OAKWOOD HEALTH CARE CENTER
ENERGY PROJECT
COMBINED HEAT AND POWER
Final Report

Prepared for

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ABSTRACT

Elderwood and Gerster Energy Services partnered to create a turnkey, grid-isolated combined heat and power (CHP) system with comfort improving HVAC modifications at Oakwood Health Care Center. The CHP objectives were to; save thermal energy, improve reliability, and to optimize system design with load factor management.

Gerster Energy Services utilizes Trane's Tracer Summit building control system to monitor and verify the performance of these objectives. The final report year was from January - December 2002. The project recovered 3,856 MMBTU of heat. The project proved the potential to avoid over 300 kW of demand and nearly 1,678,787 kWh of electric consumption.

This report supports the claim that all objectives were successfully met.

ACKNOWLEDGEMENTS

We would like to thank Scott Smith and Todd Baldyga from New York State Energy Research and Development Authority (NYSERDA) for all of their assistance during the course of this project.

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SUMMARY

In 2000 Elderwood Affiliates and Gerster Energy Services partnered to develop a unique Combined Heat and Power (CHP) demonstration project in Western New York at Oakwood Health Care Center, a long term care facility located in Amherst, a nearby suburb of Buffalo. The project partnership expanded when we added the knowledge and resources from two additional partners, NYSERDA and National Fuel Gas. Gerster Energy Services conducted the original feasibility study in the Fall of 2000, designed the systems, served as general contractor in the summer of 2001 and today maintains and monitors the total CHP system. Together the project partners developed a successful grid-isolated project that is performing as per the original plan. The competitive NYSERDA CHP application was funded based on the following objectives; energy savings, load factor management, and reliability.

Gerster Energy Services tested Oakwood's new CHP system in the fall of 2001 and on December 19, 2001, Niagara Mohawk was requested to permanently remove their wires. The new grid-isolated CHP system received its first test from nature when over the next several days the area received its greatest snowfall when over 7 feet of lake effect snow piled up in Amherst. The CHP system was tested again only 5 weeks later when a major ice storm knocked out power to the region on January 31, 2002 and the region was without power for 2-4 days. Oakwood was on-line throughout the winter ice storm and soon became crowded with resident's relatives and residents from other nursing homes who needed shelter. The Buffalo News reported the story of how the nursing home was operating "business as usual" without utility power. Once again in August 2003 during the Great Northeast Blackout Oakwood proved to be reliable as the residents were not effected by the blackout. During the first two years of operation, Oakwood's CHP system has been significantly more reliable than the utility grid.

The Oakwood CHP system consists of two natural gas fired 6-cylinder 300kw Waukesha engines each capable of operating the facility. Each gas engine can operate independently or in parallel. A third diesel engine operates as required for back-up and maintenance utilizing a closed transition transfer switch. The overall project scope of work included the addition of air conditioning to the hallways. Rather than installing much larger generators, GES value engineered an ice storage system to take advantage of the reduced nighttime electric load by operating the ice making chiller at night to freeze 6 Calmac ice tanks. The system was designed to maximize heat recovery from the engines by utilizing thermal energy from the jacket water throughout the year. The heat available from the jacket water is boosted in the winter through the use of stack exhaust recovery system. The thermal heat sinks are the domestic hot water system and space heating boiler. The entire CHP system is controlled by a Trane Summit building management system. The performance metrics are available via the GES website in near real time data.

With the actual project cost at $987,967 with no incentives and the actual savings of $55,272 the simple payback would have been 17.87 years. Including the NYSERDA incentive of $425,000 and

$155,000 from National Fuel Gas the total project cost was $407,967, which gives a simple payback of 7.38 years. The most significant factor affecting the payback/annual savings was the inflated natural gas prices experienced throughout the country. When the CHP system performance savings are adjusted for the originally anticipated gas prices, the energy savings are within 10% from projection. GES expects the energy savings to increase as we learn the intricacies of the site, fine tune the controls, and train site personnel. Continued operating experience will allow the building staff to maximize the energy savings. The energy savings should increase as a result of Niagara Mohawk's plan to phase in ratepayers exposure to the market price of electricity, hence passing the fluctuations in fuel cost on a monthly basis.

BACKGROUND

The Oakwood facility was constructed in 1983. The 110 resident room facility provides nursing care to 200 residents. The building is 3 stories with a full basement. The steel frame building utilizes an insulated foam board with a stucco exterior application. The walls are steel studs with a steel metal roof deck. The windows are operable sliders.

The building is heated with two hot water boilers and three rooftop make-up air heaters. Non-chiller air conditioning is limited to the administrative areas. A chilled water cooling system was added in 1986 for the glass atrium, resident and staff dining and the kitchen. The resident rooms are not air-conditioned.

The basement contains mechanical rooms, laundry, and space for resident services and activities. The first floor contains Unit 1, kitchen, resident and staff dining areas, and administration. The second floor contains Unit's 2 and 3 and the third floor Unit's 4 and 5. Each Unit contains 22 resident rooms. Of the 22 rooms, 4 are private rooms and 18 are double rooms.

Gerster Trane Energy Services' objective was to create a turnkey - grid isolated cogeneration system with HVAC modifications. An improvement in the annual thermal heat utilization, and a system that allows Oakwood to maximize their energy savings and reliability was sought after. The end goal achieving improved comfort and energy utilization at Oakwood.

As briefly explained in the summary, the following is a complete description of the cogeneration project deliverables provided by Gerster Trane Energy Services:

1. Engineering, project management, commissioning and documentation
2. Equipment selection, procurement:
   - (2) 300 kW natural gas engine
   - (1) 300 kW diesel engine
   - cogeneration engine exhaust heat recovery device
   - additional heat rejection fluid cooler
   - additional pumping capacity for cogeneration loop
   - heat recovery heat exchangers and accessories for boiler and DHW
   - controls
   - outdoor generator enclosure
3. Engine exhaust heat recovery device piping and heat recovery installation, modifications to engine enclosure.
4. Controls programming and monitoring

The following is a complete description of the chiller and rooftop HVAC renovation and ice storage system project deliverables provided by Gerster Trane Energy Services:

1. Engineering, project management, commissioning and documentation
2. Equipment selection, procurement:

- (1) 170 ton chiller
- (2) rooftop make-up air units
- (2) 30 hp chilled water pumps
- (2) exhaust fans
- (6) Ice storage tanks

3. Site work excavation and concrete
4. Controls programming and monitoring
5. Check/Test/Start-Up

See the diagram in Appendix A for a layout of the project.

PROJECT OBJECTIVES AND RESULTS

As stated in the abstract and summary, and in the spirit of the original application, the project objectives were as follows:

- Load Factor Management
- Energy Savings
- Reliability

1. Load Factor Management

The innovative load factor management strategy incorporates an ice storage system and electric heating capacity to the cogeneration system. Since the ice storage system was integrated, Gerster Energy Services (GES) could minimize the cost of the generation system and chiller. A smaller chiller and a smaller generator could be selected to meet the facilities load year round (see Project Economics, Cooling System Comparison Cost sub section for a discussion of cost minimizing).

The chilled water system was converted to an ice storage system. The air conditioning system was increased to cool the hallways in an effort to improve comfort levels and meet codes. A new 170 ton high efficiency ice manufacturing chiller and two new rooftop make-up air units were installed. Each rooftop includes a gas-fired heating coil and chilled water coil. Both also have electric heating coils to maximize heating season utilization of the cogeneration system, and load factor management. The original design intent was to use the electric coils to add kW load to the generator. This use improves the generator efficiency by adding load when the generator is operating at a low kW. The generators part load efficiency has been better than expected; therefore the electric coils have not been operated to improve efficiency.

A six-tank, 1,140 ton-hrs, thermal ice storage system was installed adjacent to the existing chiller. The tanks are frozen (both compressors on the chiller are running to make ice) at night when maximum electrical capacity is available from the cogeneration equipment; then used during the day. The use of the ice tanks saves on using the electric chillers during the day, when the cooling load on the building is high.

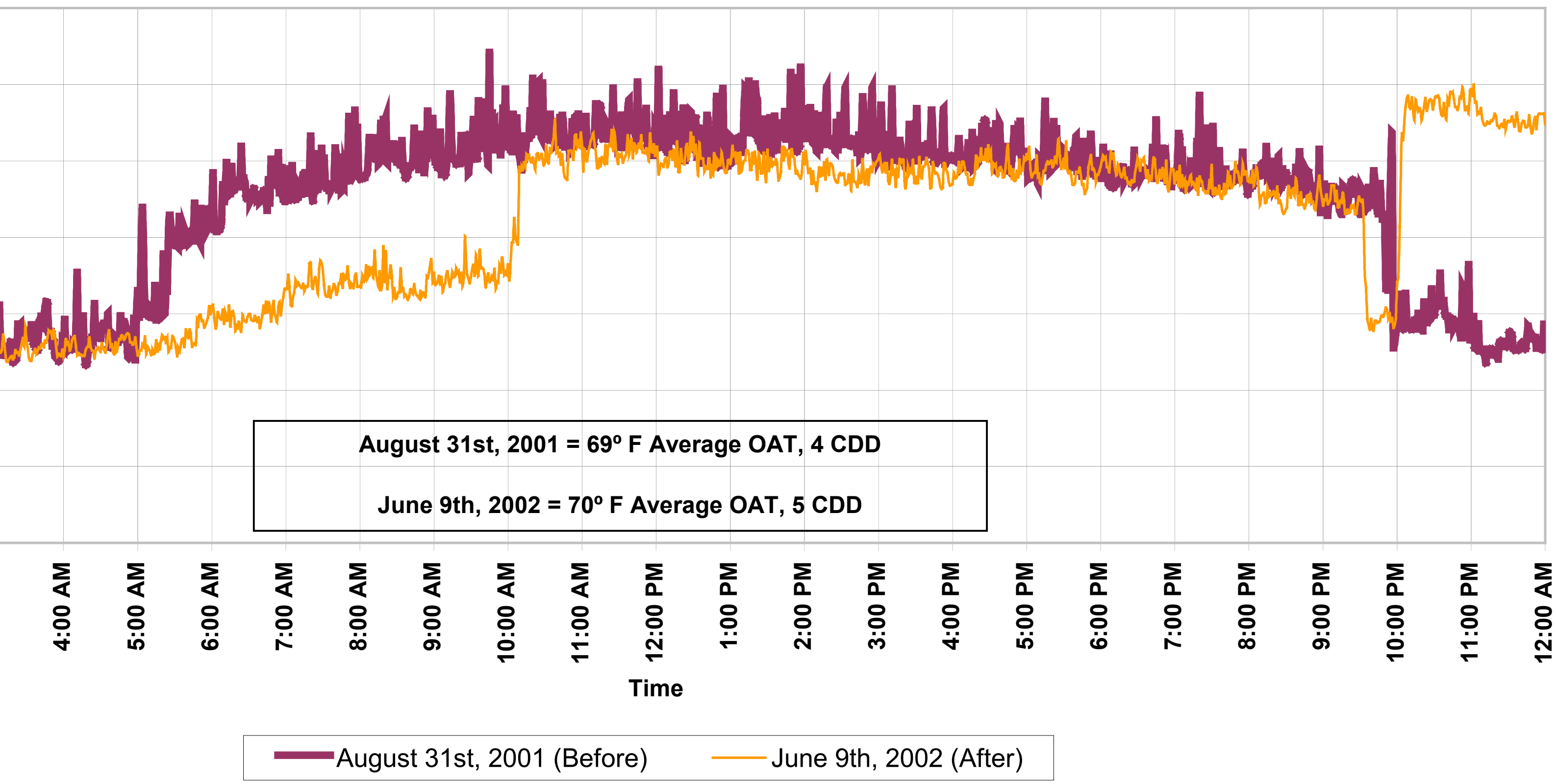
Figure 1 shows the facilities electrical load, before and after the CHP project. For the data collected on September 8th, 2001, GES ran a test where the 170-ton chiller carried out all the cooling in the facility. GES collected data on this cooling day in order to show what the load on the facility would have been without load factor management. The “test” day included ice making from 12am to 6am and 10pm to 12am. The data for this time period in the graph has been adjusted to approximate the system profile with out the ice tanks. The total kW of the facility reaches up to 420 kW. Figure 1 also shows the building load during the cooling season once load factor management was utilized. This is represented on the June 30th, 2002 load profile. Notice the load on the building barely reaches 275 kW, for a short period of time, and peaked at

310kW. The chiller came on and ice making started at 10pm, continuing through the night until 6am the next morning. Notice the jump in kW at 7am, this is when the chiller staged on to supplement cooling with the ice tank system. To make a fair comparison GES took these two days because they have a similar average outside air temperature according to www.NOAA.gov. By comparing the two figures, it's shown how GES lowered the facilities electric load. The demand for the facility is much lower than before the project. The 1,140 ton-hrs of cooling from the ice tanks reduced the kW load of the facility from a theoretical high of 460kW (Appendix B) to an actual peak of 310kW. The load factor went from 67% to 82%. Load factor management lowered the total kW of the facility.

Appendix B shows what the 2002 electric supply would have been for the facility without the cogeneration project or load factor management. The $189,574 includes the facility having conventional air conditioning. The energy estimates are derived from actual building load data and an estimated kWh consumption of a 195-ton chiller with out ice tanks. The slightly larger chiller (sized in the September 2000 energy study) would have been required to meet the cooling peaks. A further analysis of this is included in the Project Economics section. The electricity costs from the grid was calculated using actual Niagara Mohawk data from their web-site (kWh cost, dca, Niagara Mohawk tariff). The kW was determined based on historical data from the facility plus the new cooling load. The data also included a ratchet, which bills for 230 kW even if the facility was under that demand for the month.

