CHP Feasibility Assessment
The University of Montana

Missoula, Montana

Recuperated Gas Turbine with Heat Recovery Steam Generator

Northwest CHP TAP

August 1, 2016

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Executive Summary

The University of Montana is interested in CHP for its potential to provide operating cost reductions at the central heating plant. This feasibility assessment was undertaken by the NW CHP TAP (with its partner the Montana Energy Bureau) at the request of University of Montana facility managers, based on a recent CHP Qualification Screening. The screening study conducted identifies the University of Montana as a strong candidate for CHP and suggests that a more detailed analysis be completed. The purpose of this feasibility assessment is to refine and provide more certainty regarding CHP project sizing, estimate total CHP project installed costs, illustrate the economic and operational benefits of CHP to the university and to identify next steps.

The assessment evaluated the installation of a 4,600 kW gas turbine that would produce about 31.74 million kWh of electrical energy annually (or 91.7% of the University's current use). Annual operating savings of $1.311 million provide a simple payback of 9.8 years when existing financial incentives are included. Internal rate-of-return on investment (ROI) for the proposed $14.19 million dollar CHP project is 9.4%. The CHP project would also reduce greenhouse gas emissions from utility purchases and direct on-site combustion by 43%.

The University of Montana is a public research university that occupies 220 acres in Missoula, Montana. Established in 1893, the university provides instruction for over 12,900 students. Steam is provided from a central heating and power plant to a campus wide district heating system to serve 62 campus buildings plus athletic facilities. The heating plant contains three boilers: two rated at 70,000 pounds per hour and one at 30,000 pounds per hour. Current practice is to produce steam at 180-psig .

The University purchases about 34.5 million kWh of electrical energy annually at a melded (energy plus demand) cost of $0.09457/kWh. The heating plant consumes about 239,000 MMBtu of natural gas. The average total cost for natural gas during the 2015 calendar year was $7.44/MMBtu. Total annual energy costs were about $5.04 million. The University has been greatly reducing gas costs through reducing the percentage of transport gas purchased under firm contracts, thus a future natural gas delivered cost of $4.75/MMBtu is assumed for this feasibility analysis.

This feasibility analysis determines the costs and benefits of installing a 4,600 kW (ISO rating) gas turbine equipped with heat recovery steam generator (HRSG) at the central heating plant. This turbine is well matched to both University electrical and steam loads when operating in an electrical load-following mode up to its full rated output. The turbine would continuously operate at full output with utility sales of excess generation during months with peak or "Heavy Load Hours". The gas turbine selected for this analysis produces an unfired HRSG steam flow of about 10,100 lbs/hour of 175-psig steam. Steam produced enters the steam header system and passes through the existing backpressure steam turbine to supply 30-psig steam for distribution as is current practice. A recuperated gas turbine can minimize bypass of hot exhaust gases around the HRSG as the campus steam requirements between July and September are approximately 10,000 pounds per hour. Specification of a duct burner allows the HRSG to efficiently meet fall and winter campus steam loads up to 42,250 pounds per hour.

A spreadsheet-based software tool was used in this feasibility study to determine CHP annual electrical generation, utility energy sales, CHP system fuel use, and HRSG steam production by month. This monthly analysis tool includes re-rating gas turbine generating capacity, heat rate, and unfired steam production based upon both altitude and varying ambient air temperature. The tool automatically calculates monthly capacity factors, or the analyst can input monthly capacity factors determined from an hourly electrical load analysis.

The gas turbine would produce about 31.74 million kWh of electrical energy annually. An annual operating savings of $1.311 million provides a simple payback of 9.8 years. The facility's energy use profile for both baseline and CHP operating scenarios is summarized in Table 1 while estimated energy and cost savings are provided in Table 2.

Table 1: Facility Energy Use Profile

	Base Case	CHP Alternative
Annual Average Net Generator Output, kW (Includes elevation derate, ambient temperatures, and auxiliary loads)		4,067
Purchased Energy, kWh/year	34,593,944	4,143,952
Average Steam Production, lbs/hour	23,752	23,752
Generated Energy for On-Site Use		30,449,992
Generated Energy for Utility Sales, kWh		1,294,867
Boiler Fuel Use, MMBtu/year	239,043	9,688
Gas Turbine Fuel Use, MMBtu/year		330,872
HRSG Fuel Use, MMBtu/year		135,218
Total Natural Gas Use, MMBtu/year	239,043	475,778

Table 2: Estimated Operating Savings and Simple Payback

	Base Case	CHP Alternative
Boiler and CHP Natural Gas Price, $/MMbtu	$4.7500	$4.7500
Base Electric Rate, $/kWh	$0.095 (melded)	
Supplemental and Backup Electric, $/kWh	$0.072 (energy rate only)	
Demand Charges, $/year	$640,802	$328,628
Natural Gas Costs, $/year	$1,135,454	$2,259,944
Total Electricity Energy Costs, $/year	$2,630,662	$299,063
CHP O&M Costs, $/year		$317,449
Total Operating Costs, $/year	$4,406,918	$3,109,393
Operating Savings, $/year		$1,311,704
Capital Costs, $		$14,195,664
CHP Incentives or Grants, $		$1,277,610
Before-Tax Simple Payback (years)		10.8
Simple Payback w/CHP Incentive (years)		9.8

As a next step, it is recommended that the site contract with an engineering firm to move the project forward. Negotiations with the local electric utility and pre-design studies should be pursued to verify the technical and economic viability of CHP at the University and ensure that no “project-stoppers” exist. Further investigation of CHP viability could include conducting an investment grade feasibility study, which would further explore the University’s energy usage and needs, including planned expansions and overall University planning and goals.

Special consideration may also be given to power reliability concerns, fine-tuning of generating equipment and HRSG selection and estimated total installed costs, and consideration of additional equipment redundancy factors that may impact CHP system equipment selection or sizing.

1. Introduction

1.1 What is Combined Heat and Power?

Combined heat and power (CHP) is an efficient approach for generating power and useful thermal energy (heating or cooling) from a single fuel source at the point of use. Instead of purchasing electricity from the local utility and using fuel in an onsite boiler or furnace to produce needed thermal energy, an industrial or commercial facility can use CHP to provide both services onsite in one energy-efficient step. By recovering the heat normally wasted in power generation and avoiding transmission and distribution losses in delivering electricity from the power plant to the user, CHP reduces overall energy use, lowers emissions, and, depending on local conditions, provides operating savings and increased reliability to the end user.

CHP can be configured either as a topping or bottoming cycle. In a topping cycle, fuel is combusted in a prime mover such as a gas turbine or reciprocating engine, generating electricity or mechanical power. Energy normally lost in the prime mover's hot exhaust and/or cooling systems is recovered to provide process heat, hot water, or space heating/cooling for the site. In a bottoming cycle, also referred to as waste heat to power, heat energy is recovered from the hot exhaust of a furnace or kiln to generate mechanical power or electricity for the site. Common thermal loads for CHP applications can be process steam or process heat for industrial facilities; cooling, heating, and humidity control systems for buildings; or domestic hot water wherever the need exists.

The strength of CHP technology lies in its flexibility. Although natural gas is the most prevalent fuel source, CHP can also utilize opportunity fuels such as landfill gas (LFG), biomass, and digester gas. CHP is particularly effective when byproducts from industrial processes can be used as fuel.

1.2 U.S. Department of Energy CHP Technical Assistance Partnerships

U.S. DOE's CHP Technical Assistance Partnerships (CHP TAPs) promote and assist in transforming the market for CHP technologies and concepts throughout the United States.

Key services of the CHP TAPs include:

- **Market Assessments** – Supporting analyses of CHP market potential in diverse sectors, such as health care, industrial sites, hotels, and new commercial and institutional buildings.
- **Education and Outreach –** Providing information on the benefits and applications of CHP to state and local policy makers, regulators, energy end-users, trade associations, and others.
- **Technical Assistance –** Providing technical information to energy end-users and others to help them consider if CHP makes sense for them. This includes performing site assessments, producing project feasibility studies, and providing technical and financial analyses.

1.3 Overview of Site Qualification Screening Study

Our CHP Qualification Screening (QS) letter indicated that "based on our review of the technical and economic data provided, we believe the University of Montana qualifies as a strong candidate for CHP". Responses from facilities management staff indicate the following factors that favor the installation and operation of a CHP system:

- *Fuel and electricity rates combined with electric and thermal loads appear to support economic CHP operation;*
- *Concerns about future electrical energy cost increases;*
- *Concurrent electric and thermal loads (8,760 annual hours of operation including thermal loads due to a commercial kitchen, pool and athletic center, labs, greenhouses, and a laundry);*
- *Existing central heating system with large thermal demands;*
- *Advanced age of the existing boilers (46 and 55 years old);*
- *Space adjacent to the boiler house to accommodate a gas turbine power plant;*
- *Preliminary screening results showing the potential for operating savings at the university;*
- *The University's commitment to reducing its carbon footprint through funding efficiency measures and adopting a climate action plan; and*
- *Expectation of facility expansion or new construction projects within the next 5 years.*

We reviewed gas turbines that are a good "fit" for meeting the electrical and thermal loads at the University. Our preliminary analysis focused on a recuperated turbine rated at about 3,941 kW at the site elevation that is capable of meeting about 86% of campus electrical energy requirements and 83% of thermal needs. Our screening study estimated an annual operating cost savings of $1.226 million at current utility rates; a total installed cost of $7.125 million; with a simple payback of 5.8 years without incentives.

The QS screening indicates the university is a strong candidate for a CHP project and suggests a more detailed analysis be conducted with considerations given to seasonal use of thermal energy and seasonal temperature variations of gas turbine performance factored in. Facility hourly electrical energy and steam usage data could be used to identify spikes in use that could not be met by either the gas turbine or HRSG. The QS screening also had valued electrical generation at the full melded cost of electrical energy with the gas turbine offsetting both energy and all, or a portion of, demand or capacity charges. A more detailed study would examine demand benefits taking into consideration gas turbine mean time between failures; the need for scheduled outages; and the frequency and duration of forced outages.

This feasibility analysis is being conducted, at the request of facility managers, to refine and provide more certainty regarding the estimated total installed costs, and economic and operational benefits of CHP to the university. The feasibility analysis will clarify gas compression operating costs, and determine the additional costs associated with adding reliability components to the CHP project such as the ability of the gas turbine to use No. 2 (diesel) oil when natural gas supplies are interrupted, and the costs associated with providing outside air firing capability to the HRSG. The goal is to provide the information necessary for the university to make a decision on taking the next steps(s) in the CHP development process.

2. Preliminary Energy Analysis: Details and Assumptions

2.1 Detailed Facility Description

The University of Montana is a public research university that occupies 220 acres in Missoula, Montana. Established in 1893, the university employs 831 full and part-time staff to provide instruction for 12,922 students (Spring, 2015). Steam is provided from a central heating and power plant to a campus wide district heating system to serve 62 campus buildings plus athletic facilities. The heating plant contains three boilers: two rated at 70,000 pounds per hour and one at 30,000 pounds per hour. The large boilers can produce steam at up to 200-psig while the smaller boiler can operate at 275-psig. Current practice is to produce steam at pressures up to 180-psig and then to reduce the steam to a distribution pressure of 30-psig through passing it through pressure reduction valves or a 440 kW backpressure steam turbine. The steam turbine, rated for a flow of 24,978 pounds per hour, supplies about 5% of the current campus annual energy consumption.

2.2 Current Plant Energy Requirements

In addition to the steam turbine output, the University purchases about 34.5 million kWh of electrical energy annually from NorthWestern Energy at a melded (energy plus demand) cost of $0.09457/kWh. Total annual costs for the purchase of electrical energy is $3,261,008. The heating plant annually consumes about 239,000 MMBtu of pipeline transport natural gas. Total natural gas cost for the 2015 calendar year was $1,779,899. The average cost for natural gas commodity prices plus transportation and storage during the 2015 calendar year was $4.75/MMBtu. Total utility bills for the campus in CY 2015 amounted to $5,040,907. Natural gas prices have since declined.

