Energy Audits of Boiler & Chiller Plants
Energy Engineering Analysis Program

Fort Bragg, North Carolina

Volume I: Narrative Report

Final Submittal For:

Department of the Army
Savannah District Corps of Engineers

Prepared By:

GEE & JENSON

A-E Contract No. DACA21-84-C-0603

March, 1991

DEPARTMENT OF THE ARMY
CONSTRUCTION ENGINEERING RESEARCH LABORATORIES, CORPS OF ENGINEERS
P.O. BOX 9005
CHAMPAIGN, ILLINOIS 61826-9005

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ENERGY AUDIT FINAL SUBMITTAL
FOR FORT BRAGG, NORTH CAROLINA

TAB 1. EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

This document constitutes the Pre-Final Submittal for Contract DACA21-84-C-0603, Energy Audits of Boiler/Chiller Plants, Ft. Bragg, North Carolina.

The purpose of this report is to indicate the work accomplished to date, show samples of field data collected, illustrate the methods and justifications of the approaches taken, outline the present conditions, and make recommendations for the potential energy efficiency improvements to the central energy plants of Fort Bragg. The specific buildings analyzed are:

Building C-1432	82nd Heating Plant
Building D-3529	JFK Heating & Cooling Plant
Building C-6039	82nd Chiller Plant

The following buildings were part of the original scope of work, but were deleted for reasons explained further in Section 1.0 of this report:

Building C-7549	Standby Plant for C-1432
Building N-6002	New EM Barracks Complex
Building H-6240	"H" Area Chiller Plant

Work Performed

This project as specified in Army Contract Number DACA21-84-C-0603 is composed of the following steps:

1. Determine the efficiency of the boiler/chiller plants by appropriate tests.

2. Survey the installation to determine if efficiency can be improved by the repair, addition or modification of equipment and recommend improvements.

3. Evaluate the control systems and recommend changes, repairs or new controls which will improve the efficiency of the plants.

4. Review operation and maintenance procedures and provide site specific recommendations which will increase the efficiency of the plants to the maximum levels.

5. Prepare a comprehensive report to document the work performed, the results and recommendations. This report is to include Project Submission Documentation and supporting documentation for feasible Energy Conservation Opportunities (ECO's).

To date, the initial and detailed field work has been completed; the existing systems in the individual buildings have been reviewed and analyzed; the calculations on various ECO's have been completed and those not eligible for ECIP funding have either been disqualified or placed under the QRIP or PECIP. Preliminary project documentation has been completed.

It is important to note that detailed equipment loading information is either not available or not reliable. An estimated load profile has been developed for chiller analysis based on ASHRAE load factor information and available weather data.

The analysis of the central energy plants concentrated on improving the efficiency of the individual boilers and chillers and the controls required to optimize the sequence of operation. The energy savings are calculated by various methods based upon such factors as overall improvements in component efficiency, improvements to control systems, or comparisons of different equipment types (e.g. electric centrifugal vs. steam absorption chillers). The study also addresses the operation and maintenance of the equipment in such areas as blowdown control; make-up water quantities; water treatment; preventative maintenance practices; operator training; and equipment control, sequencing and monitoring. Additionally, though outside the scope of this contract, it has been identified that significant savings can be realized by making repairs to distribution systems.

Various measures have been identified which demonstrate potential energy savings. These projects include:

Building C-1432 Projects

1. Steam vs. Electricity to Run Motors
2. Bypass Air Heater
3. Replace O_2 Analyzer and Calibrate Combustion Control
4. Add Automatic O_2 Trim

Building D-3529 Projects

1. Replace O_2 Analyzer and Calibrate Combustion Controls
2. Add Automatic O_2 Trim

Note that these projects do not qualify for ECIP funding, but all have demonstrated the potential for significant energy savings and all but one are recommended for implementation under QRIP or PECIP. Appropriate project documentation is included for those projects with savings to investment ratios greater than 1.0.

In addition, various O&M actions have been identified which offer substantial energy savings potential; some with only a minimal investment. In fact, in several instances the O&M requirements are of much greater importance, and would offer more significant savings than the QRIP or PECIP projects identified.

1.0 EXISTING INSTALLATION EQUIPMENT

Fort Bragg, North Carolina is a military reservation containing approximately 130,000 acres, over 48,000 buildings and over 50,000 personnel. The mission involves the training, logistic and mobilization support of the KVIII Airborne Corps.

? I've never seen a Roman Numeral like this before.

This section of the report will describe each of Fort Bragg's boiler and chiller plants' existing equipment installations.

1.1 Boilers

Evaluation of Fort Bragg's existing boilers installations included testing for three identical watertube steam generators located at building C-1432 and five identical high temperature hot water boilers located at building D-3529. It should be noted that two water tube steam generators located at building C-7549 and two high temperature water generators located at building N-6002 were deleted from the scope of work. Specific descriptions for the equipment at each building are contained in the following sections of this report.

1.1.1 Building C-1432

This building contains three, identical, A-type watertube steam generators as manufactured by Erie City Boiler Co. Each boiler is rated at 95,000 lbs of steam per hour although they are seldom run at this rate. The boilers are equipped with O_2 trim, steam pressure controller and Forced Draft (F.D.) inlet controls. The O_2 trim is currently not functional.

The auxiliaries for each boiler are electrically driven and include the following: F.D. blower, Induced Draft (I.D.) fans, feedwater pump, condensate return pump and cooling tower for water cooled bearings. The F.D. blowers and I.D. fans are clutch coupled to steam turbines; however, the turbines are currently used only for emergencies.

The plant has common systems for:

- Water softening
- Condensate return storage
- Boiler feedwater deaeration
- Boiler feedwater makeup
- Boiler feedwater pumps and piping
- Boiler controls
- Steam header connection
- Natural gas piping supply
- Fuel oil supply

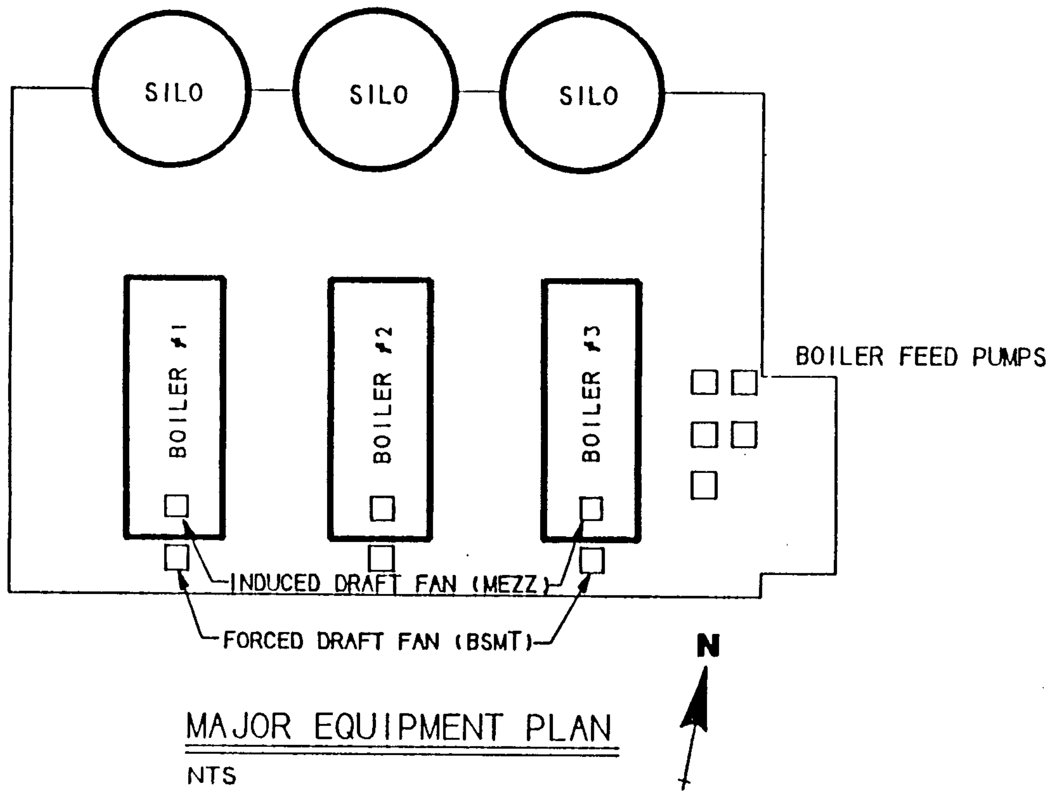
The boilers in this plant were designed to burn coal, and have been converted to burn gas or oil, using multiple Todd register type burners. The plant is licensed to burn waste oil (300,000 gallons per year), and boiler number 3 is regularly used for that purpose.

A specific description of the individual boilers to be tested in the test plan and a layout drawing of equipment are as follows:

1. Number of Boilers: 3, essentially identical.
2. Output: Saturated steam 145 PSI
3. Rated Capacity, each: 95,000 PPH
4. Manufacturer: Erie City Iron Works
5. Primary Fuel: Natural Gas

6. Secondary Fuel: No. 6 Fuel Oil
7. Feedwater Meters: Individual orifice plate meters
8. Gas Meters: One meter common to all 3 units, plus individual orifice plate meters.
9. Fuel Oil Meters: Individual positive displacement meters.
10. Waste Heat Recovery: Tubular air heaters plus economizers
11. By-Pass Damper: Exists to control flue gas flow across air preheater.
12. Stacks: Individual
13. Observed Condition: Boiler Nos. 1, 2 and 3 operational as of October 1990
14. Estimated Maximum Flows:

Gas Flow:	113,500 CFH
Oil Flow:	6,400 PPH
Water Flow:	110,000 PPH



MAJOR EQUIPMENT PLAN

NTS

MAJOR EQUIPMENT

BOILER NO. 1	STEAM @ 85.000 LBS/HR	GAS/#2 OIL/#6 OIL		
BOILER NO. 2	STEAM @ 85.000 LBS/HR	GAS/#2 OIL/#6 OIL		
BOILER NO. 3	STEAM @ 85.000 LBS/HR	GAS/#2 OIL/#6 OIL		
ID & FD FANS NO. 1	125 HP	ELECTRIC		
2	125 HP	ELECTRIC		
3	125 HP	ELECTRIC		
BOILER FEED PUMP NO. 1	125 HP	ELECTRIC (EMERGENCY)		
BOILER FEED PUMP NO. 2	40 HP	ELECTRIC		
BOILER FEED PUMP NO. 3	40 HP	ELECTRIC		
BOILER FEED PUMP NO. 4	50 HP	ELECTRIC		
BOILER FEED PUMP NO. 5	60 HP	ELECTRIC		

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ENERGY AUDITS OF BOILER AND CHILLER PLANTS

BUILDING C-1432

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

JOB NO. 84-255
DATE

GEE & JENSON
ENGINEERS-ARCHITECTS-PLANNERS, INC
2090 PALM BEACH LAKES BLVD.
WEST PALM BEACH, FLORIDA 33409

DWG. NO.

1.1.2 Building D-3529

This building contains five identical Flo-Kontrold High Temperature Hot Water (HTHW) boilers, each rated at 26 MBTU. The boilers can be fired on either natural gas or No. 6 fuel oil and are manually sequenced to match the demand on the system. The primary fuel is natural gas with the No. 6 fuel oil used during curtailment. The boilers supply HTHW to the four zones of the distribution system. They also supply HTHW for use by the 1,000 ton absorption chiller in Building H-6240 to generate chilled water. Each boiler is supplied by a 15 HP, 390 GPM circulating pump, each pump having an identical backup unit.

The accessories used on this boiler installation include a heat exchanger used to produce steam for plant space heating and the atomization of the No. 6 fuel oil. This heat exchanger consists of a HTHW coil used to produce steam inside a pressure tank. The steam is then circulated through the shell and tube heat exchanger while the No. 6 oil passes through the tubes to be preheated. The steam is also directed to the burners to provide proper atomization of the fuel oil.

The plant has some common systems for:

- Water softening
- HTHW storage and expansion
- Steam generation
- Feedwater deaeration
- Fuel oil heating
- Feedwater make-up
- Boiler controls
- Fuel oil and natural gas piping
- Zone supply and return headers

The HTHW is circulated throughout the four zones of the distribution system by a series of centrifugal pumps. There are two pumps per zone. The primary is operated continuously and the standby pump is operated at regular intervals to exercise it. The pump motors are as follows: Zone 1 - 30HP; Zone 2 - 50 HP; Zone

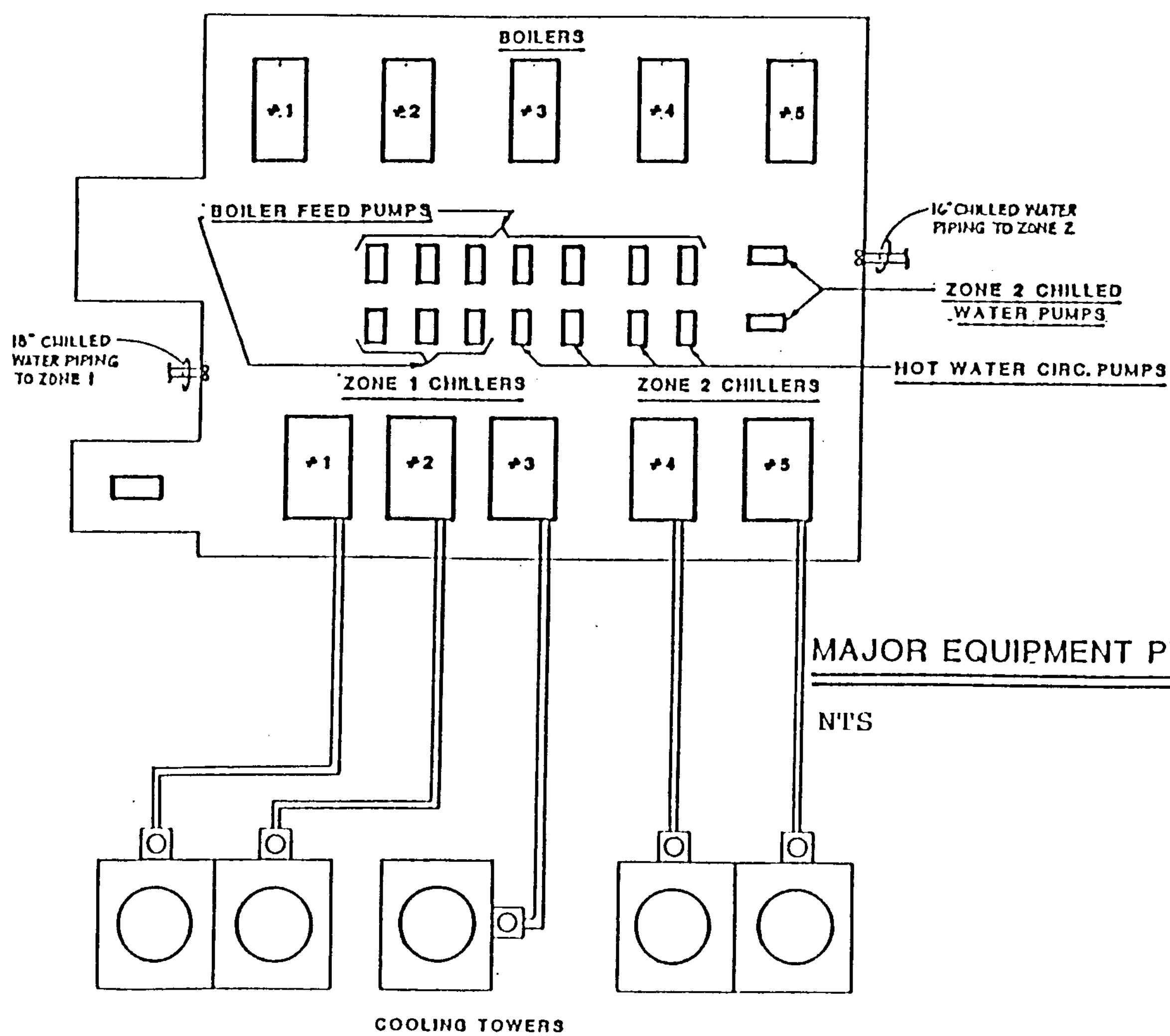
3 - 75 HP; Zone 4 - 100 HP. The standby pumps are matching units except Zone 4, which has a 75 HP back-up.

All boilers are piped into a common hot water discharge header and into a common return header. Each boiler uses a single dedicated water circulation pump to force the flow of water through the boiler and the in plant circulation loop. Separate circulation pumps are used to pump hot water to the various heating loops around the area.

The boilers are fired using natural gas 80-90% of the time, and their back up fuel is #6 fuel oil, which is from a common fuel oil supply system. All boilers have individual instrument metering equipment connected to a common central control and recording room from where firing rates are controlled. Burners are single register type gas or fuel oil fired with a forced draft fan only. Consequently, each boiler fires under positive pressure.

A specific description of the individual boilers to be tested in the test plan and a drawing of equipment are as follows:

1. Number of Boilers: 5 essentially identical
2. Output: High temperature water
3. Rated Capacity, each: 26 million BTU per hour.
4. Manufacturer: Flo-Kontrold
5. Primary Fuel: Natural gas
6. Secondary Fuel: #6 Fuel Oil
7. Water Flow Meters: Individual venturi or orifice meter at inlet of each unit.
8. Natural Gas Meters: Orifice meter for each unit
9. Fuel Oil Meters: Positive displacement meter for each unit
10. Year Built:
    - A. Nos. 1,2,3 : 1965
    - B. No. 4 : 1967
    - C. No. 5 : 1978
11. Estimated Maximum Flows:
    - Gas Flow: 32,500 CFH
    - Oil Flow: 231 GPH
    - Water Flow: 220,000 to 240,000 PPH as tested
12. Burner: All are forced draft natural gas or #6 oil burners.
13. Induced Draft Fans: Are not included
14. Waste Heat Recovery: None is present
15. Stacks: Each boiler has its own individual stack
16. Observed Condition: At time of testing, boilers 1-4 were operational. Boiler #5 was not operational.



MAJOR EQUIPMENT PLAN

NTS

MAJOR EQUIPMENT

HTHW BOILER NO. 1 - 26,000,000 BTUH
HTHW BOILER NO. 2 - 26,000,000 BTUH
HTHW BOILER NO. 3 - 26,000,000 BTUH
HTHW BOILER NO. 4 - 26,000,000 BTUH
HTHW BOILER NO. 5 - 26,000,000 BTUH

HOT WATER CIRCULATING PUMPS 1 = 30 HP
2 = 50 HP
3 = 75 HP
4 = 100 HP

BOILER FEED PUMPS

NOS. 1,2,3,4,1A,2A,3A,4A 15 HP

CHILLER NO. 1 TRANE, CENTRIFUGAL, 665 TONS
CHILLER NO. 2 TRANE, CENTRIFUGAL, 665 TONS
CHILLER NO. 3 TRANE, CENTRIFUGAL, 665 TONS
CHILLER NO. 4 YORK , CENTRIFUGAL, 709 TONS
CHILLER NO. 5 YORK , CENTRIFUGAL, 709 TONS

CHILLED WATER PUMPS ZONE 1, 300 HORSEPOWER
CHILLED WATER PUMPS ZONE 2, 150 HORSEPOWER (2 EACH)

CONDENSER WATER PUMP NO. 1 60 HP, VERTICAL TURBINE
CONDENSER WATER PUMP NO. 2 60 HP, VERTICAL TURBINE
CONDENSER WATER PUMP NO. 3 50 HP, VERTICAL TURBINE
CONDENSER WATER PUMP NO. 4 60 HP, VERTICAL TURBINE
CONDENSER WATER PUMP NO. 5 60 HP, VERTICAL TURBINE

COOLING TOWER NO. 1 40 HP, 2 SPEED, ONE CELL
COOLING TOWER NO. 2 40 HP, 2 SPEED, ONE CELL
COOLING TOWER NO. 3 40 HP, 2 SPEED, ONE CELL
COOLING TOWER NO. 4 40 HP, 2 SPEED, ONE CELL
COOLING TOWER NO. 5 40 HP, 2 SPEED, ONE CELL

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ENERGY AUDITS OF BOILER AND CHILLER PLANTS

BUILDING D-3529

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

JOB NO. 84-255
DATE

GEE & JENSON
ENGINEERS-ARCHITECTS-PLANNERS, INC
2090 PALM BEACH LAKES BLVD
WEST PALM BEACH FLORIDA 33409

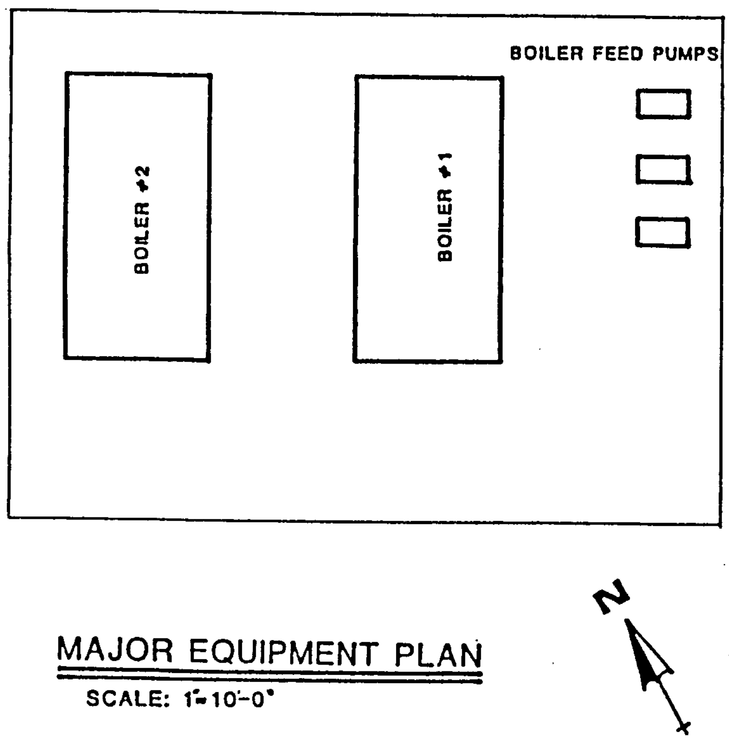
DWG NO

1.1.3 Building C-7549

This building houses two, water-tube steam generators rated at 50,000 lbs per hour as manufactured by Keeler Boiler Co. These boilers serve as standby units to those in Building C-1432 and are operated only as required for testing. The boilers are equipped with burners to use No. 2 fuel only.

The auxiliaries for these boilers consist of electrically operated feed water and fuel oil pumps, condensate holding tank and automatic control system. The automatic controls in this installation, like those in Building C-1432 are only partially operational. Please refer to the following drawing for major equipment layout for this plant.

It should be noted here that these boilers were originally tested in April 1985, but were deleted from the scope of work as per meeting minutes of June 11, 1987 (see Appendix 1.2, Volume 2).



MAJOR EQUIPMENT PLAN

SCALE: 1"=10'-0"

MAJOR EQUIPMENT

BOILER NO. 1	STEAM @ 50,000 LBS/HR	#2 OIL ONLY
BOILER NO. 2	STEAM @ 50,000 LBS/HR	#2 OIL ONLY

BOILER FEED PUMP NO. 1	50 HP
BOILER FEED PUMP NO. 2	50 HP
BOILER FEED PUMP NO. 3	50 HP

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ENERGY AUDITS OF BOILER AND CHILLER PLANTS

BUILDING C-7549

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

JOB NO. 84-255
DATE

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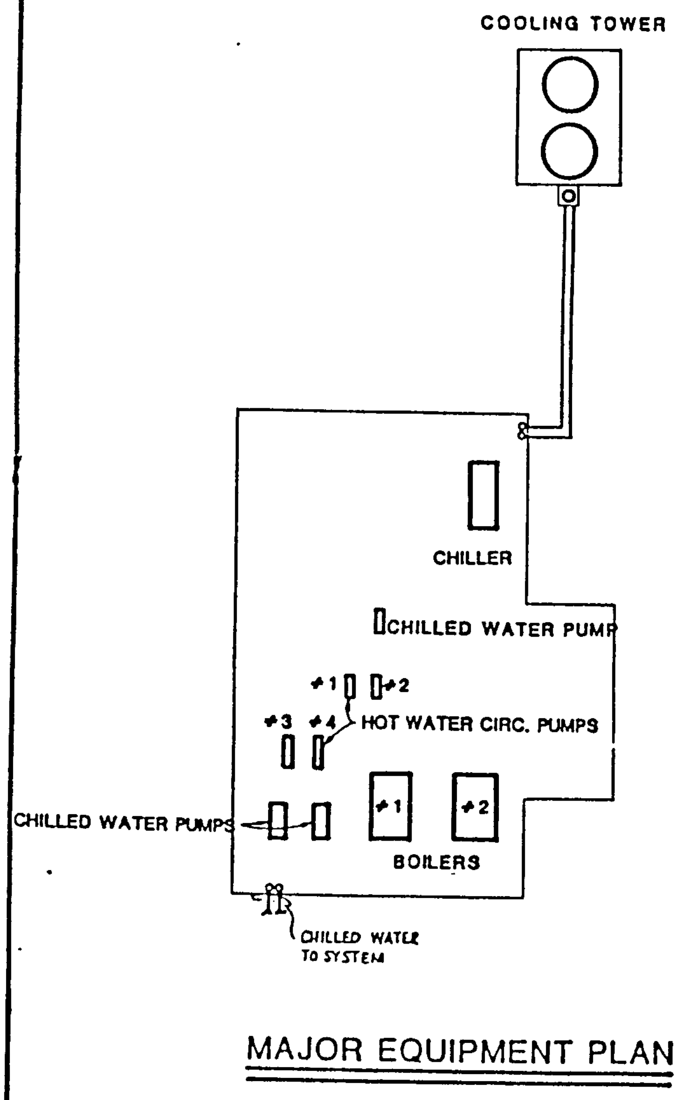
ENGINEERS-ARCHITECTS-PLANNERS, INC.
2090 PALM BEACH LAKES BLVD.
WEST PALM BEACH, FLORIDA 33409

DWG. NO.

1.1.4 Building N-6002

This building is the EM Barracks Complex with a dining facility. It houses two high temperature water generators with a total capacity of 25,000,000 BTU/HR. (See layout drawing of equipment that follows.) Pursuant to the prenegotiation conference meeting on April 30, 1984, this building was also deleted from the scope of work (see Appendix 1.1, Volume 2).



MAJOR EQUIPMENT PLAN

SCALE: 1"=30'

MAJOR EQUIPMENT

BOILER NO. 1 - 25 MILLION BTUH, NAT. GAS/#2 OIL
BOILER NO. 2 - 25 MILLION BTUH, NAT. GAS/#2 OIL

HOT WATER CIRCULATING PUMP 1 75 HP, VARIABLE SPEED
2 75 HP, VARIABLE SPEED
3 10 HP, CONSTANT SPEED
4 10 HP, CONSTANT SPEED

CHILLER NO. 1, YORK, CENTRIFUGAL, 744 TONS

CHILLED WATER PUMP 1, 20 HP
CHILLED WATER PUMP 2, 200 HP, VARIABLE SPEED
CHILLED WATER PUMP 3, 200 HP, VARIABLE SPEED

CONDENSER WATER PUMP 1, 60 HP, VERTICAL TURBINE

COOLING TOWER 1, 25 HP, 2 CELL

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ENERGY AUDITS OF BOILER AND CHILLER PLANTS
BUILDING N-6002
ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

JOB NO.		DWG. NO.
84-256	GEE & JENSON ENGINEERS-ARCHITECTS-PLANNERS, INC. 2090 PALM BEACH LAKES BLVD. WEST PALM BEACH, FLORIDA 33409	4
DATE		

1.2 Chillers

Evaluation of Fort Bragg's existing chiller installations included testing for four electrically driven centrifugal chillers located at building D-3529 and four York chillers located at building C-6039. Originally, two high temperature hot water absorption chillers for building H-6240 were to be tested, but were not tested because proper valves for flow meters were not available. (Note: One of these absorption chillers has recently been replaced by a York centrifugal chiller.) A more detailed description of these installations is contained in the following sections of this report.