Figure 1

Gerster Trane Energy Services
Oakwood CHP Report
NYSERDA Job # 6545
Facility Load Before and After
CHP Project



2. Energy Savings

Since the generators supplied 100% of the electricity to the facility, the first and most obvious energy saving was electricity from the grid. Oakwood saved what would have been $189,574 (see Appendix B) in electric bills for the final report year, if Niagara Mohawk had provided the site's electricity. Though more gas was used to produce the electricity (explained in the Project Economics section) Oakwood saved more by generating the electricity. The following calculations of data, (data collected from Table 1) shows that generating the electricity was 43% cheaper.

Price per kWh without CHP project

Total Electric Cost/ Total kWh Consumed = $189,574 / 1,678,787 kWh = $0.113/kWh

Cogen Gas Cost

21,707 MCF (cogen gas consumed) * $6.50/MCF (Oakwood's average gas cost in 2002) = $141,096

Thermal Recovery Savings

5,199 MCF (gas displaced) * $6.50/MCF = $33,794

Price per kWh with CHP project

Total Electric Cost/ Total kWh Consumed = ($141,096 - $33,794)/ 1,678,787 kWh = $0.064/kWh

Table 1 data and the data on the CD in Appendix F was collected through temperature sensors, flow meters, generator controls and various other electronic controls. Refer to Appendix A, drawing number M-3 to see where these devices are located to collect data. The Tracer Summit building automation system program was used to record this data, calculate into the correct units and place the data onto reports/ files. The data was collected in 15 minute, hourly, daily and monthly intervals.

Table 1

January 2002 - December 2002, Monthly Data

Month	Outside Air Temp Monthly Avg	Gas Meter Usage (Cogen Gas Consumed)	Building Power Usage *	Boiler Loop HX Heat Removed	DHW Heat Removed	Generator 1 Electric *	Generator 2 Electric *	Diesel Electric *	**Total kWh Generated ***	**Total Heat Recovered**	**Total Gas Displaced**	**Gas Displaced**	**Gas Displaced**	**Fuel Consumed**	**Fuel Consumed**	**Engine 1**	**Engine 2**	**Diesel**
	°F	MCF	kWh	MMBTU	MMBTU	kWh	kWh	kWh	**kWh**	**MMBTU**	**at 74% boiler eff. (MCF)**	**Engine 1 (MCF)**	**Engine 2 (MCF)**	**Engine 1 (MCF)**	**Engine 2 (MCF)**	**Runtime (hr)**	**Runtime (hr)**	**Runtime (hr)**
Jan-02	31.6	1,595	114,681	350	150	0	129,600		**129,600**	**501**	**675**	**0**	**675**	**0**	**1,595**	**53**	**744**	
Feb-02	32.2	1,430	114,681	350	150	0	115,370	0	**115,370**	**501**	**675**	**0**	**675**	**0**	**1,430**	**50**	**672**	**0**
Mar-02	39.7	1,556	124,370	320	161	1,269	123,137	626	**125,031**	**480**	**648**	**7**	**641**	**16**	**1,540**	**7**	**721**	**3.17**
Apr-02	51.7	1,632	128,219	309	76	10,476	116,466	302	**127,244**	**385**	**519**	**43**	**476**	**135**	**1,498**	**102**	**645**	**1.38**
May-02	68.4	1,678	131,013	161	111	129,436	5,033	0	**134,469**	**272**	**366**	**353**	**14**	**1,615**	**63**	**719**	**41**	**0**
Jun-02	81.4	2,008	156,212	54	110	143,340	5,178	1,006	**149,525**	**164**	**221**	**213**	**8**	**1,938**	**70**	**691**	**128**	**5.87**
Jul-02	82.7	2,532	187,492	15	92	139,379	35,040	0	**174,420**	**107**	**144**	**115**	**29**	**2,023**	**509**	**713**	**347**	**0.86**
Aug-02	72.5	2,382	182,610	18	97	148,945	28,354	1,304	**178,603**	**116**	**156**	**131**	**25**	**2,001**	**381**	**714**	**254**	**5.22**
Sep-02	74.6	2,105	160,536	53	80	137,610	18,597	1,204	**157,411**	**134**	**180**	**159**	**21**	**1,855**	**251**	**692**	**162**	**5.33**
Oct-02	37.6	1,690	134,691	242	76	30,948	99,731	2,978	**133,657**	**317**	**428**	**101**	**326**	**400**	**1,289**	**131**	**606**	**15.02**
Nov-02	26.7	1,556	122,438	351	58	852	120,681	1,095	**122,628**	**409**	**552**	**4**	**548**	**11**	**1,546**	**8**	**699**	**5.73**
Dec-02	32.2	1,543	130,438	426	45	0	130,830	0	**130,830**	**472**	**636**	**0**	**636**	**0**	**1,543**	**0**	**729**	**0**
Totals		**21,707**	**1,687,379**	**2,650**	**1,206**	**742,257**	**928,017**	**8,513**	**1,678,787**	**3,856**	**5,199**	**1,125**	**4,074**	**9,993**	**11,714**	**3,880**	**5,748**	**43**
		22,358		**3,573**	**1,626**											Total		9,671
		MMBTU		MCF	MCF													

* The Building Power Usage is calculated by the Nexus meter and therefore will give us a different number than the Total kWh Generated which is calculated by the generator control panels.

Along with supplying electricity, the CHP project included a cogeneration heat recovery loop, which utilizes heat available from the engine jacket water and exhaust. The heat recovery system was designed to provide thermal energy to the boiler and domestic hot water system. Heat available for recovery from the engine jacket water can be utilized to provide space heating via the existing boiler system and domestic water heating for the kitchen, laundry and general use. During the heating season, the balance of the thermal energy is used for space heating the building, and the domestic hot water. During the cooling season, the balance of the thermal energy not used in the domestic hot water loop is rejected to the environment through a radiator. As heat is recovered in the facility the heat recovery loop temperature is reduced. The loop water must be cooled to 140 ºF before it returns to the engine heat exchanger.

Heat recovery was approached from both the demand side and the supply side. On the supply side, the strategy was to maximize heat available from the two natural gas cogeneration engines. At full load the jacket water heat that is available is 690,000 Btuh from each engine. This winter engine was fitted with a 528,557 Btuh exhaust heat recovery unit (ERHU) to supply more heat during the colder months. This device improves both the quality and the amount of heat available to the health care center.

On the demand side, one heat sink is space heating for the facility. Before the project, the building was heated with two hot water boilers and three rooftop make-up heaters. The CHP project included a water to water shell and tube heat exchanger installed to heat or pre-heat the space heating hot water perimeter loop. The heat exchanger is sized for a maximum of 953,471 Btuh. Pre-heating boiler return water displaces natural gas used in the boiler. Enough heat from the cogen jacket water is available for the boilers not to run until it is below 17˚ F outside air temperature. Recovered heat is used toward the entire current boiler loads: building perimeter hot water loop and glycol make-up air for kitchen and laundry. The actual heat recovered for the final report year was 2,650 MMBTU.

The domestic hot water (DHW) is the other heat sink. The DHW loop is used for kitchen, laundry and general use. For the CHP project this part of the demand side included a plate and frame heat exchanger, installed on the recirculating line (between DHW heater and DHW storage tank), to heat or pre-heat the DHW loop. The cogen jacket water, after going through the space heating heat exchanger continues to the DHW heat exchanger. This heat exchanger heats the return/city water before the existing hot water heater and therefore reduces the heater's runtime. The heat exchanger is sized for a maximum of 774,585 Btuh. For four weeks when the domestic hot water heater was down, all heat was supplied from the cogen. This proved that the system is capable to provide enough heat to the DHW loop, even after supplying the heating loop. The actual heat recovered for the final report year was 1,206 MMBTU.

The system has two heat sink heat exchangers, one for space conditioning, and one for domestic hot water. Figure 2 shows the total heat recovered for the 12-month period of January 2002 through December 2002. This coincides with the first heating and cooling seasons after the addition of the cogeneration plant and heat recovery system. Looking at Figure 2 we see that the DHW drops off slightly in September through December. The DHW setpoint was changed resulting in less heat recovery. It was discovered that the setpoint for the DHW boiler to turn on, could be lowered in order to get more 'free' heat out of the cogen loop (the boiler did not stage on until the DHW loop fell below 150˚ F). This change was made in February of 2003 (see Lessons Learned section for a detailed description), which resulted in heat recovery numbers similar to early 2002.

Table 2 below summarizes Figure 2.

Table 2

Thermal Recovery Performance After CHP Project

Total MMBtu Available	Total MMBtu Recovered	Thermal Utilization
7,703*	3,856	50%

*This data was interpolated from the jacket water and EHRU manufacturer's data (see Appendix E)

The total heat recovered is the highest in the winter (7 months, Oct-Apr) due to more heat available (EHRU) and more heat use/recovery (space heating and DHW). The cooler the outside air temperature gets, the more heat that can be recovered. Figure 3 shows how much more heat can be recovered at a lower outside air temperature when space heating is needed. The health care center's heat demand is limited to only the DHW in the summer (5 months, May-Sept). So, the EHRU is bypassed lowering the heat available. Heat available was interpolated from the jacket water and EHRU manufacturer's performance data. Each month's heat available was interpolated using the hours in each month.

Figure 4 shows heat recovery on a winter day when both space heating and DHW is needed. This is a day, using the winter engine with the EHRU. The data represented is in 15-minute intervals. The heat available varies with load (see Appendix E), so there is a range of heat available throughout the day. Data for heat available was backed into using generator percent loaded per 15-minute interval. Notice the 2:30am spikes in the graphs. The corresponding increase in electric and therefore heat available is due to a rise in facility load at that point. The rise in heat recovered is due to the use of laundry machines that are part of the DHW heat recovery loop. Observe that most of the available heat is being recovered. There are currently no other loads that can be cost-effectively served by the CHP system. Figure 5 shows the heat available in 15-minute intervals, on a day in the summer. Only DHW is needed thus the EHRU is bypassed, and only jacket water heat from the engine is made available. The heat available is more than the DHW loop needs and as a result some heat is being rejected.

Figure 2

Gerster Trane Energy Services
Oakwood CHP Project
NYSERDA Job # 6545
Heat Recovered vs Heat Available
January 1, 2002 - December 31, 2002