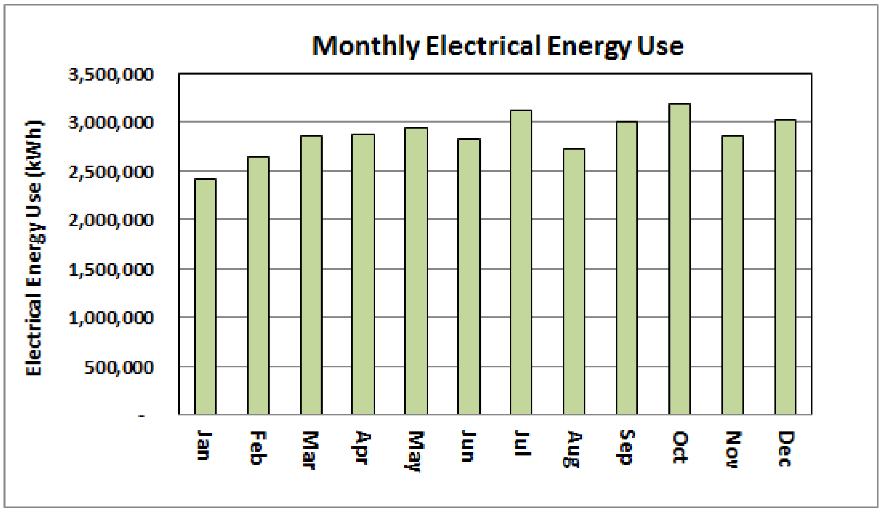
Table 3: University of Montana Energy Profile Summary (CY 2015)

Annual Electric Consumption (kWh)	34,593,944
Annual Average Hourly Electric Demand (kW)	3,950
Maximum Electric Demand (kW/hour)	6,064
Minimum Electric Demand (kW/hour)	2,587
Annual Fuel Consumption (MMBtu)	239,043
Average Natural Gas Use (MMBtu/hour)	27.4
Average Thermal Load (lbs steam/hour)	23,752

2.3 Electrical Energy Use

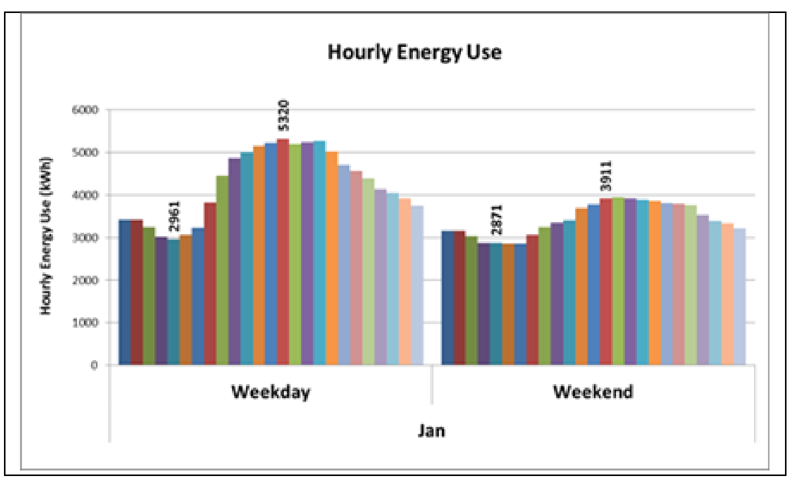
In contrast to the natural gas and steam use, University of Montana electrical energy use is fairly consistent during the course of the year, peaking in the summer period (see Figure 1). The highest electrical energy consumption—with an average monthly load of 4,289 kW—occurs in October.

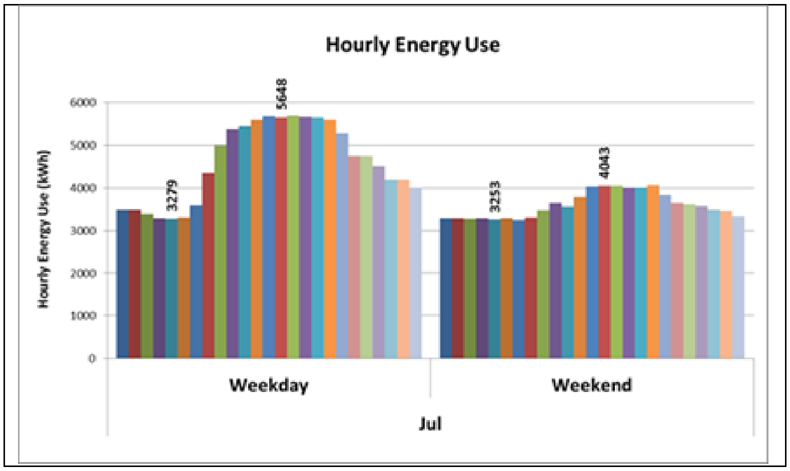
Figure 1: Monthly Electric Consumption for University of Montana



The university provided average power data—taken at 15-minute intervals--for a complete year for both their main campus and stadium meters. As seen in Figure 2, the aggregated average hourly electrical energy load profile varies little between January and July although weekday and weekend energy use profiles do vary. Average daily peak demands vary between 5,320 kWh/hour and 5,648 kWh/hour for January and July. Weekend peak demands are reduced to 3,900 to 4,050 kWh/hour.

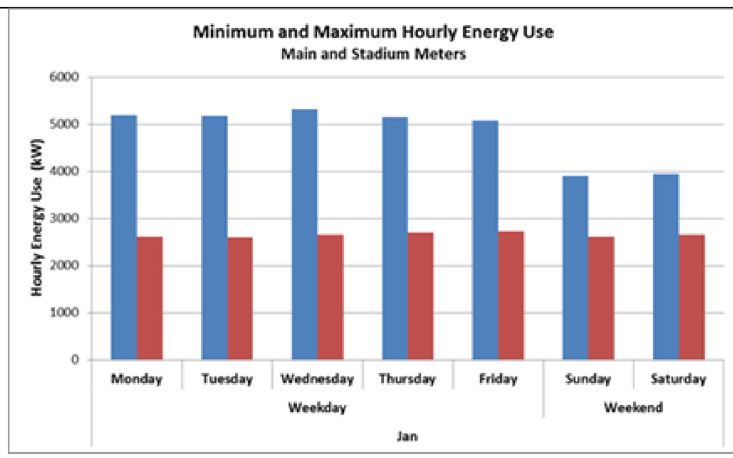
Figure 2: Hourly Electric Consumption for Months of Jan and July

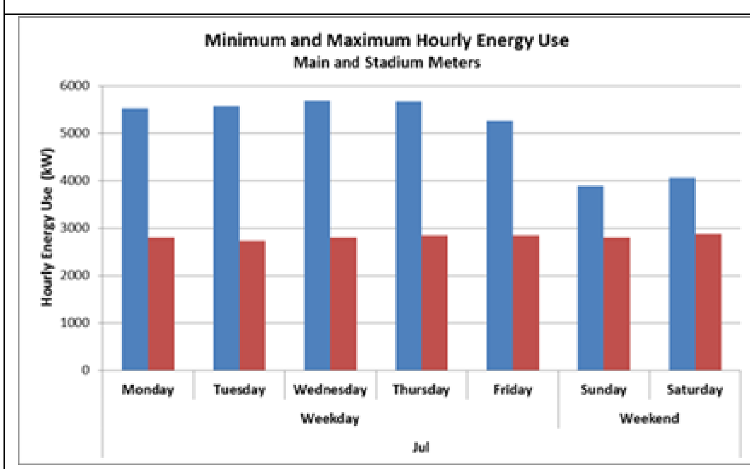




As shown in Figure 3, the average minimum and maximum hourly electrical energy use varies little by day of the week, although the July maximums are slightly higher than the January values.

Figure 3: Average Minimum and Maximum Peak Demand by Day of the Week





An examination of 15-minute electrical energy use data indicates that the peak annual demand for the university is about 6,000 kW while the lowest load required is about 2,750 kW.

2.4 Natural Gas Use and Steam Production

Energy costs by month for both the utility gas and electricity meters are summarized in Figure 4. Note that natural gas use is extremely seasonal. As shown in Figure 5, natural gas consumption peaks during the winter heating months---December to February---between 40.5 to 46.6 MMBtuh and declines to very low values of 10.3 to 12.5 MMBtuh during the summer months of June, July, August, and September.

Figure 4: Energy Cost by Month for All Meters (CY 2015)

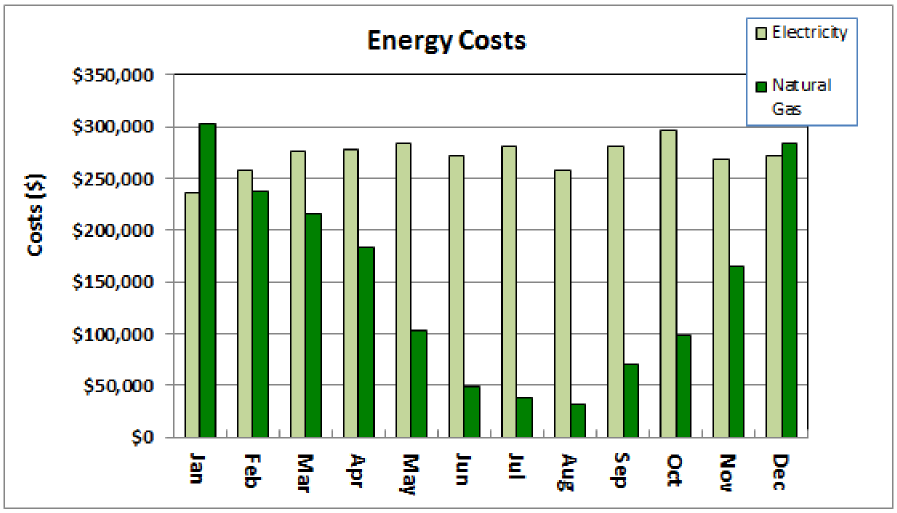
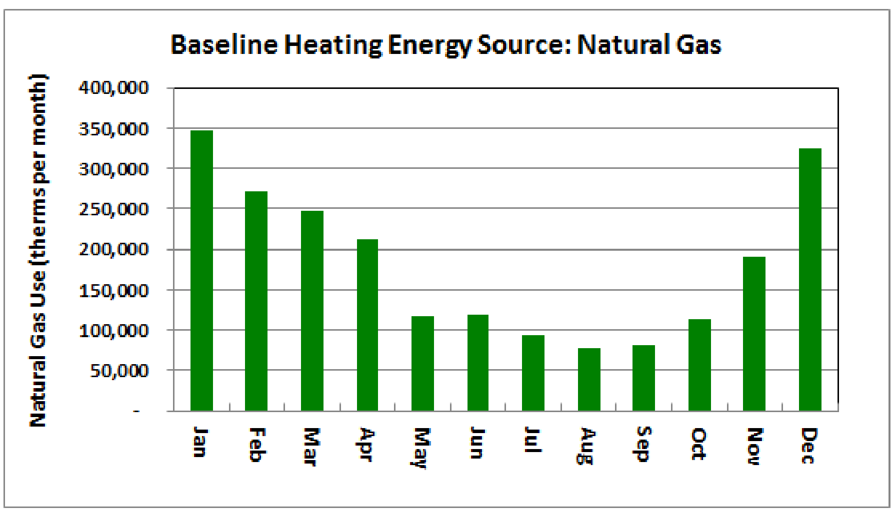


Figure 5: Total Boiler Natural Gas Consumption by Month



The university facilities staff provided steam production extracted from plant logs for all boilers by three hour intervals. The data shown in Table 4 shows average steam production is relatively constant over the course of both weekdays and weekends. While gas consumption and steam generation varies widely by month, the average steam production by 3-hour time block or by time-of-day for each month is extremely consistent. It is postulated that, due to Montana's harsh winter weather and building thermal mass, the buildings are not allowed to cool down at night, followed by a morning warmup cycle. This constant daily natural gas and steam use profile is ideal for a CHP project as backup boilers are not required to be maintained in a hot standby condition and brought on-line to meet early morning peak loads.

Table 4: Campus Steam Loads by Time of Day for Each Month of the Year

Row Labels	Average of Midnight	Average of 3:00 AM	Average of 6:00 AM	Average of 9:00 AM	Average of Noon	Average of 3:00 PM	Average of 6:00 PM	Average of 9:00 PM
⊟ Jan								
⊞ Weekday	27,330	27,858	29,129	29,437	27,992	26,362	27,535	27,463
⊞ Weekend	26,746	26,916	28,129	28,150	26,680	24,772	25,424	26,089
⊞ Feb	23,427	23,655	26,228	28,323	24,878	22,069	23,282	24,356
⊞ Mar	19,382	19,974	23,092	26,377	21,173	17,408	17,433	18,680
⊞ Apr	16,222	17,171	19,501	22,588	17,646	14,860	14,649	15,285
⊞ May	10,873	11,645	14,141	15,543	12,141	10,756	10,309	10,724
⊞ Jun	7,231	7,629	8,635	8,799	8,195	7,580	7,248	6,908
⊞ Jul	6,719	6,868	7,741	8,247	7,543	7,111	7,019	6,645
⊞ Aug	6,827	6,886	7,830	8,376	7,914	7,202	6,920	6,694
⊞ Sep	9,346	8,846	10,567	14,085	10,788	9,552	9,304	9,739
⊞ Oct	12,948	12,579	14,983	19,141	15,199	12,324	12,070	13,164
⊞ Nov	21,903	21,429	23,668	26,743	24,003	21,855	23,347	22,862
⊞ Dec	26,309	26,327	27,684	28,760	28,527	27,328	27,680	27,382
Overall Average	15,761	15,936	17,776	19,708	17,204	15,383	15,588	15,871

3. CHP Equipment Selection and Sizing

3.1 CHP System: New 4,600 kW (ISO) Recuperated Gas Turbine with HRSG

This feasibility analysis determines the costs and benefits of installing a 4,600 kW (ISO rating) recuperated gas turbine equipped with heat recovery steam generator (HRSG) at the central heating plant. The gas turbine is de-rated to 3,941 kW (at 59^{o}F)given the 3,209 elevation of the university and would be operated in an electrical load-following mode up to its full output. Due to the temperature profile at the site, the net annual electrical output (when auxiliary service loads are included) is 4,067 kW. Electrical energy must be purchased from the local electrical utility when campus electrical energy requirements exceed the generating capacity of the gas turbine. Steam is produced by routing the gas turbine exhaust through a HRSG. A duct burner is provided so the CHP project is capable of simultaneously operating in both an electrical and a steam load following mode. CHP project performance is summarized in Table 5.