1.2.1 Building D-3529

This building houses five electrically driven centrifugal chillers, three 665T Trane Centrivacs, and two 700T York Turbomasters. (Product data for the Trane chillers is not available at this time; however some data was received from Trane and include in Section 3.1.2, Volume 2 of the Appendix.) The first three chillers serve distribution zone one while zone two is served by the remaining two chillers. Condenser water is treated and monitored; however, the chilled water is not. The control of the chillers is completely manual, with the plant operators bringing individual units on line based on leaving CHWS temperature. It was reported that the chiller control system originally brought on additional chillers as needed based on the chilled water supply temperature. However, over the years, the controls have fallen into a state of disrepair and some may have been removed completely.

The chilled water circulating pump for Zone 1 is a 300 HP, 4000 gpm double-suction type. Zone 2 has two pumps, primary/standby, each rated at 150 HP, and 2127 gpm. The circulating pumps are operated continuously throughout the cooling season.

The heat rejection from the chilled water system is via open cooling towers; two dual cells, and one single cell. The condensing side of each chiller is piped to an individual tower cell to provide sequenced operation. The condenser pump and fan motors are as follows:

Tower No.	Pump Motor	Fan Motor
1	60 HP	40 HP
2	60 HP	40 HP
3	50 HP	40 HP
4	60 HP	40 HP
5	60 HP	40 HP

The circulating pump is energized when the chiller is brought on line. The fan motor cycles on automatically in response to the sump water temperature.

The chilled water distribution system for this area originates at Building D-3529 and consists of a main line running underground along Ardennes Road with multiple 8" branch lines supplying the various buildings. As in Area "C", each building has a booster pump to circulate the chilled water to the air handling units in that building.

A specific description of the individual chillers to be tested in the test plan is listed as follows (refer to equipment layout drawing for this plant):

1. Number of Chillers: 4 tested; 1 not tested (inoperative)
2. Output: Chilled water
3. Capacity, each: 2 @ 665 tons; 2 @ 700 tons
4. Manufacturer: Trane; York
5. Year Built:
6. Refrigerant: R-11; R-12
7. Flow Meter: EMCO turbine flow meter
8. Computer: EMCO FP-100
9. Watt meter: Dranetz #808
10. Thermometer: Fisher Scientific #15000B
11. Observed Condition: Four of five chillers operational on August 18, 1987.

1.2.2 Building C-6039

This building was originally equipped with four York chillers, two 1000T steam turbine driven centrifugal units and two 979T steam absorption units. At the time of our testing, the steam absorption units were being removed and the steam turbine driven chillers have been converted to electrically driven units since the time of testing. The current configuration is four York 750T chillers, one Trane 1000T and one York 1000T. For the purpose of these tests, we tested the four (4) York 750T chillers.

The chilled water pumps are two, parallel piped, horizontal, split-case centrifugal pumps operated as a primary/standby pair. Each pump is rated at 500 HP, 4400 gpm, and the primary pump operates continuously throughout the cooling season. The standby pump is operated occasionally to keep it exercised as opposed to alternating the operation of the two units.

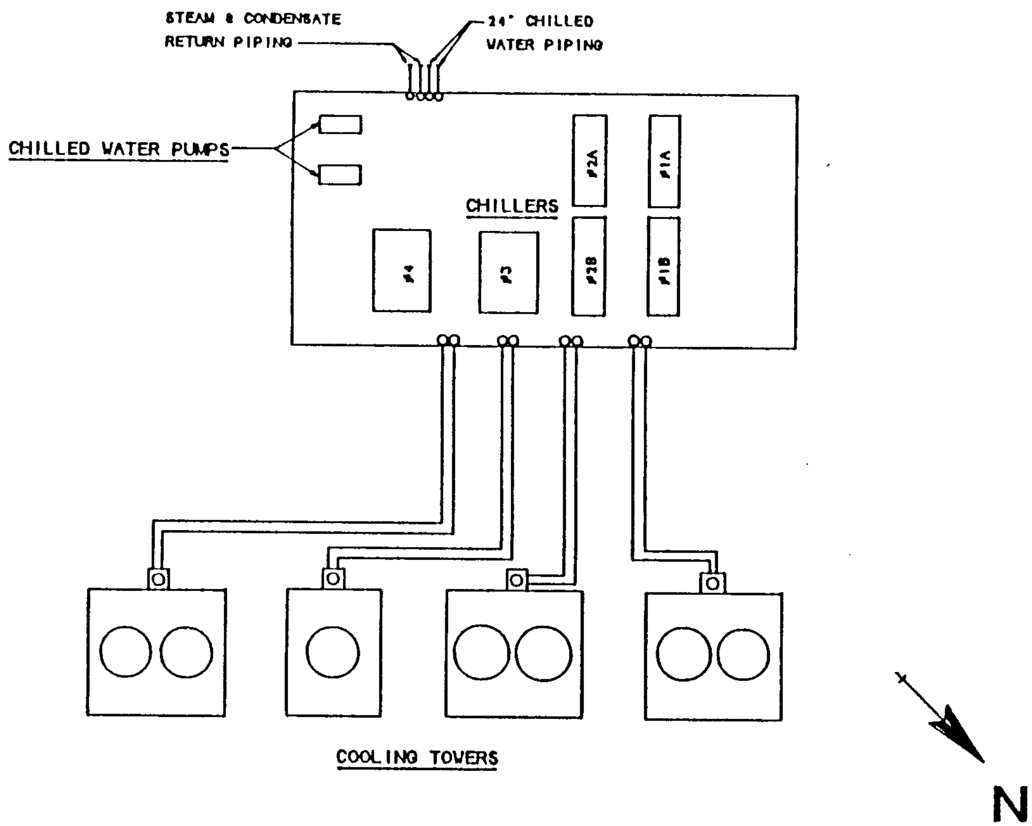
Condenser water is cooled by three dual-cell cooling towers and one single-cell tower. The condenser water pump and cooling tower fan motors are as follows:

Tower No.	Pump Motor	Fan Motor
1	100 HP	2 @ 40 HP/2 speed
2	100 HP	2 @ 40 HP/2 speed
3	75 HP	1 @ 50 HP/2 speed
4	75 HP	2 @ 40 HP/2 speed

The chilled water distribution system for this area originates at Building C-6039 and consists of 24" underground main lines with 16", 14", and 8" branch lines to supply the various buildings. Each building has a separate booster pump to circulate the chilled water to the various air handling units in that particular building.

A specific description of the individual chillers to be tested in the test plan and an equipment layout drawing are as follows:

1. Number of Chillers: 4 tested
2. Output: Chilled water
3. Capacity, each: 750 tons
4. Manufacturer: York (all)
5. Refrigerant: R-11
6. Flow Meter: EMCO turbine flow meter
7. Computer: EMCO FP-100
8. Watt Meter: Dranetz #808
9. Thermometer: Fisher Scientific #15000B
10. Observed Condition: All four chillers operational on August 24, 1987.



MAJOR EQUIPMENT PLAN

NTS

MAJOR EQUIPMENT

CHILLER NO. 1A/B - YORK CENTRIFUGAL, 750 TON
CHILLER NO. 2A/B - YORK CENTRIFUGAL, 750 TON
CHILLER NO. 3 - TRANE CENTRIFUGAL, 1000 TON
CHILLER NO. 4 - YORK CENTRIFUGAL, 1000 TON

CHILLED WATER PUMPS 1 & 2 - 500 HP, PARALLEL

CONDENSER WATER PUMP 1. 100 HP, VERTICAL TURBINE
2. 100 HP, VERTICAL TURBINE
3. 75 HP, VERTICAL TURBINE
4. 75 HP, VERTICAL TURBINE

COOLING TOWER 1. 40 HP, 2 SPEED, TWO CELL
2. 40 HP, 2 SPEED, TWO CELL
3. 50 HP, 2 SPEED, ONE CELL
4. 40 HP, 2 SPEED, TWO CELL

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ENERGY AUDITS OF BOILER AND CHILLER PLANTS BUILDING C-6039 ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)	
JOB NO. 84-255 DATE	GEE & JENSON ENGINEERS-ARCHITECTS-PLANNERS, INC 2090 PALM BEACH LAKES BLVD. WEST PALM BEACH, FLORIDA 33409 DWG. NO.

1.2.3 Building H-6240

At the time of the chiller testing, this building contained two 950T, high temperature hot water (HTHW), absorption chillers as manufactured by the Trane Company (product data not available -- see Section 3.1.2, Volume 2 of the Appendix). Within the past year, one of these chillers has been replaced with a York 950T centrifugal unit. The HTHW to the remaining absorption chiller is supplied by the boilers in Building D-3529 and returns through the base distribution system. The HTHW is circulated through the chiller by a 10 HP pump.

The two chilled water circulating pumps are of the single stage, double suction, vertical split case, centrifugal type, parallel piped for primary/standby operation. The pumps are each rated at 150 HP, 2085 gpm with the standby pump operated occasionally to exercise it.

The cooling towers are dual cell, open type of unknown manufacturer with one tower piped to each chiller. Cooling tower no. 1 has redwood slat cooling media, while tower no. 2 has PVC fill. The condenser water pumps and fan motors are as follows:

Tower No.	Pump Motor	Fan Motor
1	100 HP	2 @ 50 HP/2 speed
2	100 HP	2 @ 50 HP/2 speed

The condenser water pumps start when the chiller is brought on line and the fan motors cycle in response to the water temperature in the tower sump.

The control of these chillers is done manually by the operating personnel from Building D-3529. The plant operators decide when to start the first chiller (the centrifugal chiller) which is done manually. As it begins to approach operation at its maximum rated capacity, the operators manually start the absorption machine. During those high cooling load conditions, requiring the operation of both chillers, the centrifugal chiller runs continuously at maximum load, and the absorption unit modulates its part-load capacity to carry the remaining load. When the HTHW return temperature rises above a predetermined level, the operator switches the absorption unit off.

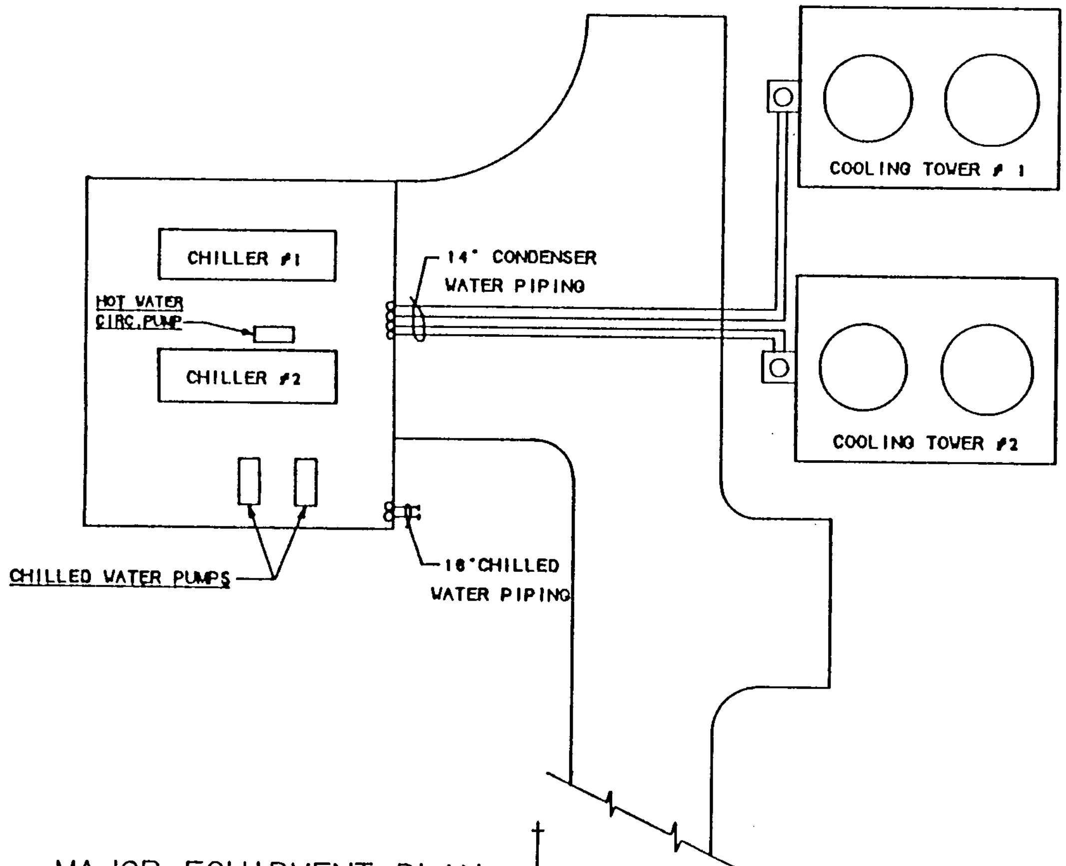
The chilled water distribution system for this area originates at Building H-6240 and consists of 16" main lines with branch lines varying in size from 4" to 12" supplying the individual buildings. As elsewhere, individual booster pumps circulate the chilled water to the air handling units in that building.

A specific description of the individual chillers to be tested in the test plan and an equipment layout drawing are as follows:

1. Number of Chillers: 2 not tested
2. Output: Chilled water
3. Capacity, each: 2 @ 950 tons
4. Manufacturer: Trane
5. Condition: Both chillers operational on August 31, 1987.

These chillers were not tested for this report. The absorption units had flow venturis installed in the high temperature hot water lines as part of the original installation. The HTHW to these units was at a temperature of 320 to 340 degrees Fahrenheit for Chiller #1 and 230 to 270 degrees Fahrenheit for Chiller #2. Pressure at both units was 320 psig.

Our original "Scope of Work" included testing of these two machines utilizing the existing flow venturis. During our setup to conduct these tests, it was discovered that special hoses and valves were required for our meter in order to safely handle these extreme temperatures and pressures. When we contacted BARCO to arrange for these hoses, we discovered that the venturis themselves required special taps for these conditions when they were originally ordered. The special taps were <u>not</u> present. We did not feel that we could connect to these venturis safely without serious injury or loss of life. Therefore, we did not test these units.



MAJOR EQUIPMENT PLAN
NTS

MAJOR EQUIPMENT

CHILLER NO. 1, YORK CENTRIFUGAL, 850 TON
CHILLER NO. 2, TRANE ABSORPTION, 850 TON

CHILLED WATER PUMPS 1 & 2, 150 HP

HOT WATER CIRCULATING PUMP, 15 HP

CONDENSER WATER PUMP NO. 1, 100 HP, VERTICAL TURBINE
CONDENSER WATER PUMP NO. 2, 100 HP, VERTICAL TURBINE

COOLING TOWER NO. 1, 50 HP, TWO CELL, 2 SPEED
COOLING TOWER NO. 2, 50 HP, TWO CELL, 2 SPEED

FORT BRAGG
U.S. ARMY ENGINEER
DISTRICT, SAVANNAH

FAYETTEVILLE, N.C.
CORPS OF ENGINEERS
SAVANNAH, GEORGIA

ENERGY AUDITS OF BOILER AND CHILLER PLANTS

BUILDING H-6240

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

JOB NO. 84-255	GEE & JENSON ENGINEERS-ARCHITECTS-PLANNERS, INC 2090 PALM BEACH LAKES BLVD. WEST PALM BEACH, FLORIDA 33409	DWG. NO.
DATE		

1.2.4 Building N-6002

This building contains one York centrifugal chiller with 744 ton total capacity, including one 20 HP chilled water pump, two 200 HP variable speed pumps, one vertical turbine condenser pump, and one two-cell cooling tower. As discussed in Section 1.1.4 of this report, this building was deleted from the scope of work during the prenegotiation conference.

2.0 PERFORMANCE TESTING

2.1 Boilers

Performance testing for existing boiler installations and procedures for operating and maintenance of boilers for Fort Bragg were conducted. The field tests were designed to determine the efficiency of the boilers while in operation, noting any changes made to equipment or controls during the tests. Testing results were recorded on the ASME abbreviated test code input/output test form as directed in the scope of work.

The following discussion of the work performed for the boilers at Fort Bragg will include these buildings: C-1432 and D-3529.

The purpose of this compilation is to present the results of the boiler efficiency tests performed on each boiler as scheduled in the boiler test plan of October 1987.

This report fulfills the requirements of specification scope of work for Fort Bragg, NC, Section 1.1 and 3.1 as far as the actual testing and reporting of results and calculations on the ASME PTC 4.1 forms. Analysis of these results, recommendations, and other supporting studies is included in Section 4.0 of this report.

Each boiler was tested in as normal an operating mode as possible with no changes to controls or operations other than to put the firing control in manual in order to hold a fixed firing rate for the duration of the test.

The test procedure used was in accordance with the ASME PTC 4.1 abbreviated form. We have collected the required data and completed the necessary calculations to show the boiler efficiency by <u>both</u> the input/output method, and by the heat loss method.

This report does show the specific boiler efficiency tests completed, their raw field data, and the resulting calculations required to complete the ASME PTC 4.1a summary sheet for abbreviated efficiency test. We have also included a graph for each boiler which plots the resulting efficiency.

The specific tests which were performed on the boilers are as follows:

1. Boiler efficiency by the input-output method, following the guide line of the ASME PTC 4.1 methods.
2. Steam quality determination using a throttling calorimeter, on those boilers which are steam generators.
3. Boiler flue gas analysis tests performed with an orsat type analyzer.
4. Flue gas temperature documentation using a certified thermometer.
5. Boiler firing capacity test of short duration to determine the maximum firing rate the boiler is normally capable of.
6. On those boilers with an air preheater - an air leakage test was performed.
7. Boiler feedwater system upset and response or recovery performance.
8. Boiler automatic controls upset and response or recovery performance.
9. Boiler ignition sequence and flame safeguard operation.

The following Instruments were used on all boiler tests where their range and application match as listed.

APPLICATION	DEVICE	RANGE	ACCURACY
Steam Pressure	WIKA 312.20 Test Gauge	0-300 PSIG	±1/4%,±3/4psig
Steam Quality	Croll-Reynolds Company Throttling Calorimeter	0-5% Moisture	± 0.08% Moisture
Air Heater	Hays Orsat	O_2,CO_2,CO	± 3%
Flue Gas Analy.	Hays Orsat	O_2,CO_2,CO	± 3%
Flue Gas Temp.	Weksler AF-12	150-750 F	± 10%, ±1.7%
Feedwater Press.	WIKA 312.20 Test Gauge	0-500 psig	±1/4%, ±1.25%
Feedwater Temp.	Weksler AA5H-9	30-300°F	±2°F, ±7/10%
Nat Gas Press.	WIKA 312.20 Test Gauge	0-30 psig	±1/4%,±0.075psig
Nat Gas Temp	Weksler A5H-9	0-120°F	±1 °F, ±8/10%
Oil Press.	WIKA 312.20 Test Gauge	0-300 psig	±1/4%, ±3/4psig
Oil Temp.	Weksler AA5H-9	30-300°F	±2°F, ±7/10%
Feedwater Temp.	Weksler AA5H-9	50-550°F	±5°F, ±1%
Oil Flow Meter	Kent Industrial	To 300°F	± 1%

The calculations for boiler efficiency are based on the input-output method as described in the ASME PTC 4.1. Heat loss method is also shown.

We tested the boilers at various firing rates as stated in the schedules in this test plan, recorded the appropriate data at each time interval, at each rate, for each fuel required.

We solved for the following data:

Steam quality - where applicable
Actual water evaporated (Flow)
Total heat input
Fuel analysis
Fuel higher heat value
Efficiency of boiler in percent
Excess air after combustion
Flue gas analysis
Rate of fuel firing
Total heat input
Total heat output
Heat loss efficiency

We completed the ASME Test Form for Abbreviated Efficiency Test Report for each run on each fuel.

In addition to that data required to be collected to perform the boiler efficiency calculation as defined previously, we collected data to study those areas detailed in Section 2.1 of the scope of work.

Additionally, we collected data to allow us to perform the heat loss method of boiler efficiency to cross check the input/output method, and also to analyze the excess air percentage and boiler flue gas outlet temperature for possible recommendations.

We also collected data during the testing of the boilers on:

1. Controls operation, in manual and auto
2. Flame Safety System Operation.
3. Burner operation
4. Boiler maximum capacity
5. Boiler minimum capacity
6. Boiler feedwater system operation
7. Boiler ignition system operation
8. Air preheater leakage test

All these and other data collected during a thorough study of the boiler plant operation were considered, analyzed, and summarized by the field evaluation engineer in Section 4.0 of this report.

2.1.1 Building C-1432

The boiler test plan of October 1987 was adhered to as closely as possible. In Fort Bragg, Building C-1432, we tested boilers 2 and 3 on their standby fuel, #6 fuel oil, because natural gas was not available. We didn't test #1 boiler because major repairs were in progress. The contractor was replacing the tubes in the boiler and had not completed work when we were in the plant testing.

Boiler #2 was tested on January 21, 1988 at 25% load capacity with #6 fuel oil for four hours with an 80.72% efficiency rating and at 50% capacity with an efficiency of 84.3%. It was again tested on January 25, 1988 at 75% load capacity with #6 fuel oil for four hours with an 85.57% efficiency and then force fired on the same day.

On January 25, 1988, boiler #3 was tested at 40% capacity with #6 fuel oil for two hours with an efficiency of 82.77%. It was tested the same day at 40% for a short duration with an efficiency of 87.16% and at 75% with #6 fuel oil for two hours with results of 86% efficiency. Boiler #3 was again tested on January 27, 1988, which concluded testing of boilers for building C-1432.

The specific boiler firing tests, both firing rates and lengths of firing tests runs, and the fuels tested were as follows:

LOCATION	BUILDING	BOILER	POINTS %	DURATION	FUEL	ADDED
Fort Bragg	D-3529	1	25,50,75,100	2 HRS	OIL	
Fort Bragg	D-3529	2	40,75	2 HRS	OIL	
Fort Bragg	D-3529	3	40,75	2 HRS	OIL	
Fort Bragg	D-3529	4	40,75	2 HRS	OIL	
Fort Bragg	D-3529	5	25,50,75,100	2 HRS	GAS	

DATA AND PLOT OF RESULTING CURVES

Following the testing of each boiler, on each fuel tested, we charted and graphed the pertinent data against the boiler's firing H/A output. This will allow the review of the graphic trends on flow, efficiency, and excess air, as it relates to each boiler and fuel tested. The test data and plots are located in Appendices 2.2.2, Volume 2.

ESTIMATED ERROR FACTOR IN CALCULATIONS

LOCATION	BOILER	FUEL	MEASUREMENT ERROR (SUM)	ERROR IN CALCULATED EFFICIENCY
Fort Bragg Building C-1432	2, 3	OIL	High Flow ±2.85% Low Flow ± 3.6%	±2.7% ±3.45%

2.1.2 Building D-3529

We adhered to the boiler test plan of October 1987 as closely as possible. In Fort Bragg, Building D-3529 we had to test boilers #1, 2, 3, and 4 on their standby fuel, #6 fuel oil, because natural gas was not available. Boiler #5 was tested on natural gas, as accurately as possible, considering the inability to finely tune firing controls system.

Boiler #1 was tested on January 5, 1988 at 100% capacity with #6 fuel oil for two hours with efficiency of 82.75% and an output of 26,000,000 BTU. It was tested again on January 6th at 50% with #6 fuel oil for two hours with an efficiency of 80.71% and at 75% capacity with the same fuel for two hours with an efficiency of 81.91%. It was also tested again at full capacity for 20 minutes to an 80.39% efficiency. The testing for boiler #1 was completed on January 7th at 25% capacity with #6 fuel oil for one hour with an 80.79% efficiency.

Boiler #2 was tested at 75% capacity for two hours on January 7, 1988 along with a short duration full-load test, resulting in a 79.21% efficiency. It was tested again at full capacity for one-half hour with a 79.19% efficiency. Testing for this boiler continued on January 8th with 25% load, but this test was not completed until January 11th because of a power outage. It resumed at 40% capacity test with #6 fuel for two hours with an efficiency of 78.08% and at 75% capacity retest due to thermometers' problems on the first test. This completed testing for boiler #2.

Boiler #3 was tested on January 14, 1988 at 40% capacity with #6 fuel oil for two hours with a 79.42% efficiency. It was tested the same day at 75% capacity for two hours with an efficiency of 81.07% and at full capacity for one-half hour with an 80.19% efficiency.

The equipment for testing was set up for boiler #4 on January 12, 1988 and began with a 75% load. This test did not meet criteria because of faulty thermometers. This boiler was retested at 40% on January 13th. Once again, the thermometers were found to be inaccurate. However, the test data was adjusted for the errors found.

Boiler #4 was tested at 40% capacity with #6 fuel oil for two hours on January 12, 1988. The results on the ASME abbreviated test form show an efficiency of 80.39%. It was tested at 75% capacity with the same fuel oil for two hours on the same day with an 80.65% efficiency. On January 13, 1988, it was tested at full capacity with #6 fuel oil for one-half hour with an efficiency of 82.3%.

Boiler #5 testing started on January 28, 1988 at 75% load, but was stopped due to unstable and faulty orsat readings. This boiler was tested again on January 29th at 25% with natural gas for two hours with a 74.82% efficiency and at 50% capacity with an efficiency of 79.53%. The testing was concluded at 75% capacity on natural gas for one-half hour with a 74.7% efficiency.

The specific boiler firing tests, both firing rates and lengths of firing tests runs, and the fuels tested are as follows:

LOCATION	BUILDING	BOILER	POINTS %	DURATION	FUEL	ADDED
Fort Bragg	D-3529	1	25,50,75,100	2 HRS	OIL	
Fort Bragg	D-3529	2	40,75	2 HRS	OIL	
Fort Bragg	D-3529	3	40,75	2 HRS	OIL	
Fort Bragg	D-3529	4	40,75	2 HRS	OIL	
Fort Bragg	D-3529	5	25,50,75,100	2 HRS	GAS	

DATA AND PLOT OF RESULTING CURVES

Following the testing of each boiler, on each fuel tested, we have graphed the pertinent data against that boiler's firing H/A output.

This will allow the review of the graphic trends on flow, efficiency, and excess air, as it relates to each boiler and fuel tested. The test data and plot are located in Appendices 2.3.2, Volume 2.

ESTIMATED ERROR FACTOR IN CALCULATIONS

LOCATION	BOILER	FUEL	MEASUREMENT ERROR (SUM)	ERROR IN CALCULATED EFFICIENCY
Fort Bragg Building D-3529	1,2,3,4	OIL	High Flow ±2.85% Low Flow ± 3.6%	±2.7% ±3.45%
	5	Nat Gas	High FLow ±3.1% Low Flow ±4.6%	±2.95% ±4.45%

2.2 Chillers

Performance testing of existing chiller plants for Fort Bragg included evaluation of the chillers' control systems, operation and maintenance procedures, cooling tower conditions and equipment, and procedures for monitoring and recording system performance. The central chilled water plants were tested for system efficiency and an examination of piping and plant connection equipment was conducted.