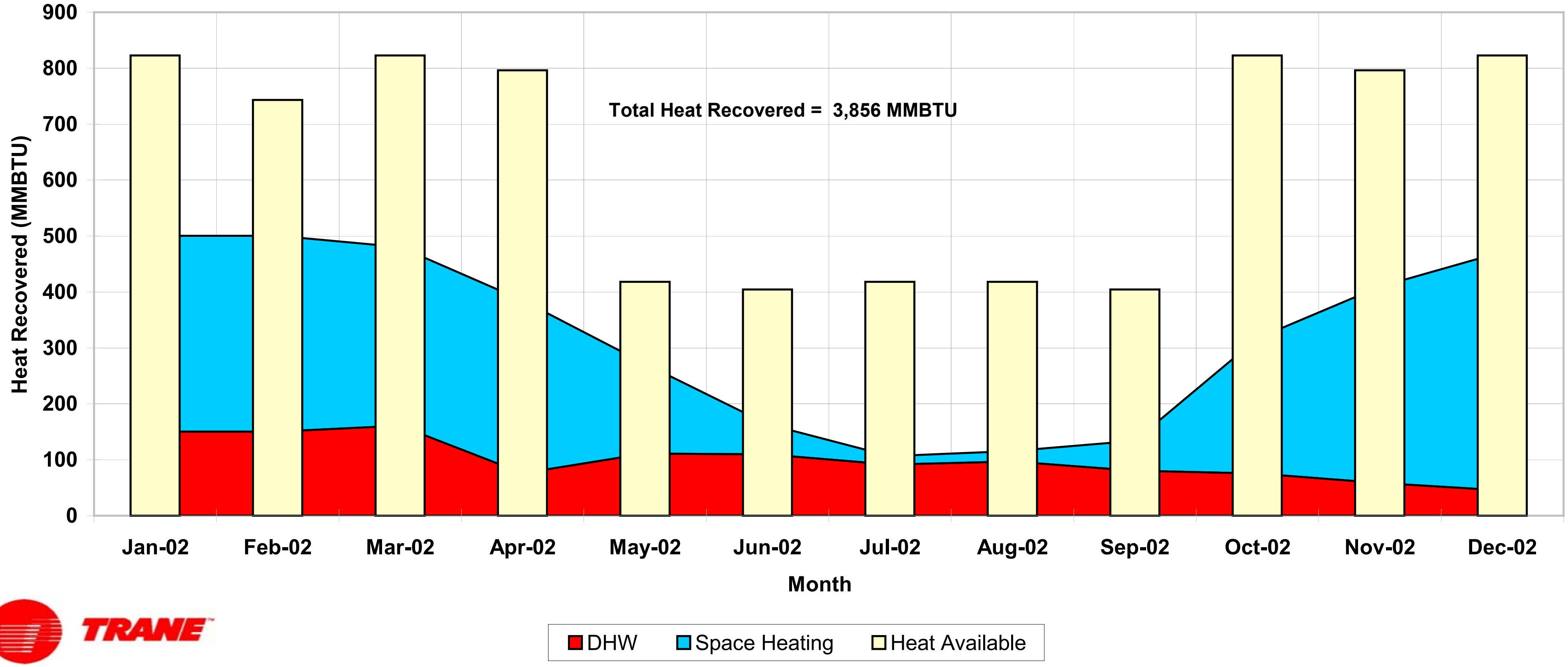
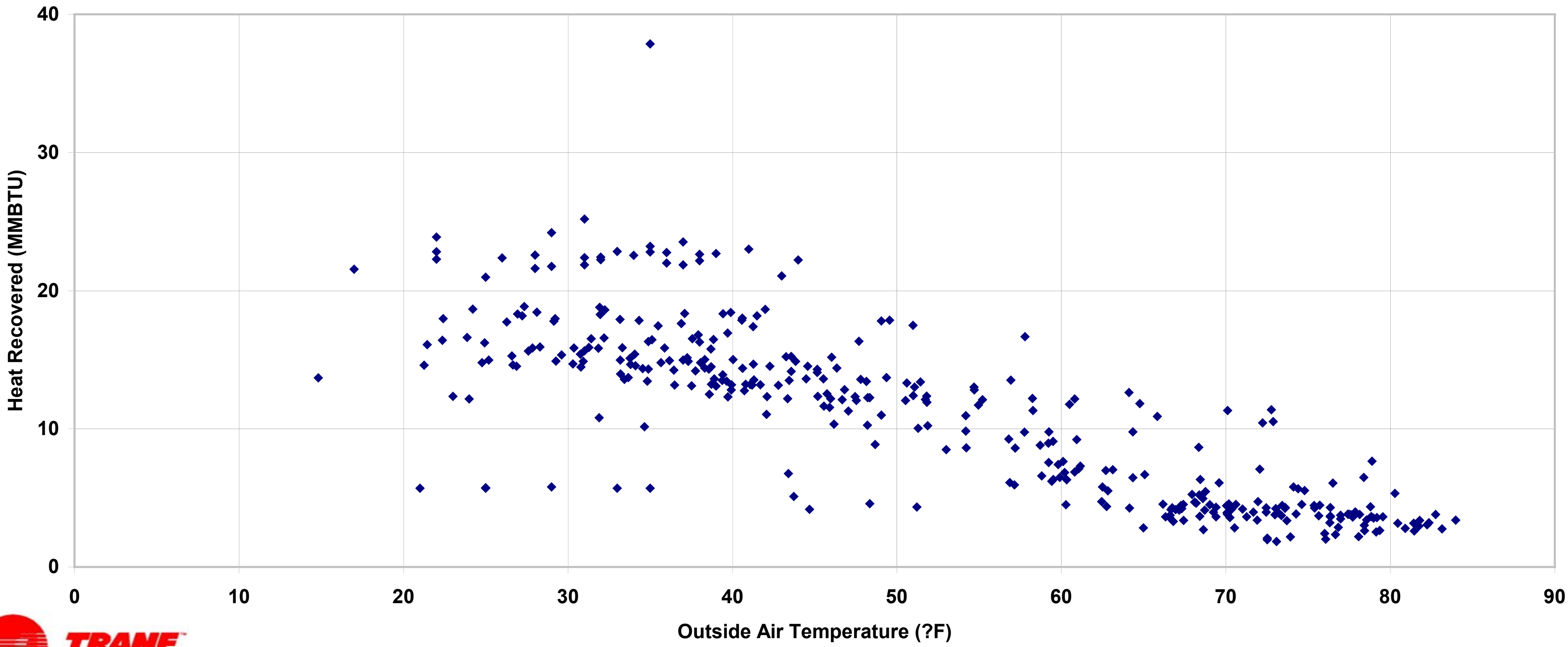


Figure 3

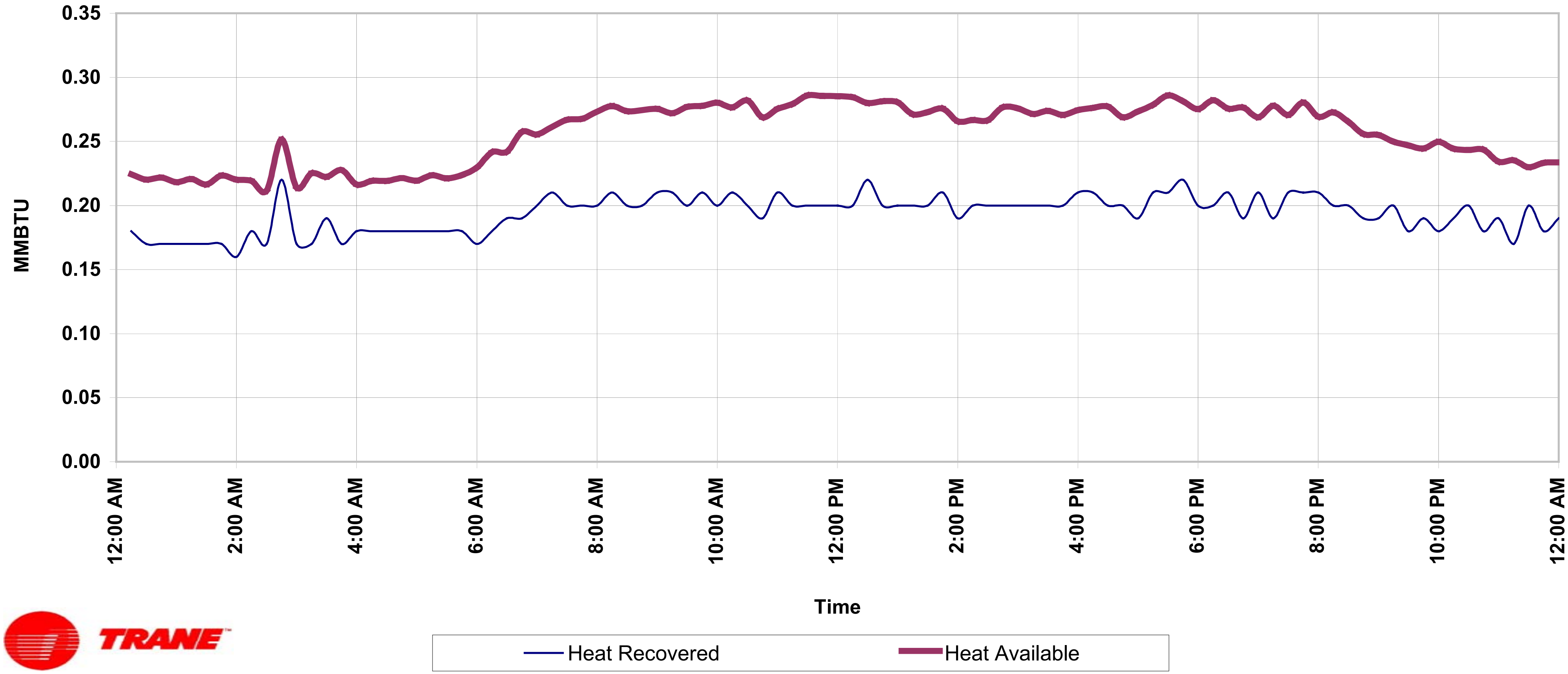
Gerster Trane Energy Services
Oakwood CHP Project
NYSERDA Job # 6545
Daily Heat Recovered vs Outside Air Temperature
January 1, 2002 - December 31, 2002



TRANE

Figure 4

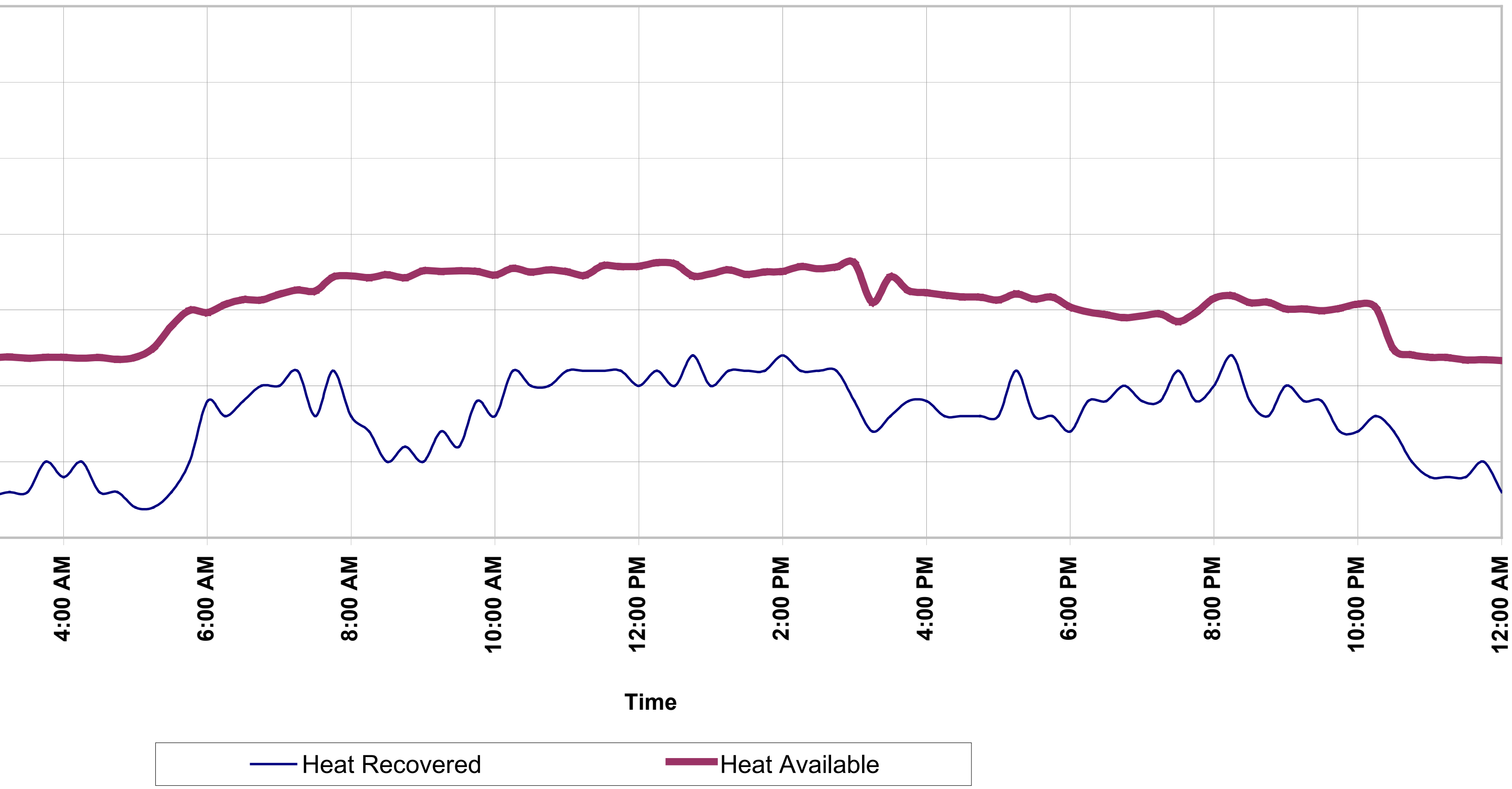
Gerster Trane Energy Services
Oakwood CHP Project
NYSERDA Job # 6545
Available Cogeneration and EHRU Heat
February 15th, 2002



TRANE

Figure 5

Gerster Trane Energy Services
Oakwood CHP Project
NYSERDA Job # 6545
Available Cogeneration Heat
June 24th, 2002



