Combined Heat and Power (CHP) Level 1 Feasibility Analysis

Prepared for

Company B

Anytown, USA

EPA COMBINED HEAT AND POWER PARTNERSHIP

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1. Executive Summary

The EPA CHP Partnership has performed a Level 1 Preliminary Economic Analysis of the installation of a combined heat and power (CHP) system at Company B's facility in Anytown, USA.[1] The purpose of this analysis is to determine whether CHP is technically appropriate at this site and whether CHP would offer significant potential economic benefit to Company B, in order for the company to make a decision about whether to fund a more comprehensive study. We have analyzed the existing electrical and thermal needs of the site, have gathered anecdotal data regarding the site operations and existing equipment, and have spoken to site personnel about the current and planned utility plant needs of the facility. Our results indicate that the site is potentially a good candidate for a CHP project.

To run an economic analysis of a system with this level of data required the use of assumptions and averages. This preliminary analysis should therefore be considered an indicator of technical and economic potential only. The EPA CHP Partnership does not design or install CHP systems and cannot guarantee the economic savings projected in this analysis. Where assumptions have been made, we have attempted to be realistic or conservative. These assumptions will be detailed in the following report and suggestions will be provided as to the scope of engineering that would be part of a Level 2 Feasibility Analysis if Company B chooses to proceed to the next step of project development.

The Company B facility in Anytown, USA, has approximately one million square feet of conditioned space on the campus. Although the operation is single shift, the rigorously controlled environment of this research facility requires 100% outside air for supply and roughly 30 air changes per hour. These conditions impose significant chilled water and hot water requirements for terminal reheat. Medium pressure steam (100 psig) is used during the day for animal sanitation. The facility has a base electric load of 3500 kilowatts (kW). It is possible that the city of Anytown, USA, could build the facility, generate power for their system, and sell steam to the Company B campus at a discount.

This analysis looks primarily at the marginal cost of generation (operating costs only—including CHP system fuel, CHP maintenance costs, and a credit for CHP thermal output) for the various options considered. It also looks at the impact of the difference in gas transportation costs imposed by the city of Anytown, USA, and Utility B. The analysis modeled four gas turbine CHP systems at two natural gas pricing levels—

[1] The analysis was performed by Energy and Environmental Analysis, Inc,1655 N. Fort Myer Drive, Arlington, VA, 22209. EEA is a technical subcontractor supporting the EPA CHP Partnership.

$8/million British thermal unit (MMBtu) and $11/MMBtu. The systems are sized to meet the base thermal requirements of the facility so that 100% of the system's thermal output can be used on site. This approach to CHP system design is the most fuel efficient, most environmentally beneficial, and usually provides the best return on investment. Two of the systems evaluated produce power in excess of the facility's base electrical needs. In a Level 2 analysis, once detailed thermal profiles of the site have been developed, other system sizes and configurations should be explored. Table 1 summarizes the options that were studied and the resulting marginal cost of generation.

Table 1 – Summary of Results

	Option 1	Option 2	Option 3	Option 4
Gas Turbine	Turbine A*	Turbine B*	Turbine C*	Turbine C*
Number of Turbines	1	1	1	2
Total Capacity (kW)	3,490	3,495	4,550	9,100
Turnkey Price	$5,095,000	$6,750,000	$5,774,000	$9,624,000
Marginal Cost of Generation at $8/MMBtu	$0.0590/kWh	$0.0538/kWh	$0.0582/kWh	$0.0632/kWh
Marginal Cost of Generation at $11/MMBtu	$0.0788/kWh	$0.0718/kWh	$0.0770/kWh	$0.0839/kWh

* Turbines A, B, and C represent actual gas turbines. In a customized feasibility analysis, the EPA CHP Partnership would identify the turbine model and manufacturer.

A number of conclusions can be drawn from the results presented:

- A CHP system appears to be a viable energy management option for Company B. A Level 2 study should evaluate the impact of various ownership options for the CHP system, including having the system completely owned and operated by Company B or partnering with the city of Anytown, USA, to build the facility and arrange to buy steam at a discount from the utility.
- If the power is to be used solely on site, either the Turbine A or the Turbine B gas turbine systems appear to be viable candidates. The difference in the marginal cost of generation was not sufficient to rule out either turbine, nor was the difference in installed costs. Maintenance contract issues, as well as basic maintainability of each machine, could make a difference in the economics and should be evaluated in the Level 2 study.
- Supplementary firing to raise additional steam in the heat recovery steam generator is important to the overall performance of the Turbine A or the Turbine B system.
- If the facility is to be constructed and owned by the utility (or in partnership with the utility), then the single Turbine C gas turbine system appears to be a viable choice. Supplementary firing (even at the cost of installing emissions after

treatment[2]) should be considered for this machine and investigated in the Level 2 study.

- The option with two Turbine C turbines did not perform as well as the other options on a marginal cost of generation basis; this outcome is primarily because the thermal output of this option could be greater than the needs of Company B.
- Although marginal cost was the primary measure of comparative performance in this analysis and is most often the determining factor for dispatch decisions, it should noted that other critical considerations are often included in investment decisions. These considerations could include capital costs, emissions profile, and other potential benefits to the site, such as enhanced power reliability.

[2] Supplementary firing was not considered for either of the Turbine C options in this analysis because of the impact on emissions. Turbine C can meet current Anytown, USA emissions standards without after treatment. The addition of supplemental duct burners, however, might require the use of after treatment.

2. Preliminary Analysis Details and Assumptions

Facility Description

Company B's campus in Anytown, USA, is engaged in research and development. The facility is based in an area that has a moderate year-round climate. The 70-acre park-like campus in Anytown, USA, is located within close proximity to several major academic research institutions and numerous leading-edge companies in the region.

There are approximately one million square feet of conditioned space on the campus. Although the operation is single shift, the rigorously controlled environment of this research facility requires 100% outside air for supply and roughly 30 air changes per hour. These conditions impose significant chilled water and hot water requirements for terminal reheat. Medium pressure steam (100 psig) is used during the day for animal sanitation.

Power Requirements – The facility's electric and thermal loads were established by evaluating 15-minute interval data for gas and electric meters in 2004. Based on this analysis, the facility has a peak electric demand of approximately 8,000 kW, yearly average demand of about 4,700 kW, and a base electric load of 3,500 kW. The base power demand is primarily used to operate the air handlers that provide the 30 air changes per hour. Figure 1 illustrates the facility's average demand for 2004. From Figure 1, it can be seen that the minimum average demand occurs in the month of March. Figure 2 displays interval demand data for the month of March and indicates that the minimum demand occurred on March 28, 2004. Figure 3 displays the interval demand data for March 28. Figures 1, 2, and 3 confirm the 3500 kW base load power demand.