The recuperated turbine was selected for analysis as its exhaust temperature of 650^{o}F to 700^{o}F produces an unfired steam flow of about 10,100 lbs/hour of 175-psig steam. Steam production would enter the existing header system and pass through the existing backpressure steam turbine as is current practice. The recuperated turbine would minimize bypass of hot exhaust around the HRSG when the campus steam requirements fall below 10,000 pounds per hour between July and September. Use of a duct burner would allow the HRSG to efficiently meet fall and winter campus steam loads up to 42,250 pounds per hour.

A non-recuperated 4,600 kW (ISO) gas turbine would provide exhaust gas at a temperature of about 950^{o}F. Without use of a bypass or dump stack, the unfired steam generation from the non-recuperated gas turbine would be approximately 21,100 pounds per hour---which greatly exceeds the campus steam requirements for the six month period between May through October. About 20% of the potentially useable thermal energy for this equipment selection alternative would have to be bypassed to a dump stack and vented to atmosphere. Although a non-recuperated turbine has a lower initial cost, gas turbine fuel consumption would increase (by over 31%) when providing the same electrical output as the turbine nominal generating efficiency (at 59^{o}F and site altitude) decreases from 33.8% for a recuperated turbine to only 25.7% (HHV basis) for the non-recuperated turbine. As the unfired steam flow is greater, however, less fuel would be required by the duct burner for steam production.

Assuming a 94.7% availability factor, the recuperated gas turbine would produce about 31.7 million kWh of electrical energy annually. About 1.29 million kWh of surplus electrical energy would be sold to the utility during on-peak or Heavy Load Hour months. Natural gas use at the central heating plant would increase from about 239,300 MMBtu/year to 475,778 MMBtu annually.

The existing heating plant contains three steam boilers- two 1962 vintage Keeler water tube boilers rated at 70,000 pounds per hour and one 1968 Babcock & Wilcox boiler rated at 30,000 pounds per hour. These would be used in a backup capacity. The large boilers can produce saturated steam at up to 200-psig while the smaller boiler can operate at 275-psig. If a unit must be kept in hot standby, facility staff indicates that the boiler burners are capable of being modulated to 1/8th of their full-firing rate.

A HRSG is capable of operating as a boiler and producing steam when the gas turbine is experiencing an outage if it is equipped with "outside air firing" or "fresh air" firing capability. This entails an additional cost of $250,000 as the burner providing the air/fuel mixture must be equipped with a sizable forced draft combustion air supply fan. The University is also interested in procuring a gas turbine that can operate on both natural gas and No. 2 (diesel) oil as a backup fuel. As the Solar Mercury is only rated for natural gas, a 4,600 Solar Centaur would be required to operate on No. 2 oil.

An on-site natural gas compressor will be required as the gas supply is regulated to 15-psig at the boiler house but is available at 70-psig upstream of the pressure regulator. Gas compressor energy consumption is greatly reduced when an interconnection pipeline is supplied so the compressor can utilize the "on the streets" pressure. The Solar Mercury requires a maximum gas fuel pressure of 167-psig between the temperature range of (-)30^{o}F and +30^{o}F. Vilter Manufacturing indicates that a screw compressor would have to provide 70.7 brake or shaft horsepower (BHP) to provide the required fuel mass flow at the required combustor pressure given site altitude and inlet pressure conditions. Such a compressor would have an inlet power requirement of about 55.5 kW. Generally, two skid-mounted compressors are installed in parallel to provide equipment redundancy and high gas turbine availability.

Table 5: Performance of CHP Project

	CHP Alternative
Prime Mover Type	Gas Turbine
Number of Prime Movers, Availability Factor	1, 94.7%
Form of Recovered Heat	175-psig steam
Fuel Type	Natural Gas
Average Annual Gas Turbine Fuel Consumption, MMBtu/hour	39.9
Net Annual Generator Output, kW (Includes elevation derate, ambient temperature profile, and auxiliary loads)	4,067
Electric Efficiency (HHV)	33.8%
Average Annual Heat Rate (includes parasitic loads, elevation derate, ambient temperature profile, and part-load operation), MMBtu/kWh	10,423
Fuel Chargeable to Power Heat Rate, (Btu/kWh)	7,461
Gas Turbine/HRSG Steam Production, unfired, lbs/hour	9,315
Average Thermal Load (lbs/hour of 175-psig steam)	23,752
Average HRSG Steam Production, lbs/hour	13,679
Boiler Efficiency,%	85%
Total CHP Efficiency (HHV)	55.4%

4. Analysis Assumptions

4.1 Energy Costs and Value of CHP Output

Monthly consumption for electrical energy and natural gas at the University of Montana are given in Table 6. Annual electrical energy consumption for the main and stadium electrical meters combined total 34.48 million kWh with a cost of $3.26 million for both energy and demand. The melded electrical energy cost amounts to $0.095/kWh. Natural gas use amounts to 239,043 MMBtu with a total cost of $1.135 million. The average cost for natural gas is $4.752/MMBtu.

Table 6: Electrical Energy and Natural Gas Use and Costs by Month

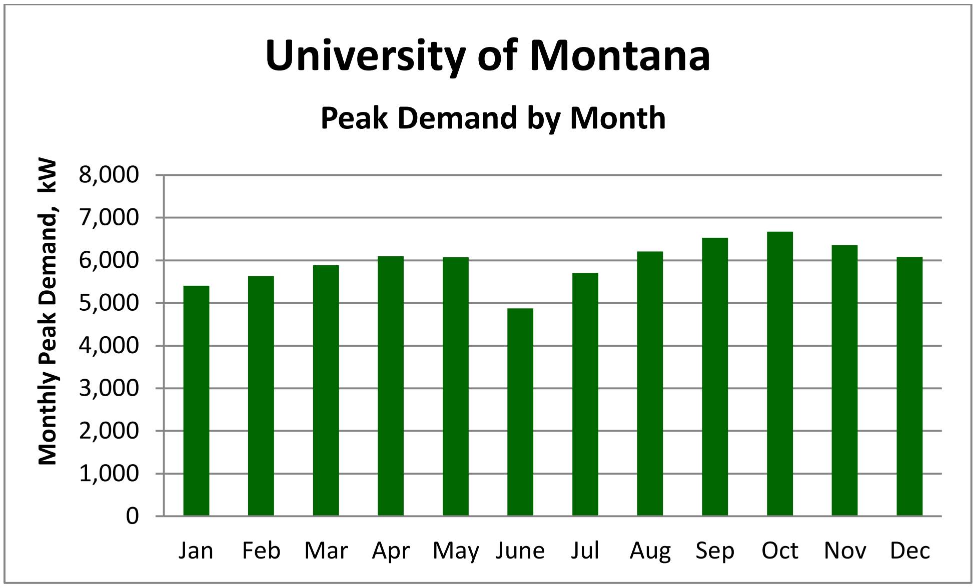
	Electricity	Electricity	Electricity	Natural Gas	Natural Gas	Natural Gas
Month	(kWh)	($)	($/kWh)	(MMBtu)	($)	($/MMBtu)
Jan--15	2,414,572	235,865	0.098	34,644	157,950	4.559
Feb--15	2,641,320	257,849	0.098	27,183	124,833	4.592
Mar--15	2,862,502	276,886	0.097	24,754	114,198	4.613
Apr--15	2,874,220	278,418	0.097	21,124	98,479	4.662
May--15	2,940,169	283,582	0.096	11,763	58,829	5.001
Jun--15	2,820,385	271,902	0.096	7,734	41,815	5.407
Jul--15	3,113,412	281,130	0.090	7,417	40,735	5.492
Aug--15	2,729,908	257,049	0.094	7,744	42,134	5.441
Sep--15	3,010,740	281,092	0.093	11,330	57,475	5.073
Oct--15	3,191,291	296,315	0.093	17,874	85,471	4.782
Nov--15	2,862,916	269,138	0.094	32,036	149,283	4.660
Dec--15	3,021,954	271,782	0.090	35,440	164,642	4.646
Totals	34,483,389	3,261,008	0.095	239,043	1,135,845	4.752

The University purchases electrical energy from Northwestern Energy under their General Service -1-Demand rate schedule. For CY 2015, the average energy cost was $0.06665/kWh while the average demand charge was $7.822/kW-mo. For the December 2015—January 2016 period, the demand charge increased to $7.90/kW-mo. When taxes and surcharges are included, the energy and demand charge offset values increase to $0.0726/kWh and $8.92/kW-mo, respectively. The CHP electrical energy production of 29.8 million kWh/year that is used on-site to displace utility purchases yields a total annual energy purchase displacement benefit of $2,167,300 when valued at $0.0726/kWh.

4.2 Demand Costs and CHP Demand Offsets

The average monthly peak demand for the University of Montana was 5,960 kW during the CY2015 billing period. Demand is summed for both the main and stadium meters. Utility-metered monthly peak demand values are shown in Figure 6 and vary from a high of 6,669 kW in October to a low of 4,873 kW in June.

Figure 6: Campus Peak Electrical Demand by Month



Total annual demand charges to the University for CY 2015 are about \$637,930 when utility taxes and surcharges are imposed. Total annual metered demand is 71,517 kW-mo. The CHP project does not produce enough power to totally offset these monthly demand charges. When the gas turbine is operating in an electrical energy load following mode with utility sales, the monthly gas turbine average power outputs vary from a high of 4,186 kW in October to a low of 3,539 kW in January. Total potential annual demand offset by the gas turbine is 48,752 kW-mo. Gas turbines are subject to scheduled and forced outages, and for this analysis an availability factor of 94.7% is assumed. Based on the availability factor, it is assumed that the CHP project will contribute to the reduction of demand charges for nine of the 12 months. Demand benefits due to CHP project operation are thus estimated at:

9 months/12 x 48,752 kW-mo x \$7.822/kW-mo x (1.141 tax multiplier) = \$326,330/year

The CHP project is thus expected to offset about \$326,330/\$637,930 x 100% or 51.2% of the utility imposed demand charges. The University must continue to pay annual demand charges that amount to \$311,590 per year. The demand offset is equivalent to about \$326,330/31,744,859 kWh or \$0.01/kWh. The total value of CHP electrical energy production consists of both electrical energy and demand offsets and is equivalent to an annual melded electrical energy value of:

Total Value of CHP Energy Production: \$0.0726/kWh + \$0.01/kWh = \$0.0826/kWh.

Table 7: Electric Rate Assumptions

Energy and Demand Charges Used in Analysis	
Generation (Offset On-Site Energy Charges)	$0.0726/kWh
Utility Sales (During Heavy-Load Hour Months)	$0.0739/kWh
Demand Offset Benefits (Assuming 75% Offset)	$6.69/kW-mo

The total value due to offset of electrical energy used on-site and offset demand charges is:

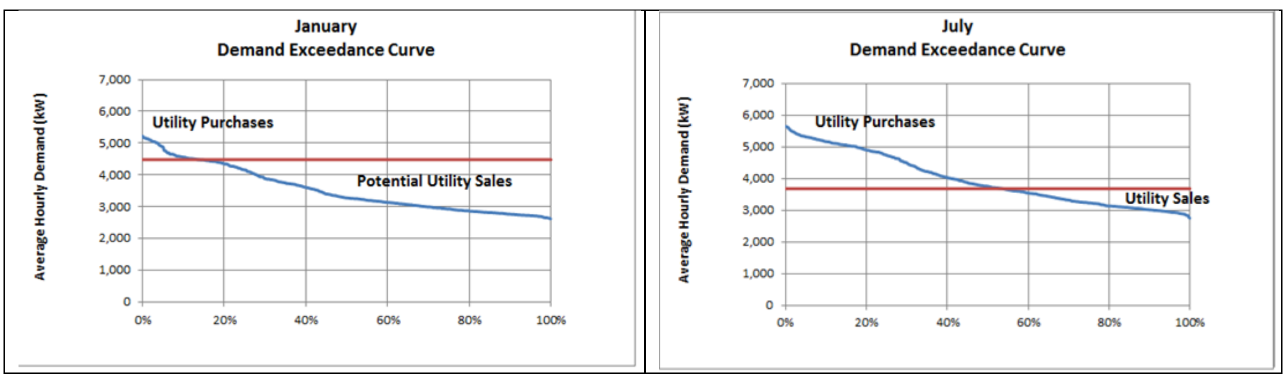
CHP Annual Electrical Energy Benefits = $2,167,300/year + $326,330/year = $2,493,960

Benefits due to energy sales to the utility during heavy load hour months are discussed in the following section.