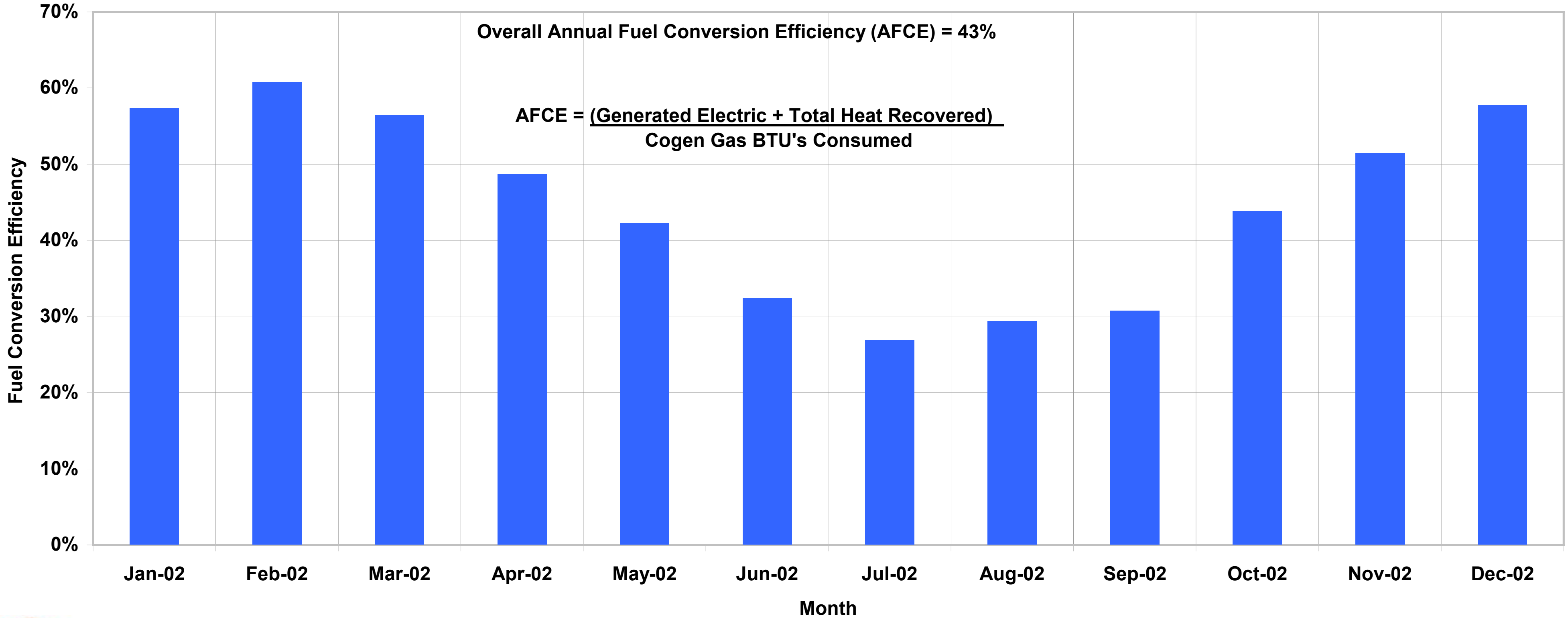
This project achieved an overall annual fuel conversion efficiency of 43% for the first year. Fuel conversion efficiency is the ratio of energy used to energy consumed. In this case the sum, in Btu's, of the power produced by the generator and the energy recovered by the heat exchangers is divided by the energy in fuel input to the engine generator. Adding the exhaust heat recovery increased the energy recovered from the gas burned in engine 2. As explained above and in Figure 2, the amount of heat recovered was increased by the addition of the new heat recovery devices. Thermal efficiency was highest at the coldest (heating season) times of the year, during that time the average fuel conversion efficiency was 55%. Figure 6 shows the fuel conversion efficiency plotted over the 12-month period of January 2002 to December 2002. The figure shows that the fuel conversion efficiency was highest during the heating months, when more heat was available/ recovered. In the summer the fuel conversion efficiency is lower because the facility only requires DHW. Figure 7 shows the daily fuel conversion efficiency versus average outside air temperature. A comparison of Figure 3 and 7 illustrates that at a lower outside air temperature more heat is recovered, therefore achieving a higher fuel conversion efficiency. There were periods in each month of low efficiency, which correlated with times both natural gas fired cogeneration units were off line for planned or unplanned maintenance and the diesel was running. Other periods of low fuel conversion efficiency included times in July – September when both natural gas fired cogeneration units were running in parallel, due to a cooling load too high for one generator. GES corrected the temporary problem by changing some programming. With only one generator running the fuel conversion efficiency was 5% better for the summer of 2003

There are a few other ideas in order to improve the fuel conversion efficiency beside making sure only one engine runs at all times. One idea that has been implemented was increasing heat recovery. In short GES has done a variety of system changes in order to maximize heat recovery. This is explained further in the Lessons Learned section of this report.

The two natural gas cogeneration units are the prime natural gas consumers for the facility. Other loads consuming natural gas include kitchen gas cooking, laundry dryers, and make-up air handling units, gas boilers and DHW heaters. Figure 8 compares the natural gas consumption of non-CHP consumers, before and after the CHP project. Individual fuel consumer numbers were based on the original energy study data. The kitchen, laundry and make-up air fuel consumption was not measured after the CHP project completion and therefore was assumed not to change. Space heating and DHW consume almost half of the total non-CHP natural gas in the whole facility. The cogeneration units use 70% of the facilities gas. 17% of it is used in heat recovery. The space heating boilers' gas use was reduced almost completely through heat recovery. The DHW heater gas use was reduced by about 50%. GES made the best use of the load from the CHP system and therefore no other loads can be cost effectively served by the CHP system, at this point.

Figure 6

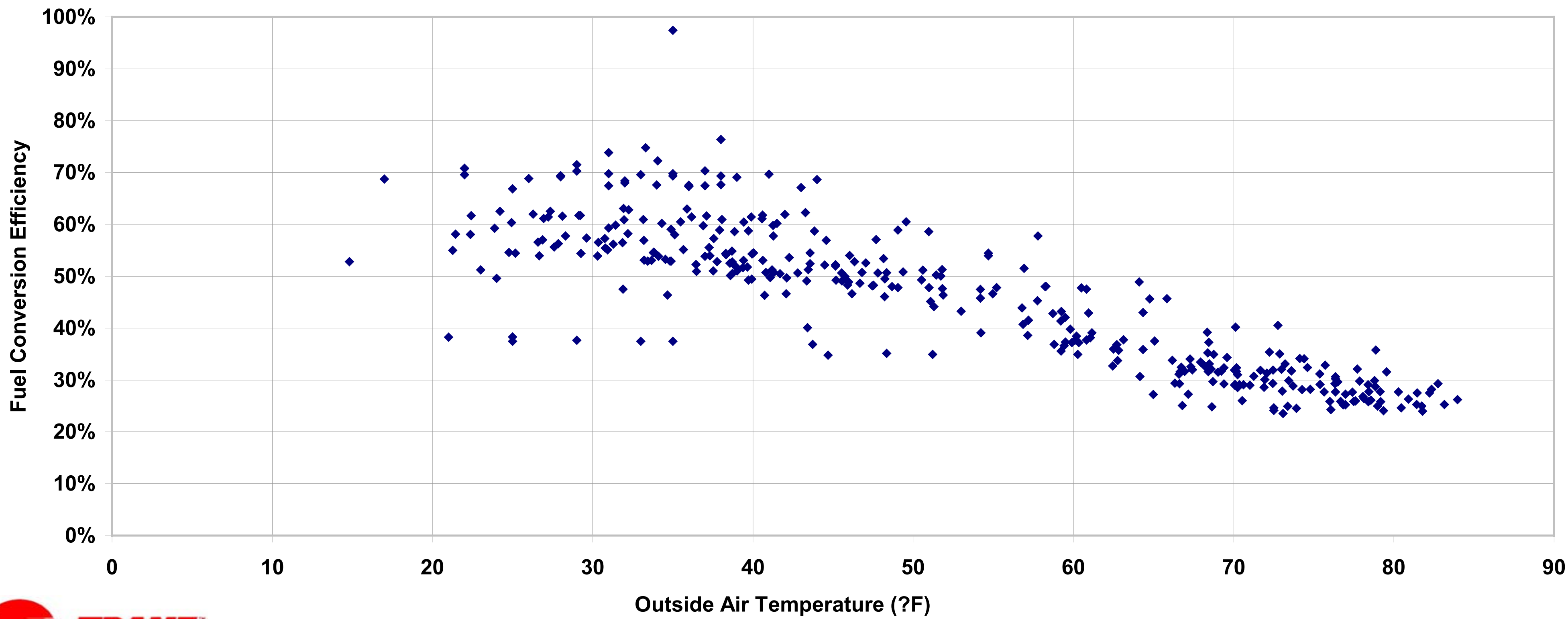
Gerster Trane Energy Services
Oakwood CHP Report
NYSERDA Job # 6545
Fuel Conversion Efficiency Per Month
January 1, 2002 - December 31, 2002



TRANE

Figure 7

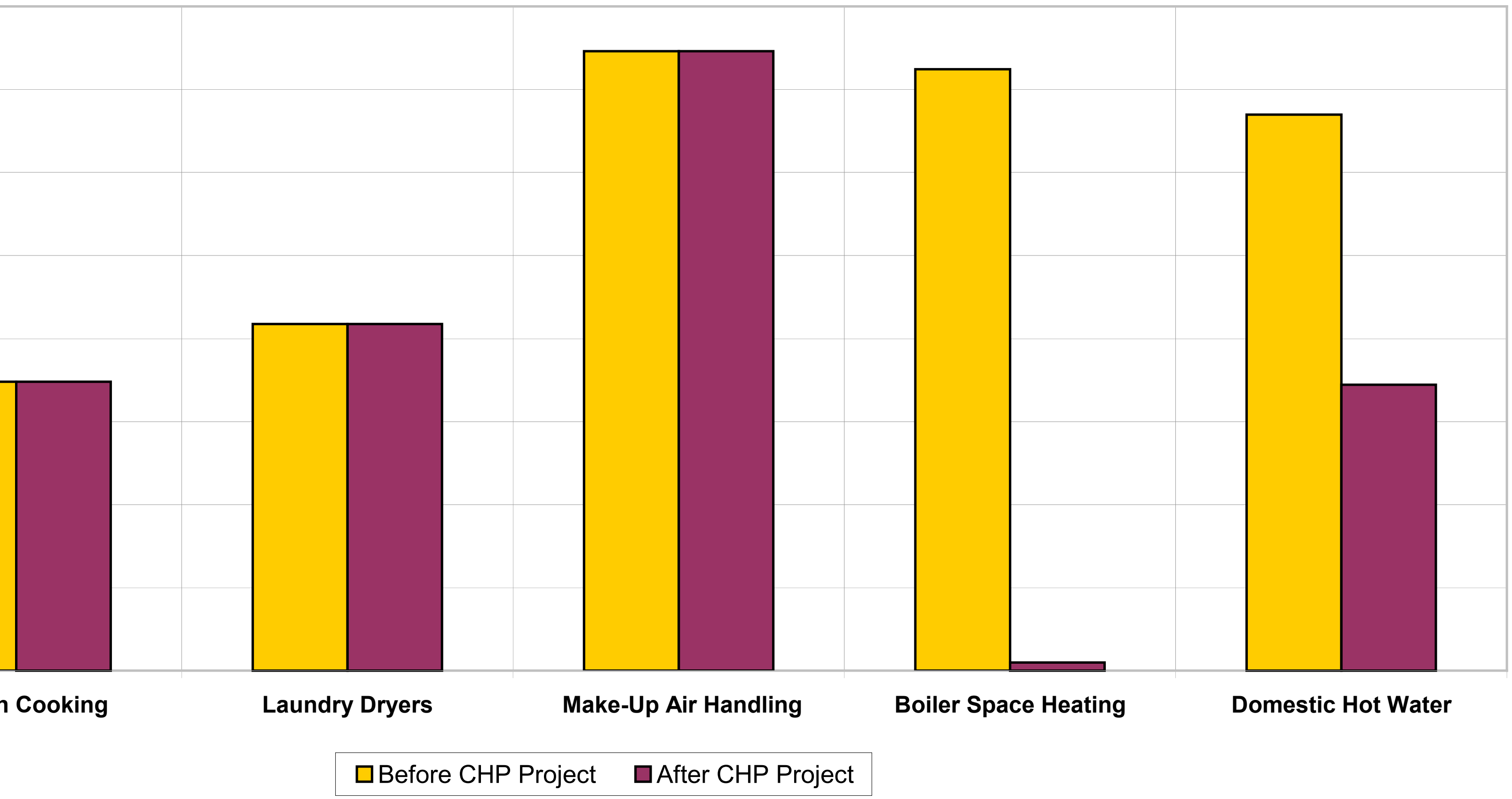
Gerster Trane Energy Services
Oakwood CHP Report
NYSERDA Job # 6545
Fuel Coversion Efficiency vs Average Outside Air Temperature
January 1, 2002 - December 31, 2002



TRANE

Figure 8

Gerster Trane Energy Services
Oakwood CHP Report
NYSERDA Job #6545
Annual Non-CHP Natural Gas Consumption



3. Reliability

The Oakwood cogeneration plant was installed as a grid isolated system, which means all electric is provided by the cogen plant. Niagara Mohawk (National Grid) ceased to provide electric service to Oakwood. Oakwood's electric supply had one level of redundancy before the project, by having Niagara Mohawk supply the electric and having a small 80 kW back-up generator. Now Oakwood has three levels of redundancy with three 300 kW generators, and keeping the 80 kW back up. There have been no outages at the facility. Any electrical outages that will occur from Niagara Mohawk will not effect Oakwood. In fact, an ice storm occurred in January of 2002, which put all other facilities around the area out of power for 5 days. At this time other health care facilities had patients check into Oakwood (the sole health care facility not affected by the storm).

The prime energy supplier is National Fuel Gas with a diesel generator serving as back up. Generator 1 is programmed to run in the summer time, generator 2 in the winter and the diesel as a standby. The two natural gas fired units are capable of operating in parallel. This allows both engines to operate at the same time facilitating maintenance with out disturbing the facility. Figure 9 shows the run time of each engine from January - December 2002. Scheduled maintenance occurred each month for the engines. During this time the other natural gas engine or the diesel was run. Other engine maintenance activities occurred during the span of the project year. These problems/ fixes are explained in Appendix C page 3 and 4.

Figure 10 shows the kWh each engine generated, from January - December 2002. The total kWh generated was 1,678,787, which establishes an average load of 192 kW. The average load is going to be higher during the summer due to running the electric chiller and air conditioning units. Figures 9 and 10 were plotted using the data collected on Table 1.

The facility had two boilers serving DHW and space heating. The project added another level of redundancy with the addition of a DHW loop heat exchanger and a space heating heat exchanger. If any maintenance needs to be completed on the boilers, heaters or heat exchangers the facility will be able to operate normally. All heat is taken from the cogeneration loop as 'free' heat, so the cogeneration heat is the primary level.

