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Defense Supply Center Columbus Central Heat Plant Modernization

Plant Assessment

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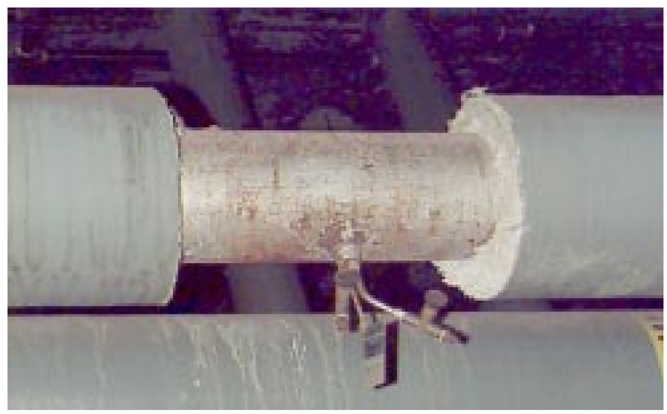

The Department of Defense (DOD) owns a large number of aging district heating systems, typically consisting of a central heat plant (CHP) and a heat distribution system. Many of these systems are nearing the end of their useful life, and incur significant maintenance and repair costs to keep them operational. This study focused on the CHP at the Defense Supply Center Columbus (DSCC), Columbus, OH to help the installation meet long-term goals of reduced energy consumption and improved air quality. Condition assessment surveys were done at the DSCC CHP. Researchers evaluated the current state of the system, provided list of modernization options, and proposed a modernization plan.

Foreword

This study was conducted for the Defense Supply Center Columbus (DSCC), Columbus, OH, under Military Interdepartmental Purchase Request (MIPR) No. SC070060089. The technical monitor was Ed Poprock, DSCC-WIC.

The work was performed by the Energy Branch (CF-E) of the Facilities Division (CF), U.S. Army Construction Engineering Research Laboratory (CERL). The CERL principal investigator was Michael K. Brewer. Mark W. Slaughter is Chief, CECER-CF-E; and Dr. L. Michael Golish is Chief, CECER-CF. The CERL technical editor was William J. Wolfe, Information Technology Laboratory.

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1 Introduction

Background

The Department of Defense (DOD) owns a large number of aging district heating systems, typically consisting of a central heat plant (CHP) and a heat distribution system. Many of these systems are nearing the end of their useful life, and incur significant maintenance and repair costs to keep them operational. Typical system designs were developed when energy costs were low and when energy efficiency was not seen to be as important a factor as it is now. To meet long-term goals of reduced energy consumption and improved air quality, the DOD's energy supply infrastructure must be revitalized. The CHP at Defense Supply Center Columbus (DSCC), Columbus, OH, is one such facility in need of repairs. DSCC tasked the U.S. Army Construction Engineering Research Laboratory (CERL) to help the installation develop a modernization plan to efficiently effect CHP repairs and system improvements.

Objectives

The objectives of this study were to conduct condition assessment surveys of the CHP at the DSCC to determine the existing state of the system, and to provide modernization options to DSCC.

Approach

1. CERL was tasked to conduct site investigations and equipment inspections at DSCC. During site visits from 21-25 October 1996 and 25-27 November 1996, CERL and its contractor, Schmidt Associates Inc. (SAI) conducted operational tests and "cold iron" inspections. Site visits and meetings fiscal year 1997 (FY97) and FY98 have helped to refine the analysis to accommodate potential mission changes.

2. The assessment team reviewed plant machinery history, system schematics, technical manuals, and plant logs (Figures 1 to 10).

3. The team constructed a model of the CHP and HTHW system using HEATMAP and other analysis tools.

4. Historical data, condition assessments, and plant configuration information were analyzed and processed with existing CERL modeling tools.

5. A series of modernization options were outlined, and a modernization plan was proposed to implement the most desirable modernization alternative.

Mode of Technology Transfer

As part of this project, CERL has delivered the HEATMAP model as a turnkey hardware and software package to allow DSCC to manipulate the model parameters for utility planning purposes. CERL has also trained DSCC personnel on the use of HEATMAP.

2 CHP Assessment

During the 21-25 October 1996 site visit, CERL and SAI conducted flue gas analysis at various locations along the flue gas path to evaluate pollution control effectiveness. Inspections were conducted on the furnace grates, forced draft plenums, furnace tubes, generation bank, generator outlet duct, mechanical dust collectors (MDCs), and electrostatic precipitators (ESPs). Appendix A summarizes test data.

During the 25-27 November 1996 site visit, CERL inspected furnace tube failures in Unit #1. At DSCC's request, CERL contracted NALCO* to conduct a tube failure analysis of the tube metal. Appendix B contains the NALCO metallurgical analysis report. NALCO reported that oxygen pitting and long-term overheating of the generator tubes were likely causes of tube failure.

Coal Handling Systems

DSCC reports excessive levels of coal fines in the storage pile runoff. The storage area does have a low curb around it, but does not have any runoff treatment. At an earlier point in time, DSCC had minimized runoff by using coal pile covers. No covers are in use now.

Pneumatic and Electronic Controls

The coal-fired units have a mix of electronic and electro-mechanical controls. The newer gas-fired unit has electronic and mechanical controls installed near the burner front.

DSCC is in the middle of an electrical system upgrade. CERL did not review the upgrade plan or inspect equipment installation.

* NALCO Chemical Co., Naperville, IL 60563-1198.

Combustion Air Flow Systems

The forced draft fan (FDF) takes suction near the roof. The FDF inlet duct forms the outside surface of the generator outlet duct. This is meant to capture a small amount of heat from the flue gas stream. However, the common duct wall between the FDF inlet air duct and generator outlet air duct is corroding due to acid condensation in the outlet ducting. The duct wall has several holes 3 to 5 in. in diameter due to the flue gas acid corrosion. At the generator outlet, the pressure is about -1.5 in WC. Although the FDF duct pressure in the vicinity of the holes was not measured, it would most likely not be as negative. Therefore, cooler FDF duct air would be drawn into the flue gas stream via the holes and further cool the gas and cause acid condensation on pollution control equipment (Figure 1). Researchers also observed that the Induced Draft (ID) and FD fan motors needed supplemental cooling with large floor fans.

High Temperature Hot Water (HTHW) Generators

Spreader Stoker

The Riley Stokers were inspected by J.W. Chappel from SAI. The rotor blades appear to be set correctly to distribute the coal evenly. However, Chappel recommends feeding coal to the stoker while in a maintenance shutdown to observe the throw of the coal without fire in the furnace. CERL and SAI can provide support in blade setting during shutdown if desired.

Traveling Grate

The grate in Unit #1 was satisfactory for firing in the 1996-1997 heating season. However, some of the components need repair or replacing such as bowed T-bars, bent rails, endclip seals, overgrate seal shoes (which need replacement due to crystallization), and worn skid shoes. The rear right thermocouple is also missing. The bent and worn components may cause the grate to bind as well as leak in tramp air (Figures 2 and 3).

Figure 1. Hole in No. 3 outlet duct.

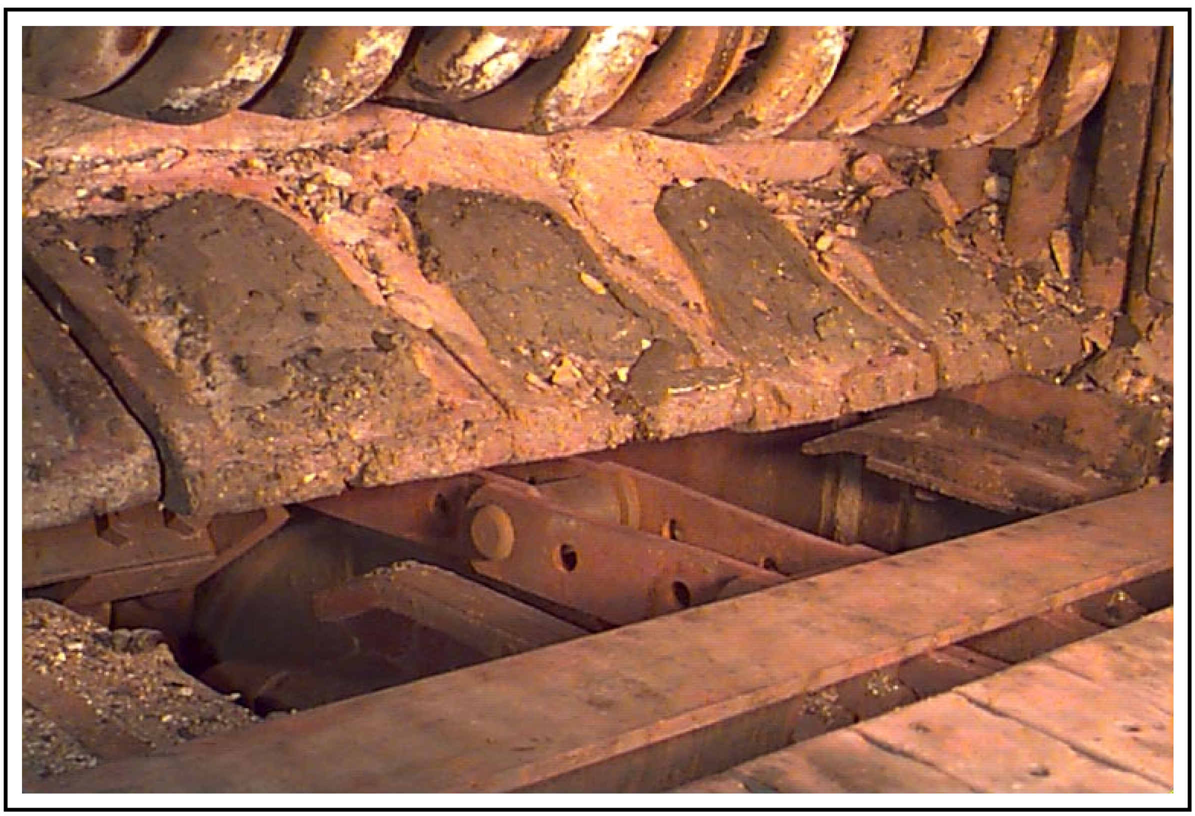

Figure 2. Rear grate seal shoes crystallized.

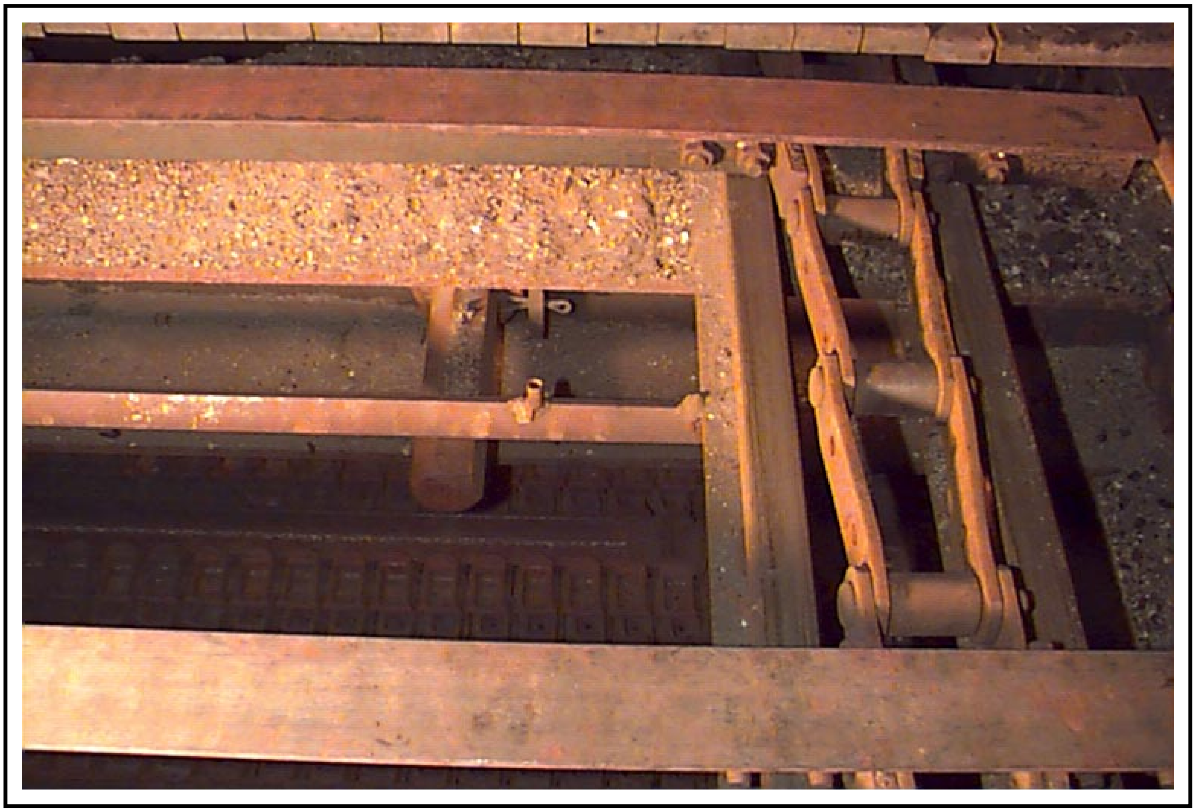

Figure 3. Missing thermocouple, Unit No. 1.

Furnace Tubes

Several tubes in Unit #1 have failed during attempted startup in the 1996-1997 heating season. As noted in the NALCO analysis, widespread oxygen pitting is suspected. The tube sample also showed signs of low level, long-term overheating.

In generator #3, the wall tubes on the right side appear to have been overheated. Some of the tubes have moved away from the wall. Lower portions of some of the wall tubes have metal surface patterns uncharacteristic of normal tubes. The metal irregularities could be due to excessive metal temperatures (Figure 4). At least 25 tubes on the left furnace look newer than the rest of the furnace.

During FY97, DSCC implemented tube repairs to units #1 and #3 to correct the tube failures discovered in FY96.

Figure 4. Overhead furnace wall tube, Generator No. 3.

Furnace Casing and Refractory

Large sections of the refractory have become wet from the water leaks in unit #1. It is likely that moisture has migrated into the casing insulation as well (Figure 5). Major portions of the refractory were replaced as part of the retubing in FY97.

Generation Tubes

The tubes were externally inspected from the top and the bottom. The tubes appear to be in good condition.

In the back pass of Unit #3, the refractory has failed in spots. The backwall and part of the side wall tubes are pushed out from the wall. Some of the header plugs are weeping and may need new seals at the next maintenance shutdown. The generation bank tubes also need air lancing to remove debris.

Figure 5. Water soaked refractory, Unit No. 1.

Multi-Cyclone Dust Collectors (MDC)

MDC #1 needs major repairs. Researchers observed a lot of flyash in the east hopper. It was not determined whether the ash was there due to an operational oversight or system malfunction. The bottom portion of the lower tubes is severely worn. The back row of spinners was also clogged with wet ash deposits. The MDC inlet dampers were not working. These dampers allow the operator to remove part of the MDC from service during low loads to keep the flue gas velocity high enough for proper dust collection. Several of the upper tubes were severely worn. The wear was so severe that a hole had developed in Tube E3. Many of the spinners are severely worn as well. At the MDC exit, wet ash has collected on top of the tube sheet. Rope packing is needed in MDC outlet expansion joint to reduce flue gas condensation in that stagnation area.

MDC #3 also requires major repairs. Several of the top tubes and spinners were worn (Figure 6). Dust collector C2 spinner is installed backward. Lower tube C3 is severely cracked and is likely to fall out soon (Figure 7). Maintenance personnel should be aware of the falling object hazard when entering the hopper to inspect or repair the MDC. At least four of the lower tube boots have broken tabs and are falling out of place (Figure 8).

Figure 6. Hole in upper tube, MDC No. 1.

Figure 7. Cracked lower tube, MDC No. 3.

Figure 8. Broken lower tube boot tabs, MDC No. 3.

The MDC is one of the simplest pollution control devices for coal boilers. As the first cleanup device, it removes the greatest amount of particulate. A correctly designed and operated MDC can clean the flue gas of most stoker boilers to compliance standards at steady state condition.

Electrostatic Precipitators (ESP)

The ESPs are in need of major repair or replacement. Moisture is entering the ESP via roof leaks (Figure 9). The plates are bowed and warped. Plate spreader bars have been installed to mitigate the bowing. However, the plates have continued to be overheated, which has been causing further warpage. The overheating may be caused by glowing ash deposits. If the oxygen level in the flue gas is above 9 percent, the carbon in the flyash will continue to burn and generate heat as it is collected on the plates. Oxygen levels of 11 to 12 percent were measured during the November 1996 site visit.

The warping and bowing prevents the wires from being centered between the plates (Figure 10). The ESP must have the wires within 1/2-in. of the mid-point of the gap between the plates. Many of the wires on the ESP are out of position 2 in. or more.

If the ESP plates and wires are in correct alignment and the field controls are properly adjusted, the field voltage should be high enough to cause 50 sparks per minute. If the spark rate is too low, the field will not be strong enough to impart a charge to the dust particles. If it is too high, the electrical discharge will be inefficient and, in the presence of high oxygen, could cause ash fires in the ESP.

Pneumatic Ash Handling System

There were abnormally high levels of ash in some of the ash hoppers. It was not determined whether this was due to an operational oversight or system degradation. The ash silo was being repaired during the October 1996 visit.

Figure 9. Roof leak in ESP.

Figure 10. Warped plates and wires off center in ESP.

HTHW Distribution System, Including Piping, Valves, Generator Pumps, and Distribution Pumps

Three of the mechanical rooms were visited. No major problems were noted in the cursory tour. The buildings are mostly served by HTHW to steam converters. A few buildings are served by HTHW to Low Temperature Hot Water (LTHW) converters or HTHW directly. The steam converters are more sensitive to temperature fluctuations. One of the purposes of the small gas-fired unit is to boost the temperature of the HTHW supply during certain conditions so that distant steam converters can produce the required pressure. CERL material engineers conducted a site visit 23 November 1998 to assess the serviceability of the HTHW distribution piping. The external inspection and water samples indicated that the piping is in fair to good condition and is not in danger of imminent failure. Table 1 summarizes inspection and repair status of the entire system.

Table 1. Inspection and repair summary.

Component	Inspected	Condition	Repair
Storage Pile	Nov-96	Coal fines in runoff	
Pneumatic and Electric Controls	NA		Upgrade in progress 96-97
Combustion Air System	Nov-96	Hole in FDF duct. Fan motors overheating	
Spreader Stoker	Nov-96	Static check satisfactory. Recommend coal throw check.	
Traveling Grate	Nov-96	Repair and replace worn and bent grate components.	
Furnace Tubes	Nov-96	Overheated and pitted tubes	Retubed Units #1 and #3 FY97.
Furnace Casing and Refractory	Nov-96	Moisture damage	Replaced during retubing FY97
Generation Tubes	Nov-96	Refractory in backpass of #3 has failed. Leaking header plugs.	
Multi-Cyclone Dust Collectors	Nov-96	Broken and worn out tubes. Leaking seals.	
Electro-Static Precipitators	Nov-96	Plates bowed and warped. Wires off-center. Leaks. High O_2 levels.	
Pneumatic Ash Handling	Nov-96	High ash levels in hoppers	Repair in progress Nov 96
High Temperature Hot Water Piping and water chemistry	Nov-98	Water samples satisfactory. Water softener may be undersized or ineffective.	

