system.

4.4 Biomass-fired Combined Heat and Power

Biomass is the only one of the renewable energy sources detailed in this report that can be implemented as a combined heat and power system. It would be used in lieu of natural gas. It would be likely for a biomass CHP plant to be more expensive considering the infrastructure for natural gas already exists at the Emerson facility.

The lifecycle of a given piece of biomass is part of a natural, short-term cycle that results in no increase to atmospheric CO_2 levels. The lack of environmental impact is due to the cycle which includes growing, processing, and then burning the biomass which, in effect, recycles the CO_2. Taking this piece of data and comparing the cost of the electrification of biomass to the cost of electricity from the New York State grid yields a cost of reducing CO_2 emissions value.

5.5 WIND

There is a possible wind farm project by Enfield Energy in Tompkins County. [24] The proposed wind-farm, Black Oak Wind Farm, will have a power capacity of 35 to 50 MW and will be located approximately 6 miles from Ithaca, NY. The Black Oak Wind Farm may possibly begin construction as early as 2012. Despite projections, there is no guarantee the wind farm would be built. If constructed, the cost to buy energy directly from Enfield could be augmented heavily by the fact that the infrastructure to create an exclusive power line to the Emerson Site from the Black Oak Wind Farm would be infeasible. The maximum available amount of power that can be supplied to the Emerson Site will be 12 GWh annually. The cost of this wind power is $0.147/kWh. These values are assumptions based on a previous study by a previous Cornell University Master of Engineering Management student team. The student team studied the feasibility of wind energy in

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[22] *"Biomass Gasification." Biomass Energy – Environmentally Friendly & Profitable Energy. 12/3/2011. http://www.biomassenergy.gr/en/articles/technology/innovation/12-biomass-gasification*
[23] *"Gasification-Based Biomass." Alantec Inc. 11/22/2011. http://www.alentecinc.com/papers/IGCC/BIO_GASIFIACTION.PDF*
[24] *"Enfield Energy." http://www.ccbconstructiononline.com/enfieldenergy/index.htm*

the New York State region. The report can be found on the Cornell Engineering Management website under "Spring 2010".[25]

The cost of single circuit transmission lines in the United States are found below. More extensive data can be found from the Ernest Orlando Lawrence Berkeley National Laboratory.[26]

Primary Voltage	Lowest Cost ($MM/mile)	Highest Cost ($MM/mile)
230 kV	$0.30	$1.60
345 kV	$0.60	$1.50
500 kV	$1.50	$2.20
765 kV	$2.00	$3.20

Table 16: Cost of High-Voltage Transmission Lines

5.6 GEOTHERMAL

6.1 Introduction

Although heating power from geothermal energy was not part of the models that were created to optimize components of this project, there is substantial potential for geothermal energy. Geothermal energy involves harvesting the Earth's sub-surface heat. This can be broken down into 2 subsets, large and small scale.

6.2 Large Scale

Large scale geothermal energy, sometimes called "Enhanced Geothermal Systems" or EGS is a recent technology. This involves very deep penetration into the Earth to find a rock formation with the right porosity and adequate amount of heat to make the drilling worthwhile. The constructed well is drilled to a depth several kilometers into the ground. It is unlikely that zoning rights will allow for this type of heat extraction. Many of the possible dangers associated with this type of operation are the same as deep hydrofracking. A much more in depth investigation of this large scale geothermal technology can be found in the report: "The Possibility of Large-Scale Geothermal Power Plants."[27]

6.3 Small Scale

Small scale geothermal technology is typically used for a single building, commercial or residential. It involves a vertical or horizontal array of pipes that are just feet or tens of feet below the surface

[25] *http://www.cee.cornell.edu/academics/graduate/engineering_management.cfm*
[26] *"The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies." Ernest Orland Lawrence Berkeley National Laboratory. Berkeley Lab. 12/3/2011 http://eetd.lbl.gov/ea/emp/reports/lbnl-1471e.pdf*
[27] *"The Possibility of Large-Scale Geothermal Power Plants" Perspectives On Global Issues. Fathali Ghahermani. 12/4/2011. http://www.perspectivesonglobalissues.com/0401/geothermal.pdf*

of the Earth which are heated up. The temperature of the Earth at this level is 55° to 60° year-round. These warmed pipes circulate water through the house and provide adequate space heating. This process is displayed below in **Figure 15: A Simple Diagram of Small-scale Geothermal Heating** Figure 15.

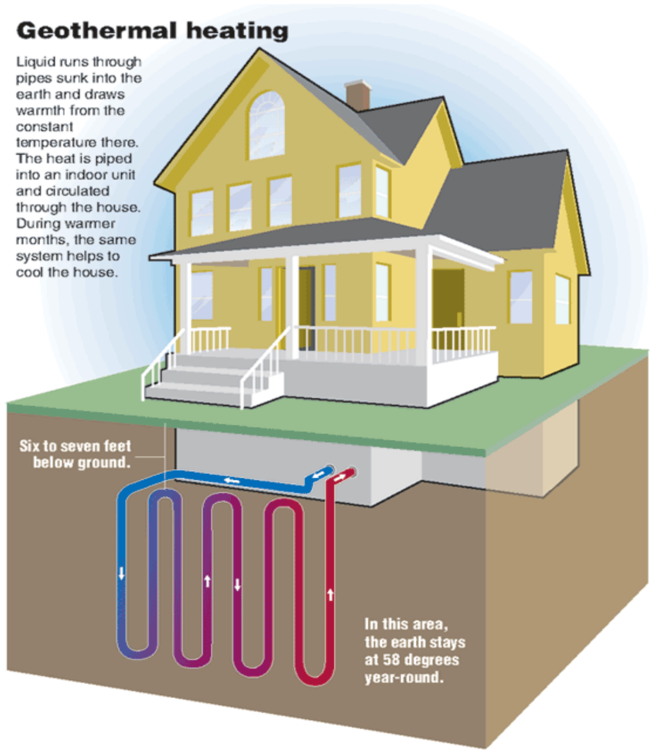


Figure 13: A Simple Diagram of Small-scale Geothermal Heating [28]

5.7 ENERGY STORAGE

5.7.1 SUMMARY

Because of the changing electrical production throughout the day by PV cells, the efficiency of the system could be greatly lower if the surplus energy were unable to be harnessed. The team looked at energy storage systems as one method of meeting the fluctuating hourly energy demand of the building. Storage systems would capture surplus energy when the building's energy production exceeds its demand and provide the extra energy required during hours where production no longer meets demand. Other than internal storage systems, a net metering contract could act as a sort of external energy storage system. A net metering contract effectively acts as a storage system by delivering energy to the grid when there is a surplus and extracting energy from the grid to meet demand at all other times. The major advantage of onsite storage is that it allows a facility to fully

[28] *"Geothermal Heating." Atlanta Geothermal. 12/5/2011. http://www.atlanta-geothermal.com/atlanta-geothermal/atlanta-geothermal-5.gif*

benefit from all of the energy it produces by reducing how much energy must be purchased from the grid. This decreases dependence on the grid, and under the right circumstances could be very cost effective.

There are many types of large scale energy storage systems including batteries, compressed air, flywheels, and pumped water. Several of the alternatives were quickly eliminated as feasible options given the research attempted to determine the most cost effective storage system for this project's application. Pumped is much too expensive for the amount of energy that this proposed storage system will handle. Pumped water and compressed air also generally require convenient geological formations in order to actually physically store the reservoir of pumped water or compressed gas. Therefore the two technologies the team focused on were battery systems and flywheels.

1.7.2 BATTERIES

2.1 Summary

The first storage technology considered was batteries. For a high power application such as this, the main concept of the battery is the same as it would be for batteries used in common appliances and vehicles. The electrochemical reactions that give the battery its charge are electrically reversible, making the battery rechargeable. The basic concept here is that any surplus energy produced would charge the battery, which would then be subsequently discharged throughout the day to supplement the system when production cannot meet demand. For large scale energy storage such as this, there are two main types of battery technologies that are used: sodium sulfur and lithium-ion. Both batteries are relatively new technologies that are continuing to develop, and consequently still dropping in price.

2.2 NAS Batteries

Sodium sulfur (NAS) batteries are economically viable for a storage capacity of about 1 MW or more. NAS batteries can last about 4500 cycles at 80% depth of discharge (DOD), a standard discharge test for most batteries. They can also run up to about 2500 cycles at a DOD of up to an astounding 96%, which demonstrates their utility for high-power applications.[29] Battery banks do, however, require a large area for installation. The one shown below in Figure 16 is part of an

[29] *Norris, Benjamin L., Jeff Newmiller, and Georgianne Peek. "NAS Battery Demonstration at American Electric Power: A Study for the DOE Energy Storage Program." Sandia National Laboratories, Mar 2007. 12/3/ 2011. http://prod.sandia.gov/techlib/access-control.cgi/2006/066740.pdf*

impressive 4 MW, 25 MWh storage capacity NAS battery bank installed in Presidio, Texas, that cost about $25 million.

Figure 14: NAS battery bank in Presidio, Texas [30]

2.3 Lithium-ion Batteries

The second type of battery, lithium-ion or LIB, is a better option for systems up to about 1 MW. These batteries are more recognizable as they are the same technology used in many car batteries as shown in Figure 7. Lithium-ion batteries have a significantly shorter life than NAS batteries at about 1200 cycles for a DOD of 80%.[31] In large quantities, they can be strung together for larger power applications. In Ohio, for example, AEP installed a Community Energy Storage (CES) of 80 units rated at 25 kW and 25 kWh using Li-ion batteries at a cost of $75,000 per unit.[32]

[30] *"Inhabitat: Energy." Inhabitat LLC. 12/3/2011. <www.inhabitat.com>*
[31] *"HEV Vehicle Battery Types." ThermoAnalytics. 12/3/2011. <http://www.thermoanalytics.com/support/publications/batterytypesdoc.html>*
[32] *"Energy Storage Projects in AEP." American Electric Power. Aeptechcentral.com. <http://www.aeptechcentral.com/CES/docs/EESATPresentationAEP-Oct4-7-2009.pdf>*

Figure 15: Typical Li-ion Battery Used to Create a Battery Bank[33]

2.2 Battery Conclusions

The merits of NAS batteries versus LIB are summarized in Figure 8: Comparison of battery technologies. Both batteries are clearly better choices than the other two technologies discussed. Their lifecycles should be expected to be significantly shorter however, due to the frequent and deep discharge the battery banks would experience on a daily basis. Their specifications are similar enough, however, that the discussion becomes moot, due to the expensive nature of providing sufficient storage capacity for the Emerson complex. For implementation in this project's application, LIB can be purchased and installed for about $3,000 per kW of installed capacity, although this price is projected to drop all the way to $1,000 per kW.[34] NAS on the other hand could provide competitive energy density at $1,000 per kWh but falls behind on power at about $6,000 per kW. From the graph of the hourly demand and production, it was determined that for this application the storage system would need capacity of about 3 MWh in order to harness all of the surplus energy. This means that the one-time installation cost for a battery bank would range from about $3MM to $9MM.

[33] *"Company to Produce High Performance Lithium Ion Batteries Just for Cars." RideLust. 19 Aug 2008. 12/3/2011. <www.ridelust.com>*

[34] *Gearino, Dan. "AEP Ohio installs a lithium-ion system that will provide some Gahanna customers with power during an outage." Columbus Dispatch. <http://www.dispatch.com/content/stories/business/2011/09/15/battery-backup.html>*

Comparison Table

Item \ Battery		NAS (Base)	Lead-Acid (Current)	Lithium Ion	Ni-H
Continuous Discharge Duration with rated output		6 hours	2 hours	3 hours	2 hours
Expected Lifetime (at standard conditions)		15 years	3 to 5 years	10 years	7 years
Size	MWh(1MW x 6h)	1	3 times	2 times	3 times
Weight	MWh(1MW x 6h)	1	6 times	2 times	6 times
Price	MWh x 15years	1	3 to 5 times	8 times	6 times
Notes	Self Discharge	No	Yes	Yes	Yes
	Memory Effect	No	No	No	Yes

Note: These data are typical values and change by the manufacturers

Figure 16: Comparison of battery technologies[35]

1.7.3 FLYWHEELS

3.1 Summary

The second type of energy storage system considered for the Emerson facility, and the more environmentally friendly of the two, was flywheels. The general concept of flywheels is to store rotational energy for long periods of time and then convert the kinetic energy into electricity when it is needed most. The energy stored in a spinning flywheel is calculated by one half its moment of inertia multiplied by its angular velocity squared: $E = \frac{1}{2} I \omega^2$. Acting as generators, flywheels can supply electricity by slowing down and converting kinetic energy to electricity upon request. Using hybrid magnetic bearings and vacuum chambers to house the flywheel, these systems can have energy efficiencies in excess of 97%.[36]

3.2 Frequency Regulation

Currently, the main usage of flywheel technology is for frequency regulation, or maintaining an electricity cycling frequency of 60 Hz (in the United States). It is inevitable that supply and demand of electricity from the grid will not be equal at all times. Exact demand is unpredictable and varies

[35] *Singer, Pete. "Korea's POSCO Develops NaS Battery for Energy Storage." RenewableEnergyWorld. 19 Nov 2010. 12/3/2011. <www.renewableenergyworld.com/rea/blog/post/2010/11/koreas-posco-deveops-nas-battery-for-energy-storage>*
[36] *"Frequency Regulation and Flywheels Fact Sheet." Beacon Power Corp. 12/2/2011. <http://www.beaconpower.com/files/Flywheel_FR-Fact-Sheet.pdf>*

on a second by second basis. Supply of electricity depends on its sources, which cannot always vary their output on this same small time scale. However, even small discrepancies between supply and demand can result in an energy mismatch, resulting in something like a ±0.5Hz fluctuation (see Figure 9). These frequency variations can have adverse effects on machines and computers that rely on precise 60Hz electricity.

Figure 17: Frequency Variation from Demand & Supply Mismatch[37]

In order to counter this variation, various types of backup generators have been used to meet gaps in supply and demand curves. However, many of these technologies are too slow to react, or are costly to start up and operate. Flywheel technology has been used in recent years as a solution to this problem, with its fast reaction time and high power capacity. These carbon emission-free rotating drums are a "green" alternative to large diesel generators or batteries, and are gaining momentum in the United States.

3.3 Beacon Power

Beacon Power Corporation, from Tyngsboro, MA, has made a case for flywheel energy storage in the past few years. Beacon Power uses groups of its Smart Energy 25 Flywheel to store energy and release it back to the grid when it is needed most. Each of the flywheels is made of a rotating carbon fiber composite rim that weighs about 900 kilograms, and spins at speeds up to 16,000 RPM (although they normally operate at half this speed). The Smart Energy 25 Flywheels have storage capacities of 100 kWh and power capacities of 25 kW. Each unit achieves 97% energy efficiency using hybrid magnetic bearings to levitate the flywheel inside a vacuum-sealed environment. They are also designed for a 20 to 30 year life cycle, requiring little maintenance.

[37] *Frequency Regulation." Beacon Power Corp. 12/2/2011. <http://www.beaconpower.com/solutions/frequency-regulation.asp>*

Figure 18: Cutaway model of the Smart Energy 25 Flywheel[38]

Beacon Power's flagship example of its flywheel technology is its Stephentown, NY plant, which opened in 2008 and reached full operation in summer 2011. The plant is now at its 20 MW capacity, supplying 10% of New York State's frequency regulation needs. With two hundred flywheels, the Stephentown plant was a substantial renewable energy undertaking, all backed by the United States Department of Energy.

Figure 19: Beacon Power Stephentown, NY Plant[39]

3.4 Flywheel Cost

[38] *"About Flywheel Energy Storage." Beacon Power Corp. 12/2/2011. <http://www.beaconpower.com/products/about-flywheels.asp>*

[39] *"First 20 MW Flywheel Plant in Full Commercial Operation." Beacon Power Corp. 12/2/2011. <http://www.beaconpower.com/company/201107-gallery.asp>*

Although flywheels are extremely efficient at storing energy, they do not provide a high amount of energy storage per unit of cost. Using Beacon Power's Smart Energy 25 Flywheel as a model, we calculated total capital expenses for various size systems. The Table below shows the price per kW of installed capacity for capital investment and maintenance, as determined by the KEMA Consulting team:

Capital Cost / Capacity	$ 1,630.00 */kW (power)*
Maintenance Cost / Capacity	$ 11.60 */kW (power)*

Figure 20: Flywheel Capacity and Maintenance Costs[40]

Using Table 2, and Beacon Power's flywheel ratings of 25 kWh of storage at 100 kW of power, a 1MW system would cost $1.63 MM and only store 250 kWh of energy, or enough to run at full capacity for 150 minutes. Maintenance costs for this system would be a minimal $11,600. A system large enough to support the example 3,183 kWh of excess energy in February (see Section 4.1 Daily Demand) would need almost 13MW capacity and would cost over $20.7MM to install.

5.7.4 STORAGE CONCLUSIONS

Table 3 below compares performance and price characteristics of the battery systems and flywheels considered.

Storage Technology	Power Cost ($/kW)	Energy Cost ($/kWh)	Life Cycle
NAS Batteries	6000	1000	6-12 years
Lithium-ion Batteries	3000	3000	3-4 years
Flywheels	1630	6520	20-30years

Table 17: Battery and flywheel cost comparison

Flywheels also have an additional maintenance cost, while batteries do not; however, this is insignificant due to the following fact. While batteries are cheaper than flywheels, they must be replaced more often. Consequently, flywheels become a more attractive energy storage option than batteries.

Additionally, flywheels could be more environmentally friendly than batteries. The ability to store clean energy encourages the installation of a larger clean energy production capacity, which would lower the end-use CO_2 emissions of the whole system. A life cycle analysis with regards to environmental friendliness was out of the scope of this project, but it is recommended that this be

[40] *"Cost Comparison for a 20 MW Flywheel-based Frequency Regulation Power Plant" KEMA Inc., Project: BPCC.0003.002, September 2007.*

taken as a further research step due to the hazardous nature of some of the materials used in batteries.

From this analysis it can be determined that a storage system is not a feasible addition to our solution. One could be added at a substantial cost, but the only benefit would be increased independence from the grid. A simpler and more cost effective solution would be to enter a net metering contract with the local energy supplier. Should technology develop to reduce the installation of storage, this conclusion ought to be reconsidered.