The purpose of this compilation is to present the results of the chiller efficiency tests performed on each chiller as scheduled in the chiller test plan of February 1986 (see Appendix 3.1.1). This report fulfills the requirements of specification scope of work for Fort Bragg, N.C., as far as the actual testing and reporting of results and calculations. Analysis of these results and calculations are included herein.

Each chiller was tested in as normal an operating mode as possible with no changes to controls or operations other than to vary the load point for each chiller test condition. We adhered to the chiller test plan of February 1986 as closely as possible.

We have collected the required data and completed the necessary calculations to show the chiller efficiency expressed as chiller Energy Efficiency Ratio (EER). This report provides the specific chiller efficiency test information including raw field data and calculations. We have also included in Appendices sections 3.2 and 3.3, Volume 2, a graph for each chiller which plots the resulting efficiency.

2.2.1 Building D-3529

Efficiency tests were conducted on chillers 1,3,4 and 5 on June 28, 1985. Chiller number 2 was not tested at all during the evaluation of chillers for building D-3529 because it was not operational at the time of testing. Additional testing was performed on the chillers August 18th and August 19, 1987. The test results were recorded on Centravac Logs and included: evaporator and condenser pressure and temperature readings of inlets and outlets, control and panel readings, liquid levels, and amperage and voltage readings. Test data and graphs showing test results are located in Appendix 3.2, Volume 2, and the Centravac Logs are provided in Appendix 3.2, Volume 2 of this report.

The specific chiller rates, lengths of test runs and the refrigerant used are as follows:

BUILDING	CHILLER	POINTS %	DURATION	REFRIGERANT
Fort Bragg:				
D-3529	1	40,60,80,100	2.5 HRS	R-11
	2	Not Tested	--	--
	3	40,60,80,100	3 HRS	R-11
	4	50,65,80	1.5 HRS	R-12
	5	50,60,70	2 HRS	R-12

The following formulas are used in calculations throughout this report:

Heat transferred:	Q(BTUH) = 500*GPM*dT 1 Ton = 12,000 BTUh
Thermal Balance:	Q cond = Q evap + Q kw
Energy Efficiency Ratio:	EER = Q evap / Watts
Kilowatts used per Ton:	kW/ton = kilowatts/TONS evap

2.2.2 Building C-6039

A test was conducted on the York turbine unit 02820CST for building C-6039 on July 29, 1985, but the unit went off on low oil pressure, and the test was not completed. Additional testing was performed on chillers 1A, 1B, 2A and 2B on August 24th through August 25, 1987. The data was recorded on the Centravac Logs and included: evaporator and condenser pressure and temperature readings, control panel readings, liquid levels, and amperage and voltage readings. Test data and graphs for these units are located in Appendix 3.3, Volume 2, and the Centravac Logs and additional data are located in Appendix 3.3, Volume 2.

The specific chiller rates, lengths of test runs and the refrigerant used are as follows:

BUILDING	CHILLER	POINTS %	DURATION	REFRIGERANT
Fort Bragg:				
C-6039	1A	50,65,80,100	1.75 HRS	R-11
	1B	50,65,80,100	1.75 HRS	R-11
	2A	50,65,80,100	1.75 HRS	R-11
	2B	50,65,80,100	1.75 HRS	R-11

3.0 CONTROL SYSTEMS/OPERATIONS & MAINTENANCE

The existing control systems and operation and maintenance procedures were evaluated for the boiler and chiller plants at Fort Bragg to determine what equipment changes or procedures could be made to improve the plants' performances. As described in the following paragraphs, there are a number of areas wherein substantial improvements can be made without large capital investments simply by repairing existing equipment and improving operation and maintenance practices. In other areas, however, capital improvements are recommended to improve efficiency, safety or environmental compliance.

3.1 Staffing

Though the focus of this study is on equipment and procedures, it is clearly true that an appropriate staffing level is necessary to properly operate and maintain the physical plant. While it was not within the scope of this study to perform a staffing analysis, it was reported that staffing levels appear to be having a negative impact in some areas, most notably in the level of maintenance performed on the equipment. A number of noted maintenance and repair deficiencies appeared to have existed for quite some time. When inquiries were made, the response was generally that manpower constraints had precluded timely maintenance or repair.

In discussions with facilities managers at Ft. Bragg, it was noted that the staffing level for operators has remained constant at 28 since 1984; yet two additional plants have been built and placed into operation since that time. Those managers estimate the additional manpower requirements for the two new plants to be 14-15 people. This estimate is largely corroborated by a fiscal year 1989 Manpower Study, which identified the need for 41 people (total) to operate and maintain the plants at Ft. Bragg. The existing staffing level represents a 32% shortfall from the recommended level.

In the current Department of Defense atmosphere of increasingly constrained personnel resources, it may not be realistic to expect the total shortfall to be staffed; however, the general level of maintenance of both the boiler and chiller plants indicates that something should be done soon. If additional manpower cannot be obtained, then additional O&M funds should be provided for the maintenance and/or repairs to be performed by contract.

It is also important that the effects of this apparent staffing shortfall be minimized by providing the current operators with appropriate aids to enable them to perform more effectively. These aids including: training, operation and maintenance guides, schedules, and checklists are covered in subsequent sections. In addition, equipment automation could release operators routine tasks, so that additional time could be spent on plant maintenance and repair activity.

3.2 Boilers

The subsequent sections will describe the following control and operational changes: manual and automatic controls operations, flame safety operations, burner operations, maximum and minimum control operations, feedwater system operations, boiler ignition system operations, air preheater control, casing repairs, oxygen analyzer additions, boiler sizing, training of personnel, fuel analysis, boiler tuning, excessive blowdown, fuel oil heater repairs, valve repairs and emergency generator set repairs.

3.2.1 Building C-1432

The boiler control system consists of a central, electrically operated master controller with a sub-master for each boiler. The master controller responds to main steam pressure while the sub-master regulates fans, fuel flow, oxygen trim and feedwater. Most of the controls (except O_2 trim) have been recently replaced and appear to be operating satisfactorily; however, key plant performance indicators are generally inoperative or provide suspect readings.

There are no combustion analyzers installed, and the operators have no access to portable equipment. As a result, the boilers fuel/air ratio is adjusted by visual observance of the boiler flame and existing stack gases. This procedure generally results in the use of too much excess air, which reduces boiler efficiency and results in flue gas condensation; which, in turn, contributes to economizer and stack corrosion. The condition of the stacks necessitated their replacement in 1987. Remedial actions are discussed in the following paragraphs.

3.2.1.1 Control Operation in Manual and Auto:

The forced draft blower, induced draft fan, fuel and feedwater controls have been recently replaced. However, further system upgrade needs to be done to allow plant operation to be more efficient. Fuel/air ratio controllers are not serviceable. Fans are not stroked correctly, and the plant tuning is poor. O_2 analyzer units need to be replaced since existing units don't work.

Though many controls have been recently replaced, the plant instrumentation is generally not operating adequately. For example, it is reported that the steam flow orifice plates are worn and that steam flow readings are highly suspect. The no. 2 steam flow recorder reads the same all the time, and large variations are shown at the same settings for the three boilers. There is no calibration program at all for plant instrumentation.

It is recommended that a calibration program be implemented as soon as possible. The calibration could be performed by maintenance contract or, alternatively, plant personnel could be trained to perform the work. Regardless of the method chosen, the calibration program should be implemented without delay.

3.2.1.2 Flame Safety Operation:

Operation of system when examined was adequate. It was observed that no limits had been tampered with or by-passed. Nevertheless, each limit and its correct function in the system should be verified. The position of scanners should be checked in order to ensure coverage of all burners in each of the multi-burner boilers. A regularly scheduled cycle should be established to check the operation of each safety limit and record the results, identify maintenance required, and assure the system is operable.

3.2.1.3 Burner Operation:

Burners need routine service and combustion checks performed as part of a regular preventive maintenance program. Sparklers were witnessed in the flame when burners were operating. Oil temperature seemed to be okay. Atomizing steam pressure was available but was being controlled manually. The steam pressure regulators are reportedly not functioning properly. Checks for water in oil need to be made. Burner nozzles should be cleaned daily and inspected for wear and correct application.

Steam differential regulators should be inspected to ensure that a constant steam pressure of 10-20 PSI greater than oil pressure is maintained through the full range of normal oil operating pressures. If the regulators fail (as reported) to maintain the proper differential, they should be repaired or replaced immediately. Steam traps and atomizing steam lines should be inspected regularly and maintained properly.

3.2.1.4 Boiler Maximum Capacity:

At the control maximum firing rate, fuel oil usage was 99% of design. Testing indicated that at the maximum firing rate, excess air was at 30%. However, the combustion smoking clearly demonstrated that there was insufficient combustion air for that firing condition. The primary reason for the false indication of the percentage of excess air is the leakage in the air preheater, which vents fresh air directly into flue gas.

In actuality, there is insufficient combustion air for efficient boiler operation. This is partly caused by the leakage of the air preheaters. It also may result from improper stroking of F.D. fans, and excess pressure drop in the combustion air and flue gas chain.

Therefore, while the boilers appear to operate at design maximum fuel flow, combustion air problems cause a significant reduction in efficiency.

3.2.1.5 Boiler Minimum Capacity:

Information on the boilers was not available to determine if the 18% minimum fire rate on oil meets design conditions for the nozzles installed or oil used. This information should be obtained in order to confirm boiler minimum firing performance on oil. In addition, the 18%

minimum firing rate should be set at the controls until improvements are made.

The boilers are said to be capable of firing at very low rates on natural gas with no apparent problems. Therefore, the practicable minimum firing capacity on natural gas is essentially zero.

3.2.1.6 Boiler Feedwater System Operation:

The existing controls of the boiler feedwater system exhibits too much deadband around the set point. Therefore, feedwater rates fluctuate widely even during steady-state firing conditions. In addition, the controls did not demonstrate smooth operation over the range of firing activity. For example, when firing rates were reduced, feedwater flow was not correspondingly decreased, resulting in an overflow of the drum.

It is recommended that the drum level controllers be repaired and calibrated.

3.2.1.7 Boiler Ignition System Operation:

During testing we witnessed the system in operation and noticed there was a great need for service and training. Control and limits need to be checked and set points established and maintained. Operators need to be trained on correct sequence to follow during light off of burner or burners. A detailed checklist should be provided to assist the operators in this process.

3.2.1.8 Air Preheater Leakage:

Based on the results of the combustion gas analysis, it is clear that the air preheaters are leaking significantly.

The basic test, using the Orsat analyzer, was repeated several times because we could not believe its results. Repeated checks and field study confirmed the results. The air preheaters on both boiler #2 and #3 in C-1432 are leaking. Excess air checks entering and leaving the air preheaters showed that the excess air on #2 boiler increased by 130%, and by 145% on #3 boiler.

This indicates leaks in the forced draft (FD) air tubes allowing much of the cold FD air to leak into and cool and dilute the flue gas. These leaks are extremely detrimental to the boiler operation, to plant efficiency and to the physical condition of the stacks and economizers.

As previously noted, the boiler air feed systems are unable to provide sufficient air at high firing rates. Three possible contributions to this problem are: (1) leaking FD air preheater tubes, (2) excessive pressure drop across the air preheaters and economizers, and (3) improper stroking. In either case, the removal or bypass of the air preheaters would probably aid combustion at high firing rates.

The leaks in the FD air preheat tubes also have the effect of cooling the stack gases. Since the air preheaters are located upstream of the economizers, the combustion gases are cooled prior to passing over the economizer tubes. This cooling is detrimental in two ways: first it reduces or completely nullifies the effectiveness of the economizer, and second it cools the combustion products, resulting in the condensation of water vapor (a by-product of combustion). This leads to corrosion of the economizer tubes.

These problems have been noted by the plant operators, and as a result, the economizers have been bypassed.

Consequently, the efficiency of the plant is negatively impacted. For the foregoing reasons, permanently bypassing the FD air preheaters should receive high priority.

3.2.1.9 Excessive Blowdown:

The operating personnel stated that the blowdown is set to maintain a Total Dissolved Solids (TDS) level of 1200 ppm. A review of the boiler operating logs confirms this operating practice. Given the general recommendation that the TDS is not to exceed 3000 ppm for boilers at these operating temperatures and pressures, the blowdown should be revised to maintain dissolved solids nearer the limit.

3.2.1.10 Established Procedures for Operation and Maintenance:

Both the boiler plants and chiller plants are currently being operated and maintained largely based on operator experience. An assortment of Standard Operating Procedures (SOP's) does exist; however, interviews of the operators indicated that they are generally not being used. Additionally, a review of the SOP's shows that some are outdated and some are lacking in important details. For example, the SOP for Waste Oil Burning advises the operators to check oil pressures and atomizing steam but doesn't indicate what the correct operating parameters should be. Copies of these SOP's are included in Appendix 4.1, Volume 2.

There are no maintenance schedules and only two written preventive maintenance procedures. Checklists are apparently not used for either operating or maintenance procedures. As a result, much of the operation and maintenance is left to the discretion of the operators. While the current operators appear to be knowledgeable and competent, it was also noted that there are substantial variations in operating procedures between the various operators. It is also worthy of note that a number of the more experienced operators are at or near retirement age, and under OPM hiring practices, there is no guarantee that the replacement operators will have more than very minimal experience and knowledge.

In accordance with DOD Guide 5000.51-G, operational guides should emphasize Total Quality Management (TQM) principles in the development of a quality improvement program. These principles focus on continuous quality improvement through process control. Operators need to have a thorough understanding of the processes which they control and the indicators which should be monitored to track quality improvement.

For example, the quality of the steam production of Building C-1432 could include such parameters as reliability, temperature consistency, energy consumption, or distribution losses. Operators should be trained to monitor system vital signs to ascertain statistical performance in each of the key indicators. Process improvement could then easily be tracked and correlated to some action. A change in the steam trap maintenance program, for instance, may result in a statistical improvement in distribution loss.

Without a clearly defined process control and quality improvement program, it is difficult to determine the effect of operations and maintenance initiatives. Another advantage is that operators control defined processes. Therefore, a change in operator doesn't change the process.

3.2.1.11 Training:

Ft. Bragg currently has plans to award a contract to perform controls maintenance and to provide controls training for the operators. While this training is clearly necessary, it is not sufficient. Specific training, operation maintenance guides and checklists should be developed for each plant, including C-1432.

In accordance with DOD Guide 5000.51-G, both management and operational personnel should receive training in continuous quality improvement through TQM principles. The importance of understanding key elements of process definition and control cannot be overemphasized.

Following initial TQM training, a boiler plant operations expert should be brought in to assist in process definition and control and to help define process indicators to properly monitor quality improvement. Training operations should focus on the following technical areas:

- specific system operational guides
- specific system troubleshooting guides
- specific system efficiency improvement guides
- specific system boiler log program, which includes calculation of the plant efficiency and percent effectiveness by shift and its operators
- water treatment training
- development of preventive maintenance schedules, guides and checklists for all major plant equipment

3.2.1.12 Additional Recommendations:

The following are additional recommendations for the boilers located at Ft. Bragg, building C-1432:

1.) Casing Leaks
Casing leaks need to be repaired especially around steam drums. Leaks were observed during testing while burning #6 oil.

2.) Oxygen Analysis
Permanently mounted oxygen analyzers should be installed or a portable unit should be purchased. Currently, the operators have no means to adjust the fuel/air mixture except by visual observation of the flame and stack. This generally results in reduced efficiency because of too much excess air being used. This deficiency is addressed in more detail in Section 4.7.1

3.) Boiler Sizing
Over the years, the load served by C-1432 has declined while the boiler capacity has remained constant. In particular, with the removal of the absorption chillers and steam auxiliaries, the summer load has been reduced to domestic hot water heating and cooking steam. The existing boilers are grossly oversized for this purpose.

We recommend that Ft. Bragg consider the feasibility of installing a smaller boiler of approximately 40 to 50,000 PPH capacity in the future to carry the lighter loads being experienced at the plant in warm weather. It is not economically justifiable to replace a boiler only to improve plant efficiency during the summertime. However, if at some future time one of the boilers requires major repairs, replacement should be considered as an option.

4.) Fuel Analysis
Operating personnel are currently testing every third load of #6 oil delivered. Random testing

should be implemented to ensure compliance with fuel quality specifications.

5.) <u>FD Heater</u>

One of two fuel oil heaters is inoperative due to a steam leak and the other appears to be in fair condition, at best. Plant personnel are in the process of installing new fuel oil heaters. Inasmuch as Building C-1432 is reported to burn oil approximately 30% of the time, it is recommended that the new fuel oil heater installation be completed expeditiously.

6.) <u>Isolation Valves</u>

A number of valves were observed to be leaking and/or not holding. At the time of the most recent site visit, one of the feedwater pumps was inoperative, and the deaerator tank was leaking, but they could not be repaired without a complete shutdown since the isolation valves would not hold. These bad valves should be repaired or replaced as soon as possible before a routine repair becomes a major problem. This is an especially serious problem considering the age and deteriorated condition of the feedwater pumps.

7.) <u>Emergency Generator Repairs/Maintenance</u>

The boiler plant is equipped with an emergency generator set to provide back-up power in case of an outage; however, it has not been operable for some time. Consequently, any interruption to the electrical service causes an immediate boiler shut-down. To avoid these nuisance shut-downs, the generator set and its' automatic transfer switch should be repaired. The repairs should be followed by a formal preventive maintenance program.

3.2.2 Building D-3529

The control scheme for this building is functionally a manual system. Individual boilers are switched by the operator based on HTHW temperatures. There is no comprehensive effort to match equipment performance to load requirements beyond operator diligence. Furthermore, the operators have no indication of plant performance other than the HTHW entering and leaving temperatures. There are no working flow meters and none of the control panel recorders are functional.

3.2.2.1 Control Operation:

Master controls were repaired and calibrated in 1989 (and seem to be functioning normally). While firing on gas, the F/A ratio is mechanically set and remains constant at all firing rates. The controllers essentially only adjust firing and feed rates based on load. In this mode, the master controls seem to be functioning normally.

However, when in the oil firing mode, the system is unusually sophisticated for the relatively small size of the boiler. The system has built-in cross limits in automatic mode and F/A ratio control, but it is not tuned properly. Therefore, the system is not holding the correct F/A ratio on oil.

Tests indicated that the actual firing rates were not equal to the firing rates indicated on the master panel.

Control panels and recorders need to be replaced. Except for the master controller, the control panels are essentially non-functional. Furthermore, parts are unavailable to repair them. None of the recorders in the panels work so there is no way for the operators to know the output of the plant. There is no O_2 trim.

Combustion analyzers are non-existent or non-functional. The boilers are being operated based solely on HTHW entering/leaving temperatures and flame observation.

Training, operation/maintenance guides, checklists and maintenance schedules are needed as discussed for Building C-1432.

Following replacement of the control panels, recorders and instrumentation, calibration of the entire system should be performed. A program of regular service should then be established. This should include the recorders and their totalizers for flow, the indicating instruments, and the combustion controls. The boilers need to be load tested on both fuels and data collected to properly tune the new controls.

3.2.2.2 Flame Safety System Operation:

The system is set up for two-fuel firing but not dual firing. Safety limits are straight forward for semi-automatic light-off and automatic shut down for out-of-limit condition. This system is based on a flame/ignitor scanner and preset operational limits. The limits should be tested at regular intervals to ensure operational readiness.

During the control systems upgrade discussed above, this system should be upgraded to allow for remote (control room) operation.

3.2.2.3 Burner Operation:

Boilers #1, #2, #3, and #4 were tested and observed on #6 oil only. Therefore, the concerns over burner performance relate only to fuel oil firing. (Boiler #5 was not operational at the time of testing.) As explained previously, these boilers are dual fuel and operate the majority of the time on natural gas with little or no burner performance difficulties. There were, however, several difficulties with the burners when fired with oil.

The majority of the problems can be traced to the steam generator. Problems with the controls, make-up feed system and pumps for the steam generator resulted in insufficient steam pressure for atomizing steam and for fuel oil pump and heater steam. As a result, the operators had difficulty with the operation of the fuel oil pump heater set and with maintaining sufficient atomizing steam pressure.

The fuel oil atomization problems were exacerbated by poor oil temperature control and atomizing steam pressure control. The oil temperature should be maintained at 200-215°F and the atomizing steam pressure should be regulated at 10-20 PSI over the oil pressure.

Additionally, the oil burner nozzles and sprayer plates need to be replaced, and the F.D. fans need to be cleaned and serviced. Following these repairs, the boilers can be properly tuned for operation on both #6 oil and natural gas.

3.2.2.4 Boiler Maximum Capacity:

The maximum firing control set points for all boilers have been set lower than the maximum design in an attempt to obtain cleaner firing. The maximum set points range from 91% of design for boiler #1 to 76% of design at boiler #3.

Proper control set up and burner repairs should be effected in order to obtain more uniform maximum firing rates at or near the design condition.

3.2.2.5 Boiler Minimum Capacity:

Minimum firing rates on oil are restricted due to lack of service to controls and burners. Some burners will trip off when they modulate down in auto or manual mode. Minimum firing rates on boilers #1 through #4 varied from 31% to 39% of maximum fire. Boiler #5 was not tested on oil.

As in the previous plant, the minimum firing rate on gas is essentially zero.

3.2.2.6 Boiler Feedwater System Operation:

During the testing, the system operated under a heavy demand due to outside temperature conditions. Boiler feedwater pumps operated at expected head. Pressure drops through the boilers appeared reasonable.

However, a major feedwater problem precludes the simultaneous operation of boilers #4 and #5. Boiler #5 was installed as a separate installation after boilers #1 through #4 were installed. The feedwater supply piping to boiler #5 was tied in too closely to the supply tap feeding boiler #4. Therefore, the operation of one boiler starves feedwater supply to the other. This piping problem should be corrected so that both units may operate at the same time.

The operators have experienced some problems due to the inadequate capacity of the expansion tank. When the original three boilers and two HTHW zones were installed, expansion was accommodated by a 2,500 gallon expansion tank. Since then, two additional boilers and two new HTHW zones have been installed. (One of the new loops is over 2.5 miles long.) The total system size has increased from an estimated 20,000 gallons to over 100,000 gallons (estimated). Still, the expansion tank capacity remains at only 2,500 gallons.

Physical constraints in Building D-3529 will make increasing the expansion volume difficult, but it needs to be done. Currently, the expansion tank is incapable of handling system upsets. When a boiler trips, the level drops immediately, along with temperature and pressure.

3.2.2.7 Boiler Ignition System Operation:

The boiler ignition system suffers due to the control problems already outlined. Operators must purge the boilers manually, open valves at the burner, then return to the control room to initiate firing. The upgraded controls discussed previously should incorporate a semi-automatic ignition system capable of either local or remote boiler light-off.

This upgrade would enable an operator to control everything from one location; burner front or control room, doesn't matter.

3.2.2.8 Established Procedures for Operation and Maintenance:

Both the boiler plants and chiller plants are currently being operated and maintained largely based on operator experience. An assortment of Standard Operating Procedures (SOP's) does exist; however, interviews of the operators indicated that they are generally not being used. Additionally, a review of the SOP's shows that some are outdated and some are lacking in important details. For example, the SOP for Waste Oil Burning advises the operators to check oil pressures and atomizing steam but doesn't indicate what the correct operating parameters should be. Copies of these SOP's are included in Appendix 4.0, Volume 2.

There are no maintenance schedules and only two written preventive maintenance procedures. Checklists are apparently not used for either operating or maintenance procedures. As a result, much of the operation and maintenance is left to the discretion of the operators. While the current operators appear to be knowledgeable and competent, it was also noted that there are substantial variations in operating procedures between the various operators. It is also worthy of note that a number of the more experienced operators are at or near retirement age, and under OPM hiring practices, there is no guarantee that the replacement operators will have more than very minimal experience and knowledge.

In accordance with DOD Guide 5000.51-G, operational guides should emphasize Total Quality Management (TQM) principles in the development of a quality improvement. These principles focus on continuous quality improvement through process control. Operators need to have a thorough understanding of the processes which they control and the indicators which should be monitored to track quality improvement.

For example, the quality of the steam production of Building D-3529 could include such parameters as reliability, temperature consistency, energy consumption, or distribution losses. Operators should be trained to monitor system vital signs to ascertain statistical performance in each of the key indicators. Process improvement could then easily be tracked and correlated to some action. A change in the steam trap maintenance program, for instance, may result in a statistical improvement in distribution loss.

Without a clearly defined process control and quality improvement program, it is difficult to determine the effect of operations and maintenance initiative. Another advantage is that operators control defined processes. Therefore, a change in operator doesn't change the process.

3.2.2.9 Training:

Ft. Bragg currently has plans to award a contract to perform controls maintenance and to provide controls training for the operators. While this training is clearly necessary, it is not sufficient. Specific training, operation maintenance guides and checklists should be developed for each plant, including D-3529.

In accordance with DOD Guide 5000.51-G, both management and operational personnel should receive training in continuous quality improvement through TQM principles. The importance of understanding key elements of process definition and control cannot be overemphasized.

Following initial TQM training, a boiler plant operations expert should be brought in to assist in process definition and control and to help define process indicators to properly monitor quality improvement. Training operators should focus on the following technical areas:

- specific system operational guides
- specific system troubleshooting guides
- specific system efficiency improvement guides

- specific system boiler log program, which includes calculation of the plant efficiency and percent effectiveness by shift and its operators
- water treatment training
- development of preventive maintenance schedules, guides and checklists for all major plant equipment

Additional recommendations for building D-3529 at Ft. Bragg includes the following:

1.) <u>Boiler Refractory and Casing Repairs</u>
The boiler interior refractory and insulation should be inspected and repaired annually. The boiler casing should be patched following the insulation repair. In the most recent site visit, it was noted that casing leaks are increasingly becoming a problem.

2.) <u>Boiler Outlet Hood Leaks</u>
During annual maintenance, the boiler should be pressurized (and smoke tested if necessary) and air pressure leaks sealed. Some leaks were noted while firing #6 oil, especially on the outlet hood.

3.) <u>Fuel Analysis</u>
Operating personnel are currently testing every third load of #6 oil delivered. Random testing should be implemented to ensure compliance with fuel quality specifications.

4.) <u>Oxygen Analysis</u>
Oxygen analyzers should be added on each boiler to allow the operators to monitor the excess air. The operators could then adjust the fuel/air ratio control for improved operation.

5.) <u>Fuel Oil Boost Pumps</u>
New fuel oil storage tanks have recently been installed at Building D-3529. It is reported by the operators that, since the installation, the fuel pumps in the basement of D-3529

frequently lose their prime. This is probably due to inadequate suction head at the pumps and can be remedied by adding booster pumps in the lines near the storage tanks.

6.) Distribution System Leaks

Significant quantities of high temperature hot water are being lost in the distribution system. The boiler logs indicate that during the nine-month period from January through September, 1990, over one million gallons of make-up water was added to the system. Based on 1988 gas prices, assuming an 80% boiler efficiency and estimating a heat value for natural gas of 1,000 BTU/FT^3 and assuming a 64°F entering water temperature, this distribution system loss resulted in approximately a $10,000 avoidable fuel expenditure over a nine-month period. This figure does not include the cost of chemical treatment or the cost of the water itself.

3.3 Chillers

During chiller testing activities and subsequent site visits, it was noted that chiller controls and instrumentation are not under a regular preventive maintenance program. Further detailed equipment operation procedures were not available.