Water Treatment Systems

The water chemistry samples drawn by CERL indicated that hardness is being controlled. However, the pH is running too high at 11.5. The hot water system should maintain a pH of 9 to 10.5 to avoid copper corrosion in heat exchangers. The sulfite level should be controlled to 50-100 ppm. Although the samples were less than 50 ppm, some sulfite was lost due to air entrained in the sampling and shipping procedure.

3 CHP and HTHW System Thermal Model

A model was constructed of the CHP and HTHW system using HEATMAP and other analysis tools. Historical data, condition assessments, and plant configuration information will be analyzed and processed with existing CERL modeling tools. CERL delivered the HEATMAP model in October 1998 as a turnkey hardware and software package to allow DSCC to manipulate the model parameters for utility planning purposes. As part of the turnkey package, CERL trained DSCC personnel on the use of HEATMAP. A summary of the HEATMAP output is in Appendix C. A summary of the analysis data sheets are in Appendix D.

Preliminary thermal energy supply analysis has been done on the existing system. Table 2 summarizes the plant model.

Table 2. Distribution Model Summary

Scenario	Annual Fuel (Mbtu/yr)	Peak HTHW Energy (Mbtu/hr)	System Losses (Mbtu/yr)	Piping Construction Cost ($) **
Log estimates	124,659	78		
101 – HTHW Current Loads	104,280	82.6	10,065	5,775,151
104 – HTHW Load reduced by demolition	60,210	48	3,019	5,595,247
105 – HTHW Load reduced by demolition, dry pipe conversion, and Bldg 41 &42 small boilers	33,288	25.7	3,302	5,091,478
106 – LTHW Current Load reduced by demolition, dry pipe conversion, and Bldg 41,42 and 27 small boilers	21,133	18.2	3,619	2,549,957

* Closure not achieved on log reading. Instrumentation has lost calibration. Log estimates adjusted using fuel consumption.

** Construction costs from HEATMAP default tables. For a new system analysis, the estimating tables would be reviewed and modified to match expected construction practices.

4 Development and Evaluation of CHP Modernization Options

Plant Alternatives

Over 19 different repair alternatives were calculated over the course of the study. In general, the alternatives were combinations of central plants, decentralized systems, government labor, contracted labor, coal, interruptible gas, firm gas, government O&M, third party O&M, load reductions due to demolition, load reduction due to dry pipe fire protection, baghouse pollution control and ESP pollution control. All of the data files were provided to DSCC throughout the project. However, to help develop a workable heat utility plan, only the more competitive options are summarized in this report. Additionally, the alternatives are grouped according to the heat loads they serve. DSCC expects to reduce the heating needs due to demolition and conversion to dry pipe fire protection conversion. CERL analyzed the cost of alternatives along a “glide path” from the current building heat load of 79.6 MBTU/hr to 37.5 MBTU/hr. Appendix D includes a data summary of repair alternatives for the CHP.

Basis for Life Cycle Costing for DSCC Project

Information/estimates were furnished by SAI and CERL. The most current version of the WinLCCID software was used for the calculations. A life cycle of 25 years was used with residual values for the central plant improvements as central plants have life expectancies of twice that of small commercial grade equipment. Appendix E shows the LCCID output.

OM&R costs for central plants were derived from industrial plants in Ohio, U.S. Army coal plant data, and DSCC cost data. Government manpower costs were derived from the most current wage grade pay scale for Columbus, OH. Central plant energy costs were estimated from 4 year averages of Redbook fuel data and HEATMAP analysis. SAI furnished new construction costs. Third party OM&R costs were scaled to that seen at Ohio industrial stoker plants.

Energy rate information were provided by Bonnie Stillwagon, DESC (tel. [703] 767-8544). DESC is currently providing firm and interruptible gas to other Federal Government customers in the area (DOE). Based on the cost of interruptible natural gas to DOE from September 1996 to February 1997, and on an estimate of the cost from the city gate to the burner tip, the cost would be $4.66/Mbtu. A price survey done in June 98 determined that Columbia gas would charge $1.50 per mcf (MBtu) to deliver gas to DSCC. Assuming the June 1998 city gate cost of $2.80/mcf, the delivered cost to DSCC would be about $4.30/mcf for interruptible gas. The utility, Columbia Gas (POC Patti Spangler, tel. [614] 460-2157), would charge a firm rate of about $6.00/Mbtu. The cost for DESC-provided #2 fuel oil would be $0.63/gal ($4.53/Mbtu).

The mix of fuel usage was determined assuming that the plant would operate from October to April. For gas use, firing for most of the 6 months would be on interruptible gas with firing on #2 backup only for the few days (zero to 10 days) of a curtailment.

Decentralized boiler OM&R was estimated from decentralized studies and market surveys conducted for Fort Meade and Fort Drum. Since the boilers will be gas only, firm gas will need to be purchased. For decentralized furnaces, 286,650 Btu/hr hot air furnaces will heat the buildings. Three FTE's will remain to operate and maintain the decentralized furnaces. OM&R estimated at about $100/year/unit.

Full Load Alternatives

Table 3 tabulates the top six options for the current load. This set of options assumes that that all the current buildings heated in 1997 will continue to need heating and that the government would operate the systems. Some of the buildings will continue to have wet pipe fire protection even though the material stored in them does not require heating. The peak building load is approximately 79 MBTU/hr.

The base case is to convert the coal stokers to gas and provide oil backup. Although coal is the status quo, significant capital must be invested in the pollution control system. Decentralized boilers have the least life cycle cost due to the large savings in labor and maintenance. However, the large capital investment has a long payback. The Army recommends energy conservation projects have savings to investment ratios (SIR's) above 3. Decentralization will save some energy by avoiding the line loses but the fuel bill will be higher due to the premium paid for firm gas.

Table 3. Full load (Scenario 101) heating options.

Name	Capital Cost	Labor Cost	OM&R	Fuel	LCC NPV	SIR	DPP
Gas Conversion - Oil BU	1,500,000	594,168	169,813	450,046	18,450,230		
Coal - Baghouse	2,570,000	594,168	319,596	210,725	17,381,820	2.1	12
Coal -ESP	2,760,000	594,168	319,596	210,725	17,530,620	1.8	14
New Gas Unit - Oil BU	3,270,000	594,168	169,813	450,046	19,835,840	0.1	99
Decentralized - Boilers	4,764,176	130,663	100,100	520,443	15,441,100	2	9
Decentralized - Furnaces	8,957,231	130,663	27,100	492,239	17,782,330	1.1	21

Reduced Load Alternatives (Demolition)

Table 4 tabulates the top 3 options for a reduced load. The coal-fired options were dropped as they will be even less competitive with a reduced load. Even though the fuel cost may drop for the coal options, the labor, and operations and maintenance costs will not drop proportionately to the fuel usage decline. For the central plant, only one coal HTHW unit would be converted to gas. The full staff is left in the plant even though the work load would be significantly reduced by not burning coal. The peak building heating load will be approximately 60 MBTU/hr.

Two factors increase the competitiveness of the decentralized options. First, the demolition reduces the construction cost about 25 percent. Second, the annual costs of the decentralized options are dramatically less than those of the central plant option. At this load point, with a SIR of 4, using decentralized boilers is a viable alternative.

Table 4. Reduced load (Scenario 104) heating options.

Option	Name	Capital Cost	Labor Cost	OM&R	Fuel	LCC NPV	SIR	DPP
3.40	Gas Conversion - Oil BU	1,895,000	594,168	184,899	325,846	17,135,530		
8.40	Decentralized - Boilers	3,640,000	87,369	76,937	380,284	11,358,890	4.7	4
9.40	Decentralized - Furnaces	6,051,209	87,369	30,986	364,919	12,661,800	2.2	8

Reduced Load Alternatives (Demolition, Dry Pipe Conversion)

Table 5 tabulates the top 3 options for a reduced load. For the central plant, only one coal HTHW unit would be converted to gas. The full staff is left in the plant even though the work load would be significantly reduced by not burning coal. The load is reduced even more as almost 1 million sq ft of building space are allowed to go cold once the fire protection system is converted to a dry pipe system. Some consideration must be given to heating the lavatory areas with small heating systems. The cost of converting the fire protection is included in the option capital cost.

These options also include the cost of installing small boilers at Buildings 41 and 42. For this set of options, the fixed costs associated with the central plant make it uneconomical when compared to decentralized plants. There is not enough load and load density to make the central plant viable. CERL also analyzed a set of scenarios that included the cost of a small boiler in Building 27. However, those calculations show that decentralized systems are still the best alternative with a greatly reduced heating load.

Table 5. Reduced load (Scenario 105) heating options.

Option	Name	Capital Cost	Labor Cost	OM&R	Fuel	LCC NPV	SIR	SIR
3.50	Gas Conversion - Oil BU	3,030,584	594,168	184,899	208,051	17,395,280	0.0	0.0
8.50	Decentralized – Boilers	3,495,584	87,369	48,643	233,521	10,752,480	19.3	1
9.50	Decentralized – Furnaces	4,694,067	87,369	23,186	226,197	11,242,330	5.7	3

Analysis Summary

With the present building load, it is desirable to select the option with the lowest first cost as the other alternatives do not have a satisfactory payback. CERL and Schmidt cost estimates show that converting to gas in at least one of the coal fired units is less costly than installing a baghouse or new ESP. Not repairing or replacing the ESP is not a prudent course of action if the central plant is to be maintained.

If the long-term plan is to demolish excess space and install dry pipe fire protection, decentralized heating is the most life cycle cost effective. The savings in labor and fuel will rapidly payback the capital cost differential. The difference in cost between decentralized boilers and furnaces is not large. An assessment of each building's comfort needs should be done to determine which system best serves the occupants. The total costs for the decentralized boiler option was slightly lower as the existing HTHW/Steam converter mechanical rooms were assumed to be satisfactory locations for the package boilers. Much of the building steam heat system was assumed to be serviceable for the new boilers. Individual gas furnaces will require more gas piping in the building. However, point-of-use gas furnaces and gas radiant heaters may best serve the building heating needs. The effect of the change in load on alternative costs is shown in Figures 11-13.

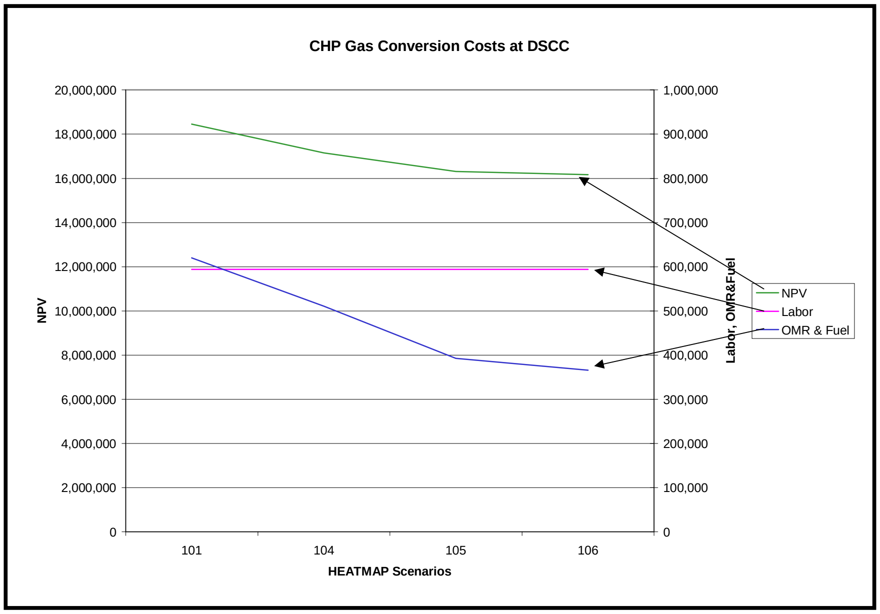

Figure 11. Gas conversion costs with decreasing load.

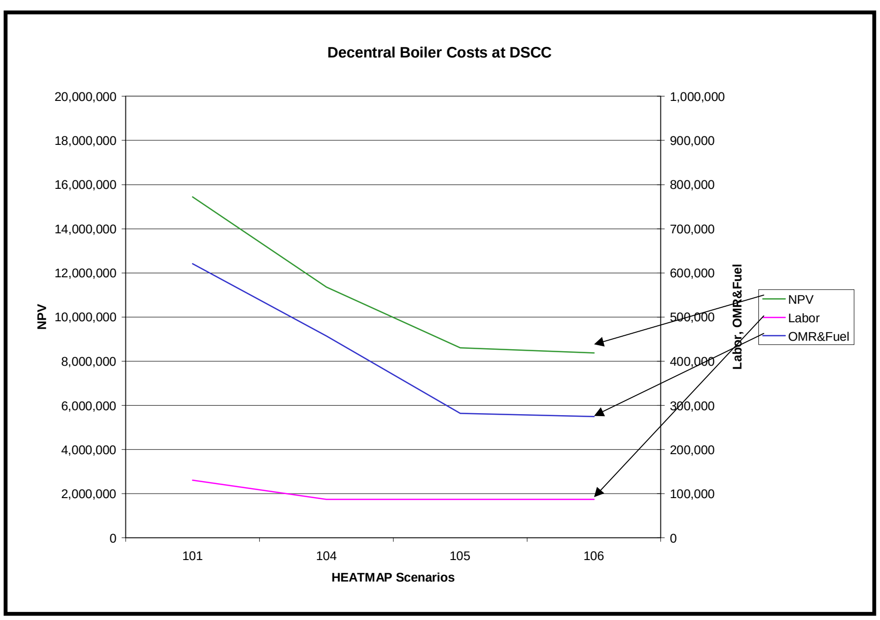

Figure 12. Decentralized boiler costs with decreasing load.

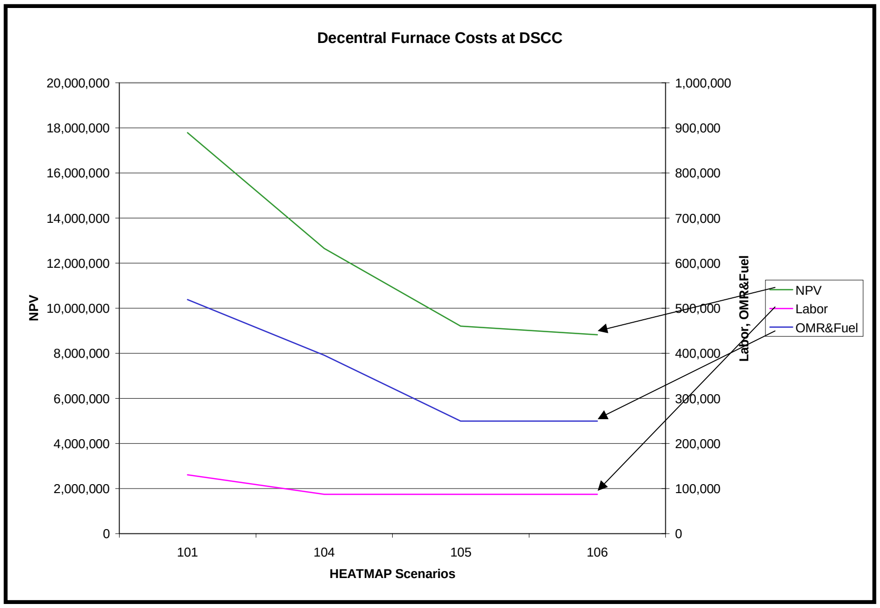

Figure 13. Decentralized furnace costs with decreasing load.

These figures indicate that, if the expected load reduction occurs, decentralized heating will be the most economical heating strategy. However, converting all of the existing buildings to decentralized heating is not currently cost effective.

5 Plant Modernization Plan

Based on the results of the study, CERL and its contractor, Schmidt and Associates, recommend a heat utility modernization schedule be developed. The team recommends short- and long-term actions to modernize the heating systems.

Short Term

Until a demolition schedule is agreed upon, the central plant will need to be maintained. The current pollution control system is need of repair. Plant records have shown that one coal boiler and the smaller gas boiler have carried the load though a whole winter. If a gas curtailment occurs, two coal boilers will be needed to meet a peak load of 80 MBTU/hr. If some buildings were allowed to have minimal heating, one boiler might be able to meet the load. DSCC's planners need to determine a reasonable schedule for funding of the demolition of the excess buildings and conversion of the remaining building to decentralized heating. It is likely that the central plant will need to operate at least two to five more heating seasons. If continued operation of coal is desired, repairs to the MDC should be conducted this summer as a minimum to reduce the cost risks associated with emission compliance. SAI has estimated that the cost to replace the MDC *alone* is about $80K in the context of a larger repair project. The cost of doing that one repair may be much higher as the mobilization costs will not be spread over as many work items. If a conversion of one boiler to gas with oil backup can be effected quickly, that will greatly reduce the emission compliance risk while waiting for the demolition and dry pipe conversion to occur.

Long Term

The long range goal should be to decentralize if the demolition and dry pipe conversion will occur. If the current load will be maintained, then the coal-fired units should be converted to gas with oil backup.

Plan Development

CERL and its contractor, SAI, can provide detailed information on implementing the most desirable modernization alternative once it is clear what load must be served. To develop construction specifications the Louisville District Corps of Engineers Office can be consulted. They can provide a variety of design, contracting, and construction services to implement the heating system modernization.

The CERL technical point of contact for this project is Michael Brewer, (217) 352-6511, X-7375 (voice), (217) 373-3430 (fax). The mailing address is:

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PO Box 9005
Champaign, IL 61826-9005

6 Conclusion

1. This study conducted condition assessment surveys of the CHP at the DSCC to determine the existing state of the system (Chapters 2 and 3).

2. The results of the surveys were analyzed, and alternative modernization options were derived from this information (Chapter 4).

3. A modernization plan was proposed to implement the most desirable alternative, and to train DSCC personnel in the use of the proposed hardware and software (Chapter 5).

Appendix A: Site Visit Data Sheets

Utility Modernization Analysis — Site General Data

Notice to users:
This spreadsheet is to assist a base or command engineer assess the economic viability of several energy supply options. It contains data extracted from site visits, HEATMAP analysis, EIS files, LCCID program files and historical cost data. For more information about the analysis contact the Utilities Division, USACERL, Champaign, IL 61826-9005 (800)872-2375 ext 5505.

Input Section Fill in all shaded boxes

Installation Name:	Defense Supply Center Columbus, OH		
Installation POCs	Ed Poprock		
MACOM POC			
Project Title	Plant Modernization at DSCC		
Project Description			
Estimated Cost		Form #/Work Order	
Design Status (0-100%)		Status of 1391 (0-100%)	
Designer			
Design POC			
Design Completion Date		Projected Project Start Date	

Note to user: Calculated fields are in blue text. Data input fields are in black or red text. Check the field comments and links before overriding a calculated field.

Utility Modernization Analysis — Site General Data

Site Information

Utility Rate Information:

Natural Gas Utility Rates:

Cooling Rate	0.600	$/therm	from		through	
Firm Boiler Rate	0.60	$/therm	from		through	

Elect/Gas Use Cost Ratio:

Electric Utility Rates:

Summer Demand		$/kW	from		through	
Ratchet		%	from		through	
Winter Demand		$/kW	Energy Ratio			
Energy	0.0312	$/kWh	Smr. El/Gas:	1.524	Wntr El/Gas:	1.524
			Demand/Gas	0.000		0.000

Fuel rate Information:

#2 Oil ($/gal)	0.63	$/MBTU	4.53	Coal Spec:		
#6 Oil ($/gal)		$/MBTU				
Coal ($/ton)	$50.59	$/MBTU	1.87			
Gas ($/ccf)	0.43	$/MBTU	4.30	Int		
Gas ($/ccf)	0.60	$/MBTU	6.00	Firm		

Annual Degree Days: Heating 5,702 Cooling 809

NOTE: Review demand charge calculations to determine appropriate values to enter for number of applicable months.