5.8 CARBON DIOXIDE (CO_2) REDUCTION COST

The cost to reduce the carbon dioxide emitted by the Emerson Plant through certain energy sources is outlined in the table below. The most significant value is the cost per ton to reduce CO_2 emissions. Obviously, it is difficult to justify spending a significantly higher amount of money on an energy source to reduce CO_2 emissions because this has not been a criterion for energy source selection before. Note that the benefits of increased energy independence are not quantified by these calculations. If ALH or local residents felt strongly enough about this independence factor, they would have to be willing to pay a premium.

Dr. James Hansen is a climatologist at Cornell University. During his 2010 Iscol Lecture, he suggested that the threshold for which investors chose to invest or not invest in a more CO_2 friendly technology is $100 per ton of CO_2 emissions reduction.[41] A value higher than this is likely too costly for the typical investor, while a value below $100 per ton of CO_2 is a more economically feasible investment.

Cost to Reduce Carbon Dioxide Emissions				
Energy Source	**Cost ($/kWh)**	**CO2 emissions (lbs/kWh)**	**Cost to Reduce CO2 ($/lb)**	**Cost to Reduce CO2 ($/ton)**
Grid	$0.13	0.524	$0	$0
Photovoltaic Cells (with incentives)	$0.20	0	$0.13	$259.73
Photovoltaic Cells (without incentives)	$0.30	0	$0.32	$641.41
Wind Farm	$0.18	0	$0.09	$172.71

Table 18: Summary of the Cost of CO_2 Reduction

[41] *"ISCOL Lecture." David R. Atkinson Center for a Sustainable Future. Cornell University. 12/3/2011 http://www.sustainablefuture.cornell.edu/events/iscol/iscol2010.php*

5.9 INCENTIVES

9.1 Summary

In many areas of the United States, older and more well-established forms of energy are often cheaper to produce than renewable energy sources. As new energy technologies arise, their costs usually start relatively high, and thus create a large barrier to entry for aspiring "green energy" companies. Financial incentives provided by state and local government programs help to ease the cost of constructing energy production facilities and improving energy efficiency in buildings and homes. Because the Emerson plant is within the state of New York, we examined both state and federal incentives in order to predict possible cost reductions from incentives.

9.2 New York State

The state of New York has a number of financial incentives for renewable energy. The state, along with the New York State Energy Research and Development Authority (NYSERDA) has provided a number of incentives to offset some of the costs associated with alternative energy sources. Grants will cover various prices per kW or kWh of installation capacity for sources such as energy storage, natural gas, CHP, PV, solar thermal, or general energy efficiency improvements. The state will also provide tax or property rebates based on installation of commercial or residential energy installations. (More detailed incentives can be found in Appendix F.)

9.3United States

The U.S. federal government has a number of programs in place to help encourage developers to install renewable technologies. Like New York State, the federal government provides grants for various sources of energy as well as tax credits and rebates for a number of different industries. They also provide federal loans to aid investment costs for alternative energies. The U.S. Department of Energy is the major driving force behind implementing new incentives to make alternative energy sources more attractive and cost effective. (More detailed federal incentives can be found in Appendix H)

9.4 Incentives for Emerson

Although there are a number of incentives available from the state of New York and from the United States federal government, most of them are dependent on a formal application process and production capacity within a given range for electricity. Furthermore, many programs begin and end as grant money expires, so available incentives at a given time are constantly changing. Since no incentive is a “guarantee”, CGCG made a very conservative assumption for incentives at the Emerson facility. Although scenarios consider a number of different energy sources, a small incentive of $0.10/kWh (about 30% of installed cost) was applied only to the installation of PV for electricity. This percentage is an average value of incentives in New York for photovoltaic projects.[42] As a final decision is made for energy sources at the Emerson facility, incentives can be approached more thoroughly in order to assess which currently available grants and rebates there are for the Ithaca, NY area at that time.

[42] *“Federal Renewable Energy Incentives.”GetSolar.com. 2011. <http://www.getsolar.com/cost_solar-energy-incentives-federal.php>*

6. OPTIMIZATION MODEL

6.1 MODEL DESIGN

1.1 Summary

In order to determine the most cost effective combination of energy sources (and the amount of energy that would be generated from each one for the Emerson site), a model was created that would allow us to find a feasible solution.

In the process of creating such a model CGCG considered many alternatives, finally settling on a linear programming solution. This particular model was chosen because it is easy to use, allows easy manipulation of basic parameters, and provides a sensitivity analysis for our base solution.

In the creation of this model, CGCG chose to select a cost minimization strategy as the objective function of the problem. The model, complete with its constraints and explanations, is presented below.

1.2 Parameters

t = Month {January, February, March, April, etc.)

i = Energy source {CHP, PV, Biomass, Wind, Grid, Solar Thermal}

C_i = Cost to generate 1 kWh from source i

$Area$ = Total usable area of the roof

$Size_i$ = Area needed to generate 1 kWh from source i

$CO2_i$ = CO2 emissions generated per Kwh from source i

$CO2_{max}$ = Maximum CO_2 emissions allowed for the whole system

E_{it} = Maximum energy available from source i at time t

W_t = Hot water demand for time t

Hw_i = Hot water gallons generated from 1 kWh from source i

1.3 Decision Variables

X_{it} = Amount kWh generated from source i at time t

There is one decision variable per source, per month of the year; therefore, for 12 months and 7 sources, there are 84 decision variable.

1.4 Objective

The overall objective of the optimization problem is to minimize the total cost:

MINIMIZE: $\Sigma_i [\Sigma_t (C_i \cdot X_{it})]$

1.5 Constraints

The decision variables are subject to the constraints defined below:

1. $X_{it} \leq E_{it} \ \forall \ i,t$
2. $\Sigma_i [\Sigma_t (CO2_i X_{it})] \leq CO2_{max}$
3. $\Sigma_i [\Sigma_t (Size_i X_{it})] \leq Area$
4. $\Sigma_i [Hw_i X_{it}] \leq W_t \ \forall \ t$

The definition of each of these constraints is briefly described below:

1. The amount of energy generated from source *i* at time *t* has to be less than or equal to the maximum amount available in that month for that particular source
2. The amount of CO_2 emitted from all sources at all times must be less than the maximum CO_2 emissions from the whole system
3. The area used by all of the sources of energy must be less than or equal to the total area of the roof
4. The total amount of hot water generated from all the sources at time *t*, must be less than or equal than the hot water demand for that time

This model was a key component of the project's analysis. The tool created in Microsoft Excel (explained in Section 6.2 Optimization Model Implementation) was used throughout the project and included as part of the project deliverables.

6.2 OPTIMIZATION MODEL IMPLEMENTATION

2.1 Purpose and Approach

The purpose of the CGCG optimization model is to determine the most cost effective means to heat and power the Emerson Plant. A linear program was developed to minimize this cost, while satisfying electricity/heat demand, CO_2 emissions constraints, and space limitations, as formulated in Section 6.1. This model was developed in Microsoft Excel using Excel's built in Solver function in order to maximize accessibility and ease of use. The CGCG optimization model contains three tabs: (1) User Guide, (2) Dashboard, and (3) Results and Graphs.

2.2 User Guide

The first tab contained in the workbook is the User Guide. This tab contains a description of the model, its purpose, and constraints. It is essentially identical to this Optimization Manual, and was included to make the CGCG optimization model a self-explanatory, standalone document.

2.3 Dashboard

The optimization model is located on the Dashboard tab and is composed of four sections: (1) Run Control and Final Results, (2) Input Parameters, (3) Constraints, and (4) Optimization Model. The default values provided in these sections represent CGCG's best estimates, but the user is encouraged to run customized scenarios with his/her own estimates.

The first section, 'Run Control and Final Results,' contains buttons that run two different scenarios and displays the resulting cost and CO_2 emissions for each scenario type.

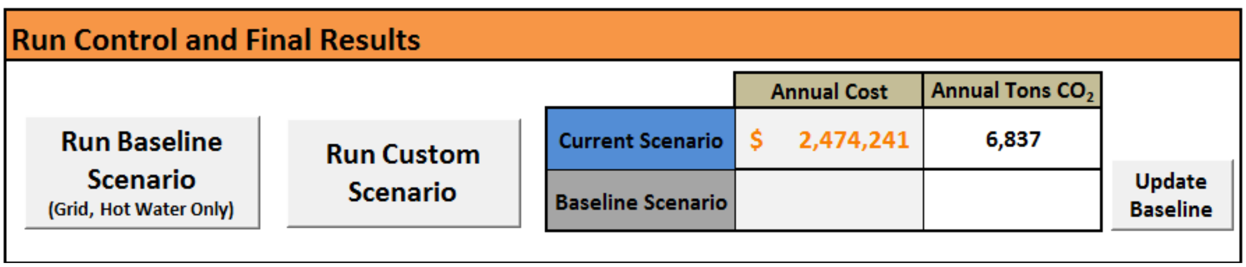


Figure 21

The first button runs the Baseline Scenario, a predefined scenario designed to reflect the current conditions at the Emerson complex and that therefore only enables grid electricity and natural gas fed boilers. This scenario calculates the total annual energy cost and associated tons of CO_2 produced shown in the 'Current Scenario Cost' cells. The second scenario type, called a Custom Scenario, is identical to the Baseline Scenario except it considers user defined energy sources, rather than grid and hot water only. The results of the most recent scenario can be saved at any time in the "Baseline Scenario" cells by clicking the "Update Baseline" button.

The 'Set Input Parameters' section allows the user to toggle which energy sources are considered in the scenario. The normalized cost per kWh for each energy source is also defined in this area, along with the CO_2 emissions and the size of the solar panels. The user can restore the CGCG default values in this section by clicking the 'Restore Defaults' button found in the top right corner. Please refer to the energy research sections for further discussion of how these values were obtained.

Set Input Parameters | Restore Defaults

Energy Sources		
Type	**Toggle**	**$/kWh**
CHP (Elec.)	On	$ 0.070
PV	On	$ 0.190
Wind	On	$ 0.147
Biomass	On	$ 0.175
Solar Thermal	On	$ 0.064
Grid	On	$ 0.129
Hot Water	Off	0.048

On
Off

Emissions (lbs CO_2/kWh)	
CHP	0.479
Grid	0.524
Hot Water	0.479

Solar Panel Size (kWh/m^2)	
PV	115.0
Solar Thermal	505.6

Figure 22

The "Constraints" section defines the constraints for the model, which include the annual electricity and hot water demand. The annual demand is converted to monthly demand using seasonal consumption rates identified in the supporting research. "Max Wind" defines the amount of wind energy available in case the user wishes to place a constraint on this amount. The PV and Solar Thermal roof area constraints reflect the total roof space, and the roof space of the largest building on the complex, respectively. The final constraint specifies the maximum allowable CO_2 emissions. Again, the user can restore the CGCG default values in this section by clicking the 'Restore Defaults' button found in the top right corner.

Set Constraints | Restore Defaults

	Annual Elec. Demand (kWh)	Annual H.W. Demand (kWh)	Max Wind (kWh)	PV Roof Area (m^2)	Solar Thermal Roof Area (m^2)	CO_2 Emissions (Tons)
Constraints	14,434,053	12,755,162	12,000,000	37,350	9,400	100,000
Run Results	14,434,053	12,755,162	-	-	-	6,837

Figure 23

The 'Optimization Model' is the last section and contains the decision variables used to perform the actual optimization calculations. It specifies the kWh produced per month from each source and the total CO_2 emissions from each source. These results are provided in a user friendly format in the subsequent 'Results and Graphs' section.

2.4 Results and Graphs

The 'Results and Graphs' tab provides additional information to help the user interpret the model's output. This information is divided into three sections: (1) Total Demand, (2) Total Production, and (3) Energy Independence.

The "Total Demand" section illustrates the relative hot water and electricity demand at the Emerson facility. Note that hot water has a larger seasonal variance than electricity.

Total Demand

Monthly Energy Demand (kWh)		
Month	**Electricity**	**Hot Water**
January	1,144,871	1,410,981
February	1,131,622	1,284,446
March	1,168,359	1,223,517
April	1,234,606	1,018,543
May	1,297,842	894,887
June	1,330,966	855,067
July	1,281,582	890,689
August	1,222,561	903,762
September	1,174,382	906,761
October	1,164,746	981,842
November	1,156,314	1,101,780
December	1,126,202	1,282,887

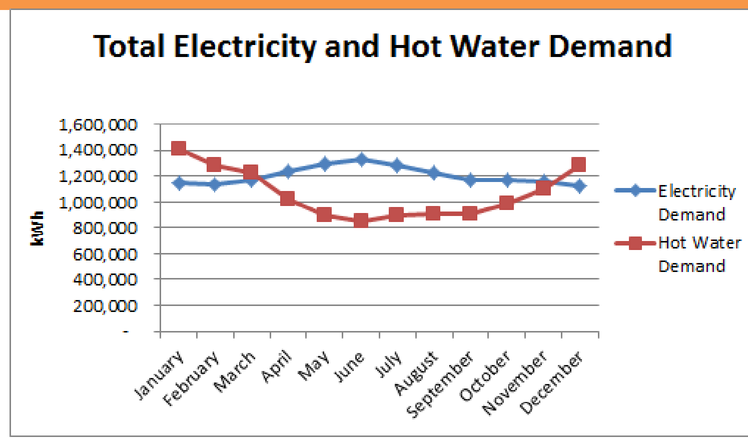
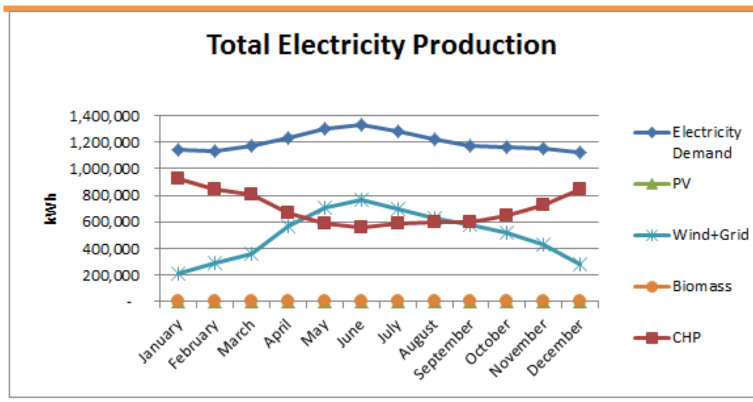


Figure 24

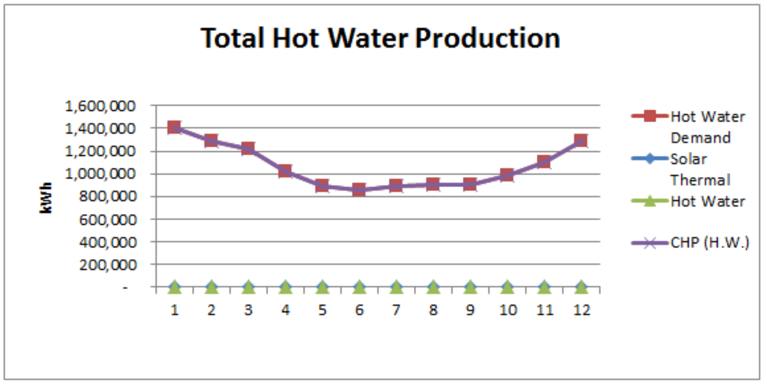
The "Total Production" section displays the amount of energy and hot water that is produced by each energy source. This section also provides the relative cost as a function of the amount of energy produced for each source. Note that Wind and the Grid are combined, since this energy comes from the same immediate source.



Total Elec. Production and Cost			
Source	**Prod.**	**Elec. Cost**	**Total Cost**
PV	0%	0%	0%
Wind+Grid	42%	57%	57%
Biomass	0%	0%	0%
CHP	58%	43%	43%

Wind/Grid Ratio	
% Wind	0%
% Grid	100%

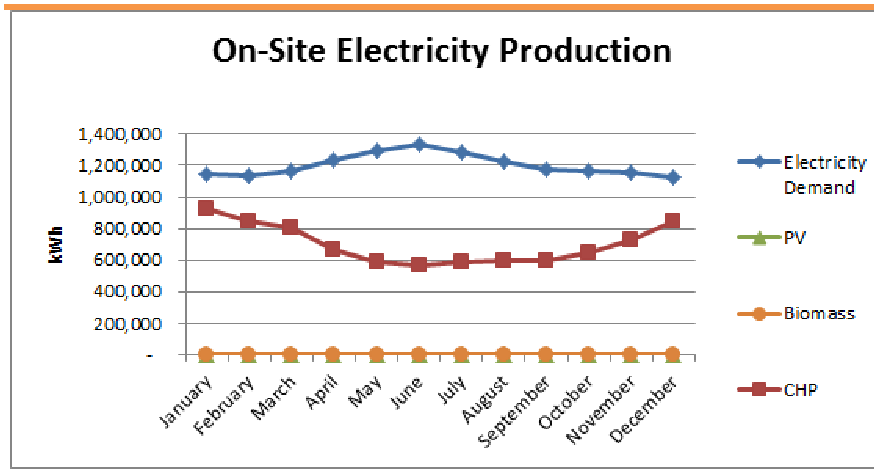
Figure 25



Total Hot Water Production and Cost			
Source	Prod.	H.W. Cost	Total Cost
Thermal	0%	0%	0%
Hot Water	0%	0%	0%
CHP (H.W.)	100%	100%	43%

Figure 26

The final section details on-site energy production and provides the same information as the "Total Production" section, but only includes energy that is produced at the Emerson plant.



On-Site Energy Production	
Source	Prod.
PV	0%
Biomass	0%
CHP	58%
Total	58%

Figure 27

2.5 Assumptions and Caveats

The following assumptions and caveats were made during the formulation of the optimization model:

1. Default electricity/hot water demand assume 100% site occupancy.
2. Demand was forecasted using CBECS data, not site specific data.
3. Cost per kWh was calculated assuming linearly scaled cost.
4. Although seven energy sources were considered, there are additional systems not included that may offer better results.
5. If an infeasible solution is found, the user must look to the constraints section to determine which constraint cannot be met.

6. The cost of producing one kWh using of CHP is the cost per kWh for CHP (Electricity) plus the cost per kWh for Hot Water. This is because Hot Water is assumed to be generated using natural gas fed boilers at 90% efficiency, which is the same rate used for CHP, which also uses natural gas.
7. There is an existing natural gas line at the Emerson complex that has sufficient capacity to meet demand.