Figure 1 – Average Hourly Demand

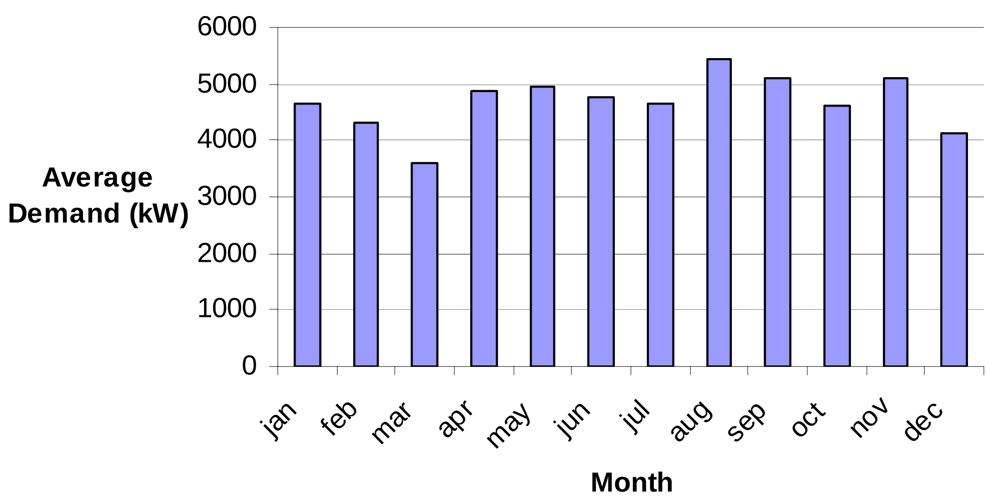


Figure 2 – Interval Demand Data for the Month of March

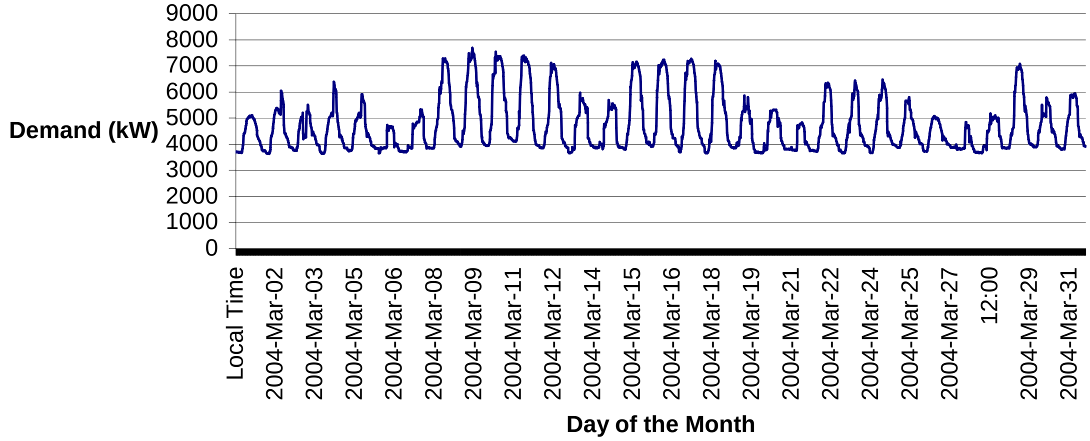
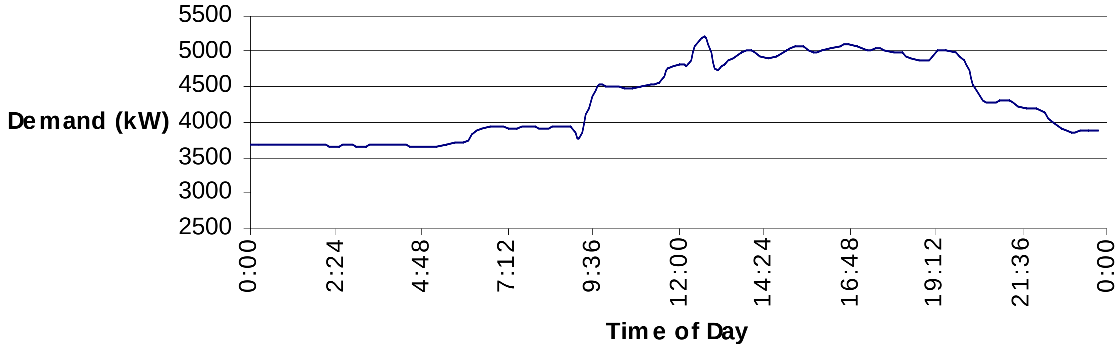
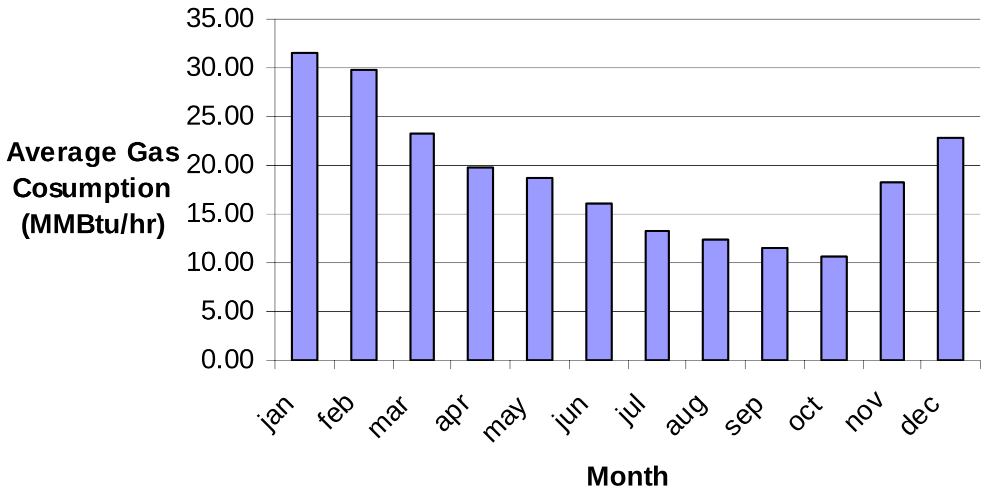


Figure 3 – Interval Demand Data for March 28, 2004



Thermal Requirements – Figure 4 demonstrates the facility's current average hourly demand for natural gas based on monthly natural gas bills.