NOTE: The above rates should include any applicable taxes and surcharges.

Chillers	Chiller #	Chiller #	Chiller #	Chiller #	
Capacity					tons (circle one)
Type					(cent., recip., screw, absorb)
Manufacturer					
Age					
Last Inspection Date					
Condition					
Primary Fuel					

Distribution System Length [ ] feet Diameter of Main [ ] inches

Type of Distribution System: Direct Buried, Above Ground, or Shallow Trench (circle one)

Distribution System is: Loop, Branched, or Combination (circle one)

Utility Modernization Analysis — Site General Data

Technology Considerations

	YES/NO
Is it replacement in kind?	y

Different Technology Considerations:	YES/NO
Central Energy Plants	Y
Decentralized system	Y
Standalone Satellite Plants and Distribution	Y
Satellite Plants with Common Distribution	
Other	

Fuels Considered:	Primary	Alternate
Natural Gas	Y	Y
Fuel Oil	Y	Y
Coal	Y	
Wood		
Other		

Describe Other	

	Heating
LTHW	In Bldg
HTHW	CHP
Steam	In Bldg

	Cooling
Electric	
Engine Driven Chillers	
Absorption	

Distribution System Type:	YES/NO
Above Ground	Y
Shallow Trench	N
Direct Buried	

Distribution System Type:	YES/NO
Above Ground	
Shallow Trench	
Direct Buried	

Master Planning Coordination:	
Are the projects compatible with CURRENT infrastructure projects?	
Are the projects compatible with PLANNED infrastructure projects?	

Condition Ratings:	
Is the Installation Status Report (ISR) used to rate the central plants?	
Is the Installation Status Report used to rate the distribution systems?	
Is anything being done to reevaluate ISR readings?	

	Plant Personnel:	Telephone/Fax
Plant Engineer	Ed Poprock	(614) 692-6703, FAX 3093
Plant Foreman		(614) 692-2717,3645
Plant Operator		
Plant Maintenance		

	Heating/Cooling Mechanical Shop:	Telephone/Fax
Chief		
Foreman	Art Thompson	
Maintenance		

Utility Bills		
Gas Co Rep	Patti Spangle Columbia Gas	(614) 460-2157

Utility Modernization Analysis — Heat Plant Data

Existing Equipment

Plant Data

Plant Peak Load		**lbs/hr** or MBbu/hr (circle one)				
Plant No-Load Load		**lbs/hr** or MBbu/hr (circle one)				
Reported M/U Rate (Daily Ave)		gallons				
Plant Annual Coal Use	4617	Tons	13500	Btu/lbs	124659	MBTU/yr
Plant Annual Steam Prod.		KLbs stm	180	Days Oper.	0.0%	Ave Eff
Peak Plant Capacity	180	lbs/hr or **MBTU/hr** (circle one)				
Plant Annual Oil Use		Gallons	139,000	Btu/gal	0	MBTU/yr
Plant Annual Gas Use		ccf	0.1	MBTU/ccf	0	MBTU/yr

Boilers

	Unit #1	Unit #2	Unit #3		
Capacity	70	40	70		lbs/hr or **MBTU/hr** (circle one)
Type	WT	WT	WT		(water tube, fire tube)
Convection Heating Surface	6993		6993		ft2
Water Wall Surface	1238	582	1238		ft2
Total HS	8231	2441	8231		
MAWP Pressure	500	500	500		
Oper Pressure					
Safety Set Press					
Manufacturer	IBW	Geo. Marker	Erie City		
Built	1962	1995	1962		
NBPVII No.	M2913	FCW-11-941	M2911		
Last Inspection Date					
Condition					
Grate	Riley				
Burner Data					
Primary Fuel	Coal	N. Gas	Coal		
Alternate Fuel	none	none	none		
Controls					
Safety Vlv					
WS Internal		Sl. Scale			
FS Intermal		No Hot Spt			

Utility Modernization Analysis — Plant Water Treatment Data

Water Treatment System

Water Treatment Equipment and Chemicals used or Contractor (please list)					
Makeup Rate	0	gallons/day	0	lbs/hr (ave)	0.00 gpm
Ave Annualized Makeup Rate	#DIV/0!	Peak	#DIV/0!	No/Low Load	

Water Treatment Beds

Regeneration		Manual/Auto			
Bed Types		Zeolite Softner/H-OH IX			
Number of Beds					
Bed Diameter (in)		X-Area (ft2)	0.00	Max rate	0.00 gpm
Vessel Ht. (in)		Bed Ht. (est)	0	Bed Vol (est)	0.00 ft3
Resin Cap (18-24K/ft3)					

Water Analysis

Hardness		ppm
Conductivity		microMho
TDS		ppm

Utility Modernization Analysis — Boiler Data Sheet

Boiler Test Data (Unit #3) - DSCC, Columbus, OH

Enerac ESP Inlet 25-Nov-96

Time	16:20	16:30	16:40	16:50	17:00	17:10
Combustion Eff(%)	84.4	84.3	84.2	84.9	85	85.6
Amb Temp (F)	65	66	65	65	65	67
Stack Temp (F)	254	262	265	283	265	251
O2 (dry)	12.0%	11.8%	11.9%	10.4%	11.1%	11.1%
CO(ppm)	26	25	23	29	16	14
CO2	7.7%	7.9%	7.9%	9.1%	8.5%	8.5%
Combustibles	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
Boiler outlet (in WC)						
Excess Air %	108.0%	104.0%	105.0%	80.0%	91.0%	92.0%
NO (pm)	189.0	182.0	182.0	237.0	210.0	171.0
NO2 (ppm)	0	0	0	0	4	0
NOx (ppm)	189	182	182	237	213	171
SOx (ppm)	385	399	399	461	433	409

Plant/Gage Readings

Flue Gas Temp (F)	371	371	373	369	369	364
Oxygen %	7.6	7.5	7.6	8.3	7.6	6.7
H2OFlow(Klbs/hr)	490.3	502.3	503.7	505.4	505.6	505.8
Btu Out(KBtu/hr)	26800	28500	28600	33900	34800	35600
H2O Temp In (F)	367	364	364	343	342	340
H2O Temp Out (F)	426	427	427	423	426	426
Furn Press (in WC)	-0.12	-0.08	-0.08	-0.08	-0.06	-0.07
Last Pass (in WC)	-1.1	-1.1	-1.1	-1.5	-1.5	-1.5
ID Fan Inlet (in WC)	-1.6	-1.6	-1.7	-2.6	-2.6	-2.5
Opacity	1.6	1.4	19.8	2.5	2.6	1.6
HW Inlet (psig)	328	330	333	335	335	334
HW Outlet (psig)	346	345	346	349	350	350

Generator Outlet Data

Oxygen %	8.1	8.1	8.3	9.6	8.3	7.6
Combustibles %	0	0.1	0	0	0	0.2
CO(ppm)	20	21	22	23	27	0
Temperature (F)	391	394	396	397	408	394
Static Press(in H2O)	-0.65	-0.7	-0.71	-0.86	-1.4	-1.0

Mechanical Collector Input

Oxygen %	8.5	8.1	8.4	6.3	8.8	7.6
CO(ppm)	0	0.1	0	0.1	0.1	0.2
Combustibles %	32	32	26	58	22	0
Temperature (F)	374	374	375	371	376	369
Static Press(in H2O)	-0.64	-0.71	-0.7	-0.86	-1.4	-1.0

Mechanical Collector Output

Oxygen %	8.6	8.8	7.8	8.3	8.5	7.9
CO(ppm)	0.1	0.1	0.1	0.1	0.1	0.2
Combustibles %	30	30	24	31	0	0
Temperature (F)	368	369	370	365	368	364
Static Press(in H2O)	-1.4	-1.55	-1.5	-2.7	-2.6	-2.15

Utility Modernization Analysis — Boiler Calc. Sheet I

Boiler Test Data		Fuel (Btu/lb)	13500
ESP Outlet			
Ave. Enerac Data	25-Nov-96		Calculated
(ESP Inlet) Time	16:45	Excess Air	63.90%
Combustion Eff(%)	84.7	Eff w/o rad	84.99%
Amb Temp (F)	66	Rad Loss	1.50%
Stack Temp (F)	263	Eff w/rad	83.5%
O2 (dry)	11.4%		Fuel Curve
CO(ppm)	22	Btu/lb	12048
CO2	8.3%	Excess Air	65.0%
Combust	0.11%	Eff w/o rad	83.5%
Boiler outlet (in WC)		Rad Loss	1.5%
Excess Air %	96.7%	Eff w/rad	82.0%
NOx (pm)	195		
NOx (pm)	1		
NOx (pm)	196		
SOx (ppm)	414		

Ave. Plant/Gage Readings	
Flue Gas Temp (F)	370
Oxygen %	7.6
H2OFlow(Klbs/hr)	502.2
Btu Out(KBtu/hr)	31367
H2O Temp In (F)	353
H2O Temp Out (F)	426
Furn Press (in WC)	-0.08
Last Pass (in WC)	-1.3
ID Fan Inlet (in WC)	-2.1
Opacity	4.92
HW Inlet (psig)	333
HW Outlet (psig)	348
Ave. Generator Outlet Data	
Oxygen %	8.3
Combustibles %	0.1
CO(ppm)	19
Temperature (F)	397
Static Press(in H2O)	-0.89
Ave. Mechanical Collector Input	
Oxygen %	8.0
CO(ppm)	0.08
Combustibles %	28
Temperature (F)	373
Static Press(in H2O)	-0.89
Ave. Mechanical Collector Output	
Oxygen %	8.3
CO(ppm)	0.12
Combustibles %	19
Temperature (F)	367
Static Press(in H2O)	-1.98

Utility Modernization Analysis — Boiler Calc. Sheet II

Coal Boilers				Flue Gas Losses			
	Btu/lb	T amb (F)	Flue gas (F)	Dry Gas	Water Vapor	Unacctd.	Total Loss
HHV	13500	396.7	80	0.09531	0.03977	0.01500	15.01%
Combustion Eff		84.99%		Stochiometric	Excess Air		
Fuel	% lb/lb AF	lb/lbmol	lbmol/lb AF	lbmol/lb AF	lbmole/lb AF		
C	70.41%	12	0.05868				
H2	4.83%	2	0.02415				
O2	8.28%	32	0.00259				
N2	1.41%	28	0.00050				
S	1.01%	32	0.00032				
H2O (liq)	8.05%	18	0.00447				
Ash	6.08%	MW	Mole Fract				
Total	100.07%						
Air				0.32037002			
N2	79.00%			0.25319359			
O2	21.00%			0.06730463			
Incremental Excess Air					0.04301		
Excess Air %					64%		

Dry gas loss includes sensible heat in water vapor. Water vapor loss include fuel moisture and H2 formation. 1.5% unaccounted in coal.

Balance C, H2 and S for stocimetric conditions. Balance O2, N2 at excess air conditions.

Solution balances the combustion equation for stochiometric conditions and then calculates excess air and recalculates flue gas products and properties

Flue Gas		% Gas Vol (dr	Dry Gas Fract	LbMoles/lb fuel
O2	8.33%	8.33%	0.08333	
CO (ppm)	18.83	0.00%	0.00002	
CO2	not meas			0.05750
Combustibles	0.05%	0.05%	0.00050	
NOx (ppm)		0.00%	0.00000	
SOx (ppm)		0.00%	0.00000	
H2O				0.02862
N2				0.25357
SO2				0.00032
				0.42386

Assume 2% carbon loss to ash (98% C forms CO2)

			deg F	346.7			
	Polynomial Coeff		deg K	447.981481			
Gas	a	b	c	cp	cp ave (Btu/lb	lbmole/lb fuel	Btu/lb fuel deg F
CO2	10.34	0.00274	-195500	10.5933175	10.5933175	0.05750	0.60913164
SO2	7.7	0.0053	0.00000083	10.2408724	10.2408724	0.00032	0.00323228
H2O	8.22	0.00015	0.00000134	8.55611835	8.55611835	0.02862	0.24489512
N2	6.5	0.001		6.94798148	6.94798148	0.41528328	2.88538056
O2	8.27	0.000258	-187700	7.45029383	7.45029383	0.04301	0.32043064
						Sum	4.06307024

Polynomial equations from Perry's Chemical Handbook Table 3-181, Originally from US Bureau of Mines Bull 371, 1934 and USBM Bull 477, 1948.

Utility Modernization Analysis Boiler Data Sheet

Boiler Test Data (Unit #3) - DSCC, Columbus, OH

Enerac ESP Inlet 25-Nov-96

Time	16:00	16:10	16:11	16:13	16:15	
Combustion Eff(%)			86.1%	82.2%	79.9%	
Amb Temp (F)			66	66	66	
Stack Temp (F)			124	204	232	
O2 (dry)			15.6%	12.6%	12.9%	
CO(ppm)			10	18	28	
CO2			3.0%	4.7%	4.6%	
Combustibles			0.00%	0.04%	0.11%	
Boiler outlet (in WC)						
Excess Air %			259%	135%	141.0%	
NO (pm)			79	143	172	
NO2 (ppm)			0	1	0	
NOx (ppm)			79	143	172	
SOx (ppm)			46	267	351	

Plant/Gage Readings

Flue Gas Temp (F)	366	369				
Oxygen %	9.3	6.9				
H2OFlow(Klbs/hr)	484.8	489.3				
Btu Out(KBtu/hr)	25100	26700				
H2O Temp In (F)	368	367				
H2O Temp Out (F)	422	426				
Furn Press (in WC)	-0.03	-0.09				
Last Pass (in WC)	-1.1	-1.0				
ID Fan Inlet (in WC)	-1.4	-1.4				
Opacity	1.2	1.4				
HW Inlet (psig)	326	328				
HW Outlet (psig)	341	346				

Generator Outlet Data

Oxygen %	8.6	8.3				
CO(ppm)	0	0				
Combustibles %	24	17				
Temperature (F)	384	388				
Static Press(in H2O)	-0.63	-0.57				

Mechanical Collector Input

Oxygen %	8.5	8.3				
CO(ppm)	0	0				
Combustibles %	29	25				
Temperature (F)	370	370				
Static Press(in H2O)	-0.55	-0.57				

Mechanical Collector Output

Oxygen %	8.8	8.7				
CO(ppm)	0	0.1				
Combustibles %	27	30				
Temperature (F)	365	366				
Static Press(in H2O)	-1.3	-1.2				

Utility Modernization Analysis — Boiler Calc. Sheet I

Boiler Test Data

		Fuel (Btu/lb)	13500
Ave. Enerac Data	25-Nov-96		Calculated
(ESP Inlet) Time	16:09	Excess Air	65.40%
Combustion Eff(%)	82.7%	Eff w/o rad	85.25%
Amb Temp (F)	66	Rad Loss	1.50%
Stack Temp (F)	187	Eff w/rad	83.8%
O2 (dry)	13.7%		Fuel Curve
CO(ppm)	19	MBtu/gal	13500
CO2	4.1%	Excess Air	65.0%
Combust	0.05%	Eff (w/o rad)	83.6%
Boiler outlet (in WC)		Rad Loss	1.5%
Excess Air %	178.3%	Eff (w/rad)	82.1%
NOx (pm)	131		
NOx (pm)	0		
NOx (pm)	131		
SOx (ppm)	221		

Ave. Plant/Gage Readings

Flue Gas Temp (F)	368
Oxygen %	8.1
H2OFlow(Klbs/hr)	487.1
Btu Out(KBtu/hr)	25900
H2O Temp In (F)	368
H2O Temp Out (F)	424
Furn Press (in WC)	-0.06
Last Pass (in WC)	-1.05
ID Fan Inlet (in WC)	-1.4
Opacity	1.3
HW Inlet (psig)	327
HW Outlet (psig)	344

Ave. Generator Outlet Data

Oxygen %	8.5
CO(ppm)	0.0
Combustibles %	21
Temperature (F)	386
Static Press(in H2O)	-0.60

Ave. Mechanical Collector Input

Oxygen %	8.4
CO(ppm)	0.00
Combustibles %	27
Temperature (F)	370
Static Press(in H2O)	-0.56

Ave. Mechanical Collector Output

Oxygen %	8.8
CO(ppm)	0.05
Combustibles %	29
Temperature (F)	366
Static Press(in H2O)	-1.25

Utility Modernization Analysis — Boiler Calc. Sheet II

Coal Boilers				Flue Gas Losses			
	Btu/lb	T amb (F)	Flue gas (F)	Dry Gas	Water Vapor	Unacctd.	Total Loss
HHV	13500	386.0	80	0.09272	0.03977	0.01500	14.75%
Combustion Eff		85.25%		Stochiometric	Excess Air		
Fuel	% lb/lb AF	lb/lbmol	lbmol/lb AF	lbmol/lb AF	lbmole/lb AF		
C	70.41%	12	0.05868				
H2	4.83%	2	0.02415				
O2	8.28%	32	0.00259				
N2	1.41%	28	0.00050				
S	1.01%	32	0.00032				
H2O (liq)	8.05%	18	0.00447				
Ash	6.08%	MW	Mole Fract				
Total	100.07%						
Air				0.32037002			
N2	79.00%			0.25319359			
O2	21.00%			0.06730463			
Incremental Excess Air					0.04402		
Excess Air %					65%		

Balance C, H2 and S for stocimetric conditions. Balance O2, N2 at excess air conditions.

Dry gas loss includes sensible heat in water vapor. Water vapor loss include fuel moisture and H2 formation. 1.5% unaccounted in coal.

Solution balances the combustion equation for stochiometric conditions and then calculates excess air and recalculates flue gas products and properties

Flue Gas		% Gas Vol (dr	Dry Gas Fract	LbMoles/lb fuel
O2	8.45%	8.45%	0.08450	
CO (ppm)	20.50	0.00%	0.00002	
CO2	not meas			0.05750
Combustibles	0.00%	0.00%	0.00000	
NOx (ppm)		0.00%	0.00000	
SOx (ppm)		0.00%	0.00000	
H2O				0.02862
N2				0.25357
SO2				0.00032
				0.42453

Assume 2% carbon loss to ash (98% C forms CO2)

			deg F	336.0			
	Polynomial Coeff		deg K	442.055556			
Gas	a	b	c	cp	cp ave (Btu/lb	lbmole/lb fuel	Btu/lb fuel deg F
CO2	10.34	0.00274	-195500	10.5507876	10.5507876	0.05750	0.60668611
SO2	7.7	0.0053	0.00000083	10.2050873	10.2050873	0.00032	0.00322098
H2O	8.22	0.00015	0.00000134	8.54816191	8.54816191	0.02862	0.24466739
N2	6.5	0.001		6.94205556	6.94205556	0.41907063	2.90921159
O2	8.27	0.000258	-187700	7.42352114	7.42352114	0.04402	0.32675668
						Sum	4.09054276

Polynomial equations from Perry's Chemical Handbook Table 3-181, Originally from US Bureau of Mines Bull 371, 1934 and USBM Bull 477, 1948.