The subsequent sections will describe the following recommended control systems and operational improvements: installation or repair/reinstallation of microprocessor controls; provision of additional metering equipment; calibration of existing metering and recording equipment; development and implementation of detailed equipment-specific operation and maintenance guides and preventive maintenance schedules; development and implementation of improved log maintenance practices; implementation of central equipment control; staffing necessary equipment repairs; and refrigerant use.

3.3.1 Staffing

As noted in the previous section on boiler plants, there appears to be a significant (32%) staffing shortfall for the operation of the boiler and chiller plants. This shortfall underscores the need for the operators to be well trained and equipped with the latest tools (ie: operation/maintenance guides and checklists) to function efficiently. In addition, the equipment should be configured, controlled, and instrumented properly for operation with a minimum staff.

3.3.2 Established Procedures for Operation and Maintenance

Written operating and maintenance procedures are limited to: a PM Procedure for Electric Motors, a Chiller Pre-Season Preventive Maintenance Standard Operating Procedure (SOP), a Chiller Start-up SOP, and a procedure for changing chilled water zone pumps. The existence of these SOP's is a step in the right direction; however, much more is needed. The SOP's (enclosed in Appendix 4.2, Volume 2) are generally very brief and general in nature; lacking in important equipment specific information. It is recommended that, in conjunction with site-specific operator training, detailed operation and maintenance guides and equipment maintenance schedules be developed and implemented. The operations program should be developed using TQM principals, as discussed previously, so that processes can be monitored for improvement.

3.3.3 Plant Control Systems

As was the case with boiler operations, the chiller plants are being operated largely by operator experience. The controls are automatic only to the extent that the compressor inlet vanes are controlled by the chiller leaving water temperature. Sequencing of chillers is done manually based on the chilled water supply temperature leaving the buildings. In some cases, the chiller equipment has been previously microprocessor controlled, but over the years, the controls have been allowed to fall into a state of disrepair. It was also noted that the newer York chillers are equipped with individual microprocessor controls.

It is strongly recommended that the new York machines be tied to a central control to automatically bring the units on based on load conditions. The sophisticated controls in place on these machines would make central control relatively easy. These machines would serve the variable load on the system. One of the older chillers would remain on line manually to serve the base load. An alarm would signal the central panel if for any reason the base machine shut down.

Central automatic control of these units would allow better control over chill water supply temperature. Currently, chill water temperatures vary from approximately 41°F to 46°F during normal operations. Achieving a steady state 45°F chilled water supply temperature would raise the average evaporator temperature, resulting in a significant increase in efficiency. Central automatic control would also free an operator for other duties.

3.3.4 Chiller Instrumentation and Metering Equipment

The existing chiller plant metering and instrumentation equipment is substantially insufficient, and its calibration is questionable. The system instrumentation is limited to thermometers or recording thermistors, and the data obtained from these devices makes their accuracy suspect. The chilled water distribution system is not equipped with flow meters, so the only available flow information available is the nameplate data on the pumps. Make-up water is not metered at all, so there is no way for the operators to detect the existence of leaks in the chilled water distribution system.

It is recommended the following additional instrumentation and metering devices be installed at all the chiller plants:

1. Make-up water meters
2. Zone CHW flow meters
3. Individual chiller CHW flow meters
4. Condenser water flow meters
5. Condenser make-up water meters
6. System pressure gauges
7. Inlet/outlet pressure gauges at condenser and chiller barrels

Additionally, it is recommended that the current instrumentation is calibrated and that recalibration is performed annually thereafter.

Ideally, the installation of the new metering and instrumentation equipment would be performed concurrent with installation of microprocessor controls so that they could be located in one control panel (per plant). Such an installation would facilitate improved monitoring of plant performance by the operators. Given the previously discussed staffing shortfall, Ft. Bragg may wish to consider operating several chiller plants from a central control room. For example, the chillers in Buildings D-3529, C-6039 and H-6240 could all be operated from controls located in Building D-

3529. At a minimum, it is recommended that the chillers in Building H-6240 be controlled and monitored from another location, most logically from Building D-3529.

It is imperative that adequate system performance indicators be installed as soon as possible. Without these devices, there is no accurate method for determining system operation or monitoring process improvement.

3.3.5 Establishment of Proper Log Maintenance Practices

With the current level of metering and instrumentation available at the chiller plants and the uncertainty about the accuracy of the instrumentation, the maintenance of a proper chiller plant log is not practical. However, when the proper metering equipment and instrumentation equipment is installed and calibrated, it is recommended that the plant log maintenance practices be improved so that plant efficiency can be monitored; operating trends can be followed to predict maintenance problems; and the process can be continually evaluated for improvement. Maintaining a proper log would be particularly easy if the instrumentation and controls were centrally located as previously recommended.

3.3.6 Cooling Towers

As a general observation, a number of cooling tower deficiencies were noted as discussed in the following paragraphs.

1. Building D-3529: This chiller plant has four cooling towers with a total of five cells (one for each of the five chillers). Towers 1 and 2 are in poor condition, and 3 is in fair condition. These towers have a combination of redwood slat and PVC cooling media and were noted to be in need of numerous repairs, such as: rebuilding the distribution decks and covers, repairing holes in fan cowlings, and replacing the fill. Operators reported excessive condenser water return temperatures

under high load conditions, indicating inefficient cooling tower operation. Based on visual observation of the sumps, no serious water treatment problems were apparent.

It was also noted that the cooling towers are currently piped such that each cell is dedicated to only a single chiller unit. In the interest of redundancy and flexibility, Ft. Bragg should consider piping the CWS and CWR water via common headers if future major repairs necessitate repiping.

2. Building C-6039: This building has four cooling towers. Cooling tower 3 is a GYRCO unit less than a year old, and in excellent condition. Towers 1, 2 and 4 are old Pritchard units noted to be in fair condition. Cooling towers 1 and 2 have redwood slat cooling media, which is in fair to poor condition, and tower 4 has a combination of wood slats and PVC media. All three older towers (1, 2 and 4) have wooden safety rails around the top deck, which are in marginal condition, creating a safety concern. It is recommended that towers 1, 2 and 4 be repaired or replaced. As in the case at the other chiller plants, the cooling towers are piped such that each tower supports one (and only one) chiller.

3. Building H-6240: This building has two older dual-cell cooling towers, each supporting a single chiller. Tower 1 has wood slat fill, and tower 2 has PVC fill. Both towers need repair of the top decking, and it is recommended that the wood slat media in tower 1 be replaced with PVC fill.

3.3.7 Refrigerants

All of the 12 centrifugal chillers observed and/or tested as part of this study use R-11 or R-12 refrigerant.

While this does not pose an immediate problem, it is worthy of note that, because of their ozone depletion potential, the Montreal Protocol has targeted these refrigerants for elimination by the year 2000, and the USEPA has promulgated a final rule, under the authority of the Clean Air Act, to enforce the provisions of the Protocol. In the interim, ozone depleting chemicals (including R-11 and R-12) will be subject to production and import quotas.

The major refrigerant manufacturers are working to develop new, environmentally safe refrigerants, but until they are developed, it appears that R-22 (which is one-tenth as damaging to the ozone layer as R11 and R12) will be the refrigerant of choice for large centrifugal chillers. Unfortunately, due to its substantially different physical characteristics, it is likely that some modifications to existing chillers will be required to accommodate its use.

It is strongly recommended that a refrigerant conversion program be developed for implementation during the next five years. Failure to do so will result in major refrigerant procurement problems in the late 1990's.

4.0 SPECIFIC EFFICIENCY IMPROVEMENTS

In accordance with the Scope of Work paragraph 3.6, twenty-six potential specific efficiency improvement items have been considered. Potential efficiency improvements are described in the following paragraphs.

4.1 Controls to Assure Proper Combustion Air/Fuel Ratios

The proper control of the air-fuel ratio in the operation of a boiler is critical to its performance. Insufficient air flow will cause incomplete combustion of the fuel leading to poor boiler efficiency. Excessive air flow can cause steam temperature control problems caused by the increased mass flow rate through the boiler, as well as inefficiency due to the energy consumed to heat the excess air.

This item has been combined with the specific efficiency improvement entitled, Reduce Excess Air. See Section 4.7.

4.2 Feedwater Treatment

The proper chemical treatment and deaeration of the boiler feedwater is essential to the life of the boiler. At the elevated temperatures encountered in the boiler, the presence of dissolved oxygen in the feedwater, will increase corrosion levels dramatically.

4.2.1 Building C-1432

The existing feedwater system uses Zeolite softeners, which require no heat input. The deaerator operated according to nameplate data; therefore, there are no recommendations for improving the efficiency of the feedwater system. There was no reported internal scale or corrosion, however, boilers were not inspected internally. We, therefore, conclude that the system is adequate. It should be noted, however, that the equipment is not calibrated; correcting this condition is recommended. No economic justification is performed as the cost of implementation is zero and the benefit is as stated.

4.2.2 Building D-3529

The existing feedwater system uses Zeolite softeners, which require no heat input. The deaerator operated according to nameplate data; therefore, there are no recommendations for improving the efficiency of the feedwater system. Again, the boilers were not inspected internally.

4.3 Waste Heat Recovery

Due to the inherent inefficiencies created by the manufacturing process, a boiler will discharge heat from its stack in the form of flue gases, as well as in the form of heated water discharged to control corrosion or sediment buildup. These heat losses can be significant in some instances.

4.3.1 Building C-1432

Blowdown heat exchangers were installed in 1987; however, as has been previously noted, the economizers are currently bypassed due to the poor condition of the air preheaters and the resultant cool stack gas temperatures. Consequently, the boiler efficiency is negatively impacted. This problem is further addressed in Section 4.6.

4.3.2 Building D-3529

Inspection of this boilerhouse revealed no steam condensate or blowdown. Also, no excessive exhaust gas temperatures were reported and none were noted during inspection. Therefore, there are no recommendations for improving efficiency in the area of waste heat recovery.

4.4 Operations and Maintenance Procedures

The conditions under which mechanical equipment operates many times are so severe that premature failure occurs if proper operation and maintenance procedures are not followed. The high temperatures and pressures encountered will cause metals to fatigue and fail in a relatively short time if not controlled and anticipated.

4.4.1 Boilers

4.4.1.1 Building C-1432:

4.4.1.1.1 Auxiliary Drives. Turbine drives should be used instead of electricity to run motors, since the turbines are already in place. This has been examined more thoroughly in section 4.23.

4.4.1.1.2 Baffle Walls. Inspection of the baffle walls revealed holes as large as 2'-2". The baffle walls should be repaired. The cost of repairing the baffle wall will be less than $100. Although repairing the baffle wall will increase the efficiency by forcing gas over the generating bank, the increase is not measurable. Therefore, no economic justification can be performed.

4.4.1.1.3 TDS Blowdown. Though the appropriate range for TDS for this plant is 3,000-3,500, some operators are apparently (based on interviews and log examination) trying to maintain it at around 1,000. Obviously, this practice reduces the energy efficiency of the boilers because the low TDS is achieved through excessive blow-down. The "Chemical Test Procedure, Steam Plants" correctly addresses this issue, but the procedure is apparently not followed by all operators.

4.4.1.1.4 Fuel/Air Adjustment. Currently, the boiler fuel/air ratio is adjusted by visual observation of the burner flame and stack gases. This less-than-desireable operation method generally results in reduced boiler efficiencies due to the introduction of too much excess air in the boiler combustion charge. However, due to the lack of automatic O_2 trim or O_2 analyzers for manual O_2 trim, there is currently no way for the operators to improve the combustion efficiency of the boiler plants. It is strongly recommended that O_2 analysis equipment be purchased to allow for the proper adjustment of the fuel/air ratio. This topic is covered more fully in Section 4.7.

4.4.1.1.5 Monitoring and Logging Plant Operating Parameters. It is currently impossible for the plant operators to monitor plant efficiency since the necessary metering and instrumentation is either non-existent, non-functional or inaccurate. At the present time, the only information logged on the Facilities Engineering Operating Log (DA Form 3967) is steam pressure (always 145 PSI) and fuel used. This information by itself has no value except to show that steam was made and fuel was burned. It is recommended that the plant instrumentation be upgraded so that critical information concerning the plant operation and efficiency can be monitored and logged. At a minimum, instrumentation for the following applications should exist and should be regularly maintained and calibrated:

- Steam pressure
- Steam flow
- Feedwater Flow
- Fuel Flow (natural gas and oil)
- Flue Gas Temperature
- O_2/CO_2 Analysis
- Make-up Water flow
- Make-up Water temperature
- Economizer water temperature
- Feedwater heater temperature
- Feedwater heater pressure
- Deaerator temperature
- Deaerator pressure
- Natural gas pressure
- Natural gas temperature
- Fuel Oil pressure
- Fuel oil temperature
- Condensate pressure return
- Condensate return temperature
- Atomizing steam pressure

Following the metering and instrumentation repairs and upgrades and in conjunction with a tailored training program (reference paragraph 3.2.1.11) a guide and worksheet should be developed to assist the operators in monitoring and logging the appropriate information and computing boiler efficiency.

Using TQM principles, certain performance criteria would be selected as representative of the quality of the process. These criteria would be charted and statistically evaluated to monitor trends and track improvement.

4.4.1.1.6 Established Procedures for Operation and Maintenance. As noted and discussed in paragraph 3.2.1.10, there is a general lack of established written procedures for the operation and maintenance of boiler and chiller plant equipment. Additionally, neither an operation/maintenance checklist nor a comprehensive maintenance program exist. Obviously, this brings into question the adequacy and uniformity of operating procedures and the quality of the maintenance program.

It is important to note that this is not considered to be an operator problem. The establishment of adequate process control is a management function. It is strongly believed that if proper process quality improvement procedures are implemented, the operators can quickly demonstrate significant plant performance improvements.

It is not possible to quantify the effect of those factors on the operating efficiency of the equipment; however, it is fairly obvious that the equipment must be properly operated and maintained to attain peak performance.

4.4.1.1.7 Training. The importance of training to the overall effectiveness of plant operation and maintenance has been previously discussed. (See, for example, paragraph 3.2.1.11.) An appropriately tailored training program, especially in the area of continuous quality improvement through process control, can have a positive impact on the efficiency of plant operations as well.

Again, it is probably not possible to accurately quantify the impact, but it is fairly obvious that operators trained in efficient plant operations will be better equipped to operate the equipment at a high level of output efficiency. It is imperative that this training encompass the various operating parameters and their effect on plant efficiency, calculating efficiency and making appropriate adjustments to improve efficiency.

As previously discussed, that training should be provided in conjunction with the development of operation and maintenance guides, and recurring maintenance schedules.

4.4.1.2 Building D-3529:

The provisions of paragraphs 4.4.1.1.4, 4.4.1.1.5, 4.4.1.1.6 and 4.4.1.1.7 apply to Building D-3529 as well as Building C-1432.

During inspection, it was noted that the sight glasses in the rear wall of some boilers were plugged with ash. To assist operators in boiler light off, the rear wall sight glasses should be workable. There is no economic justification for this action based on efficiency, but from an operations standpoint, it should be done.

Boiler #5 was tested on gas and severe burner rumble accompanied by high levels of CO were experienced at low load. Testing was discontinued due to the concern for safe operations. Inspection revealed that the furnace is thickly coated with carbon, especially in the area between tube rows. The boiler operator stated that a 55 gallon drum of carbon was collected from the furnace floor prior to inspection. The economic justification performed demonstrates the savings incurred in tuning this boiler. It was noted at the most recent site visit that this boiler has now been properly tuned.

4.4.2 Chillers

Observations of operations and maintenance procedures were not conducted during initial testing activities; however, they were observed and discussed at length during the site visit following the 60% submission. The greatest concern with O&M on chillers would stem from the apparent lack of processes for maintaining critical performance data on machine and system operations.

Records of specific maintenance and repair of individual equipment components may be available. However, log information on system performance; including such indicators as flow rates, temperature changes, and pressure drops, has not been produced, and it appears be unavailable.

Equipment performance characteristics are key measurements used to develop a cost effective process quality improvement program. This data is vital in system diagnostics and in making informed decisions on equipment repair or upgrade. At this time, however, sufficient equipment performance information is not available.

Following the 60% submittal, another site visit was conducted to update our analysis of current operations and maintenance procedures so that specific improvements could be addressed. That site visit confirmed our previous suspicions regarding the inadequacy of system performance data being measured and logged. In fact, it was found that, in most instances, the instrumentation necessary to measure system performance was either non-existent or inoperative. The only obtainable chiller system performance data was recording temperature charts from Building C-6039 and, after examination, the information recorded on those charts must be considered highly suspect. For example, examination of the temperature data recorded for July 4, 1989 shows that a higher cooling load existed at midnight than at 2:00 p.m. While it is possible that an aberrant load condition could have existed on that particular day, examination of the data on many other days also has shown temperature data to exist that is not consistent with what would be normally encountered cooling load conditions. Consequently, the temperature data recorded is considered to be of no useful engineering value.

Additionally, because pressure data had not been produced, a set of pressure gauges was included with the test equipment for post - 60% site visit. Unfortunately, it was found that those pumps for which pressure data was desired were not equipped with pressure taps. Consequently, pressure data is also not available for analysis.

From the foregoing discussion, it should be clear that insufficient data exists to make equipment specific recommendations to increase the efficiency of the chiller equipment. However, from observation and discussion at the most recent site visit, a number of general recommendations can be made.

4.4.2.1 <u>Established Procedures for Operation and Maintenance</u>:

This has become a recurring theme at this point, but it is a theme whose importance cannot be overstressed. Additionally, it is a theme with particular potential for improvement to the efficiency of operation of the chiller plants.

Currently, the plants are operated based solely on operator experience and knowledge and utilizing the zone CHWS and CHWR temperatures as controlling system parameters. There are no established procedures for chiller sequencing or setpoints for bringing additional chillers on line or removing chillers from operation. As a result, there appears (from the limited historical data) to be little consistency in how the plants are operated. As an example, examination of the CHWR/CHWS temperature charts from Building C-6039 show the system being operated with roughly a 50°F return temperature on some days and roughly a 55°F return temperature on others. Since the efficiency of the chillers is greatly affected by the entering water temperature, this apparent difference in operating preference can translate to operating at less than optimal conditions at least part of the time. Generally speaking, chillers operate more efficiently with higher entering water temperatures (which translate to higher evaporator temperatures for the same load condition.) However, the ability of the cooling coils served by the chilled water to satisfy the cooling load of the conditional space (particularly the latent load) decreases as the temperature of the chilled water increases. Therefore, the most efficient chilled water return temperature (chiller entering water temperature) is the highest temperature at which the cooling load can be satisfied. This temperature will vary with temperature and humidity conditions but 55°F is a pretty good starting point.

If the chillers are continued to be operated manually, it is recommended that the operators be provided with manual control setpoints at which they bring additional chiller equipment on line or remove equipment from duty. That temperature should be based on the ability of the local cooling systems (i.e.: the building comfort cooling systems) to provide adequate cooling at various chilled water temperatures and ambient conditions. Additionally, the operators should be provided with chiller sequencing guidelines based on load conditions, chiller capacity and chiller efficiency. Of course, if microprocessor controls are installed (as discussed in section 3.3.3, they will perform the previous two functions automatically.

4.4.2.2 Instrumentation and Measurement Equipment:

There is a notable absence of recording instrumentation, and the accuracy of much of the instrumentation is subject to question. During the recent site visit, a number of instances were noted where instrumentation accuracy was in doubt. Since the operators are using this instrumentation to make their control decisions, inaccurate instrumentation could result in substantial impairment to the overall plant efficiency. For example, it is quite conceivable that, based on erroneous chilled water temperature information, an operator could bring an extra chiller on line long before it is needed with an obvious negative impact on plant efficiency. Consequently, it is recommended that all plant instrumentation and measurement equipment be included in a comprehensive, documented, and regularly scheduled calibration program.

4.5 Installation of New Burner Equipment

The design and condition of the burners on a boiler will affect the combustion efficiency of the equipment. The fuel must be mixed with the combustion air in order to assure complete combustion of the fuel. Since this technology is undergoing continuous improvement, the same potential savings may be realized by upgrading from an older, less efficient system. However, as discussed below, it appears that the existing equipment is functioning well. If major repairs become necessary, new equipment should be considered.

4.5.1 Building C-1432

The existing burners allowed boiler operation at low excess air levels; therefore, new burner equipment would not improve the boiler efficiency. Inspection of the boilers revealed maintenance repairs of the existing burner throats. Although the damage is not excessive, new refractory patches should be installed as a preventative maintenance procedure. No economic justification was performed.

4.5.2 Building D-3529

During testing in January 1988, it was noted by the inspector that Boiler #1 could not be fired on gas. Operator Richard Smith indicated that the burner throat was burned out, but that repairs to the system should be completed by December 1988. Those repairs have been completed.

There are no recommendations for improving efficiency based on installations of new burner equipment.

4.6 Economizers/Air Preheaters

An economizer is used to preheat water by utilizing lower energy boiler heat just prior to its discharge to the atmosphere. Air preheaters also use this low energy flue gas to heat the combustion air prior to its introduction into the furnace or burner area. This helps offset the energy required to heat the air to flame temperature.

4.6.1 Building C-1432

The boilers in Building C-1432 are equipped with air heaters and have been retrofitted with economizers. In the normal installation, the air heaters are installed downstream of the economizers. This configuration takes advantage of the fact that the flue gases are hotter nearer the boiler and, hence, better able to preheat the relatively high temperature (approximately 200°F) boiler feedwater. Then the flue gases at the reduced temperatures can preheat the lower temperature entering air charge.

In the case of the boilers in Building C-1432, however, the air heaters are installed upstream of the economizers. This is inherently an undesirable configuration since the air heaters extract heat from the flue gases before they reach the economizer and, consequently, the temperature difference between the flue gases and the feedwater is small. Since the rate of heat transfer is largely a function of temperature difference, this arrangement results in little heat transfer from the flue gases to the feedwater.

In the case of the boilers in Building C-1432, this undesirable situation is made worse by the fact that the air heaters are leaking badly which further cools the flue gases prior to reaching the economizer.

Inspection of the air heaters in this building revealed that approximately 20% of the tubes, as seen from the top, had holes and cracks in them with sulfur deposits on the inside of the tubes. During the boiler testing, instances were noted where the flue gas temperature was actually higher leaving the economizer than it was at the economizer inlet. The economizers are currently non-functional. They were secured because they were lowering the flue gas temperature to below the dew point, and the resultant condensation was causing severe corrosion of the economizer tubes. As a result, the increased efficiencies attainable through the use of the economizers is not being realized.

As noted in paragraph 3.2.1.4, the boilers smoke excessively at high firing rates due to insufficient combustion air. This is probably caused by a combination of the following: 1) leaking air heaters, 2) excessive pressure drop across the air heaters and economizers, and 3) improperly stroked fans. Causes one and two above would be eliminated by bypassing the air heaters, and three can be eliminated by field service work.

Note that taking action to repair this deficiency is not optional if the boilers are to remain in service. The only option is how to repair the deficiency by replacing the air heaters or by bypassing them. In making the replace or bypass decision, the following should be considered:

1. The air heaters are incorrectly located upstream of the economizers.

2. Replacing the air heaters would cost about 7-10 times more than bypassing them.

3. Operating the boilers with properly designed and operating economizers should result in efficiency increases that are at least equal to those realized by utilizing the air heaters in a good state of repair.

4. Bypassing the air heaters would result in reduced pressure drops in the intake and flue systems which, in turn, would result in reduced fan operating costs.

In summary, for Building C-1432:

1. Significant air preheater leakage was noted during boiler testing. From testing and calculations performed, the air heater leakage appears to be 50-60% of the theoretical plus excess air.

2. Cost savings due to reduced F.O. and I.D. fan power consumption were calculated. The calculations are included in Appendix 2.2.3, Volume 2.

3. ECIP and Life Cycle Cost Analysis were completed.

4. It is recommended that the air heaters be permanently bypassed.

4.6.2 Building D-3529

The high temperature hot water boilers in Building D-3529 are package units operating in forced draft condition. They are not equipped with stack heat recovery equipment of any type. Examination of the operating conditions recorded during the boiler testing performed in 1988 shows that the addition of economizers is not economically feasible or physically practical. Table 1 records the flue gas temperature and average by boiler at various firing rates. Table 2 shows the boiler feedwater temperatures and boiler outlet temperatures at corresponding firing rates. As shown in Table 3, there is very little difference between boiler feedwater temperatures and flue gas temperatures, particularly at the lower firing rates at which the boilers are operated. For example, at 50% firing, the temperature difference is only 88°F, and at 25%, the temperature difference is a mere 27°F. To capture a meaningful quantity of waste heat at these very low temperature differences would require a huge and prohibitively expensive economizer. No cost analysis has been performed due to the obvious physical impracticality of adding economizers under the existing operating conditions.

Table 1

Flue Gas Temp °F

Boiler	Load 25%	40%	50%	75%	100%	Capacity
D3529 Boiler 1	402.6		407	448.66	485.5	498
D3529 Boiler 2		394.11		483		516
D3529 Boiler 3		382.88		458.77		483.75
D3529 Boiler 4		410.44		460.88		501.75
D3529 Boiler 5	373.22		398.1	418		
Average	387.9	395.8	402.6	453.9	485.5	499.9

Table 2
Boiler Feedwater Temp °F

Load	25%	50%	75%	100%
Temp	361	322	286*	250

*Interpolated

Table 3
Temp Difference Between Feedwater and Flue Gas °F

Load	25%	50%	75%	100%
Gas Temp	388	403	454	486
BFW Temp	361	322	286	250
Difference	27	81	168	236

4.7 Reduce Excess Air

Excess air is introduced to assure complete combustion of the fuel. Ideally, the minimum quantity of air for complete combustion would be introduced. However, due to the turbulent conditions at the burner, excess air is necessary to assure proper fuel and air mixing to support combustion. Excess air should be minimized to yield peak efficiency.

4.7.1 Building C-1432

The savings due to excess air reduction were calculated based on percent oxygen. For Building C-1432 the reduction in excess O_2 represents a savings of $14,062/year. The changes required to meet the improved efficiencies are found below.

The percent oxygen in the flue gas at the Central Heating Plant Building C-1432 in Fort Bragg was determined by testing and is listed in Table 1 below:

Table 1

% Oxygen

Load / Boiler	25%	40%	50%	75%	100%
D-1432 Boiler 2	11.94		8.44	6.29	5.2
D-1432 Boiler 3		11.53		8.06	6.08

The flue gas temperature was also measured, and is listed in Table 2 below:

Table 2

Flue Gas Temp °F

Load / Boiler	25%	40%	50%	75%	100%
D-1432 Boiler 2	310		312.47	308.94	318
D-1432 Boiler 3		228.88		229.66	231

The following two Tables (3 and 4) were taken from "The Control of Boilers" page 72, 1986, by Sam Dukelow. They show how combustion efficiency relates to percent O_2 and flue gas temperature. As seen, efficiency increases on decreasing percent O_2 and decreasing flue gas temperature.