Figure 4 – Average Hourly Natural Gas Consumption



As described above, natural gas is currently used for hot water (primarily for terminal reheat) and steam for process cleaning. The process steam is used during daily operations. Hot water is used to heat supply air to ensure the buildings meet the design point of 72°F (when necessary). Company B has made the corporate decision to replace their centrifugal chillers with double effect absorption chillers. Based on weather data and load data provided by Company B, Dr. John Smith of the city of Anytown, USA, developed an estimate of the facility's chilled water loads and the steam that would be required by the double effect absorbers to meet the estimated chilled water load. This analysis used the chilled water and steam estimates developed by Dr. Smith and overlaid the steam requirement of the proposed chillers to the steam that is currently required to supply the hot water and process steam needs for facility. The results (average hourly aggregate steam requirements) are shown in Figure 5.

Figure 5 – Average Hourly Aggregate Steam Requirements

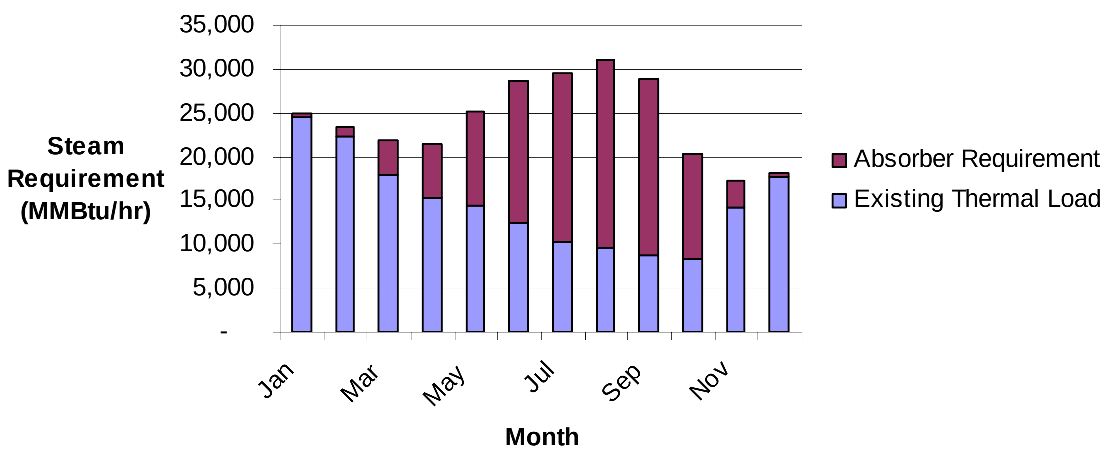


Figure 5 shows that the steam requirement of the absorption chiller fills in demand during the months when the facility's hot water demand tapers off. This analysis indicates that there will be a reliable steam demand of at least 17,000 to 20,000 lbs/hour year-round once the absorption chillers are installed. Table 2 presents the total purchased power and boiler fuel for the facility with current equipment (including existing electric chillers and based on 2004 utility data) and for the situation where the existing electrical centrifugal chillers are replaced by double effect absorption chillers. Annual purchased power is reduced by approximately 5,730,000 kilowatt-hours (kWh); boiler fuel is increased by 109,500 MMBtu/yr.

Table 2 – Facility Purchased Power and Boiler Fuel Consumption

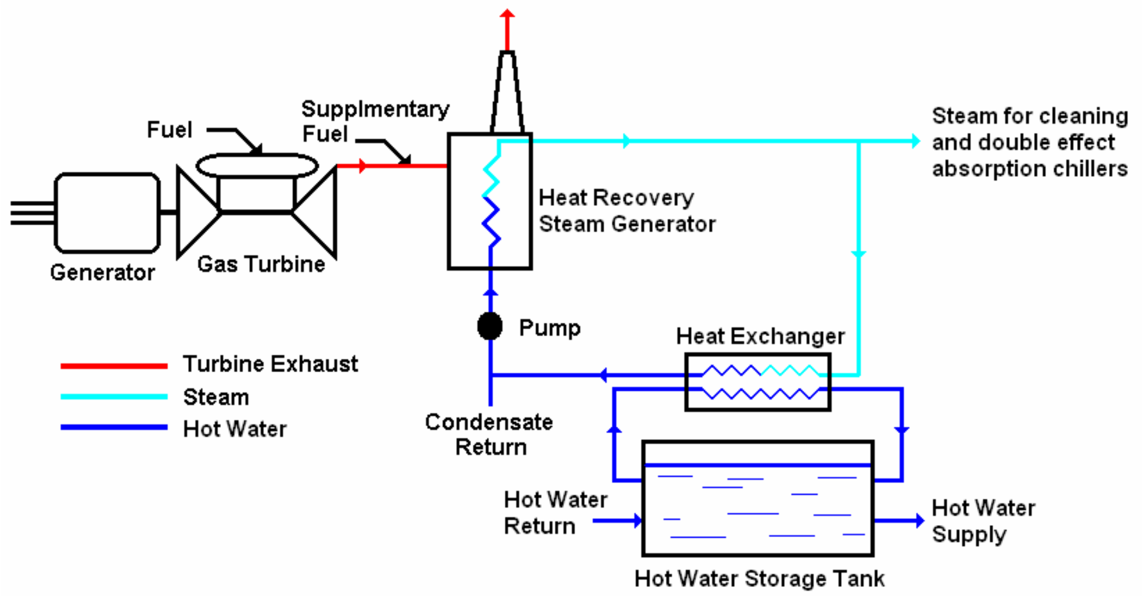
	Current Equipment (With Electric Chillers)	With Absorption Chillers
Annual Purchased Power (kWh)	40,988,040	35,258,040
Annual Boiler Fuel (MMBtu)	165,892	275,391

Dr. Smith's analysis calculated 24 hour daily averages for chiller operations, which was considered sufficient for this level of analysis. However, it is our understanding that the energy management system at the facility prevents chiller operation when the outside air temperature is below 64°F. Bin temperature data for the area seems to indicate that this operating regimen would result in virtually no chiller operation in the months of January, February, November, and December. Chiller operation in the summer would vary from 12 to 16 hours per day. This information needs to be studied much more closely in any Level 2 analysis to be certain that "needle peaks" for the steam consumption arising from absorption chiller operations are not masked by averaging chiller operation data. Further analysis also would help confirm the potential usefulness of chilled water storage to reduce such steam demand peaks.