Utility Modernization Analysis — Boiler Data Sheet

Boiler Test Data (Unit #3) - DSCC, Columbus, OH

Enerac ESP Inlet 26-Nov-96

Time	8:40	8:50	9:00	9:10	9:20	9:30
Combustion Eff(%)	83.4	83.4	82.1	82.7	82.6	82.6
Amb Temp (F)	47	46	46	45	45	45
Stack Temp (F)	267	272	275	277	278	281
O2 (dry)	11.7%	11.4%	12.2%	11.7%	11.8%	11.7%
CO(ppm)	25	25	25	27	31	28
CO2	8.0%	8.2%	7.6%	8.0%	7.9%	8.0%
Combustibles	0.11%	0.11%	0.11%	0.11%	0.11%	0.10%
Boiler outlet (in WC)						
Excess Air %	121.0%	115.0%	133.0%	121.0%	123.0%	121.0%
NO (pm)	209.0	221.0	224.0	239.0	225.0	229.0
NO2 (ppm)	8	9	13	15	15	15
NOx (ppm)	216	230	237	254	239	243
SOx (ppm)	426	447	408	427	416	421

Plant/Gage Readings

Flue Gas Temp (F)	340	346	342	344	348	347
Oxygen %	7.1	8	6.9	7	7.7	7.3
H2OFlow(Klbs/hr)	510	510.7	511.6	512.3	510.7	513.6
Btu Out(KBtu/hr)	35100	35500	35000	35300	35400	35600
H2O Temp In (F)	326	330	323	322	326	327
H2O Temp Out (F)	422	422	420	421	422	422
Furn Press (in WC)	-0.09	-0.09	-0.07	-0.06	-0.1	-0.08
Last Pass (in WC)	-1.3	-1.6	-1.8	-1.8	-1.8	-1.7
ID Fan Inlet (in WC)	-2.9	-2.2	-2.3	-2.3	-2.4	-3.2
Opacity	25	30	34	34	31	28
HW Inlet (psig)	299	301	298	296	303	301
HW Outlet (psig)	312	319	315	312	320	318

Generator Outlet Data

Oxygen %	7.8	8.5	8.4	8.5	8.4	8.6
Combustibles %	0.1	0.1	0.1	0.1	0.1	0.1
CO(ppm)	20	26	31	21	24	28
Temperature (F)	343	347	343	341	345	344
Static Press(in H2O)	-1.3	-1.4	-1.4	-1.45	-1.5	-1.45

Mechanical Collector Input

Oxygen %	7.7	8.7	8.4	8.7	8.6	8.4
CO(ppm)	0.1	0.1	0.1	0.1	0.1	0.1
Combustibles %	32	31	35	35	30	32
Temperature (F)	363	367	363	365	367	368
Static Press(in H2O)	-1.3	-1.4	-1.4	-1.5	-1.5	-1.45

Mechanical Collector Output

Oxygen %	8.5	8.9	8.7	8.7	8.7	9
CO(ppm)	0.1	0.1	0.1	0.1	0.1	0.1
Combustibles %	30	31	30	35	29	34
Temperature (F)	350	353	351	349	351	351
Static Press(in H2O)	-2.7	-3.0	-3.0	-3.5	-3.1	-3.1

Utility Modernization Analysis — Boiler Calc. Sheet I

Boiler Test Data

		Fuel (Btu/lb)	13500
Ave. Enerac Data	26-Nov-96		Calculated
(ESP Inlet) Time	9:05	Excess Air	64.33%
Amb Temp (F)	82.8	Eff w/o rad	86.63%
Amb Temp (F)	46	Rad Loss	1.50%
Stack Temp (F)	275	Eff w/rad	85.1%
O2 (dry)	11.8%		Fuel Curve
CO(ppm)	27	MBtu/gal	12048
CO2	8.0%	Excess Air	64.0%
Combust	0.11%	Eff (w/o rad)	85.2%
Boiler outlet (in WC)		Rad Loss	1.3%
Excess Air %	122.3%	Eff (w/rad)	83.9%
NOx (pm)	225		
NOx (pm)	13		
NOx (pm)	237		
SOx (ppm)	424		
Ave. Plant/Gage Readings			
Flue Gas Temp (F)	345		
Oxygen %	7.3		
H2OFlow(Klbs/hr)	511.5		
Btu Out(KBtu/hr)	35317		
H2O Temp In (F)	326		
H2O Temp Out (F)	422		
Furn Press (in WC)	-0.08		
Last Pass (in WC)	-1.7		
ID Fan Inlet (in WC)	-2.6		
Opacity	30.33		
HW Inlet (psig)	300		
HW Outlet (psig)	316		
Ave. Generator Outlet Data			
Oxygen %	8.4		
Combustibles %	0.1		
CO(ppm)	25		
Temperature (F)	344		
Static Press(in H2O)	-1.42		
Ave. Mechanical Collector Input			
Oxygen %	8.4		
CO(ppm)	0.1		
Combustibles %	33		
Temperature (F)	366		
Static Press(in H2O)	-1.43		
Ave. Mechanical Collector Output			
Oxygen %	8.8		
CO(ppm)	0.1		
Combustibles %	32		
Temperature (F)	351		
Static Press(in H2O)	-3.1		

Utility Modernization Analysis — Boiler Calc. Sheet II

Coal Boilers				Flue Gas Losses			
	Btu/lb	T amb (F)	Flue gas (F)	Dry Gas	Water Vapor	Unacctd.	Total Loss
HHV	13500	343.8	80	0.07896	0.03977	0.01500	13.37%
Combustion Eff		86.63%		Stochiometric	Excess Air		
Fuel	% lb/lb AF	lb/lbmol	lbmol/lb AF	lbmol/lb AF	lbmole/lb AF		
C	70.41%	12	0.05868				
H2	4.83%	2	0.02415				
O2	8.28%	32	0.00259				
N2	1.41%	28	0.00050				
S	1.01%	32	0.00032				
H2O (liq)	8.05%	18	0.00447				
Ash	6.08%	MW	Mole Fract				
Total	100.07%						
Air				0.32037002			
N2	79.00%			0.25319359			
O2	21.00%			0.06730463			
Incremental Excess Air					0.04330		
Excess Air %					64%		

Dry gas loss includes sensible heat in water vapor. Water vapor loss include fuel moisture and H2 formation. 1.5% unaccounted in coal.

Balance C, H2 and S for stocimetric conditions. Balance O2, N2 at excess air conditions.

Solution balances the combustion equation for stochiometric conditions and then calculates excess air and recalculates flue gas products and properties

Flue Gas		% Gas Vol (dr	Dry Gas Fract	LbMoles/lb fuel
O2	8.37%	8.37%	0.08367	
CO (ppm)	25.00	0.00%	0.00003	
CO2	not meas			0.05750
Combustibles	0.10%	0.10%	0.00100	
NOx (ppm)		0.00%	0.00000	
SOx (ppm)		0.00%	0.00000	
H2O				0.02862
N2				0.25357
SO2				0.00032
				0.42470

Assume 2% carbon loss to ash (98% C forms CO2)

			deg F	293.8			
	Polynomial Coeff		deg K	418.62963			
Gas	a	b	c	cp	cp ave (Btu/lb	lbmole/lb fuel	Btu/lb fuel deg F
CO2	10.34	0.00274	-195500	10.3715009	10.3715009	0.05750	0.59637686
SO2	7.7	0.0053	0.00000083	10.0641952	10.0641952	0.00032	0.00317651
H2O	8.22	0.00015	0.00000134	8.51763047	8.51763047	0.02862	0.24379351
N2	6.5	0.001		6.91862963	6.91862963	0.41635825	2.88062852
O2	8.27	0.000258	-187700	7.30696976	7.30696976	0.04330	0.31635543
						Sum	4.04033082

Polynomial equations from Perry's Chemical Handbook Table 3-181, Originally from US Bureau of Mines Bull 371, 1934 and USBM Bull 477, 1948.

Utility Modernization Analysis — Boiler Data Sheet

Boiler Test Data (Unit #3) - DSCC, Columbus, OH

Enerac ESP Inlet 26-Nov-96

Time	8:00	8:10	8:20	8:30	9:40	
Combustion Eff(%)	84.6	84.0	84.2	83.8		
Amb Temp (F)	51	50	48	48		
Stack Temp (F)	263	272	273	273		
O2 (dry)	10.9%	11.0%	10.8%	11.1%		
CO(ppm)	27	25	28	29		
CO2	8.7%	8.6%	8.8%	8.5%		
Combustibles	0.11%	0.11%	0.11%	0.11%		
Boiler outlet (in WC)						
Excess Air %	104%	106%	101%	108%		
NO (pm)	218	201	204	209		
NO2 (ppm)	5	0	4	4		
NOx (ppm)	223	201	207	212		
SOx (ppm)	438	493	482	492		
Plant/Gage Readings						
Flue Gas Temp (F)					345	
Oxygen %					7.4	
H2OFlow(Klbs/hr)					510.8	
Btu Out(KBtu/hr)					35200	
H2O Temp In (F)					324	
H2O Temp Out (F)					421	
Furn Press (in WC)					-0.09	
Last Pass (in WC)					-1.7	
ID Fan Inlet (in WC)					-3.3	
Opacity					30	
HW Inlet (psig)					299	
HW Outlet (psig)					315	
Generator Outlet Data						
Oxygen %					8.4	
Combustibles %					0.1	
CO(ppm)					30	
Temperature (F)					345	
Static Press(in H2O)					-1.45	
Mechanical Collector Input						
Oxygen %					8.6	
CO(ppm)					0.1	
Combustibles %					36	
Temperature (F)					369	
Static Press(in H2O)					-1.45	
Mechanical Collector Output						
Oxygen %					9.1	
CO(ppm)					0.1	
Combustibles %					35	
Temperature (F)					352	
Static Press(in H2O)					-3.2	

Utility Modernization Analysis — Boiler Calc. Sheet I

Boiler Test Data

Fuel (Btu/lb)	13500

Ave. Enerac Data (ESP Inlet)	26-Nov-96		Calculated
Time	8:32	Excess Air	64.75%
Combustion Eff(%)	84.2	Eff w/o rad	86.57%
Amb Temp (F)	49	Rad Loss	1.50%
Stack Temp (F)	270	Eff w/rad	85.1%
O2 (dry)	11.0%		Fuel Curve
CO(ppm)	27	MBtu/gal	13500
CO2	8.7%	Excess Air	64.0%
Combust	0.11%	Eff (w/o rad)	85.2%
Boiler outlet (in WC)		Rad Loss	1.3%
Excess Air %	104.8%	Eff (w/rad)	83.9%
NOx (pm)	208		
NOx (pm)	3		
NOx (pm)	211		
SOx (ppm)	476		

Ave. Plant/Gage Readings	
Flue Gas Temp (F)	345
Oxygen %	7.4
H2OFlow(Klbs/hr)	510.8
Btu Out(KBtu/hr)	35200
H2O Temp In (F)	324
H2O Temp Out (F)	421
Furn Press (in WC)	-0.09
Last Pass (in WC)	-1.7
ID Fan Inlet (in WC)	-3.3
Opacity	30.00
HW Inlet (psig)	299
HW Outlet (psig)	315

Ave. Generator Outlet Data	
Oxygen %	8.4
Combustibles %	0.10
CO(ppm)	30
Temperature (F)	345
Static Press(in H2O)	-1.45
Ave Mechanical Collector Input	
Oxygen %	8.6
CO(ppm)	0.10
Combustibles %	36
Temperature (F)	369
Static Press(in H2O)	-1.45
Ave Mechanical Collector Output	
Oxygen %	9.1
CO(ppm)	0.10
Combustibles %	35
Temperature (F)	352
Static Press(in H2O)	-3.20

Utility Modernization Analysis — Boiler Calc. Sheet II

Coal Boilers

	Btu/lb	T amb (F)	Flue gas (F)
HHV	13500	345.0	80
Combustion Eff		86.57%	

Flue Gas Losses

Dry Gas	Water Vapor	Unacctd.	Total Loss
0.07951	0.03977	0.01500	13.43%

Dry gas loss includes sensible heat in water vapor. Water vapor loss include fuel moisture and H2 formation. 1.5% unaccounted in coal.

Fuel	% lb/lb AF	lb/lbmol	lbmol/lb AF	Stochiometric lbmol/lb AF	Excess Air lbmole/lb AF
C	70.41%	12	0.05868		
H2	4.83%	2	0.02415		
O2	8.28%	32	0.00259		
N2	1.41%	28	0.00050		
S	1.01%	32	0.00032		
H2O (liq)	8.05%	18	0.00447		
Ash	6.08%	MW	Mole Fract		
Total	100.07%				
Air				0.32037002	
N2	79.00%			0.25319359	
O2	21.00%			0.06730463	
Incremental Excess Air					0.04358
Excess Air %					65%

Balance C, H2 and S for stocimetric conditions. Balance O2, N2 at excess air conditions.

Solution balances the combustion equation for stochiometric conditions and then calculates excess air and recalculates flue gas products and properties

Flue Gas		% Gas Vol (dr	Dry Gas Fract	LbMoles/lb fuel
O2	8.40%	8.40%	0.08400	
CO (ppm)	30.00	0.00%	0.00003	
CO2	not meas			0.05750
Combustibles	0.10%	0.10%	0.00100	
NOx (ppm)		0.00%	0.00000	
SOx (ppm)		0.00%	0.00000	
H2O				0.02862
N2				0.25357
SO2				0.00032
				0.42504

Assume 2% carbon loss to ash (98% C forms CO2)

				deg F	295.0
				deg K	419.277778

Gas	a	b	c	cp	cp ave (Btu/lbı	lbmole/lb fuel	Btu/lb fuel deg F
	Polynomial Coeff						
CO2	10.34	0.00274	-195500	10.3767231	10.3767231	0.05750	0.59667714
SO2	7.7	0.0053	0.00000083	10.0680811	10.0680811	0.00032	0.00317774
H2O	8.22	0.00015	0.00000134	8.51845543	8.51845543	0.02862	0.24381712
N2	6.5	0.001		6.91927778	6.91927778	0.4174389	2.8883757
O2	8.27	0.000258	-187700	7.31044579	7.31044579	0.04358	0.31860699
						Sum	4.05065469

Polynomial equations from Perry's Chemical Handbook Table 3-181, Originally from US Bureau of Mines Bull 371, 1934 and USBM Bull 477, 1948.

Utility Modernization Analysis — Boiler Data Sheet

Boiler Test Data (Unit #3) - DSCC, Columbus, OH

Enerac ESP Outlet 26-Nov-96

Time	8:14:33	8:15:23	8:21:18	8:30:02	8:40	8:50
Combustion Eff(%)	96.9	97.6	98.1	97.6	97.2	97.1
Amb Temp (F)	51	51	50	49	47	46
Stack Temp (F)			259	258	259	261
O2 (dry)	10.5%	10.5%	10.6%	10.2%	10.6%	10.8%
CO(ppm)	24	20	20	29	26	26
CO2	7.8%	9.0%	8.9%	9.2%	8.9%	8.8%
Combustibles	0.00%	0.00%	0.00%	0.03%	0.05%	0.06%
StackDraft(neg"H2O)	1.3	1.5	1.5	1.8	1.9	1.8
Excess Air %	94%	96%	97%	91%	98.0%	101.0%
NOx (ppm)	142	187	193	206	222	245
SOx (ppm)	0	0	36	77	113	142

Time	9:00	9:10	9:20	9:30	9:40:06	
Combustion Eff(%)	96.7	96.7	96.5	96.3	96.4	
Amb Temp (F)	44	43	43	42	42	
Stack Temp (F)	263	263	267	265	266	
O2 (dry)	11.2%	10.8%	10.8%	11.1%	11.0%	
CO(ppm)	26	26	29	26	26	
CO2	8.4%	8.7%	8.7%	8.5%	8.6%	
Combustibles	0.07%	0.07%	0.08%	0.09%	0.09%	
StackDraft(neg"H2O)	1.9	2.3	2.3	2.3	2.8	
Excess Air %	109.0%	102.0%	102.0%	108.0%	105%	
NOx (ppm)	239	255	247	229	242	
SOx (ppm)	161	176	197	209	209	

Utility Modernization Analysis — Boiler Calc. Sheet I

Boiler Test Data

Fuel (Btu/lb): 13500

Ave. Enerac Data (ESP Outlet)	26-Nov-96
Time	8:28
Combustion Eff(%)	97.4
Amb Temp (F)	49
Stack Temp (F)	259
O2 (dry)	10.5%
CO(ppm)	24
CO2	8.8%
Combust	0.02%
StackDraft(neg"H2O)	1.6
Excess Air %	96.2%
NOx (pm)	199
SOx (ppm)	92

Calculated		
N2	80.70%	
Excess Air	NA	??
Excess Air	NA	??

Fuel Curve	
MBtu/gal	13500
Excess Air	
Eff (w/o rad)	
Rad Loss	
Eff (w/rad)	0.0%

Ave. Enerac Data (ESP Outlet)	26-Nov-96
Time	9:20
Combustion Eff(%)	96.5
Amb Temp (F)	43
Stack Temp (F)	265
O2 (dry)	11.0%
CO(ppm)	27
CO2	8.6%
Combust	0.08%
StackDraft(neg"H2O)	2.3
Excess Air %	105.2%
NOx (pm)	242
SOx (ppm)	190

Utility Modernization Analysis — HTW Plant Data

Auxiliary Equipment (ESP #2)

Precipitator #2 — **25-Nov-96**

Time	16:00	16:10	16:20	16:30	16:40	16:50
Primary Volts x 10	36	30	36	18	26	26
Primary Amps x 10	3.7	2.8	3.7	0.97	1.9	2.2
Secondary kV1	0	0	0	0	0	0
Secondary Amps	0.25	0.21	0.25	0.09	0.14	0.18
Secondary kV2	0	0	0	0	0	0
Sparks/Min x 10	0.0	0.0	0.2	0	0.6	0.8
Arcs/Min x 10		0.0	0	0	0.4	0

Time	17:00	17:10
Primary Volts x 10	16	30
Primary Amps x 10	0.79	2.7
Secondary kV1	0	0
Secondary Amps	0.07	0.24
Secondary kV2	0	0
Sparks/Min x 10	1.6	1.8
Arcs/Min x 10	0	1.4

Precipitator #2 — **26-Nov-96**

Time	8:40	8:50	9:00	9:10	9:20	9:30
Primary Volts x 10				34	32	30
Primary Amps x 10				2.5	3.1	2.3
Secondary kV1				0	0	0
Secondary Amps				0.16	0.25	0.25
Secondary kV2				0	0	0
Sparks/Min x 10				0.6	0.6	0.6
Arcs/Min x 10				0.2	0	0.2

Utility Modernization Analysis HTW Plant Data

Auxiliary Equipment (ESP #2) -- Average Values

Precipitator #2

	25-Nov-96
	Average
Time	16:35
Primary Volts x 10	27
Primary Amps x 10	2.35
Secondary kV1	0
Secondary Amps	0.18
Secondary kV2	0
Sparks/Min x 10	0.6
Arcs/Min x 10	0.3

Precipitator #2

	26-Nov-96
	Average
Time	9:20
Primary Volts x 10	32
Primary Amps x 10	2.6
Secondary kV1	0
Secondary Amps	0.22
Secondary kV2	0
Sparks/Min x 10	0.6
Arcs/Min x 1	0.1

Utility Modernization Analysis Boiler NDT Data Sheet

Boiler Test Data (Unit #3) - DSCC, Columbus, OH
Boiler Tube Testing

Rear Wall		Right Wall		Left Wall
top (straight)	elbow (bend)	top	bottom	top
0.103		0.113	0.112	0.106
	0.148	0.112	0.115	0.108
0.101		0.117	0.109	0.106
0.108		0.111	0.111	0.124
0.097		0.110	0.108	0.126
0.109		0.112	0.109	0.110
	0.146	0.112		0.110
0.108		0.111		0.108
0.106				
0.106				
0.109				

Minimum	0.097
Ave.	0.112

** Calibration factor = 0.253.

NOTES: 1. The rear wall tubes above are identified as follows -- left-to-right, the thicknesses are for every fifth tube, starting with the second tube from the left.
The right wall is the wall to the right when looking from the front to the rear of the generator. "Top" measurements were taken about 5-feet high for every tenth tube going from right to left and starting with the second tube from the right. "Bottom" measurements were taken about 2-feet high for every tenth tube starting with the tenth tube from the right, the top and bottom measurements thus being staggered.
Left wall measurements were taken about 5-feet high going from left to right, starting with the second tube from the left.