Figure 9

Gerster Trane Energy Services
Oakwood CHP Project
NYSERDA Job # 6545
Cumulative Hours of Operation of Generators
January 1, 2002 - December 31, 2002

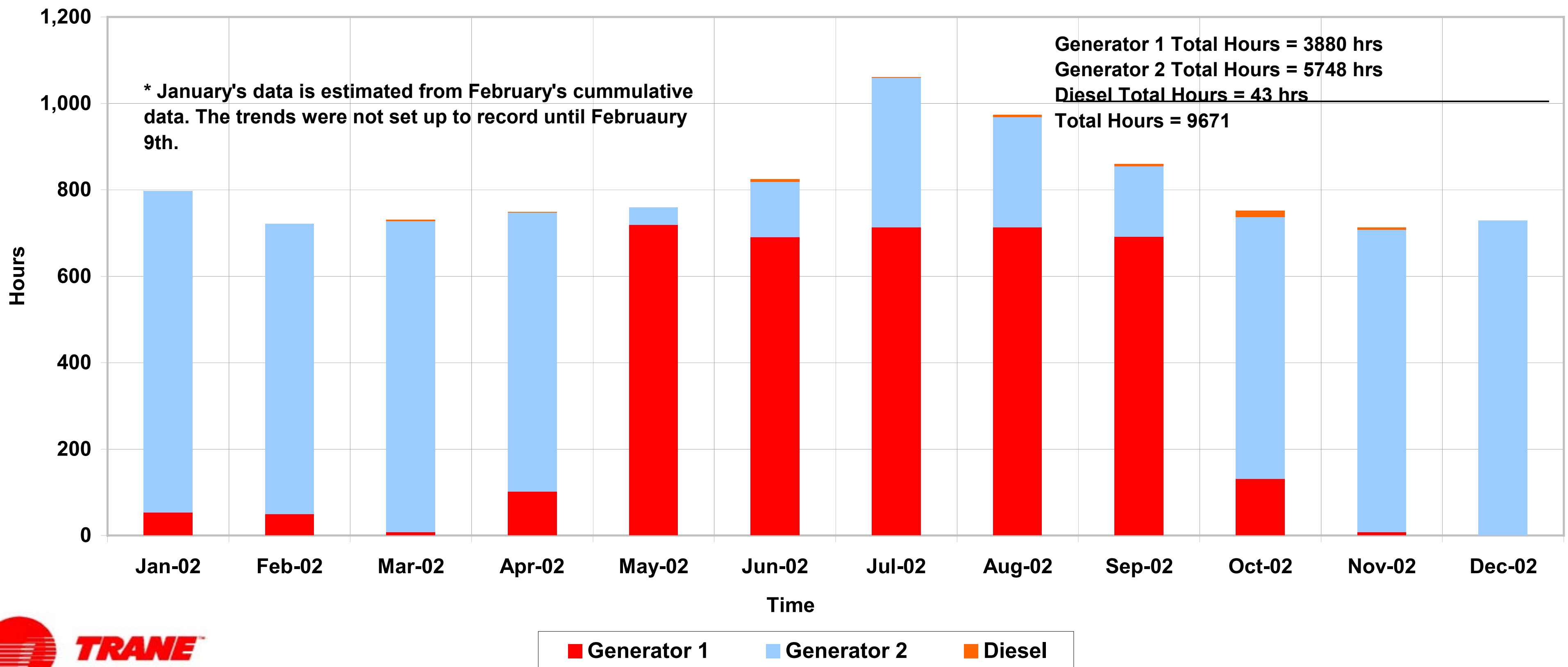
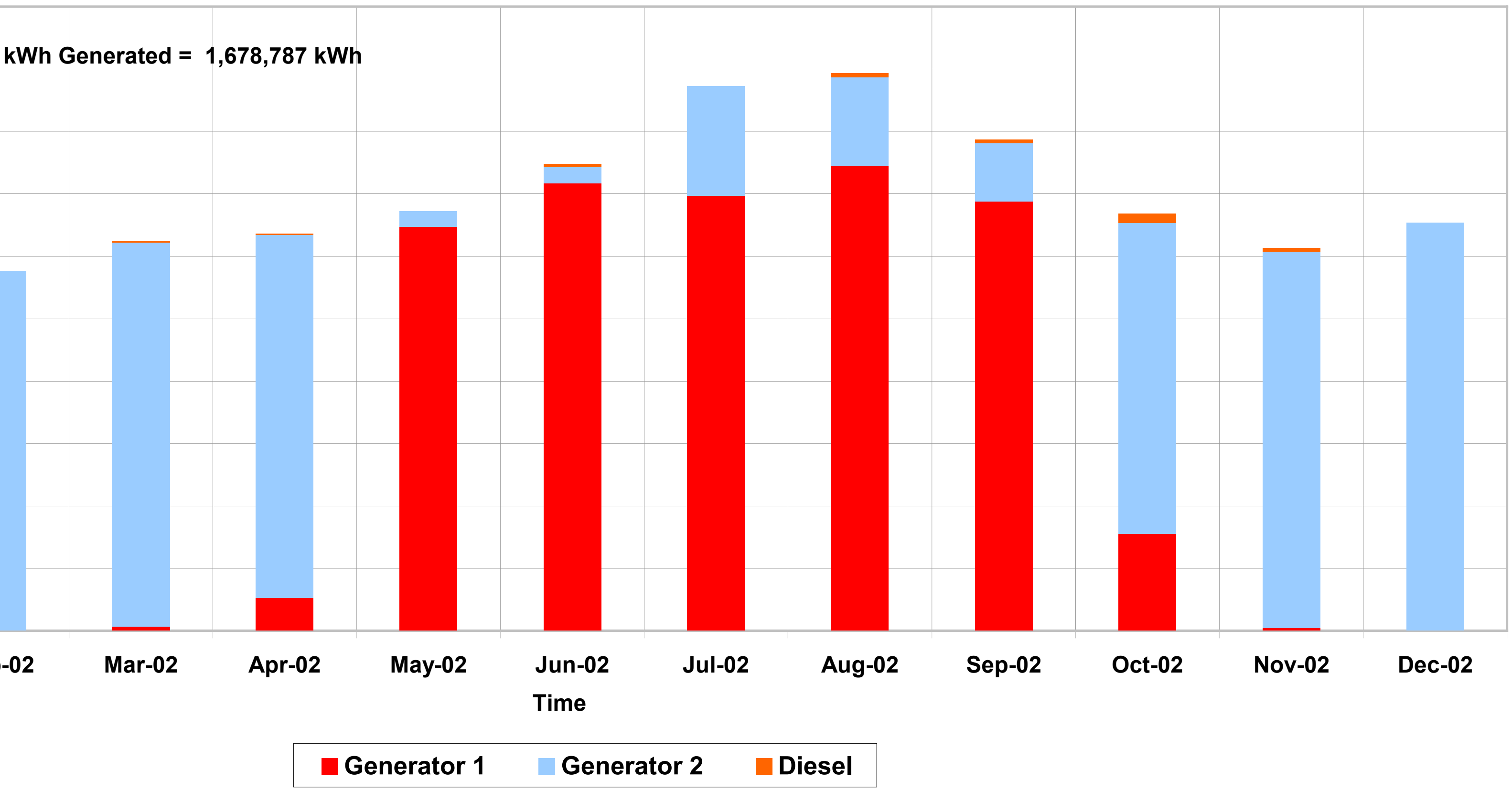


Figure 10

Gerster Trane Energy Services
Oakwood CHP Project
NYSERDA Job # 6545
kWh Generated
January 1, 2002 - December 31, 2002



ECONOMICS

When originally studied in September 2000, the net savings were estimated at $96,918. Table 3 shows the details of this estimate. A significant factor in the saving estimate is the $5.00/MCF & $5.50/MCF gas cost estimate.

Table 3
Predicted Operating Savings
Savings Summary Page From
September 2000 Oakwood Energy Study

Electrical Energy Savings:

The grid isolated cogeneration system eliminates the traditional monthly electric bill.

1999 NMPC Bill:	$153,941
Added Electricity Cost for Hallway AC:	$ 11,625
Total	$165,566

Cogeneration Fuel Cost:

Full Load Inputs:

	Btuh Input	MCF/hr	kWh/MCF
Waukesha model VGF 18GLD 280 kW engine:	3,384,960	3.28	91.4

Average Engine Efficiency: 91.4 kWh/MCF

Annual kWh:
1,462,880 kWh 1999
75,000 kWh Hallway AC
1,537,880 kWh Annual

Annual Fuel Consumption: $\frac{1{,}537{,}880 \text{ kWh}}{91.4 \text{ kWh/MCF}} = 16{,}825 \text{ MCF}$

Annual Fuel Cost: 16,825 MCF * $5.00/MCF (based on negotiated fuel price) = $84,129

Cogeneration Annual Maintenance Cost:

A total maintenance agreement defines Oakwood's risk for cogen system maintenance and repairs.

1,537,880 kWh * $0.015/total maintenance = $23,068

Project Economics Summary

Electric Savings	$165,566	
Thermal Savings	$ 38,549	$5.50/MCF
Gross Savings	$204,115	
Cogen Fuel Cost	$ 84,129	$5.00/MCF
Cogen Maintenance Cost	$ 23,068	
Annual Cogen Cost	$107,197	
Gross Savings	$204,115	

Annual Cogen Cost	-$107,197	
Net savings	$ 96,918	(financing not included)

Table 4 part 1 shows what Oakwood saved for the first year of the CHP project. This table takes into account the actual maintenance cost for the cogen. Part 2 shows what Oakwood would have saved for the first year of the CHP project if the gas prices were to remain the same as in the energy study of the facility, in the year 2000.

It was shown earlier that the heat recovery project improves the cogeneration plant fuel conversion efficiency. The added heat recovery improves the economics of the generation plant. Without the heat recovery there would have been an added cost for DHW and space heating.

Table 4
First Year Operation Savings Summary
January 2002-December 2002
Actual Recorded Data

1. Oakwood Project Economics Summary (based on average 2002 natural gas at $6.50/MCF)

Electric Savings	$189,574	(2002 Oakwood electric bill if purchased from NIMO, see Appendix D)
Thermal Savings	$ 33,794	(5,199 MCF displaced * $6.50/MCF, see Table 1)
Gross Savings	$223,368	
Cogen Fuel Cost	$141,096	(21,707 MCF fuel consumed * $6.50/MCF, see Table 1)
Cogen Maintenance Cost	$ 27,000	(see Appendix F) *
Annual Cogen Cost	$168,096	
Gross Savings	$223,368	
Annual Cogen Cost	- $168,096	
Net savings	$ 55,272	

The savings for Oakwood, based on an average $6.50/MCF was $55,272.

* The maintenance agreement is with Trane Service of Western New York. It is a comprehensive preventative maintenance contract that includes work on the generators and engines. Oakwood pays $2,250 a month for this service.

2. Oakwood Project Economics Summary (based on natural gas at $5.50/MCF used in 9/2000 Study)

Electric Savings	$189,574	
Thermal Savings	$ 28,594	$5.50/MCF
Gross Savings	$218,168	
Cogen Fuel Cost	$108,535	$5.00/MCF*
Cogen Maintenance Cost	$ 27,000	
Annual Cogen Cost	$135,535	
Gross Savings	$218,168	

Annual Cogen Cost	- $135,535
Net savings	$ 82,633

* At the time of the energy study it was anticipated that the gas used for cogeneration was to be $0.50/MCF cheaper than what the rest of the facility was receiving.

Comparing Table 3 to the actual savings (at the same gas price) of $82,633 (see Table 4, part 2), there is a difference of $14,285. Although the original savings were just an estimate of mechanical and electrical equipment use, there are some factors that may have brought the actual number closer to the estimate. These factors include gas cost, outside air temperature and having one engine running during the cooling season (as explained in Project Objectives and Results). GES also fine-tuned the system to increase the savings (see Lessons Learned).

The actual gas cost was higher which led to less potential savings. Table 5 shows what effect gas costs has on the cogeneration project economics. If the price per MCF was approximately $9.85 and all other factors remained the same, the cogeneration project would have broken even. On the other hand, if there were a decrease (of $2.50/MCF) to $4.00/MCF, the project would have saved $96,542.

Table 5

Gas Cost Effect on Project Economics

$10.00	$9.85	$9.50	$9.00	$8.50	$8.00	$7.50	$7.00	$6.50	$6.00	$5.50	$5.00	$4.50	$4.00	$3.50
$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574	$189,574
$51,990	$51,201	$49,391	$46,791	$44,192	$41,592	$38,993	$36,393	$33,794	$31,194	$28,595	$25,995	$23,396	$20,796	$18,197
$241,564	$240,775	$238,965	$236,365	$233,766	$231,166	$228,567	$225,967	$223,368	$220,768	$218,169	$215,569	$212,970	$210,370	$207,771
$217,070	$213,775	$206,217	$195,363	$184,510	$173,656	$162,803	$151,949	$141,096	$130,242	$119,389	$108,535	$97,682	$86,828	$75,975
$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000	$27,000
$244,070	$240,775	$233,217	$222,363	$211,510	$200,656	$189,803	$178,949	$168,096	$157,242	$146,389	$135,535	$124,682	$113,828	$102,975
$241,564	$240,775	$238,965	$236,365	$233,766	$231,166	$228,567	$225,967	$223,368	$220,768	$218,169	$215,569	$212,970	$210,370	$207,771
$244,070	$240,775	$233,217	$222,363	$211,510	$200,656	$189,803	$178,949	$168,096	$157,242	$146,389	$135,535	$124,682	$113,828	$102,975
($2,506)	($0)	$5,748	$14,002	$22,256	$30,510	$38,764	$47,018	$55,272	$63,526	$71,780	$80,034	$88,288	$96,542	$104,796

Table 6 shows what the energy cost would have been at Oakwood without the CHP project. Based on the final report project years gas price the average cost to produce electricity went down by 43% (see Project Objectives and Results, Energy Savings section). Looking back onto Figure 1 we also see that electric consumption would have been higher, without utilizing load factor management. Without load factor management and the cogeneration project, the electric bill would have been much higher for the final report year. The bill would have been higher when you compare the cost of producing electricity and receiving it from the utility company. Although Oakwood paid more in gas, the lower cost in producing electricity offset the gas cost.