4.3 Potential Sales to the Local Utility

When hourly electrical load data is taken into consideration, it is apparent that some electrical energy must be purchased from the serving utility each month when on-site electrical loads exceed the net temperature adjusted generating capacity of the gas turbine. Each month also has periods when the potential gas turbine output exceeds on-site energy needs. This is an opportunity for electrical energy sales. The quantity of energy potentially available for sale during the months of January and July is proportional to the bounded area shown in Figure 7 (remember that the difference in available kW less site required kW multiplied by time in hours gives kWh).

Figure 7: Potential Energy Available for Utility Sales in January and July



About 3.67 million kWh of additional electrical energy could be produced annually if the gas turbine was to operate at its full-rated output during each month. This quantity of energy production reflects the availability factor used for gas turbine operation. Excess electrical energy could be used to meet future on-site loads or sold back to the serving utility.

In their "Qualifying Facility Power Purchase" electric tariff (applicable for any seller with a nameplate capacity of 3 MW or less who enters into a power purchase agreement with the utility) NorthWestern Energy establishes different rates under Option 1(a) for non-wind installations. Energy provided during "On-Peak" hours of the day is valued at $0.09273/kWh with energy delivered during "Off-Peak" hours valued at only $0.05314/kWh. On-Peak hours are also referred to as "Heavy Load" hours and indicate the weekday and Saturday hours between 7 a.m. through 10 p.m. except for holidays during the months of January, February, July, August, and December. Off-peak hours are all hours that are not considered to be on-peak.

It would not be cost-effective to operate the gas turbine during “off-peak” months with no Heavy Load hours. Rather than operate the gas turbine at full-firing rate only during the on-peak hours during the Heavy Load hour months, we assume that the gas turbine will operate at full output for each of these five critical months. Taking Sundays and holidays into consideration, a reasonable estimate for a weighted average utility purchase price is $0.0739/kWh. With a total expected utility sales of 1,294,867 kWh/year during Heavy Load hour months only, the benefit from utility purchases amounts to about $95,690 annually (See Section 5 for additional details).

4.4 Gas Turbine Performance

The prime mover selected for evaluation in this feasibility study is the Solar Mercury 50-6400R recuperated gas turbine-generator set. The gas turbine is equipped with a dry low-NOx combustion system and is rated to provide a gross electrical output of 4,600 kW when equipped with a 96% efficiency generator and when operating under ISO conditions consisting of sea level, 59^{o}F, and 60% relative humidity (RH). This gas turbine is de-rated to produce only 3,941 kW at 59^{o}F at an altitude of 3,209 feet. Total service load is 114 kW when the gas compressor is included, leading to a net electrical output of 3,827 kW at a temperature of 59^{o}F. Performance information for both the gas turbine and heat recovery steam generator (HRSG) are summarized in Table 8.

The HRSG selected for this analysis is rated to produce steam at the usual boiler plant pressure of 175-psig. This pressure is selected so the existing backpressure steam turbine located in the boiler house can continue to operate as installed. The HRSG is equipped with a combustion air fan and duct burner so it can continue to provide steam when the gas turbine is off-line. The unfired HRSG will produce about 9,969 to 10,163 pounds per hour of steam just from the hot-650^{o}F to 710^{o}F-gas turbine exhaust. The duct burner can be used to preheat the oxygen rich exhaust gas to provide a total steam flow of up to 42,250 lbs/hour of 175-psig saturated steam. The recuperated Solar Mercury gas turbine was selected for this application in large part due to its low unfired steam production. A recuperated gas turbine uses its hot exhaust gases to preheat combustion air. This decreases the firing rate or rate of fuel consumption and improves the electrical generating efficiency---expressed as heat rate in Btu/kWh---of the gas turbine. The lower exhaust temperature also suppresses the rate of unfired steam production.

A non-recuperated gas turbine with an equivalent electrical generating capacity (such as the 4,600 kW Solar Centaur) would produce hot exhaust gas in the range of 940^{o}F to 970^{o}F. The mass flow of hot gas would provide an unfired steam flow of about 21,170 lbs/hour. As the steam flow requirements at the University fall below 20,000 lbs/hour for about five months of the year, excess hot exhaust would have to bypass the HRSG and be released to atmosphere via a “dump” stack were a non-recuperated turbine selected. In contrast, the unfired steam flow produced by the recommended Solar Mercury closely matches and does not greatly exceed the minimum monthly site steam requirement of 8,650 lbs/hour.

High temperature pollution control equipment (selective catalytic reduction or SCR) is available that is capable of operating at temperatures of up to 1,100°F. A high temperature SCR installation allows the catalyst to be placed directly downstream of the turbine exhaust flange.

Table 8: Gas Turbine and HRSG (Steam Boiler) Performance

Gas Turbine:		
KW Gross Output @ ISO Conditions:	4,600	kW
Site Ambient Temperature for Performance Analysis:	59	°F
Site Elevation for Performance Analysis:	3,209	feet
Site Ambient Relative Humidity for Performance Analysis:	60	%
Turbine Inlet Pressure Loss:	4.0	"H2O
Turbine Outlet Pressure Loss:	7.0	"H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	35.8	MMBtu/hr
KW Gross Output @ specified site conditions:	3,941	kW
Condensate Pump Power:	1.4	kW
Boiler Feed Pump Power:	17.9	kW
Total Auxiliary Power Consumption:	59	kW
Net Gas Turbine Power Production:	3,882	kW
Black Start kW Requirement (Turbine Generator Set Only)	206	kW

Boiler:		
Condensate Return:	60	%
Condensate Temperature:	212	°F
Makeup Water Temperature:	70	°F
Process Steam Pressure:	175.0	psig
Process Steam Temperature:	377	°F
Steam Contributed by Gas Turbine:	10,163	lbm/hr
Steam Contributed by Ductburners:	32,049	lbm/hr
Ductburner Fuel Consumption (LHV):	28.8	MMBtu/hr
Deaerator Steam Consumption:	2,965	lbm/hr
Boiler Steam Flow:	42,212	lbm/hr
Steam Flow to Process:	39,247	lbm/hr

Gas turbine performance at "off-design" conditions are shown in Table 9. The nominal power output at the generator terminals can be seen to range from 4,497 kW at an ambient temperature of 23°F down to 3,712 kW at 72°F. Power output, fuel flow rate, exhaust gas temperature, and exhaust gas mass flow all are shown to vary with respect to ambient temperature. The GilMore CHP system assessment model is designed to conduct a "monthly" analysis, using monthly average electrical demand, monthly average gas consumption and thermal requirements, and gas turbine performance when derated to reflect monthly average temperatures.

Table 9: Solar Mercury Gas Turbine "Off-Design" Performance

						CHP Off Design	
						Incl Ductburner	
					# of Turbines in Service	1	
					Process Steam Demand	40,315	lbm/hr
					Unfired Steam Flow	10,114	lbm/hr
Site Elevation:	3,209	feet			Max Steam Flow	40,227	lbm/hr
Barometric Pressure:	26.57	"Hg			Firing Temperature	1,509	°F
Inlet Duct Loss:	4.0	"H2O			Duct Burner Fuel Flow	29.1	MMBtu/hr
Exhaust Duct Loss:	7.0	"H2O			Relative Humidity	60	%
Ambient Temperature (T1):	59.0	23.0	34.0	44.0	72.0	54.0	°F
Part Power (kWe), % Load, or 0 for Max	0	0	0	0	0	0.0	kWe
Engine Inlet Air Temperature (T1):	59.0	23.0	34.0	44.0	72.0	54.0	°F
Nominal Output Power @ Terminals:	3,941	4,497	4,368	4,188	3,712	4,021	kWe
Fuel Flow (LHV)	35.8	38.9	38.5	37.4	34.4	36.3	MMBtu/hr
Inlet Air Flow:	122,458	131,088	130,120	126,973	118,389	123,938	lbm/hr
Exhaust Gas Temperature (T7):	695	653	669	679	708	690	°F
Exhaust Gas Mass Flow:	124,195	132,977	131,990	128,785	120,056	125,699	lbm/hr
Exhaust Gas Volumetric Flow:	31,462	33,698	33,446	32,629	30,408	31,823	SCFM
Nominal Electrical Efficiency @ Terminals	37.6	39.4	38.7	38.3	36.9	37.8	%
Nominal Electrical Heat Rate @ Terminals	9,083	8,655	8,818	8,919	9,254	9,030	Btu/kWHR
Exhaust Heat Captured:	14.2	13.7	14.2	14.2	14.1	14.2	MMBtu/hr
% Argon, wet:	0.9	0.9	0.9	0.9	0.9	0.9	
% CO_2, wet:	2.4	2.5	2.5	2.5	2.4	2.5	
% H_2O, wet:	5.4	5.5	5.4	5.4	5.4	5.3	
% N_2, wet:	75.7	75.7	75.7	75.7	75.7	75.8	
% Oxygen, wet:	15.5	15.5	15.5	15.5	15.6	15.6	
					Net CHP System Efficiency =	86.8	% (LHV)

4.5 CHP Project Total Installed Cost Estimate

Equipment and installation cost estimates are supplied by vendor cost quotations or extracted from Section 3 'Technology Characterization—Combustion Turbines' from the March, 2015 U.S. EPA "Catalog of CHP Technologies". The catalog indicates equipment, design, installation, permitting, and project management cost data for gas turbine CHP systems of various generating capacities. Cost estimates for the 4,600 kW Solar Mercury system were extrapolated from data for a 3,510 kW Solar Centaur 40 unit and a 7,520 kW Solar Taurus 70. The cost estimates are augmented through obtaining actual cost quotations for various equipment components such as the Solar Mercury turbine, dual gas compressors and a Rentech HRSG with outside air firing capability.

Since the EPA Catalog displays costs for an unfired HRSG producing 150-psig steam, a cost quotation was obtained for an appropriate sized HRSG equipped with a duct burner. This HRSG is designed to produce up to 42,250 pounds per hour of 175-psig steam and, for equipment redundancy purposes, is equipped with a forced draft combustion air fan that allows fresh air firing. This option allows the HRSG to continue to produce steam when the gas turbine goes off-line meaning that the existing boilers do not have to be maintained in a "hot standby" condition. The scope of supply includes a low-NOx duct burner, inlet ducting and exhaust diverter valve, finned tube feedwater economizer, outlet ducting, a main stack with silencer, and controls. It is assumed that the makeup water treatment provided for the existing boilers is suitable for the HRSG.

The EPA CHP cost estimates are based upon a "buildable site" with existing natural gas supply system, tying the steam output into an existing steam header with existing water treatment, deaerator, feedwater pumps, and condensate return system. The fuel system consists of a fuel gas compressor (dual skid-mounted compressors for redundancy purposes), fuel gas filter, regulator, and heater. Emissions control equipment includes dry low-NOx combustion with a CO oxidation catalyst, selective catalytic reduction (SCR) for NOx control, and a continuous emissions monitoring system. The cost quotations include switchgear, interconnection, controls and a transformer. Also included is a building with an expected cost of $100/square foot. The estimate includes project engineering, procurement, and construction management costs, shipping costs, development and permitting fees, commissioning, startup, and site testing; and a contingency fund. Project financing costs are not included as state financing is assumed. As shown in Tables 10 and 11, the total installed cost for the CHP project is estimated at $14,195,664 or $3,086/kW when the ISO rating is taken for the rated gas turbine generating capacity. An examination of the project cost escalation rates from *Chemical Engineering* magazine indicates that costs have not increased between 2013 and the present.