Table 3

Combustion Efficiency Chart - Gas

CO_2		12.1	11.5	11.0	10.4	9.8	9.2	8.7	8.1	7.5	6.9	6.4	5.8
Excess Air		0	4.5	9.5	15.1	21.3	28.3	36.2	45.0	55.6	67.8	82.2	99.3
Oxygen		0	1	2	3	4	5	6	7	8	9	10	11
	°F												
	300	85.6	85.4	85.2	85.0	84.7	84.5	84.2	83.9	83.5	83.0	82.4	81.7
	350	84.6	84.3	84.1	83.8	83.5	83.2	82.8	82.4	81.9	81.3	80.6	79.8
	400	83.5	83.2	82.9	82.6	82.2	81.8	81.4	80.9	80.3	79.6	78.8	77.8
	450	82.5	82.1	81.8	81.4	81.0	80.5	80.0	79.4	78.7	78.9	77.0	75.9
	500	81.4	81.0	80.6	80.2	79.7	79.1	78.6	77.9	77.1	76.2	75.2	73.9
	550	80.3	79.9	79.4	79.0	78.4	77.8	77.2	76.4	75.5	74.5	73.4	71.9
	600	79.2	78.7	78.2	77.7	77.1	76.4	75.7	74.9	73.9	72.8	71.5	69.9
	650	78.1	77.6	77.1	76.5	75.8	75.1	74.3	73.4	72.3	71.1	69.7	67.9
	700	77.0	76.5	75.9	75.3	74.5	73.7	72.9	71.9	70.7	69.4	67.8	65.9
	750	75.9	75.4	74.7	74.1	73.2	72.4	71.5	70.4	69.1	67.7	66.0	63.9
	800	74.8	74.2	73.5	72.8	71.9	71.0	70.0	68.8	67.5	65.9	64.1	61.9
	850	73.7	73.1	72.3	71.6	70.6	69.7	68.6	67.3	65.9	64.2	62.3	59.9
	Loss per Percent Combustibles												
		2.8	3.0	3.2	3.4	3.7	4.0	4.3	4.6	5.0	5.5	6.1	6.8

Table 4

Combustion Efficiency Chart - #6 Oil

CO_2		16.1	15.3	14.5	13.8	13.0	12.2	11.5	10.7	9.9	9.2	8.4	7.7
Excess Air		0	4.7	9.9	15.7	22.2	29.5	37.7	47.1	58.0	70.7	85.7	103
Oxygen		0	1	2	3	4	5	6	7	8	9	10	11
	°F												
	300	89.7	89.5	89.2	89.0	88.8	88.5	88.1	87.8	87.3	86.7	86.1	85.4
	350	88.7	88.4	88.1	87.9	87.3	87.2	86.8	86.4	85.8	85.1	84.4	83.5
	400	87.6	87.3	87.0	86.7	86.3	85.9	85.4	84.9	84.2	83.4	82.6	81.5
	450	86.6	86.2	85.9	85.6	85.1	84.7	84.1	83.5	82.7	81.8	80.8	79.6
	500	85.5	85.2	84.8	84.4	83.8	83.3	82.7	82.0	81.1	80.1	79.0	77.6
	550	84.5	84.1	83.7	83.2	82.6	82.0	81.3	80.6	79.6	78.4	77.2	75.6
	600	83.4	83.0	82.5	82.0	81.3	80.7	79.9	79.1	78.0	76.7	75.4	73.6
	650	82.4	81.9	81.4	80.8	80.1	79.4	78.5	77.7	76.5	75.1	73.6	71.7
	700	81.3	80.8	80.2	79.6	78.8	78.1	77.1	76.2	74.9	73.4	71.8	69.4
	750	80.3	79.7	78.1	78.4	77.6	76.8	75.7	74.7	73.3	71.6	70.0	67.7
	800	79.2	78.6	77.9	77.2	76.3	75.4	74.3	73.2	71.7	70.0	68.1	65.7
	850	78.1	77.5	76.7	76.0	75.0	74.1	72.9	71.7	70.1	68.3	66.2	63.7
	Loss per Percent Combustibles												
		2.9	3.0	3.2	3.4	3.6	3.8	4.1	4.4	4.7	5.0	5.4	6.0

Using the O_2 and temperature measurements from the boiler tests combustion efficiencies were determined. These are presented in Table 5.

Table 5

Approximate Combustion Efficiency from Table 4 *

Boiler	25%	40%	50%	75%	100%
D-1432 Boiler 2	85.4		87.0	88.1	88.5
D-1432 Boiler 3		Not Available			

#6 Fuel Oil is Used

The combustion efficiencies were extrapolated from the published data since the efficiencies calculated during testing were boiler efficiencies which included heat losses. Since the combustion efficiency does not include heat losses, and the heat losses were estimates, the combustion efficiency could not be calculated from the boiler efficiencies.

Comparing the efficiencies from Table 5 with those possible from Table 4, reasonable efficiency improvements can be made by adjusting the percent O_2 recommended by "The Control of Boilers" on page 57. This is shown in Table 6 below.

Table 6

Excess Air Required at Full Capacity

Fuel	% Oxygen in flue Gas	% Excess Air Min.
Natural gas	1.5 to 3	7-15
Fuel oil	0.6 to 3	3-15
Coal	4.0 to 6.5	25-40

Table 7 tabulates the improved efficiency at capacity for the Fort Bragg boilers in Building C-1432.

Table 7

Reasonable Efficiency Improvement

C-1432 Boiler 2	0.5%	
C-1432 Boiler 3	1 %	(See Note A)

Note A: Since the combustion efficiency at the given temperature and pressure is not shown, the improvement was assumed to be approximately 1%.

Although the improved efficiency was based on the use of #6 fuel oil, we can assume that the improved efficiency will also occur when burning natural gas.

Table 8 represents the Fuel Consumption for Building C-1432 in 1990.

Table 8
Fuel Consumption

FUEL	AMOUNT	BTU	%
Natural Gas	304,371 MCF	3.15328×10^{11}	99.54
Fuel Oil #6	430,861 GAL	9.6811×10^{8}	.31
Waste Oil	197,370 GAL	4.688×10^{8}	.15

Note B: Since Boiler 1 at Building C-1432 was not available for testing, we will assume that the efficiency improvement will be the average of Boilers 2 and 3, approximately .75%.

As reported by Mr. Jude at the Ft. Bragg Energy Branch, 1990 natural gas prices are $.39534/therm and fuel oil prices are $.99/gallon. As seen in Table 8, fuel consumption has been given to us on a plant-wide basis; therefore, a cost savings must be determined on the same basis.

The cost savings is calculated as follows:

Central Heating Plant (Bldg. C-1432) year 1987

Fuel Oil (Density = 8.22 lb/gal)

$$430{,}861 \text{ GAL } \left(\frac{.885}{.8925}\right) = 427{,}240 \text{ GAL}$$

$$430{,}861 - 427{,}240 = 3{,}621 \text{ GAL SAVED}$$

$$3{,}621 \text{ GAL} \times \$.99/\text{GAL} = \$\,3{,}585 \text{ SAVED}$$

Natural Gas

$$3.04371 \times 10^{8} \times \frac{.885}{.8925} = 3.01813 \times 10^{8} \text{ ft}^{3}$$

$$3.04317 \times 10^{8} - 3.01813 \times 10^{8} = 255{,}800 \text{ ft}^{3}$$

$$255{,}800 \text{ ft}^{3} \times \frac{1036 \text{ BTU}}{\text{ft}^{3}} \times \frac{\$.39534/\text{therm}}{10^{5} \text{ BTU/therm}} = \underline{\mathbf{\$10{,}477}} \text{ Saved}$$

Total $ Savings

$3,585 + 10,477 = $14,062

The dollars and BTU savings are due to increased efficiency caused by decreasing the percent oxygen to the optimal level for combustion. This improvement to the combustion control system can be accomplished in two ways. They are:

1. Replace the combustion controls with a new system and reinstate O_2 controls.

2. Replace only the O_2 analyzer and controller to reinstate O_2 trim, and calibrate the remaining equipment.

Life cycle cost analyses were performed for each scheme. The cost estimates located in Appendix 2.2.3 and 2.2.4, Volume 2 of this report along with the LCCA Summary form.

Scheme 1 does not qualify. This is logical since the boilers are running fairly efficiently now without O_2 trim. The replacement of all combustion control equipment is unnecessary. Scheme 2 on the other hand has an SIR of 3.15. Although it does not qualify as an ECIP since the total investment is under $200,000, it is a viable ECO.

4.7.2 Building D-3529

The savings due to excess air reduction were calculated based on percent oxygen. For the hot water plant, the reduction in excess of O_2 represents a savings of $30,619/year. The changes required to meet the improved efficiencies are as follows.
The percent oxygen in the flue gas at the Hot Water Plant Bldg. D-3529 in Fort Bragg was determined by testing and is listed in Table 1 below:

Table 1
% Oxygen

Load						
Boiler	25%	40%	50%	75%	100%	Capacity
D-3529 Boiler 1	8.9		9.5	6.63	4.38	7.2

D-3529 Boiler 2		11.04		8.81	7.25
D-3529 Boiler 3		10.01		7.42	7.2
D-3529 Boiler 4		8.13		8.04	4.125
D-3529 Boiler 5	11.6		1.38	1.06	

The flue gas temperature was also measured, and is listed in Table 2 below:

Table 2

Flue Gas Temp ^{o}F

	Load					
Boiler	25%	40%	50%	75%	100%	Capacity
D3529 Boiler 1	402.6		407	448.66	485.5	498
D3529 Boiler 2		394.11		483		516
D3529 Boiler 3		382.88		458.77		483.75
D3529 Boiler 4		410.44		460.88		501.75
D3529 Boiler 5	373.22		398.1	418		

The following two Tables (3 and 4) were taken from Sam Dukelow's "The Control of Boilers" page 72, 1986. They show how combustion efficiency relates to percent O_2 and flue gas temperature. As seen, efficiency increases on decreasing % O_2 and decreasing flue gas temperature.

Table 3

Combustion Efficiency Chart - Gas

CO_2		12.1	11.5	11.0	10.4	9.8	9.2	8.7	8.1	7.5	6.9	6.4	5.8
Excess Air		0	4.5	9.5	15.1	21.3	28.3	36.2	45.0	55.6	67.8	82.2	99.3
Oxygen		0	1	2	3	4	5	6	7	8	9	10	11
	°F												
	300	85.6	85.4	85.2	85.0	84.7	84.5	84.2	83.9	83.5	83.0	82.4	81.7
	350	84.6	84.3	84.1	83.8	83.5	83.2	82.8	82.4	81.9	81.3	80.6	79.8
	400	83.5	83.2	82.9	82.6	82.2	81.8	81.4	80.9	80.3	79.6	78.8	77.8
	450	82.5	82.1	81.8	81.4	81.0	80.5	80.0	79.4	78.7	78.9	77.0	75.9
	500	81.4	81.0	80.6	80.2	79.7	79.1	78.6	77.9	77.1	76.2	75.2	73.9
	550	80.3	79.9	79.4	79.0	78.4	77.8	77.2	76.4	75.5	74.5	73.4	71.9
	600	79.2	78.7	78.2	77.7	77.1	76.4	75.7	74.9	73.9	72.8	71.5	69.9
	650	78.1	77.6	77.1	76.5	75.8	75.1	74.3	73.4	72.3	71.1	69.7	67.9
	700	77.0	76.5	75.9	75.3	74.5	73.7	72.9	71.9	70.7	69.4	67.8	65.9
	750	75.9	75.4	74.7	74.1	73.2	72.4	71.5	70.4	69.1	67.7	66.0	63.9
	800	74.8	74.2	73.5	72.8	71.9	71.0	70.0	68.8	67.5	65.9	64.1	61.9
	850	73.7	73.1	72.3	71.6	70.6	69.7	68.6	67.3	65.9	64.2	62.3	59.9
	Loss per Percent Combustibles												
		2.8	3.0	3.2	3.4	3.7	4.0	4.3	4.6	5.0	5.5	6.1	6.8

Table 4

Combustion Efficiency Chart - #6 Oil

CO_2		16.1	15.3	14.5	13.8	13.0	12.2	11.5	10.7	9.9	9.2	8.4	7.7
Excess Air		0	4.7	9.9	15.7	22.2	29.5	37.7	47.1	58.0	70.7	85.7	103
Oxygen		0	1	2	3	4	5	6	7	8	9	10	11
	°F												
	300	89.7	89.5	89.2	89.0	88.8	88.5	88.1	87.8	87.3	86.7	86.1	85.4
	350	88.7	88.4	88.1	87.9	87.3	87.2	86.8	86.4	85.8	85.1	84.4	83.5
	400	87.6	87.3	87.0	86.7	86.3	85.9	85.4	84.9	84.2	83.4	82.6	81.5
	450	86.6	86.2	85.9	85.6	85.1	84.7	84.1	83.5	82.7	81.8	80.8	79.6
	500	85.5	85.2	84.8	84.4	83.8	83.3	82.7	82.0	81.1	80.1	79.0	77.6
	550	84.5	84.1	83.7	83.2	82.6	82.0	81.3	80.6	79.6	78.4	77.2	75.6
	600	83.4	83.0	82.5	82.0	81.3	80.7	79.9	79.1	78.0	76.7	75.4	73.6
	650	82.4	81.9	81.4	80.8	80.1	79.4	78.5	77.7	76.5	75.1	73.6	71.7
	700	81.3	80.8	80.2	79.6	78.8	78.1	77.1	76.2	74.9	73.4	71.8	69.4
	750	80.3	79.7	78.1	78.4	77.6	76.8	75.7	74.7	73.3	71.6	70.0	67.7
	800	79.2	78.6	77.9	77.2	76.3	75.4	74.3	73.2	71.7	70.0	68.1	65.7
	850	78.1	77.5	76.7	76.0	75.0	74.1	72.9	71.7	70.1	68.3	66.2	63.7
	Loss per Percent Combustibles												
		2.9	3.0	3.2	3.4	3.6	3.8	4.1	4.4	4.7	5.0	5.4	6.0

Using the O_2 and temperature measurements from the boiler tests, the following combustion efficiencies were determined. See Table 5.

Table 5
Approximate Combustion Efficiency from Table 4 *

Boiler	25%	40%	50%	75%	100%	Capacity	Avg
D-3529 Boiler 1	81.5		83.00	83.8	84.0	82.1	82.9
D-3529 Boiler 2		81.5		80.7		82.0	81.4
D-3529 Boiler 3		83.0		83.0		82.6	82.9
D-3529 Boiler 4		84.2		82.7		83.8	83.6
D-3529 Boiler 5		82		87.2	87.1		85.4

#6 Fuel Oil is Used

The combustion efficiencies were extrapolated from the published data since the efficiencies calculated during testing were boiler efficiencies which included heat losses. Since the combustion efficiency does not include heat losses, and the heat losses were estimates, the combustion efficiency could not be calculated from the boiler efficiencies.

Comparing the efficiencies from Table 5 with those possible from Table 4, reasonable efficiency improvements can be made by adjusting the % O_2. The adjustment is made to obtain the percent O_2 recommended by "The Control of Boilers" on page 57. This is shown in Table 6 below.

Table 6
Excess Air Required at Full Capacity

Fuel	% Oxygen in flue Gas	% Excess Air Min.
Natural gas	1.5 to 3	7-15
Fuel Oil	0.6 to 3	3-15
Coal	4.0 to 6.5	25-40

Table 7 tabulates the improved efficiency at capacity for the Fort Bragg boilers in Plant D-3529.

Table 7

Reasonable Efficiency Improvement

D-3529	Boiler 1	2.3%	
D-3529	Boiler 2	2.4%	
D-3529	Boiler 3	2.4%	
D-3529	Boiler 4	0.6%	
D-3529	Boiler 5	0%	(See Note A)

Note A: Boiler #5 was not tested completely since there were problems with the controls. Therefore, we assume that the efficiency can be improved 0.5%.

Although the improved efficiency was based on the use of #6 fuel oil, we can assume that the improved efficiency will also occur when burning natural gas.

Table 8 represents the Fuel Consumption for Building D-3529 in 1990.

Table 8

1990 Fuel Consumption

FUEL	AMOUNT	BTU
Fuel Oil #6	20,580 GAL	4.6241×10^{7}
Natural Gas	322,568 (MCF)	3.34×10^{11}

As reported by Mr. Jude of the Ft. Bragg Energy Branch, 1990, natural gas prices are $.39534/therm and fuel oil prices are $.99/gallon. As seen in Table 8, fuel consumption has been given to us on a plant-wide basis; therefore, a cost savings must be determined on the same basis.

The cost savings are calculated as follows:

Fuel Oil Saved

$$20{,}580 \text{ GAL} \times \frac{.8263}{.8456} = 20{,}110$$

$20,580 - 20,011 = 470$ GAL

470 GAL x $.99/gal = $465 Saved at 1990 Prices

Natural Gas Saved

$$3.22568 \times 10^8 \text{ ft3} \times \frac{.8263}{.8456} = 3.15205 \times 10^8 \text{ ft}^3$$

$$3.22568 \times 10^8 - 3.15205 \times 10^8 = 7,362,302$$

$$7,362,302 \text{ ft}^3 \times 1036 \frac{\text{BTU}}{\text{ft}^3} = 7.627 \times 10^9 \text{ BTU Saved}$$

$$7.627 \times 10^9 \text{ BTU} \times \frac{\$.39534/\text{Therm}}{10^5 \text{ BTU/Therm}} = \$30,154 \text{ Saved at 1990 Prices}$$

Total $ Saved = $30,154 + 465 = $30,619

The dollars and BTU savings are due to increased efficiency caused by decreasing the percent oxygen to the optimal level for combustion. This improvement to the combustion control system can be accomplished two ways. They are:

1. Add O_2 trim with manual adjustment.

2. Add Automatic O_2 trim.

Life cycle cost analyses were performed for each scheme. The cost estimates are located in Appendices 2.3.3 and 2.3.4, Volume 2, along with the LCCA Summary forms.

Both schemes 1 and 2 qualify with high SIR's. Scheme 1, however, has a higher SIR and is recommended for implementation.

4.8 Loading Characteristics and Scheduling vs. Equipment Capacity

The efficiency of most heating and cooling equipment will decrease significantly as the load decreases. Therefore, proper matching of equipment operation to load is critical to the effective control of energy consumed.

4.8.1 Boilers

4.8.1.1 Building C-1432:

Although no seasonal loading characteristics were available for evaluation, it can be assumed that loads are higher in the winter than the summer due to the additional demand for comfort heating. As seen in the Appendix 2.2.2, Volume 2, the boiler efficiency decreases with increasing excess air. Also, the boilers operate with lower excess air at high loads. Thus, the boilers are more efficient at high loads.

To take advantage of this fact, when loads are low, the least number of boilers, operated at high capacity, should be used to meet the demand. It is more efficient to operate one boiler at high capacity than to operate two boilers at low capacity.

The boilers are currently manually sequenced by the operators based on the steam flow through the boilers; however, as indicated earlier, the steam flow measuring and instrumentation equipment is in need of calibration, so their sequencing decisions are probably not based on accurate information.

The piping is configured such that the entire load may be satisfied by one boiler. In fact, for the large majority of the year, only one boiler is on line. It is reported that, even on the coldest days, two boilers can easily carry the load and that most often the full load could be carried by only one.

Currently, the maximum capacity of the boilers is restricted by the badly leaking air preheaters. It has been previously recommended in this report to bypass the air preheaters such that adequate combustion air can be provided at all loads. When that recommendation has been effected, the plant will likely be able to carry the full load on only one boiler, even during periods of heaviest demand. If possible, implementation of that practice is recommended.

4.8.1.2 Building D-3529:

Although no seasonal loading characteristics were available for evaluation, it can be assumed that loads are higher in the winter than the summer due to the additional demand for comfort heating. As seen in Section 4.7.2, Reduce Excess Air, the boiler efficiency decreases with increasing excess air. Also, the boilers operate with lower excess air at high loads. Thus, the boilers are more efficient at high loads.

To take advantage of this fact, when loads are low, the least number of boilers, operated at high capacity, should be used to meet the demand. It is more efficient to operate one boiler at high capacity than to operate two boilers at low capacity.

The boilers are manually sequenced by the operators. Normally, the sequencing should be based on HTW flow through the boilers at a constant leaving temperature; however, due to inoperative flow meters, the operators in this building have no indication of boiler operating rates. Consequently, the boilers are sequenced based on visual and aural observation of the operating boiler (s) and leaving water temperatures.

The plant piping is configured such that a single boiler or multiple boilers can be utilized to satisfy the load on all zones.

On the basis of the boiler efficiency testing conducted as part of this study, it is recommended that the boilers be sequenced in the following order:

1. Boiler #5 or #4
2. Boiler #3
3. Boiler #1
4. Boiler #2

Note that because of a design flaw in the feedwater piping system, boilers #4 and #5 cannot be operated at the same time.

4.8.2 Chillers

At present, the chillers at Fort Bragg are sequenced manually at the operators discretion, based on existing observed load conditions. Many of the new chillers (approximately 10) have microprocessor control for individual chillers as well as manual limit controls.

Load profile curves were not furnished by the Corps, nor were they available at the site. However, our field observations suggest that the existing present load falls considerably short of the actual connected chiller capacity. Such an overcapacity situation would support an analysis for control of the chillers in multiples, where the best combination of numbers of chillers and load point sequences could significantly improve operating efficiency.

It must be emphasized that in order to establish the necessary load profile curves, it is absolutely imperative that accurate flow and temperature measuring and instrumentation devices be installed. Currently, the only operable recorders are the temperature recorders in Building C-6039, and they are not working properly. It is recommended that each chiller plant have properly calibrated recording flow rate meters for each zone CHWS line and recording thermometers for each zone CHWS and CHWR line. If that option is not economically possible due to funding constraints, then accurately calibrated non-recording flow rate meters and thermometers should be installed, and the operators should log the readings every hour. Without taking those actions, the load profile cannot be established. Further, without accurate flow and temperature information, there is no way to establish the instantaneous cooling load and, thus, be equipped with the necessary information to make intelligent chiller sequencing decisions.

As discussed in Section 3.3.3, these plants appear to have been previously controlled by automatic microprocessors and that option should again be considered. Because there is no reliable information available from which to establish a load profile and no information on the chiller operation and sequencing to satisfy the loads, there is no way to predict the actual savings from installing automated controls. However, from the observations previously made, it appears unlikely that the chiller plants are currently being operated as efficiently as possible. Given that and given the previously noted staffing shortfall, it appears automating the chiller controls is worthy of serious consideration.

4.9 Variable Speed Circulation Pumps or Alternate Pumps Based on Seasonal Loading

In large water circulating systems, where pump horsepower requirements can exceed 50 horsepower, the use of two-way flow control valves and variable speed motor controls to maintain system pressure, can be feasible. As the loads change at the terminal equipment, the valves close causing an increase in water pressure. This increase in pressure is detected and the pump speed is reduced, thereby saving motor horsepower.

4.9.1 Boilers

4.9.1.1 Building C-1432:

No variable speed pumps were observed in this building. However, the application of variable speed drives would be to the boiler feed pumps which are already equipped with turbine drives as well as constant speed motors. Variable speed operation can be achieved by using the turbines instead of the motors. This option is discussed in the Specific Efficiency Improvement entitled: Steam Drive Auxiliaries vs. Electric Drives. See Section 4.23.1.

4.9.1.2 Building D-3592:

It is assumed that pumping is constant, with no variations based on seasonal loading since no data was available. In this case, variable speed pumps offer no increase in efficiency.

4.9.2 Chillers

Since insufficient data was available of the system beyond the chiller plant, a specific quantitative analysis could not be done for this ECO. However, a generic analysis was made utilizing a plant in the order of magnitude of those existing at Fort Bragg.

An analysis was conducted to evaluate the economic feasibility of incorporating a variable speed pumping arrangement into the central plant chilled water distribution systems. Energy savings are achieved by the decrease in pump brake horsepower associated with reduced flow requirements at partial load conditions.

A "Generic" 1500 ton plant consisting of three 500 ton chillers was studied. A flow rate of 2.4 gpm per ton was used (3600 gpm) which corresponds to a 10 degree temperature difference between the chilled water supply and return. The head on the distribution pump was assumed to be 120 feet resulting in a nominal 150 horsepower motor.

Since no load information on the central plant is available, the Trane "Trace" output was used to generate a part load profile. In a variable flow arrangement, the supply and return temperature difference remains relatively constant with the flow varied in direct proportion to the imposed load. From the pump affinity laws, the pumping power will be reduced ideally by the cube of the flow. However, due to decreasing motor and pump efficiencies at reduced rpm and flow respectively, and minimum flow requirements of the chillers, a cubic decrease in horsepower requirements is not achieved.

For the constant flow arrangement a single circulating pump distributes chilled water to the load. Since investigation of the actual terminal equipment is beyond the scope of work, a typical 3 way mixing valve with a valved bypass arrangement is assumed. The chillers are piped in a parallel configuration with no provisions made for automatic control of the chiller shutoff valves. A schematic of this scheme is presented in Sketch #1 on page one of the Appendix 3.1.3, Volume 2 for the chillers.

Manufacturers data was used to approximate the typical full load pump and motor efficiencies. Since the base distribution systems are rather large, a pump head of 120 feet was assumed. This value is typical for several of the pumps at the central plants.

The chillers do not operate from November through March which yields 5136 operating hours per year. With the above information the annual kilowatt hours associated with the pump operation are calculated based upon constant flow. This information is presented in page two of the Appendix 3.1.3, Volume 2 for the chillers.

With a variable flow system, provisions must be made to ensure that minimum flow is maintained through the chillers. This is generally accomplished by one of two methods. The first approach is to reconfigure the system into a primary/secondary pumping arrangement. This requires that dedicated circulating pumps be provided for each chiller, which are interlocked to run when the chiller is operating, and the piping is configured into a primary loop. The distribution pump draws water off of the primary loop to serve the load.

The second method is to provide motorized valves such that at part load (part flow) the flow through an inactive chiller can be diverted to the other machines. Since the flow through the active chiller(s) is varying, control of the leaving chilled water temperature is more difficult. Due to an increased complexity of controls associated with this scheme the first method was adopted for the purposes of this analysis. A schematic of the revised system layout is shown in Sketch #2 on page three of the Appendix 3.1.3, Volume 2 for the chillers.

The primary pumps are sized for the chilled water flow through each machine with a head equal to the pressure drop through the chiller and primary loop piping. This head is estimated to be approximately 20 feet which reduces the head seen by the secondary pump to 100 feet (120-20). The number of primary pumps operating coincides with the number of chillers operating and depends upon the partial load on the central plant. Since three equal tonnage chillers have been assumed, one pump/chiller operates 33% load, two operate up to 66% load, and three above 66%. The energy consumed by these primary pumps must be accounted for to provide an accurate analysis.

The secondary pump head at design flow is used to calculate the head imposed by the system at partial loads (gpm) by using the pump affinity laws. Since the efficiency of a pump varies with speed, (gpm) an approximation of the pump efficiency at various flows was made by interpolating between typical full and part load efficiencies. The pump brake horsepower at each load condition can then be calculated by using the part-load head, gpm and pump efficiency values.

Once the pump brake horsepower is calculated the energy consumption in kilowatts may be determined by accounting for motor and drive efficiencies. The efficiency of a typical NEMA "B" 4 pole nominal 1800 rpm electric motor decreases at reduced speed. An interpolation of manufacturers data for a typical motor was performed to determine the motor efficiency at each part load condition. The drive efficiency for a variable torque, adjustable frequency, type motor controller remains relatively constant at various frequencies. Therefore, an average efficiency of 92% was used for the motor controller.