7. ECONOMIC ANALYSIS

7.1 COSTS OF ENERGY SYSTEMS

7.1.1 SUMMARY

This section provides an overview about the economic tools that CGCG used for calculating the costs of energy systems. Economic evaluation methods and a sample cost calculation are explained in following section.

7.1.2 EXPLANATION OF METHODS

2.1 Time Value of Money

Money available at the present time is worth more than the same amount in the future due to its potential earning capacity. This core principle of finance holds that any amount of money is worth more the sooner it is received.

In the project, CGCG used the time value of money method to evaluate the financial risk of investments. For each energy system, the present value of costs is calculated.

2.2 Discounted Cash Flow Analysis

Discounted cash flow analysis uses future free cash flow projections and discounts them to arrive at a present value.[43] For the purpose of economic feasibility, CGCG used a 7% discount rate. The following figure illustrates a sample project with positive and negative cash flows.

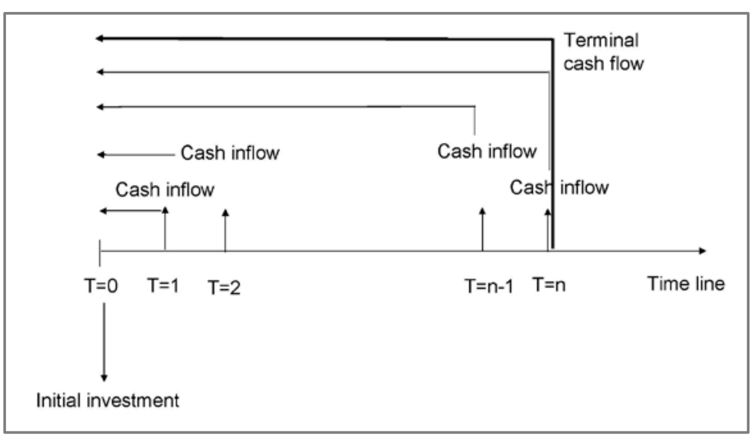


Figure 28: Sample Cash Flows

[43] *Vanek, Francis, "Energy Systems Engineering", Pages 61-70*

2.3 Levelized Cost of Energy

The levelized cost per unit of energy output provides a way to combine all cost factors into a cost-per-unit measure that is comparable between technologies. This method gives the price at which electricity must be generated from a specific energy source to break even.

This method helps to assess the cost of an energy generation system by including all the costs over its life time. If the average output of electricity in kWh is known for an energy source, the sum of all the initial investment and operational expenditures divided by the annual output gives a cost per kWh value.

$$Levelized\ Cost = \frac{Total\ Annual\ Cost}{Annual\ Output}\ (in\ units\ of\ kWh)$$

Equation 1

$$Total\ annual\ cost\ = annualized\ cost\ + operating\ cost + ROI$$

Equation 2

Here, annualized capital cost is calculated using the discount rate for the project over the project lifetime. Operating cost typically includes cost for fuel, maintenance of energy systems, administrative costs, and insurance costs related to the project.

7.1.3 SAMPLE COST CALCULATION

3.1 Levelized Cost for CHP

For the economic calculations of all energy systems, CGCG followed the same approach. This example explains the approach step by step.

<u>NPC of Installation Costs</u>: For the CHP System, we first calculated the net present cost (NPC) of installation costs. Over the 25 year life cycle, the CHP system must be replaced three times. Therefore, we calculated the NPC of CHP installation at years 1, 9 and 18. Note that since CGCG is considering a 25 year project life cycle, the remaining 2 years of life of the CHP units are not factored into these calculations.

<u>Annual Payments</u>: The total present value is distributed in equal payments with time period of 25 years and discount rate 7%. For the purpose of this project CGCG assumed salvage value of zero at the end of the CHP system life cycle.

Annual Total Cost: Total cost is the sum of yearly payments, maintenance and fuel costs. This value is the total amount that needs to be paid annually to break even on all expenditures. The following table illustrates the costs calculated for the CHP System:

Year	Installation Cost	Maintenace Cost	Fuel Cost	Payment	Total Cost	Recurrent Costs
1	$ 1,596,625.00	$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
2		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
3		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
4		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
5		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
6		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
7		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
8		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
9	$ 1,596,625.00	$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
10		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
11		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
12		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
13		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
14		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
15		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
16		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
17		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
18	$ 1,596,625.00	$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
19		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
20		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
21		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
22		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
23		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
24		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89
25		$ 83,873.89	$887,655.00	$252,065.56	$ 1,223,594.45	$ 971,528.89

Table 19

Levelized Cost: For the CHP system, CGCG used following formula to calculate the cost per kWh:

$$Cost\ per\ kWh = \frac{Annual\ \sum Payment + Maintenance + Fuel}{Annual\ Maximum\ Output}$$

Equation 3

After calculations, we obtained the cost $0.0729 per kWh of electricity for the Emerson building. This levelized cost is then fed to the model as an input parameter for CHP system.

7.2 ECONOMIC MODEL

After each technology was defined and researched and the optimization model determined the scenarios, an economic feasibility model was performed. CGCG decided to perform a Net Present Value (NPV) analysis (which is analogous to a Net Present Cost analysis) since it is a simple, but yet a very effective method to determine the feasibility of the proposed scenarios. It also provides a tool which can aid ALH analyze different options and choose the one that suits its interests best. By having this value, ALH will be able to evaluate the scenarios proposed in this report and choose that one that best suits its interests.

The net present value is understood as the difference between the present value of the cash inflows and the present value of the cash outflows. The following formula represents this:

$$NPV = \sum_{t=0}^{N} \frac{CF_t}{(1+i)^t}$$

Equation 4

Where t is any particular period, CF indicates the cash flow at the end of period t, i represents the cost of capital, and T the number of periods making up the economic life of the investment.

Cash inflows are positive values of CF_t, and cash outflows are negative values of CF_t. For any given period t, a collection of all the cash flows (negative and positive) is performed and is summed together. Once all the costs were acquired via the team's research all this information was introduced into the Microsoft Excel spreadsheet. This simplified the calculations methods by taking advantage of the tools Excel provides.

One thing to take into account, as Pamela Peterson and Frank Fabozzi comment in "Capital Budgeting: Theory and Practice"[44], is that a positive net present value means that the investment increases the value of the firm. The return is more than sufficient to compensate for the required return of the investment. A negative net present value means that the investment decreases the value of the firm. The return is less than the cost of capital. A zero net present value means that the return just equals the return required by owners to compensate them for the degree of uncertainty of the investment's future cash flows and the time value of money.

At the end, because the net present value is a measure of how much ALH's wealth is expected to increase with an investment, NPV can help us identify which scenario maximizes ALH's wealth.

The way CGCG calculated the NPV (analogous NPC) was by forecasting the future cash flows, choosing the appropriate discount rate and finding the present value of the forecasted cash flows. The objective is always to maximize the NPV, which is equivalent to minimizing the NPC. This is the case for the analysis of installing the systems at the Emerson complex. Since this analysis does not include any income, the NPV is seen as a negative, which is equivalent to a NPC.

[44] *Peterson, Pamela P. , Fabozzi, Frank J., "Capital Budgeting: Theory and Practice", John Wiley & Sons, 2002.*

It is important to choose a proper discount rate because a rate that is too high will reject projects that add value to the firm while a rate that is too low will accept projects that subtract value. [45] For the purposes of this economic feasibility study, the discount rate has been determined to be 7%.

Considering all the different technologies researched, the team examined how to combine them and obtained several alternatives that would be feasible and fulfill ALH's requirements. Five alternatives or scenarios have been defined and will be analyzed and discussed in the following pages.

[45] *Ehrhardt, Michael C., "The Search for Value: Measuring the Company's Cost of Capital", Harvard Business School Press, 1994.*

8. SCENARIOS

8.1 SUMMARY

In order to determine the installation cost of each technology for every scenario, CGCG first estimated annual energy demands for the Emerson complex, as described in Section 4.1:

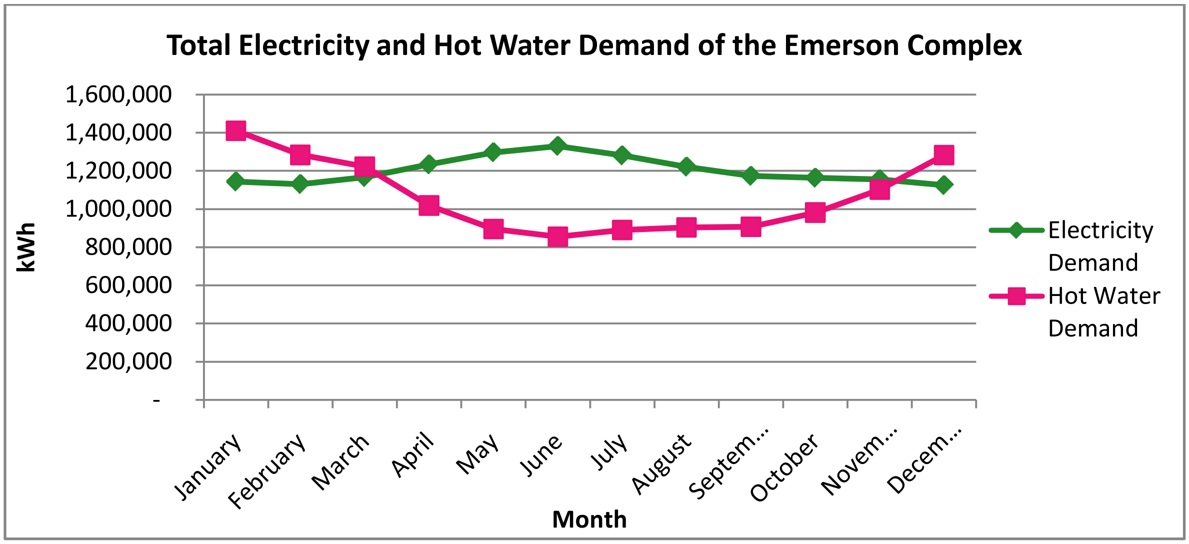


Figure 29: Total Energy Demand of the Emerson Complex

As seen in this figure, the highest demand for heat (and thus hot water) is in the winter months, with a peak demand in January of 1,400 MWh. In contrast, the highest electricity demand occurs in the summer, with a peak demand in June of 1,300 MWh.

Regardless of the scenario considered, CGCG has determined that Emerson will require 14,400 MWh of electricity and 12,700 MWh of heat in order to meet demand.

8.2 SCENARIO 1 – BASELINE

The baseline scenario was developed as a benchmark for future optimization situations. This scenario explores the alternative of buying all of the energy required from the grid and meeting the hot water demand using boilers. This situation was analyzed in order to compare the cost of a standard situation with the cost of installing different types of energy sources (as described in the other scenarios, below).

The following graph shows the costs required to produce energy using this scenario over a 25-year life span:

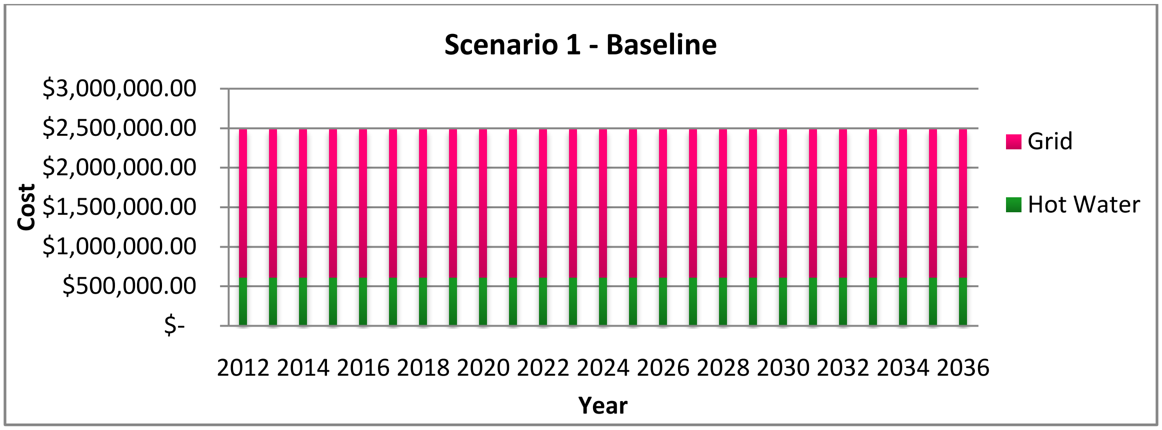


Figure 30: Scenario 1 Costs

The total energy cost per year under this scenario is $2.48 MM. From the graph, it is clear that the total cost per year is constant. The operator (ALH) will not incur in any varying installation or maintenance costs since every unit of energy will be purchased from a third party energy distributor.

Total energy production is broken down and plotted using the optimization model:

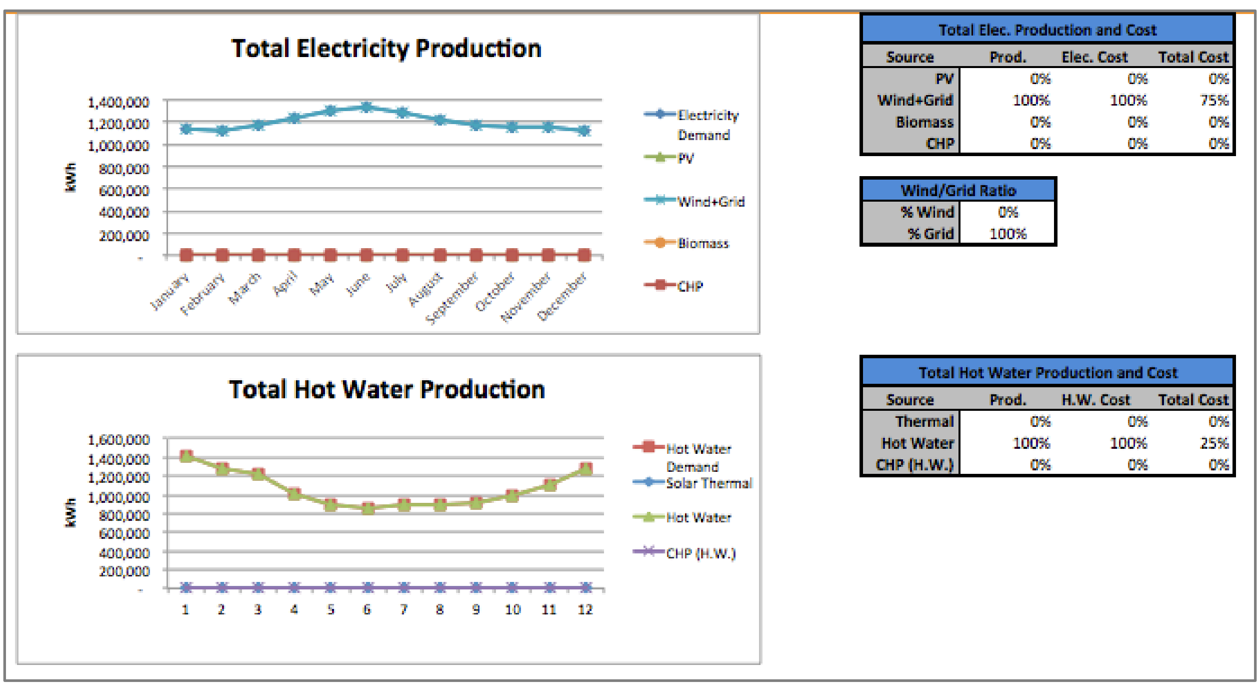


Figure 31: Scenario 1 Energy Production

As seen in Figure 33, the grid is used to completely meet electricity demand. In regards to the heat (hot water) demand, boilers will used to meet demand. (Electricity and heat production percentages are broken down in the tables at the right of Figure 33.)

The electricity cost in this scenario is \$1.87 MM, which accounts for 75% of the total yearly cost. This scenario does not take into consideration any CO_2 constraints, and thus the optimization model has provided an output of 6,800 tons of CO_2 emissions. The net present cost of this scenario, as determined by the economic model, is \$30.98 MM.

8.3 SCENARIO 2 – MINIMIZE COST

After establishing the baseline scenario, CGCG constructed a scenario to minimize total cost. This scenario considers all of the energy sources included in the optimization model and aims to meet the electricity and hot water demand while minimizing total cost.