Table 10: Total Installed CHP System Costs by Equipment Component/Activity

Installation Costs	Total Cost
Solar Gas Turbine Installed Cost	$ 4,500,000
Steam Turbine Installed Cost per kW	
Electrical and Interconnection Equipment	$ 1,094,915
Fuel System / Gas Compression	$ 802,787
HRSG (Rentech quote)	$ 1,895,000
- Fresh air firing option	$ 250,000
Pollution Control and Continuous Emissions Monitoring, including SCR and CO Oxidation Catalyst	$ 754,924
Building	$ 395,900
Constructrion / Installation	$ 2,401,852
Engineering / Construction Management	$ 802,700
Shipping	$ 151,009
Development Fees	$ 719,956
Contingency	$ 426,621
Financing	
Total Installed Costs	$14,195,664

1. Cost quote for a Solar Mercury 50 SoLONOx turbine generator set.

Table 11: Budgetary Installed Cost Estimate

	CHP Alternative
Number of Gas Turbines	1
Electric Generating Capacity (ISO Rated)	4,600
CHP Design, Equipment, and Installation Costs	$14,195,664
Incentive Grants (Investment Tax Credit)	$1,277,610
Avoided Equipment Replacement Costs	$0
Incremental Installed Costs	$12,918,054
Total Installed Costs ($/kW)	$3,086

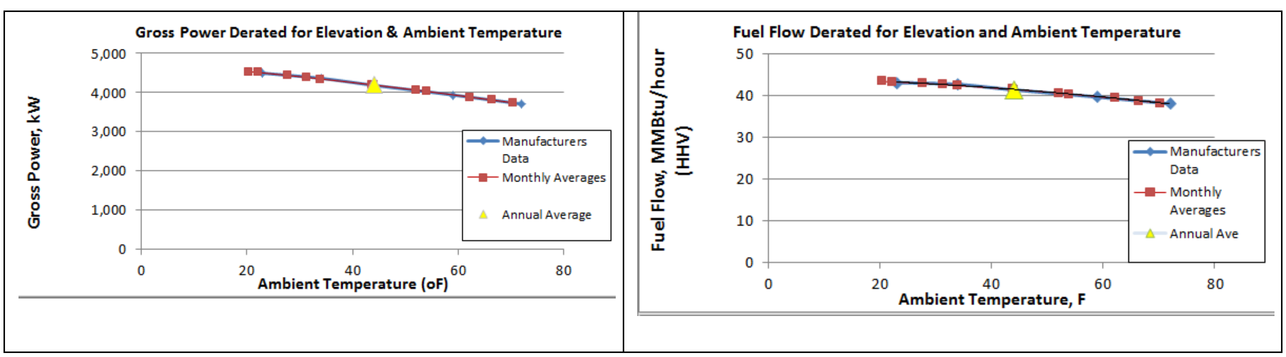
5. Feasibility Analysis

5.1 Technical Analysis Methodology

The Gilmore software tool was used for the initial analysis of the University of Montana CHP project. The user initiates the tool by entering the average facility electrical and thermal energy consumption plus electrical energy and fuel use costs by month. This information is extracted from utility billing data. The software tool then determines the average electrical load (in kW) for each month plus the average fuel use (in MMBtu/hour). Assuming that all natural gas purchases shown on the meter for the central plant are used for steam generation, the fuel use is converted into average pounds of steam generation (pounds/hour) for each month (Note: this assumption will be verified during a future site visit). The tool then requires that the user enter the boiler efficiency, steam production pressure and the pressure in the condensate receiver tank. The receiver tank pressure is used with lookup tables to determine the feedwater temperature and enthalpy (Btu/lb).

Off-design performance information is supplied by equipment manufacturers and entered into an equipment library for subsequent use in the software tool. The off-design turbine performance data is determined in accordance with the site altitude and varies as a function of ambient temperature. Off-design data includes the gas turbine output (kW), the fuel-firing rate, and the exhaust gas mass flow and temperature. Exhaust gas properties are used to determine unfired steam production. The analyst then enters monthly average temperature data for the site and service loads for the gas compressor, HRSG condensate feed pump, and boiler feedwater pump. Curve fit algorithms internal to the software tool are used with equipment library data to determine the expected net gas turbine electrical generating and steam production potential by month.

Figure 8: Gas Turbine Electrical Output and Fuel Flow De-rated by Altitude and Ambient Temperature

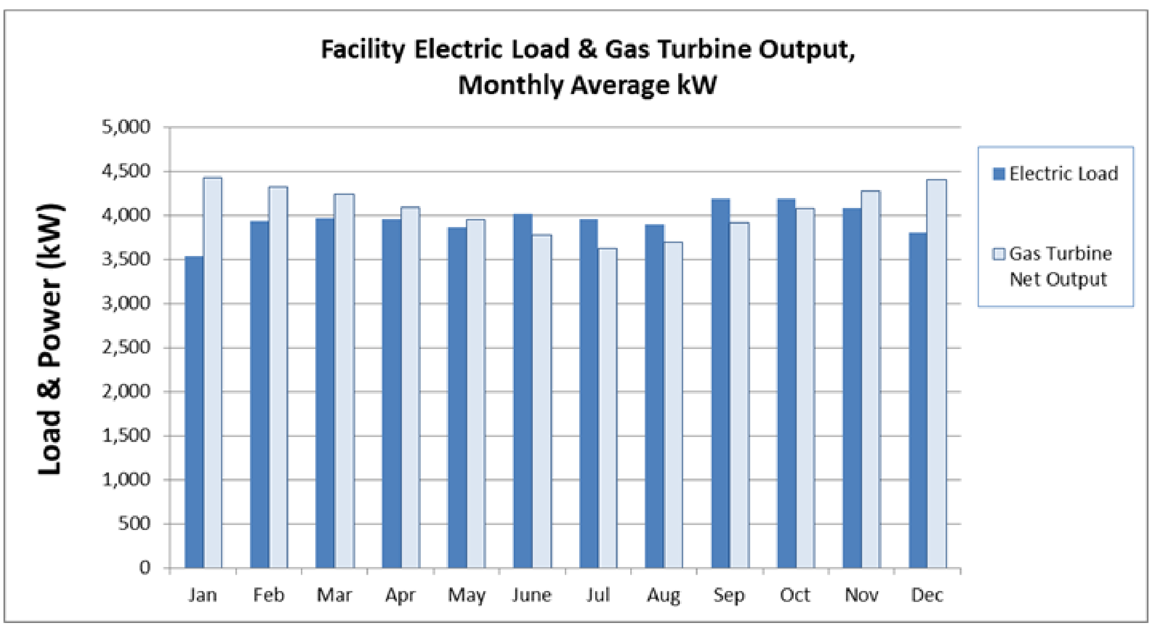


Gas compression costs are dependent upon the supply pressure and the pressure requirement at the gas turbine combustor. Natural gas pressure is regulated to 15-psig at the central boiler house, but is available at an "on the streets" pressure of 70-psig upstream of the pressure regulator. Taking gas at the higher pressure reduces gas compressor costs in addition to the size of the compressor drive motor.

The Solar Mercury gas turbine has a peak gas fuel pressure requirement of about 167-psig. Vilter Manufacturing (a gas compressor supplier) estimates that a 75-hp compressor is required for this application. Two skid mounted compressors are supplied for equipment redundancy purposes. Each compressor would have an input power requirement of about 55 kW, although only one would be in operation at any time. Total auxiliary power and gas compressor load (the service load) is estimated at 114 kW.

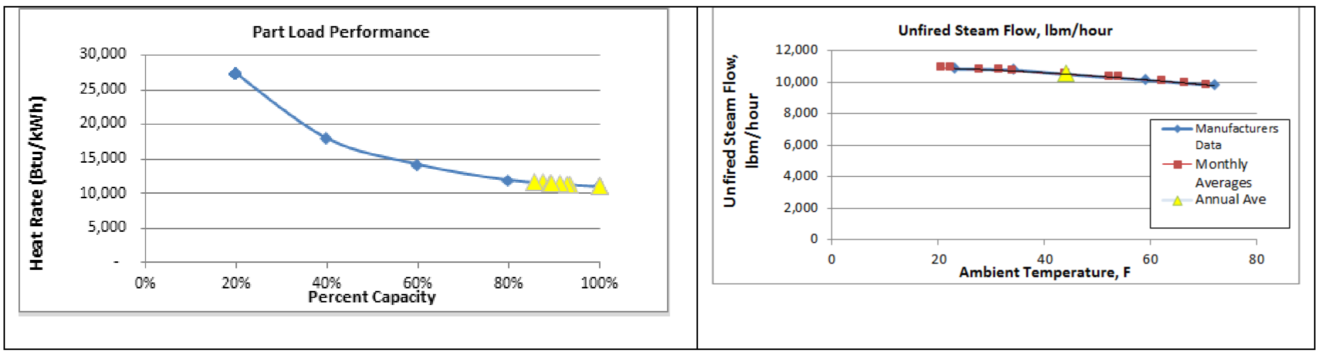
The software tool automatically deducts the service loads from the monthly gas turbine generating potential to determine the net gas turbine output. The facility's electrical load divided by the net gas turbine output is defined as the capacity factor or percentage of full-power output that the gas turbine must provide to satisfy the monthly electrical load requirement. The capacity factor is set at 100% when the loads exceed the gas turbine output or when utility power sales are under consideration. Off-design performance data is used to determine the turbine fuel consumption and exhaust gas mass flow and temperature at the part-load firing rate consistent with the capacity factor. The capacity factor, when multiplied by the monthly gas turbine output, the availability factor; and the hours in a given month yields the monthly generation in kWh. Monthly fuel consumption and unfired steam generation are also calculated based upon availability factor. Electric loads and expected gas turbine output by month are shown in Figure 9.

Figure 9: Matching of Gas Turbine Potential Generating Capacity to University Monthly Electrical Load Requirements



In the hourly load-following analysis with sales to the electrical utility, the University of Montana gas turbine would operate with a capacity factor of 94.1%. Absent sales to the electric utility, the capacity factor would be 88.8%. This is an indication that the Solar Mercury gas turbine is well matched to on-site electrical energy requirements. Matching equipment to load requirements is important as the gas turbine heat rate starts to increase below 90% of the turbine's full-firing rate. This drop in electrical generating efficiency occurs as the compressor of the gas turbine provides a fixed volume of combustion air. A reduced firing rate means that an increase in excess air is available for the amount of fuel provided to the combustor. Combustion efficiency drops when this excess air is heated and goes up the stack. It is not good practice to oversize gas turbines because, at low-firing rates, the gas turbine is less effective at generating electricity with more of the input energy being converted into waste heat. The gas turbine "part-load performance" curve shown in Figure 10 is used in this analysis. The squares or triangles on the part-load performance curve indicates actual operating points for each month when utility sales are assumed. Note that the gas turbine generally operates with a monthly capacity factor exceeding 90%. An availability factor of 94.7% is applied to the gas turbine operating time to decrease electrical generation to account for scheduled maintenance and unforced outages.

Figure 10: Gas Turbine Part-Load Heat Rate and Unfired Steam Production versus Ambient Temperature

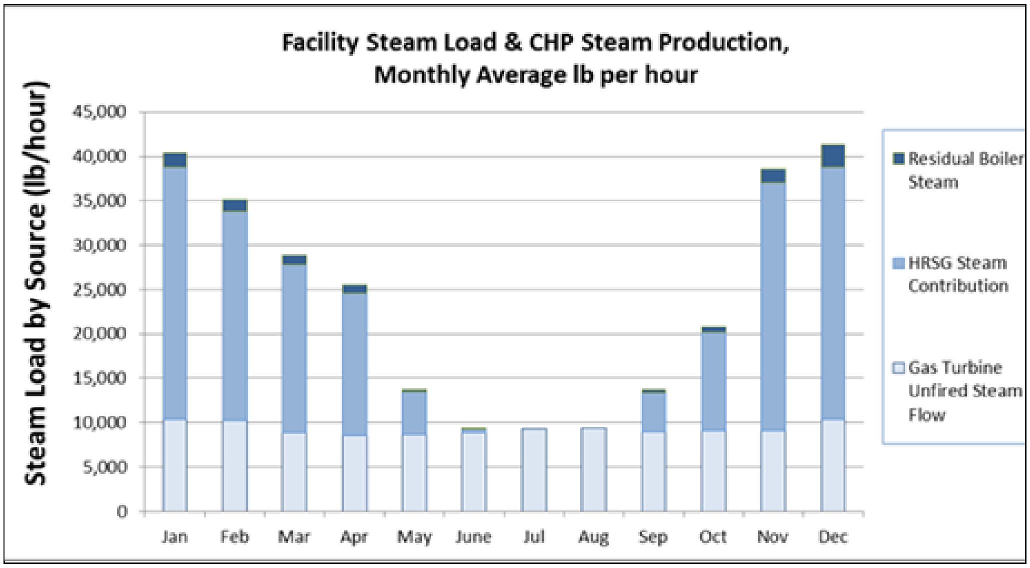


5.2 Meeting On-Site Steam Loads

The Solar Mercury gas turbine was selected for this evaluation in large part due to its low unfired steam production rate of 10,114 lbs/hour (at 59^{o}F). The gas turbine maximum unfired steam flow is shown versus ambient temperature in Figure 11.). When steam requirements exceed the unfired production rate, a duct burner injects natural gas into oxygen-rich gas turbine exhaust which is at a temperature of 650^{o}F to 710^{o}F. The hot exhaust is equivalent to pre-heated combustion air leading to very efficient combustion. The Gilmore tool determines the HRSG fired-steam production and fuel consumption by deducting the unfired steam production due to gas turbine exhaust from the total facility monthly average steam requirements. While the Solar Mercury gas turbine is only rated for operation with natural gas, the backup boilers provide additional steam generation reliability as they can be fueled with either natural gas or No. 2 fuel oil.

The HRSG duct burner allows for steam-load following up to the full-steam output of the HRSG (about 42,500 lbs/hour). Steam loads in excess of the HRSG capacity are met by the existing steam boilers which are used for backup capacity. Steam requirements when the gas turbine is down for maintenance are met by the backup boilers or through using the "fresh air" firing capability of the HRSG. Figure 11 indicates that the gas turbine exhaust provides for about 38.5% of the annual university steam requirements while the HRSG accounts for about 57.4% of steam needs. The backup boilers provide the remainder of the steam. Brian Kerns, Engineer, Facilities Services at the University of Montana, indicates that the existing boiler burners have a turndown ratio of about 8:1. The provision of fresh air firing for the HRSG means that the boilers don't have to be maintained in hot standby and produce un-needed steam during the summer months when steam requirements are minimal.