Using the average monthly load at Fort Bragg and the above information, calculations were performed to determine the energy usage of the secondary chilled water pump using the variable speed drives. A summary of the formulas and efficiencies used for these calculations is contained on page four of the Appendix 3.1.3, Volume 2 for the chillers. These calculations were made and are presented in tabular form on page five and six of the Appendix 3.1.3, Volume 2 for the chillers.

The energy usage scheme is summarized on page six of the Appendix 3.1.3, Volume 2 for the chillers. Based upon these calculations, incorporation of a variable speed chilled water distribution system at Fort Bragg will save 24,210 kwh per year.

An estimate of the anticipated first costs associated with implementation of a variable speed pumping scheme was made. A copy of the estimate is contained on page seven of the Appendix 3.1.3, Volume 2. This data was used to complete a Life Cycle Cost Analysis Summary Sheet of the Energy Conservation Investment Program (ECIP).

The SIR for Fort Bragg was calculated to be 0.934. The Savings Investment Ratio was less than one, since this ECO is not economically feasible at this site. The Life Cycle Cost Analysis Summary Sheets are contained on pages eight through twelve of the Appendix 3.1.3, Volume 2, with miscellaneous calculations found on pages thirteen and fourteen of the Appendix 3.1.3, Volume 2 for the chillers.

4.10 Voltage Regulators on Large Electrical Equipment

Where the voltage supply from the utility grid fluctuates or where the loads on the various phases of the electric system are unbalanced, the application of voltage regulators may improve performance. This was discussed with the base utility representative, and it was determined that this was not required at this facility.

Based on our meeting with the Corps on December 12, 1985, there was agreement between the Corps and the A/E that the application of voltage regulation at these facilities is not feasible.

4.11 Steam Pressure or Hot Water Temperature Reductions Based on Seasonal Loading

The energy consumed to elevate the temperature or pressure of the feedwater can be significant to any boiler system. For every increase in energy level on the output, a corresponding increase in input energy is required. Depending upon the configuration of the overall system, a potential savings exists in reducing the energy level at the boiler output.

4.11.1 Building C-1432

No site specific data is available; however, these are not high temperature-high pressure boilers. Operation at a lower temperature would not be appropriate since the boilers are not equipped with superheaters. Operation at lower pressure (below 110 psig) would reduce pump power, however, boiler capacity and steam distribution capacity might be adversely affected. At one time, this plant supplied 165 PSI steam to absorption chillers. Since the absorption chillers have been removed, the pressure has been reduced to 120 PSI. Reducing pressure below 120 psi would reduce the enthalpy available to operate the auxiliary drive turbines. Therefore, any additional reduction in operating pressure is not recommended.

4.11.2 Building D-3529

No data on seasonal loading was provided to evaluate. Therefore, no recommendations can be made. However, it is recognized that multiple boilers are operated at low firing rates. As stated previously, a significant gain would be realized if the boilers were operated at higher firing rates.

4.12 Reductions in Make-Up Water Quantities

The make-up water required for boilers, chillers and cooling towers can be significant. The actual water consumption is one consideration, but the cost of chemicals required to treat this water usually overshadows the cost of water. The cost of lost energy is also extremely high.

4.12.1 Building C-1432

Inspection of the boiler house revealed numerous small steam and condensate leaks amounting to only a few gallons per minute, at most. However, very large quantities of make-up water are added to the system, indicating substantial leaks in the distribution system.

It was reported by the Central Heating/Chilling Plant operators that approximately 71,500 gallons of make-up water are used in Building C-1432 per day. While limited log data is available to verify that figure, a check of the make-up log for September 1990 (a light heating month) showed an average daily make-up water average of 62,317 gallons per day. Consequently, on an annual basis (including the high-heating-load winter months), 71,500 gallons per day should be approximately correct. This quantity is indicative of <u>very</u> large distribution and load losses.

Though the distribution system is not included in the scope of this contract, the following calculations are included to illustrate the magnitude of the problem and the potential for savings attainable by repairing the distribution system.

<u>Assumptions</u>:

1. Make-up water temperature = 60°F
2. The majority of the water is lost as steam. This is typically the case since steam exists as vapor at higher pressures while condensate exists as liquid at lower pressures. In the vapor state and at higher pressures, there is more opportunity for leaks. Assume 80% steam leaks and 20% condensate leaks.

3. "Normal" make-up = 10% of steam load.

Knowns: (From previous calculations)

1. Average steam production approximately equals 48,140 pounds per hour.
2. Enthalpy of steam = 1192.4 BTU/lb
3. Enthalpy of condensate = 147.9 BTU/lb (approx.)
4. Boiler efficiency approximately equals 85%.
5. Average fan and pump power is about 147 HP.
6. Fuel cost per BTU = 4.246×10^{-6} \$/BTU
7. Electric cost = \$.03739/KW.HR + \$9.25/KW.Month
8. Motor efficiency = 90%

Calculations:

$$\frac{71{,}500 \text{ Gal/day } (8.33 \text{ lbm/Gal})}{24 \text{ hr.}} = 24816 \text{ lbm/hr.}$$

Make-up due to leaks = (.9)(24816 lbm/hr) = 22,334 lbm/hr

h Steam = 1192.4 BTU/lbm

h Cond = 147.9 BTU/lbm

h Make-up = 28.1 BTU/lbm

$$\begin{aligned}\text{Lost Energy} &= .8\,(22{,}334) \text{ lbm/hr } (1192.4 - 28.1) \text{ BTU/lbm} + \\ &\ .2\,(22{,}334) \text{ lbm/hr } (147.9 - 28.1) \text{ BTU/lbm} \\ &= 2.134 \times 10^{7} \text{ BTU/hr}\end{aligned}$$

$$\text{Wasted Heat Input} = \frac{2.134 \times 10^{7}}{.85} \text{ BTU/hr} = 2.510 \times 10^{7} \text{ BTU/hr}$$

Cost to Heat = $(2.510 \times 10^{7}$ BTU/hr$)(4.246 \times 10^{-6}$ \$/BTU) = \$106.94/hr

Annual Avoidable Fuel Cost = (\$106.94/hr)(24 hr/day)(365 days/yr)

Annual Avoidable Fuel Cost = \$936,800

$$\text{Total Fan/Pumping Input} = \frac{(147 \text{ HP})(.746 \text{ KW/HP})}{.9} = 122 \text{ KW}$$

$$\text{Input Due to Leaks} = \frac{22{,}334}{48{,}140}(122 \text{ KW}) = 56.6 \text{ KW}$$

Elect Cost = 56.6 (.03739)(24)(365) + (\$9.25)(56.6)(12)

= \$24,821

Total Avoidable Cost = $936,000 + $24,821

$$\approx \$961,600/\text{YEAR}$$

Note that this does not include the cost to treat the additional water nor the cost of the water itself.

From the foregoing, it can be said that approximately <u>$1 million per year</u> in fuel and electric costs could be avoided by reducing the distribution system leaks. This far outweighs the combined efficiency measures for the boilers and indicates that repairs to the distribution system should be a high priority item.

No estimate of the costs to repair the distribution system can be made without first performing a thorough audit of distribution system conditions. Such an audit is clearly not included in the scope of this study.

4.12.2 Building D-3529

During inspection of this boilerhouse, no leaks were noted within the plant. Large quantities of make-up water, 1,200-8,000 gal/day were reported as a result of leaks in the zones, which are out of the scope of this report. However, from the foregoing discussion and calculations for Building C-1432, it should be clear that necessary distribution system repairs and maintenance are very costly in terms of energy use.

4.13 Evaluation of Electric Versus Steam/HTW/Absorption Chillers

Over the past twenty years, the increasing cost of electricity has made alternate energy sources practical. Where steam or hot water is readily available, an absorption chiller system may be feasible. The major deterrent to this type of system is the increased maintenance costs associated with chiller operation. Historically, these maintenance costs have been high enough to make absorption chillers impractical except in areas where electrical energy costs are very high.

Recent studies have shown that unless the fuel cost to produce steam or HTW is nearly zero, absorption machines are not cost effective. With initial cost and maintenance cost being significantly higher for absorption machines vs. electric, operating cost would have to significantly lower in order to make absorption equipment life cycle cost effective.

For example, with a new chiller operating at 0.6 kw per ton (centrifugal) and an electric rate of $.05 per kw, operating (energy) cost is about $.03 per ton of cooling capacity.

A comparable absorption machine utilizing steam produced by an 80% efficiency boiler burning oil at $1.00 per gallon would cost about $.15 per ton. Even burning natural gas at $.47 per therm (100,000) absorption would be more than electric cost for energy at $.098 per ton. (See following calculation.)

A detailed analysis could be done on this particular ECO, however, our experience and apparently the experience at the Corps of Engineers (since most existing absorption machines have been replaced over the last 3± years) would indicate that such a detailed analysis is unwarranted. Such an analysis would not result in an ECIP even approaching 1.

Electric vs. Steam/HTW/Absorption Table

1. Centrifugal Chiller @ 0.6 kw per ton of output

   Electric Rate = $.03739/KW-HR + $9.25/KW-MONTH

   For Full Time Chiller Use:

   $$\frac{\$9.25/\text{KW-MONTH}}{(30\ \text{DAY/MTH})(24\ \text{HR/DAY})} = \$.0128/\text{KW-HR}$$

   Electric Rate = ($.03739 + .0128)/KW-HR = $.050/KW-HR

   Electric Cooling Cost = 5¢/KW-HR x .6 KW/TON = 3¢/TON-HR

2. Absorption Machine

   Requires, per manufacturers data, 18.7 lb steam/ton-hr

   $$18.7\ \text{lbs. steam} \times 900\ \frac{\text{BTU}}{\text{lb}} = 16{,}830\ \text{BTU/Ton}$$

   w/80% efficiency boiler = 21,000 BTU of fuel input per ton cooling

   a) Oil @ 140,000 BTU/Gal @ $.99 per gallon =

   $$\frac{21{,}000\ \text{BTU Fuel}}{\text{Ton Cooling}} \times \frac{\text{Gal Fuel}}{140{,}000\ \text{BTU Fuel In}} \times \frac{99¢}{\text{Gal Fuel}} =$$

   <u>15¢ PER TON</u> Cooling

   b) Natural Gas @ 40¢ per Therm (100,000)

   $$\frac{21{,}000\ \text{BTU}}{\text{Ton Cool}} \times \frac{\text{Therm}}{100{,}000\ \text{BTU}} \times \frac{40¢}{\text{Therm}} =$$

   <u>8.4¢ PER TON</u> Cooling

ENERGY COST OF ELECTRIC VS. ABSORPTION INDICATES <u>SIGNIFICANT</u> SAVINGS WITH ELECTRIC.

4.14 Control Systems to Operate Chillers at Energy Efficient Operating Condition

The design of a centrifugal chiller causes the most efficient operating point to occur at approximately 70 to 80 percent of full load. Also, no two machines are going to operate at the same efficiency throughout their load range. Therefore, the units should be utilized in such a way that overall energy consumption is minimized by operating the most efficient units at their most efficient capacity.

In addition, the controls should allow for the highest temperature chill water which the distribution system (fan-coils, AHU's, etc.) can accommodate. Controlling the chillers to produce 41°F chill water when a 45°F design temperature is acceptable results in significantly lower evaporator temperatures and a reduction in machine capacity. This alone can result in a 10% to 15% reduction in machine efficiency.

Specific measures in this regard have been addressed previously.

4.15 Use of Heavy Oils for Plants with Light Oil Burners

The cost of heavy oils is usually less than the cost of the lighter grade fuel oils, thereby creating a potential reduction in energy costs. This potential savings will be offset by possible increases in maintenance costs and equipment expenditures required for proper handling and burning of the heavy fuels.

4.15.1 Building C-1432

No light oil was used in the boilerhouse inspected.

4.15.2 Building D-3529

No light oil was used in the boilerhouse inspected.

4.16 Blowdown Control

Blowdown is used to control the accumulation of solids in the internal piping of the boiler. If not properly controlled, the use of water, chemicals and fuel can cause the system's economic efficiency to be poor.

4.16.1 Building C-1432

The operating personnel state the blowdown is set to maintain a TDS level of 1200 ppm. A review of the boiler operating logs confirms this operating practice. Given the general recommendation that the TDS is not to exceed 3000 ppm for boilers operating at this pressure and temperature, this procedure is generally wasteful of both chemical treatment and heat energy. In Building C-1432, waste has been minimized by the installation of a blowdown heat exchanger in 1987. However, because maintaining TDS at these low levels provides no appreciable benefit, wasting any amount of heat and chemicals is unacceptable. Consequently, the procedure should be discontinued.

4.16.2 Building D-3529

Blowdown control is not applicable to continuous blowdown, it is a manual setting. Since no other blowdown was noted during inspection, there are no recommendations for improving efficiency based on blowdown control.

4.17 Condenser/Cooling Tower Water Treatment

Wherever water is heated, cooled, and oxygenated, the formation of scale and algae will occur. The application of chemicals and continuous monitoring is required to control the effects of these items. Fouling of the chiller's condenser tubes will cause the system efficiency to decrease. The corrosion of system components will require their replacement much sooner than normal.

Water treatment of the condenser water was observed to be installed and operating at all installations. The basic method utilized was a timed (pulse) meter which injected chemicals into the system. Chemicals were stored in drums for each chiller/tower combination and separate feeder systems were installed on each.

Our investigation indicated acceptable levels of algae growth in the towers, minimal scaling in the tower basins, no foaming in the basins, minimal corrosion of tower components and acceptable pressure drops through chiller condensers.

While the system installed is apparently working satisfactorily, no readings were taken or available regarding tower bleed rate. Installation of an automatic measurement (conductance) of dissolved solids and automatic bleed could result in make-up water savings.

A visual inspection indicated that the water treatment program was generally acceptable. Since the largest inefficiencies in cooling tower performance result from deteriorated fill material, fine tuning water treatment at this stage would offer little improvement.

A quantitative analysis (or ECIP) is very difficult for the water treatment since it would have to relate to the system as presently installed and its effect which is almost impossible to determine. An analysis of bleed rate and water make-up reduction could be done and quantified; however, that would require data that is not currently available. If the recommendations regarding instrumentation and logging procedures are implemented and followed, then data can be gathered such that a full analysis can be made in the future.

4.18 Use of Pulverized Wood as a Boiler Fuel in Building C-1432

Energy costs and availability are a significant factor in the operation of any central energy plant. Where a stable supply of wood or other energy source is available, this may yield a feasible fuel alternative. Obviously, significant boiler modifications would be required to implement such a change in fuel sources.

The boilers in this building were built by Erie City Iron Works in 1953 and were designed to burn pulverized coal. However, the stokers were removed and burners were installed to burn oil and natural gas. Additionally, all of the material handling equipment has been removed, except for a feeder and a silo.

The prohibitively high cost of replacement equipment compared to the less significant fuel cost savings makes this project not feasible. This is demonstrated in the economic justification, which as a payback period of 97 years.

1) Total Fuel Cost for 1987

#6 Fuel Oil: 889,950 GAL x \$0.55/GAL = 489,473

Natural Gas: $293{,}932{,}000\ FT^3 \times \frac{1000\ BTU}{FT^3} \times \frac{\$0.326}{10^4\ BTU} = \underline{958{,}218}$

\$1,447,691

2) Total Fuel BTU/YR

#6 Fuel: $889{,}950\ GAL \ast 8.1\ \frac{LB}{GAL} \ast 18200\ \frac{BTU}{LB}$ 1.31 x 10"

Natural Gas: $293{,}932{,}000\ FT^3 \times 1000\ BUT/FT^3$ 294 x 10"

Waste Oil: $357{,}354\ GAL \times 8\ \frac{LB}{GAL} \ast \times 19{,}000\ \frac{BTU}{LB}\ast$ 0.54 x 10"

4.79 x 10" BTU

Notes: Fuel usage per Mr. Steve Smith, Energy Officer fuel prices per Mr. Marvin Todd, Chief Maintenance Division, Telecon 1/3/88 values for fuel oil and NG from Babcock & Wilcox "Useful Tables"

* Assumed values for waste oil

Assumptions for Burning Wood:

1.) Wood chips readily available
2.) Wood chips delivered by truck
3.) Cost of wood chips: $18/2000 LB, delivered
4.) Existing ID and FD fan capabilities are sufficient for new system.
5.) Existing system has sufficient air/water cooling to prevent wood chips from melting.
6.) Energy output remains constant: No energy savings
7.) Fuel Usage Distribution

#6 Fuel Oil	19%
Natural Gas	55%
Waste Oil	11%
Wood	15%

Fuel Cost, with Wood Burning:

#6 Fuel: $4.79 \times 10'' \text{ BTU} \times 0.19 \times \frac{\text{LB}}{18200\text{BTU}} \times \frac{\text{GAL}}{8.1 \text{ LB}} \times \frac{\$0.55}{\text{GAL}} = \$339,543$

Natural Gas: $4.79 \times 10'' \text{ BTU} \times 0.55 \times \frac{\$0.326}{100000 \text{ BTU}} =$ 858,847

Wood: Heat Value: Dry = 9170 BTU/LB
Wet = 4500 BTU/LB
Moisture = 40-60%

$$0.50 \times 6835 \frac{\text{BTU}}{\text{LB}} \times y = 0.15 \times 4.79 \times 10'' \text{ BTU}$$

$$y = 21,024,140 \text{ LB/YR}$$
$$y = 10,512 \text{ TONs}$$

Wood Cost: 10,512 TONS x $18.00/TON = 189,217

$1,387,607/YR

Fuel Cost Savings:

Cost without burning wood	$1,447,691
Cost with burning wood	1,387,607
	$ 60,084/YR

Estimated cost of all equipment to allow use of wood as fuel $5,836,377

Payback Time $\frac{\$5,836,377}{\$\ 60,084/YR}$ = 97 years

Cost For Use Of Pulverized Wood

Description	Estimated Price
1. Keep air heaters: replace tubes 30,000 x 3	$ 90,000
2. Install grating 3 x 45,000	130,000
3. Truck Dumping System Scale Dump Hopper Freight Misc (10%)	119,180
4. Storage for Truck Dump	90,860
5. Conveyor Systems Disc Screen Output Conveyor Pneumatic Conveyor Wood Storage to Feeder	153,120
6. Disc Screen	22,968
7. Magnet to Remove Iron	14,500
8. Wood Hog	35,960
9. Wood Chip Storage	237,800
10. Wood Feeders Assume: 4 each x 3 BLRS	576,000
11. Ash Handling System Conveying Pipe Ash Storage Silo Ash Unloading Equipment	1,000,000
12. Motor Control/Start-up System	274,000
13. Control System Boilers 274,000 Truck Handling System	548,000
Subtotal	3,297,388
14. Equipment Installation (45%)	1,483,825

15. Structural Steel	(10%)	329,739
16. Engineering	(12%)	395,687
17. Profit & Overhead	(10%)	329,739
Subtotal		2,538,990
Equipment Subtotal		3,297,388
GRAND TOTAL		$5,836,378

With current technological developments in fuels (such as coal liquefaction) a significant capital expenditure to burn wood chips would not be recommended. The existing plants currently have alternative fuel capabilities through fuel oil and natural gas.

Instead of using wood chips, an alternative energy consideration could be a solid waste to energy plant. The saturated steam demands of the facility make this type of approach viable. In addition, at current fuel costs, a plant in the 800 ton/day capacity could be economically feasible, providing both a low cost energy source along with an answer to refuse disposal problems.

4.19 Deactivation of Facilities by Satelliting of Central Plants

In a large, campus style distribution system, the energy consumed by pumping chilled or hot water can be significant. By distributing smaller systems throughout the distribution system, pumping requirements are reduced, but overall system efficiency may not improve due to the use of smaller less efficient cooling or heating equipment.

4.19.1 Chillers

The decision to decentralize a portion or all of a system load is based on the profile of the loads served. For example, if a chapel, used only for weekend services, is supported by a main chiller plant, there would be obvious potential for savings through decentralizing that load. However, this decision would be based on the actual profile of that individual load as compared with the total system load.

Actual load profiles are essential to complete an analysis of this issue. Unfortunately, neither load profiles nor historical information from which to establish a load profile is available. Consequently, a meaningful analysis of savings available (if any) based on decentralization is not possible at this time.

During recent site visits, additional effort was focused on this issue. However, the current cooling load information (which is itself suspect) demonstrated a 24 hour, 7 day per week minimum load requirement of at least one large chiller. In addition, operators could not identify small off-peak loads which would be candidates for satellite systems.

In a system this size, it is difficult to imagine that there isn't a greater variance between peak and off-peak load conditions. The varying times at which "indicated" peak occurred was also puzzling.

However, until accurate load information can be developed, a recommendation for satellite system simply cannot be made.

4.20 Variable or Two-Speed Cooling Tower Fan

The efficiency of the chiller will improve as cooler condenser water is delivered. However, the lower limit suggested by most manufacturers is 70 degrees. As this lower limit is approached, the cooling tower fan operation can be modified to save on fan energy consumption.

A generic study is included herein and based on this study such implementation may be feasible for an ECIP.

Energy is consumed in driving the fan, or fans, necessary to achieve proper air movement through a cooling tower. The quantity of air flow through a tower necessary to maintain desired leaving water temperatures will vary with changing loads and ambient conditions. The goal of this energy conservation measure is to reduce the fan energy consumption while maintaining a constant leaving water temperature.

The obvious goal of this energy conservation measure (ECM) would be to reduce the fan energy consumption to a minimum. Due to the numerous variables which affect cooling tower and chiller operation this analysis is very complex. The changes in ambient wet bulb temperature, dry bulb temperature, systems load, air density and water flow rate all affect the tower performance. In order to analyze this ECM several of these factors will need to be considered constant.

One major consideration must be that the efficiency of the centrifugal chiller will improve as the condenser water temperature decreases. Therefore, the low end temperature at which the system is controlled must be carefully selected. Eighty-five degrees is normally selected for the high load inlet temperature to the chiller. As the ambient temperatures and loads decrease, colder water is possible from the tower. On average, a one percent reduction in energy consumption can be expected with a one degree reduction in condenser water temperature. However, this is limited to low temperature of approximately 65°F; based upon a design condensing temperature of 85°F, a potential reduction approaching 20% of design energy consumption can be achieved by lowering the condenser water to 65°F when ambient conditions and system load permits.

The locale being studied will yield ambient conditions which would allow the water temperature to drop below 65°F if permitted to do so. It is during these periods of time when variable speed fan control would be feasible. Since the existing cooling towers are already utilizing two speed motors, the overall plant energy savings possible from a variable speed fan installation would be minimal.

The potential for energy savings by utilizing a variable speed fan control, although small, does exist. However, recent studies on the existing towers demonstrated that this project would not offer a significant cost savings due to base loading conditions. Instead, efforts should focus on:

1. repairing/replacing cooling media in the towers, and
2. repiping towers to a manifold distribution system.

Once these two activities are complete, the control system should bring on individual cooling tower cells to meet the demand placed on the manifold. The estimated base load is greater than the smallest single tower cell, even under low ambient conditions.

The manifold system would, in effect, create a staged variable capacity condenser water system, roughly equivalent to variable speed fans. It would also offer redundancy and ease of operation.

Based on other recommended actions, the installation of variable speed cooling tower fans is not recommended.

4.21 Free Cooling Cycles

In certain locations, it may be possible to cool the chilled water by using the cold condenser water when outdoor air temperatures are low enough. Rather than using the refrigerant/compressor cycle to exchange heat from the buildings to outdoors, this cycle is bypassed directly to the cooling towers.

An analysis was conducted to evaluate the economic feasibility of incorporating a free cooling arrangement into the central plant chilled water systems. Energy savings are achieved by the avoidance of chiller compressor operation associated with operation of the cooling tower to produce chilled water at low ambient temperature and partial load conditions.

A "Generic" 1500 ton plant consisting of three 500 ton chillers was studied. A flow rate of 2.4 gpm per ton was used (3600 gpm) which corresponds to a 10° temperature difference between the chilled water supply and return. The condenser water system is comprised of three single cell cooling tower each with a 25 horsepower fan motor. This tower selection was made from manufacturers data assuming the tower capacity is 30% greater than the chiller capacity, and using a design wetbulb temperatures of 79°, a 7° approach, and a 10° range.

Since no information on the central plant loading is available, the Trane "Trace" output was used to generate a part load profile. The chillers are piped in a parallel configuration with no provisions made for automatic control of the chillers shutoff valves. A schematic of this scheme is presented in Sketch #1 on page 15 of the Appendix 3.1.3, Volume 2 for the chillers.

To incorporate a free cooling operational scheme, plate type heat exchangers are used to transfer heat between the condenser and chilled water loops. Two heat exchangers are required to satisfy the maximum wintertime part load conditions of 979 tons, since the cooling towers have a nominal capacity of 650 tons each. A diagram of this arrangement is contained in Sketch #2 on page 16 of the Appendix 3.1.3, Volume 2.

A determination of the ambient wetbulb temperature that will produce sufficiently cold leaving tower water must be made to ascertain the hours of operation during which free cooling is available. A 55° wintertime supply chilled water temperature was assumed as per ASHRAE 1983 Equipment Volume, page 21.9. From manufacturers' data on heat exchangers, it was determined a 5° approach between entering and leaving water could reasonably be attained. Due to mixing associated with the three chiller parallel configuration, the heat exchangers must produce 53° water. Therefore, with a 5° approach, the cooling towers must be capable of producing 48° leaving water temperature.

A typical cooling tower performance curve at varying ambient wet bulb temperatures was obtained from Chapter 20 of the ASHRAE 1988 Equipment Volume. Although the tower range will vary in proportion to the imposed load, an average range based upon the average load was calculated. With the leaving tower water temperature and condenser water range determined, an ambient wetbulb temperature of 36° was obtained from the tower performance curve. From the cooling tower performance curve, it is apparent that as the tower range is reduced, the ambient wetbulb temperature at which free cooling tower is available increases. To account for the varying cooling tower range, an ambient wetbulb temperature of 38° was used for the temperature at which free cooling is available. Detailed calculations are contained on page 17 of the Appendix 3.1.3, Volume 2 for the chillers.

To find the hours when the wetbulb temperature is below 38° weather data for each fort was obtained from "Engineering Weather Data", TM-785. Since this publication divides each month into three time periods of observation, the average load coinciding with these time periods was determined from the Trace output. This data was then used to calculate the ton-hours of chiller operation that could be avoided utilizing free cooling.

To evaluate the energy savings, the chiller efficiency must be accounted for. For this generic study a full load efficiency of 0.70 kw per ton was used with part load efficiencies determined from a typical centrifugal chiller unloading curve at a reduced condenser water temperature of 65°. The formulas used to perform these calculations are summarized on page twenty-three of the Appendix for the chillers, with the weather data and load profiles contained on pages nine through twelve of the Appendix 3.1.3, Volume 2 for the chillers. The results of the calculations are presented on page fourteen of the Appendix 3.1.3, Volume 2 for the chillers.

To determine the net energy savings, the increased cooling tower fan energy consumption associated with free cooling must be accounted for. The periods at which the potential for free cooling exist are characterized by low ambient wetbulb temperatures. Therefore, the existing two speed cooling towers would be operating a low speed if the chillers were being used to handle the load. To produce free cooling however, the tower's fan would have to operate on high speed, thus increasing the tower power consumption. The chiller energy savings is reduced slightly by this increased tower energy consumption. The formulas used to determine the impact of the increased tower energy consumption are presented on page eighteen of the Appendix 3.1.3, Volume 2.