Combined Heat and Power Options

Several CHP options based on gas turbine generators were evaluated. Gas turbines have long been used in CHP applications, and the steam that can be generated from hot turbine exhaust matches the steam conditions (temperature and pressure) that the Company B facility currently uses, along with the steam requirements of double effect absorption chillers. As shown in Figure 6, a gas turbine would generate electric power at the facility. This power could solely be used on site, or if Anytown's electric utility chose to build the plant, they could deliver the power to their grid. In the latter case, Company B would purchase 100% of their power needs from the utility. Hot exhaust is then routed to the heat recovery steam generator (HRSG). As will be discussed below, two analyzed options incorporated the use of a duct burner in the turbine exhaust to provide additional steam beyond what the unfired gas turbines could provide. (The turbine exhaust still has 15% oxygen sufficient to support further combustion.)

Figure 6 – System Schematic



Steam from the HRSG would be provided to meet three primary thermal demands. The first demand is heating the hot water that is required for domestic hot water needs and for terminal reheat in the heating, ventilation, and air conditioning (HVAC) system. Secondly, it might be useful to have a hot water storage tank[3] to provide the system with a thermal flywheel as indicated in Figure 6. Lastly, steam would also be supplied to the double effect absorption chillers and for the facility's cleaning requirements.

Gas Turbine Options

Three different gas turbines have been considered in this Level 1 analysis. These are Turbine A, Turbine B, and Turbine C.[4] Table 3 presents the key performance features for each of these machines.

Table 3 – Candidate Gas Turbines

	Turbine A	Turbine B	Turbine C
Net Generating Capacity (kW) each:	3,490	3,495	4,550
Heat Rate (Btu/kWh, HHV):	14,248	13,680	10,290
Electric Generating Efficiency (HHV):	24.0%	24.9%	33.2%
Duct Firing Capability:	Yes	Yes	No
Unfired Steam Production (lbs/hr):	19,600	20,000	14,100
Fired Steam Production (lbs/hr):	30,400	29,000	N/A

[3] The cost of hot water storage was not included in this analysis
[4] In a customized feasibility analysis, the EPA CHP Partnership would name actual equipment manufacturers to form the basis of this analysis.

The four cases included in this analysis consist of the following:

- Option 1 – One Turbine A (Power used only on site)
- Option 2 – One Turbine B (Power used only on site)
- Option 3 – One Turbine C (100% of the power exported)
- Option 4 – Two Turbine Cs (100% of the power exported)

Table 4 summarizes the key parameters of each proposed CHP option. For the first two options outlined in the table, an additional variation is considered—supplemental firing in the HRSG. Supplementary firing will allow the first two options to raise additional steam. Use of the supplemental burners can be modulated to match HRSG steam output to hourly steam demand at the facility.

Table 4 –CHP Options

	Option 1	Option 2	Option 3	Option 4
Gas Turbine:	Turbine A	Turbine B	Turbine C	Turbine C
Number of Turbines:	1	1	1	2
Total Capacity (kW):	3,490	3,495	4,550	9,100
Supplemental Firing Capability?	Yes	Yes	No[5]	No
Max Steam, unfired (lbs/hr)	19,600	20,000	14,100	28,200
Max Steam, fired (lbs/hr):	30,400	29,000	na	na
Fuel Consumption, Unfired (MMBtu/hr)	49.7	47.8	46.8	93.6
Fuel Consumption, Fired (MMBtu/hr):	61.4	56.8	na	na
Assumed Availability:	92%	92%	92%	92%

<u>Screening Analysis</u>

Electricity Production

As described above, the baseload electric demand of the plant was verified to be 3,500 kW. Annual plant operating hours are 8,760. The first two CHP options considered were both assumed to provide 3,490 kW and 3,495 kW respectively. The third option considered was 4,550 kW and the fourth option considered was 9,100 kW (twice the third option). For the first two options, all power output could be used on site. For the last two options, the gas turbines provide power output that exceeds the plant's base load. For conservatism, the analysis assumes an availability factor of 92% for the turbines, representing 8,059 run hours per year. Typical gas turbine systems have actual availabilities of 97 to 98%.

As described in Table 2, total plant power consumption is estimated to be 35,258,040 kWh/yr after conversion of the electric chillers to double effect absorption units; total needed boiler fuel without CHP is estimated to be 275,390 MMBtu/yr. The total power

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[5] It is believed that if Turbine C is not supplementary fired, that selective catalytic reduction (SCR) would not be required. However, adding a supplementary burner would change this. For Turbine A and Turbine B, SCR would be required as a NOx control measure regardless if the turbines were supplementary fired or not.

generated, CHP fuel consumed (including for the supplemental HRSG duct burner where appropriate), and boiler fuel consumed for steam needs not met by the CHP system for each of the options are shown in Table 5 and Table 6.

Table 5 – Annual CHP Energy Balance (Unfired HRSG Case)

	Option 1	Option 2	Option 3	Option 4
Gas Turbine	Turbine A	Turbine B	Turbine C	Turbine C
Number of Turbines	1	1	1	2
Total Generation (kWh)	28,203,667	28,244,074	36,769,824	73,539,648
Purchased Power (kWh)	7,054,373	7,013,966	35,258,040	35,258,040
CHP Fuel Consumed (MMBtu)	401,724	386,267	378,237	756,473
Boiler Fuel Consumed (MMBtu)	73,624	70,257	127,908	26,673

Table 6 – Annual CHP Energy Balance (Fired HRSG Case)

	Option 1	Option 2	Option 3	Option 4
Gas Turbine	Turbine A	Turbine B	Turbine C	Turbine C
Number of Turbines	1	1	1	2
Total Generation (kWh)	28,203,667	28,244,074	36,769,824	73,539,648
Purchased Power (kWh)	7,054,373	7,013,966	35,258,040	35,258,040
CHP Fuel Consumed (MMBtu)	440,037	419,937	378,237	756,473
Boiler Fuel Consumed (MMBtu)	22,031	24,311	127,908	26,673

Recommended Activities for Level 2: Assumptions on peak, average, and base electric loads should be reviewed in detail and specific seasonal and/or daily variations should be identified and included for system sizing and detailed economic calculations. A detailed electric profile would enable an accurate analysis of savings and would ensure that the system is sized correctly for the application. The load profile should also consider any projected load growth at the facility. As described earlier, a much more thorough analysis of the facility's chilled water consumption should be included in a Level 2 analysis. This information would help to confirm that the 3,500 kW baseload demand is unaffected by the switch from electric chillers to absorption chillers and would also more accurately estimate total annual power needs at the facility.