Table 6 shows a simple energy only cost analysis of what the facility would have paid without having a cogeneration plant in 2002.

Table 6
Energy Costs

Energy Cost with out Retrofit				**Energy Cost with Retrofit**		
Oakwood's 2002 electric bill if purchased from NiMo (includes new chiller and no ice storage system) 1,678,787 kWh = $189,574 (see appendix D)						
Oakwood's 2002 gas bill with out cogen				Oakwood's 2002 gas bill with cogen		
Facility Gas Use		31,149	MCF	Facility Gas Use	31,149	MCF
Cogen Fuel Used	-	21,707	MCF			
Gas Consumption Displaced by Cogen				Facility Gas Cost	$202,760	
@ 74% boiler efficiency	+	5,199	MCF	(See Appendix D, gas bill for 2002)		
Net Facility Gas Use		14,641	MCF			
		14,641	MCF			
	*	$6.50	$/MCF			
Total Facility Gas Cost		$95,167				
Electric Bought		$189,574				
Gas Bought	+	$95,167				
Total Cost of Energy		$284,741		Total Cost of Energy	$202,760	

* Table 6 data has been rounded to the nearest dollar and therefore will be slightly different than Table 4.

The energy cost Oakwood paid in 2002 with the retrofit was just the gas bill, $202,760. That equals an energy only, savings of, $284,741 – $202,760 = $81,981 for the first year of cogeneration operation.

Cooling System Comparison Costs

Taking into consideration load factor management and energy savings, GES chose a smaller generator, and a smaller chiller with an ice storage system. A traditional system would have required a larger generator and a larger chiller with out an ice storage system. The total facility load cooling demand is 195 tons (this was taken from the September 2000 energy study). The new 170 ton chiller with ice storage would have had to been 25 tons larger with out the ice storage system. A 195-ton chiller would have added $20,000 to the project cost. If the chiller were 25 tons larger the building load would have been 460 kW. All three 300 kW generators would have had to been 550 kW, in order to support the facilities maximum load. This would have added $630,000 to the project cost. On the other hand the ice storage tanks added cost was $80,000.

Cooling System without Ice Storage	Added Cost	Cooling System with Ice Storage	Added Cost
195 Ton Chiller	$20,000	Ice Storage Tanks	$80,000
550 kW Generator	$630,000		
Total Added Cost	$650,000	Total Added Cost	$80,000

In short the project would have cost $570,000 more if Oakwood/GES went with a traditional system.

Project Costs

The project cost is broken down as follows.

Description	Cost
(2) 300 kW Natural Gas Engine	
(1) 300 kW Diesel Engine	
Engine Enclosure	
Thermal Recovery Heat Sinks	
Engine 1 -Jacket Water recovery	
Engine 2 -Jacket Water and Exhaust Heat Recovery Unit	
Boiler System	
Domestic Hot Water System	
Cogeneration System Control and Monitoring	
Controls and Automation	
Engineering	
Project Management	
Commisioning	
Check/Test/ Start-Up	
	$987,967

With the actual project cost at $987,967 with no incentives and the actual savings of $55,272 the simple payback would have been 17.87 years. Including the NYSERDA incentive of $425,000 and $155,000 from National Fuel Gas the total project cost was $407,967, which gives a simple payback of 7.38 years. Since the first years savings calculation, changes have been made to the system that in turn will elevate the savings hence lower the payback.

ENVIRONMENTAL BENEFITS

The environmental benefits shown below are based on NYSERDA's Technical Assistance Evaluation released in the spring of 2002 (see Appendix D):

From January – December 2002 the total electric avoided equaled 1,678,787 kWh. The total heat recovered for this same period was 3,856 MMBTU.

Conversion Factors Used to Determine Reduction

	Electric (lb/kWh)	Natural Gas (lb/MMBTU)	Reduced Emissions Due to Displaced Grid Supplied Electricity (lbs)	Reduced Emissions Due to Displaced Gas by Recovered Heat (lbs)
NO_x	0.0013	0.1	2,182	386
SO_2	0.00302	0	5,070	-
CO_2	0.882	117	1,480,690	451,152

Generator 1 ran for 3,880 hours, generator 2 ran for 5,748 hours and the diesel ran for 43 hours, totaling 9,671 run hours from January – December 2002.

The natural gas engines used a total of 21,707 MCF generating 1,678,787 kWh. The generators average load was 64%. The annual emissions for these generators at 64% load is:

	Generated Emissions Not to Exceed (lbs)
NO_x	3,280
CO	2,870
CO_2	2,331,017
NMHC	1,230

See Appendix E for the manufacturer's specifications on generated emissions. CO_2 generated emissions was interpolated based on Waukesha representative data of 379 lbs/hr at 100% load.

LESSONS LEARNED

Some fine-tuning during commissioning included changes in the heat sinks (heating and domestic hot water (DHW) loop) and implementing some programming. Significant man hours were spent optimizing flows, approach temperatures, set points and reset schedules to optimize heat recovery.

After monitoring the site for most of the winter season we came up with a few ways to optimize the thermal recovery. GES came to the conclusion to change the reset schedule for the two space heating boilers. With that program the boilers would stage on and operate for a minimum run time. At first they would stage on when the outside air temperature would fall 5 degrees below set point. GES found that space heating was satisfied until the outside air temperature fell 20 degrees below set point. This added to Oakwood's savings because the facility could use more cogen heat instead of turning on the gas-fired boilers. Based on daily average heat recovery and using bin data approximately 162 MCF in boiler savings was calculated. At $6.50/ MCF, this change saves $1,053 annually.

The kitchen and laundry DHW need at least 145˚ F supply water. There is enough heat available out of the cogen loop for the DHW side to be at 145˚ F. The domestic hot water heater would turn on when the temperature of the storage tank dropped below 160˚ F. GES lowered the domestic hot water heater setpoint to 150˚F in February 2003, allowing for more hours that the cogenerator could supply heat to the DHW loop. Figure 11 shows how the change in setpoint in February 03' changed the amount of heat recovery in the DHW loop. An additional benefit was saving the DHW heater's life. March through August 2003, DHW heat recovered/ gas displaced averaged 174 MCF per month. Oakwood averaged 136 MCF per month in 2002. If the 174 MCF/month average were to continue for one year, at $6.50/MCF there would be annual savings of $2,964 from changing the setpoint.

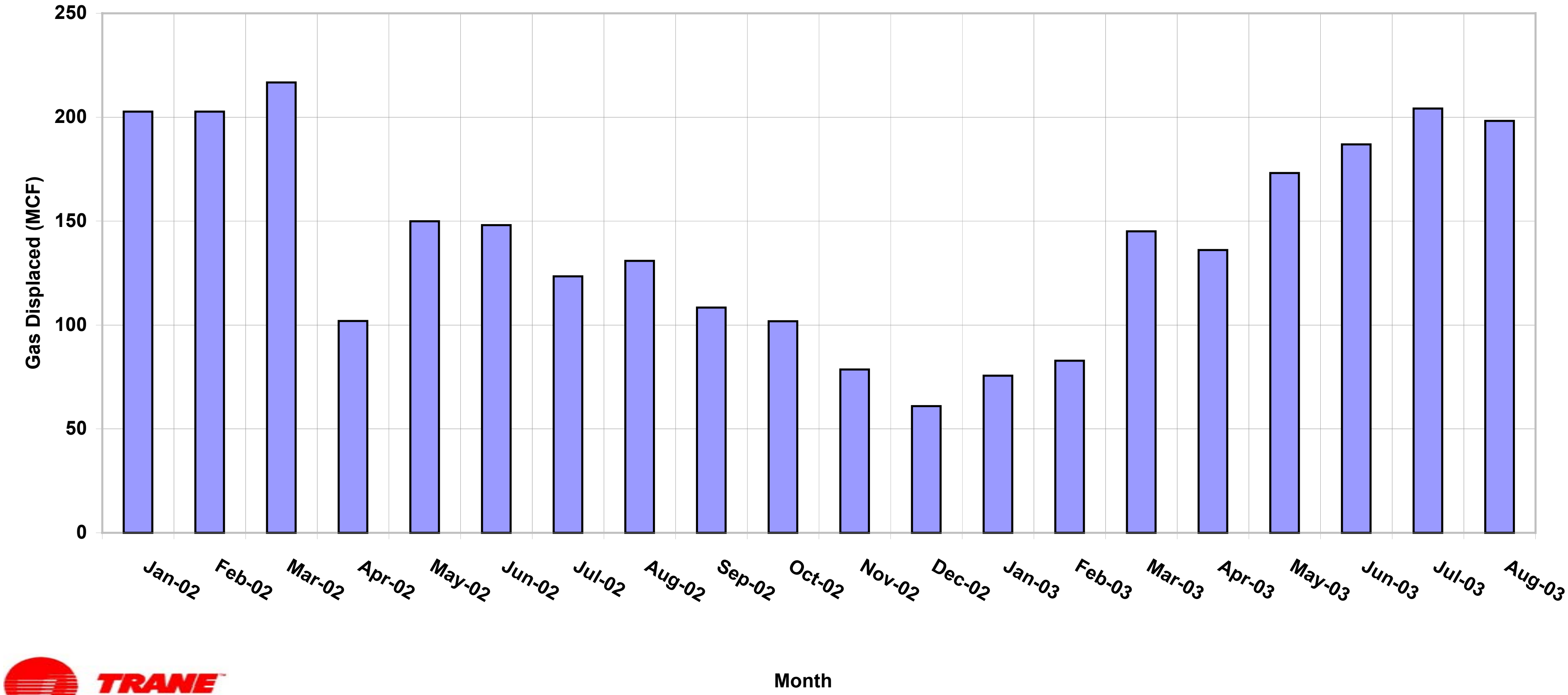
There appears to be an anomaly when comparing January - February periods of 2002 to 2003. The DHW gas displaced was higher in 2002 due to DHW boiler maintenance for four weeks. The DHW boilers were down and we supplied all heat to the DHW loop from cogen heat recovery. In 2003 most heat was being used in the heating heat recovery loop, and what was left over could be used in the DHW heat recovery loop.

After optimizing these programs in Tracer Summit, alarms were programmed to alert GES staff of sub par performance. There is enough heat from the cogen to space heat the facility when the outside air temperature (OAT) is above 17˚ F. One such alarm would tell GES staff if the space heating boilers came on and it was over 17˚ F OAT. An alarm was also set up to show if the DHW heater staged on. This alarm helped to show if the cogen could not supply enough heat to the DHW loop, leading GES staff and Oakwood staff to investigate the matter further. Monitoring and verification (M&V) alarms were added to the system. These alarms show if the heat recovery system is not up to par. When an alarm is received GES staff are able to troubleshoot the problem before a larger problem arises. Knowing how much heat Oakwood should recover in each heat exchanger, the following M&V alarms were programmed: low heat recovery alarm for the domestic hot water heat exchanger and the space heating heat exchanger (based on OAT).