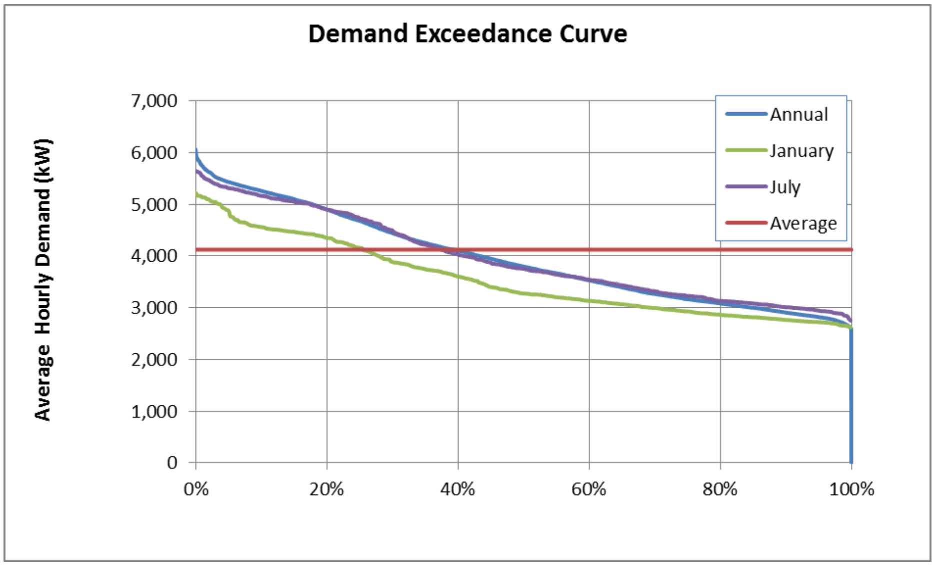
Figure 11: Steam Production by Source: Unfired Gas Turbine, HRSG, and Backup Boilers



5.3 Using Hourly Electrical Energy Use Data to Determine CHP Energy Production

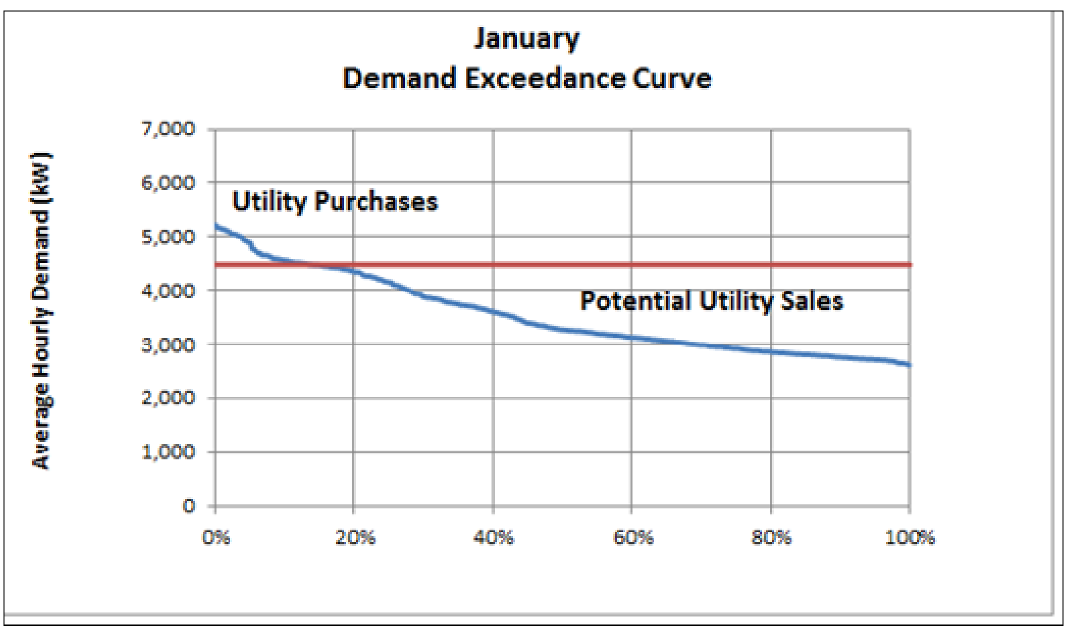
One year's worth of electrical energy use data was obtained from campus operations staff that indicates the average electrical demand over 15-minute intervals. The blue line shown on Figure 12 represents the exceedance curve for hourly electrical demand. An exceedance curve shows the percentage of time in an operating year that a given electrical load is equaled or exceeded. The red line shows the average annual gas turbine electrical output. This curve indicates that the gas turbine can meet the entire campus electrical load about 55% of the time. Electrical energy must be purchased from the local utility when the campus demand exceeds the generating capability of the gas turbine.

Figure 12: Campus Demand Exceedance Curve (blue) and Gas Turbine Output (red)



Exceedance curves were prepared for each month of the CY2015 operating year with the gas turbine output adjusted to reflect the monthly average temperature. The triangular area bounded by the demand exceedance curve and the gas turbine output is proportional to the load that is not served by the CHP project. An exceedance and turbine output curve for January is shown in Figure 13. When the gas turbine's potential output exceeds the campus requirements, the turbine will operate at part-load unless the analysis considers sales of surplus electrical energy to the local utility. Our analysis approach considers both the electrical generating part-load efficiency of the gas turbine, the fuel-firing rate at part-load efficiency, and part-load efficiency of the HRSG.

Figure 13: Electrical Load Exceedance Curve for January



The CHP project net generation output by month, utility purchase requirements by month, and electrical energy available for export or sale to the utility is shown in Table 12. These results were extracted from an hourly analysis where the analyst used a separate spreadsheet to determine the monthly and annual electrical energy loads above the capacity of the gas turbine as well as the overall potential for utility sales. Table 12 indicates that utility purchase requirements amount to about 2.8 million kWh/year, with potential sales to the electrical utility of 3.67 million kWh.

The hourly analysis is used in conjunction with the GilMore software tool through adjusting monthly capacity factors. When a "**monthly**" analysis is to be done, the software tool calculates the capacity factor that the gas turbine must operate at to meet on-site loads, then adjusts generation to account for the availability factor. With a more detailed "**hourly**" analysis, the capacity factors determined by the hourly spreadsheet are directly entered into the GilMore tool. The analysis tool is thus "forced" to conduct a monthly analysis while operating the gas turbine in accordance with the operation that would actually be required when meeting hourly loads—with utility energy purchases accounted for.

Table 12: Annual CHP Project Energy Generation, Utility Energy Purchase Requirements, and Potential Utility Sales (Hourly Analysis, Electrical Load Following, No Utility Sales)[1]

	Net Generator Output, kW	Plant Energy Use, kWh	Energy Use Above Generator Output, kWh	Energy Generated, kWh	Available for Export, kWh	Percent Not Met	Plant Capacity Factor from Hourly Data
Annual	4,067	34,593,944	2,843,180	30,067,974	3,671,480	8.2%	88.8%
January	4,425	2,632,931	96,309	2,402,180	715,446	3.7%	78.9%
February	4,325	2,639,536	199,159	2,311,037	441,582	7.5%	86.1%
March	4,237	2,956,254	247,931	2,564,783	420,360	8.4%	87.5%
April	4,087	2,851,472	250,897	2,462,745	323,836	8.8%	85.7%
May	3,952	2,873,179	217,463	2,514,963	269,209	7.6%	89.2%
June	3,777	2,894,002	248,492	2,505,298	70,169	8.6%	93.7%
July	3,626	2,944,950	230,586	2,570,502	-15,946	7.8%	94.9%
August	3,699	2,896,608	223,785	2,531,164	75,348	7.7%	92.9%
September	3,920	3,013,397	338,421	2,533,202	139,404	11.2%	92.7%
October	4,082	3,114,498	341,908	2,625,642	250,291	11.0%	91.5%
November	4,274	2,943,228	252,166	2,548,436	365,640	8.6%	89.4%
December	4,402	2,833,890	196,063	2,498,023	603,318	6.9%	82.7%

1. Note: the energy generation of 30,067,974 kWh shown in Table 12 is slightly different than the result of 29,852,647 kWh per year shown in Table 13 due to round-off errors.

The use of monthly capacity factors determined through an hourly load analysis yields a decrease in the projected CHP project annual electrical energy generation. As shown in Table 13, the original GilMore monthly analysis predicted an annual electrical energy generation of about 31.96 million kWh when the plant is operated in an electrical load-following mode with no utility sales taken into consideration. When capacity factors are adjusted to account for actual versus average hourly loads, the expected electrical generation is reduced to 29.85 million kWh/year—a reduction in electrical output of 6.6%. The reduction in electrical generation is about 4.5% for the monthly and hourly scenarios that include utility sales during the five Heavy-Load hour months. This reduction is due to consideration of electrical loads that are above the capacity of the gas turbine to provide. These loads must be met through utility purchases.

With the hourly analysis including utility sales, about 30.45 million kWh of the 31.74 million kWh generated is used on-site to offset utility purchases while 1.29 million kWh are sold to the utility. The CHP analysis based upon monthly CHP generating capacity---with capacity factors determined based upon serving hourly load requirements---yields more accurate energy generation results than an analysis based upon meeting monthly average hourly energy usage values. The hourly analysis with utility sales is taken as the recommended CHP analysis methodology and operating strategy.

Table 13: Monthly Operation When Hourly Loads are Considered

Scenario	Monthly Analysis		Hourly Analysis	
	No Sales	With Sales	No Sales	With Sales
Total Installed Cost	$ 14,195,664	$ 14,195,664	$ 14,195,664	$ 14,195,664
Avoided Costs	$ -	$ -	$ -	$ -
Grants	$ 1,277,610	$ 1,277,610	$ 1,277,610	$ 1,277,610
Annual O&M Costs	$ 319,698	$ 332,647	$ 298,526	$ 317,449
Energy Cost Savings	$ 1,610,063	$ 1,602,245	$ 1,495,965	$ 1,519,283
Total Operating Savings	$ 1,290,364	$ 1,365,289	$ 1,197,439	$ 1,297,525
Generation, kWh/yr	31,969,848	33,264,715	29,852,647	31,744,859
Heat Recovered by CHP, MMBtu/yr	80,626	83,764	75,262	79,923
Average Capacity Factor	95.1%	98.7%	88.8%	94.1%
Payback Before Incentives (years)	11.00	10.40	11.86	10.94
Payback with Incentives (years)	10.01	9.46	10.79	9.96

1. Note: the energy generation of 29,852,647 kWh shown in Column 4 of Table 13 is slightly different than the result of 30,067,974 kWh per year shown in Table 13 due to round-off errors.

5.4 Economic Analysis for New 4.6 MW (ISO) Gas Turbine with HRSG (Hourly Analysis with Utility Sales)

Simple payback in years is calculated by dividing the total CHP project total installed costs by the annual benefits. Benefits are the dollar value of the electrical energy produced and used on site plus the value of sales to the electrical utility less fuel plus operating and maintenance costs. Annual energy use and costs for both the baseline and CHP alternatives are shown in Table 14.

Table 14: Energy Use and Costs for CHP System (Hourly Analysis with Utility Sales)

ENERGY COSTS - BASELINE		Annual
Baseline Electricity Energy Cost	$	2,630,662
Baseline Electricity Demand Cost	$	640,802
Baseline Fuel Cost	$	1,135,454
Total Baseline Energy Costs	$	4,406,918
ENERGY COSTS - ALTERNATIVE		**Annual**
Alternative Electricity Energy Cost	$	299,063
Alternative Electricity Demand Cost (Demand Charges Not Offset)	$	314,449
Alternative Fuel Cost	$	2,259,944
Total Alternative Energy Costs	$	2,873,456
COSTS SAVINGS		**Annual**
Electricity Energy and Demand Cost Savings	$	2,657,951
Fuel Costs Increase	$	1,124,490
Total Annual O&M Costs	$	317,449
Total Operating Savings	$	1,311,704

Table 14 indicates that the total annual energy savings of $1.533 million with the CHP project in place is equivalent to the baseline energy cost of $4.4 million less the post-CHP installation energy costs of $2.87 million. Electrical energy sales to the utility are projected to have a value of $95,691 with annual O&M costs predicted to be $317,499 yielding an overall reduction in operating costs of $1.31 million. With no financial incentives included, the simple payback on investment in the natural gas-fired CHP project is:

Simple Payback = $14,195,664 million/ ($4,406,918 - $2,873,456 + $95,691 - $317,449) = 10.8 years

A 10% federal investment tax credit can be applied to the total CHP equipment and installation costs (10% x $ 14,195,664 = $1,419,566). Mechanisms are available to pass this credit through to a private company with tax liability that can make use of the credit. It is assumed that a partner is found ,can utilize the tax credit, and be willing to pass 90% of the value of the credit back to the University for the rights to use the full credit. The availability of federal tax incentive of 0.9 x $1,419,566 = $1,277,600 reduces the simple payback to:

Simple Payback with Incentives = ($14.195 - $1.277) million/ ($1,311,704) = 9.8 years

6. Life Cycle Cost Analysis

6.1 Inputs and Results

Life-cycle cost analysis is a method for assessing the total cost of facility ownership taking into account all costs of acquiring, owning, and disposing of the project. Life-cycle cost analysis results in several indicators of a project's worth that may be of interest to utilities, governments, investment bankers and developers. The most common are the net present value, the internal rate of return, the benefit-cost ratio, and the discounted and simple payback period.