The net energy saving of the free cooling schemes is summarized for each site on page nineteen of the Appendix. Based upon these calculations, incorporation of a free cooling chilled water arrangement system at Fort Bragg will save 20,736 kwh per year. The energy savings at Fort Bragg are less since the chillers are shutdown during the winter months when the low ambient temperatures required for free cooling are available.

An estimate of the anticipated first costs associated with implementation of a variable speed pumping scheme was made. A copy of the estimate is contained on page twenty of the Appendix 3.1.3, Volume 2. This data was used to complete a Life Cycle Cost

Analysis Summary Sheet of the Energy Conservation Investment Program (ECIP).

The SIR for Fort Bragg was calculated to be 0.047, and therefore, implementation at this site is not economically justifiable. The Life Cycle Cost Analysis Summary Sheets are contained in Appendix 3,1.4, Volume 2, with additional calculations found in Appendix 3.1.3, Volume 2.

Based upon this analysis, incorporation of a free cooling arrangement is not economically feasible at Fort Bragg. Therefore, we recommend that the current arrangement be retained and further investigation of the potential for free cooling be directed towards air side economizers for the terminal air handling equipment.

During recent site visits, it was also determined that the central cooling plants are not serving winter cooling loads, and are shut down from October until May. Therefore, free cooling is simply not warranted.

4.22 Addition of Steam Accumulators

This item was deleted from consideration in a meeting held in Atlanta, Georgia on October 9, 1985.

4.23 Steam Driven Auxiliaries vs. Electric Drives

The energy consumed by system auxiliaries, particularly pumps and compressors, can be significant for large central energy plants. All feasible energy sources should be considered including purchased electricity, and steam produced on site.

4.23.1 Building C-1432

This boilerhouse had 3 ID fans, 3 FD fans, condensate pumps and boiler feed pumps that are equipped with dual drives (turbine drives and electric motors).

Inspection of the boilerhouse revealed that these turbine drives are in place and appear capable of running the auxiliary equipment. Operators interviewed indicated that the auxiliaries were run on electricity, only using the turbines in cases of emergency. Because a heat balance shows that the steam required by the turbines could be used in the deaerator at a significant yearly savings, it is recommended that plant operators utilize the turbines to power the auxiliaries.

1. Turbines were observed to be in place but only used in emergencies to run ID Fan, FD Fan, condensate pumps, and BF Pump

2. Costs to run the motors on electricity and by turbines were compared, given electricity rates and motor demands.

3. The calculations (included in Appendix 2.2.3, Volume 2) predict an annual savings of over $23,000 with no front-end capital outlay.

4. It is recommended that the auxiliaries be run on steam in place of electricity.

4.23.2 Building D-3529

Inspection of this boilerhouse revealed that it is a hot water generating plant with only a small steam generator used as deaerator and atomizing steam.

Since an adequate supply of steam is not available, it would not be feasible to use steam driven auxiliaries in this plant. It is recommended that electric drive continue to be used in this facility as long as it remains a hot water generating plant. No economic justification was performed.

4.24 Variable Speed Induced Draft Fans and Forced Draft Blowers

The method selected for controlling the quantity of air entering the boiler can affect the plant efficiency. The use of variable frequency controls or fan motors can more accurately match motor horsepower to required air flow rates. When fan efficiency is improved, overall plant efficiency is improved.

Currently, air volume through the FD fans is controlled through inlet vanes. When controls are properly set up, these vanes will modulate air flow to meet optimum combustion efficiency.

As previously stated, it is recommended that the existing steam driven auxiliaries be utilized as primary units, with electrically driven devices being used as standby equipment.

Therefore, it would be impractical to install variable speed controls on the standby units.

4.25 Fuel Quality Changes

The type of fuel used in a boiler will affect the operating costs for the plant, the efficiency of the plant, and the maintenance costs of the plant. A balance must be reached between the savings of a lower grade fuel and the reduction in burner efficiency and added maintenance costs.

4.25.1 Building C-1432

The fuels used in this building are: natural gas as the primary fuel and fuel oil #6 as the secondary fuel. Calculations using data collected from Mr. Steve Smith, Energy Officer on 2/23/88 show that natural gas is used nearly 75% of the time while #6 oil is only used 25% of the time. No quality changes can be made on natural gas, the primary fuel, to increase efficiency. No test results were made available to compare fuel analysis to standard data ranges.

4.25.2 Building D-3529

The fuels used in this building are natural gas, as the primary fuel and fuel oil #6 as the secondary oil. Calculations using data collected from Mr. Steve Smith, Energy Officer on 2/23/88 show that natural gas is used 95% of the time and fuel oil #6 is used only 5% of the time. No quality changes can be made on natural gas, the primary fuel to increase efficiency. No test results were made available to compare fuel analysis to standard data ranges.

Since natural gas is used as the primary fuel, it is not recommended that fuel quality changes be made at this point. Once a fully development operation and maintenance program is developed, the cost of operations under either fuel oil or natural gas can be quantified. At that point, a break-even comparison of procurement costs for each fuel can be made, to guide the purchase decision of either fuel.

4.26 Instruments and Controls to Facilitate Efficient Operations

For a chiller or boiler plant to operate efficiently, it must be able to respond to changes in system load. In most cases, this means a relatively small change in temperature could signal a reduction in system load. The plant operator and his controls must be able to detect this change and respond accordingly.

Evaluation of Fort Bragg's boiler and chiller plants' instruments and control systems' were addressed in detail in Section 3.0 of this report.

The installation of adequate controls and the implementation of a rigorous calibration and maintenance programs for these devices are strongly recommended.

5.0 PROJECT DEVELOPMENT

Several ECIP projects were evaluated for Fort Bragg's boiler plants and are as follows:

Building C-1432 ECIP Projects Evaluated

1. Steam vs. Electricity to Run Motors
2. Bypass Air Heater
3. Add Automatic O_2 Trim
4. Add O_2 Analyzer and Manually Adjust O_2

Building D-3529 ECIP Projects Evaluated

1. Add O_2 Analyzers and Manually Adjust O_2
2. Add Automatic O_2 Trim

Please refer to the ECIP table following this section for additional cost saving information.

All of the projects for building C-1432, with the exception of item number 3, met the qualifications of the ECIP program, except for the $200,000 funding criteria. The ECIP projects for building D-3529 also did not qualify because they were under the funding criteria. However, all of these projects, except for number 3 above, have savings-to-investment ratios greater than one and should be considered for implementation under either the QRIP or PECIP programs.

Regarding O_2 trim, it should be noted that, for both buildings, the option of adding O_2 analyzers and manually adjusting the O_2 trim has a higher SIR. This is the recommended alternative for both buildings.

With respect to chiller plants, the concept of variable speed pumping and free cooling have been analyzed on generic load information. Since the chiller plants are not used for winter cooling, additional analysis for free cooling is unwarranted. However, variable speed chill water pumping may have some viability as an ECIP. Unfortunately, without specific load data, a determination on this matter cannot be finalized at this time.

In addition to the ECIP projects identified above, it is recommended that a number of O&M funded initiatives be instituted at the base level. Several of the O&M related projects offer substantial energy improvements and cost savings with a relatively small investment. Indeed, the QRIP/PECIP projects should not be undertaken until the higher priority O&M actions are implemented, or the cost savings potential of these projects will not be fully realized.

FORT BRAGG PROJECT RECOMMENDATIONS

Project Descriptions	Project Type	Reference Report Page
Boilers:		
Bldg. C-1432		
1. Steam vs. Electricity, to Run Motors*	No Cost	120
2. Bypass Air Heaters*	QRIP	35-36, 69-71
3. Add O_2 Analyzer for Manual O_2 Trim*	PECIP	73-78
4. Replace O_2 Analyzer and Calibrate Combustion Control*	Does Not Qualify	73-78
5. Calibration of All Operative Instrument Controls	O&M	31
6. Replace Inoperative Controls	O&M	31
7. Retune Boilers & Restoke Fans	O&M	31
8. Tune Control Systems	O&M	33
9. Operating Procedures & Checklists	O&M	36-37
10. Check Systems for Correct Setpoint & Operation	O&M	32-34
11. Check Aiming of Scanners	O&M	32
12. Routine Burner Service & Combustion Checks	O&M	32
13. Preventative Maintenance Service on Burners	O&M	33
14. Repair or Replace Steam Regulators	O&M	33
15. Calibrate & Service Drum Level	O&M	34
16. Update Boiler Ignition System to Semi-Automatic Operation of Flame Safety System	O&M	32-34
17. Operating & Maintenance Schedule Development	O&M	36-38
18. Operator Training, Improvement & Operational Guides, Boiler Log Program, Preventative Maintenance Schedule	O&M	38
19. Replace Casings Around Steam Drums	O&M	38

Project Descriptions	Project Type	Reference Report Page
20. Installation of Smaller Boilers for Lighter Load Periods	O&M	39
21. Analysis of Fuel Delivered	O&M	39
22. FD Heater Replacement (Current Operation)	O&M	39
23. Isolation Valves Repaired	O&M	39
24. Repair Baffe Walls	O&M	58
25. Instrumentation & Metering Equipment Required for Proper Maintenance	O&M	60
26. Install New Refractory Patches	O&M	68
27. Repairs to Distribution System	O&M	96-98
Bldg. D-3529		
1. Add O_2 Analyzers and Manually Adjust O_2*	PECIP	78-84
2. Add Automatic O_2 Trim	PECIP	78-84
3. Control Panels, Recorders & Instrumentation Replacement	O&M	41
4. O&M Procedure Guides & Checklists	O&M	42
5. O&M Schedule Development	O&M	42
6. Calibration of Entire Control System	O&M	42
7. Upgrade Control System for Remote Operation	O&M	42
8. Burner Service Technician to: Replace Oil Gun Nozzles & Sprayer Plates in boilers 1 and 4, Correct Oil Temp. Controls, and Repair Atomizing Steam Control System	O&M	43
9. Repair Steam Generator Controls, Makeup Feed Control & Pump System	O&M	43
10. Burner & Control Service for Boilers	O&M	44
11. Controls Tuned to Agreed Maximum and Minimum Firing Rate	O&M	44

Project Descriptions	Project Type	Reference Report Page
12. Revision to/from Feedwater Piping for Boiler #5	O&M	44
13. Increase Expansion Tank Capacity	O&M	45
14. Semi-Automatic Boiler Ignition System Installation	O&M	45
15. Operator Training, O&M Guidelines and Checklists, Maintenance Schedule Program, Boiler Log Program, and Preventative Maintenance Schedules	O&M	46-47
16. Boiler & Refractory and Casing Repairs	O&M	47
17. Boiler Outlet Hood Leaks Repaired	O&M	48
18. Oil Supply Analyzed for Delivered Oil	O&M	48
19. Add Fuel Oil Boost Pumps Lines Near Storage Tanks	O&M	48
20. Repair Distribution Leaks	O&M	48, 98
21. Rear Wall Sight Glasses' Maintenance	O&M	62
22. Sequencing of Boilers	O&M	86-87
23. Repairs to Distribution System	O&M	98
<u>Chillers</u>:		
1. Automatic Chiller Controls	O&M	50, 87-88
2. Variable Speed Pumping*	O&M	90-93
3. Free Cooling*	O&M	115-118
4. Variable Speed Cooling Tower Fans	O&M	112-114
5. Cooling Tower Repair/Replacement (Bldg. C-6039 & Bldg. H-6240)	O&M	53, 104
6. Operator Training	O&M	52
7. Establish O&M Procedure Guidelines and Checklists, and Equipment Maintenance Schedules	O&M	52

Project Descriptions	Project Type	Reference Report Page
8. Install Additional Chiller Instrumentation & Metering Devices: Makeup Water Meters, Zone CHW Flow Meters, Individual Chiller CHW Flow Meters, Condenser Flow Meters, Condenser Makeup Water Meters, System Pressure Gauges and Inlet/Outlet Gauges	O&M	51
9. Chiller Log Implementation	O&M	52
10. Repiping CWS & CWR Via Common Headers (Bldg. D-3529)	O&M	53
11. Repairs to Distribution System	O&M	96-98
12. Control System Upgrade	O&M	101

*See Life-Cycle Cost Analysis Summaries for Further Review

PRODUCTIVITY CAPITAL INVESTMENT PROGRAM

Project	Cost	Annual Savings ($)	S/I	Amortization (YR)	Program
Steam vs. Electric for fan & Pump Drives Bldg. C-1432	$ 0	$ 23,000	∞	0	N/A
Bypass Air Heaters Bldg. C-1432	13,000	18,608	13.2	.70	QRIP
Replace Combustion Controls & O_2 Analyzer Bldg. C-1432	303,013	14,657	.48	20.7	N/A
Add O_2 Analyzer and Use Manual O_2 Trim Bldg. C-1432	45,585	14,062	2.83	3.2	PECIP
Add Automatic O_2 Trim Bldg. D-3529	98,674	30,619	3.1	3.2	PECIP
Add O_2 Analyzer and Use Manual O_2 Trim Bldg. D-3529	90,451	30,619	3.4	3.0	PECIP

DOCUMENTATION FOR PRODUCTIVITY CAPITAL INVESTMENT PROGRAMS
For use of this form, see AR 5-4; the proponent agency is OCA.

1. PROJECT NO.

REQUIREMENT CONTROL SYMBOL DD-M(R) 1561

2. TO:	3. THRU:	4. FROM:	5. DOD COMP NAME: Army	6. DOD COMP CODE
			7. COMMAND CODE	8. DATE

9. PROJECT TITLE
Bypass Air Heaters, Bldg. C-1432

10. TYPE OF PROJECT *(Check one)*
[X] QRIP [ ] OSD PIF [ ] PECIP

11. AMORTIZATION YEARS/MONTHS
$ 13,000 *(Project Cost)* ÷ 18,608 *(Average Annual Savings)* X 12 *(No. Mos)* = 0.70 *(years)* or 8.4 *(months)* *(amortization)*

12. FUNCTIONAL AREA WHERE SAVINGS WILL OCCUR
024 Army Energy Management

13. ECONOMIC LIFE
15 years

14. EXPECTED OPERATIONAL DATE
June 1992

15. SUBMITTING UNIT(S)

16. UNIT ID CODE

17. PROJECT DESCRIPTION
Bypass deteriorated air heaters on three 95,000 lb/hr boilers in Building C-1432 to improve boiler efficiencies, reduce electrical consumption costs and allow proper boiler operation at high firing rates.

18. DETAILED JUSTIFICATION
Inspection has revealed that at least 20% of the tubes are cracked or perforated and there were significant sulfer deposits inside the tubes. As a result of the deteriorated condition of the air heaters, it has been necessary to bypass the economizers to avoid the formation of corrosive condensation on the economizer tubes when the flue gases are cooled to below the dewpoint by a combination of leaking intake air and heat transfer to the boiler feedwater in the economizers. Consequently, the efficiency gains (5-10%) that can be realized by economizer operation are lost. Additionally, the leakage in the air heaters precludes the delivery of the appropriate amount of combustion (See Continuation Sheet)

19. SAVINGS DISPOSITION

20. OTHER REMARKS *(Continue on page 5, if more space is needed)*

air at high firing rates. As a result, during certain periods of high heat load conditions, it is necessary to operate two boilers at low firing rates (and low efficiencies) instead of satisfying the load with one boiler operating at a higher (and more efficient) firing rate.

21a.

SUMMARY OF DOLLAR SAVINGS
(ROUND OFF TO THE NEAREST DOLLAR)

Attach computation sheet identifying the method and source of data for savings

SAVINGS BREAKOUT	PRESENT METHOD	PROPOSED METHOD				DIFFERENCE/SAVINGS			
		1ST YR	2D YR	3D YR	4TH YR	1ST YR	2D YR	3D YR	4TH YR
SALARY/LABOR/ OVERTIME									
MATERIAL/ SUPPLIES									
UTILITIES									
MAINTENANCE/ REPAIR									
TRANSPORTATION									
LEASE COSTS									
SALVAGE/ TURN-IN									
ENERGY *(Identify)* Elect.	32,371	13,763				18,608			
CONTRACT COSTS									
OTHER *(Identify)*									
TOTALS									

b. **PRIORITIZATION**

(1) INTERNAL RATE OF RETURN *(IRR)*

Divide estimated project cost 13,000 by average annual savings 18,608 = 0.70 factor.

Based on factor and number of years economic life of the project, select the IRR from Table H-3, App H, Ch. 5, AR 5-4 = 300+ % IRR.

(2) SAVINGS TO INVESTMENT RATIO *(S/I)*

Multiply annual savings 18,608 X discount factor 9.19 = 171,008 and divide by present value of investment *(undiscounted)* 13,000 = 13.2 S/I.

(Based on economic life 15 years, select discount factor from Table H-4, App H, Ch. 5, AR 5-4.

(3) RATE OF INVESTMENT PER MANPOWER SPACE *(RIMS)*

Divide estimated project cost ________ by number of manpower space savings ________ = ________ RIMS.

(Manpower requivalents cannot be used in this computation.)

22. COST FOR PROJECT TO BECOME OPERATIONAL

EQUIPMENT TYPE a	PROPOSED SOURCE OF PROCUREMENT b	UNIT PRICE c	QUANTITY d	TOTAL COST e	APPROPRIATION, BUDGET ACTIVITY OR PROGRAM ELEMENT f	FY FUNDS REQUIRED g
(1)						
(2)						
(3)						
(4)						
(5)						
(6) TRANSPORTATION (*Equipment delivery*)						
(7) EQUIPMENT MODIFICATION[1]				13,000		
(8) EQUIPMENT INSTALLATION						
(9) MAINTENANCE CONTRACT[2]						
(10) FACILITIES MODIFICATION[3]						
(11) TRAINING						
(12) OTHER (*Specify*):				-0-		
(13) TOTAL REQUIRED FOR PROJECT TO BECOME OPERATIONAL[4]				13,000		
(14) TOTAL AMOUNT OF FUNDING REQUESTED IN THIS PROPOSAL				13,000		
(15) TOTAL AMOUNT OF FUNDING REQUIRED FROM OTHER SOURCE[5]				-0-		
(16) TOTAL (*Sum of (14) + (15) above*)				13,000		

[1] *Not to exceed 10% of equipment cost for QRIP projects.*

[2] *Applicable to OPA QRIP provided cost is included in packaged deal involving one bill for the equipment and initial maintenance.*

[3] *Normally not OPA funded.*

[4] *Used to compute amortization in Item 11.*

[5] *Specify source to include certification that funds are available, if financed from the regular budget:*

Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

23. SUMMARY OF SAVINGS *(MANPOWER AND DOLLARS)*

ITEMS	SAVINGS			REAPPLICATION OF SAVINGS					
	NO. MPR OR MHR	TYPE PERS[6]	DOLLARS	PROGRAM ELEMENT		TDA PARA AND LINE		FUNCTION CODE	
a	*b*	*c*	*d*	*e.* FROM	*f.* TO	*g.* FROM	*h.* TO	*i.* FROM	*j.* TO
(1) REQUIREMENTS AND AUTHORIZATIONS ELIMINATED									
(2) REQUIREMENTS ONLY ELIMINATED									
(3) BORROWED MILITARY MANPOWER RELEASED									
(4) OVERHIRES OR TEMPORARIES TERMINATED									
(5) HOURS OVERTIME ELIMINATED									
(6) MANHOURS SAVED FROM MULTIPLE POSITIONS[7]									
(7) OTHER DOLLAR SAVINGS *(Excluding Manpower), e.g.,* CONTRACT COSTS & UTILITIES									
(8)									
(9)									
(10)									
(11) TOTAL DOLLAR SAVINGS									

[6] *(1) US Graded*
(2) US Wage Board
(3) DHFN
(4) IHFN
(5) Officer
(6) WO
(7) Enlisted

[7] *Reflect specific duties being performed with additional manhours available (equivalent manyears)*

24. REGULATORY APPROVAL/COORDINATION		
a. **INVESTMENT STATEMENT** This proposal has been reviewed and it cannot be implemented with existing equipment or facilities. This investment is in accordance with established investment planning. The project complies with public laws, OSD policies and regulations, and all other regulatory constraints. _______________ *(Cite regulatory approvals, e.g., TAGO Control No.) (Ex. New Start, TAGO Approval, etc.)*		
b. OTHER COORDINATION *(Functional Coordination at local level, e.g., Fac Eng, Log, Pers, etc.)* _______________ _______________		
25. SUBMITTED BY *(Typed name, grade and title of Subordinate Command/Agency or Project Initiator)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
26. APPROVAL RECOMMENDED BY *(MACOM/Agency)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
FOR USE BY HQDA ON OSD PIF PROJECTS ONLY		
27. APPROVED BY	SIGNATURE	DATE *(YYMMDD)* AUTOVON
20. OTHER REMARKS *(Cont'd)*		

Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

DOCUMENTATION FOR PRODUCTIVITY CAPITAL INVESTMENT PROGRAMS
For use of this form, see AR 5-4; the proponent agency is OCA.

1. PROJECT NO.

REQUIREMENT CONTROL SYMBOL DD-M(R) 1561

2. TO:	3. THRU:	4. FROM:	5. DOD COMP NAME Army	6. DOD COMP CODE
			7. COMMAND CODE	8. DATE

9. PROJECT TITLE
Add O_2 Analyzers, Bldg. C-1432

10. TYPE OF PROJECT *(Check one)*
☐ QRIP ☐ OSD PIF ☒ PECIP

11. AMORTIZATION YEARS/MONTHS
$ 45,585 *(Project Cost)* ÷ 14,062 *(Average Annual Savings)* × 12 *(No. Mos)*
= 3.2 *(years)* or 38.9 *(months)* *(amortization)*

12. FUNCTIONAL AREA WHERE SAVINGS WILL OCCUR
024 Army Energy Management

13. ECONOMIC LIFE
15 years

14. EXPECTED OPERATIONAL DATE
June 1992

15. SUBMITTING UNIT(S)

16. UNIT ID CODE

17. PROJECT DESCRIPTION
Calibrate combustion controls and add O_2 Analyzers in Building C-1432 to allow more efficient boiler operation by reducing excess air consumed.

18. DETAILED JUSTIFICATION
Currently, the boilers are operated purely by visual and aural observation by the boiler operators. Essentially, the operators are adjusting the fuel/air mixture of the boilers by observing the color of the stack gases and by listening to the boilers. This procedure is generally considered to result in operating with high levels of excess air and test results on these boilers have shown this to be the case in Building C-1432. As a result, the boilers are operating at reduced levels of efficiency and the opportunity exists to save fuel and energy dollars through this investment.

19. SAVINGS DISPOSITION

20. OTHER REMARKS *(Continue on page 5, if more space is needed)*

21a.

SUMMARY OF DOLLAR SAVINGS
(ROUND OFF TO THE NEAREST DOLLAR)

Attach computation sheet identifying the method and source of data for savings

SAVINGS BREAKOUT	PRESENT METHOD	PROPOSED METHOD				DIFFERENCE/SAVINGS			
		1ST YR	2D YR	3D YR	4TH YR	1ST YR	2D YR	3D YR	4TH YR
SALARY/LABOR/ OVERTIME									
MATERIAL/ SUPPLIES									
UTILITIES									
MAINTENANCE/ REPAIR									
TRANSPORTATION									
LEASE COSTS									
SALVAGE/ TURN-IN									
ENERGY *(Identify)* Fuel	$1,673,170	1,659,108				$14,062			
CONTRACT COSTS									
OTHER *(Identify)* ______									
TOTALS									

b. **PRIORITIZATION**

(1) INTERNAL RATE OF RETURN *(IRR)*

Divide estimated project cost 45,585 by average annual savings 14,062 = 3.2 factor.

Based on factor and number of years economic life of the project, select the IRR from Table H-3, App H, Ch. 5, AR 5-4 = 35 % IRR.

(2) SAVINGS TO INVESTMENT RATIO *(S/I)*

Multiply annual savings 14,062 X discount factor 9.19 = 129,230 and divide by present value of investment *(undiscounted)* 45,585 = 2.83 S/I.

(Based on economic life 15 years, select discount factor from Table H-4, App H, Ch. 5, AR 5-4.

(3) RATE OF INVESTMENT PER MANPOWER SPACE *(RIMS)*

Divide estimated project cost ______ by number of manpower space savings ______ = ______ RIMS.

(Manpower requivalents cannot be used in this computation.)

22. COST FOR PROJECT TO BECOME OPERATIONAL

EQUIPMENT TYPE a	PROPOSED SOURCE OF PROCUREMENT b	UNIT PRICE c	QUANTITY d	TOTAL COST e	APPROPRIATION, BUDGET ACTIVITY OR PROGRAM ELEMENT f	FY FUNDS REQUIRED g
(1) Oxygen Controllers		1,650	3	4,950	OPA	92
(2) Wiring, Conduit, Fittings			1	2,200	OPA	92
(3) O_2 Analyzers		11,215	3	33,645	OPA	92
(4)						
(5)						
(6) TRANSPORTATION *(Equipment delivery)*						
(7) EQUIPMENT MODIFICATION[1]						
(8) EQUIPMENT INSTALLATION		907	3	2,720	OPA	92
(9) MAINTENANCE CONTRACT[2]				2,070	OMA	92
(10) FACILITIES MODIFICATION[3]						
(11) TRAINING						
(12) OTHER *(Specify)*:						
(13) TOTAL REQUIRED FOR PROJECT TO BECOME OPERATIONAL[4]				45,585		
(14) TOTAL AMOUNT OF FUNDING REQUESTED IN THIS PROPOSAL				45,585		
(15) TOTAL AMOUNT OF FUNDING REQUIRED FROM OTHER SOURCE[5]				N/A		
(16) TOTAL *(Sum of (14) + (15) above)*				45,585		

[1] *Not to exceed 10% of equipment cost for QRIP projects.*

[2] *Applicable to OPA QRIP provided cost is included in packaged deal involving one bill for the equipment and initial maintenance.*

[3] *Normally not OPA funded.*

[4] *Used to compute amortization in Item 11.*

[5] *Specify source to include certification that funds are available, if financed from the regular budget:*

Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

23. SUMMARY OF SAVINGS (*MANPOWER AND DOLLARS*)

ITEMS	SAVINGS			REAPPLICATION OF SAVINGS					
				PROGRAM ELEMENT		TDA PARA AND LINE		FUNCTION CODE	
a	NO. MPR OR MHR *b*	TYPE PERS[6] *c*	DOLLARS *d*	*e.* FROM	*f.* TO	*g.* FROM	*h.* TO	*i.* FROM	*j.* TO
(1) REQUIREMENTS AND AUTHORIZATIONS ELIMINATED									
(2) REQUIREMENTS ONLY ELIMINATED									
(3) BORROWED MILITARY MANPOWER RELEASED									
(4) OVERHIRES OR TEMPORARIES TERMINATED									
(5) HOURS OVERTIME ELIMINATED									
(6) MANHOURS SAVED FROM MULTIPLE POSITIONS[7]									
(7) OTHER DOLLAR SAVINGS (*Excluding Manpower*), e.g., CONTRACT COSTS & UTILITIES									
(8)									
(9)									
(10)									
(11) TOTAL DOLLAR SAVINGS									

6 *(1) US Graded*
(2) US Wage Board
(3) DHFN
(4) IHFN
(5) Officer
(6) WO
(7) Enlisted

7 *Reflect specific duties being performed with additional manhours available (equivalent manyears)*

24. REGULATORY APPROVAL/COORDINATION

a. INVESTMENT STATEMENT

This proposal has been reviewed and it cannot be implemented with existing equipment or facilities. This investment is in accordance with established investment planning. The project complies with public laws, OSD policies and regulations, and all other regulatory constraints.