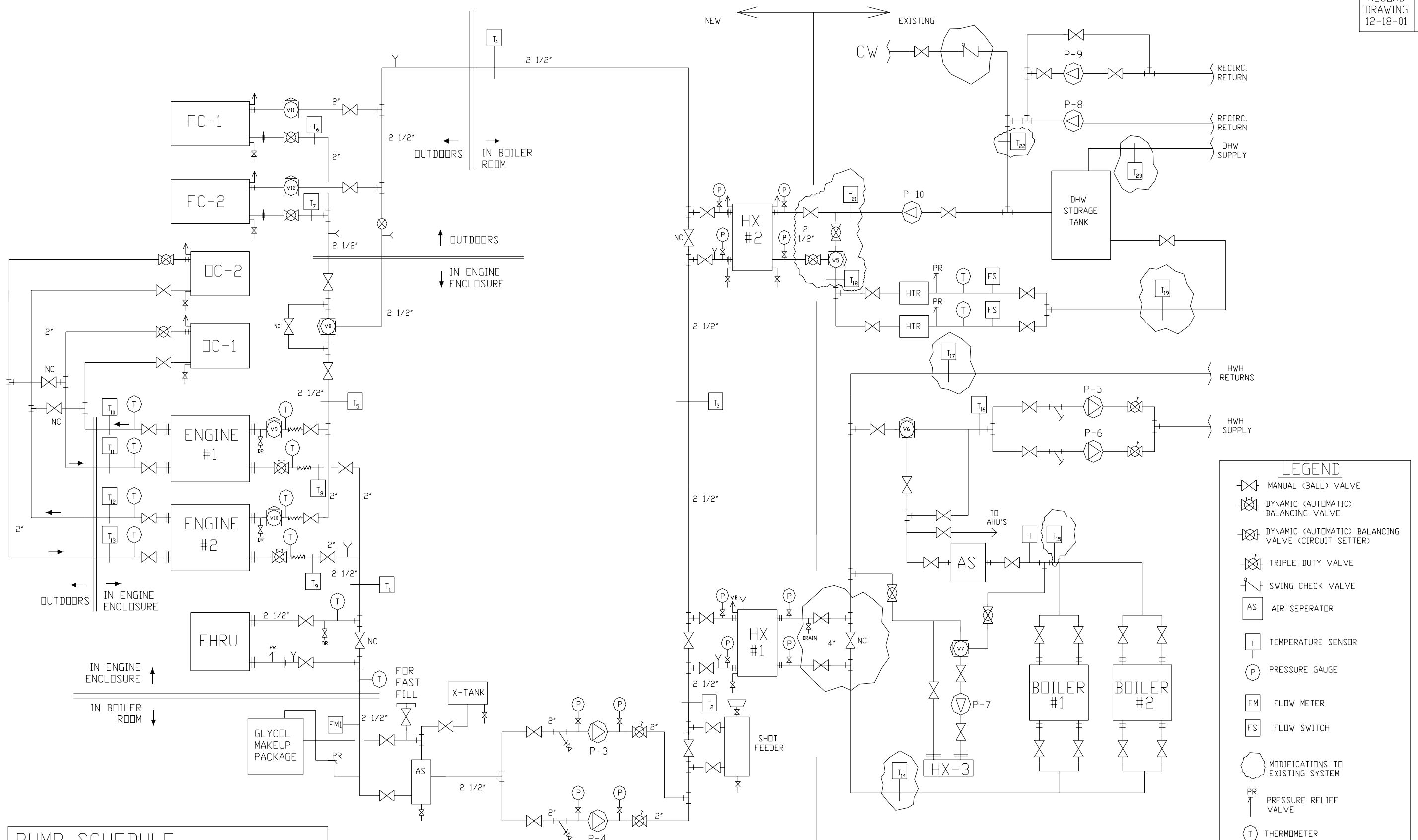
The flexibility designed into the system is a great asset for the health care facility, as they are poised to optimize their energy decisions for years to come.

Figure 11

Gerster Trane Energy Services
Oakwood CHP Project
NYSERDA Job # 6545
Domestic Hot Water Gas Displaced per Month



RECORD DRAWING 12-18-01 | CHK BY: WJF



PUMP SCHEDULE				
NO.	GPM	FT HEAD	HP	MODEL
P-3 P-4	80	125	5	B&G SER. 80 1 1/2 X 1 1/2 X 7B

NOTES:

1. SYSTEM FLUID IS 40% ETHYLENE GLYCOL.
2. PUMP GPM AND FT. HEAD IS TOTAL WITH BOTH PUMPS RUNNING TOGETHER.

NEW EXISTING

LEGEND

- MANUAL (BALL) VALVE
- DYNAMIC (AUTOMATIC) BALANCING VALVE
- DYNAMIC (AUTOMATIC) BALANCING VALVE (CIRCUIT SETTER)
- TRIPLE DUTY VALVE
- SWING CHECK VALVE
- AS AIR SEPERATOR
- T TEMPERATURE SENSOR
- P PRESSURE GAUGE
- FM FLOW METER
- FS FLOW SWITCH
- MODIFICATIONS TO EXISTING SYSTEM
- PR PRESSURE RELIEF VALVE
- T THERMOMETER
- AIR VENT
- DRAIN
- INLINE PUMP
- BASE MOUNTED PUMP
- STRAINER OR SUCTION DIFFUSER
- 3-WAY CONTROL VALVE
- 2-WAY CONTROL VALVE

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HEALTH CARE CENTER
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GERSTER TRANE
45 EARHART DR.
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PHONE: 716-626-1260
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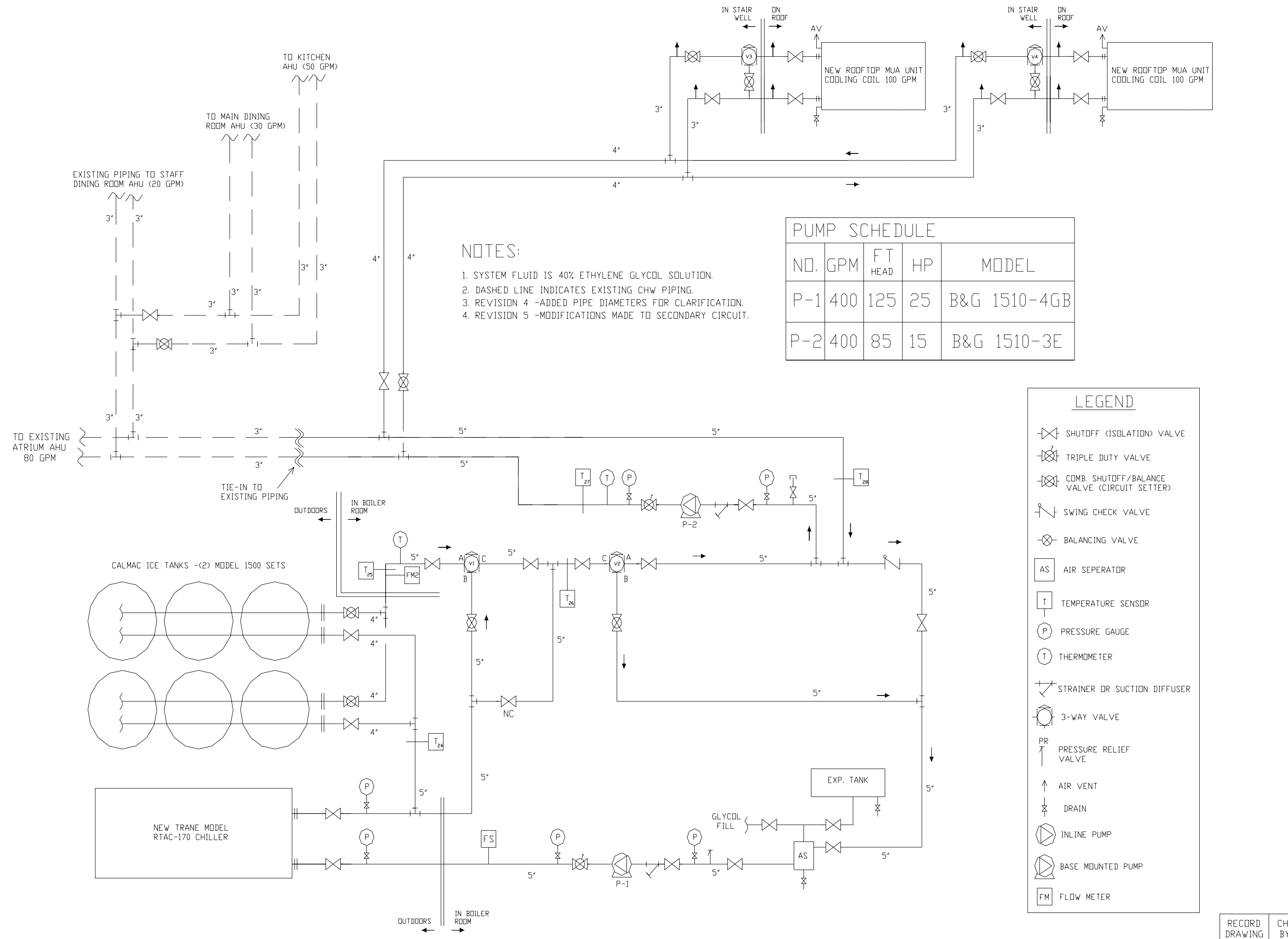
JOB NO.	900864
DATE:	5-23-01
DRAWN BY:	WFL
CHK BY:	TAL
SCALE:	NONE

REVISION		
NUM.	DATE	BY
1	5-24-01	WFL
2	5-31-01	WFL
3	12-18-01	WFL

DRAWING TITLE:
COGENERATION SYSTEM HEAT RECOVERY HEAT REJECTION PIPING SCHEMATIC

DRAWING NUMBER:
M-3



NOTES:

1. SYSTEM FLUID IS 40% ETHYLENE GLYCOL SOLUTION.
2. DASHED LINE INDICATES EXISTING CHW PIPING.
3. REVISION 4 -ADDED PIPE DIAMETERS FOR CLARIFICATION.
4. REVISION 5 -MODIFICATIONS MADE TO SECONDARY CIRCUIT.

PUMP SCHEDULE

NO.	GPM	FT HEAD	HP	MODEL
P-1	400	125	25	B&G 1510-4GB
P-2	400	85	15	B&G 1510-3E

LEGEND

- SHUTOFF (ISOLATION) VALVE
- TRIPLE DUTY VALVE
- COMB. SHUTOFF/BALANCE VALVE (CIRCUIT SETTER)
- SWING CHECK VALVE
- BALANCING VALVE
- AS AIR SEPERATOR
- T TEMPERATURE SENSOR
- P PRESSURE GAUGE
- T THERMOMETER
- STRAINER OR SUCTION DIFFUSER
- 3-WAY VALVE
- PR PRESSURE RELIEF VALVE
- AIR VENT
- DRAIN
- INLINE PUMP
- BASE MOUNTED PUMP
- FM FLOW METER

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JOB NO.	900864
DATE:	5-23-01
DRAWN BY	WFL
CHK BY:	TAL
SCALE:	NONE

REVISION

NUM	DATE	BY
1	5-22-01	WFL
2	5-25-01	WFL
3	5-31-01	WFL
4	6-14-01	WFL
5	6-19-01	WFL
6	12-18-01	WFL

DRAWING TITLE:
CHILLED WATER PIPING SCHEMATIC

RECORD DRAWING 12-14-01

CHK BY: WJF

DRAWING NUMBER: M-4

Appendix A
Table of Logged Points

* The table includes logged points that are used in this report.

Many other points (as shown on the drawings) are being recorded in order to maximize the systems capabilities.

Temperature Sensors
T1
T2
T3
T4
T5
T8
T9
Flow Meter
FM1

Each generator also has its own control panel where data points are logged from.

Appendix B

2002 Oakwood Electric Bills If Purchased From NIMO

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Totals
Base kWh	129600	115370	125031	127244	134469	149525	174420	178603	157411	133657	122628	130830	1,678,788
Base kW	218	227	211	258	358	453	460	439	412	288	290	226	
sc3 cc	$ 260.15	$ 260.15	$ 260.15	$ 260.15	$ 260.15	$ 260.15	$ 260.15	$ 260.15	$ 260.15	$ 260.15	$ 260.15	$ 260.15	
sc3 block1 kWh (450 Hrs)	98100	102150	94950	116100	134469.07	149524.81	174419.82	178603.16	157411.35	129600	122627.73	101700	
dd block 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
ctc block 1	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	$ 0.02187	
sc3 block 2 kWh	31500	13219.88	30081.22	11143.85	0	0	0	0	0	4057.03	0	29130.03	
dd block 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
ctc block 2	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	$ 0.00988	
ctc kWh costs	$ 2,456.67	$ 2,364.63	$ 2,373.76	$ 2,649.21	$ 2,940.84	$ 3,270.11	$ 3,814.56	$ 3,906.05	$ 3,442.59	$ 2,874.44	$ 2,681.87	$ 2,511.98	
kWh cost	0.03603	0.03529	0.03857	0.04177	0.03279	0.04359	0.05616	0.05681	0.05456	0.05401	0.05050	0.05350	
dca	0.00624	0.00731	0.00417	0.00158	0.00914	0.00106	-0.00914	-0.00902	-0.00594	-0.00663	-0.00406	-0.00666	
total kWh costs	$ 7,934.86	$ 7,279.39	$ 7,717.59	$ 8,165.23	$ 8,579.13	$ 9,946.39	$12,015.78	$12,441.50	$ 11,095.93	$ 9,207.11	$ 8,376.70	$ 8,640.06	
billed kW	230	230	230	258	358	453	460	439	412	288	290	230	
dd demand cost	$ 8.21	$ 8.21	$ 8.21	$ 8.21	$ 8.21	$ 8.21	$ 8.21	$ 8.21	$ 8.21	$ 8.21	$ 8.21	$ 8.21	
ctc demand cost	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	$ 6.76	
total demand cost	$ 3,443.10	$ 3,443.10	$ 3,443.10	$ 3,862.26	$ 5,359.26	$ 6,781.41	$ 6,886.20	$ 6,571.83	$ 6,167.64	$ 4,311.36	$ 4,341.30	$ 3,443.10	
sbc	$ 207.36	$ 184.59	$ 200.05	$ 203.59	$ 215.15	$ 239.24	$ 279.07	$ 285.77	$ 251.86	$ 213.85	$ 196.20	$ 209.33	
subtotal	$11,845.47	$11,167.23	$11,620.89	$12,491.23	$14,413.69	$17,227.19	$19,441.20	$19,559.24	$ 17,775.57	$13,992.47	$13,174.35	$12,552.64	
grt	$ 493.56	$ 465.30	$ 484.20	$ 520.47	$ 600.57	$ 717.80	$ 810.05	$ 814.97	$ 740.65	$ 583.02	$ 548.93	$ 523.03	

sales tax	$ 473.82	$ 446.69	$ 464.84	$ 499.65	$ 576.55	$ 689.09	$ 777.65	$ 782.37	$ 711.02	$ 559.70	$ 526.97	$ 502.11	
Total bill	$12,812.85	$12,079.22	$12,569.93	$13,511.35	$15,590.80	$18,634.08	$21,028.90	$21,156.58	$ 19,227.25	$15,135.18	$14,250.26	$13,577.77	$ 189,574
											Average cost per kWh		0.113