Thermal Energy Production

Options 1 and 2 (unfired simple cycle turbines) and Option 3 (single Turbine C) all produce thermal energy at levels at or below the 17 to 20 MMBtu/hr minimal thermal demands of the site (including absorption chiller requirements). Boiler fuel requirements, as shown in Table 5, remain significant in these options—to meet steam needs when hourly demand is beyond CHP system thermal capacities and when the systems are down for maintenance. Additional boiler fuel consumption is much lower for Options 1 and 2 with supplemental duct firing (Table 6) because the HRSG can increase steam output to meet higher peak hourly demands. The boiler fuel consumption in these two cases is essentially for supplying steam when the CHP systems are down for maintenance.

Similarly, the boiler fuel consumption for Option 4 (the two Turbine Cs) is for meeting steam demands when the turbines are down for maintenance. The tables do not show, however, that the average steam output of Option 4 at 29.2 MMBtu/hr often exceeds maximum hourly steam demands and is therefore underutilized.

Recommended Activities for Level 2: The Company B facility has fairly detailed 15-minute interval data available with which to measure likely minimum and maximum steam consumptions. Using monthly average data, while appropriate for this level of analysis, might mask steam consumption minimums that would lead to the dumping of thermal energy, which would hurt the project's overall economics. The use of interval data would prevent such an error. Interval data also should be used to confirm the usefulness of hot water storage and if useful, the necessary capacity.

Similarly, a much more thorough analysis of the facility's chilled water consumption should be included in a Level 2 analysis. This analysis would help confirm minimum and maximum steam requirements, as well as the potential usefulness of chilled water storage.

Budget Installation Costs

Preliminary budgetary cost estimates were developed for each option and included the following equipment: turbine/generator, HRSG, electrical switchgear and controls, mechanical interconnection to the existing thermal system, and necessary emission control system (SCR for Turbine A and Turbine B).[6].Budgetary estimates for each of the turbine systems were provided by the respective vendors. The Turbine A system and the Turbine B system were both quoted with duct burners. A discount was estimated based on in-house data for the lack of such a burner where appropriate for Options 1 and 2. The budget costs are turnkey and include engineering, labor, and commissioning. Total installed cost estimates for the six systems are detailed in Table 7 below.

Table 7 – Budgetary Cost Estimates

	Option 1	Option 2	Option 3	Option 4
Gas Turbine	Turbine A	Turbine B	Turbine C	Turbine C
Turnkey Price w/Duct Burner	$5,095,000	$6,750,000	$5,774,000	$9,624,000
Deduction for Duct Burner	($250,000)	($250,000)	N/A	N/A
Turnkey Price w/o DB	$4,845,000	$6,500,000	N/A	N/A
Price per kW (w/ DB)	$1,460/kW	$1,931/kW	$1,269/kW	$1,058/kW
Price per kW (w/o DB)	$1,388/kW	$1,860/kW	N/A	N/A
Incremental Maintenance	$0.006/kWh	$0.006/kWh	$0.008/kWh	$0.008/kWh

Recommended Activities for Level 2: Following the electrical and thermal energy analysis and system size/application decision detailed in the previous sections, substantial preliminary design engineering (30%) would enable an accurate installation cost to be

[6] A fuel gas compressor is not required because there is a high pressure transmission line just across the street from the plant.

determined for this system. Assumptions about the ability of existing plant systems to be used for the CHP system need to be confirmed. The requirements and cost of connecting with a nearby high pressure gas line would also have to be estimated. Installation cost issues will have the single biggest impact on return on investment for the project.

Emissions

Current emissions standards in Anytown, USA, are expected to require SCR for the Turbine A and the Turbine B systems. The Turbine C system, if installed without a duct burner, might be permittable without SCR.

Recommended Activities for Level 2: This analysis did not consider existing emissions at the Company B facility and how these emissions might impact compliance requirements for the CHP system. The level 2 analysis should evaluate costs associated with initial and ongoing environmental compliance and reporting. Once a decision to proceed with the project has been made, the site should engage qualified environmental consultants to manage environmental compliance, including confirmation of the anticipated requirements for emission control and reporting processes, and securing of construction permits.

Utility Interconnection

Options 1 and 2 would be designed to operate in parallel with the utility and will need to meet Utility B's interconnection and safety requirements.[7] It is anticipated that the power export options (3 and 4) would have the active participation of the Anytown, USA, utility in the design and implementation.

Recommended Activities for Level 2: Engage in preliminary discussions with Anytown, USA,'s municipal utility regarding interconnection and capture all costs associated with meeting interconnection requirements.

Maintenance

Based on our discussions with vendors, this analysis uses an incremental maintenance cost for the CHP systems of \$0.006/kWh for the Turbine A and Turbine B gas turbines and \$0.008/kWh for Turbine C.

[7] "Parallel" with the utility means the on-site generation system is electrically interconnected with the utility distribution system at a point of common coupling at the site (common busbar) and facility loads are met with a combination of grid- and self-generated power. Interconnection requires various levels of equipment safeguards to ensure power does not feed into the grid during grid outages. A parallel configuration is in contrast to "grid isolated" operation, wherein the CHP system serves either the entire facility or an isolated load with no interconnection with the utility's distribution system. Grid isolated systems typically require increased capacity to cover facility peak demands and redundancy for back-up support.

Recommended Activities for Level 2: A detailed maintenance proposal from the vendor of the equipment selected in the final design should be provided and associated costs included in the final economic analysis.

Power Reliability –CHP System as Backup Power

The primary benefit of a CHP system is that it produces power for less money than separate heat and power. An additional benefit can be the use of the onsite capacity to provide backup generation in the event of a utility outage. In certain applications, the value of this additional reliability can outweigh all other factors in the investment decision.

In order to implement this capability, there are added costs to tie into the existing electrical systems that are beyond the scope of this level of analysis. Those costs can include engineering, controls, labor, and materials. The engineering required to analyze the existing electrical system, determine critical loads, provide a design, and determine cost to provide backup power from the system can be fairly costly.

The justification for this additional cost should be financial: it pays to do it if there is a way to account for the benefits in the financial analysis. One simple method is to offset the turnkey cost of a similarly sized backup generator against the incremental cost of the CHP system. There are other ways to account for the reliability benefits using assumptions of avoided catastrophic revenue losses due to utility blackouts. Regardless of how the benefits are quantified, it is important to provide some estimate that captures reliability benefits to balance the incremental costs associated with this added capability.

Recommended Activities for Level 2: If the facility is interested in pursuing running the system in the event of a utility outage, the engineering firm hired to perform the Level 2 analysis should be very experienced in electrical design and use of CHP as a backup system. Extensive review of the site’s existing electrical system and identification of critical loads should be considered along with the system sizing criteria previously discussed in order to come up with the optimal system to meet the facility’s needs.