The proposed CHP project at University of Montana in Missoula, Montana has been determined to have technical and financial viability. The CHP projects analyzed consists of one 4.6 MW natural gas turbine with electricity sales during the months of December to February and July and August. Results of the life cycle cost analysis using RELCOST Financial are shown in Table 15 and the financial and technical assumptions used in the analysis are summarized in **Table 16.** The simple payback of this project with incentives is 9.9 years and the project internal rate of return (IRR) is 9.4%%. Financial viability is indicated because the IRR is greater than the 5% discount rate assumed in the analysis.

Table 15: Life Cycle Cost Analysis Results (RELCOST)

One 4.6 MW Gas Turbine	
Project IRR	9.4%
Discounted Payback (years)	11.1
Simple Payback (years)	9.9

Table 16: General Financial Assumptions in RELCOST Model

Project	
Project Life	15 years
Discount Rate	5%
Escalation	
General Inflation	2.5%
Electricity, Relative to General Inflation	0.0%
Natural Gas, Relative to General Inflation	0.0%

6.2 Life Cycle Cost Calculator Description

The RELCOST Financial model was developed by Washington State University Energy Program for evaluating the financial viability of energy projects. It can be used to evaluate a variety of factors key to project success, such as the minimum power sales price, the optimum mix of equity and capital to attract investors, or sensitivity to incentives. Methods of evaluating financial performance provided by RELCOST are: life cycle cost analysis, pro forma statements, sensitivity analysis, and financial ratios.

Pro forma financial statements provided are the Income Statement, Cash Flow Statement, Balance Sheet, and Sources/Uses of Funds Statement for each project year in the 30-year analysis period. Flexible user inputs include capital costs for construction, funding (equity, grants, and loans), operating costs (purchased fuels, labor, materials/expendables, etc.), taxes and fees (depreciation, tax credits, franchise costs, tax rates, etc.), cost escalation factors, income from energy, power and co-product sales, and income from sales of carbon offsets, renewable energy credits and renewable energy production incentives.

RELCOST includes a spider diagram utility, which allows visually assessing project sensitivity to variations in key inputs, such as changes in fuel prices or cost overruns. The ability to rapidly conduct "What If" evaluations enables the user to determine those factors that represent the greatest amount of risk to the project, obtain guidance on key points of negotiation, identify break-even values, and examine alternative scenarios. Up to nine scenarios may be defined for each project. The ability to easily switch between scenarios facilitates selecting alternatives, such as system design options or funding choices.

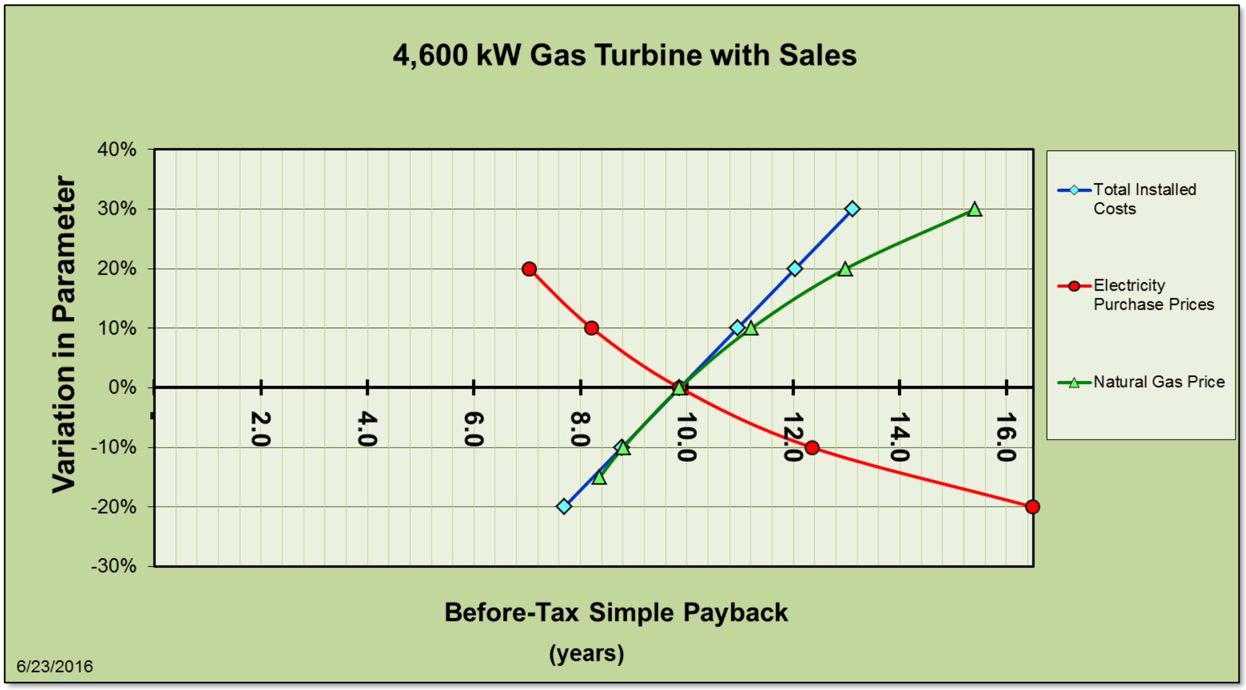
6.3 Sensitivity Analysis

Because no project goes exactly according to plan, a sensitivity analysis is performed to identify those factors that are most likely to impact project viability. By identifying the relative importance of risky variables, the decision-maker can adjust projects to reduce the risks and consider responses.

Sensitivity of this project to variations in three factors is shown in the “spider diagram” in the Figure 14 below. In this diagram, the most likely outcome – the outcome if all the inputs and assumptions as summarized in Tables 16 – is located at the intersection of all the lines at 0% variation in parameters. Each line is created by varying a parameter one by one, while holding others constant. The corresponding change in the internal rate of return is plotted on the spider diagram for each change in input. The flatter a line on the spider diagram, the more sensitive project performance is to changes in that parameter.

The sensitivity analysis indicates project viability is most sensitive to capital expenses and electricity price and less sensitive to natural gas price. Because of the sensitivity of project viability to these parameters, they should be considered carefully in further investigation. Increases in capital cost negatively impacts the viability of the project, and decreases in fuel and electricity purchase costs positively impacts viability. Figure 1, shows that if capital expenses increase by 30%, simple payback increases to 10.3 years. If natural gas price is reduced by 20%, simple payback decreases to less than 8 years. If electricity purchase price increases by 20%, simple payback decreases to 7 years. A 10% increase in total project installed costs would increase the simple payback to about 11 years.

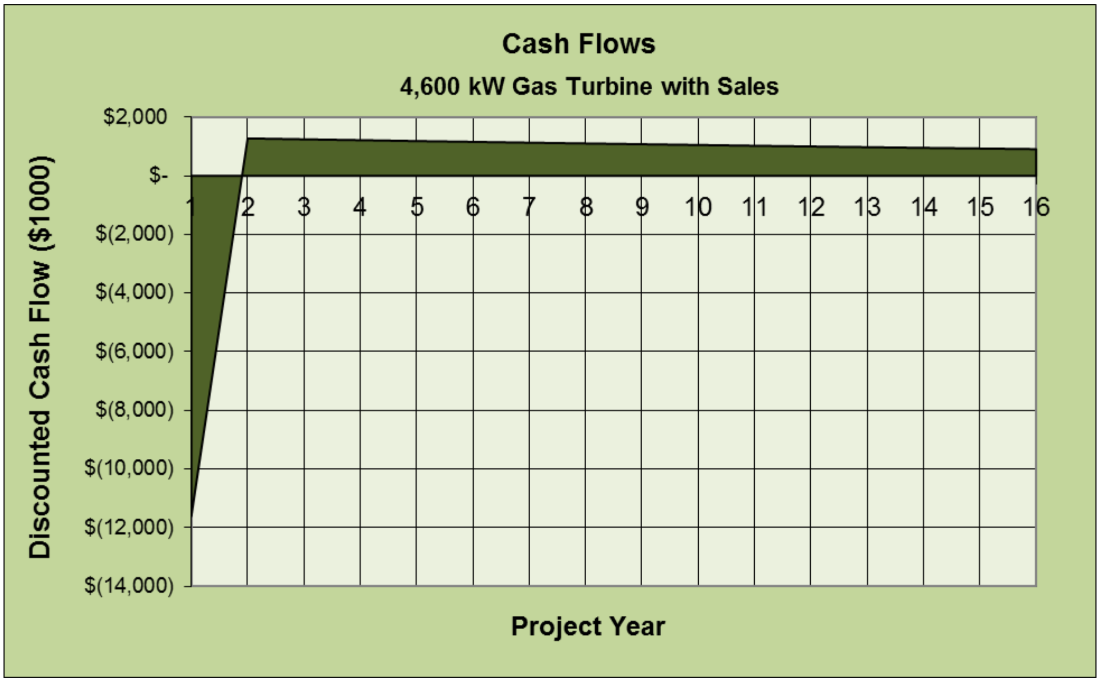
Figure 14: Spider Diagram Showing Sensitivity of Project Viability to Variation in Selected Parameters (RELCOST Financial)



6.4 Financial Statements and Figures

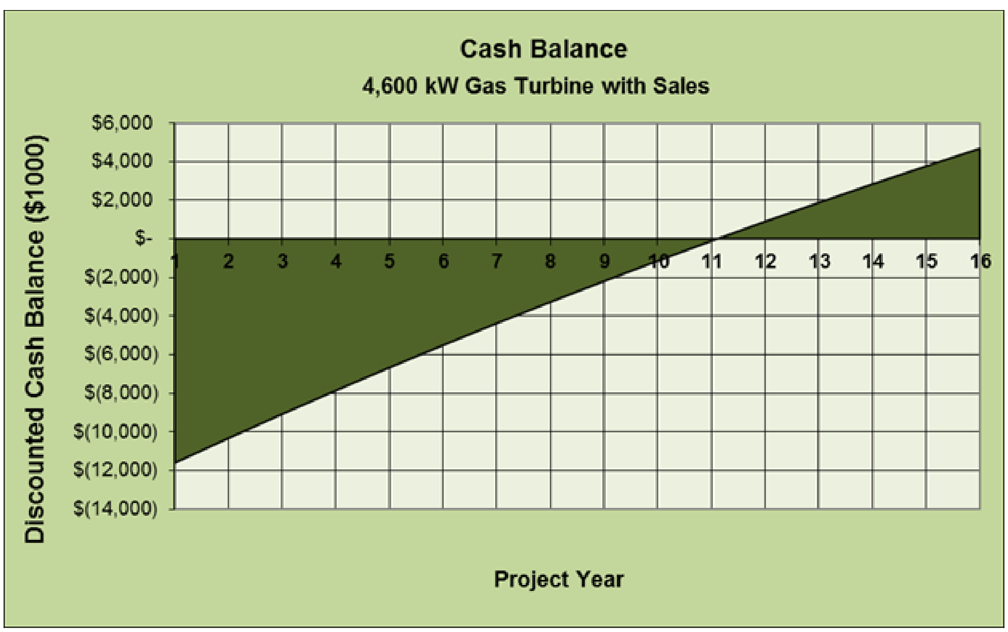
Estimated annual cash flows for this project are shown in Figure 15. A cash flow statement and income statement for the first five years of the project are attached. The income statement, also called a profit and loss statement, reports flows of revenues and expenses incurred to produce and finance operations. The cash flow statement demonstrates a company's ability to meet its obligations and finance operations. Lenders often place high priority on the cash flow statement. Positive cash flow is desirable, but even healthy businesses can have a negative net cash flow in, for example, a year of high capital expenditures. A repeated negative net cash flow over a number of years is usually an indication of trouble.

Figure 15. Discounted Cash Flows (RELCOST Financial)



Cash balances for each year of the project are shown in Figure 16. The cash balance becomes positive in the discounted payback year.

Figure 16: Discounted Cash Balances (RELCOST Financial)



7. Emissions Analysis

7.1 Air Emissions Analysis

An analysis of air emissions reductions was performed for a proposed CHP project at the University of Montana in Missoula, Montana, using the EPA's *CHP Emissions Calculator* *https://www.epa.gov/chp/chp-emissions-calculator* with inputs based on Washington State University Energy Program's feasibility study for this project. Air emissions considered include greenhouse gas emissions, which contribute to climate change, and gases referred to as criteria pollutants, as regulated under the Clean Air Act.