2. Comments regarding physical condition of HTW generator. Grate: T-Bar warped; edge seal leaks; chain wear right side sprockets; some skidshoe wear excessive. Convection pass: tubes OK.
Air heater: four holes in duct wall, Upper W and N, Lower N and E.
MDC: exit OK; top tubes worn; spinners worn; C2 spinner backwards; lower C3 broken almost all around; boot tab broken D2, A6, B7 and E7.

Utility Modernization Analysis — Boiler NDT Calc Sheet

Boiler Test Data

Boiler Tube Testing

Minimum	0.097	Min (psig) P	935
Ave.	0.11215152	Ave (psig) P	1,108

Tube Type	SA 178 grA
Stress Factor (ASME Code)	11800
Temp (F)	600
Tube OD (in)	2.25
e factor	0

Utility Modernization Analysis — Boiler NDT Data Sheet

Boiler Test Data (Unit #1) - DSCC, Columbus, OH

Boiler Tube Testing	Rear Wall (Top)	Rear Wall (Elbow)	Right Wall	Left Wall
	0.111	0.127	0.111	0.106
	0.102	0.118	0.107	0.107
	0.092	0.12	0.101	0.107
	0.102		0.108	0.106
	0.103		0.104	0.108
	0.108		0.109	0.106
	0.111		0.106	0.105
	0.134			
	0.139			

Minumum	0.092
Ave.	0.110

Comments regarding physical condition of HTW generator. Grate: T-Bar bowed; endclip seals not working; OK to fire this Winter; rear-top air seal - overgrate seal shoes crystallized; rear right TC gone; some skid shoes worn down; left end - one rail bent, clip binding. Backpass: failed refractory; tubes need air lancing; header plugs leaking; backwall tubes pushed out. MDC: lots of flyash in East hopper; bottom lower tubes worn severely; Row A spinners clogged; dampers for upper MDC not working; upper tubes severely worn; hole in E3 tube; spinners severely worn; exit has mud; rope packing needed in x-joint.

Boiler Test Data (Unit #1) - DSCC, Columbus, OH

Data taken 11/26/96 for HTW Generator #1, down due to leaking tubes

Furnace Roof, R-L Tube #	12" from knuckle	At knuckle	Calibra-tion Factor	Missing Tubes
2	0.103	0.128	0.26	10
4	0.18		0.26	30
6 (hole)	0.107		0.26	34
8	0.107		0.26	35
23	0.15		0.25	
25	0.119		0.25	
27	0.13		0.25	
29	0.132		0.25	
31	0.144		0.25	
32	0.152		0.25	
33	0.152		0.25	

Minimum	0.103
Ave.	0.134

Utility Modernization Analysis — Boiler NDT Calc Sheet

Boiler Test Data

Boiler Tube Testing

Minimum	0.092	Min (psig) P	879
Ave.	0.10992308	Ave (psig) P	1,082
Tube Type	SA 178 grA		
Stress Factor (ASME Code)	11800		
Temp (F)	600		
Tube OD (in)	2.25		
e factor	0		

Minimum	0.103	Min (psig) P	1,003
Ave.	0.13366667	Ave (psig) P	1,358
Tube Type	SA 178 grA		
Stress Factor (ASME Code)	11800		
Temp (F)	600		
Tube OD (in)	2.25		
e factor	0		

Utility Modernization Analysis MDC Inspection

Unit #1

Top Tubes

	E	D	C	B	A
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Dirty Gas In →

Top Tube Tube Sheet (clean gas outlet)

	E	D	C	B	A
1					
2					
3					
4					
5					
6					
7					
8					
9					Clogged
10					Clogged

Dirty Gas In →

Bottom Tube (Ash hopper inspection)

	E	D	C	B	A
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Dirty Gas In →

Other Notes:

Utility Modernization Analysis — MDC Inspection

Unit #3

Top Tubes

	E	D	C	B	A
1					
2	Worn		Spin Bkwd		
3	Worn				
4	Worn				
5	Worn				
6	Worn				
7	Worn				
8	Worn				
9					
10					

Dirty Gas In →

Top Tube Tube Sheet (clean gas outlet)

	E	D	C	B	A
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Dirty Gas In →

Bottom Tube (Ash hopper inspection)

	E	D	C	B	A
1					
2					
3			Broken		
4					
5					
6					
7					
8					
9					
10					

Dirty Gas In →

Other Notes:

Pipe Schedule Thickness Correction

		Temperature	400		
		Std Temp	70		
Size	Sched 40	Sched 80		Sched 40	Sched 80
3	0.216	0.300		0.212	0.295
4	0.237	0.337		0.233	0.331
5	0.258	0.375		0.254	0.369
6	0.280	0.432		0.275	0.425
8	0.322	0.500		0.317	0.492
10	0.365	0.593		0.359	0.583
12	0.406	0.687		0.399	0.676
14	0.438	0.750		0.431	0.738
16	0.500	0.843		0.492	0.829

Thickness Testing

Site	BLdg 17-18 Crossover			Cold Wall (in)
Pipe Size	6			0.280
Pipe Temp	400	Std Temp	70	
Air Temp	35			

Location	Thickness	Corrected	Notes
Top 12	0.311	0.306	
1:30	0.302	0.297	
Side 3	0.287	0.282	
4:30	0.307	0.302	
Bottom 6	0.306	0.301	
		0.000	
Top 12	0.317	0.312	
1:30	0.315	0.310	
Side 3	0.309	0.304	

Piping severely corroded from exposure to weather. Schedule 40 specified.

Thickness Testing

Site	Bldg 12, S end		Cold Wall (in)
Pipe Size	6		0.280
Pipe Temp	420	Std Temp	70
Air Temp	34		

Location	Thickness	Corrected	Notes
Top 12	0.330	0.324	
1:30	0.301	0.296	
Side 3	0.313	0.308	
4:30	0.288	0.283	
Bottom 6	0.235	0.231	
7:30	0.281	0.276	
Side 9	0.273	0.268	
10:30	0.301	0.296	
		0.000	

Piping only moderately corroded from exposure to weather. Schedule 40 specified.

Thickness Testing

Site	Bldg 30 S side		Cold Wall (in)
Pipe Size	6		0.280
Pipe Temp	407	Std Temp	70
Air Temp	34		

Location	Thickness	Corrected	Notes
Top 12	0.278	0.273	
1:30	0.284	0.279	
Side 3	0.303	0.298	
		0.000	
Top 12	0.280	0.275	
1:30	0.252	0.248	
Side 3	0.300	0.295	
		0.000	
		0.000	

Piping only moderately corroded from exposure to weather. Schedule 40 specified. Not allowed to remove asbestos from bottom of pipe.

Thickness Testing

Site	Bldg 30 Mech room Converter		Cold Wall (in)
Pipe Size	Unk		Unk
Pipe Temp	237	Std Temp 70	
Air Temp	86		

Location	Thickness	Corrected	Notes
Bottom	0.451	0.447	
		0.000	

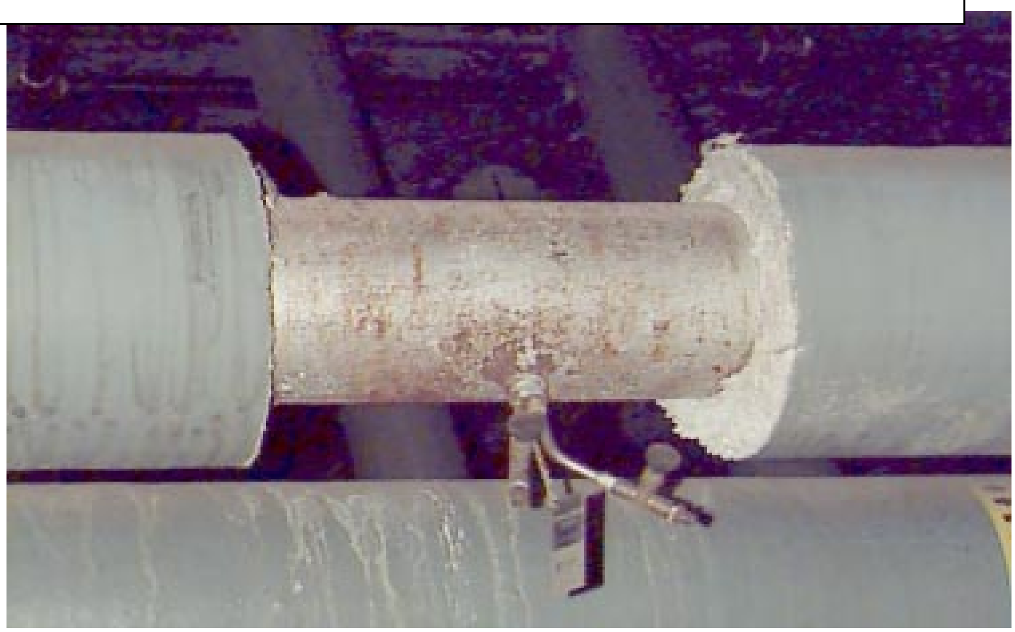
Vessel corroded. Nameplate not readible. Recommend checking waterline thickness.

Thickness Testing

Site	Bldg 30 Mech Room			Cold Wall (in)
Pipe Size	6			0.280
Pipe Temp	375	Std Temp	70	
Air Temp	86			

Location	Thickness	Corrected	Notes
Top 12	0.281	0.277	
1:30	0.272	0.268	
Side 3	0.280	0.276	
4:30	0.270	0.266	
Bottom 6	0.299	0.294	
		0.000	
		0.000	
		0.000	
		0.000	

Piping not corroded as not exposured to weather. Schedule 40 specified.



Appendix B: Nalco Metallurgical Analysis

NALCO

DSCC
COLUMBUS, OHIO

Nalco Metallographic Analysis No. 076564

Specimen: **Hot Water Boiler**

Sampling Date: **January 16, 1997**

CONTENTS

NALCO CHEMICAL COMPANY
ONE NALCO CENTER ◻ NAPERVILLE, ILLINOIS 60563-1198

NALCO

NALCO METALLOGRAPHIC ANALYSIS

Analysis No. 076564

FROM: DSCC
COLUMBUS, OHIO

DESCRIPTION OF SAMPLE

Three sections of boiler tubing were received for metallurgical analysis, Figure 1. The sections were reportedly removed from a 300 psi hot water boiler. The sections have lengths of 20", 19", and 14-3/4". The outer diameter of each section is 1-1/4". The sections were submitted following failures in the top wall section of the boiler. No failure is present on any of the received sections.

The internal surface of each section contains a deposit and/or corrosion product layer on one side of the tube, Figure 2. A sample of the material overlying the surface was scraped and submitted for x-ray analysis. The results of this analysis will be forwarded upon completion. The surface contour is mostly smooth, Figure 3. The side of the section which contains the deposit and/or corrosion product exhibits scattered, mostly shallow depressions. The deepest measured depression reduced the wall thickness by 0.020", Figure 4.

The external surface is covered by a thin brown deposit which overlies a thick layer of thermally deteriorated metal (iron oxide). The surface contour appears mostly smooth.

MICROSCOPIC EXAMINATIONS

Seven specimens were cut from the sections at selected locations and prepared for microscopic examination. The microstructure in some locations examined consists of partially spheroidized pearlite in a ferrite matrix, Figure 5. Other locations, however, exhibited almost complete decarburization, Figure 6.

A series of nine microhardness measurements were conducted on the mounted specimens. The average Knoop hardness number was 108.

The internal surface profile is mostly smooth. Specimens removed from the side of the tube containing the deposit and/or corrosion product exhibited scattered, shallow, oxide-filled depressions, Figure 7. A moderately thick, dense iron oxide layer is present in places.

The external surface profile is smoothly undulating. A thick iron oxide layer is present in places, Figure 8. The maximum measured

NALCO METALLOGRAPHIC ANALYSIS

Analysis No. 076564

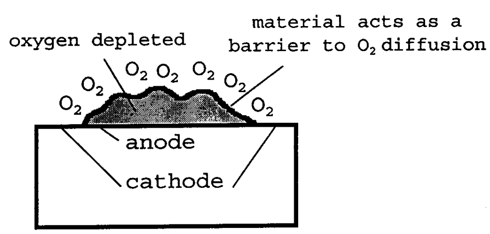
FROM: DSCC
COLUMBUS, OHIO

thickness of the oxide is 0.014", as measured using an optical microscope equipped with a calibrated video imaging system.

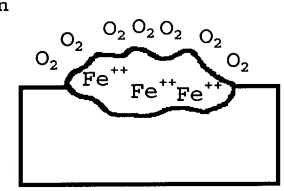
CONCLUSION

The received sections contain no failure. The internal surface of one side of each section contains a deposit and/or corrosion product layer. Scattered depressions are present on this side of the tube. Most of the metal loss is shallow, however, the deepest measured depression reduced the wall thickness by 0.020". The appearance of the attack most closely resembles oxygen corrosion.

Oxygen corrosion resulted from exposure of metal surfaces to waters containing dissolved oxygen. The resulting corrosion product shields the underlying metal and acts as a barrier to oxygen diffusion. As a result, a local area of reduced oxygen concentration develops [see (A) below]. A difference in electrochemical potential exists between regions of a metal in contact with waters containing different levels of dissolved oxygen. This difference in potential results in corrosion (B).



(A)



(B)

The presence of oxygen attack on only one side of each section indicates that the damage most likely occurred during an idle period or periods.

Specific interest was expressed in the composition of the material overlying the internal surface. A sample was scraped from the surface and submitted for analysis. Results of the analysis will be forwarded upon completion.

NALCO

NALCO METALLOGRAPHIC ANALYSIS

Analysis No. 076564

FROM: DSCC
COLUMBUS, OHIO

Analysis indicated that the section experienced long term, mild overheating. Microstructural evidence indicated that metal temperatures between 850 and 1050°F were reached for an extended period. The reported overheating occurred due to excessive heat input relative to coolant flow rate. Three possible causes of excessive heat input relative to coolant flow rate are:

1. Excessive heat input with specified coolant flow.
2. Specified heat input with insufficient coolant flow.
3. Excessive heat input with insufficient coolant flow.

As a result of overheating, a significant amount of oxidation has occurred. The maximum measured external surface oxide thickness was 0.014". No bulging or other significant damage resulted from the overheat.

A. C. BIONDO

Words and concepts referred to in this report are discussed and illustrated in *The Nalco Guide to Boiler Failure Analysis*.

ACB:dmc
3/7/97

NALCO

Figure 1
As-received Boiler Tube Sections

Figure 2
Photograph of a Split Section Showing the Internal Surface Deposit and/or Corrosion Product Layer Present on One Side of the Tube

NALCO

Figure 3
Close-up of the Smooth Internal Surface Contour

Figure 4
Close-up of a Depression Underlying the
Deposit and/or Corrosion Product Layer Shown in Figure 2

NALCO

Figure 5
Microstructure Consisting of Partially
Spheroidized Pearlite in a Ferrite Matrix
Magnification: 1000x Etchant: Picral

Figure 6
Micrograph Showing a Region of
Nearly Complete Decarburization
Magnification: 1000x Etchant: Nital

NALCO

Page 7 of 7
Analysis No. 076564

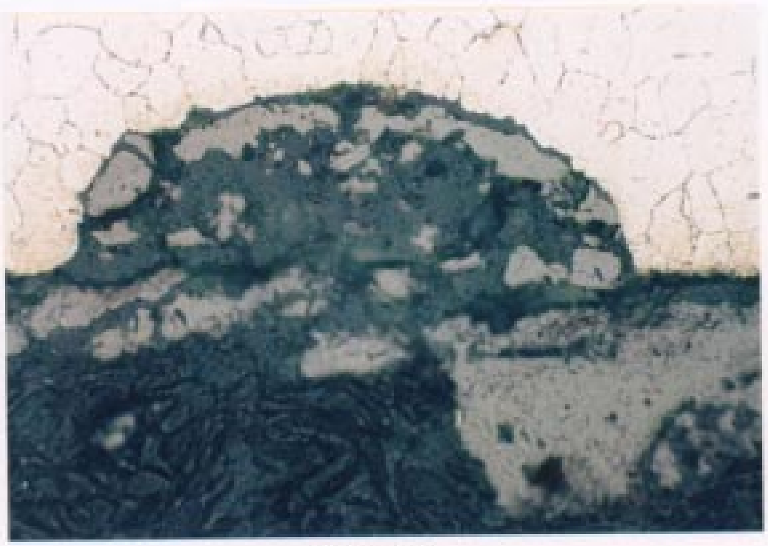


Figure 7
Micrograph Showing a Shallow, Oxide-filled Depression on the Internal Surface
Magnification: 500x Etchant: Nital

Figure 8
Micrograph Showing a Fairly Thick External Surface Oxide Layer
Magnification: 200x Etchant: Picral