Baseline Utility Costs

The objective of this analysis was to calculate the marginal cost of generation of the various CHP options as a function of the fuel cost. Currently natural gas is transported to the facility by the Anytown, USA,’s municipal utility. To calculate the appropriate cost of fuel, the transportation rate of the utility must be added to an estimated natural gas commodity cost. The commodity cost is estimated by adjusting the 18-month strip at Henry Hub[8] by the approximate basis[9] between Henry Hub and the Anytown border. In addition, for comparison, the cost of fuel was calculated as if the natural gas had been

[8] This is a futures contract that would allow a company to buy a specified quantity of natural gas at a single price for the period of 18 months.

[9] The current difference in spot market prices of natural gas at Henry Hub and in Anytown, USA.

delivered by the utility at their electric generation transportation tariff. The cost of fuel is summarized in Table 8.

Table 8 – Cost of Fuel ($/MMBtu)

	Anytown, USA	Utility
Henry Hub 18 Month Strip	$11.53	11.53
Basis to State Border	($3.83)	($3.83)
Transportation Costs	$3.20	$0.20
Totals	$10.90	$7.90

Because this calculation is clearly speculative regarding the calculation of the commodity costs, the costs used in the analysis were rounded to $11.00/MMBtu and $8.00/MMBtu.

Recommended Activities for Level 2: Gas utilities are often willing to negotiate favorable gas rates for CHP sites based on their substantial, constant, year-round demand. A minor reduction in gas rates can have a profound impact on return on investment. Inquiries should be made into negotiated rates based on the projected volumes of gas consumption with CHP.

3. Economic Analysis

The results of the economic screening for the CHP options without supplemental duct burners are shown in Table 9 and graphically in Figure 7. The marginal cost of generation was calculated for each CHP option. The marginal cost includes operating costs only—including CHP system fuel, CHP maintenance costs, and any credit for CHP thermal output for the various options considered.

Table 9 – Marginal Costs of Generation (without supplemental firing)

	Option 1	Option 2	Option 3	Option 4
Gas Turbine	Turbine A	Turbine B	Turbine C	Turbine C
Number of Turbines	1	1	1	2
Total Capacity (kW)	3,490	3,495	4,550	9,100
Marginal Cost of Generation at $8/MMBtu	$0.0627/kWh	$0.0573/kWh	$0.0582/kWh	$0.0632/kWh
Marginal Cost of Generation at $11/MMBtu	$0.0840/kWh	$0.0765/kWh	$0.0770/kWh	$0.0839/kWh

Figure 7 – Marginal Costs of Generation (without supplemental firing)

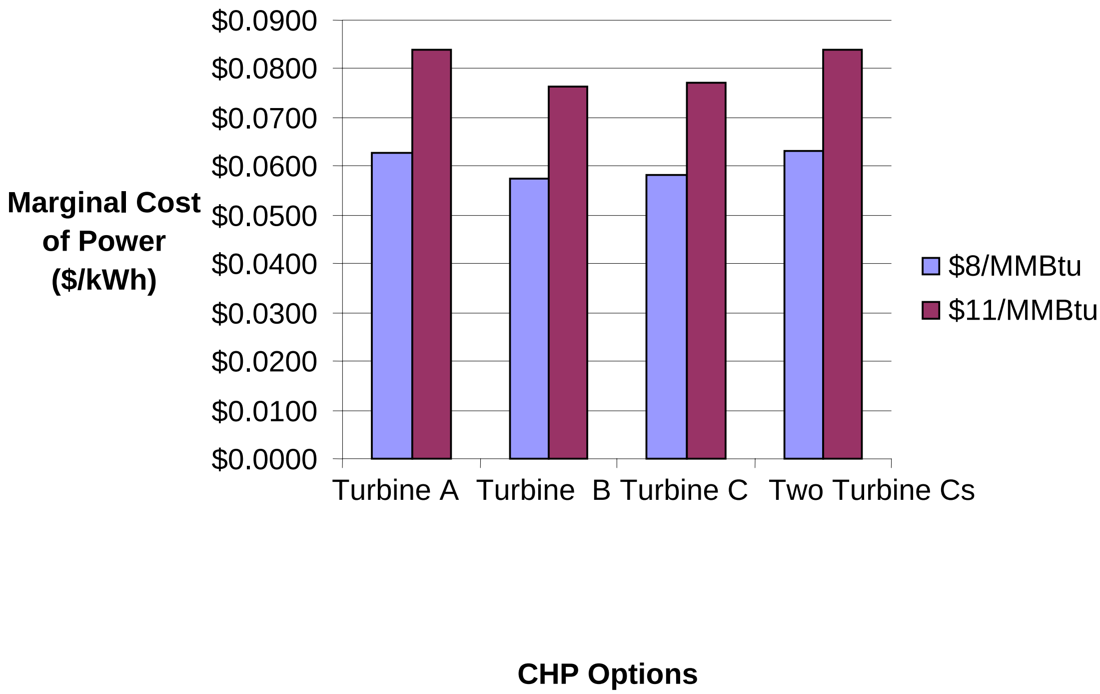
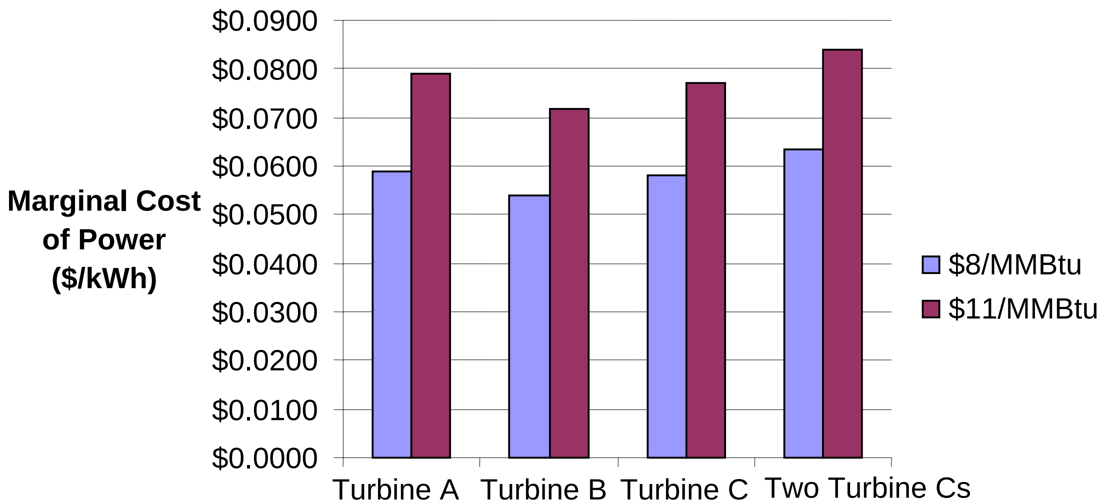


Table 10 and Figure 8 present the results for the CHP options with in inclusion of supplemental HRSG duct firing for Options 1 and 2.