Figure 34 shows how costs will be distributed along the life cycle of the project:

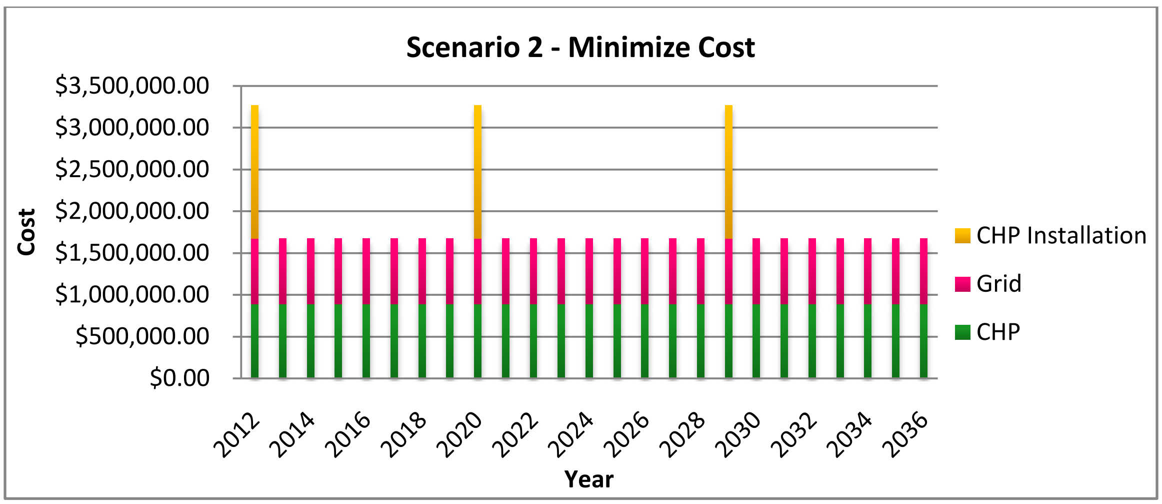


Figure 32: Scenario 2 Costs

In this scenario, a CHP life cycle of approximately nine years was considered. With a project life span of 25 years, ALH will need to install five CHP systems during year 1 and replace them twice: first during year 9 and then again during year 18. The three yellow bars in Figure 34 represent this increased cost. For three of the years, annual cost will be \$3.26 MM. For the remaining 22 years, annual cost will be only \$ 1.67 MM. The cost breakdowns can be seen in the following tables:

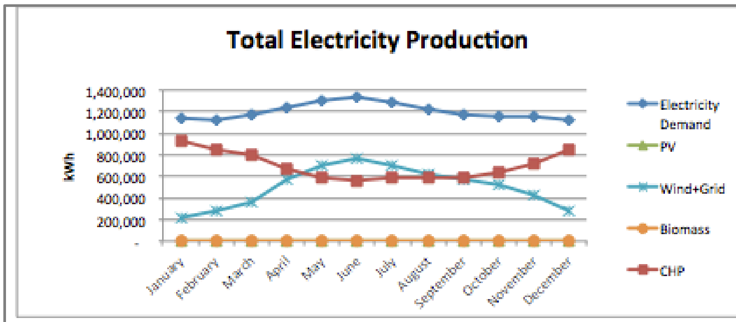
CHP Installation Years	
CHP	$ 887,655.00
Grid	$ 784,554.59
CHP Installation	$ 1,596,625.00
Total	**$ 3,268,834.59**

Non Installation Years	
CHP	$887,655.00
Grid	$ 784,554.59
Total	**$ 1,672,209.59**

Tables 20 & 21

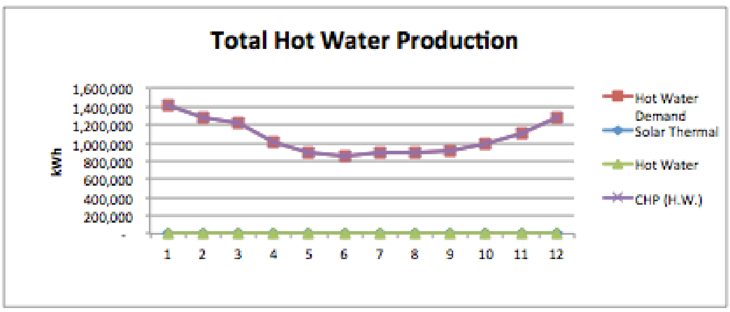
The row labeled "CHP" in each table includes annual costs of maintenance and fuel (in the form of natural gas) for the CHP system.

The optimization model found that the best alternative in this case was to use the grid and CHP to meet the demand. Five CHP systems will meet all the hot water needs and a large fraction of the electricity demand. (Note that CHP systems can also be used to create hot water in the summer to run a chiller. This would increase the usage of the CHP systems during the summer, but was out of the scope of this project.) The grid will then be used the meet the remaining electricity requirement.



Total Elec. Production and Cost			
Source	Prod.	Elec. Cost	Total Cost
PV	0%	0%	0%
Wind+Grid	42%	57%	57%
Biomass	0%	0%	0%
CHP	58%	43%	43%

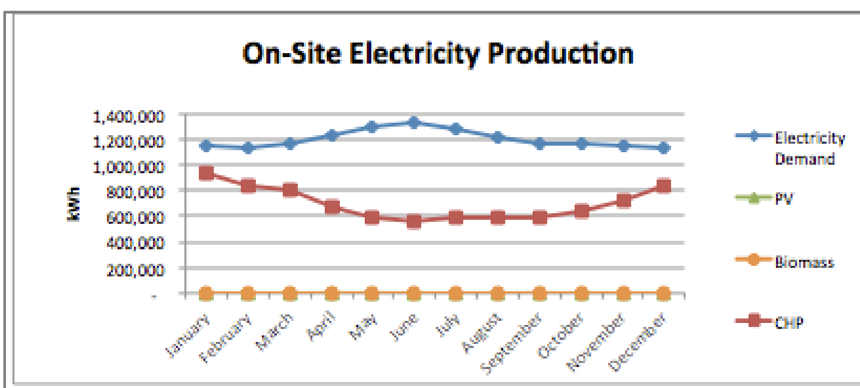
Wind/Grid Ratio	
% Wind	0%
% Grid	100%



Total Hot Water Production and Cost			
Source	Prod.	H.W. Cost	Total Cost
Thermal	0%	0%	0%
Hot Water	0%	0%	0%
CHP (H.W.)	100%	100%	43%

Figure 33: Scenario 2 Energy Production:

The grid will produce 42% of Emerson's electricity demand, while the five installed CHP units will produce the remaining 58% on site.



On-Site Energy Production	
Source	Prod.
PV	0%
Biomass	0%
CHP	58%
Total	58%

Figure 34: Scenario 2 On-Site Production

Even though emissions are not constrained in this scenario, the total amount of CO_2 emitted decreased by 3% from the baseline scenario, bringing CO_2 emissions down to 6,600 tons per year. The net present cost of this scenario was calculated as $23.88 MM.

8.4 SCENARIO 3 – INCLUDE PHOTOVOLTAICS

In order to make energy production "greener", CGCG introduced photovoltaic panels to the possible scenarios as a way to reduce CO_2 emissions. Scenario 3 considers the use of the grid, CHP, and PV in order to meet the demand of electricity and hot water. Figure 37 indicates the distribution of costs for this scenario:

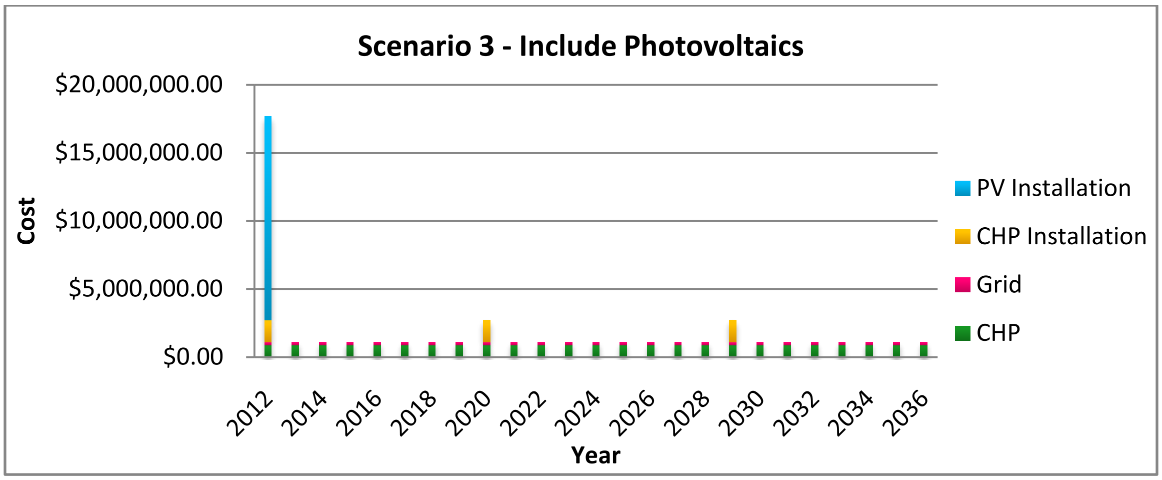


Figure 35: Scenario 3 Costs

Scenario 3 has one major difference from Scenario 2, which the installation cost of the PV panels in year one. If this cost were removed from year one, the situation and payments would be exactly the same as in Scenario 2 (with CHP installation costs in years 1, 9, and 18). One important consideration to note is that after the initial installation of PV in year one, there will be no recurring expenses for this energy source because it the panels require little or no maintenance.

Tables 23, 24, & 25 provide a breakdown of the three different annual costs for this scenario:

PV and CHP Installation Year	
CHP	$ 887,655.00
Grid	$ 225,556.45
CHP Installation	$ 1,596,625.00
PV Installation	$ 14,953,228.16
Total	**$ 17,663,064.60**

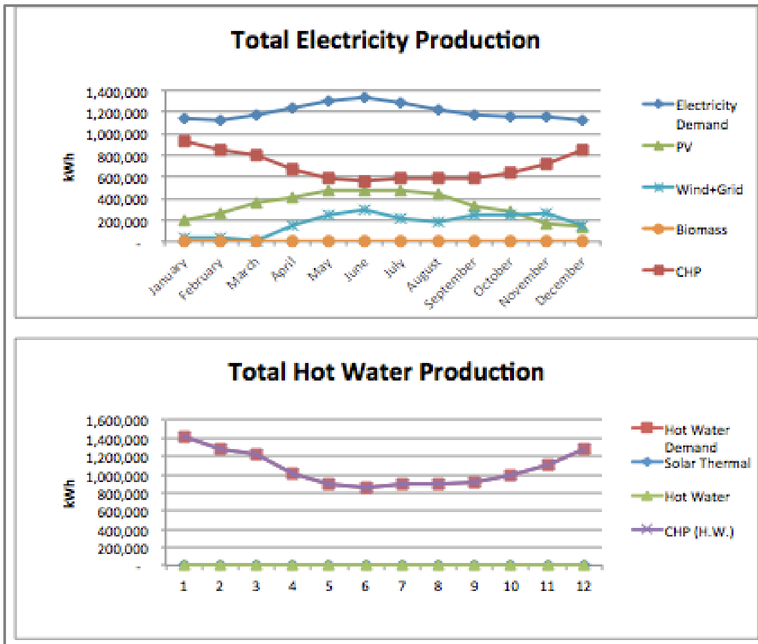
CHP Installation Years	
CHP	$ 887,655.00
Grid	$ 784,554.59
CHP Installation	$ 1,596,625.00
Total	**$ 3,268,834.59**

Non Installation Years	
CHP	$887,655.00
Grid	$ 225,556.45
Total	**$ 1,113,211.45**

Tables 22, 23, & 24

The total cost of $17.63 MM in year one represents a one-time payment that includes both PV and CHP installations. After this, in years 9 and 18, yearly costs will be $3.26 MM to account for the replacement of the five CHP systems. Finally, on years that no installation is necessary, there are only the recurrent costs of CHP (maintenance and natural gas) and electricity from the grid that provide an annual cost of $1.11 MM.

The installation of the PV panels has been estimated to fill 90% of the total roof area. The figures below illustrate the energy production breakdown for Scenario 3:



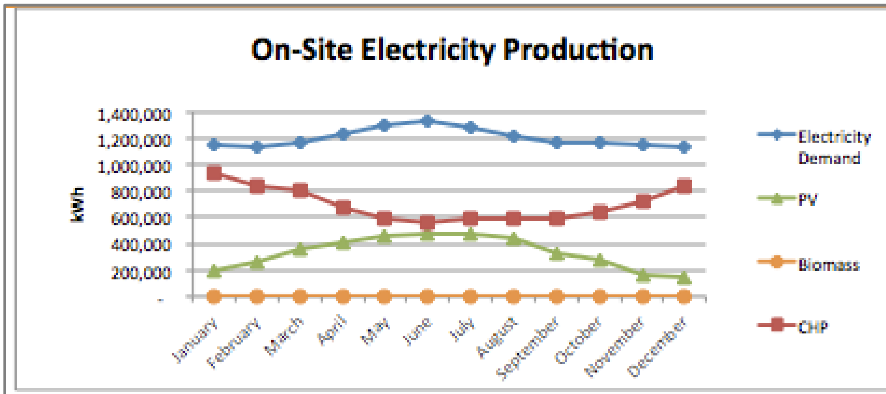
Total Elec. Production and Cost			
Source	Prod.	Elec. Cost	Total Cost
PV	28%	47%	47%
Wind+Grid	14%	16%	16%
Biomass	0%	0%	0%
CHP	58%	36%	36%

Wind/Grid Ratio	
% Wind	0%
% Grid	100%

Total Hot Water Production and Cost			
Source	Prod.	H.W. Cost	Total Cost
Thermal	0%	0%	0%
Hot Water	0%	0%	0%
CHP (H.W.)	100%	100%	36%

Figure 36: Scenario 3 Energy Production

The installed PV panels will account for 28% of electricity production, the grid will provide 14%, and the CHP systems will cover the remaining 58% along with the total heat (hot water) demand. One important aspect of to highlight is that 86% of the electricity required will be produced on-site, as seen in Figure 39.



On-Site Energy Production	
Source	Prod.
PV	28%
Biomass	0%
CHP	58%
Total	86%

Figure 37: Scenario 3 On-site Production

With the roof area constraint limiting the quantity of PV panels ALH is able to install (roof area from every building is considered), the optimization model has provided an expected reduction in CO_2 emissions of 18% in comparison to the baseline scenario to 5,600 tons of CO_2 per year. The net present cost of implementing this scenario is $31.86 MM.

8.5 SCENARIO 3A – PHOTOVOLTAICS AND SOLAR THERMAL

Scenario 3A represents a small variation of Scenario 3; it reduces the amount of PV panels installed on the roofs in order to make space for solar thermal panels that produce hot water. The solar thermal panels will be installed on Building #34 which has the largest roof area (See Figure 1). PV panels will be installed on the remaining building roofs.

The following graph shows the costs throughout the 25 year cycle:

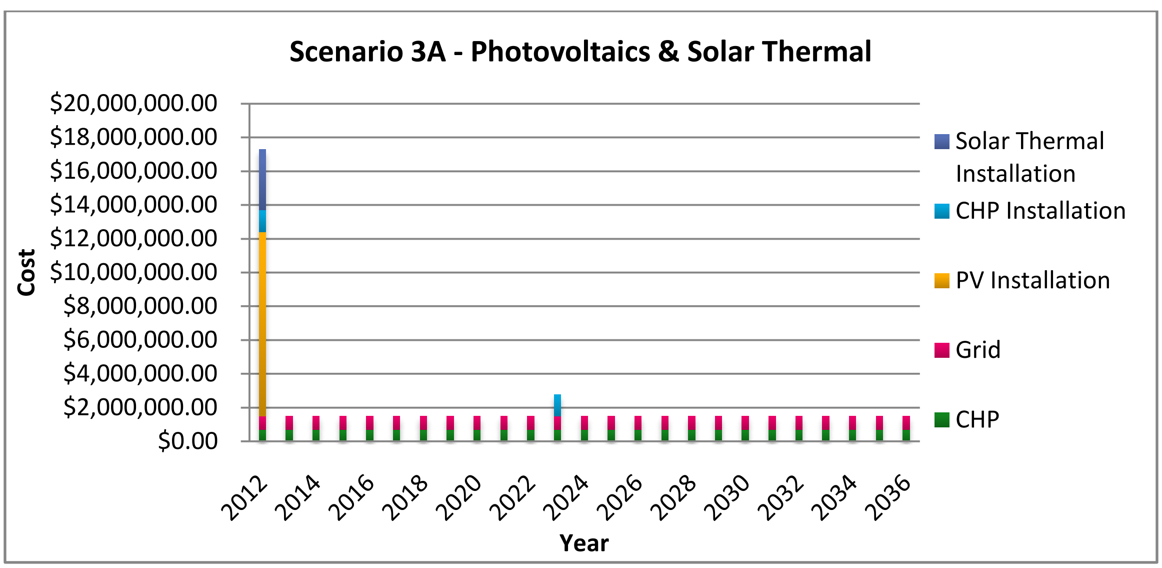


Figure 38: Scenario 3A Costs

In this scenario, the installation costs of the PV, solar thermal panels, and CHP systems are all included in year one. Since the solar thermal panels will be working in parallel with the CHP systems, the life cycle of the latter system will be increased from 9 to 12 years. Taking this into account, there will be installations costs for the CHP systems only on years 1 and 12. Solar thermal and PV panels have life cycles of 25 years and no maintenance costs, and thus there are no additional costs for these systems after year one. The cost breakdown is shown in the following tables:

PV, Solar Thermal, and CHP Installation Year	
CHP	$ 710,124.00
Grid	$ 781,688.33
PV Installation	$ 10,924,878.80
CHP Installation	$ 1,277,300.00
Solar Thermal Installation	$ 3,596,890.78
Total	**$ 17,290,881.91**

CHP Installation Year	
CHP	$ 710,124.00
Grid	$ 781,688.33
CHP Installation	$ 1,277,300.00
Total	**$ 2,769,112.33**

Non Installation Years	
CHP	$710,124.00
Grid	$ 781,688.33
Total	**$ 1,491,812.33**

Tables 25, 26, & 27

These tables show that there will be a cost of $17.29 MM in year 1. In year 12, the total cost will be $2.76 MM, due to the replacement of the four CHP systems. The remaining years will have an annual expense of $1.49 MM.

For heat and hot water, the CHP systems will meet the remaining demand not met by the solar thermal panels. PV panels and the grid will cover electricity demand not met by CHP. By reducing the number of CHP systems from 5 to 4 (as part of the hot water demand will be covered by the solar thermal panels), CO_2 emissions are reduced to 4,750 tons.

The NPC of Scenario 3A is $35 MM. This represents a significant cost increase from other scenarios because of the inclusion of the solar thermal panels in the model.