NALCO CHEMICAL COMPANY
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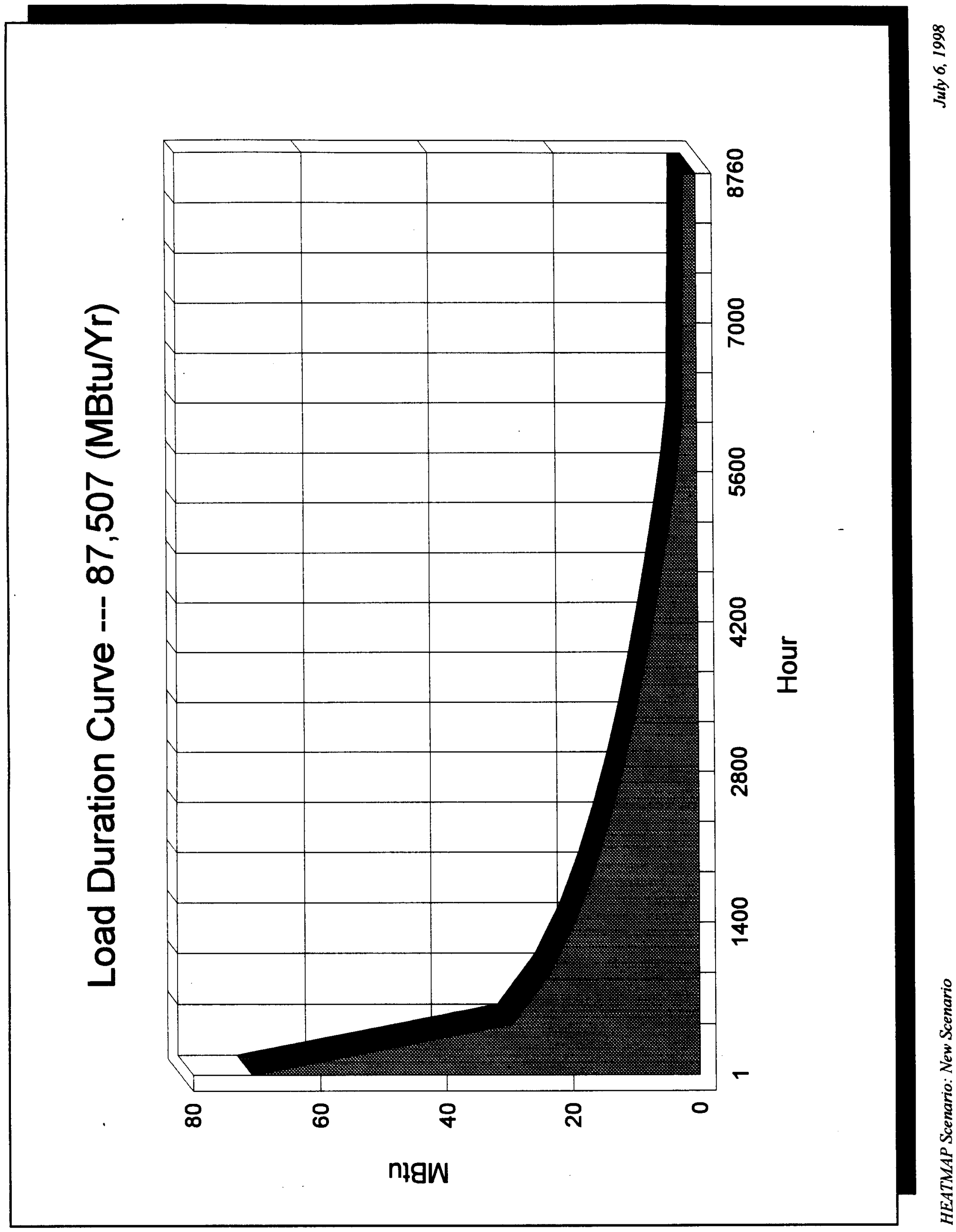
Appendix C: HEATMAP Data Output

July 6, 1998

Page 1

HEATMAP Consumer Load Summary
101 - New Scenario

ID	Consumer name	(Sq Ft)	Heating Annual (MBtu/Yr)	Heating Peak (kBtu/Hr)	Hot water Annual (MBtu/Yr)	Hot water Peak (kBtu/Hr)	Process Annual (MBtu/Yr)	Process Peak (kBtu/Hr)	Total Annual (MBtu/Yr)	Total Peak (kBtu/Hr)
40	Consumer 40	28,070	504.8	658.3	106.5	24.3	0.0	0.0	611.3	682.6
100	Demolish	2,802	45.5	125.5	13.3	3.0	0.0	0.0	58.8	128.5
10-2	after indiv. heating	21,730	390.8	530.8	82.5	18.8	0.0	0.0	473.3	549.6
1	Demolish	270,500	4,865.0	5,037.2	1,026.4	234.3	0.0	0.0	5,891.4	5,271.5
41	Plus 42, Stay heated wet/dry	735,796	12,980.6	15,520.0	3,491.9	797.2	0.0	0.0	16,472.5	16,317.2
27	Stay wet/heated OR dry/cold	283,183	4,996.0	6,249.2	1,344.0	306.8	0.0	0.0	6,340.0	6,556.0
30	wet to dry and cold	174,307	3,134.9	3,344.2	661.4	151.0	0.0	0.0	3,796.3	3,495.2
150	Demolition scheduled	26,381	379.1	740.1	125.2	28.6	0.0	0.0	504.3	768.7
2	Demolition Scheduled	247,900	4,458.5	4,641.7	940.7	214.8	0.0	0.0	5,399.2	4,856.5
5	Demolish	246,400	3,918.6	4,544.4	935.0	213.5	0.0	0.0	4,853.6	4,757.9
306	Demolish	56,218	991.8	1,420.1	266.8	60.9	0.0	0.0	1,258.6	1,481.0
308	Install indiv. heating	51,230	736.1	1,325.0	243.1	55.5	0.0	0.0	979.2	1,380.5
17	Wet to dry and cold	176,948	3,182.4	3,391.1	671.4	153.3	0.0	0.0	3,853.8	3,544.4
18	Wet to dry and cold	174,383	3,136.3	3,345.6	661.7	151.1	0.0	0.0	3,798.0	3,496.7
49	Plus 46	1,720	30.3	90.2	8.2	1.9	0.0	0.0	38.5	92.1
10	Wet to dry S 1-6 and cold, S	130,636	2,349.5	2,564.3	495.7	113.2	0.0	0.0	2,845.2	2,677.5
19	Wet to dry and cold	174,383	3,136.3	3,345.6	661.7	151.1	0.0	0.0	3,798.0	3,496.7
9	Install indiv. heating	283,213	5,093.6	5,259.2	1,074.7	245.4	0.0	0.0	6,168.3	5,504.6
11b	Staying wet and heated	86,265	1,551.5	1,759.0	327.3	74.7	0.0	0.0	1,878.8	1,833.7
12b	Staying dry and heated	131,200	2,314.7	3,053.2	622.7	142.2	0.0	0.0	2,937.4	3,195.4
12a	Staying dry and heated	152,000	2,681.6	3,496.6	721.4	164.7	0.0	0.0	3,403.0	3,661.3
11a	Staying wet and heated	196,935	3,474.4	4,446.5	934.6	213.4	0.0	0.0	4,409.0	4,659.9
	TOTAL:	3,652,200	64,352.3	74,887.8	15,416.2	3,519.7	0.0	0.0	79,768.4	78,407.5

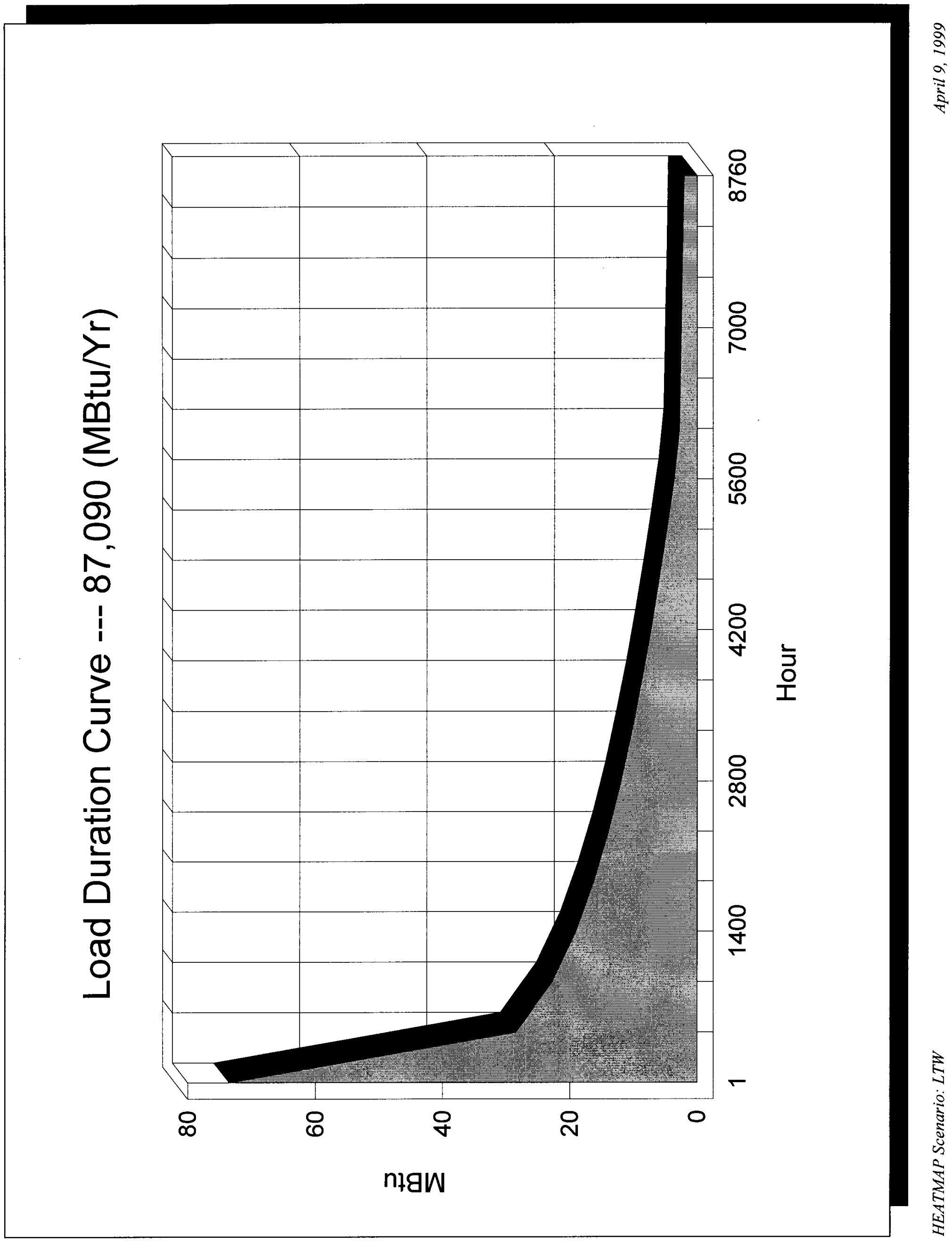

Load Duration Curve --- 87,507 (MBtu/Yr)
MBtu
80
60
40
20
0
1
1400
2800
4200
5600
7000
8760
Hour
July 6, 1998
HEATMAP Scenario: New Scenario

July 7, 1998

HEATMAP Consumer Load Summary
103 - LTW

Page 1

ID	Consumer name	(Sq Ft)	Heating Annual (MBtu/Yr)	Heating Peak (kBtu/Hr)	Hot water Annual (MBtu/Yr)	Hot water Peak (kBtu/Hr)	Process Annual (MBtu/Yr)	Process Peak (kBtu/Hr)	Total Annual (MBtu/Yr)	Total Peak (kBtu/Hr)
10-2	after indiv. heating	21,730	390.8	530.8	82.5	18.8	0.0	0.0	473.3	549.6
100	Demolish	2,802	45.5	125.5	13.3	3.0	0.0	0.0	58.8	128.5
1	Demolish	270,500	4,865.0	5,037.2	1,026.4	234.3	0.0	0.0	5,891.4	5,271.5
40	Consumer 40	28,070	504.8	658.3	106.5	24.3	0.0	0.0	611.3	682.6
41	Plus 42, Stay heated wet/dry	735,796	12,980.6	15,520.0	3,491.9	797.2	0.0	0.0	16,472.5	16,317.2
27	Stay wet/heated OR dry/cold	283,183	4,996.0	6,249.2	1,344.0	306.8	0.0	0.0	6,340.0	6,556.0
30	wet to dry and cold	174,307	3,134.9	3,344.2	661.4	151.0	0.0	0.0	3,796.3	3,495.2
150	Demolition scheduled	26,381	379.1	740.1	125.2	28.6	0.0	0.0	504.3	768.7
2	Demolition Scheduled	247,900	4,458.5	4,641.7	940.7	214.8	0.0	0.0	5,399.2	4,856.5
5	Demolish	246,400	3,918.6	4,544.4	935.0	213.5	0.0	0.0	4,853.6	4,757.9
306	Demolish	56,218	991.8	1,420.1	266.8	60.9	0.0	0.0	1,258.6	1,481.0
308	Install indiv. heating	51,230	736.1	1,325.0	243.1	55.5	0.0	0.0	979.2	1,380.5
17	Wet to dry and cold	176,948	3,182.4	3,391.1	671.4	153.3	0.0	0.0	3,853.8	3,544.4
18	Wet to dry and cold	174,383	3,136.3	3,345.6	661.7	151.1	0.0	0.0	3,798.0	3,496.7
49	Plus 46	1,720	30.3	90.2	8.2	1.9	0.0	0.0	38.5	92.1
10	Wet to dry S 1-6 and cold, S	130,636	2,349.5	2,564.3	495.7	113.2	0.0	0.0	2,845.2	2,677.5
19	Wet to dry and cold	174,383	3,136.3	3,345.6	661.7	151.1	0.0	0.0	3,798.0	3,496.7
9	Install indiv. heating	283,213	5,093.6	5,259.2	1,074.7	245.4	0.0	0.0	6,168.3	5,504.6
11b	Staying wet and heated	86,265	1,551.5	1,759.0	327.3	74.7	0.0	0.0	1,878.8	1,833.7
12b	Staying dry and heated	131,200	2,314.7	3,053.2	622.7	142.2	0.0	0.0	2,937.4	3,195.4
12a	Staying dry and heated	152,000	2,681.6	3,496.6	721.4	164.7	0.0	0.0	3,403.0	3,661.3
11a	Staying wet and heated	196,935	3,474.4	4,446.5	934.6	213.4	0.0	0.0	4,409.0	4,659.9
	TOTAL:	3,652,200	64,352.3	74,887.8	15,416.2	3,519.7	0.0	0.0	79,768.4	78,407.5

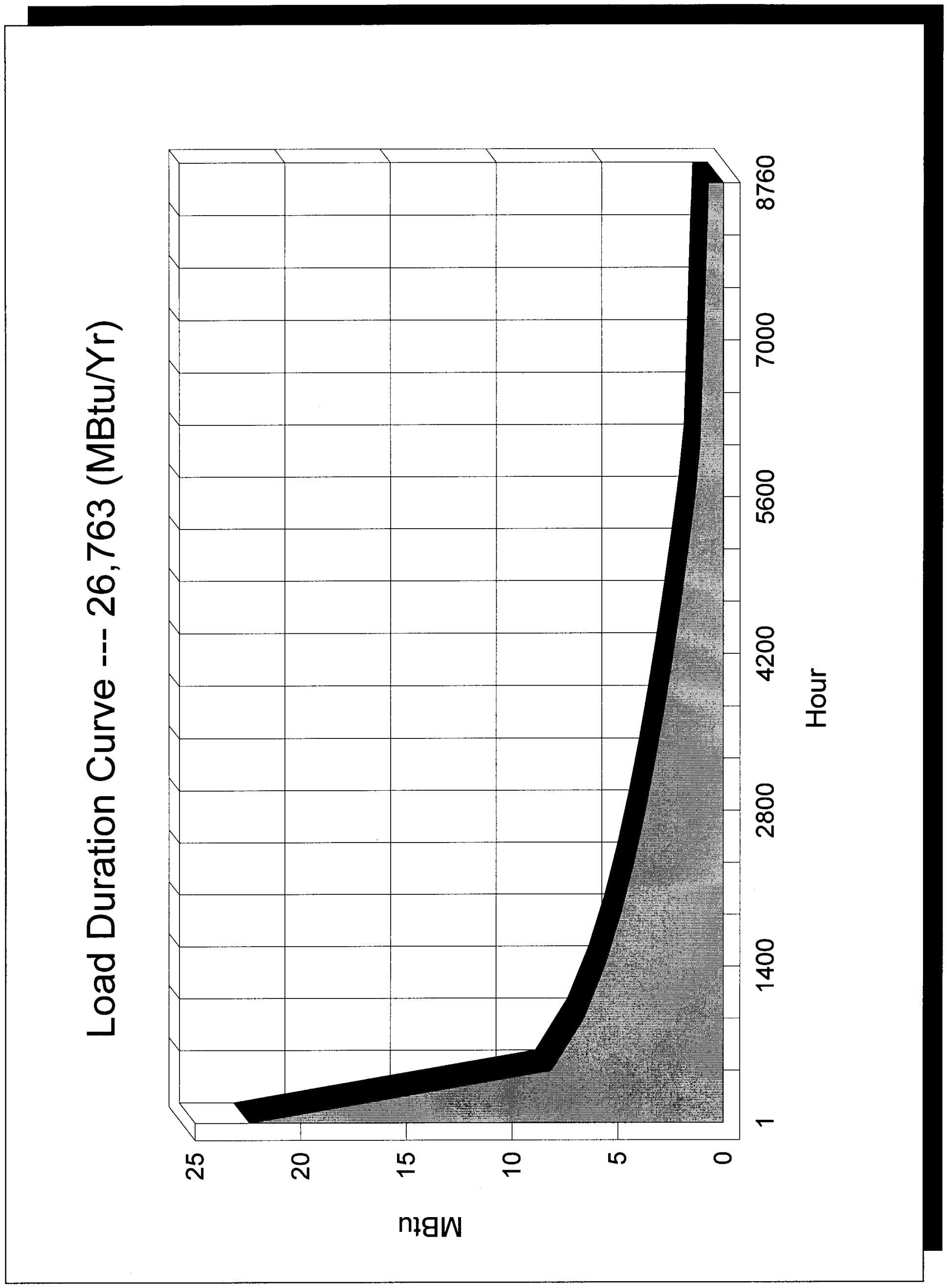

Load Duration Curve --- 87,090 (MBtu/Yr)
MBtu
80
60
40
20
0
1
1400
2800
4200
5600
7000
8760
Hour
April 9, 1999
HEATMAP Scenario: LTW

July 6, 1998

HEATMAP Consumer Load Summary
105 - HTW with dry pipe/demolition

Page 1

ID	Consumer name	(Sq Ft)	Heating Annual (MBtu/Yr)	Heating Peak (kBtu/Hr)	Hot water Annual (MBtu/Yr)	Hot water Peak (kBtu/Hr)	Process Annual (MBtu/Yr)	Process Peak (kBtu/Hr)	Total Annual (MBtu/Yr)	Total Peak (kBtu/Hr)
40	Consumer 40	28,070	504.8	658.3	106.5	24.3	0.0	0.0	611.3	682.6
9a	after indiv. heating	43,626	784.6	961.6	165.5	37.8	0.0	0.0	950.1	999.4
10-2	after indiv. heating	21,730	390.8	530.8	82.5	18.8	0.0	0.0	473.3	549.6
41	Plus 42, Stay heated wet/dry	735,796	12,980.6	15,520.0	3,491.9	797.2	0.0	0.0	16,472.5	16,317.2
27	Stay wet/heated OR dry/cold	283,183	4,996.0	6,249.2	1,344.0	306.8	0.0	0.0	6,340.0	6,556.0
308	Install indiv. heating	51,230	736.1	1,325.0	243.1	55.5	0.0	0.0	979.2	1,380.5
11b	Staying wet and heated	86,265	1,551.5	1,759.0	327.3	74.7	0.0	0.0	1,878.8	1,833.7
12b	Staying dry and heated	131,200	2,314.7	3,053.2	622.7	142.2	0.0	0.0	2,937.4	3,195.4
12a	Staying dry and heated	152,000	2,681.6	3,496.6	721.4	164.7	0.0	0.0	3,403.0	3,661.3
11a	Staying wet and heated	196,935	3,474.4	4,446.5	934.6	213.4	0.0	0.0	4,409.0	4,659.9
	TOTAL:	1,730,035	30,415.1	38,000.2	8,039.5	1,835.4	0.0	0.0	38,454.6	39,835.6



HEATMAP Scenario: HTW (demo, dry pipe, 41&42 ind heat)