Table 10 – Marginal Cost of Generation (with supplemental firing)

	Option 1	Option 2	Option 3	Option 4
Gas Turbine	Turbine A	Turbine B	Turbine C	Turbine C
Number of Turbines	1	1	1	2
Total Capacity (kW)	3,490	3,495	4,550	9,100
Marginal Cost of Generation at $8/MMBtu	$0.0590/kWh	$0.0538/kWh	$0.0582/kWh	$0.0632/kWh
Marginal Cost of Generation at $11/MMBtu	$0.0788/kWh	$0.0718/kWh	$0.0770/kWh	$0.0839/kWh

Figure 8 – Marginal Costs of Generation (with supplemental firing)



CHP Options

The best performing system, based on the marginal cost of generating, was the Turbine B gas turbine with supplementary firing. The primary reason for this outcome was that Turbine B is slightly more efficient than Turbine A and with supplementary firing, it could meet more of the thermal energy requirement than the single Turbine C. The results for the two Turbine C options varied. The single Turbine C had competitive marginal generating costs with the unfired simple cycle turbines used in Options 1 and 2. While the recuperated Turbine C produces much less usable thermal energy per kWh generated than either of the simple cycle turbines, the higher electric generating efficiency of Turbine C keeps marginal costs competitive. The greater thermal displacement of Options 1 and 2 when supplemental duct firing is added further lowers the marginal costs of these options—duct firing results in a $0.003 to $0.005/kWh reduction in marginal generating costs. The marginal costs of Option 4 (two Turbine Cs) are comparatively high due to the fact that there are times when the combined thermal output of the two-turbine system is above the thermal demands of the site and is essentially wasted.

The tables also illustrate that the $3/MMBtu difference in gas costs between the $8/MMBtu case and $11/MMBtu case results in an almost $0.02/kWh increase in marginal generating costs across the four options. Detailed summaries of the results are included in the appendix.

4. Conclusions

This Level 1 analysis points to several conclusions:

- A CHP system appears to be a viable energy management option for Company B. A Level 2 study should evaluate the impact of various ownership options for the CHP system, including having the system completely owned and operated by Company B or partnering with Anytown, USA, to build the facility and arrange to buy steam at a discount from the utility.
- If the power is to be used solely on site, either the Turbine A or the Turbine B systems appear to be viable candidates. The difference in the marginal cost of generation was not sufficient to rule out either turbine, nor was the difference in installed costs. Maintenance contract issues, as well as basic maintainability of each machine, certainly could make a difference in the economics and should be evaluated in the Level 2 study.
- Supplementary firing to raise additional steam in the heat recovery steam generator is important to the overall performance of the Turbine A or the Turbine B systems.
- If the facility is to be constructed and owned by the utility (or in partnership with the utility), then the single Turbine C system appears to be a viable choice. Supplementary firing (even at the cost of installing SCR[10]) should be considered for this machine and investigated in the Level 2 study.
- The option with two Turbine C turbines did not perform as well as the other options on a marginal cost of generation basis; this outcome is primarily because the thermal output of this option could be greater than the needs of Company B.
- Although marginal cost was the primary measure of comparative performance in this analysis and is most often the determining factor for dispatch decisions, it should noted that other critical considerations are often included in investment decisions. These considerations could include capital costs, emissions profile, and other potential benefits to the site, such as enhanced power reliability.

[10] Supplementary firing was not considered for either of the Turbine C options in this analysis because of the impact on emissions. Turbine C can meet current Anytown, USA emissions standards without aftertreatment. The addition of supplemental duct burners may require use of SCR.

Appendix

Company B - $8.00/MMBtu Gas Price Case

Plant Consumption Details

Peak Demand (Annual peak), kW	8,000	Based on 2004 electricity usage
Average MW Demand, kW	4,679	Based on 2004 electricity usage
Average Thermal Heating Demand, MMBtu/hr	15.15	Based on 2004 natural gas usage
Average thermal Cooling Demand, MMBtu/hr	10.00	Estimated based on converting existing chiller load to double effect absorption
Operating Hours	8,760	
Current Annual Power Consumption, kWh	40,988,040	Based on 2004 electricity usage
Base Case Annual Power Consumption, kWh	35,258,040	Based on converting existing chiller load to double effect absorption
Base Case Annual Thermal Consumption, MMBtu	220,313	Includes heating and cooling loads
Plant annual power to heat ratio	0.6	
Estimated Boiler Heater Efficiency %	80%	
Average Gas Cost $/MMBtu	$8.00	

CHP Options

Prime Mover	**Turbine A w/duct firing**	**Turbine A w/o duct firing**	**Turbine B w/duct firing**	**Turbine B w/o duct firing**	**One Turbine C**	**Two Turbine Cs**
Turbine Capacity, kW	3,490	3,490	3,495	3,495	4,550	4,550
Number of Turbines	1	1	1	1	1	2
Duct Burner Capability?	Yes	Yes	Yes	Yes	No	No
CHP System Electric Capacity kW	3,490	3,490	3,495	3,495	4,550	9,100
Electrical Efficiency, HHV	24.0%	24.0%	24.9%	24.9%	33.2%	33.2%
MMBtu/hr Thermal Provided (unfired)	20.3	20.3	20.7	20.7	14.6	29.2
Power to Heat Ratio	0.6	0.6	0.6	0.6	1.1	1.1
System Availability, %	92%	92%	92%	92%	92%	92%
System Hours of Operation	8,059	8,059	8,059	8,059	8,059	8,059
Power Generated Annually, kWh	28,203,667	28,203,667	28,244,074	28,244,074	36,769,824	73,539,648
Thermal Generated Annually, MMBtu	202,688	164,050	202,688	167,282	117,987	235,973
CHP Thermal, MMBtu/yr	164,050	164,050	167,282	167,282	117,987	235,973
Duct Burner Thermal, MMBtu/yr	38,638	0	35,405	0	0	0
Capital Cost, $	$5,095,000	$4,845,000	$6,750,000	$6,500,000	$5,774,400	$9,624,000
Capital Costs, $/kW	$1,460	$1,388	$1,931	$1,860	$1,269	$1,058
O&M Cost, $/kWh	$0.0060	$0.0060	$0.0060	$0.0060	$0.0080	$0.0080