8.6 SCENARIO 3B – GRID, CHP, AND PV WITH STORAGE

Another variation of Scenario 3 that CGCG considered was the use of storage to save any excess energy produced. Once again, the scenario includes the use of PV panels and the grid to meet the electricity demand and CHP to cover the heat demand. The installation of storage units (flywheels) is included in this scenario. The following figure shows how the costs will be distributed throughout the 25-year life cycle:

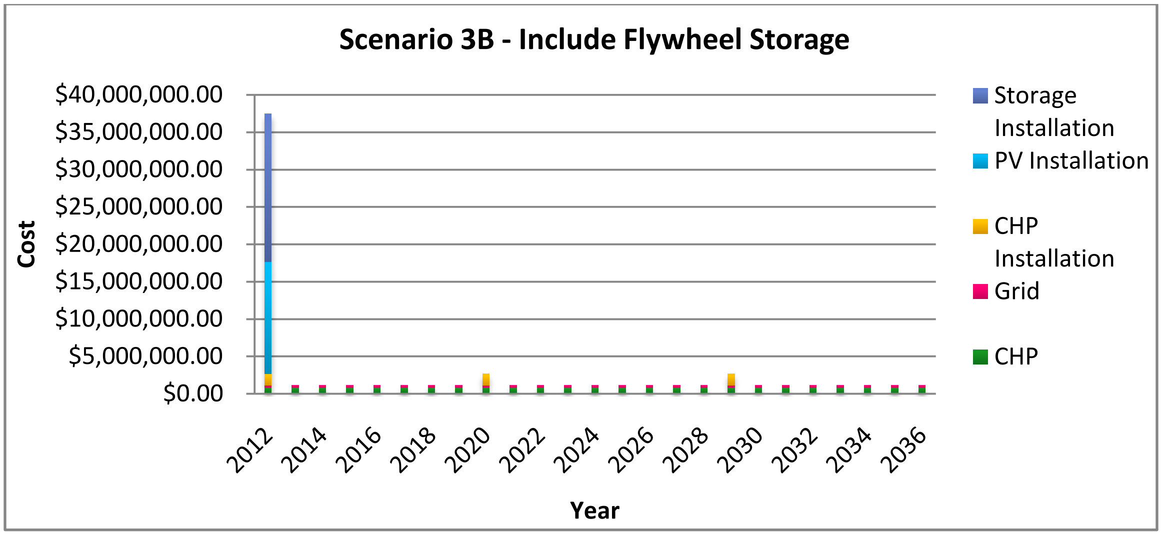


Figure 39: Scenario 3B Costs

It is clear from this figure that the installation of the storage flywheels significantly increases the costs in year one. The following tables provide the breakdown of annual costs:

CHP, PV, and Storage Installation Year	
CHP	$ 887,655.00
Grid	$ 225,556.45
CHP Installation	$ 1,596,625.00
PV Installation	$ 14,953,228.16
Storage Installation	$ 19,840,000.00
Total	**$ 37,503,064.60**

CHP Installation Years	
CHP	$ 887,655.00
Grid	$ 784,554.59
CHP Installation	$ 1,596,625.00
Total	**$ 3,268,834.59**

Non Installation Years	
CHP	$887,655.00
Grid	$ 225,556.45
Total	**$ 1,113,211.45**

Tables 28, 29, & 30

From these tables, year one shows a cost of $37.50 MM. After this is covered, there will be 22 years with costs of $1.11 MM. Finally, CHP systems will require replacement in years 9 and 18, resulting in an annual cost of $3.26 MM. The total amount of CO_2 emitted in this scenario (5,600 tons) is the same as in Scenario 3 because the total energy demand will be covered by the same sources as that scenario. The NPC of Scenario 3B is $51.70 MM: the highest among all scenarios. This cost could be reduced drastically by scaling down the size of the energy storage system, and thereby reducing energy independence.

8.7 SCENARIO 3C – GRID, CHP, PV, AND BIOMASS

The last scenario CGCG developed was another variation of Scenario 3. In Scenario 3C, the use of a biomass source is introduced. With this new source, there will be four sources covering the total demand of energy: the grid, CHP, PV, and biomass. Figure 42 shows the annual costs found:

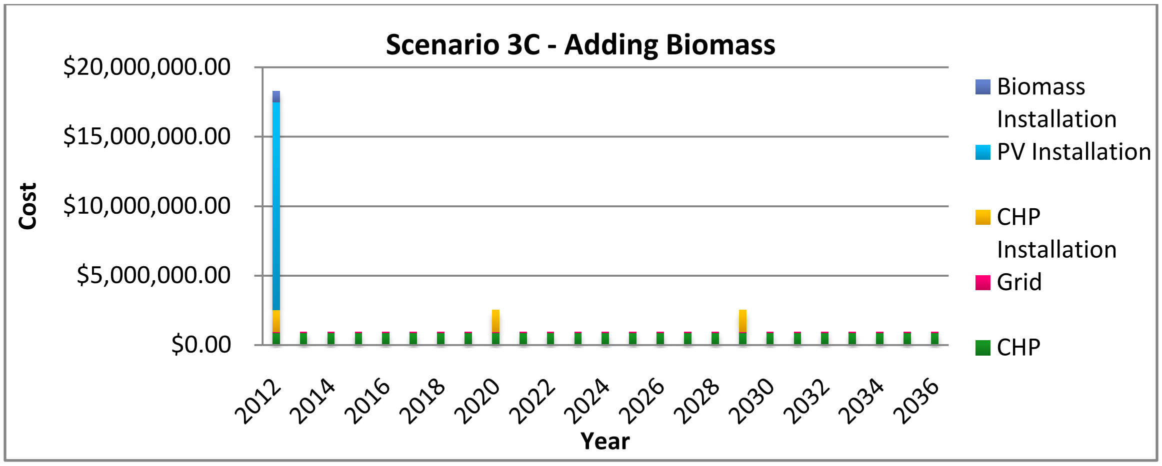


Figure 40: Scenario 3C Costs

As seen in this figure, the PV installation represents the largest cost, followed by the CHP installation. Note that the lowest installation cost comes from biomass. Tables 32, 33, & 34 present the cost breakdown:

CHP, PV, and Biomass Installation Year		
CHP	$	887,655.00
Grid	$	57,958.13
Biomass	$	103,179.00
CHP Installation	$	1,596,625.00
PV Installation	$	14,953,228.16
Biomass Installation	$	800,000.00
Total	**$**	**18,398,645.29**

CHP Installation Years		
CHP	$	887,655.00
Grid	$	57,958.13
Biomass	$	103,179.00
CHP Installation	$	1,596,625.00
Total	**$**	**2,645,417.13**

Non Installation Years		
CHP		$887,655.00
Grid	$	57,958.13
Biomass	$	103,179.00
Total		**$1,048,792.13**

Tables 31, 32, & 33

It is important to mention that biomass requires maintenance and gas to in order to operate. The row "biomass" in the tables above includes these costs.

Similar to Scenarios 3, 3A, and 3B, Scenario 3C will have a high first year cost of $18.39 MM. Afterwards, two years with costs of $2.64 MM (years 9 and 18) and 22 years with $ 1.04 MM. Overall, the costs add up to a NPC of $31.86 MM.

By introducing the use of a biomass source, CO_2 emissions will decrease slightly compared to Scenarios 3 and 3B to a total of 5,200 tons.

8.8 SCENARIO 4 – INTRODUCE WIND ENERGY

A scenario considered utilizing the Enfield Black Oak Wind Farm for energy. If this plan becomes a reality, Scenario 4 will use wind as a source of electricity. The total costs implied in this scenario over the life span of the project are shown in the following graph:

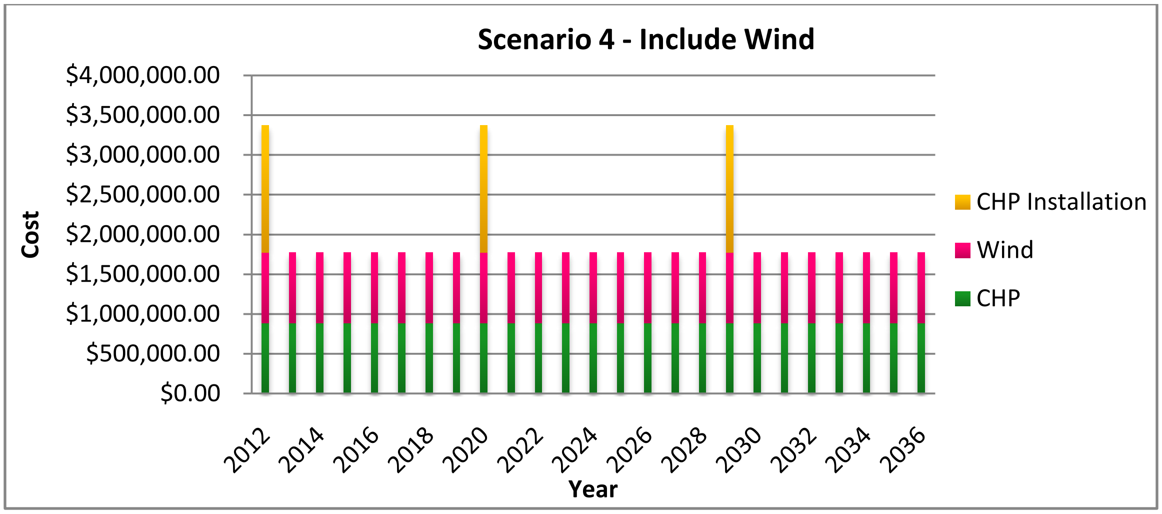


Figure 41: Scenario 4 Costs

From this graph it is evident that in years 1, 9, and 18 there will be additional costs regarding the installation (year 1) and replacement (years 9 and 18) of the CHP systems. Since wind energy will be bought from the Enfield Black Oak Wind Farm, there are no installation or maintenance costs considered for that energy source.

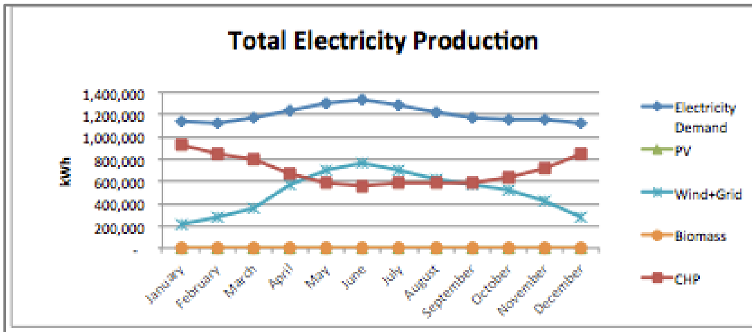
The following tables describe the cost breakdown:

CHP Installation Years	
CHP	$ 887,655.00
Wind	$ 888,859.53
CHP Installation	$ 1,596,625.00
Total	**$ 3,373,139.53**

Non Installation Years	
CHP	$887,655.00
Wind	$ 888,859.53
Total	**$ 1,776,514.53**

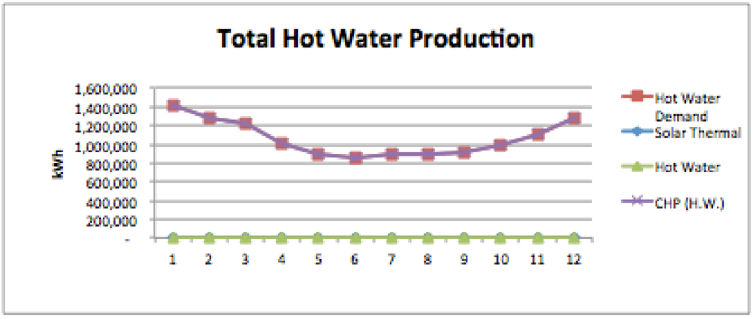
Table 34 & 35

This scenario includes three years in which the total cost will be $3.37 MM and 22 years in which the annual cost will be $1.47 MM. Once again, CHP will be used to cover the total demand of hot water. The grid will be used to cover 34% of the electricity demand while the remaining 66% will come from the Enfield wind farm, as shown in Figure 44 below:



Total Elec. Production and Cost			
Source	Prod.	Elec. Cost	Total Cost
PV	0%	0%	0%
Wind+Grid	42%	59%	59%
Biomass	0%	0%	0%
CHP	58%	41%	41%

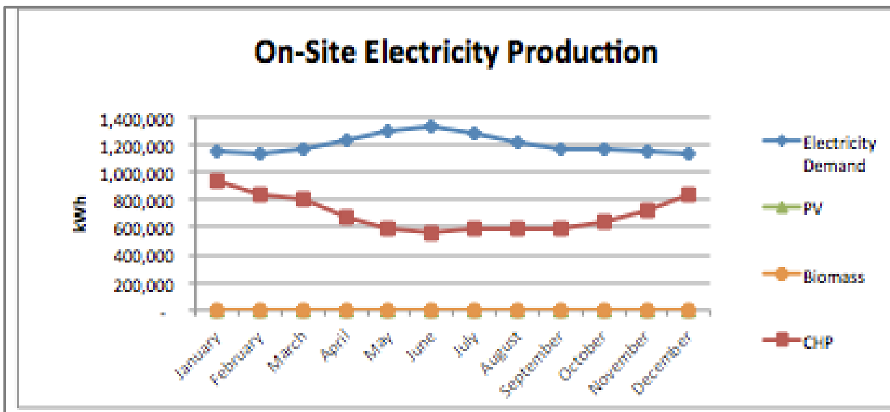
Wind/Grid Ratio	
% Wind	66%
% Grid	34%



Total Hot Water Production and Cost			
Source	Prod.	H.W. Cost	Total Cost
Thermal	0%	0%	0%
Hot Water	0%	0%	0%
CHP (H.W.)	100%	100%	41%

Figure 42: Scenario 4 Energy Production

Due to the fact that part of the electricity will be purchased from the wind farm, the total production on site will decrease to 58% as seen in Figure 45.



On-Site Energy Production	
Source	Prod.
PV	0%
Biomass	0%
CHP	58%
Total	58%

Figure 43: Scenario 4 Onsite Production

ALH can expect a reduction in CO_2 emissions of 18% with respect to Scenario 1, dropping the total emission to 5,600 tons per year. Finally, the net present cost obtained by the economic model for this scenario is $25.18 MM.

8.9 COMPARATIVE ANALYSIS

After each scenario was run through the optimization model and economic model, the final results were compiled and are displayed in Figure 46 and Figure 47:

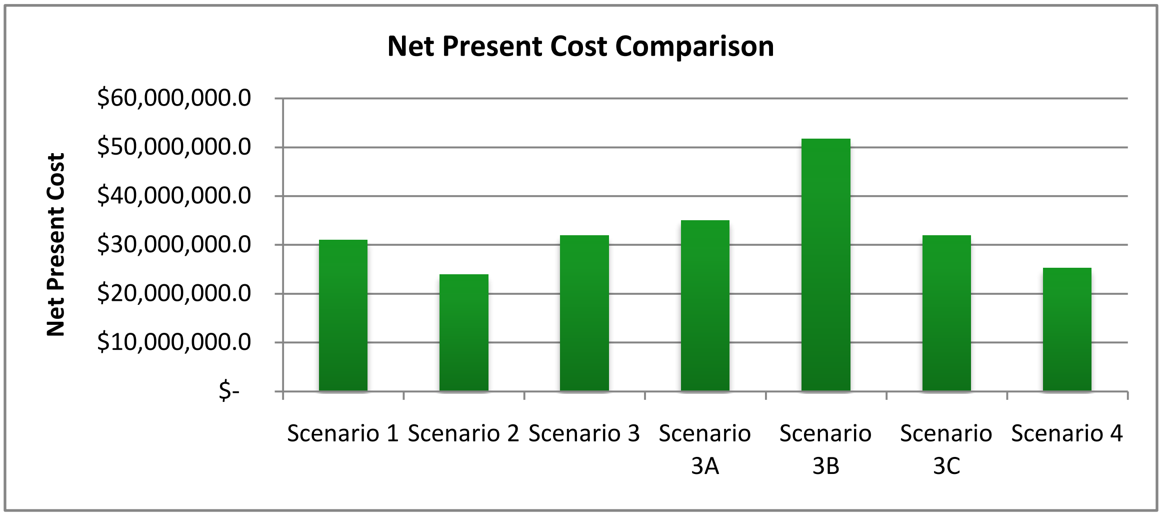


Figure 44: Net Present Cost

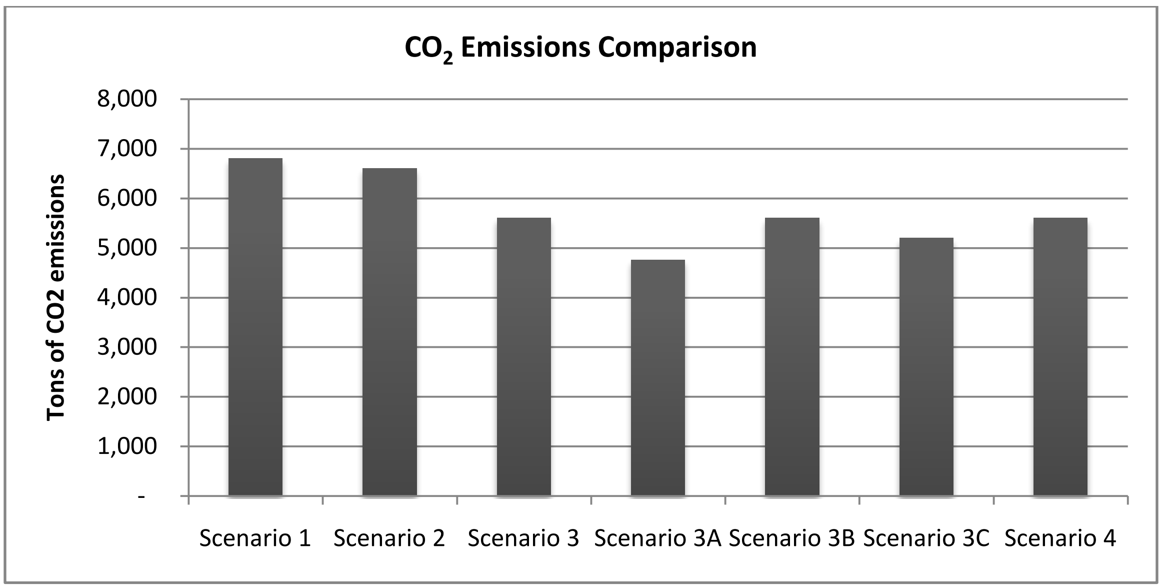


Figure 45: Comparison of CO_2 Emissions per Year

From this analysis, it can be seen that purchasing all of the required electricity from the grid and relying on boilers for hot water provides a relatively high NPC (Scenario 1). This scenario also emits the largest amount of CO_2.

In contrast, Scenario 3 has the third highest NPC value but shows a significant decrease in CO_2 emissions due to the fact that almost a third of the electricity produced will come from PV which does not produce any CO_2 emissions. Scenario 3A shows that the installation of solar thermal panels increases NPC to $35 MM, but in turn drops the CO_2 emissions to 4,756 tons per year. Scenario 4, has the third lowest CO_2 emissions but has a $25.18 MM NPC, compared to the lowest NPC of $23.88 MM displayed by Scenario 2. Scenarios 3B and 3C show a significant decrease in CO_2 emissions compared to Scenario 1 but at larger costs: $51.7 MM and $31.86 MM, respectively.

At the end, it is up to the developer (ALH) to decide. After a careful research and model building, results have been gathered and discussed thoroughly by this report. ALH must evaluate which aspect is most important to them, minimizing cost or reducing carbon dioxide emissions, and assign proper weights to each. After this decision has been made, one of the scenarios discussed here will become a guideline to follow for the repurposing of the Emerson complex in Ithaca, New York.