April 9, 1999

Appendix D: CHP Modernization Analysis Data Sheets

Utility Modernization Analysis — Option List

Option	Name	Capital Cost	Labor Cost	OM&R	Fuel	LCC NPV	SIR	Fuel increase 29% SIR	Salv K$
1	Coal -ESP	**2,760,000**	**594,168**	**532,935**	215,913	21,436,330			1035
2	Coal - Baghouse	**2,570,000**	**594,168**	**532,935**	215,913	21,296,910			963.8
2a	Coal - Baghouse (OM&R adjusted)	**2,570,000**	**594,168**	318,000	215,913	18,161,720		0.3	963.8
3	Gas Conversion - Oil BU	**1,500,000**	**594,168**	163,000	455,804	19,473,490			562.5
3a	Gas Conversion - Oil BU (3rd Pty)	**1,500,000**	**219,763**	163,000	455,804	14,019,160	Base		562.5
3a-1	Gas Conversion - Oil BU (3rd Pty, 29% inc)	**1,500,000**	**219,763**	163,000	584,125	16,073,770		Base	562.5
3b	Gas Conversion - Oil BU (One unit, Dry Pipe)	**2,150,584**	**594,168**	163,000	224,822	16,294,400			806.5
3c	Gas Conversion - Oil BU (3rd Pty, Dry Pipe)	**2,150,584**	**219,763**	163,000	224,822	10,840,980	7.2		806.5
3c-1	Gas Conversion - Oil BU (3rd Pty, Dry Pipe, 29%)	**2,150,584**	**219,763**	163,000	287,380	11,842,610		9.1	806.5
4	New Gas Unit - Oil BU	**3,270,000**	**594,168**	163,000	455,804	20,855,950			1226
5	Coal - Baghouse - Gas BU	**3,290,000**	**594,168**	**532,935**	237,445	22,267,760			1234
6	Oil Conversion - Gas BU	**2,320,000**	**594,168**	163,000	479,716	20,300,770			870
6a	Oil Conversion - Gas BU (29% fuel price increase)	**2,320,000**	**594,168**	163,000	614,972	22,410,950			870
7	New Oil - Gas BU	**4,040,000**	**594,168**	163,000	479,716	21,644,820			1515
7a	New Oil - Gas BU (29% fuel price increase)	**4,040,000**	**594,168**	163,000	614,972	24,824,700			1515
8	Decentral - Boilers ** (Wet Pipe Fire Prot)	**4,764,176**	**130,663**	100,100	576,388	16,879,860			
8a	Decentral - Boilers ** (Dry Pipe Fire Prot)	**3,495,584**	**87,369**	47,943	280,551	9,613,835	3.2	3.5	
9	Decentral - Furnaces **(Wet Pipe Fire Prot)	**8,957,231**	**130,663**	27,100	576,388	19,646,960	0.3	0.1	
9a	Decentral - Furnaces ** (Dry Pipe Fire Prot)	**5,691,778**	**87,369**	13,900	280,551	11,124,770	1.7	1.9	
	Total								

Utility Modernization Analysis — Option List

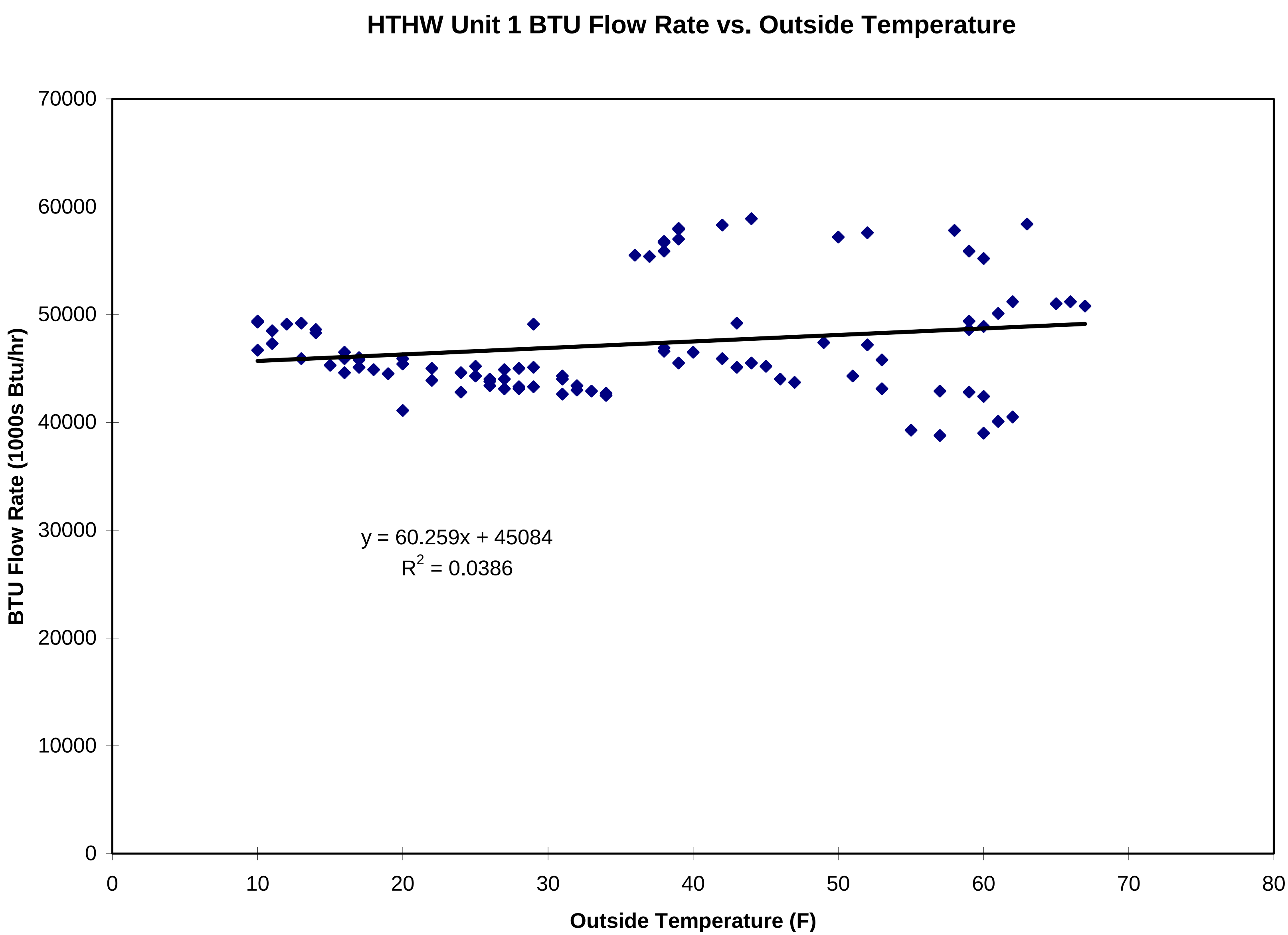
	Option	Production Peak Load MBTU/hr	Bldg Served Sq. ft.	Coal Fuel MBTU/yr	Gas Fuel MBTU/yr	Oil Fuel MBTU/yr	Elect MWhr/yr	Bldg Peak Loan MBTU/hr
	1	80.8	3,652,200	**106,669**			514	78.4
	2	80.8	3,652,200	106,669			514	78.4
	2a	80.8	3,652,200	106,669			514	78.4
	3	80.8	3,652,200		**102,904**		427	78.4
Base Case	3a	80.8	3,652,200		102,904		427	78.4
	3a-1	80.8	3,652,200		102,904		427	78.4
	3b	41.2	1,730,035		**50,166**		292	39.8
	3c	41.2	1,730,035		50,166		292	39.8
	3c-1	41.2	1,730,035		50,166		292	39.8
	4	80.8	3,652,200		102,904		427	78.4
	5	80.8	3,652,200	96,001.92	10,290		427	78.4
	6	80.8	3,652,200			102,904	427	78.4
	6a	80.8	3,652,200			102,904	427	78.4
	7	80.8	3,652,200			102,904	427	78.4
	7a	41.2	3,652,200			102,904	427	78.4
	8	78.4	3,652,200		93,845		427	**78.4**
	8a	39.9	1,730,035		45,241		292	39.9
	9	78.4	3,652,200		93,845		427	78.4
	9a	39.9	1,730,035		45,241		292	39.9
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
	Total							

Utility Modernization Analysis — Option List

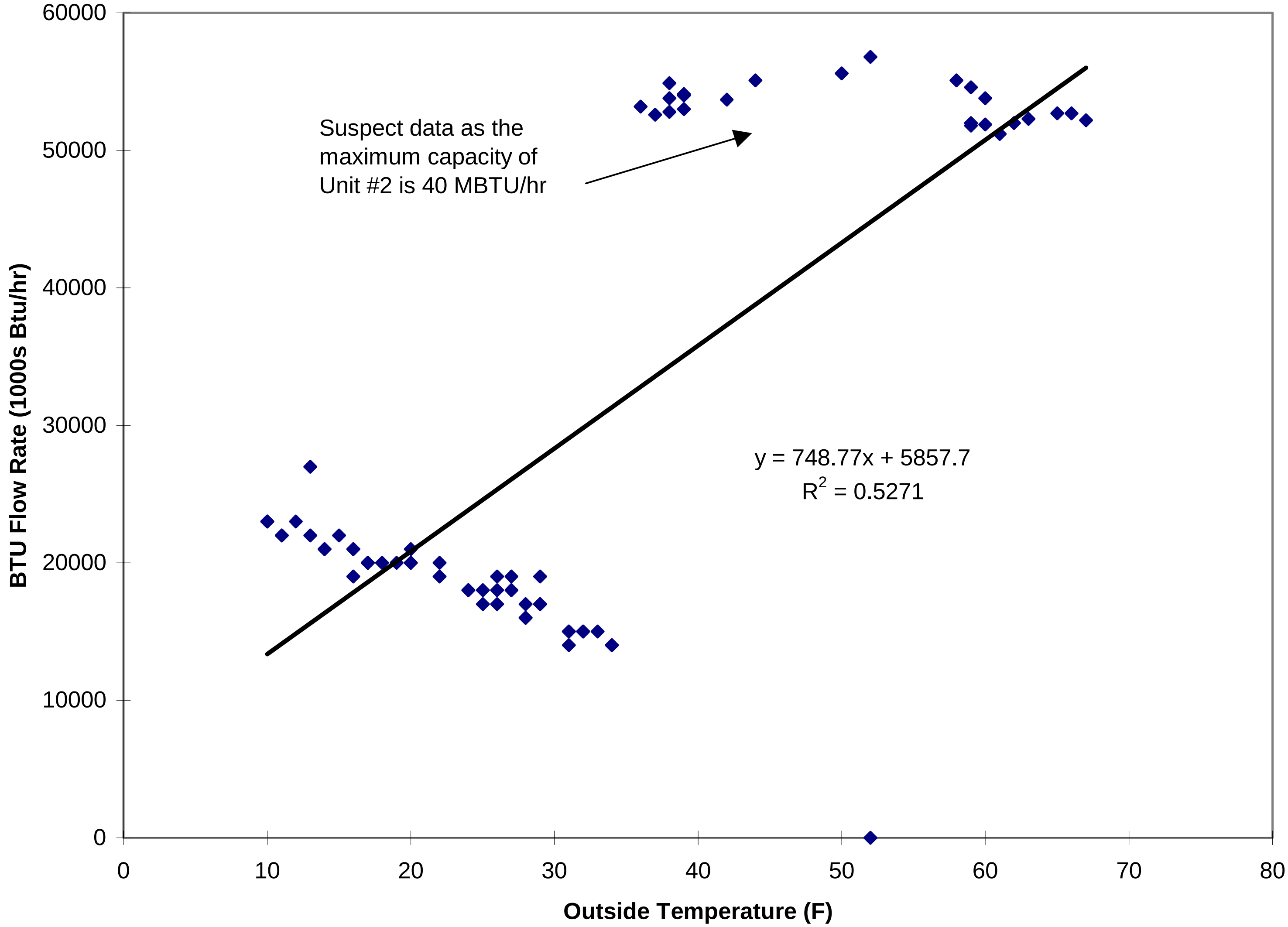
LCCID ECIP (Saving +/ Cost -) Entries

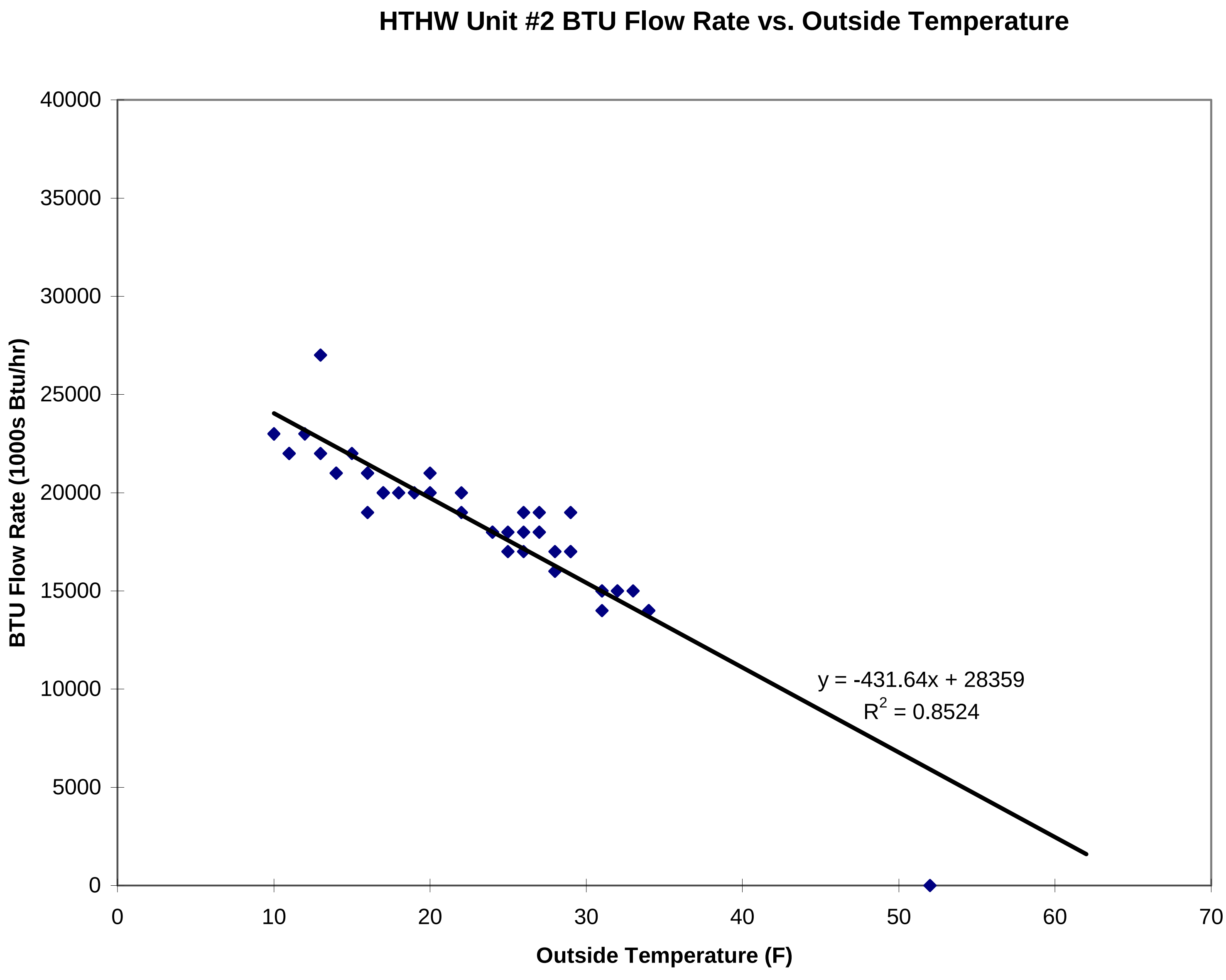
	Option	Capital	Savings Labor	Savings OM&R	Coal MBTU/yr	Gas MBTU/yr	Oil MBTU/yr	Elect MWhr/yr
	1	2,760,000	-374,405	-369,935	-106,669	102,904	0	-88
	2	2,570,000	-374,405	-369,935	-106,669	102,904	0	-88
	2a	2,570,000	-374,405	-155,000	-106,669	102,904	0	-88
	3	1,500,000	-374,405	0	0	0	0	0
Base Case	3a	1,500,000	0	0	0	0	0	0
0	3a-1	1,500,000	0	0	0	0	0	0
	3b	2,150,584	-374,405	0	0	52,738	0	135
	3c	2,150,584	0	0	0	52,738	0	135
	3c-1	2,150,584	0	0	0	52,738	0	135
	4	3,270,000	-374,405	0	0	0	0	0
	5	3,290,000	-374,405	-369,935	-96,002	92,614	0	0
	6	2,320,000	-374,405	0	0	102,904	-102,904	0
	6a	2,320,000	-374,405	0	0	102,904	-102,904	0
	7	4,040,000	-374,405	0	0	102,904	-102,904	0
	7a	4,040,000	-374,405	0	0	102,904	-102,904	0
	8	4,764,176	89,100	62,900	0	9,059	0	0
	8a	3,495,584	132,393	115,057	0	57,663	0	135
	9	8,957,231	89,100	135,900	0	9,059	0	0
	9a	5,691,778	132,393	149,100	0	57,663	0	135
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
								0.0
	Total							

Appendix E: LCCID Output

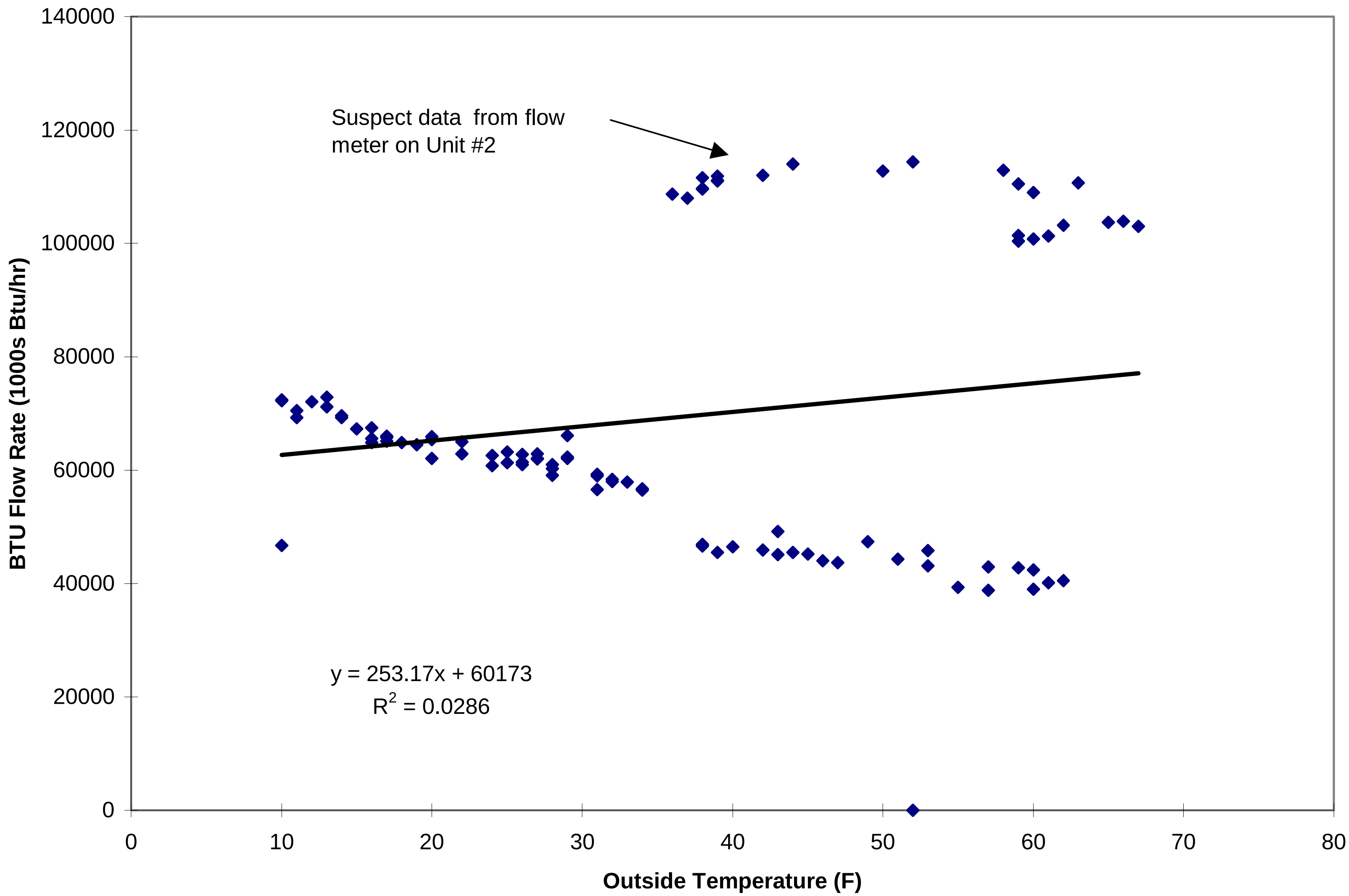

HTHW Unit 1 BTU Flow Rate vs. Outside Temperature
70000
60000
50000
40000
30000
20000
10000
0
BTU Flow Rate (1000s Btu/hr)
y = 60.259x + 45084
R2 = 0.0386
0
10
20
30
40
50
60
70
80
Outside Temperature (F)