Economics	**Base System***	**Turbine A w/duct firing**	**Turbine A w/o duct firing**	**Turbine B w/duct firing**	**Turbine B w/o duct firing**	**One Turbine C**	**Two Turbine Cs**
Energy Summary							
Purchased Power, kWh	35,258,040	7,054,373	7,054,373	7,013,966	7,013,966	35,258,040	35,258,040
Generated Power, kWh	0	28,203,667	28,203,667	28,244,074	28,244,074	36,769,824	73,539,648
Boiler Steam, MMBtu/yr	220,313	17,625	58,899	17,625	56,205	102,326	21,338
CHP Thermal Used, MMBtu/yr	0	202,688	164,050	202,688	167,282	117,987	198,975
Boiler Fuel, MMBtu/yr	275,391	22,031	73,624	22,031	70,257	127,908	26,673
CHP Fuel, MMBtu/yr (CHP system + duct burner)	0	440,037	401,724	421,853	386,267	378,237	756,473
Cost Summary							
Boiler Fuel Savings	n/a	($2,026,879)	($1,614,138)	($2,026,879)	($1,641,076)	($1,179,867)	($1,989,749)
CHP Fuel	n/a	$3,520,298	$3,213,791	$3,374,822	$3,090,139	$3,025,894	$6,051,787
CHP O&M	n/a	$169,222	$169,222	$169,464	$169,464	$294,159	$588,317
Total Costs	n/a	$1,662,641	$1,768,875	$1,517,407	$1,618,528	$2,140,185	$4,650,356
Cost per kWh Generated:	n/a	$0.0590	$0.0627	$0.0537	$0.0573	$0.0582	$0.0632

* Base System assumes existing chiller load converted to double effect absorption

Cost per Generated kWh = total incremental cost of CHP (CHP fuel+CHP O$M-boiler savings) diveded by kWh generated

Company B - $11.00/MMBtu Gas Price Case

Plant Consumption Details

Peak Demand (Annual peak), kW	8,000	Based on 2004 electricity usage
Average MW Demand, kW	4,679	Based on 2004 electricity usage
Average Thermal Heating Demand, MMBtu/hr	15.15	Based on 2004 natural gas usage
Average thermal Cooling Demand, MMBtu/hr	10.00	Estimated based on converting existing chiller load to double effect absorption
Operating Hours	8,760	
Current Annual Power Consumption, kWh	40,988,040	Based on 2004 electricity usage
Base Case Annual Power Consumption, kWh	35,258,040	Based on converting existing chiller load to double effect absorption
Base Case Annual Thermal Consumption, MMBtu	220,313	Includes heating and cooling loads
Plant annual power to heat ratio	0.6	
Estimated Boiler Heater Efficiency %	80%	
Average Gas Cost $/MMBtu	$11.00	

CHP Options	**A**	**B**	**C**	**D**	**E**	**F**
Prime Mover	**Turbine A w/duct firing**	**Turbine A w/o duct firing**	**Turbine B w/duct firing**	**Turbine B w/o duct firing**	**One Turbine C**	**Two Turbine Cs**
Turbine Capacity, kW	3,490	3,490	3,495	3,495	4,550	4,550
Number of Turbines	1	1	1	1	1	2
Duct Burner Capability?	Yes	Yes	Yes	Yes	No	No
CHP System Electric Capacity kW	3,490	3,490	3,495	3,495	4,550	9,100
Electrical Efficiency, HHV	24.0%	24.0%	24.9%	24.9%	33.2%	33.2%
MMBtu/hr Thermal Provided (unfired)	20.3	20.3	20.7	20.7	14.6	29.2
Power to Heat Ratio	0.6	0.6	0.6	0.6	1.1	1.1
System Availability, %	92%	92%	92%	92%	92%	92%
System Hours of Operation	8,059	8,059	8,059	8,059	8,059	8,059
Power Generated Annually, kWh	28,203,667	28,203,667	28,244,074	28,244,074	36,769,824	73,539,648
Thermal Generated Annually, MMBtu	202,688	164,050	202,688	167,282	117,987	235,973
CHP Thermal, MMBtu/yr	164,050	164,050	167,282	167,282	117,987	235,973
Duct Burner Thermal, MMBtu/yr	38,638	0	35,405	0	0	0
	5.095		6.75			9.624
Capital Cost, $	$5,095,000	$4,845,000	$6,750,000	$6,500,000	$5,774,400	$9,624,000
Capital Costs, $/kW	$1,460	$1,388	$1,931	$1,860	$1,269	$1,058
O&M Cost, $/kWh	$0.0060	$0.0060	$0.0060	$0.0060	$0.0080	$0.0080

Economics	**Base System***	**Turbine A w/duct firing**	**Turbine A w/o duct firing**	**Turbine B w/duct firing**	**Turbine B w/o duct firing**	**One Turbine C**	**Two Turbine Cs**
Energy Summary							
Purchased Power, kWh	35,258,040	7,054,373	7,054,373	7,013,966	7,013,966	35,258,040	35,258,040
Generated Power, kWh	0	28,203,667	28,203,667	28,244,074	28,244,074	36,769,824	73,539,648
Boiler Steam, MMBtu/yr	220,313	17,625	58,899	17,625	56,205	102,326	21,338
CHP Thermal Used, MMBtu/yr	0	202,688	164,050	202,688	167,282	117,987	198,975
Boiler Fuel, MMBtu/yr	275,391	22,031	73,624	22,031	70,257	127,908	26,673
CHP Fuel, MMBtu/yr (CHP system + duct burner)	0	440,037	401,724	421,853	386,267	378,237	756,473
Cost Summary							
Boiler Fuel Savings	n/a	($2,786,958)	($2,219,440)	($2,786,958)	($2,256,479)	($1,622,317)	($2,735,905)
CHP Fuel	n/a	$4,840,410	$4,418,963	$4,640,380	$4,248,942	$4,160,604	$8,321,208
CHP O&M	n/a	$169,222	$169,222	$169,464	$169,464	$294,159	$588,317
Total Costs	n/a	$2,222,673	$2,368,745	$2,022,886	$2,161,927	$2,832,446	$6,173,620
Cost per kWh Generated*:	n/a	$0.0788	$0.0840	$0.0716	$0.0765	$0.0770	$0.0839

* Base System assumes existing chiller load converted to double effect absorption

Cost per Generated kWh = total incremental cost of CHP (CHP fuel+CHP O$M-boiler savings) diveded by kWh generated