9. CONCLUSIONS

After researching numerous energy sources and analyzing them at the Emerson facility through an optimization model, CGCG drew a number of conclusions and recommendations for ALH to follow in the next steps of this project:

1. There are many feasible solutions to this project that take into consideration various combinations of all the energy sources considered. The final scenario to be installed must be chosen in order to most closely meet the needs of the tenants and minimize the impact on the environment.
2. All the assumptions made in the project must be revised before a final scenario is chosen. Many of them may change with time, and others may have a larger impact than what was originally considered
3. CHP is necessary in order to make a significant cost reduction and it is the major heat supplier for the site
4. PV energy is extremely expensive (even with incentives) and only becomes a part of the solution when CO_2 constraints are high and there are no other alternative sources of energy. However, when solar PV is bundled with the substantial cost savings from CHP, it is possible to deliver a system that both reduces cost and CO_2 emissions compared to Scenario 1, and at the same time results in a 4 MW solar PV array (equivalent to 2,000 household size systems) installed at Emerson.
5. The optimization model and economic spreadsheet (deliverables for this project) are useful tools that may be used by ALH to refine this project as new information becomes available. Other users may even utilize these models for similar projects by implementing their own constraints, energy prices, and demand data.

10. APPENDICES

A. TEAM COMPOSITION

Itotoh Akhigbe was born and raised in Nigeria. At the age of nineteen, he left his country for Washington, D.C., where he obtained his Bachelor of Science in Electrical Engineering at Howard University. During this time, he took part in research work with a professor specializing in renewable energy. He currently attends Cornell University where he plans to receive his Master of Engineering in Engineering Management. His career interests include renewable energy and technology consulting.

Corey Belaief, originally from Plymouth, Massachusetts, graduated in May 2011 with a Bachelor of Science in Mechanical Engineering from Cornell University. He is currently pursuing a Master's degree in Engineering Management from Cornell, and plans to apply his technical background, passion for renewable energy, and leadership skills to a career in technology consulting. In recent summers, Corey has worked as a mechanical design engineer in new product development and as a business development associate at a technology startup in New York City.

Omer Yigit Gursoy completed the dual diploma program between SUNY Binghamton University and Istanbul Technical University with a major in Information Systems Engineering. After graduation, he worked as a software engineer in the financial industry and as a software tester in the telecommunication industry. His major skills include information technology systems, software engineering and project management.

He is currently pursuing a Master's degree in Engineering Management at Cornell University. With this degree, Omer aims to perfect his managerial and technical skills. In this project, he has served as the liaison between ALH and CGCG. In this role, he coordinated meetings with the partner, improved internal communication, and tracked the project status and deliverables.

Pouyan Khajavi studied Electrical Power Engineering at University of Tehran in his home country of Iran. He continued his education with a Master of Science in Electrical Power Systems Restructuring with a Minor in smart grids, in the same university. During this period, he published several scientific papers in international journals and at conferences.

After his graduation in 2010, Pouyan started working in the high voltage substations section in Monenco Consulting Company as a Power System Protection specialist in which he worked among six other highly experienced engineers in the protection and control team. He is pursuing his Master’s degree in Engineering Management at Cornell University with interests in energy systems, energy industry and renewable energies.

Alejandro Martinez will graduate from Cornell University with a Master of Engineering in Engineering Management in May 2012. He has a Master's degree from Cornell University in Operations Research with a minor in Manufacturing, and obtained his undergraduate degree in Systems Engineering from Universidad Metropolitana in Caracas, Venezuela. He completed an undergraduate thesis in Applied Decision Analysis, where he created a mathematical model to help manufacturing corporations participating in closed bids to make decisions on bid prices and delivery dates, taking into consideration variables such as: the corporate indifference of selling price, the relationship with each particular client, and the cost of missed opportunities among others.

This research was then applied to a specific pipeline company in Venezuela (SOLTUCA), where Alejandro worked for two years. There, he held the position of “Production Line Manager,” and was in charge of one line’s production and its three shifts of employees, which consisted of a few engineers and over one hundred union workers; and “Plant Expediter”, where he led all the automation projects for the company and was part of the team that discussed the new collective contract with the union for eight hundred workers.

After his first Master's degree, he was offered a position as process manager in Galletas Puig, Venezuela's largest cookie manufacturer. There he helped generate new mission and vision statements for the company, introduced international financial and accounting regulations, and developed efficiency indicators for the production line.

Graham Peck graduated from Virginia Tech in 2011 with a Bachelor’s degree in Civil and Environmental Engineering and a minor in Green Engineering while receiving his Engineer-in-Training certification. He has four summer internship experiences at engineering consulting firms. These internships include environmental, transportation, and traffic engineering departments. His major skills include green buildings and sustainable transportation planning.

Graham is pursuing a Master of Engineering in Engineering Management at Cornell University and intends to obtain his LEED Accredited Professional Certification during that time.

Ptah Plummer was born and raised in Harlem, New York City. He graduated from Cornell University in May 2008 with a Bachelor of Science in Operations Research & Engineering (OR&E). He worked at John Jay College of Criminal Justice of the City University of New York (CUNY) as a Systems Manager of Career Development Services, in which he managed the department's database system. He returned to Cornell to further his education, and is currently pursuing a Master of Engineering degree in Engineering Management. Professionally, he aspires to utilize technical and analytical skills to make a positive environmental and social impact.

Brad Sandahl was born and raised in the United States and graduated from Cornell University in 2010 with a Bachelor's degree in Operations Research (OR). After completing his undergraduate studies, Brad worked as a Risk Analyst at Pacific Northwest National Laboratory and applied OR concepts to optimize programs for multiple government agencies. After completing his Master's degree in Engineering Management, Brad wishes to return to the private sector and work as a consultant in energy services, where he interned during past summers. This project has been directly in-line with Brad's interests, as it has allowed him to apply OR optimization concepts, act as an energy services consultant to ALH, and increase his familiarity with his market sector of choice.

Taylor Schulz studied Mechanical Engineering at the University of Maryland, College Park, graduating in May 2011. As an undergraduate, he was part of a fourteen member, four-year research project to develop inventory and customer relationship management software for small businesses. His experience working on projects in large teams will help the team manage its resources throughout the project. During the past summer, Taylor worked at GE Energy on energy storage systems.

Manuel Garcia Vilches graduated in 2008 with a Bachelor's degree in Telematics Engineering from ITAM in Mexico. He has over four years of working experience involved in the financial and consulting industries developing infrastructure and supply chain projects. His major skills include business process management, project management, and business case development.

Currently, he is a Masters student of Engineering Management at Cornell University. Using the aforementioned skills, he will help ensure that this project follows the best practices of the industry.

B. PROJECT MILESTONES & DELIVERABLES

As determined by CEE 5910, this project contains a very specific set of milestones and deliverables for the Fall 2011 semester. These important meetings, reports, and presentations are all detailed in the table below:

Milestones	Duration	Start	Finish	Predecessor
Project Launch Meeting	1 day	Mon 8/29/11	Mon 8/29/11	
Mini Course Meetings	6 days	Mon 8/29/11	Mon 9/5/11	
Personal Goal Assignment	3 days	Thu 9/1/11	Mon 9/5/11	
Mini Course Assignment	7 days	Fri 9/9/11	Mon 9/19/11	
Literature Review	10 days	Tue 9/13/11	Mon 9/26/11	
Project Proposal - Draft	10 days	Tue 9/13/11	Mon 9/26/11	
Project Proposal - Final	5 days	Tue 9/27/11	Mon 10/3/11	6
Mid Semester Peer Evaluation	7 days	Thu 10/13/11	Fri 10/21/11	
Mid Semester Management Report	7 days	Thu 10/13/11	Fri 10/21/11	
Interim Presentation	7 days	Thu 10/20/11	Fri 10/28/11	
Final Oral Presentation	14 days	Mon 10/31/11	Thu 11/17/11	
Final report - Draft	25 days	Tue 11/1/11	Mon 12/5/11	
Final Report	8 days	Tue 12/6/11	Thu 12/15/11	12
Final Team Management Report	5 days	Fri 12/9/11	Thu 12/15/11	
Personal Reflections	5 days	Fri 12/9/11	Thu 12/15/11	
End of Semester Peer Evaluation	5 days	Fri 12/9/11	Thu 12/15/11	
Client Presentation	1 day	Thu 12/15/11	Thu 12/15/11	

Table 36: Project Milestones and Deliverables

The following Gantt Chart includes the overall project timeline and major deliverables:

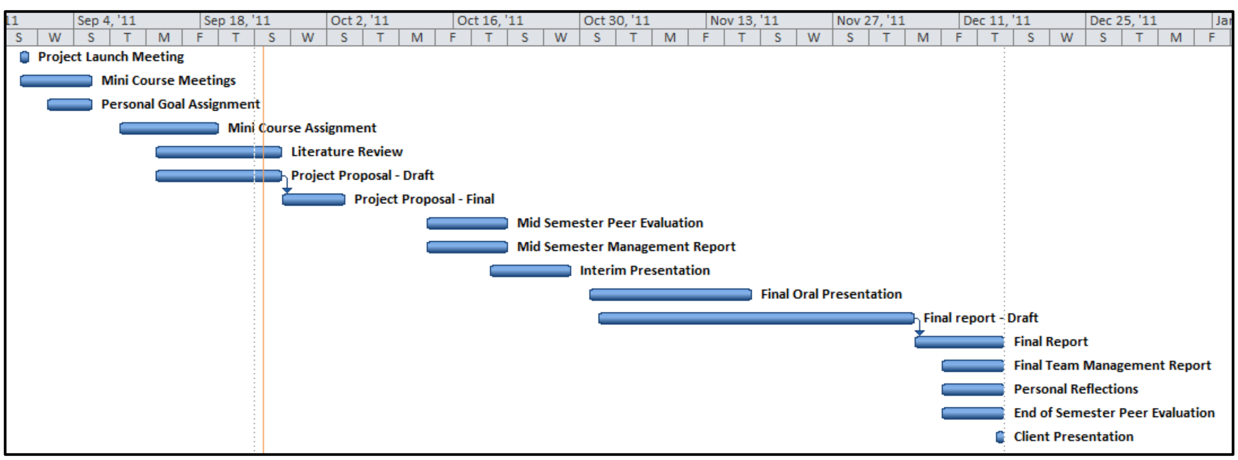


Figure 46: Gantt Schedule

C. 25 VS. 75 YEAR LIFE CYCLE

At the beginning of this project, CGCG was asked by ALH to consider a 75-year life cycle. After analyzing this possibility very carefully, the choice was made to reduce the life cycle to 25 years. The reasons why this choice was made are the following:

1. It was considered that the life cycle of the project should not be longer than the longest life cycle of any of the technologies implemented (PV has a 25 year life cycle)
2. 25 years allows the customer to reevaluate the technologies used in light of any technological developments throughout the project lifetime

The combination of these reasons lead CGCG to believe that after 25 years, the whole project ought to be reconsidered (calculate new time value of money, research new technologies, consider new assumptions, calculate new prices per kWh, research new incentives, etc.).

Even though the building's life cycle is much longer than 25 years, this threshold is far enough from today to become a break point, where a decision could be made to continue with the current strategy and mix of technologies or to take the facility in a completely new direction.

D. PROJECT FREQUENTLY ASKED QUESTIONS

CGCG posed the following questions to ALH during the initial project stages in order to garner a better understanding of the project and scope. The team compiled ALH's responses into the following FAQs:

1) What is the budget for the whole project?

- Up to $100 MM dollars total
- $85 MM dollar power plant
- Acquisition price for the building of $4 MM

2) What are the objectives? What is the scope?

- CGCG will study the possibility of developing economically feasible energy alternatives for the repurposed Emerson plant in Ithaca, NY

3) What is the payback period time for the project?

- CGCG recommends a payback period for 25 years instead of 75 years as initially recommended by ALH. The life cycle of most energy source installations will not be more than 25 years. By that time, currently installed technologies may be obsolete and it may need reconsideration. Furthermore, new technologies might be available at cheaper costs than available at the start of the project.

4) What kinds of tenants or customers are considered?

- Light manufacturing, food processing, office space, laboratory space, data center, etc.
- Not residential (yet)

5) What are the energy sources that ALH is interested in?

- A combination of solar, wind, CHP, biomass, and possibly geothermal

6) How "green" should the solution be?

- As "green" as possible considering the goal of cost minimization. CGCG has presented a number of solutions with varying levels of CO_2 emissions.

7) Does ALH have a pre-agreement with a potential tenant?

- No, there is no such agreement.

8) What are the dimensions of the building? Is there a blueprint?

- The manufacturing complex had been in use since the early 1900's until 2009 and contains 17.5 acres of floor space split between several floors as well as an additional 95 acres of property.

9) Is it possible to see the site in person?

- The site is closed and is private property.

10) Is the building structurally sound? Will it support the weight of solar panels?

- Building upgrades are out of the project scope (e.g. reinforcement of roof)

11) Will ALH use the Emerson facility to become an energy seller?

- ALH can sell energy only to tenants inside the facility.
- If there is left over electricity, it may be sold to the grid for credit.

12) What are the economic and ecological metrics to be considered?

- Cost per kWh
- CO_2 emissions

13) What are the incentives considered? (tax credit, installation grant, etc.)

- CGCG assumed only a $0.10/kW incentive for capacity of installed PV

B. AVERAGE MONTHLY DEMAND DATA

Month	Electrical Demand (kWh)	Average Electrical Demand (kW)
January	1,144,871	1,590
February	1,131,622	1,571
March	1,168,359	1,623
April	1,234,606	1,714
May	1,297,842	1,803
June	1,330,966	1,848
July	1,281,581	1,780
August	1,222,561	1,698
September	1,174,381	1,631
October	1,164,746	1,618
November	1,156,314	1,606
December	1,126,202	1,564

Table 37: Average Monthly Electrical Demand of the Emerson Complex

F. DETAILED NEW YORK STATE INCENTIVES

NYSERDA – Performance-Based Incentives for Existing Facilities Program[46]

Base Incentive	Upstate
Electric Efficiency	$0.12 kWh
Energy Storage	$300/kW
Natural Gas	$15/MMBtu
Combined Heat and Power	$0.10/kWh + $600/kW
Demand Response	$100/kW
Industrial and Process Efficiency	$0.12/kWh - 15/MMBtu
Monitoring-Based Commissioning	$0.05/kWh

Table 38: Summary of Performance-Based Incentives

Combined Heat and Power (CHP) Incentives [47]

"Incentives are offered to offset the installation cost of clean, efficient, and commercially available CHP systems."

Incentives: $0.10/kWh + $600/kW (kW is summer peak demand reduction, not installed capacity)
Incentive Cap: $2MM per CHP Project (may not exceed 50% of Project cost)

Minimum Project Size: ≥ 250 kW

Eligibility: A CHP System must: (1) Consist of a commercially available reciprocating engine or gas turbine-based CHP system that results in electrical peak demand reduction during the summer capability period. (2) Have a 60% annual fuel conversion efficiency based on a higher heating value (HHV) including parasitic losses. (3) Use at least 75% of the generated electricity on-site. (4) Have a NOx emission rate < 1.6 lbs./MWhr

Local Option - Solar, Wind & Biomass Energy Systems Exemption[48]

Incentive Type:	Property Tax Incentive
Eligible Renewable/Other Technologies:	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Solar Pool Heating, Daylighting, Anaerobic Digestion
Applicable Sectors:	Commercial, Industrial, Residential, Agricultural
Amount:	100% exemption for 15 years.

[46] *http://www.nyserda.ny.gov/en/Page-Sections/Commercial-and-Industrial/Programs/Existing-Facilities-Program/Performance-Based-Incentives.aspx*
[47] *http://www.nyserda.ny.gov/en/Page-Sections/Commercial-and-Industrial/Programs/Existing-Facilities-Program/Performance-Based-Incentives/Combined-Heat-and-Power-Incentives.aspx*
[48] *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY07F&re=1&ee=1*

Eligible System Size:	Farm-waste energy systems: maximum size of 400 kW Other eligible property: no specific limits
Start Date:	Before 07/01/1988 or between 01/01/1991 & 12/31/2014
Expiration Date:	12/31/2014
Web Site:	http://www.tax.ny.gov/research/property/assess/manuals/vol4/pt1/s...
Authority 1: **Date Enacted:** **Date Effective:** **Expiration Date:**	NYCL Real Property Tax § 487 1977 (subsequently amended) Before 07/01/1988 or between 01/01/1991 & 12/31/2014 12/31/2014 (as amended)
Authority 2: **Date Enacted:**	Exemption Handbook 11/06/2009 (most recent version)

NYSERDA - PV Incentive Program[49]

Incentive Type:	State Rebate Program
Eligible Renewable/Other Technologies:	Photovoltaics
Applicable Sectors:	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, State Government, Institutional, (Must be customer of an investor-owned utility in NY)
Amount:	$1.75/watt DC; Incentive may be reduced for potential production losses associated with shading, system orientation, tilt angle, and other factors
Maximum Incentive:	Maximum determined by sector, incentive level; may not exceed 40% of costs after any available tax credits Residential: $12,250 Non-residential: $87,500 Non-profit, gov't, schools: $43,750
Eligible System Size:	None specified, but systems may not exceed 110% of demonstrated energy demand.
Equipment Requirements:	Systems and components must be new; modules and inverters must meet applicable UL and IEEE standards; monitoring equipment with accuracy of +/- 5% required; minimum five-year system warranty against breakdown or degradation of more than 10% from original rated output; two-year warranty on battery back-up systems.
Installation Requirements:	System must be a grid-connected, end-use application; be installed by

[49] *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY10F&re=1&ee=1*

	a pre-approved contractor; and comply with New York's Standard Interconnection Requirements and all federal, state and local codes.
Ownership of Renewable Energy Credits:	NYSERDA for first 3 years of system operation, customer/generator thereafter
Funding Source:	RPS surcharge
Program Budget:	2010-2015: $144 M ($2 M per month) 2008-2009: $75.3 M*
Start Date:	08/12/2010 (current PON 2112)
Expiration Date:	12/31/2015
Web Site:	http://www.nyserda.org/funding/2112pon.asp

NYSERDA - Solar Thermal Incentive Program[50]

Incentive Type:	State Rebate Program
Eligible Renewable/Other Technologies:	Solar Water Heat
Applicable Sectors:	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, State Government, Fed. Government, Multi-Family Residential, Agricultural, Institutional
Amount:	$1.50 per kWh displaced annually
Maximum Incentive:	Residential: $4,000 per site/meter Non-residential: $25,000 per site/meter
Eligible System Size:	No limits specified
Equipment Requirements:	All solar thermal systems and components must be new (used or refurbished monitoring meters permitted); collectors and hot water tanks must be SRCC rated and listed as program eligible in Power Clerk; five year all-inclusive, fully transferable warranty required on installation and components against degradation of more than 10% from rated output.
Installation Requirements:	System must generally supplement an existing electric water heater
Ownership of Renewable Energy Credits:	NYSERDA for first three years of operation; customer thereafter