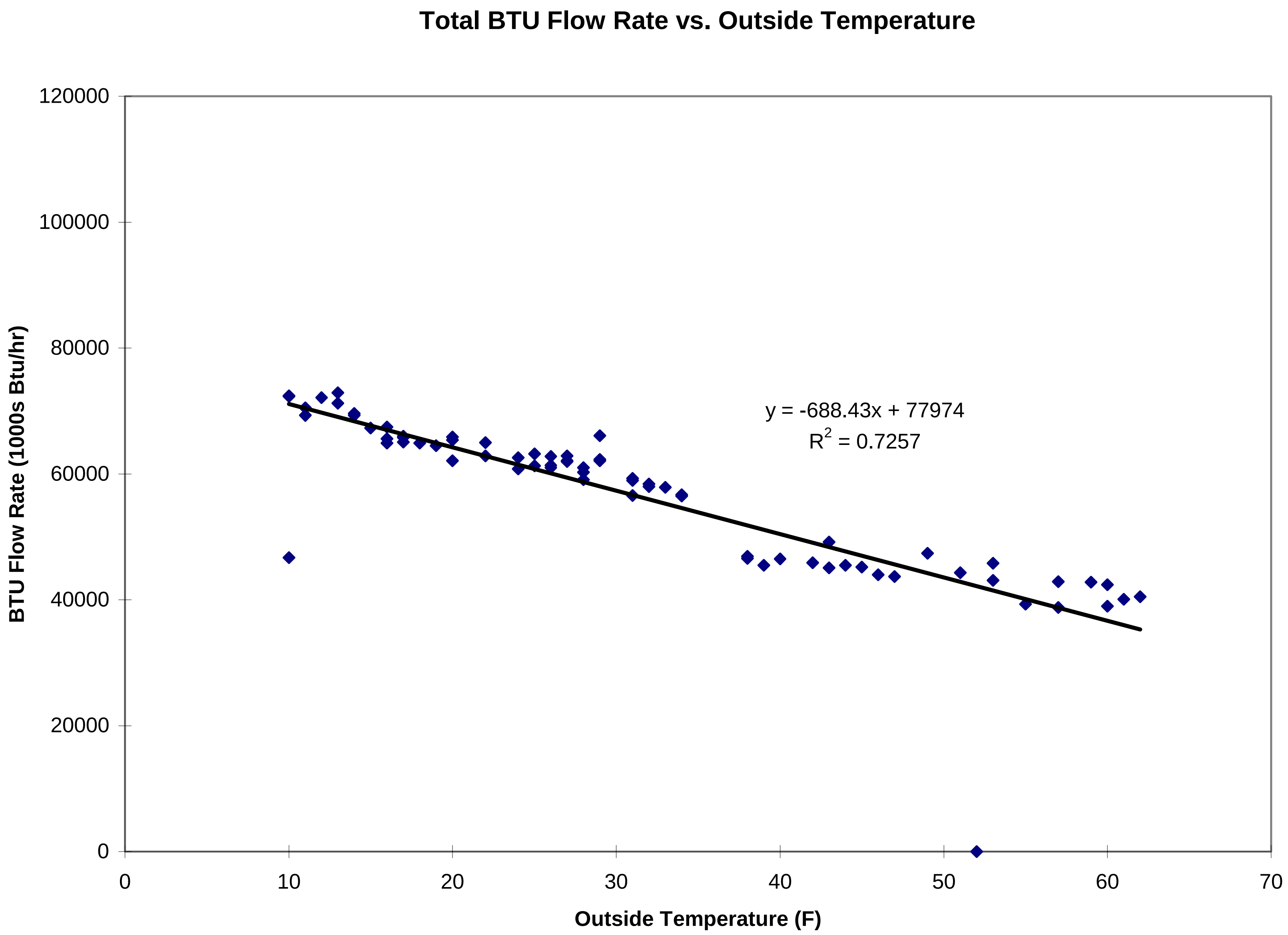
HTHW Unit # 2 BTU Flow Rate vs. Outside Temperature




HTHW Unit #2 BTU Flow Rate vs. Outside Temperature
BTU Flow Rate (1000s Btu/hr)
40000
35000
30000
25000
20000
15000
10000
5000
0
0
10
20
30
40
50
60
70
Outside Temperature (F)
y = -431.64x + 28359
R2 = 0.8524

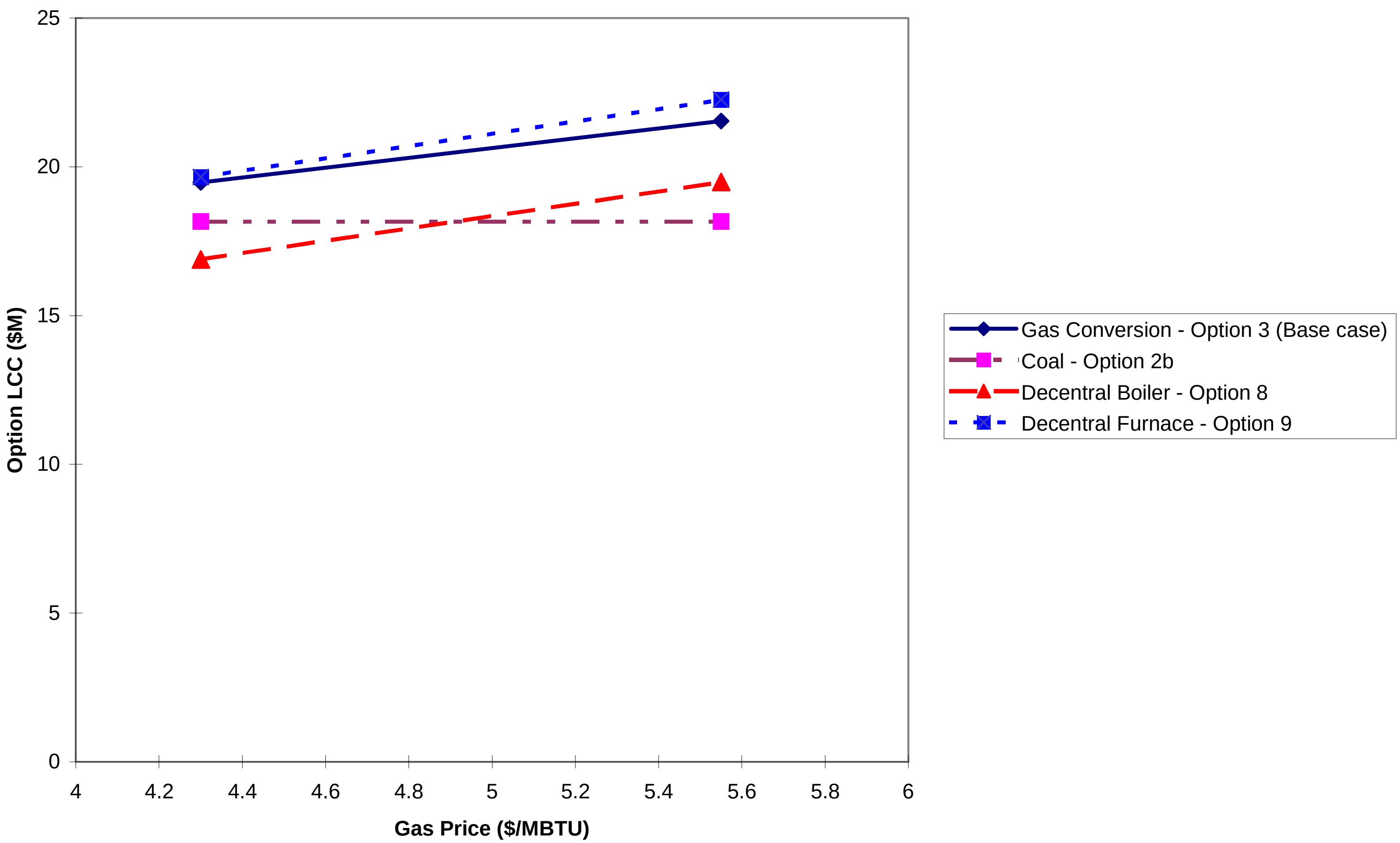
Total BTU Flow Rate vs. Outside Temperature

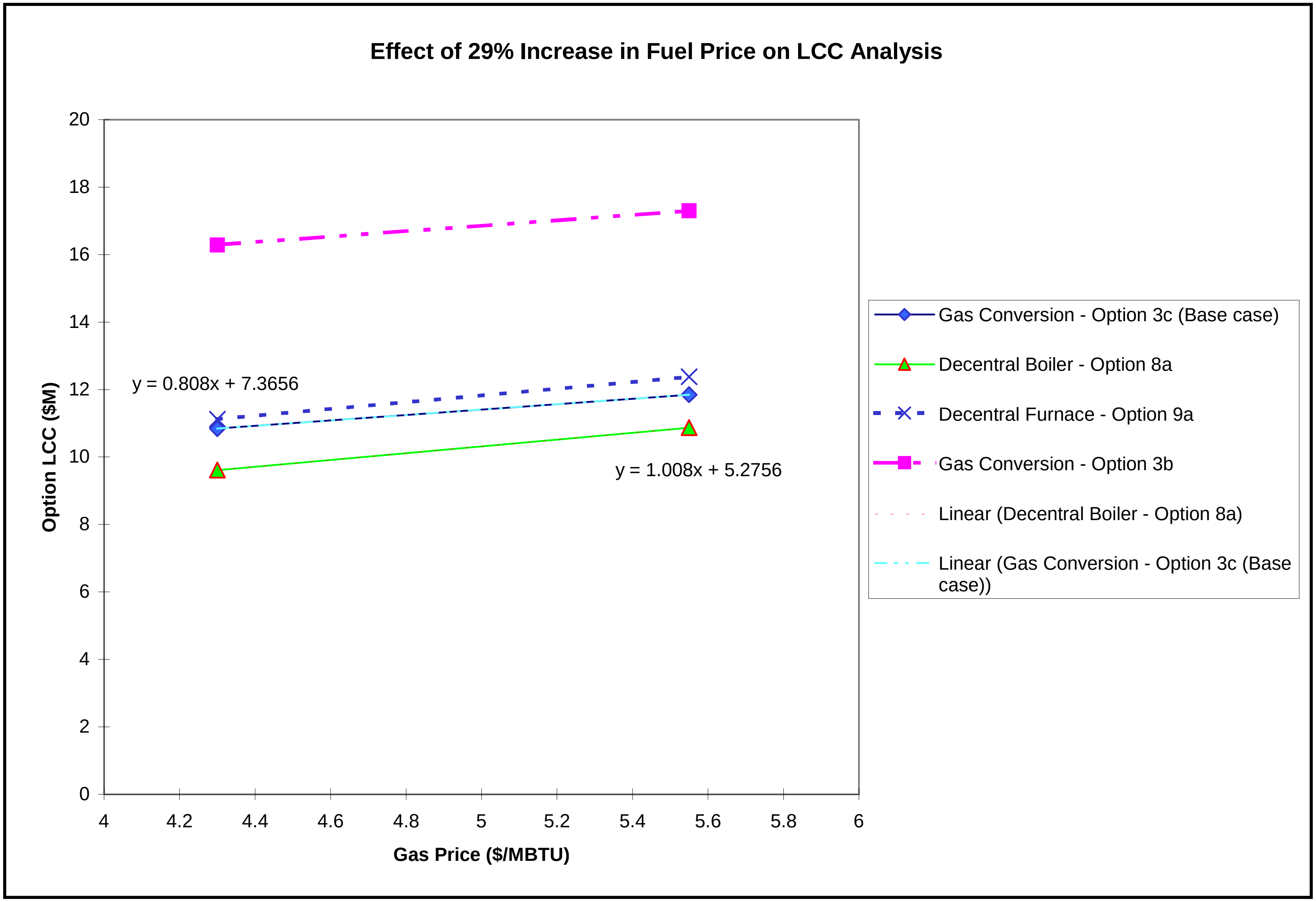


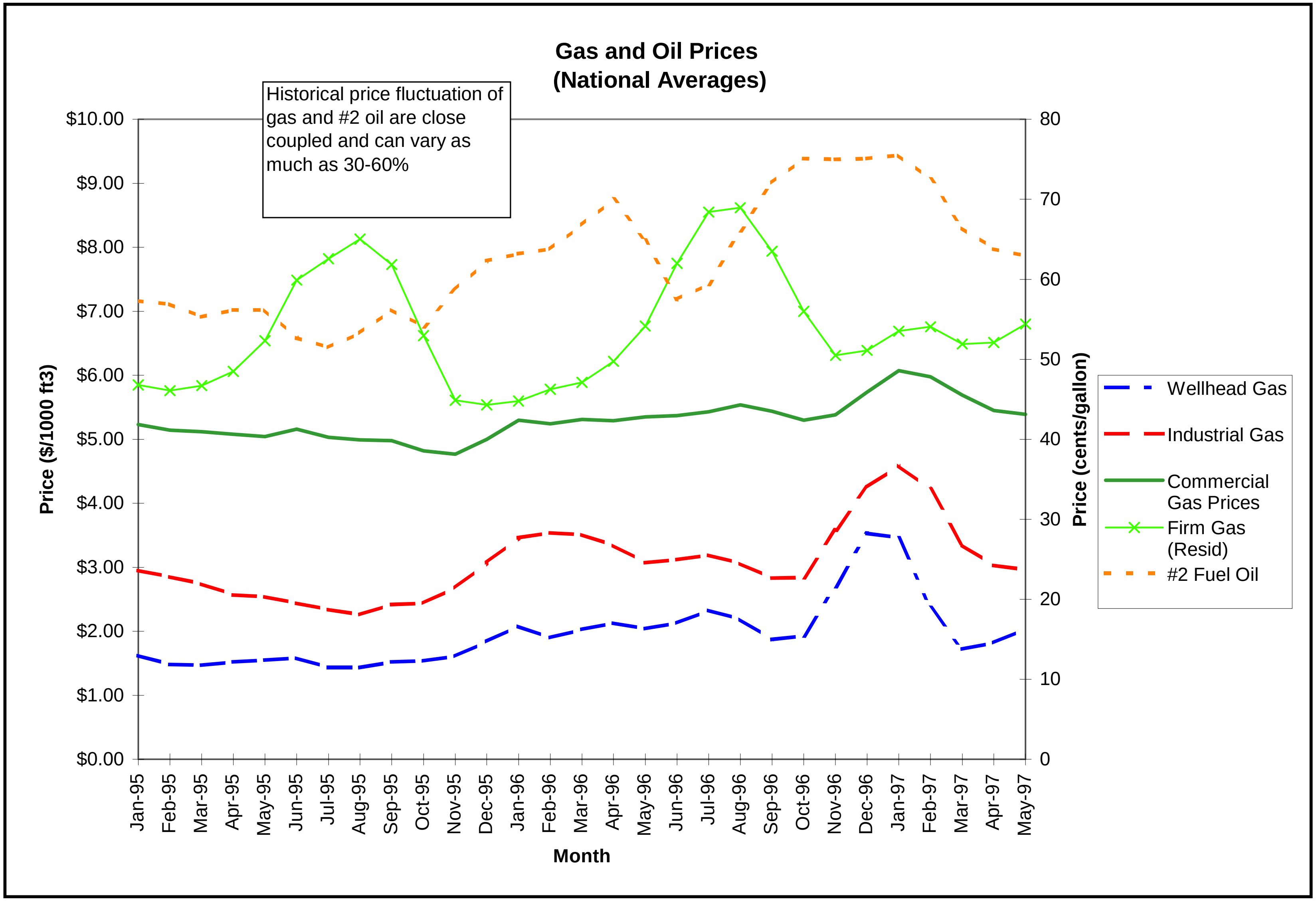

Total BTU Flow Rate vs. Outside Temperature
120000
100000
80000
60000
40000
20000
0
BTU Flow Rate (1000s Btu/hr)
y = -688.43x + 77974
R2 = 0.7257
0
10
20
30
40
50
60
70
Outside Temperature (F)

Appendix F: Net Present Value Sensitivity Analysis

Effect of 29% Increase in Fuel Price on LCC Analysis




Effect of 29% Increase in Fuel Price on LCC Analysis
Option LCC ($M)
Gas Price ($/MBTU)
20
18
16
14
12
10
8
6
4
2
0
4
4.2
4.4
4.6
4.8
5
5.2
5.4
5.6
5.8
6
y = 0.808x + 7.3656
y = 1.008x + 5.2756
Gas Conversion - Option 3c (Base case)
Decentral Boiler - Option 8a
Decentral Furnace - Option 9a
Gas Conversion - Option 3b
Linear (Decentral Boiler - Option 8a)
Linear (Gas Conversion - Option 3c (Base case))


Gas and Oil Prices
(National Averages)
Historical price fluctuation of gas and #2 oil are close coupled and can vary as much as 30-60%
Price ($/1000 ft3)
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
Price (cents/gallon)
80
70
60
50
40
30
20
10
0
Jan-95
Feb-95
Mar-95
Apr-95
May-95
Jun-95
Jul-95
Aug-95
Sep-95
Oct-95
Nov-95
Dec-95
Jan-96
Feb-96
Mar-96
Apr-96
May-96
Jun-96
Jul-96
Aug-96
Sep-96
Oct-96
Nov-96
Dec-96
Jan-97
Feb-97
Mar-97
Apr-97
May-97
Month
Wellhead Gas
Industrial Gas
Commercial Gas Prices
Firm Gas (Resid)
#2 Fuel Oil

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ATTN: CEHEC-IM-LP (2)
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Defense Tech Info Center 22304
ATTN: DTIC-O (2)

11
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