The emissions of a CHP system with one 4.6 MW natural gas turbine to meet the site's electricity and thermal needs were analyzed. The scenario analyzed includes electricity sales in the utility's high demand months of December to January, and July and August. Results are shown in Table 17 with both baseline (conventional system) and CHP project emissions shown in Figure 17. Assumptions used in the emissions analysis are summarized in Tables 18, 19, and 20. The EPA analysis includes the direct emissions associated with fuel combustion at the site and at the utility power plant. It also includes emissions associated with electricity transmission and distribution (T&D) losses to the site. It does not include pre-combustion emissions associated with extraction, processing, and delivery of fuel either to the site or to the electric utility.

7.2 Greenhouse Gas Emissions

Greenhouse gas emissions contribute to climate change by trapping heat in the atmosphere. The four most important greenhouse gases are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases. The first three of these are considered in this analysis. The total global warming potential of these three gases is quantified in terms of "carbon dioxide equivalent" (CO_2e). The carbon dioxide equivalent of a gas equals the quantity of carbon dioxide that would have the same global warming potential as the other gas. For example, the global warming potential of methane is 25 pounds CO_2e per pound of methane.

The greenhouse gas emissions reduction of the CHP system is 19,691 metric tonnes, which is a 43% reduction in the baseline emissions. This is equivalent to removing 3,746 passenger cars from the road, as shown in Table 17.

7.3 Criteria Pollutants

The Clean Air Act requires the U.S. Environmental Protection Agency to set standards for six common air pollutants, referred to as "criteria pollutants". They are particle pollution, ground-level ozone, carbon monoxide, sulfur oxides (SOx), nitrogen oxides (NOx), and lead. This analysis quantifies NOx and SOx, which are generally of greatest concern in CHP projects. Emissions of NOx are predicted to decrease by 39.2 tonnes/year (86%). SOx emissions are virtually eliminated (reduced by nearly 100%), equivalent to by 32.9 metric tonnes annually due to the proposed CHP project, as shown in Table 17.

Table 17: Carbon Dioxide Equivalent Greenhouse Gas and Priority Pollutant Emissions Reductions

Annual Emissions Analysis	CHP System	Displaced Electricity Production	Displaced Thermal Production	Emissions/Fuel Reduction	Percent Reduction
NO_x (tons/year)	6.58	33.35	12.43	39.20	86%
SO_2 (tons/year)	0.13	32.97	0.07	32.92	100%
CO_2 (tons/year)	26,293	31,302	14,534	19,543	43%
CH_4 (tons/year)	0.50	0.576	0.27	0.354	42%
N_2O (tons/year)	0.05	0.474	0.03	0.452	90%
Total GHGs (CO_2e tons/year)	26,318	31,461	14,548	19,691	43%
Fuel Consumption (MMBtu/year)	449,829	335,658	248,654	134,483	23%
Equal to the annual GHG emissions from this many passenger vehicles:				3,746	
Equal to the annual GHG emissions from the generation of electricity for this many homes:				1,870	

This CHP project will avoid yearly emissions of greenhouse gases by 19,691 tons of carbon dioxide equivalent.

Table 18: Baseline and CHP Project Fuel Use and Displaced Electricity Generation Profile

CHP Technology:	Combustion Turbine	
Fuel:	Natural Gas	
Unit Capacity:	3,826	kW
Number of Units:	1	
Total CHP Capacity:	3,826	kW
Operation:	8,296	hours per year
Heat Rate:	10,423	Btu/kWh HHV
CHP Fuel Consumption:	330,831	MMBtu/year
Duct Burner Fuel Consumption:	118,998	MMBtu/year
Total Fuel Consumption:	**449,829**	**MMBtu/year**
Total CHP Generation:	**31,740**	**MWh/year**
Useful CHP Thermal Output:	198,923	MMBtu/year for thermal applications (non-cooling)
	-	MMBtu/year for electric applications (cooling and electric heating)
	198,923	**MMBtu/year Total**

Displaced On-Site Production for		Existing Gas Boiler
Thermal (non-cooling) Applications:	0.10	lb/MMBtu NOx
	0.00%	sulfur content
Displaced Electric Service (cooling and electric heating):		
	There is no displaced cooling service	

Displaced Electricity Profile:	eGRID Fossil Fuel (2012 data)	
Egrid State:	NPP Northwest	
Distribution Losses:	6%	
Displaced Electricity Production:	31,740	MWh/year CHP generation
	-	MWh/year Displaced Electric Demand (cooling)
	-	MWh/year Displaced Electric Demand (electric heating)
	1,940	MWh/year Transmission Losses
	33,680	**MWh/year Total**

Table 19: Annual Emissions Analysis for CHP Project and for Displaced Electrical Energy Production Summary

Annual Analysis for CHP				
	CHP System: Combustion	CHP System: Duct Burners		Total Emissions from CHP System
NO_x (tons/year)	1.82	4.76		6.58
SO_2 (tons/year)	0.10	0.03		0.13
CO_2 (tons/year)	19,337	6,955		26,293
CH_4 (tons/year)	0	0		0
N_2O (tons/year)	0	0		0
Total GHGs (CO_2e tons/year)	19,356	6,962		26,318
Fuel Consumption (MMBtu/year)	330,831	118,998		449,829

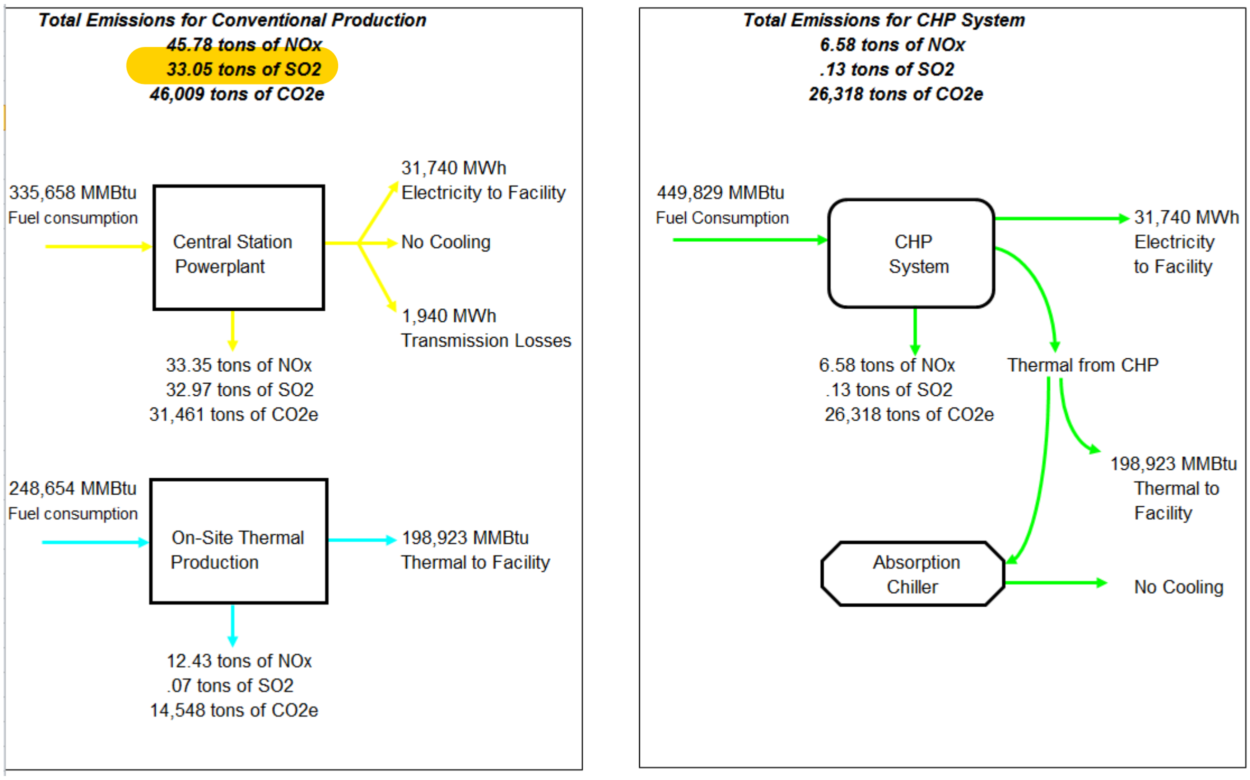
Annual Analysis for Displaced Electricity Production					
	Displaced CHP Electricity Generation	Displaced Electricity for Cooling	Displaced Electricity for Heating	Transmission Losses	Total Displaced Emissions from Electricity Generation
NO_x (tons/year)	31.43	-	-	1.92	33.35
SO_2 (tons/year)	31.08	-	-	1.90	32.97
CO_2 (tons/year)	29,499	-	-	1,802.98	31,302
CH_4 (tons/year)	0.542	-	-	0.033	0.576
N_2O (tons/year)	0.447	-	-	0.027	0.474
Total GHGs (CO_2e tons/year)	29,649	-	-	1,812	31,461
Fuel Consumption (MMBtu/year)	316,324	-	-	19,334	335,658

Table 20:Emission Rates for CHP System and for Displaced Thermal Production

Emission Rates			
	CHP System including Duct Burners	Combustion Turbine Alone	Displaced Electricity
NOx (lb/MWh)	0.41	0.11	1.98
SO2 (lb/MWh)	0.01	0.01	1.96
CO2 (lb/MWh)	1,657	1,218	1,859

Emission Rates	
	Displaced Thermal Production
NOx (lb/MMBtu)	0.10
SO2 (lb/MMBtu)	0.00059
CO2 (lb/MMBtu)	116.90

Figure 17: Total Emissions for Baseline and CHP System (From EPA Emissions Calculator)



8. Summary and Conclusions

The feasibility analysis results suggest that a gas turbine CHP project is cost effective for the University of Montana. When operating in an electrical load-following mode with limited utility sales, the recommended gas turbine would produce about 31.74 million kWh of electrical energy annually. Natural gas consumption at the central plant would increase from about 239,300 MMBtu/year to 475,778 MMBtu per year. An annual operating savings of $1.297 million would provide a simple payback of 10.9 years on the $14.19 million dollar project. The simple payback is reduced to 9.9 years when existing financial incentives are taken into consideration. The internal rate-of-return on investment (ROI) for the proposed project is 9.4%.

The CHP project also reduces greenhouse gas emissions from utility purchases and direct combustion by 43%---from 45,936 metric tonnes per year to 26,293 metric tonnes annually. Regional NOx and SOx emissions are reduced by 39.2 tonnes per year (86%) and 32.9 tonnes annually (an almost 100% reduction).

A site visit indicated that ample space exists around the central heating plant to install a CHP project. In particular, the natural gas pressure regulator, electrical transformer, existing stack, and high pressure steam pipelines are in close proximity at one corner of the heating plant. A consultant has already been hired to identify both electrical interconnection requirements and costs as well as make recommendations regarding interconnection of the HRSG steam production with the existing high pressure steam piping.

As a next step, it is recommended that the site contract with an engineering firm to move the project forward. Negotiations with the local electric utility and pre-design studies should be pursued to verify the technical and economic viability of CHP at the University. Further investigation of CHP viability could include conducting an investment grade feasibility study, which would further explore the University's energy usage and needs, including overall facility planning and/or goals. Detailed actions (some of which are ongoing) and site information needed for such a study includes:

- *Initiation of discussions with NorthWestern Energy to discuss interconnection requirements and resolve load balancing issues,*
- *Determining whether "islanding" or providing the ability to operate the CHP project during utility outages should be incorporated into the project design,*
- *Investigation of utility policies used to impose electrical demand charges and verification of demand offset benefits,*
- *Negotiating power purchase agreement provisions for utility sales during Heavy Load hour months and/or all months when excess generation is available,*
- *Continuing to monitor firm and interruptible natural gas pricing and availability,*
- *Holding discussions with air quality regulatory agencies to resolve pollution control system requirements,*

- *Identifying a pollution control system that can meet air quality requirements during normal operation and when gas turbine exhaust bypasses the HRSG during low steam demand summer months,*
- *Conducting a steam system assessment to verify boiler combustion and overall efficiency, condensate return (%) and return temperature; boiler blowdown rate, makeup water flows, and deaerator steam requirements. The steam system assessment should also result in a list of cost-effective steam system energy efficiency improvement measures. Implementation of these measures may require re-evaluating necessary HRSG steam production capability,*
- *Determining whether cost benefits should be assigned to the CHP project due to offsetting the need to replace one of the older steam boilers in the near future,*
- *Investigating potential University energy efficiency actions that could result in reductions in annual electrical energy usage (such as widespread change outs to LED lighting technologies in interior and exterior applications),*
- *Determination of the desirability of being able to operate a gas turbine on No. 2 oil as well as natural gas,*
- *Investigation of potential monetary or generating resource diversification benefits due to* CO_2 *and other priority pollutant emission reductions,*
- *Initiating discussions with the legislature regarding CHP project funding,*

Special consideration may also be given to power reliability concerns, fine-tuning of generating equipment and HRSG selection and estimated total installed costs, and consideration of additional equipment redundancy factors that may impact CHP system equipment selection or sizing.