____

(Cite regulatory approvals, e.g., TAGO Control No.) (Ex. New Start, TAGO Approval, etc.)

b. OTHER COORDINATION *(Functional Coordination at local level, e.g., Fac Eng, Log, Pers. etc.)*

____

____

25. SUBMITTED BY *(Typed name, grade and title of Subordinate Command/Agency or Project Initiator)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
26. APPROVAL RECOMMENDED BY *(MACOM/Agency)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
FOR USE BY HQDA ON OSD PIF PROJECTS ONLY		
27. APPROVED BY	SIGNATURE	DATE *(YYMMDD)* AUTOVON

20. OTHER REMARKS *(Cont'd)*

Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

DOCUMENTATION FOR PRODUCTIVITY CAPITAL INVESTMENT PROGRAMS
For use of this form, see AR 5-4; the proponent agency is OCA.

1. PROJECT NO.

REQUIREMENT CONTROL SYMBOL DD-M(R) 1561

2. TO:

3. THRU:

4. FROM:

5. DOD COMP NAME: Army

6. DOD COMP CODE

7. COMMAND CODE

8. DATE

9. PROJECT TITLE

Add O_2 Analyzers to Bldg. D-3529

10. TYPE OF PROJECT (Check one)

☐ ORIP ☐ OSD PIF ☒ PECIP

11. AMORTIZATION YEARS/MONTHS

$ 90,451 (Project Cost) ÷ 30,619 (Average Annual Savings) X 12 (No. Mos)

= 2.95 (years) or 35.4 (months) (amortization)

12. FUNCTIONAL AREA WHERE SAVINGS WILL OCCUR

13. ECONOMIC LIFE

14. EXPECTED OPERATIONAL DATE

15. SUBMITTING UNIT(S)

16. UNIT ID CODE

17. PROJECT DESCRIPTION

Add oxygen analyzers to the boilers in Building D-3529 to allow the operators to operate the boilers more efficiently by manually adjusting the fuel/air mixture to the most efficient level of excess air consumed.

18. DETAILED JUSTIFICATION

(Same Justification as "Add O_2 Analyzers, Bldg. C-1432")

19. SAVINGS DISPOSITION

20. OTHER REMARKS (Continue on page 5, if more space is needed)

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Figure II-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R).

21a.

SUMMARY OF DOLLAR SAVINGS
(ROUND OFF TO THE NEAREST DOLLAR)

Attach computation sheet identifying the method and source of data for savings

SAVINGS BREAKOUT	PRESENT METHOD	PROPOSED METHOD				DIFFERENCE/SAVINGS			
		1ST YR	2D YR	3D YR	4TH YR	1ST YR	2D YR	3D YR	4TH YR
SALARY/LABOR/OVERTIME									
MATERIAL/SUPPLIES									
UTILITIES									
MAINTENANCE/REPAIR									
TRANSPORTATION									
LEASE COSTS									
SALVAGE/TURN-IN									
ENERGY *(Identify)* Fuel	1,340,810	1,310,191				30,619			
CONTRACT COSTS									
OTHER *(Identify)* ______									
TOTALS									

b. PRIORITIZATION

(1) INTERNAL RATE OF RETURN *(IRR)*

Divide estimated project cost 90,451 by average annual savings 30,619 = 2.95 factor.

Based on factor and number of years economic life of the project, select the IRR from Table H-3, App H, Ch. 5, AR 5-4 = 40 % IRR.

(2) SAVINGS TO INVESTMENT RATIO *(S/I)*

Multiply annual savings 30,619 X discount factor 10.01 = 306,496 and divide by present value of investment *(undiscounted)* 90,451 = 3.39 S/I.

(Based on economic life 15 years, select discount factor from Table H-4, App H, Ch. 5, AR 5-4.

(3) RATE OF INVESTMENT PER MANPOWER SPACE *(RIMS)*

Divide estimated project cost ______ by number of manpower space savings ______ = ______ RIMS.

(Manpower requivalents cannot be used in this computation.)

22. COST FOR PROJECT TO PERATIONAL

EQUIPMENT TYPE a	PROPOSED SOURCE OF PROCUREMENT b	UNIT PRICE c	QUANTITY d	TOTAL COST e	APPROPRIATION, BUDGET ACTIVITY OR PROGRAM ELEMENT f	REQUIRED g
(1) O_2 Analyzers		11,215	5	56,073		
(2) O_2 Analyzers		660	5	3,300		
(3)						
(4)						
(5)						
(6) TRANSPORTATION (Equipment delivery)						
(7) EQUIPMENT MODIFICATION[1]						
(8) EQUIPMENT INSTALLATION		6,216	5	31,078		
(9) MAINTENANCE CONTRACT[2]						
(10) FACILITIES MODIFICATION[3]						
(11) TRAINING						
(12) OTHER (Specify):				90,451		
(13) TOTAL REQUIRED FOR PROJECT TO BECOME OPERATIONAL[4]				90,451		
(14) TOTAL AMOUNT OF FUNDING REQUESTED IN THIS PROPOSAL				90,451		
(15) TOTAL AMOUNT OF FUNDING REQUIRED FROM OTHER SOURCE[5]				none		
(16) TOTAL (Sum of (14) + (15) above)				90,451		

[1] *Not to exceed 10% of equipment cost for QRIP projects.*

[2] *Applicable to OPA QRIP provided cost is included in packaged deal involving one bill for the equipment and initial maintenance.*

[3] *Normally not OPA funded.*

[4] *Used to compute amortization in Item 11.*

[5] *Specify source to include certification that funds are available, if financed from the regular budget:*

Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

23. SUMMARY OF SAVINGS (*MANPOWER AND DOLLARS*)

ITEMS	SAVINGS			REAPPLICATION OF SAVINGS					
				PROGRAM ELEMENT		TDA PARA AND LINE		FUNCTION CODE	
a	NO. MPR OR MHR b	TYPE PERS[6] c	DOLLARS d	e. FROM	f. TO	g. FROM	h. TO	i. FROM	j. TO
(1) REQUIREMENTS AND AUTHORIZATIONS ELIMINATED									
(2) REQUIREMENTS ONLY ELIMINATED									
(3) BORROWED MILITARY MANPOWER RELEASED									
(4) OVERHIRES OR TEMPORARIES TERMINATED									
(5) HOURS OVERTIME ELIMINATED									
(6) MANHOURS SAVED FROM MULTIPLE POSITIONS[7]									
(7) OTHER DOLLAR SAVINGS (*Excluding Manpower*), e.g., CONTRACT COSTS & UTILITIES									
(8)									
(9)									
(10)									
(11) TOTAL DOLLAR SAVINGS									

6 *(1) US Graded*
(2) US Wage Board
(3) DHFN
(4) IHFN
(5) Officer
(6) WO
(7) Enlisted

7 *Reflect specific duties being performed with additional manhours available (equivalent manyears)*

Figure . . . Documentation for *Productivity Capital Investment Program (DA Form 5108-R)*—Continued.

24. REGULATORY APPROVAL/COORDINATION

a. INVESTMENT STATEMENT

This proposal has been reviewed and it cannot be implemented with existing equipment or facilities. This investment is in accordance with established investment planning. The project complies with public laws, OSD policies and regulations, and all other regulatory constraints.

______________________________:

(Cite regulatory approvals, e.g., TAGO Control No.) (Ex. New Start, TAGO Approval, etc.)

b. OTHER COORDINATION *(Functional Coordination at local level, e.g., Fac Eng, Log, Pers, etc.)*

____

____

25. SUBMITTED BY *(Typed name, grade and title of Subordinate Command/Agency or Project Initiator)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
26. APPROVAL RECOMMENDED BY *(MACOM/Agency)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON

FOR USE BY HQDA ON OSD PIF PROJECTS ONLY

27. APPROVED BY	SIGNATURE	DATE *(YYMMDD)* AUTOVON

20. OTHER REMARKS *(Cont'd)*

Figure II-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

DOCUMENTATION FOR PRODUCTIVITY CAPITAL INVESTMENT PROGRAMS
For use of this form, see AR 5-4; the proponent agency is OCA.

1. PROJECT NO.

REQUIREMENT CONTROL SYMBOL DD-M(R) 1561

2. TO:

3. THRU:

4. FROM:

5. DOD COMP NAME
Army

6. DOD COMP CODE

7. COMMAND CODE

8. DATE

9. PROJECT TITLE
Add Automatic O_2 Trim
Bldg. D-3529

10. TYPE OF PROJECT *(Check one)*
☐ GRIP ☐ OSD PIF ☒ PECIP

11. AMORTIZATION YEARS/MONTHS
\$ 98,674 *(Project Cost)* ÷ 30,619 *(Average Annual Savings)* X 12 *(No. Mos)*
= 3.22 *(years)* or 38.7 *(months)* *(amortization)*

12. FUNCTIONAL AREA WHERE SAVINGS WILL OCCUR
024 Army Energy Management

13. ECONOMIC LIFE
15 years

14. EXPECTED OPERATIONAL DATE
June 1992

15. SUBMITTING UNIT(S)

16. UNIT ID CODE

17. PROJECT DESCRIPTION
Add automatic oxygen trim to the boilers in Building D-3529 to allow more efficient boiler operation by reducing excess air consumed.

18. DETAILED JUSTIFICATION
(Same Justification as "Add O_2 Analyzers, Bldg. C-1432")

19. SAVINGS DISPOSITION

20. OTHER REMARKS *(Continue on page 5, if more space is needed)*

21a.

SUMMARY OF DOLLAR SAVINGS
(ROUND OFF TO THE NEAREST DOLLAR)

Attach computation sheet identifying the method and source of data for savings

SAVINGS BREAKOUT	PRESENT METHOD	PROPOSED METHOD				DIFFERENCE/SAVINGS			
		1ST YR	2D YR	3D YR	4TH YR	1ST YR	2D YR	3D YR	4TH YR
SALARY/LABOR/ OVERTIME									
MATERIAL/ SUPPLIES									
UTILITIES									
MAINTENANCE/ REPAIR									
TRANSPORTATION									
LEASE COSTS									
SALVAGE/ TURN-IN									
ENERGY *(Identify)* Fuel	1,340,810	1,310,191				30,619			
CONTRACT COSTS									
OTHER *(Identify)*									
TOTALS									

b. **PRIORITIZATION**

(1) INTERNAL RATE OF RETURN *(IRR)*

Divide estimated project cost 98,674 by average annual savings 30,619 = 3.22 factor.

Based on factor and number of years economic life of the project, select the IRR from Table H-3, App H, Ch. 5, AR 5-4 = 35 % IRR.

(2) SAVINGS TO INVESTMENT RATIO *(S/I)*

Multiply annual savings 30,619 X discount factor 10.01 = 306,496 and divide by present value of investment *(undiscounted)* 98,674 = 3.1 S/I.

(Based on economic life 15 years, select discount factor from Table H-4, App H, Ch. 5, AR 5-4.

(3) RATE OF INVESTMENT PER MANPOWER SPACE *(RIMS)*

Divide estimated project cost ______ by number of manpower space savings ______ = ______ RIMS.

(Manpower requivalents cannot be used in this computation.)

22. COST FOR PROJECT TO BECOME OPERATIONAL

EQUIPMENT TYPE a	PROPOSED SOURCE OF PROCUREMENT b	UNIT PRICE c	QUANTITY d	TOTAL COST e	APPROPRIATION, BUDGET ACTIVITY OR PROGRAM ELEMENT f	FY FUNDS REQUIRED g
(1) O_2 Analyzers		11,215	5	56,073	OPA	
(2) O_2 Controllers		1,650	5	8,250	OPA	
(3)						
(4)						
(5)						
(6) TRANSPORTATION *(Equipment delivery)*						
(7) EQUIPMENT MODIFICATION[1]		654	5	3,269	OPA	
(8) EQUIPMENT INSTALLATION		6,216	5	31,082	OPA	
(9) MAINTENANCE CONTRACT[2]						
(10) FACILITIES MODIFICATION[3]						
(11) TRAINING						
(12) OTHER *(Specify)*:						
(13) TOTAL REQUIRED FOR PROJECT TO BECOME OPERATIONAL[4]				98,674	OPA	
(14) TOTAL AMOUNT OF FUNDING REQUESTED IN THIS PROPOSAL				98,674		
(15) TOTAL AMOUNT OF FUNDING REQUIRED FROM OTHER SOURCE[5]				none		
(16) TOTAL *(Sum of (14) + (15) above)*				98,674		

[1] *Not to exceed 10% of equipment cost for QRIP projects.*

[2] *Applicable to OPA QRIP provided cost is included in packaged deal involving one bill for the equipment and initial maintenance.*

[3] *Normally not OPA funded.*

[4] *Used to compute amortization in Item 11.*

[5] *Specify source to include certification that funds are available, if financed from the regular budget:*

Figure H-1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

23. SUMMARY OF SAVINGS *(MANPOWER AND DOLLARS)*

ITEMS	SAVINGS			REAPPLICATION OF SAVINGS					
	NO. MPR OR MHR	TYPE PERS[6]	DOLLARS	PROGRAM ELEMENT		TDA PARA AND LINE		FUNCTION CODE	
a	b	c	d	e. FROM	f. TO	g. FROM	h. TO	i. FROM	j. TO
(1) REQUIREMENTS AND AUTHORIZATIONS ELIMINATED									
(2) REQUIREMENTS ONLY ELIMINATED									
(3) BORROWED MILITARY MANPOWER RELEASED									
(4) OVERHIRES OR TEMPORARIES TERMINATED									
(5) HOURS OVERTIME ELIMINATED									
(6) MANHOURS SAVED FROM MULTIPLE POSITIONS[7]									
(7) OTHER DOLLAR SAVINGS *(Excluding Manpower), e.g.,* CONTRACT COSTS & UTILITIES									
(8)									
(9)									
(10)									
(11) TOTAL DOLLAR SAVINGS									

[6] *(1) US Graded*
(2) US Wage Board
(3) DHFN
(4) IHFN
(5) Officer
(6) WO
(7) Enlisted

[7] *Reflect specific duties being performed with additional manhours available (equivalent manyears)*

24. REGULATORY APPROVAL/COORDINATION		
a. **INVESTMENT STATEMENT** This proposal has been reviewed and it cannot be implemented with existing equipment or facilities. This investment is in accordance with established investment planning. The project complies with public laws, OSD policies and regulations, and all other regulatory constraints. ______________________________ : *(Cite regulatory approvals, e.g., TAGO Control No.) (Ex. New Start, TAGO Approval, etc.)*		
b. OTHER COORDINATION *(Functional Coordination at local level, e.g., Fac Eng, Log, Pers, etc.)* ______________________________ ______________________________		
25. SUBMITTED BY *(Typed name, grade and title of Subordinate Command/Agency or Project Initiator)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
26. APPROVAL RECOMMENDED BY *(MACOM/Agency)*	SIGNATURE	DATE *(YYMMDD)* AUTOVON
FOR USE BY HQDA ON OSD PIF PROJECTS ONLY		
27. APPROVED BY	SIGNATURE	DATE *(YYMMDD)* AUTOVON
20. OTHER REMARKS *(Cont'd)*		

Figure H–1. Documentation for Productivity Capital Investment Program (DA Form 5108-R)—Continued.

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft. Bragg REGION NO. 4 PROJECT NUMBER ____________

PROJECT TITLE Bldg. C-1432 FISCAL YEAR ____________

DISCRETE PORTION NAME Steam vs. Electricity For Aux. Equipment Dri

ANALYSIS DATE 12/30/90 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   A. CONSTRUCTION COST $ 0
   B. SIOH $ |
   C. DESIGN COST $ |
   D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ |
   E. SALVAGE VALUE OF EXISTING EQUIPMENT $ |
   F. TOTAL INVESTMENT (1D-1E) $ 0

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$23050	9.19	$ 211,830
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$23,050		$ 211,830

3. NON ENERGY SAVINGS (+) / COST (-)
   A. ANNUAL RECURRING (+/-) $ 0
      (1) DISCOUNT FACTOR (TABLE 1) ______
      (2) DISCOUNTED SAVING/COST (3A X 3A1) $ 0

   B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$ 0

   C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ 0

   D. PROJECT NON ENERGY QUALIFICATION TEST
   (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 69,904
      a. IF 3D1 IS = OR > 3C GO TO ITEM 4
      b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ______
      c. IF 3D1b IS = > 1 GO TO ITEM 4
      d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 23,050

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 211,830

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= ∞

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft. Bragg REGION NO. 4 PROJECT NUMBER ________

PROJECT TITLE Bldg. C-1432 FISCAL YEAR ________

DISCRETE PORTION NAME By-Pass Air Heater

ANALYSIS DATE 1/7/91 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   - A. CONSTRUCTION COST $ 13,000
   - B. SIOH $ 715
   - C. DESIGN COST $ 780
   - D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 13,046
   - E. SALVAGE VALUE OF EXISTING EQUIPMENT $ ________
   - F. TOTAL INVESTMENT (1D-1E) $ 13,046

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$ 18608	9.19	$ 171,008
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$ 18,608		$ 171,008

3. NON ENERGY SAVINGS (+) / COST (-)
   - A. ANNUAL RECURRING (+/-) $ 0
     - (1) DISCOUNT FACTOR (TABLE 1) ________
     - (2) DISCOUNTED SAVING/COST (3A X 3A1) $ 0
   - B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$

   - C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ 0
   - D. PROJECT NON ENERGY QUALIFICATION TEST
     - (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 56,433
       - a. IF 3D1 IS = OR > 3C GO TO ITEM 4
       - b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ________
       - c. IF 3D1b IS = > 1 GO TO ITEM 4
       - d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 18,608

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 171,008

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 13.1

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft. Bragg REGION NO. 4 PROJECT NUMBER ______

PROJECT TITLE Study Bldg. C-1432 FISCAL YEAR ______

DISCRETE PORTION NAME Replace Combustion Controls & Add O2 Trim

ANALYSIS DATE 12/90 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   - A. CONSTRUCTION COST $ 301,956
   - B. SIOH $ 16,608
   - C. DESIGN COST $ 18,117
   - D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 303,013
   - E. SALVAGE VALUE OF EXISTING EQUIPMENT $ –
   - F. TOTAL INVESTMENT (1D-1E) $ 303,013

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$		$
B. DIST	$		$		$
C. RESID	$		$ 4238	13.25	$ 56,154
D. NG	$		$ 10,419	10.01	$ 104,294
E. COAL	$		$		$
F. TOTAL			$ 14,657		$ 160,448

3. NON ENERGY SAVINGS (+) / COST (-)
   - A. ANNUAL RECURRING (+/-) $ -1723
     - (1) DISCOUNT FACTOR (TABLE 1) 9.11
     - (2) DISCOUNTED SAVING/COST (3A X 3A1) $ -15,697
   - B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$

   - C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Ba4) $ -15,697
   - D. PROJECT NON ENERGY QUALIFICATION TEST
     - (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 52,948
       - a. IF 3D1 IS = OR > 3C GO TO ITEM 4
       - b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ______
       - c. IF 3D1b IS = > 1 GO TO ITEM 4
       - d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ -1040

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 144,751

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 0.48

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft. Bragg REGION NO. 4 PROJECT NUMBER ____________

PROJECT TITLE Bldg. C-1432 FISCAL YEAR ____________

DISCRETE PORTION NAME Calibrate Combustion Controls And Provide O_2 Analyzer

ANALYSIS DATE 1/7/91 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   A. CONSTRUCTION COST $ 45,585
   B. SIOH $ N/A
   C. DESIGN COST $ N/A
   D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 41,027
   E. SALVAGE VALUE OF EXISTING EQUIPMENT $ N/A
   F. TOTAL INVESTMENT (1D-1E) $ 41,027

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$14 062	9.19	$129,230
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL			$14 062		$129,230

3. NON ENERGY SAVINGS (+) / COST (-)
   A. ANNUAL RECURRING (+/-) $ -345
      (1) DISCOUNT FACTOR (TABLE 1) 9.11
      (2) DISCOUNTED SAVING/COST (3A X 3A1) $ -3140

   B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$ 0

   C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Ba4) $ 0

   D. PROJECT NON ENERGY QUALIFICATION TEST
   (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 42,645
      a. IF 3D1 IS = OR > 3C GO TO ITEM 4
      b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ______
      c. IF 3D1b IS = > 1 GO TO ITEM 4
      d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $13717

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $129,230

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 3.15

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft. Bragg REGION NO.____ PROJECT NUMBER________

PROJECT TITLE Bldg. D-3529 FISCAL YEAR________

DISCRETE PORTION NAME Add O_2 Analyzers

ANALYSIS DATE 1/7/91 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   - A. CONSTRUCTION COST $ 90,451
   - B. SIOH $ N/A
   - C. DESIGN COST $ N/A
   - D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 81,406
   - E. SALVAGE VALUE OF EXISTING EQUIPMENT $____
   - F. TOTAL INVESTMENT (1D-1E) $ 81,406

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST \$/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL \$ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$		$
B. DIST	$		$		$
C. RESID	$		$ 30,154	13.25	$ 399,540
D. NG	$		$ 465	10.01	$ 4,655
E. COAL	$		$		$
F. TOTAL			$ 30,619		$ 404,195

3. NON ENERGY SAVINGS (+) / COST (-)
   - A. ANNUAL RECURRING (+/-) $ -344
     - (1) DISCOUNT FACTOR (TABLE 1) 9.11
     - (2) DISCOUNTED SAVING/COST (3A X 3A1) $ -3137
   - B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS \$ (+) COST \$ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$

   - C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ -3137
   - D. PROJECT NON ENERGY QUALIFICATION TEST
     - (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 133,384
       - a. IF 3D1 IS = OR > 3C GO TO ITEM 4
       - b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ______
       - c. IF 3D1b IS = > 1 GO TO ITEM 4
       - d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 30,275

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 401,058

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 4.9

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft. Bragg REGION NO.____ PROJECT NUMBER________

PROJECT TITLE Bldg. D3529 FISCAL YEAR________

DISCRETE PORTION NAME Add Automatic O2 Trim

ANALYSIS DATE 1/7/91 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   - A. CONSTRUCTION COST $ 98,674
   - B. SIOH $ N/A
   - C. DESIGN COST $ N/A
   - D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 88,806
   - E. SALVAGE VALUE OF EXISTING EQUIPMENT $ –
   - F. TOTAL INVESTMENT (1D-1E) $ 88,806

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$		$		$
B. DIST	$		$		$
C. RESID	$		$ 30,154	13.25	$ 399,540
D. NG	$		$ 465	10.01	$ 4,655
E. COAL	$		$		$
F. TOTAL			$ 30,619		$ 404,195

3. NON ENERGY SAVINGS (+) / COST (-)
   - A. ANNUAL RECURRING (+/-) $ -344
     - (1) DISCOUNT FACTOR (TABLE 1) 9.11
     - (2) DISCOUNTED SAVING/COST (3A X 3A1) $ -3137
   - B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$

   - C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ -3137
   - D. PROJECT NON ENERGY QUALIFICATION TEST
     - (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 133,384
       - a. IF 3D1 IS = OR > 3C GO TO ITEM 4
       - b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ________
       - c. IF 3D1b IS = > 1 GO TO ITEM 4
       - d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 30,275

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 401,058

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 4.5

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft. Bragg REGION NO. 4 PROJECT NUMBER ______

PROJECT TITLE Generic 1500 Ton Plant FISCAL YEAR ______

DISCRETE PORTION NAME Variable Speed Pumping - Chilled Water

ANALYSIS DATE 12/31/90 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   - A. CONSTRUCTION COST $ 75,900
   - B. SIOH $ 4175
   - C. DESIGN COST $ 4554
   - D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 76,166
   - E. SALVAGE VALUE OF EXISTING EQUIPMENT $ ______
   - F. TOTAL INVESTMENT (1D-1E) $ 76,166

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$ 2.58	2832.8	$ 7309	9.19	$ 67,169
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL		2832.8	$ 7309		$ 67,169

3. NON ENERGY SAVINGS (+) / COST (-)
   - A. ANNUAL RECURRING (+/-) $ -100
     - (1) DISCOUNT FACTOR (TABLE 1) 9.11
     - (2) DISCOUNTED SAVING/COST (3A X 3A1) $ -911
   - B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$			$ 0

   - C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ -911
   - D. PROJECT NON ENERGY QUALIFICATION TEST
     (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 22,165
       - a. IF 3D1 IS = OR > 3C GO TO ITEM 4
       - b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = ______
       - c. IF 3D1b IS = > 1 GO TO ITEM 4
       - d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ 7209

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ 66,258

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)= 0.87

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM

LOCATION: Ft. Bragg REGION NO. 4 PROJECT NUMBER ________

PROJECT TITLE Generic 1500 Ton Plant FISCAL YEAR ________

DISCRETE PORTION NAME Free Cooling

ANALYSIS DATE 12/31/90 ECONOMIC LIFE 15 YEARS PREPARED BY RDM

1. INVESTMENT COSTS
   A. CONSTRUCTION COST $ 159,500
   B. SIOH $ 8773
   C. DESIGN COST $ 9570
   D. ENERGY CREDIT CALC (1A+1B+1C)X.9 $ 160,059
   E. SALVAGE VALUE OF EXISTING EQUIPMENT $ 0
   F. TOTAL INVESTMENT (1D-1E) $ 160,059

2. ENERGY SAVINGS (+) / COST (-)
   ANALYSIS DATE ANNUAL SAVINGS, UNIT COST $ DISCOUNTED SAVINGS

FUEL	COST $/MBTU(1)	SAVINGS MBTU/YR(2)	ANNUAL $ SAVINGS(3)	DISCOUNT FACTOR(4)	DISCOUNTED SAVINGS(5)
A. ELEC	$ 2.58	240.5	$ 620.5	9.19	$ 5702
B. DIST	$		$		$
C. RESID	$		$		$
D. NG	$		$		$
E. COAL	$		$		$
F. TOTAL		240.5	$ 620.5		$ 5702

3. NON ENERGY SAVINGS (+) / COST (-)
   A. ANNUAL RECURRING (+/-) $ -600
      (1) DISCOUNT FACTOR (TABLE 1) 9.11
      (2) DISCOUNTED SAVING/COST (3A X 3A1) $ -5466

   B. NON RECURRING SAVINGS (+) / COST (-)

ITEM	SAVINGS $ (+) COST $ (-)(1)	YEAR OF OCCURRENCE(2)	DISCOUNT FACTOR (3)	DISCOUNTED SAVINGS (+) COST(-)(4)
a.	$			$
b.	$			$
c.	$			$
d. TOTAL	$ 0			$ 0

   C. TOTAL NON ENERGY DISCOUNTED SAVINGS (+) / COST (-) (3A2+3Bd4) $ -5466

   D. PROJECT NON ENERGY QUALIFICATION TEST
   (1) 25% MAX NON ENERGY CALC (2F5 X .33) $ 1881
      a. IF 3D1 IS = OR > 3C GO TO ITEM 4
      b. IF 3D1 IS < 3C CALC SIR = (2F5+3D1) ÷ 1F = .047
      c. IF 3D1b IS = > 1 GO TO ITEM 4
      d. IF 3D1b IS < 1 PROJECT DOES NOT QUALIFY

4. FIRST YEAR DOLLAR SAVINGS 2F3+3A+(3B1d ÷ YEARS ECONOMIC LIFE) $ ________

5. TOTAL NET DISCOUNTED SAVINGS (2F5+3C) $ ________

6. SIR (IF < 1 PROJECT DOES NOT QUALIFY) (SIR)=(5 ÷ 1F)=