[50] *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY87F&re=1&ee=1*

Funding Source:	RPS surcharge
Program Budget:	Total (2010-2015): $24.965 million (~$4.3 million annually)
Start Date:	12/10/2010
Expiration Date:	12/31/2015 (or until funds are exhausted)
Web Site:	http://www.nyserda.org/Funding/2149pon.asp

H. DETAILED U.S. FEDERAL INCENTIVES

Business Energy Investment Tax Credit (ITC)[51]

Incentive Type:	Corporate Tax Credit
Eligible Renewable/Other Technologies:	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, CHP/Cogeneration, Solar Hybrid Lighting, Fuel Cells using Renewable Fuels, Microturbines, Geothermal Direct-Use
Applicable Sectors:	Commercial, Industrial, Utility, Agricultural
Amount:	30% for solar, fuel cells and small wind;* 10% for geothermal, microturbines and CHP*
Maximum Incentive:	Fuel cells: $1,500 per 0.5 kW Microturbines: $200 per kW Small wind turbines placed in service 10/4/08 - 12/31/08: $4,000 Small wind turbines placed in service after 12/31/08: no limit All other eligible technologies: no limit
Eligible System Size:	Small wind turbines: 100 kW or less* Fuel cells: 0.5 kW or greater Microturbines: 2 MW or less CHP: 50 MW or less*
Equipment Requirements:	Fuel cells, microturbines and CHP systems must meet specific energy-efficiency criteria
Authority 1:	26 USC § 48
Authority 2:	Instructions for IRS Form 3468
Authority 3:	IRS Form 3468

Renewable Electricity Production Tax Credit (PTC)[52]

Incentive Type:	Corporate Tax Credit
Eligible Renewable/Other Technologies:	Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Hydrokinetic Power (i.e., Flowing Water), Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal
Applicable Sectors:	Commercial, Industrial
Amount:	2.2¢/kWh for wind, geothermal, closed-loop biomass; 1.1¢/kWh for other eligible technologies. Generally applies to first 10 years

[51] *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1*
[52] *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1*

	of operation.
Eligible System Size:	Marine and Hydrokinetic: Minimum capacity of 150 kW Agricultural Livestock Waste: Minimum capacity of 150 kW
Carryover Provisions:	Unused credits may be carried forward for up to 20 years following the year they were generated or carried back 1 year if the taxpayer files an amended return.
Expiration Date:	Varies by technology
Web Site:	http://www.irs.gov/pub/irs-pdf/f8835.pdf
Authority 1: **Date Enacted:**	26 USC § 45 1992 (subsequently amended)

USDA - High Energy Cost Grant Program[53]

Incentive Type:	Federal Grant Program
Eligible Efficiency Technologies:	Unspecified Technologies
Eligible Renewable/Other Technologies:	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Hydroelectric, Small Hydroelectric
Applicable Sectors:	Commercial, Residential, Nonprofit, Local Government, State Government, Tribal Government
Amount:	$75,000-$5,000,000
Maximum Incentive:	$5 million
Start Date:	2000
Web Site:	http://www.rurdev.usda.gov/UEP_Our_Grant_Programs.html
Authority 1:	7 CFR 1709

USDA - Rural Energy for America Program (REAP) Grants[54]

Incentive Type:	Federal Grant Program
Eligible Efficiency	Unspecified Technologies

[53] *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US56F&re=1&ee=1*
[54] *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US05F&re=1&ee=1*

Technologies:	
Eligible Renewable/Other Technologies:	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, CHP/Cogeneration, Hydrogen, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Renewable Fuels, Fuel Cells using Renewable Fuels, Microturbines, Geothermal Direct-Use
Applicable Sectors:	Commercial, Schools, Local Government, State Government, Tribal Government, Rural Electric Cooperative, Agricultural, Institutional, Public Power Entities
Amount:	Varies
Maximum Incentive:	25% of project cost
Start Date:	FY 2003
Web Site:	http://www.rurdev.usda.gov/rbs/busp/bprogs.htm
Authority 1: **Date Enacted:** **Date Effective:**	7 USC § 8106 5/13/2002 FY 2003

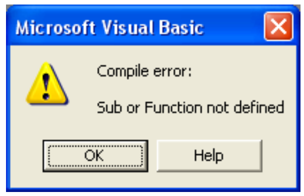
U.S. Department of Energy - Loan Guarantee Program[55]

Incentive Type:	Federal Loan Program
Eligible Efficiency Technologies:	Unspecified Technologies
Eligible Renewable/Other Technologies:	Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Hydroelectric, Geothermal Electric, Fuel Cells, Daylighting, Tidal Energy, Wave Energy, Ocean Thermal, Biodiesel, Fuel Cells using Renewable Fuels
Applicable Sectors:	Commercial, Industrial, Nonprofit, Schools, Local Government, State Government, Agricultural, Institutional, Any non-federal entity, Manufacturing Facilities
Amount:	Varies. Program focuses on projects with total project costs over $25 million.
Maximum Incentive:	Not specified.
Terms:	Full repayment is required over a period not to exceed the lesser of 30 years or 90% of the projected useful life of the physical asset to be financed
Web Site:	http://www.lgprogram.energy.gov
Authority 1:	42 USC § 16511 et seq.
Authority 2:	10 CFR 609

[55] *http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US48F&re=1&ee=1*

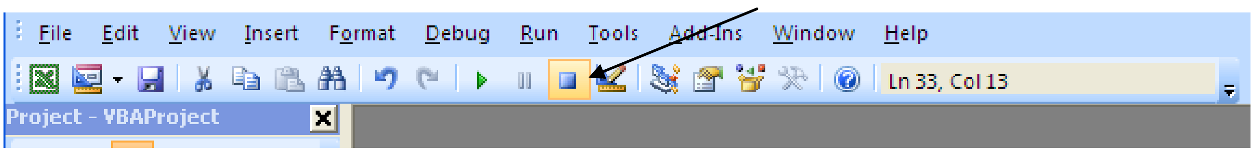
I. MODEL TROUBLESHOOTING

Personal system settings can cause the embedded Excel optimization macros to crash, which may throw the following error message:

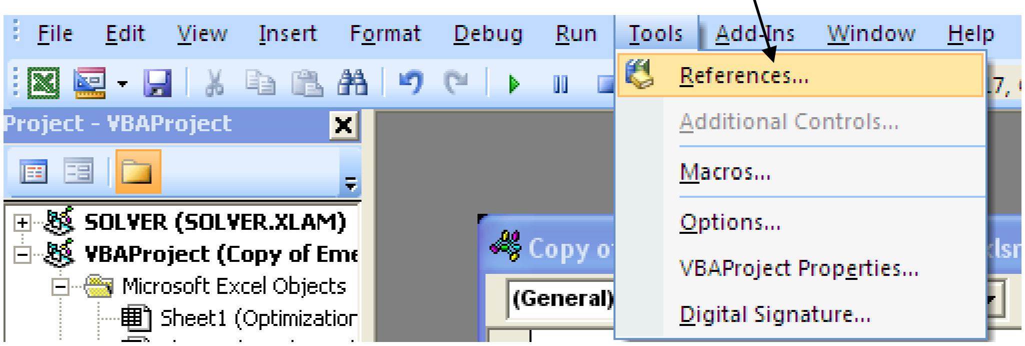


This indicates that the Excel Solver is not currently referenced, and must be added. To fix this problem, take the following actions:

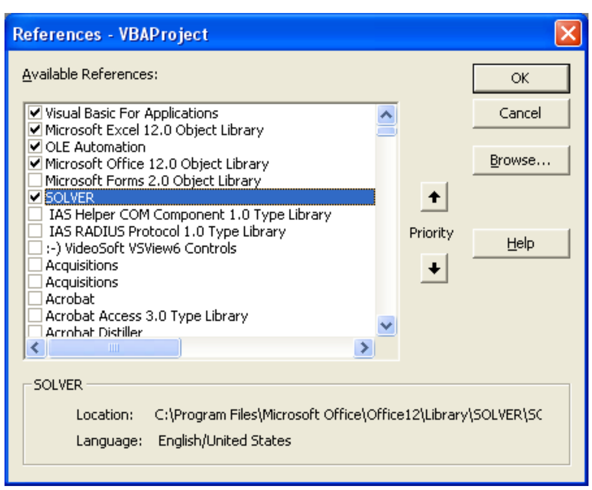
1. Click “Alt + F11” to access VBA (if not open already) and click OK on the error box
2. Click the ‘Reset’ button (blue square) to terminate the macro



3. Under the Tools menu at the top of the screen, select References



4. Add SOLVER to the list of available references, click OK, and exit VBA.



J. SOLAR APPENDIX

SOLAR PHOTOVOLTAIC APPENDIX

Product Name	E19/315
Manufacturer	Sun Power
Nominal Power	315 W
Solar to Electrical Efficiency	% 19.3
Weight	18.6 Kg
Overall Size	1559 x 1046 x 46 mm
Cell Configuration	96 back-contact solar cells.
Operating Temperature Range	- 40 to + 85 °C
Open Circuit Voltage (Voc)	64.6 V
Short Circuit Current (Isc)	6.14 A
Maximum Power Voltage (Vmpp)	54.7 V
Maximum Power Current (Impp)	5.76 A

Table 39 – Technical Specifications of a Typical Monocrystalline Silicon Photovoltaic Panel

Product Name	YL245P-32b
Manufacturer	Yingli
Nominal Power	245 W
Solar to Electrical Efficiency	% 13.7
Weight	22.5 Kg
Overall Size	1810 x 990 x 50 mm
Cell Configuration	66 Polycrystalline cells
Operating Temperature Range	-40°C to +85°C
Open Circuit Voltage (Voc)	40.8 V
Short Circuit Current (Isc)	8.22 A
Maximum Power Voltage (Vmpp)	32.2 V
Maximum Power Current (Impp)	7.61 A

Table 40 – Technical Specifications of a typical Polycrystalline silicon photovoltaic Panel

Month	Energy Produced in each month (MWh)	Average Power in each month (kW)
January	49.94	68.43
February	68.04	93.23

March	94.17	129.03
April	108.98	149.32
May	123.00	168.54
June	123.25	168.87
July	125.06	171.31
August	116.60	159.87
September	87.85	120.37
October	73.35	100.50
November	44.39	60.83
December	36.88	50.53
Total	1051.62	-

Table 41 – Electrical output of a system of 1 MW installed capacity with 10 degrees tilt located in Ithaca, NY

SOLAR THERMAL APPENDIX

J.1 Types of System

Solar water heaters can be either active or passive. An active system uses an electric pump to circulate the heat-transfer fluid; a passive system has no pump. The amount of hot water a solar water heater produces depends on the type and size of the system, the amount of sun available at the site, proper installation, and the tilt angle and orientation of the collectors.

Solar water heaters are also characterized as open loop (also called "direct") or closed loop (also called "indirect"). An open-loop system circulates household (potable) water through the collector. A closed-loop system uses a heat-transfer fluid (water or diluted antifreeze, for example) to collect heat and a heat exchanger to transfer the heat to household water [3].

J.2 Direct and In-Direct Systems

Direct or open loop systems circulate potable water through the collectors. They are cheaper than indirect systems and offer superior heat transfer from the collectors to the storage tank, but have many drawbacks:

- They offer little or no overheat protection.
- They offer little or no freeze protection.
- The collectors will accumulate scale in hard water areas.

- They are often not considered suitable for cold climates since, in the event of the collector being damaged by a freeze, pressurized water lines will force water to gush from the freeze-damaged collector until the problem is noticed and rectified.

Indirect or closed loop systems use a heat exchanger that separates the potable water from the fluid, known as the "heat-transfer fluid" (HTF) that circulates through the collector. The two most common HTFs are water and an antifreeze/water mix that typically uses non-toxic propylene glycol. After being heated in the panels, the HTF travels to the heat exchanger, where its heat is transferred to the potable water. Though slightly more expensive, indirect systems offer freeze protection and typically offer overheat protection as well.

J.3 Active and Passive Systems

Passive systems rely on heat-driven convection or heat pipes to circulate water or heating fluid in the system. Passive solar water heating systems cost less and have extremely low or no maintenance, but the efficiency of a passive system is significantly lower than that of an active system, and overheating and freezing are major concerns.

Active systems use one or more pumps to circulate water and/or heating fluid in the system.

Though slightly more expensive, active systems offer several advantages:

- The storage tank can be situated lower than the collectors, allowing increased freedom in system design and allowing pre-existing storage tanks to be used.
- The storage tank can always be hidden from view.
- The storage tank can be placed in conditioned or semi-conditioned space, reducing heat loss.
- Drain back tanks can be used.
- Superior efficiency.
- Increased control over the system.

Modern active solar water systems have electronic controllers that offer a wide-range of functionality, such as the modification of settings that control the system, interaction with a backup electric or gas-driven water heater, calculation and logging of the energy saved by a SWH system, safety functions, remote access, and various informative displays, such as temperature readings.

The most popular pump controller is a differential controller that senses temperature differences between water leaving the solar collector and the water in the storage tank near the heat exchanger.

In a typical active system, the controller turns the pump on when the water in the collector is about 8–10 °C warmer than the water in the tank, and it turns the pump off when the temperature difference approaches 3–5 °C. This ensures the water always gains heat from the collector when the pump operates and prevents the pump from cycling on and off too often. (In direct systems this "on differential" can be reduced to around 4 °C because there is no heat exchanger impediment.)

Some active SWH systems use energy obtained by a small photovoltaic (PV) panel to power one or more variable-speed DC pump(s). In order to ensure proper performance and longevity of the pump(s), the DC-pump and PV panel must be suitably matched. These systems are almost always of the antifreeze variety and often do not use controllers, as the collectors will almost always be hot when the pump(s) are operating (i.e. when the sun is bright). Sometimes, however, a differential controller (that can also be powered by the DC output of a PV panel) is used to prevent the operation of the pumps when there is sunlight to power the pump but the collectors are still cooler than the water in storage. One advantage of a PV-driven system is that solar hot water can still be collected during a power outage if the Sun is shining.

An active solar water heating system can also be equipped with a bubble pump (also known as geyser pump) instead of an electric pump. A bubble pump circulates the heat transfer fluid (HTF) between collector and storage tank using solar power and without any external energy source and is suitable for flat panel as well as vacuum tube systems. In a bubble pump system, the closed HTF circuit is under reduced pressure, which causes the liquid to boil at low temperature as it is heated by the sun. The steam bubbles form a geyser pump, causing an upward flow. The system is designed such that the bubbles are separated from the hot fluid and condensed at the highest point in the circuit, after which the fluid flows downward towards the heat exchanger caused by the difference in fluid levels. The HTF typically arrives at the heat exchanger at 70 °C and returns to the circulating pump at 50 °C. In frost prone climates the HTF is water with propylene glycol anti-freeze added, usually in the ratio of 60 to 40. Pumping typically starts at about 50 °C and increases as the sun rises until equilibrium is reached depending on the efficiency of the heat exchanger, the temperature of the water being heated and the strength of the sun.

Figure 49 shows different types of system configuration using direct method.

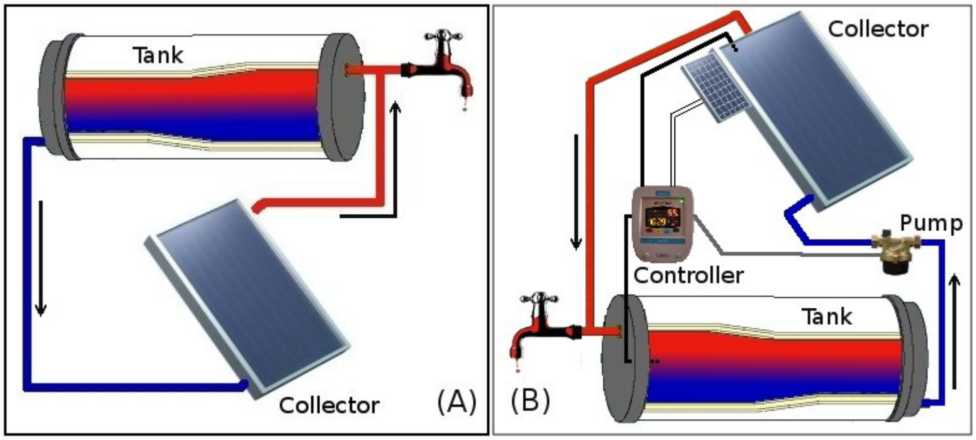


Figure 47 - Direct systems: (A) Passive CHS system with tank above collector. (B) Active system with pump and controller driven by a photovoltaic panel

Figure 50 shows system configurations of indirect systems.

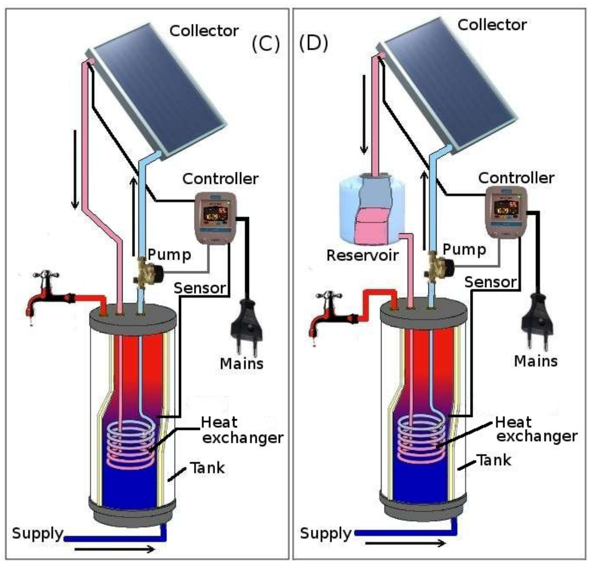


Figure 48 - Indirect active systems: (C) Indirect system with heat exchanger in tank; (D) Drainback system with drainback reservoir.

One thing to remember is the system used for Emerson facility should be used alongside with CHP system and the solar water heaters will act only as pre-heater. In this method, the hot water goes out of the reservoir tank to the CHP system and it heated to the desired degree. A system used for an industrial use should be of Drain-back system shown in Figure 50D.