NYSERDA CHP Agreement No. 6545
Oakwood Health Care Center, Inc.
200 Bassett Rd.
Gerster Trane Energy Project
45 Earhart Drive
Suites 103 - 108
Buffalo, NY 14221

Site	Start Date	End Date	NG Used (scf)(mcf)	NG Cost	Oil Used (gal)	Oil Cost	Other Fuel Type	Other Fuel Type Units	Other Fuel Used	Other Fuel Cost	Maintenance Cost	Grid Peak Electricity	Grid Total Electricity	Electricity Dollars
Oakwood	12/19/01	12/31/01	633	$3,799	n/a	n/a	diesel	gals	not used	not used	$2,250	n/a	n/a	n/a
Oakwood	01/01/02	01/31/02	1595	$9,571	n/a	n/a	diesel	gals	not used	not used	$2,250	n/a	n/a	n/a
Oakwood	02/01/28	02/28/02	1430	$8,579	n/a	n/a	diesel	gals	not used	not used	$2,250	n/a	n/a	n/a
Oakwood	03/01/02	03/31/02	1556	$9,336	n/a	n/a	diesel	gals	23	$23	$2,250	n/a	n/a	n/a
Oakwood	04/01/30	04/30/02	1632	$9,792	n/a	n/a	diesel	gals	52	$53	$2,250	n/a	n/a	n/a
Oakwood	05/01/02	05/31/02	1678	$10,067	n/a	n/a	diesel	gals	0	$0	$2,250	n/a	n/a	n/a
Oakwood	06/01/02	06/30/02	2008	$12,048	n/a	n/a	diesel	gals	96	$97	$2,250	n/a	n/a	n/a
Oakwood	07/01/02	07/31/02	2532	$15,189	n/a	n/a	diesel	gals	14	$14	$2,250	n/a	n/a	n/a
Oakwood	08/01/02	08/31/02	2382	$14,290	n/a	n/a	diesel	gals	86	$87	$2,250	n/a	n/a	n/a
Oakwood	09/01/02	09/30/02	2105	$12,633	n/a	n/a	diesel	gals	87	$89	$2,250	n/a	n/a	n/a
Oakwood	10/01/02	10/31/02	1690	$10,138	n/a	n/a	diesel	gals	246	$249	$2,250	n/a	n/a	n/a
Oakwood	11/01/02	11/30/02	1556	$9,339	n/a	n/a	diesel	gals	94	$95	$2,250	n/a	n/a	n/a
Oakwood	12/1/2002	12/31/02	1543	$9,259	n/a	n/a	diesel	gals	0	$0	$2,250	n/a	n/a	n/a
Total			22340	$134,039					698	$707	$29,250			

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Prime Mover #	Start Date	End Date	Hours Run	kWh Output	Heat Recovered Displaced MCF	Heat Recovery Medium	Fuel Type	Fuel Units	Fuel Used MCF	Technical Difficulties
Unit #1	12/19/01	n/a								
	01/01/02	n/a								
	02/01/02	n/a								
	03/01/02	03/31/02	7	1269	6	glycol	nat gas	MCF	15	none
	04/01/02	04/30/02	102	10476	64	glycol	nat gas	MCF	223	none
	05/01/02	05/31/02	719	129436	312	glycol	nat gas	MCF	1587	none
	06/01/02	06/30/02	691	143340	192	glycol	nat gas	MCF	1938	none
	07/01/02	07/31/02	713	139379	103	glycol	nat gas	MCF	2023	none
	08/01/02	08/31/02	714	148945	118	glycol	nat gas	MCF	2001	none
	09/01/02	09/30/02	692	137610	143	glycol	nat gas	MCF	1855	none
	10/01/02	10/31/02	131	30948	91	glycol	nat gas	MCF	400	none
	11/01/02	11/30/02	8	852	4	glycol	nat gas	MCF	11	none
	12/01/02	12/31/02	0	0	0	glycol	nat gas	MCF	0	none
Unit # 2	12/19/01	12/31/02	312	51437	71	glycol	nat gas	MCF	633	none
	01/01/02	01/31/02	744	129600	598	glycol	nat gas	MCF	1595	none
	02/01/02	02/28/02	672	115370	618	glycol	nat gas	MCF	1430	none
	03/01/02	03/31/02	721	123137	577	glycol	nat gas	MCF	1541	none
	04/01/02	04/30/02	645	116466	403	glycol	nat gas	MCF	1409	none
	05/01/02	05/31/02	41	5033	18	glycol	nat gas	MCF	91	none
	06/01/02	06/30/02	128	5178	7	glycol	nat gas	MCF	70	none
	07/01/02	07/31/02	347	35040	26	glycol	nat gas	MCF	509	none
	08/01/02	08/31/02	254	28354	22	glycol	nat gas	MCF	381	none
	09/01/02	09/30/02	162	18597	19	glycol	nat gas	MCF	251	none
	10/01/02	10/31/02	606	99731	294	glycol	nat gas	MCF	1290	none
	11/01/02	11/30/02	699	120681	493	glycol	nat gas	MCF	1546	none
	12/01/02	12/31/02	729	130830	572	glycol	nat gas	MCF	1543	none
Diesel	12/19/01	n/a								
	01/01/02	n/a								
	02/01/02	n/a								
	03/01/02	03/31/02	3.17	626	n/a	n/a	Diesel	Gal.	52	none
	04/01/02	04/30/02	1.38	302	n/a	n/a	Diesel	Gal.	23	none
	05/01/02	05/31/02	0	0	n/a	n/a	Diesel	Gal.	0	none
	06/01/02	06/30/02	5.87	1006	n/a	n/a	Diesel	Gal.	96	none
	07/01/02	07/31/02	0.86	0	n/a	n/a	Diesel	Gal.	14	none
	08/01/02	08/31/02	5.22	1304	n/a	n/a	Diesel	Gal.	86	none
	09/01/02	09/30/02	5.33	1204	n/a	n/a	Diesel	Gal.	87	none
	10/01/02	10/31/02	15.02	2978	n/a	n/a	Diesel	Gal.	246	none
	11/01/02	11/30/02	5.73	1095	n/a	n/a	Diesel	Gal.	94	none
	12/01/02	12/31/02	0	0	n/a	n/a	Diesel	Gal.	0	none
Total			9880	1,730,225	4752					

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Prime Mover #	Date	Downtime Due to Repair	Planned?	Maintenance Activity	Cost of Maintenance
Unit #2	1/18/2002	n/a	yes	Scheduled Maintenance - oil sampling	$2,250
	1/28/2002	9 hrs	yes	Switch to diesel - perform	
				scheduled maintenance - Monthly list	
				Change oil, filters Check timing, valves,	
				batteries, plugs, air filters, glycol levels,	
				nuts, clamps, bolts - Switch back to	
				Unit #2	
Unit #2	2/28/2002	n/a	yes	Oil sampling	$2,250
Diesel	3/5/2002			Checked Block Heater	$2,250
Unit #2	3/12/2002	8 hrs	yes	Scheduled Maintenance - changed oil	
				and filters, oil sample, cleaned breather	
				element	
	3/14/2002	6.5 hrs	yes	Oil sampling, inspection	
				cleaned micro-spin, replaced air pre-filter	
Unit #1 &	4/29/2002	n/a	yes	Change over from Winter (#2) to	$2,250
Unit #2				Summer (#1)	
Unit #2	5/7/2002	n/a	no	Checked knock detection alarm	$2,250
Unit # 1 &	5/15/2002	n/a	yes	Scheduled Maintenance - Changed oil,	
Unit #2				checked fluid levels, checked heat	
				exchangers and fans, adjusted valves.	
				Building heat recovery loop bypassed	
				5/13 to 6/3 to boost domestic hot water	
				recovery due to installation of new	
				water heater.	
Unit #1	5/28/2002	n/a	yes	Oil Sample	
Unit #1	6/3/2002	n/a	yes	Scheduled Maintenance - checked	$2,250
				tightness of nuts & bolts on engine,	
				cleaned drip pan.	
	6/17/2002	n/a	yes	Oil Sample	
Unit #2	6/1/2002	n/a	yes	Check to see if engine would start w/	
				pre-alarm on	
	6/29/2002	n/a	no	Knock detect warning, reset, Engine started	
	6/30/2002	n/a	no	Knock detect warning, reset, Engine started	
Diesel	6/3/2002		yes	General inspection. checked batteries, belts,	
				tank, oil and water levels	

Unit #1	7/1/2002	n/a	yes	Oil Sample	$2,250
	7/23/2002	n/a	yes	Changed oil	
Unit #2	7/7/2002	n/a	no	Knock detect warning, reset, Engine started	
Unit #1&2	7/15/2002	n/a	yes	Scheduled Maintenance - filled oil	
				reservoir tanks, cleaned air filter &	
				breather element, took oil sample.	
Diesel	7/15/2002			General inspection. checked batteries, belts,	
				tank, oil and water levels	
Unit #1	8/1/2002	n/a	no	Changed oil filters	$2,250
	8/14/2002	n/a	yes	Oil sampling.	
	8/27/2002	n/a	yes	Scheduled Maintenance - Changed oil,	
				filters, micro-spin element. Checked	
				fluid levels and spark plugs.	
Unit #2	8/7/2002	n/a	no	Kraft replaced knock detection module.	
	8/27/2002	n/a	yes	Add oil to reservoir tank, check fluid	
				levels.	
Diesel	8/7/2002	n/a	no	Kraft replaced voltage regulator	
	8/27/2002	n/a	yes	General inspection. checked batteries, belts,	
				tank, oil and water levels	
Unit #1	9/26/2002	n/a	yes	Took oil sample.	$2,250
Unit #2	9/11/2002	n/a	no	Assisted Waukesha rep with inteface	
				with knock detector.	
Unit #1	10/2/2002		yes	New oil tank delivered	$2,250
	10/3/2002		yes	Installed oil fill line from oil storage tank	
	10/8/2002	n/a	yes	Changed oil, took oil and glycol samples	
	10/9/2002		no	Repaired Block Heater leak	
Unit #2	10/7/2002	n/a	yes	Changed oil. Opened exhaust bypass for	
				exhaust heat recovery. Took oil and	
				glycol samples. Changed to winter engine #2	
Diesel	10/9/2002		yes	Scheduled Maintenance - Changed oil fiters,	
				drain oil	
Unit #2	11/4/2002	n/a	yes	Took oil sample and checked fluid levels.	$2,250
	11/19 - 11/20/2002	n/a	yes	Scheduled Maintenance - Changed oil fiters,	
				micro-spin element, pre-air filter and spark	
				plugs. Checked and adjusted all fluid levels.	
Unit #1	11/19/2002	n/a	yes	Checked over and tightened oil pan.	
Diesel	11/19/2002			General inspection. checked batteries, belts,	
				tank, oil and water levels	
Unit #2	12/23/2002	n/a	yes	Oil sample	$2,250
	12/30/2002	n/a	no	Checked & replaced oil supply line to micro-spin	

DRESSER Waukesha

SAA No. 2001- 122

CERTIFICATION OF ENGINEERING APPROVAL

Are Special Codes or Equipment Required for this Approval? Y

List: Code 4287: 210°F JW Thermostats.
Code 1100: 176psi BMEP continuous with 5% overload.

Engineering Approval:

Ignition Timing 13 °BTDC Carb Setting (Lambda or MAFR) 7.8% O2

When operating per the site conditions listed and with a commercial quality natural gas consisting of 93% Methane by volume, WKI(TM)=91, and 900 Btu/ft3 SLHV, WED approves a maximum continuous rating of 432 BHP @1800 RPM with no overload requested.

For the site conditions listed and per the above stated fuel with the engine operating at the stated BHP @1800 RPM, the following heat rejection and emissions are stated below:

	--guaranteed--		-estimated-
BHP: (@1800 RPM)	432	324	216
BSFC: (Btu/bhp-hr)	7052±4%	7383±4%	8047
Induction Air: (scfm)	902±6%	708±6%	514
Exhaust Flow: (lb/hr)	3931±6%	3086±6%	2243
Exhaust Temp: (°F)	852±50	842±50	831
Heat To: (Btu/hr x 1000)			
Jacket Water:	734±6%	618±6%	492
Lube Oil:	115±6%	108±6%	99
Intercooler:	218±6%	141±6%	78
Total Exhaust:	803±6%	623±6%	445
Radiation:	76±25%	75±25%	74
Emissions Not To Exceed:			
*NOx: (g/bhp-hr)	2.0	2.0	1.95
CO: (g/bhp-hr)	1.75	1.75	1.75
NMHC: (g/bhp-hr)	0.75	0.75	0.75

* NOx emission at absolute humidity of 75 grains H2O/lb dry air.

Fuel must conform to WED "Gaseous Fuel Specification" S7884-7.

Joe Lange

Signed: Joe Lange

4/19/2001

Date: 04/19/2001

Mark J. Helgren

Signed: Mark J. Helgren

4/19/2001

Date: 04/19/2001