J.4 Other Components of system

<u>J.4.4 Collector Mounting Systems</u>: The three most common mounting systems for solar collectors are the roof mount, ground mount, and awning mount. Roof-mounted collectors are held by

brackets, usually parallel to and a few inches above the roof. Ground-mount systems can be as simple as four or more posts in the ground, lengths adjusted to affect optimal tilt. An awning mount attaches the collectors to a vertical wall. Horizontal supports push the bottoms of the collectors out to achieve the desired tilt. When choosing a mounting system, roof mounts are usually the cheapest option, provided tilt and orientation are within acceptable parameters. If weight is an issue, ground mounts can be a good choice. Wall mounts are another solution that can work well in some situations.

J.4.5 Solar Storage Tank: A solar water tank is an insulated water storage tank. Cold water that used to go directly to the conventional water heater enters the solar tank and solar-heated water exits. In closed-loop systems, the water is heated by contact with a coil of pipe containing the water or antifreeze that circulates through the collectors. In open-loop systems, the potable water is directly circulated through the collectors. The preheated solar water is then plumbed back to the cold side of the existing heater, which now functions as a backup. Whenever hot water is turned on in the house, preheated solar hot water is moved from the solar tank to the backup heater.

J.4.6 Water Pump: Pumps are used in active systems. They circulate water or antifreeze between the solar collector and the storage tank. The right size of the pump depends on the size of the system and the distance and height between the collector(s) and the storage tank. AC pumps plug into a wall outlet while DC pumps are powered from a DC source, such as a photovoltaic panel. Good pumps can last as long as 20 years with heavy use.

J.4.7 Heat Exchanger: Heat exchangers are used in closed-loop solar hot water systems. They enable the transfer of heat from one fluid to another without the two mixing. Internal heat exchangers are inside the tank and not visible. They can be as simple as a coil of pipe resting in the bottom of the tank, or wrapped around the outside beneath the insulation and cover. As the heated fluid from the solar collector travels through the coil, the heat is passed from the hotter fluid to the cooler potable water.

An external heat exchanger is usually a pipe within a pipe. The solar fluid and potable water flow counter to one another, and heat is transferred within the heat exchanger pipe. Fluid may be moved with pumps, thermosyphoning, or a combination of the two.

J.4.8 Expansion Tank: Closed-loop systems require an expansion tank. An expansion tank has a chamber in which air is locked inside a bladder or diaphragm. It screws into standard 1/2-inch or 3/4- inch threaded plumbing fittings. When pipes are filled with heat-transfer fluid (water and glycol) and the operating pressure of the system is set, the fluid will occupy a given volume based on the temperature. As the fluid is heated by the sun, it expands. This is where the expansion tank is critical. Without it, there is a chance of explosion in the system. The expansion tank allows the fluid to safely expand by compressing the air in the chamber. The size of the expansion tank needed depends on the total volume of fluid, which is determined by the number and size of collectors, and the length and diameter of the pipes in the solar loop. With the proper expansion tank in place, the fluid can go from 0 to 200°F (-18-93°C) with the pressure in the solar loop remaining the same.

J.4.9 Controls: In active systems using pumps, whenever the collector is hotter than the storage tank, the pump should be on and the system circulating. When the tank is hotter than the collector, the pump should be off. This function is performed by either a differential thermostat control system or the use of a PV-powered pump. The differential thermostat controller compares heat sensor readings from the storage tank and collectors and switches the pump accordingly. With a PV-powered pump, a solar-electric panel is connected directly to the pump. It´s a simple setup—when the sun comes out, the pump comes on. The brighter the sun, the faster it pumps.

J.4.10 Isolation Valve: An isolation valve should be a part of every solar water heater to isolate the solar tank in case of a problem, while still allowing the backup water heater to remain in service. The isolation valve is a manual valve or valves placed in both the incoming and outgoing potable water lines to the solar tank. It can be a three-valve configuration, or a three-port and two-port valve. Manually turning the valve or valves will place the solar tank "on line" or "off line." It works by directing the flow either through or past the solar tank. These valves can also be plumbed to bypass the backup gas or electric water heater, allowing them to be turned off (eliminating standby heat loss) during the seasons when the SHW system can supply 100 percent of the household's hot water.

Table 43 shows the output of the solar panel system described in table 18 which uses Vacuum Tube Collectors.

Month	Energy Produced in each month (MWh)	Average Power in each month (kW)
January	262.52	359.70
February	341.59	468.04
March	470.40	644.53
April	469.72	643.59
May	494.60	677.69

June	478.46	655.57
July	496.68	680.53
August	484.17	663.40
September	420.58	576.27
October	367.80	503.94
November	236.00	323.36
December	220.35	301.91
Total	4742.88	-

Table 42 – Electrical output of the 4.57 MW system using Vacuum Tube Collectors with 38 degrees tilt

2.5.1 Size of the System: Considering each of the different panel types presented earlier a certain amount of panels could be installed on the roof of the buildings.

Panel presented in Table 44 has been chosen as a Polycrystalline panel.

Panel Type	YL245P-32b by Yingly
Panel Output	245 (Watt)
Size of panels	1.7919 (m^2)
Theoretical number of panels installed	16675
Practical number of panels installed (90%)	15007
Total installed Capacity	3,676 (kW)
Installation cost of the system	$ 3.50 ($/Watt)
Total Cost of the system	$ 12,868,990

Table 43 – System Size and Cost using Polycrystalline panels

Table 45 shows the output of the solar panel system described above which uses Polycrystalline panels.

Month	Energy Produced in each month (MWh)	Average Power in each month (kW)
January	183.65	251.63
February	250.20	342.82
March	346.26	474.43
April	400.70	549.03
May	452.28	619.70
June	453.19	620.94

July	459.73	629.91
August	429.01	587.82
September	323.03	442.61
October	269.71	369.54
November	163.24	223.67
December	135.62	185.82
Total	3866.67	-

Table 44 – Electrical output of the 3.67 MW system using Polycrystalline Panels with 10 degrees tilt

Month	Energy Produced in each month (MWh)	Average Power in each month (kW)
January	204.59	280.32
February	278.73	381.90
March	385.73	528.52
April	446.39	611.62
May	503.84	690.34
June	504.85	691.73
July	512.15	701.73
August	477.92	654.83
September	359.86	493.07
October	300.46	411.68
November	181.85	249.17
December	151.08	207.01
Total	4307.46	-

Table 45 – Electrical output of the 4 MW system using Monocrystalline Panels with 10 degrees tilt

The output powers of two different systems are shown in figure 2 compared to the power demand of Emerson plant in each month.

PV UNCERTAINTY APPENDIX

J.1 PV Price Uncertainty

In analyzing the energy system for Emerson Plant, the team faced many uncertain aspects. In this part some of the formerly deterministic values have been considered to be uncertain and to have a probabilistic form instead.

The uncertainty is only considered for the installation price of PVs, the incentive received by the owners and the price of electricity bought form the grid. For each of these variables a different distribution function has been considered.

J.2 Price of PVs

The price of PV has been assumed to be a fixed price in this report and in the technology research part of this report. However the price of PV system could be assumed a probabilistic function. Table 1 shows the distribution used for installation cost of PVs, the mean value and the Standard deviation. The Panels considered here are Monocrystalline panels chosen for the Emerson plant.

Distribution	Normal
Mean ($/Watt)	$ 3.85
Standard Deviation ($/Watt)	$ 0.20

Table 46 –The cost distribution of Solar Panels

Considering this, distribution the Probability density function (PDF) function for PV installation cost will be a normally distributed variable.

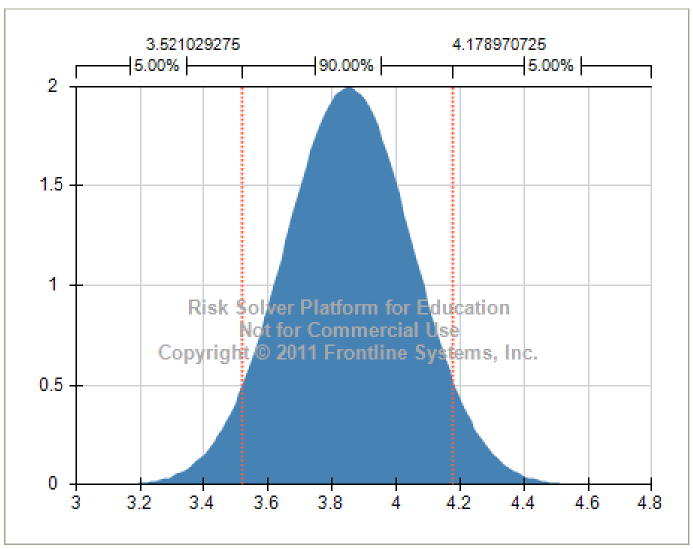


Figure 49 – Density Function for Price of PVs

Considering the density function shown in figure 1 the cost of the solar panel system for Emerson plant could be calculated using Simulation.

Using the Risk Solver Platform and running the simulation for 1000 times, the installation cost of the PV system is calculated.

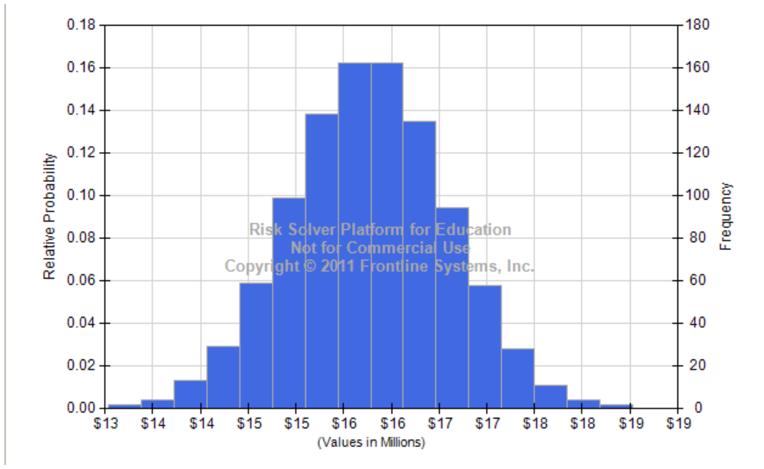


Figure 50 – The distribution of System's Total cost

Table 48 shows the information about the total cost of the system.

Mean Cost of the system	$ 15,772,618
Standard Deviation	$ 819,404.01
Chance of Price being 14..9 M$ or less	0.16

Table 47 – Total Cost of the system

Incentive: Another part which could be considered as probabilistic is the incentive available to the owners. Using the same way the incentive could be a probabilistic function.

Distribution	Normal
Mean ($/kWh)	$ 0.10
Standard Deviation ($/kWh)	$ 0.03

Table 48 –The probabilistic function for Incentives

Considering this, distribution the Probability density function (PDF) function for incentives will be a normally distributed variable.

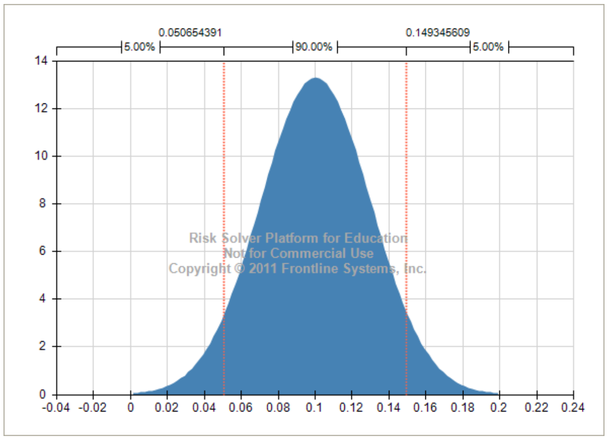


Figure 51 – Density Function for Price of Incentive

Considering the density function shown in figure 3 the cost of the each kWh produced by the solar panel system for Emerson plant could be calculated using Simulation.

A discount rate of 7% and a life cycle of 25 years have been considered for the project.

Figure 4 shows the cost per kWh of energy produced by the PV system after considering the incentive and running the simulation.

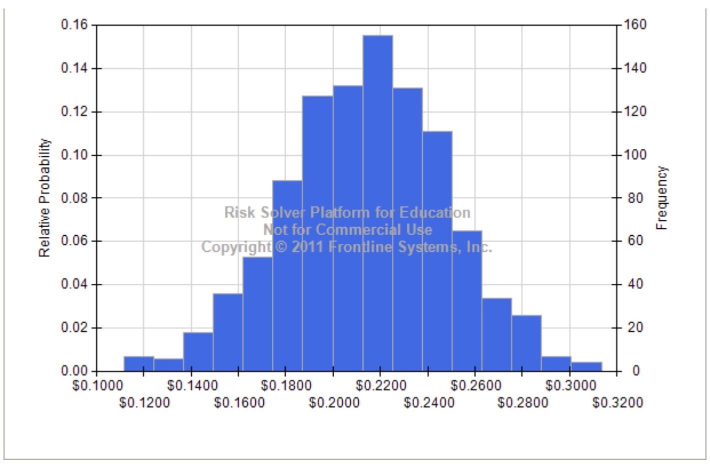


Figure 52- Distribution of price of each kWh produced by the PV system considering the inventive.

Table 50 shows the mean value and the standard deviation of the price of electricity produced by PV system.

Mean Cost of the system	$ 0.2141
Standard Deviation	$ 0.0336

Chance of price equal or less than 0.19 $/kWh	33%

Table 49- Cost of Electricity produced by the PV system

The chance of receiving a price of electricity lower than 19 cent/kWh is 33%.

J.3 The Grid

The last thing which will be considered as a probabilistic function is the price of electricity from the grid. For the price of grid a different distribution has been considered. Since the price of electricity from the grid is more likely to increase rather than decrease, PERT distribution has been considered for Grid Price.

Minimum Price ($/kWh)	0.09
Most likely price ($/kWh)	0.13
Maximum Price ($/kWh)	0.25

Table 50-Cost of Electricity from the Grid

Figure 55- Density Function for Price of Grid shows the distribution function for the price of Grid.

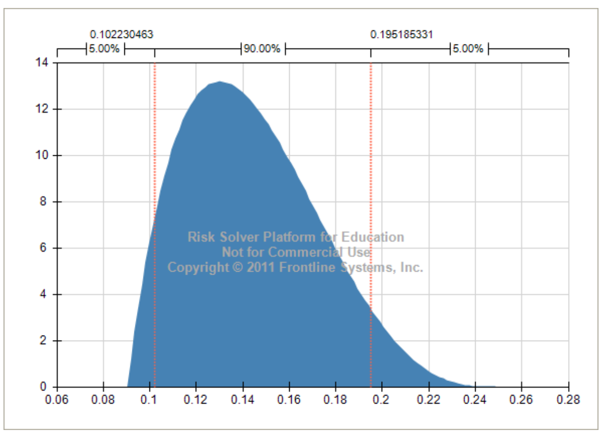


Figure 53- Density Function for Price of Grid

As it can be seen in the distribution function, the higher prices are more likely to happen. Considering the distribution for the price of the grid the savings of the PV system and its net present cost can be easily calculated.

Mean Net present cost of the system	$ -3,555,829
Standard Deviation	$ 2,219,187

Table 51 – The net present cost of the system considering Incentive, PV price and Grid price being probabilistic

Figure 56 shows the distribution of the net present cost for this project. Note that the values are negative.

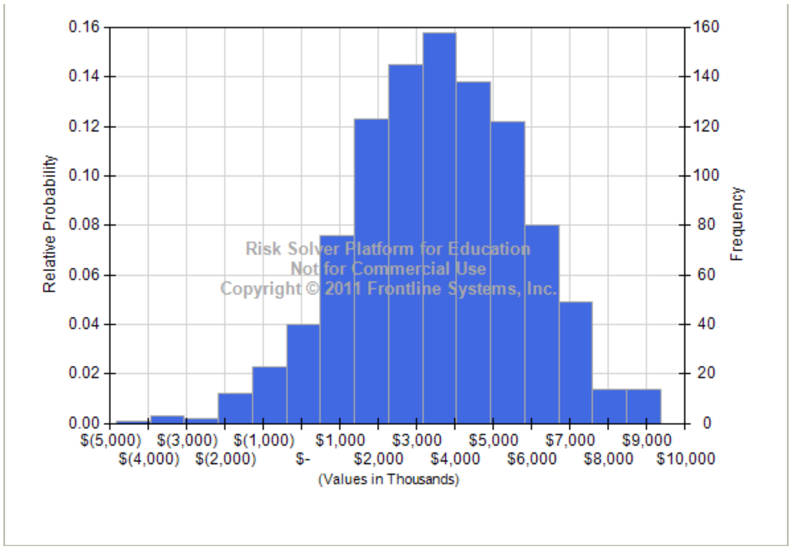


Figure 54 – The distribution of net present cost of the PV system.

Figure 57 shows the inner construction of a flat plate collector.

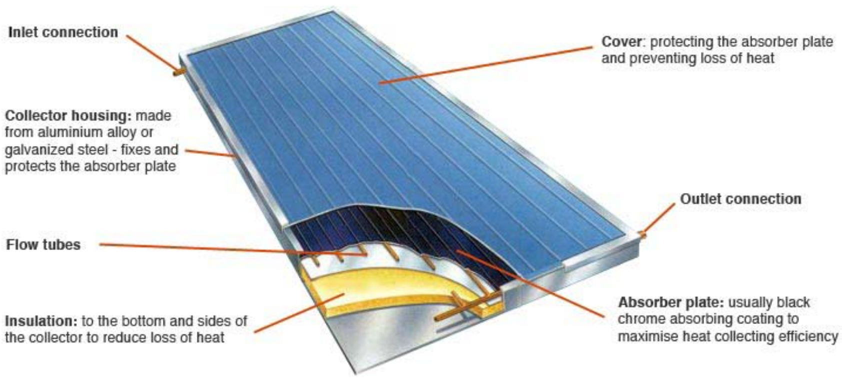


Figure 55 – Flat Plate Collector Construction

Figure 58 shows the installation of Flat Plate Collectors on a roof of a building.

Figure 56 – Flat Plate Collectors Use on Roof

Figure 59 shows a typical Vacuum Tube collector system.

Figure 57 – Application of Vacuum Tube Collectors on building's roof

Table 53 – Share of costs in total cost show the share of each part of the system in final cost.

Collectors	57%
Exchanger, Pump	11%
Storage Tanks	8%
Installation, Supports	24%

Table 52 – Share of costs in total cost